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Regretting carbon capture from bioenergy – A case study

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ABSTRACT

Both deploying and not deploying carbon capture and storage (CCS) may lead to regret, be it in terms of climate damage, carbon revenues, or sociopolitical impacts. To support robust decision making (RDM) on CCS, our study aims to identify high-regret scenarios of a bioenergy CCS (BECCS) investment decision by E.ON in Malmö, Sweden. Across 1.000.000 input scenarios, regret is quantified as the difference in net present value between deploying amine CCS and three alternative decisions: no CCS, oxyfuel CCS, or chemical-looping CCS. Scenarios of positive regret are thus undesirable and of interest, and were identified using data mining. Amine CCS is regrettable relative to no CCS in 90 % of scenarios if CO_2 removal revenues—excluding subsidies—fall below 220 EUR/tCO_2. Relying on revenues from the European Union Emissions Trading System may only be robust if removals are integrated into the system through public procurement. In revenue scenarios above 285 EUR/tCO_2, amine CCS is robust and the no CCS decision leads to regret in 75 % of cases. Contrastingly, amine CCS leads to regret relative to oxyfuel when oxygen separation is inexpensive, and relative to chemical-looping when its capital cost is not unexpectedly high. Alternative capture technologies could therefore enable low-regret CCS if cost uncertainties were reduced.

1. Introduction

Past carbon capture and storage (CCS) projects have often been abandoned, frequently due to lack of enduring incentives (Martin-Roberts et al., 2021). Today, CCS still faces substantial uncertainty, including technological, economic, political, and social (Mahjour and Faroughi, 2023; Stenström et al., 2024). Yet short-term incentives exist and long-term policies could emerge (Zakkour et al., 2024) to support the CCS upscaling urgently needed for durable net-zero (Kazlou et al., 2024; Fankhauser et al., 2022).

Given these uncertain prospects, decision-makers may regret deploying or not deploying CCS – whether due to climate damage or foregone policy incentives. We therefore see potential in systematically analyzing decision-maker expectations about the future and identifying both high-regret scenarios and low-regret decisions. Such analysis can support robust decision-making (RDM) on CCS, which is the main contribution of this research.

This contribution is particularly relevant as an increasing number of actors are currently committing to CCS. Notable European examples include the Brevik cement CCS project in Norway (Heidelberg Materials, 2025), the Porthos CO_2 transport and storage project in the Netherlands (Porthos, 2025), bioenergy CCS (BECCS) projects at the Asnæs and Avedøre plants in Denmark (Ørsted 2025), the Net Zero Teesside gas-power CCS project in the UK (Net Zero Teesside, 2025), and Stockholm Exergi's BECCS project in Sweden (Stockholm Exergi AB, 2025).

By applying RDM theory (Lempert, 2019) we have previously studied the BECCS project of Stockholm Exergi (Stenström et al., 2024), who made their final investment decision in 2025. In Stenström et al. (2025) we conducted a similar analysis of 113 potential BECCS projects in Sweden. In the present work, we illustrate how the RDM can be applied to a new BECCS case, as detailed in the methodology section. We focus on regret as a conceptual tool, on the choice of CO2 capture technology, and on future scenarios of European Union (EU) policy incentives.

The case concerns BECCS at a planned combined heat and power (CHP) plant being developed by E.ON in Malmö, Sweden. Realizing this BECCS project would contribute by around 270 ktCO_2 p.a. towards the Swedish indicative target of 3–10 Mt p.a. by 2045 (Rodriguez, 2024). It could also contribute to EU-level targets, for which some modeled

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Nomenclature

ASU	Air Separation Unit
BECCS	Bioenergy with Carbon Capture and Storage
CAPEX	Capital expenditures
CART	Classification And Regression Trees
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilization
CDR	Carbon Dixode Removal
CFB	Circulating Fluidized Bed
CEPCI	Chemical Engineering Plant Cost Index
CHP	Combined Heat and Power
CRC	Carbon Removal Credit
DR	Discount Rate
EPC	Engineering, Procurement, and Construction
ETS	Emissions Trading System
HEX	Heat Exchanger
LHV	Lower Heating Value
NPV	Net Present Value
OPEX	Operational expenditures
RDM	Robust Decision Making
TRL	Technology Readiness Level

scenarios estimate combined BECCS and DACCS deployment in the range of 178–486 $MtCO_2$ p.a. by 2050 (Pu Yang et al., 2024). While our practical findings are mostly relevant to BECCS and CHP in a Nordic and European context, our methodology could be usefully applied to CCS projects beyond this context. We do not address carbon capture and utilization (CCU), as its climate mitigation potential is small compared to CCS (Mac Dowell et al., 2017).

E.ON – the decision-maker of interest – is planning to replace decommissioned district heating capacity with a new, biomass-fired, 175 MWth CHP plant. District heating is common in Swedish cities. The heat is typically supplied by centralized woodchip- or waste-fired CHP plants, or large-scale heat pumps, and distributed via underground piping networks using water as heat carrier (Beiron, 2022).

As implied, E.ON is also preparing for a delayed CCS investment following the CHP investment in 2028. An amine-based capture technology has already been specified and is the main CO_2 capture technology considered, owing to its maturity and compatibility with the planned circulating fluidized bed (CFB) boiler (Ramboll, 2023). Oxyfuel combustion, another mature capture technology, is also under consideration. Although relatively immature, we also study chemical-looping combustion due to its theoretically low costs and energy penalty (Lyngfelt et al., 2019). These three technologies were chosen for comparison since they were of interest to E.ON and were included in Ramboll's (2023) initial technology screening study. Out of the different capture technologies (including various post-combustion types) the screening study proposed a post-combustion amine design, which is why it is considered the baseline choice for E.ON. We note that CO_2 transport and storage infrastructure is also within our study's scope, but its layout (and therefore costs) would be similar indifferently to the capture technology choice.

We will now define regret in the context of E.ON's BECCS project. Within RDM, regret is typically a performance metric derived from deliberation with decision-makers. The RDM methodology is both participatory and iterative, inviting decision-makers into the quantitative analysis (Lempert, 2019; Workman et al., 2024). We therefore consulted E.ON representatives on multiple occasions throughout 2025 to frame their decision situation, important scenarios, and performance metrics. We could then commit to three regret-based metrics. While E. ON also has non-economic interests, the chosen metrics are economic and based on the net present value (NPV) of alternative decisions, shown in Eqs. (1) through (3).

$$regret_{no\ ccs} = NPV_{no\ ccs} - NPV_{amine} \tag{1}$$

$$regret_{oxy} = NPV_{oxy} - NPV_{amine} \tag{2}$$

$$regret_{clc} = NPV_{clc} - NPV_{amine} \tag{3}$$

Here, regret quantifies the NPV difference between deploying amine CCS and three alternative decisions: no CCS, oxyfuel CCS, or chemical-looping CCS. These alternatives and scenarios are detailed later. Notably, if regret is positive in a scenario, then the amine CCS decision performs relatively poorly in NPV terms. Furthermore, when discussing regret in relation to scenarios we use the following terms:

- Regrettable – a scenario with positive regret.
- Density – the ratio of regrettable scenarios to total number of scenarios.
- Robust – a decision with negative regret across most scenarios is robust (and has low density).

Taken together, these RDM concepts provide tools for identifying high-regret scenarios and low-regret decisions. This is useful since it provides decision makers with greater confidence when making decisions under uncertainty (Lempert, 2019). For example, we may identify scenarios that should be avoided for E.ON to commit to their BECCS investment, or we may quantify the regret associated with not investing.

We now specify our research aims and questions. Given the uncertainties and urgency of CCS upscaling, our general aim is to support robust decision-making on CCS. More specifically, we aim to systematically analyze high-regret scenarios when deploying amine CCS and discuss the relative importance of policy incentives and the choice of capture technology. The scenarios also include system shocks, like electricity and biomass shortages. We use the BECCS project of E.ON as our case study. Our research questions correspond to our three regret metrics:

1. Under what conditions would deploying amine CCS lead to regret, relative to not deploying CCS?
2. Under what conditions would deploying amine CCS lead to regret, relative to oxyfuel CCS?
3. Under what conditions would deploying amine CCS lead to regret, relative to chemical-looping CCS?

The rest of the article is structured as follows. We first provide background on CO_2 capture technologies and on emerging policy incentives relevant to European BECCS. Then, we describe our three-step methodology: the framing and sampling of model inputs, the exploration of model outputs, and the search for regrettable scenarios through sensitivity analysis and data mining. We then illustrate results separately for our three research questions. Finally, we conclude with a discussion of our findings.

2. Background

This section elaborates on the studied CO_2 capture technologies and on emerging policy incentives for BECCS.

2.1. Capturing CO_2 using amine and oxyfuel technologies

As mentioned, two mature CO_2 capture technologies are considered in this study: amines and oxyfuel combustion. Below, we will describe general aspects of these technologies. For more details, we refer readers to Bui et al. (2018).

Amine capture is a post-combustion process, meaning it is designed to separate CO_2 from flue gases downstream of a combustion process –

here, CFB combustion of solid biomass using air as oxidizing agent. During the capture process, an amine solvent absorbs CO_2 from flue gases and is then regenerated in a stripper column using steam. In addition to steam, power is typically needed for CFB fans and subsequent CO_2 compression and liquefaction.

It is possible to reduce the overall energy penalty of amine capture, especially in a CHP context where heat can be recovered and supplied as profitable district heating (Roshan Kumar et al., 2023). For E.ON, heat exchangers, heat pumps, and flue gas condensation can be leveraged to achieve a total CHP efficiency of 98 % based on the lower heating value (LHV) of the input fuel (if calculating based on higher heating value, the efficiency would be lower). The drawback is a reduced electrical efficiency, from 28 % in the no CCS case to 18 % in the heat integrated amine case (Ramboll, 2023).

Oxyfuel capture, the other mature technology considered, uses pure O_2 supplied by a cryogenic air separation unit (ASU) instead of air for combustion. The N_2 content in the flue gas stream is therefore minimized, resulting in no significant energy demand for separating CO2. However, the ASU demands around 230 kWh/tO_2 separated (Farajollahi and Hossainpour, 2022). And, like amine capture, power is also needed for CFB fans and CO_2 compression and liquefaction.

For the E.ON case, the overall energy balances and thus operational expenditures (OPEX) can be expected to be similar between amine and oxyfuel capture. Contrastingly, capital expenditures (CAPEX) may differ, as amines require a dedicated capture plant whereas oxyfuel requires the ASU.

2.2. Capturing CO_2 using chemical-looping combustion

Another option for CO_2 capture is the relatively immature technology chemical-looping combustion, which is at an estimated technology readiness level (TRL) of 6, using the EU TRL scale. Contrastingly, amines and oxyfuel are at TRL 9 and 7, respectively (Bui et al., 2018). The motivation for studying chemical-looping is its theoretically low energy penalty and CAPEX (Lyngfelt and Leckner, 2015) and thus its potential relevance to E.ON and other CCS developers. Accordingly, proponents of chemical-looping combustion have argued that the technology could reduce economic risk when considering investments in BECCS deployment (Lyngfelt et al., 2022). Below, we provide background on a proposed process design from the literature, which underpins the model in the methodology section.

During chemical-looping combustion, chemically active solid metal oxides – known as oxygen carriers – are used as bed material in a fluidized-bed fuel reactor. These oxygen carriers continuously oxidize the fuel and are then circulated to a separate air reactor, where new O_2 is supplied from intake air. In the air reactor, the oxygen carriers are thus re-oxidized before circulating back to the fuel reactor. This closed loop ensures that fuel and air never mix, and that the fuel reactor flue gases are not diluted by N2, thus avoiding energy-intensive CO_2 separation.

Compared to conventional combustion plants, the additional energy penalty of this capture process could principally be zero, if disregarding the work for circulating oxygen carriers and compression and transport of CO_2. However, it is not yet a commercially available technology and additional engineering efforts would be needed to separate fuel and air reactors, maximize fuel conversion in the fuel reactor, and design adequate flue-gas cleaning system. Respectively, the reactions in fuel and air reactors follow Eqs. (4) and (5), and summarize to (6) (Rydén et al., 2014).

$$C_nH_m + (2n+1/2m)MeO_x \rightarrow nCO_2 + (1/2m)H_2O + (2n+1/2m)MeO_{x-1} \quad (4)$$

$$MeO_{x-1} + 1/2O_2 \rightarrow MeO_x \quad (5)$$

$$C_nH_m + (n+1/4m)O_2 \rightarrow nCO_2 + (1/2m)H_2O \quad (6)$$

Proposals for chemical-looping plant designs have commonly been derived directly from the design of current CFB boilers (Lyngfelt et al., 2001). Both designs would utilize the same bed-material size (0.1–0.3 mm), although for chemical-looping the material would need oxygen carrying properties, such as iron or ilmenite ore. Both designs would utilize similar temperature levels (800–1000 °C) and the same air and flue gas velocities. However, the following major changes are needed (Lyngfelt and Leckner, 2015):

- The CFB furnace needs to be divided into two separate but interconnected sections, i.e. the air reactor and fuel reactor of chemical-looping.
- The CFB convection section needs to be divided into two parts, one for the air reactor and one for the fuel reactor. The fuel reactor would typically be adiabatic and thus relatively inexpensive.
- Furthermore, the conventional bed material, usually silica sand in biomass and waste incineration, needs to be replaced with oxygen-carrier particles. Cheap and readily available transition-metal ores, such as iron ore or by-products from metallurgical industries, will most likely suffice as oxygen carrier.

Notably, these changes are not expected to alter the total size, cross section or height of the boiler, or the total heat transfer area of the convection section, or (to a significant degree) the technological complexity level. Thus, fully developed, a chemical-looping boiler is not expected to have larger CAPEX or larger footprint than the corresponding CFB boiler – unless its design includes flexibility measures, as discussed below. CAPEX could even be reduced, as discussed in Lyngfelt & Leckner (2015).

In this study, we assume that E.ON could choose to build a flexible chemical-looping combustion plant. The idea is that this plant could first be operated as a regular CFB plant and subsequently as a chemical-looping plant, after minor modifications. The plant would be similar to e.g. the semi-commercial plant Chalmers Power Central, located at the campus of Chalmers University of Technology, Göteborg, Sweden. The Chalmers plant was originally built as a regular CFB boiler. Later, an additional fuel reactor separate from the regular CFB was installed, utilizing the same solids circulation loop. The plant can be operated either as a conventional 12 MWth CFB plant, or as a 2–4 MWth chemical-looping gasification plant (Berdugo Vilches et al., 2017). Switching between the modes of operation can be done in a day.

Similarly, we here assume that E.ON could initially build a conventional CFB boiler, and prepare the boiler for a future investment and retrofit of chemical-looping components. These components include: an additional fuel reactor; cyclones; an oxygen polishing chamber to oxidize unconverted volatile fuel species from the fuel reactor (typically around 10% of total fuel flow for biomass); an ASU to provide oxygen to the oxygen polishing chamber; a second convection section for heat recovery; and CO_2 compression and liquefaction equipment (cf. Lyngfelt and Leckner, 2015; Farajollahi and Hossainpour, 2022). Once retrofitted, fuel would be combusted in the fuel reactor while air is supplied to the original CFB – now functioning as the air reactor. Oxygen carriers would circulate between the two, enabling chemical-looping combustion and CO_2 separation without significant energy penalty.

Notably, it is not the purpose of this paper to examine the precise engineering of this chemical-looping design, for example how heat transfer equipment is configured or how gas velocities are maintained. Instead, we will assume that the design is doable, similar to the Chalmers plant, at an assumed cost. The case has been included to examine if a solution like this could reduce the risk of regret during early BECCS deployment projects. Owing to the low TRL and uncertainties of the studied design, additional cost factors will be introduced in the methodology section.

2.3. Emerging policy incentives for BECCS

With the capture technologies described, we now elaborate on emerging policy incentives for deploying these technologies and for subsequent CO_2 transport and storage, i.e., for complete BECCS projects delivering megatons of stored CO_2. Under EU regulation, each such ton could be commodified as a certified carbon removal credit (Schenuit et al., 2023), which we will refer to as CRC. Below, we describe three levels of policy incentives involving CRCs, ordered by increasing coerciveness: (1) voluntary and state-aid incentives, (2) CRC integration into emissions compliance markets, and (3) quota obligations.

Firstly, corporates may voluntarily purchase CRCs delivered by E.ON in pursuit of net zero targets, for example to offset hard-to-abate emissions. To complement this (uncertain) source of revenue, Swedish BECCS developers have sought co-financing through state subsidies distributed via reverse auctions (Fridahl et al., 2024). This type of co-financing could be problematic depending on whether it reduces overall decarbonization efforts, thus undermining environmental integrity (Dufour et al., 2024). A debated case is Stockholm Exergi, who secured voluntary CRC contracts before securing a reverse auction subsidy of approximately 160 EUR/tCO_2 (cf. Stockholm Exergi, 2025). While we consider the integrity of co-financing models to be important, we cannot assess it in this study, and will assume E.ON could profit from *some* type of voluntary CRC revenues combined with reverse auction subsidies.

Alternatively, CRCs from BECCS and other CO_2 removal methods could be integrated into the EU Emissions Trading System (ETS). As the ETS cap is approaching zero, some hard-to-abate emissions may be cheaper to offset by CO_2 removal than to eliminate, thus motivating the CRC integration (Sultani et al., 2024). Integration could also help stabilize ETS prices and enable a net-negative emissions cap (Fridahl et al., 2023). Direct and unconstrained CRC integration could be possible, potentially linking the ETS and CRC prices (Sultani et al., 2024). Alternatively, a centralized EU institution could procure CRCs in anticipation of future demand, and later release them into the ETS to stabilize future prices within some politically determined price corridor (Rickels et al., 2022). This and other CRC purchasing programs were under consideration in recent consultation sessions initiated by the EU Directorate-General for Climate Action (European Commission, 2025) but have yet to be institutionalized. Still, E.ON may anticipate some type of EU-level incentive.

Finally, hard-to-abate emitters such as aviation, waste, or agriculture could be mandated to purchase CRC credits from BECCS (Zetterberg et al., 2021). Alternatively, fossil fuel extractors could be obliged to store CO_2 in proportion to the fossil carbon they extract, thus securing net zero targets (Jenkins et al., 2023). The obligation would be fulfilled no matter the origin of the CO2, thus providing an incentive for BECCS. Such CO_2 storage obligations could be further discussed as they hold substantial mitigation potential (Zakkour et al., 2024) and have gained some recent support in the EU Net-Zero Industry Act (European Commission, 2025) but will not be modelled in this study.

3. Methodology

Since the studied capture technologies and policy incentives have now been introduced, we can describe our RDM methodology. RDM typically involves framing, exploring and choosing decisions of interest, based on modelling and stakeholder deliberation (Lempert, 2019). As mentioned, the model was framed by consulting E.ON representatives and by analysis of published feasibility studies of their BECCS project (Ramboll, 2023). The process was iterative and is illustrated in Fig. 1. Importantly, we frame the decision in line with our research questions: the decision-maker may regret amine CCS compared to never deploying CCS, or compared to oxyfuel or chemical-looping CCS. We will identify

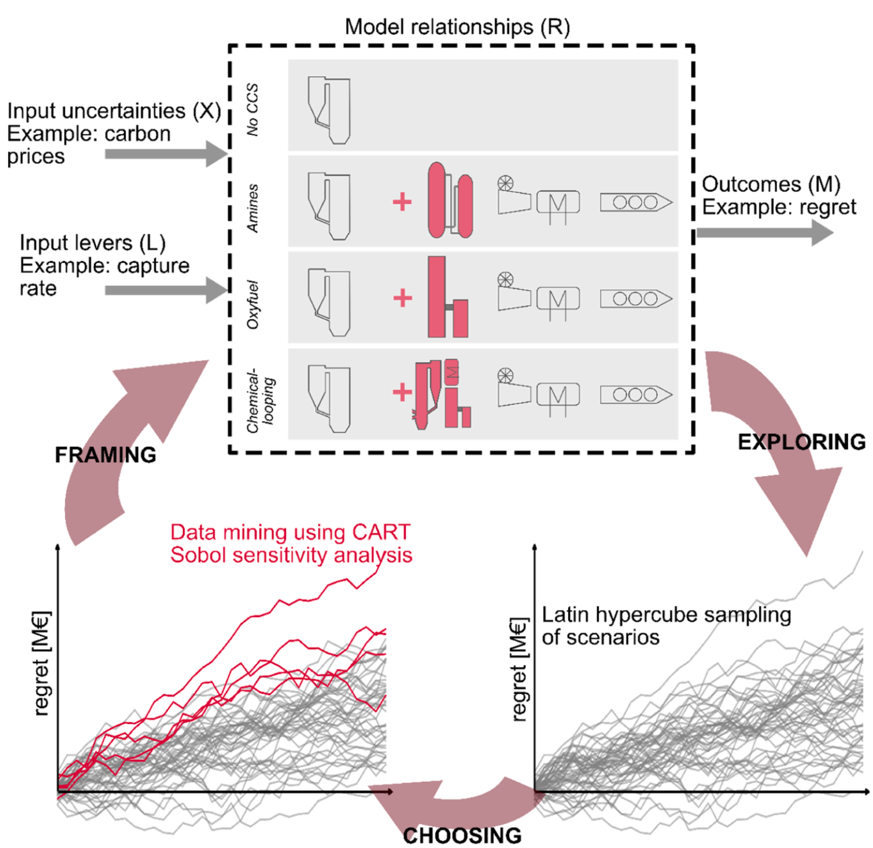

Fig. 1. The CCS deployment decision was framed using an XLRM framework. The decision was then explored across many modelled scenarios, and key scenarios were identified using sensitivity and data mining analysis. This process was iterative.

conditions that lead to high-regret scenarios.

In Fig. 1, the framed decision is organized in an XLRM framework. The framework is commonly used within RDM to organize key elements of the analysis, including what model is used and its inputs and outputs. X and L represent uncertainties and decision levers, which are inputs. R is the model. The idea is to explore regret – the model outcome M – across many scenarios. Here, a scenario is a specific combination of levers, such as CO_2 capture technologies and investment timings, and uncertainties, like electricity and carbon prices. The modelled scenarios can then be analyzed using Sobol sensitivity and Classification and Regression Trees (CART) algorithms, aiming to identify high-regret scenarios. The model is written in Python, relies extensively on the EMA Workbench (Kwakkel, 2017), and is available on GitHub (Stenström, 2025). Modelling details are specified in the following sections.

3.1. Framing the investment decision model

Our model evaluates four decisions available to E.ON, here named after the respective capture technology deployed: amines, oxyfuel, chemical-looping, and no CCS, where CO_2 is never captured. These are illustrated in Fig. 2, along with their respective definitions of regret. The timing of investments is also illustrated. Since all decisions entail a boiler investment in 2028, the CAPEX of the boiler has no impact on regret and is therefore set to zero. Accordingly, any delayed investments in CCS equipment are additional to the boiler. This delayed equipment includes alternative capture technologies, marked in red, and CO_2 compression, liquefaction, transport, and storage infrastructure. Investments in CCS would occur later in time, whenever E.ON decides to deploy CCS. We explore investment delays of 5, 10, 15, and 20 years after 2028.

As the performance metric of the model is regret, see Eqs. (1) through (3), the NPV of each decision must be calculated. We use Eq. (7), where t is the year, $t_{lifetime}$ is the economic lifetime, and DR is the discount rate.

$$NPV = \sum_{t=0}^{t_{lifetime}} \frac{revenues(t) - costs(t)}{(1 + DR)^t} \tag{7}$$

The revenues include sold heat, power, and potential CRC revenues. Heat and power balances were estimated for each capture technology based on Ramboll (2023) and are displayed in Table 1, along with assumptions on fuel inputs and loads from CCS equipment. Any energy penalties were accounted for as foregone (negative) revenues relative to the no CCS case. However, scenarios of CRC and energy revenues will be detailed in the following section.

Table 1
Assumptions related to energy balances.

Parameter	Value	Unit	Reference/comment
Biomass input*			
LHV	10.44	MJ/kg	Ramboll (2023)
Heat input (LHV)	174	MW	Ramboll (2023)
Full load hours**	4500	h/yr	Ramboll (2023)
Loads from CCS equipment			
Heat reboiler	2.24	MJ/kgCO2	Ramboll (2023)
Work ASU	828	MJ/tO2	Farajollahi & Hossainpour (2022)
Work compression and liquefaction	0.43	MW/(kgCO2/s)	Deng et al. (2019)
CHP output***			
Power - no CCS	48	MW	Ramboll (2023)
Heat - no CCS	140	MW	Ramboll (2023)
Power - amines	32	MW	Ramboll (2023)
Heat - amines	140	MW	Ramboll (2023)
Power - oxyfuel	31	MW	*Calculated*
Heat - oxyfuel	140	MW	*Calculated*
Power - chemical-looping	41	MW	*Calculated*
Heat - chemical-looping	140	MW	*Calculated*

* Fuel composition taken from Fortet Casabella & Chehade (2023).
** The plant can only operate at full load when there is district heating demand, i.e., during colder months of the year.
*** Outputs are displayed for 90 % capture rate, while 86–94 % were explored. Heat values include steam condensation, recovered heat, and flue gas condensation for district heating.

Notably, the CO_2 capture rate is assumed to be the same across all capture technologies. This was done to simplify the comparison between the technologies. However, in practice, we recognize that oxyfuel and chemical-looping could easily achieve higher capture rates than amines. This represents a limitation of our method for comparing technology performance, but ensures that the volumes of captured CO_2 remain constant in each scenario across all technologies.

3.2. Exploring scenarios of costs, revenues, and shocks

In this section we describe scenario-dependent assumptions on costs, revenues, and possible system shocks that could lead to regret. All

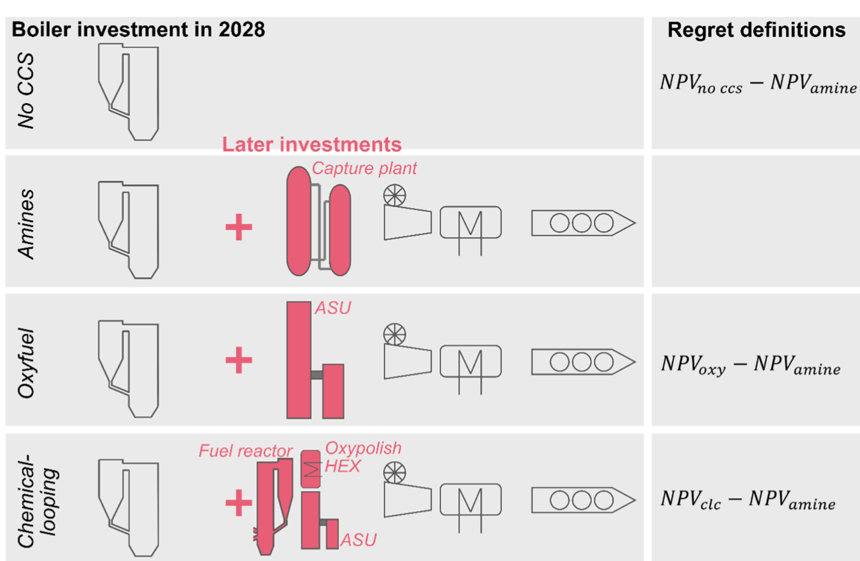

Fig. 2. The alternative decisions studied. In the no CCS case, no carbon capture equipment is deployed. The other decisions involve investments in CCS later in time. Major CAPEX equipment that differ between decisions are highlighted in red.

numerical values are specified at the end of the section.

Considering costs, the main CAPEX differences between the modelled decisions were illustrated in red in Fig. 2. Amines require a capture plant, oxyfuel requires an ASU, and chemical-looping requires a fuel reactor, cyclones, an oxygen polish chamber, ASU, and other minor auxiliary equipment. To estimate a base CAPEX of these items, cost functions from Farajollahi & Hossainpour (2022) and Deng et al. (2019) were applied. Eq. (8) exemplifies the general form of these cost functions, focusing on the ASU. Here, the constant α is multiplied by the oxygen mass flow, $\dot{m}_{O2}$, raised to an exponent β to estimate the base ASU CAPEX.

$$CAPEX_{ASU} = \propto \cdot \dot{m}_{O2}{}^{\beta} \tag{8}$$

All cost functions are further detailed in Appendix A. An exception is the amine CAPEX, which does not rely on a cost function as it was taken directly from Ramboll (2023). As mentioned, the no CCS case is assumed to have zero CAPEX, as any CCS investments are additional to the no CCS case.

Typically, base CAPEX estimates are escalated using cost factors and allocated depending on plant outputs, project contingencies, technology maturity etc. Useful guidelines can be found in Ali et al. (2019) and Roussanaly et al. (2021). We followed a similar procedure to Ali et al. but modified to align with the cost methodology of Ramboll (2023). Practically speaking, we applied an engineering, procurement, and construction (EPC) cost factor to our base CAPEX estimates. We then applied a common project and technology contingency factor, and an additional factor for owner's cost of capital. See Appendix A for details.

However, beyond such cost estimates, early Nordic CCS projects have faced significant cost overruns, as described in Beiron & Johnsson (2024). They report overrun factors up to 45 %. We therefore apply similar overrun factors to the E.ON case, varied across scenarios. Additionally, since the chemical-looping design is immature we multiply its CAPEX by a cost immaturity factor. This factor is arbitrarily varied between 0 and 400 %, allowing us to explore the break-even point at which chemical-looping becomes regrettable compared to amine CCS.

We note that CAPEX is estimated based on a feasibility study in the amine case (Ramboll, 2023) and on cost functions in the oxyfuel and chemical-looping cases. While the methodologies differ, they all produce CAPEX ranges rather than point estimates. The idea is then not to compare technologies based on point estimates, but to explore CAPEX thresholds above which one technology outperforms the other.

Regarding OPEX, these mainly concern fuel and energy penalty costs, non-energy variable OPEX, fixed OPEX, and transport and storage costs, as detailed in Appendix A. Energy penalties lead to foregone CHP revenues, as already mentioned. Non-energy variable OPEX are minor but include e.g. amine solvent and oxygen carrier makeup. Fixed OPEX was estimated by Ramboll (2023) for the amine case, which we assume are similar for oxyfuel and chemical looping. This implies that we use the same fixed OPEX estimate (around 4 MEUR p.a.) for all capture technologies. While the fixed OPEX could differ between the cases, we neglect the impacts of this difference on regret, since it would be small relative to other operational costs and revenues (such as fuel costs and CHP and CRC revenues).

CO_2 transport and storage costs are generally high for Swedish CCS, but would also be similar irrespective of capture technology choice. These costs are therefore represented simply as one cost interval for ship transport and one for storage, were indicative values were given by Kjärstad based on previous work (cf. Kjärstad and Johnsson, 2021).

Considering revenues from CHP and CRCs, diverse scenarios are explored. Electricity prices were varied widely. District heating prices were set as a fixed share of electricity prices, which represents a simplified assumption of how CHP operators adjust their prices.

CRC revenue scenarios were based on the policy incentives described in the background section. E.ON could sell CRCs at some voluntary market price. They could also receive a reverse auction state aid, here assumed to be 160 EUR/tCO_2 flat, the same as for the existing case Stockholm Exergi. Furthermore, in some scenarios, CRCs could be sold at an EU ETS price, reflecting CO_2 removals integrated into the ETS. Additionally, some CRC procurement scheme could be established to stabilize future ETS prices within some uncertain price cap. To model CRC procurement, we assume future price caps across many scenarios, and assume that CRCs would be procured at this price level. These are simplifications that may differ from future CRC procurement programs, but they reflect the early price incentive that such programs are meant to stimulate (cf. Rickels et al., 2022). The modelled price levels are illustrated in Fig. 3.

Beyond scenarios of expected costs and revenues, we modeled three scenarios of system shocks relevant to E.ON's BECCS project. Their exact model implementations are naturally debatable, but the implementations below were considered sufficient for the purpose of identifying regrettable scenarios:

- "Bioshortage" – Competition for biomass could intensify, leading to medium- to long-term price increases. In such scenarios, the base biomass price increases by 10% annually, compounding each year for 10 years. This scenario was considered since future average biomass prices are of key concern to E.ON. A 10% annual increase is roughly twice the historical rate of price increase between 1993 and 2022 (Swedish Energy Agency, 2026). If these price increases are combined with high baseline biomass prices, which is the case in some of our modelled scenarios, the long-term biomass price reaches very high levels (~200 EUR/MWh).
- "Powersurge" – Electricity demand could intensify, leading to quick and sustained price increases. In such scenarios, the base electricity price increases by 20% annually, compounding each year for 3 years. Similar to biomass, electricity prices are of key concern to E.ON. This scenario reflects heightened electricity prices like the shock experienced in 2022 during Russia's invasion of Ukraine. If base electricity prices are high, at 100 EUR/MWh, and these are further increased by 60% over three years, E.ON would operate under sustained electricity prices of 160 EUR/MWh, which corresponds to the annual average spot price in 2022 at 161.4 EUR/MWh (Swedish Energy Agency, 2026). We note that most of our scenarios have lower prices, since 160 EUR/MWh is extreme in the Swedish context where historical prices have typically remained below 50 EUR/MWh.
- "Loadchange" – The CHP plant could be operated for more or fewer full load hours per year than projected, owing to unexpected changes in demands for heat or CO_2 removal. In such scenarios, full load hours either increase or reduce by 1500 hours per year. Again, full load hours was considered a key uncertainty by E.ON. They highlighted that increasing load hours brings substantial economic benefits, as more CO_2 can be captured using the same equipment (and levelized CAPEX is therefore reduced) but that this may not be possible if there is no demand for the additional CHP. The design full load hours were set to 4000–5000 based on Ramboll (2023), while increases or reductions of 1500 hours were assumed based on Beiron et al. (2022), who characterized the operational dynamics of 110 CHP plants across Sweden. The change of 1500 was assumed to cover a wide range of full load hours, where higher values correspond to near-baseload or waste-fired CHP plants (6500 hours or more), while lower values correspond to middle- or peak-load CHP plants (below 3000 hours).

The above-described scenarios of costs, revenues, and shocks are considered parameters to the XLRM model in Fig. 1. All parameter ranges are specified in Table 2.

Importantly, we sampled scenarios from the uncertainties and levers of Table 2 using Latin hypercube sampling (McKay et al., 1979). This technique does not assume probability distributions of parameters. Instead, each parameter range is divided into bins. Samples are then taken evenly from each possible bin combination. For example, a low

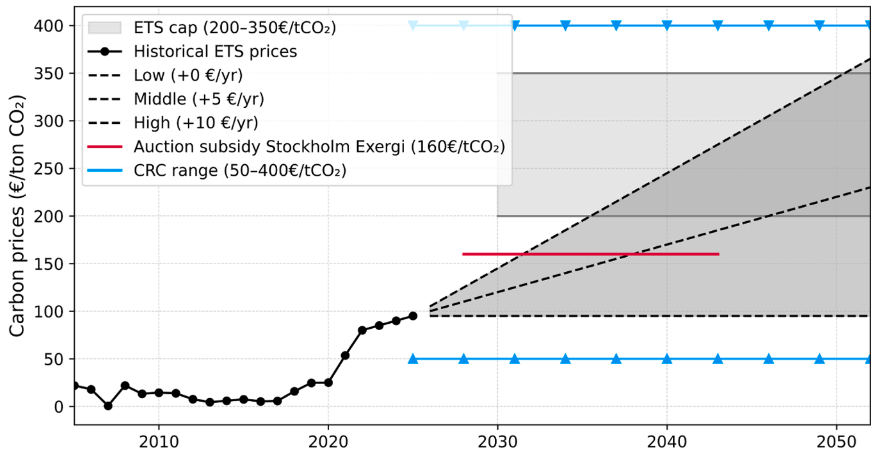

Fig. 3. The CO2 price ranges modelled. Respectively, the upper and lower shaded areas represent possible ETS caps and ETS prices. The red line represents a flat reverse auction subsidy of 160 EUR/tCO_2 for 15 years, like the Stockholm Exergi subsidy. Blue lines represent the lower and upper limits of voluntary CRC prices. Here, BECCS can be incentivized either by the ETS price, or by a combination of voluntary CRC prices and a reverse auction subsidy.

electricity price is combined with low biomass costs in one scenario and medium biomass costs in another. By this logic, the parameter space can be thought of as a hypercube from which scenarios are evenly sampled. Additional adjustments are made to ensure even sampling (cf. Preece and Milanović, 2016), i.e., that all combinations of scenarios are explored.

The main implications of this sampling technique are that (1) we do not make formal probabilistic claims of the model outputs, i.e., of expected values or confidence intervals, and (2) we ensure that diverse and "unlikely" scenarios are explored. This logic is consistent with RDM (Lempert, 2019).

Using Latin hypercube sampling, the BECCS investment decision was modelled and regret was quantified across 1.000.000 scenarios (taking approximately 30 min on a 12th-generation Intel Core i5 processor (1.6 GHz) with 16 GB RAM). We then sought high-regret scenarios using Sobol sensitivity analysis and CART data mining, as described in the next section.

3.3. Searching for regrettable scenarios

To find regrettable scenarios we studied the influence of model parameters on regret, using Sobol sensitivity analysis. The method quantifies a set of sensitivity indices per parameter – uncertainties and levers – which are described below. Among other assumptions detailed in Rosolem et al. (2012), the Sobol method assumes parameter independence. This generally holds for our model, except for district heating prices. However, we neglect potential impacts from this exception.

Formally, a change in parameter i contributes to the variance in regret, $V(regret)$. The 1st order sensitivity index represents the main effect from changing parameter i alone, while the 2nd order index accounts for interaction effects between i and another parameter. That said, we focus on the total-order sensitivity index, S_{Ti}, which represents the summed 1st and 2nd order effects of parameter i. The index can be expressed using Eq. (9). Here, $V_{\sim i}$ is the average variance when all parameters *except i* are allowed to vary (Rosolem et al., 2012):

$$S_{Ti} = 1 - \frac{V_{\sim i}(regret)}{V(regret)} \tag{9}$$

Notably, for all parameters, we calculated sensitivity indices and ranked them by their S_{Ti}. A higher S_{Ti} implies greater impact on regret, and the 10 most impactful parameters are presented in the results section.

Furthermore, to identify key scenarios, we utilized the data mining algorithm CART. Although we describe general aspects of the algorithm here, the reader may refer to Krzywinski & Altman (2017) for details.

Essentially, CART constructs a decision tree that predicts high-regret scenarios based on values of model uncertainties and levers. That said, the decision tree is not used for prediction, but for scenario separation. It consists of nodes and parameter splits, as in Fig. 1 in Krzywinski & Altman (2017), where each node is a subset of scenarios having the same uncertainties and levers.

CART recursively splits each node into two new nodes. For example, based on whether the electricity price is above or below 50 EUR/MWh. The "best" split is always chosen, defined as the split that either maximizes or minimizes the density of regrettable scenarios in the two new nodes. Scenario nodes of high density are here of interest, as they describe what uncertainties and lever ranges often lead to regret. We could find, for example, that the decision to deploy amine CCS has a density of 80 % when electricity prices are below 50 EUR/MWh. Under such example conditions, we regret the amine decision in 80 % of scenarios.

CART was repeatedly applied to the data set of 1.000.000 scenarios. Key, regrettable scenarios were identified and are presented as results.

4. Results

In the following three sections we summarize key results for our three research questions. The reader should note that we present sensitivity results before model outcomes. Although this ordering is unorthodox, it aligns with the RDM methodology, where models are used to explore assumptions and their influence on outcomes rather than to make predictions (Lempert, 2019). All scatter plots visualize only 1–5% of the 1.000.000 scenarios, since plotting all scenarios would clutter the figures.

4.1. Regretting amine CCS relative to no CCS

In Fig. 4 we illustrate results when regret is defined relative to the no CCS decision, as in Eq. (1). The upper radial convergence diagram shows the Sobol sensitivity results for the 10 parameters contributing most to regret variance. To interpret these, we note that:

- Red circles represent total order sensitivity indices, pink circles represent 1st order sensitivity indices, and grey edges represent 2nd order sensitivity indices.
- Greater radius/width implies greater parameter importance.
- The numbers inside each circle quantify the total order indices.
- The pink and red circles of the CRC price and auction subsidy parameters overlap, since their total and 1st order sensitivity indices are approximately equal.

Table 2
All parameter ranges of the model, organized in the XLRM framework.

(X) Uncertainties	Low	High	Unit	Reference*	Usage
Operational parameters					
Full load operating hours	4000	5000	h/yr	Ramboll (2023)	*The number of hours the CHP plant operates per year.*
Price electricity	10	100	EUR/MWh	Beiron & Thunman (2024)	*District heating prices are set locally and adapted to the regional electricity price.*
Price district heating	50	95	% of electricity price	Assumed	
Cost biomass	20	100	EUR/MWh	Beiron & Thunman (2024)	*The input fuel cost.*
Cost CO2 transport	52	70	EUR/tCO2	Est. from Kjärstad & Johnsson (2021)	*Includes ship transport at 15 bar(g), harbor and terminal costs, CO2 injection, monitoring, closure.*
Cost CO2 storage	12	16	EUR/tCO2	Est. from Kjärstad & Johnsson (2021)	
Cost amine makeup	25	35	SEK/kg	Ramboll (2023)	*Costs for replacing amine solvent and oxygen carriers.*
Cost oxygen carriers	200	600	EUR/t	Lyngfelt & Leckner (2015)	
Price CRC	50	400	EUR/tCO2	Assumed	*A price incentive from voluntary CRC markets.*
Price increase ETS	0	10	EUR/(tCO2*yr)	Altaghlibi & Gentile (2025) ***	*The ETS allowance prices increase at this rate, and are capped in some scenarios.*
Price cap ETS	200	350	EUR/tCO2	Assumed	
Capital cost parameters					
Economic lifetime	20	30	yr	Beiron & Johnsson (2024)	*The economic lifetime of CO2 capture technologies.*
Discount rate	5	10	%	Beiron & Johnsson (2024)	*Discount rate of costs/revenues.*
CAPEX amine plant	153	230	MEUR	Ramboll (2023)	*Capital costs of the amine capture plant incl. CO2 compression and liquefaction.*
CAPEX exponent fuel reactor	0.48	0.72	-	Farajollahi & Hossainpour (2022)	*Represents β in CAPEX=α•x^β, used to estimate base CAPEX costs of fuel reactor and ASU.* **
CAPEX exponent ASU	0.68	1.02	-	Farajollahi & Hossainpour (2022)	
CAPEX compression & liquefaction	20	30	MEUR/(kgCO2/s)	Deng et al. (2019)	*Used to estimate capital costs of CO2 compression (15 bar) and liquefaction.*
OPEX fixed	3.6	5.4	MEUR/yr	Ramboll (2023)	*Includes staff and maintenance.*
EPC cost factor	5	15	%	Ramboll (2023)	*These are cost factors that escalate base CAPEX estimates, in line with established CCS cost methodologies (cf.* Ali et al., 2019*).* **
Contingencies cost factor	15	35	%	Ramboll (2023)	
Owners' cost factor	3	7	%	Ramboll (2023)	
Overrun cost factor	0	45	%	Beiron & Johnsson (2024)	*An additional cost factor reflecting unexpected cost overruns.*
Immaturity cost factor	0	400	%	Assumed	*An additional cost factor reflecting uncertainties of low-TRL chemical-looping CCS.*
dT log mean temp. diff.	350	530	C	Est. from Crafoord & Lewenhaupt (2025)	*Used to determine areas and costs of convective heat exchangers after the chemical-looping fuel reactor.* **
Heat transfer coefficient U	40	50	W/(m2K)	Casarosa et al. (2004)	
CEPCI	750	950	-	University of Manchester (2024)	*A Chemical Engineering Plant Cost Index is used to transform outdated cost estimated to the cost year of 2024.*
Fuel reactor efficiency	0.8	0.95	molO2/molO2, stoichiometric	Assumed	*Determines what fraction of fuel is oxidized by oxygen carriers in CLC fuel reactor.*
Policies and shocks					
Reversed auction	True/False		-	cf. Fridahl et al. (2024)	*Adds a revenue of 160 EUR/tCO2 for 15 years.*
ETS integration	True/False		-	cf. Rickels et al. (2022)	*Enables the alternative to sell CRCs to the ETS price.*
ETS procurement	True/False		-	cf. Rickels et al. (2022)	*Enables the alternative to sell CRCs to the ETS cap level.*
Bioshortage	True/False		-	Assumed	*Increase biomass costs by 10 % per year for 10 years.*
Powersurge	True/False		-	Assumed	*Increase electricity prices by 20 % per year for 3 years.*
Loadchange	−1500/0/1500		h/yr	Assumed	*Increases/decreases full load operating hours of the plant.*
(L) Levers					
Investment delay	5/10/15/25		yr	Assumed	*The number of years after the boiler investment in which any CCS investments occur.*
Capture rate	86	94	%	Assumed	*The fraction of CO2 captured.*
(R) Model relationships					
BECCS investment model - Python-based using EMA Workbench (Kwakkel, 2017)				Stenström (2025)	Model developed using the EMA Workbench (Kwakkel, 2017).
(M) Model outcomes					
$\boldsymbol{regret_{no\ ccs} = NPV_{no\ ccs} - NPV_{amine}}$			MEUR	Assumed	*See* Eqs. (1) *through* (3)
$\boldsymbol{regret_{oxy} = NPV_{oxy} - NPV_{amine}}$			MEUR	Assumed	
$\boldsymbol{regret_{clc} = NPV_{clc} - NPV_{amine}}$			MEUR	Assumed	

* If parameter ranges were available, these were taken directly from the references. If only point estimates were available, ranges were constructed based on the author's best judgment.
** See Appendix A for detailed descriptions of cost calculations.
*** The reference only projects ETS prices until 2035. We extended their projection linearly until 2050, but assumed (conservatively) that most scenarios achieve lower prices. At the low end, a price increase of 0 EUR/tCO2 p.a. implies no increase in ETS prices relative to today's level of about 80 EUR/tCO2.

Accordingly, the CRC price is seemingly the most important parameter, followed by any unexpected changes in full load operating hours (a reduction or increase of 1500 hours annually) and by subsidies from reverse auctions. These parameters can be expected to be sensitive since they directly impact the annual revenues and CO_2 volumes.

The boxplots of Fig. 4 illustrate the ranges of regret explored, divided into three subsets. The upper boxplot illustrates all scenarios, in which regret ranges between −800 and 800 MEUR. The box spans the interquartile range, from the 1st to the 3rd quartile. The line inside the box marks the median regret value. The whiskers extend to 1.5 times the

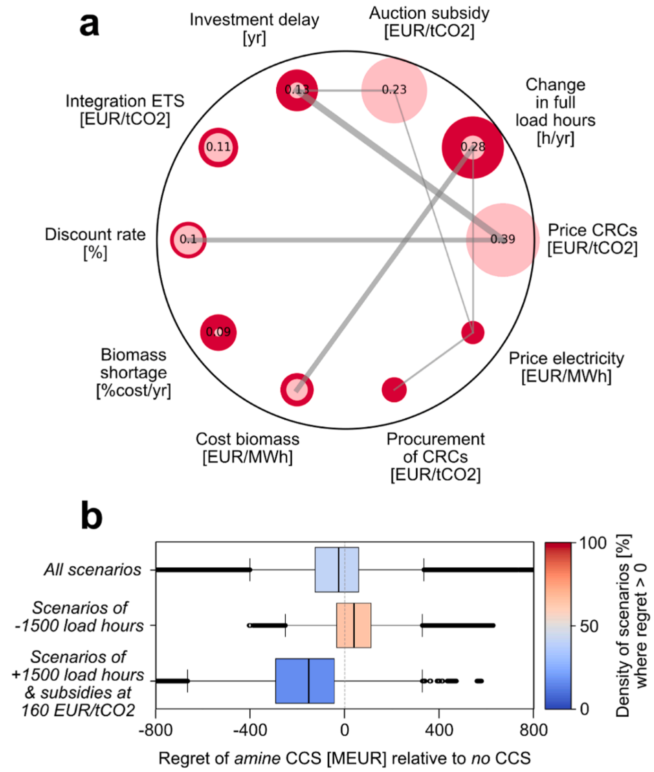

Fig. 4. Sobol sensitivity indices of 10 important parameters illustrated in a radial convergence diagram (**a**), and the explored ranges of regret illustrated in three boxplots (**b**).

interquartile range, and black circles beyond the whiskers represent outliers. In this figure, the outliers are dense enough to appear as almost solid lines. The color of the boxes represents the density of regrettable scenarios. About 42 % of scenarios of the upper box are regrettable, while 58 % have negative regret. This implies that, in most explored scenarios, the amine CCS decision has higher NPV than the no CCS decision – so amine CCS could be considered more robust.

However, robustness depends on what scenarios realize. The middle boxplot shows that, if full load hours are reduced by 1500 and no subsidy is secured, about 65 % of scenarios have positive regret. Under these conditions, amine CCS is not robust. Contrastingly, amine CCS could be robust in scenarios visualized by the lower boxplot. If full load hours are increased by 1500 and a subsidy of 160 EUR/tCO_2 is secured, only 16 % of scenarios have positive regret.

As mentioned, we sought conditions leading to high regret using CART. Fig. 5 visualizes cases where the only sources of carbon revenues are from voluntary CRC markets and reverse auction subsidies (possible ETS revenues are excluded). Respectively, the boxplots with black and grey outlines represent cases with and without subsidies. Each boxplot visualizes a range of regret values, indicated by the y axis, depending on the CRC price range, indicated by the x axis. A key finding is that amine CCS is regrettable in more than 90 % of scenarios if CRC prices fall below 220 EUR/tCO_2, and if no subsidy is secured. This is illustrated by the three red boxplots. Contrastingly, amine CCS may be robust if prices exceed 285 EUR/tCO_2, as illustrated by the rightmost boxplot.

Alternatively, the main source of carbon revenue could be from selling CRCs to an integrated ETS market, as in Fig. 6 (possible subsidies or voluntary market revenues are here excluded). Whether ETS revenues are sufficient depends on whether CRCs are procured from E.ON in advance, ahead of demand (cf. Rickels et al., 2022). Such procurement scenarios can achieve earlier (and possibly higher) price levels than direct ETS integration. Without a procurement scheme (panel **a** in Fig. 6) the investment is not robust, since regret is positive in most scenarios. Even at sharply rising ETS allowance prices, above 8.66 EUR/tCO_2 p.a., regret is positive in more than 55% of cases. The investment is more robust if CRCs are procured (panel **b**) since regret is more frequently negative across all scenarios. Above 8.66 EUR/tCO_2 p.a., regret is negative in 71% of cases.

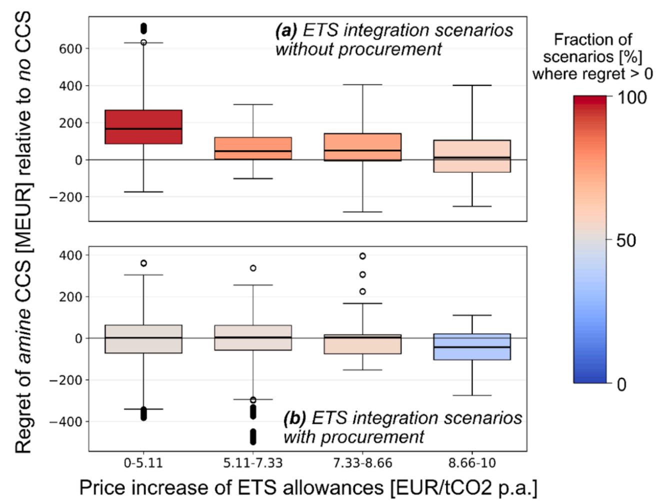

Fig. 6. Boxplots indicating regret values for ranges of scenarios, either with procurement of CRCs to an ETS market (**a**) or without (**b**). Notably, amine CCS only has low regret if procurement occurs and ETS prices rise sharply, e.g. at 8.66 EUR/tCO2 p.a.

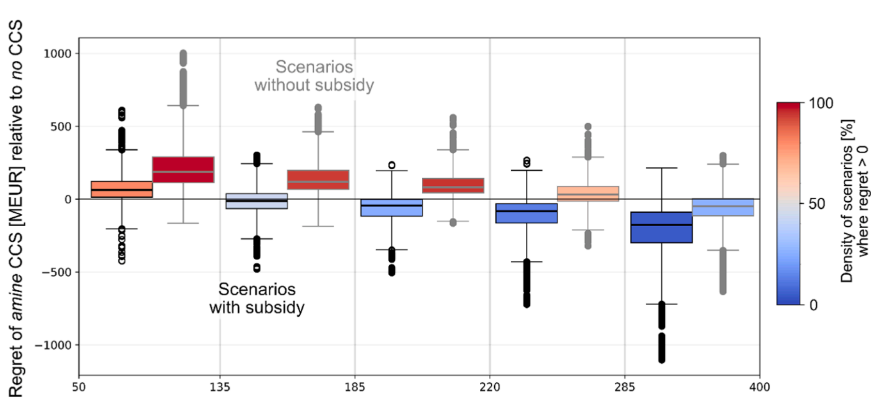

Fig. 5. Boxplots indicating regret values for ranges of scenarios, either with subsidies of 160 EUR/tCO2 (black outlines) or without (grey outlines). Notably, amine CCS is regrettable in more than 90 % of scenarios if voluntary CRC prices fall below 220 EUR/tCO2, as shown by the red boxplots.

4.2. Regretting amine CCS relative to oxyfuel CCS

In Fig. 7 we illustrate results when regret is defined relative to oxyfuel CCS, as in Eq. (2). Again, the upper radial convergence diagram shows sensitivity indices for the 10 parameters with the most impact on regret. Notably, the CAPEX of the ASU has the largest sensitivity indices and is thus expected to be the strongest driver of regret. Here, the ASU CAPEX is represented by β in Eq. (8) and ranges between 0.68 and 1.02. The second most important parameter is the timing of the investments, i.e., the delay of CCS investments after the initial boiler investment. As mentioned, delays of 5, 10, 15, and 20 years were modelled. That the ASU CAPEX is the most sensitive parameter could be expected, since the ASU is the main component that differs between the amine and oxyfuel case.

Similar to Fig. 4, the boxplots of Fig. 7 illustrate the ranges of regret explored. Across all scenarios in the upper boxplot, regret ranges between −230 and 400 MEUR. The density is about 80 %, implying that amine CCS is often regrettable relative to oxyfuel and thus not robust. This is exaggerated in the middle boxplot, where the CCS investment occurs early (after 5 or 10 years) and where the ASU is inexpensive, i.e., the β exponent is below 0.98. This exponent corresponds to an ASU CAPEX lower than 211 MEUR. Contrastingly, if the ASU CAPEX is above 211 MEUR and investments occur late (after 15 or 20 year), amine CCS is more robust than oxyfuel. This is illustrated by the lowest, blue boxplot.

The importance of the ASU CAPEX is also supported by the CART analysis, as illustrated in Fig. 8. The left plot shows how regret reduces with increasing ASU costs. When β is lower than 0.98, amine CCS is regrettable in more than 60 % of cases. Furthermore, the right plot shows regret against the ratio between amine and oxyfuel CAPEX. This ratio is clearly a key factor in determining whether amine CCS is regrettable

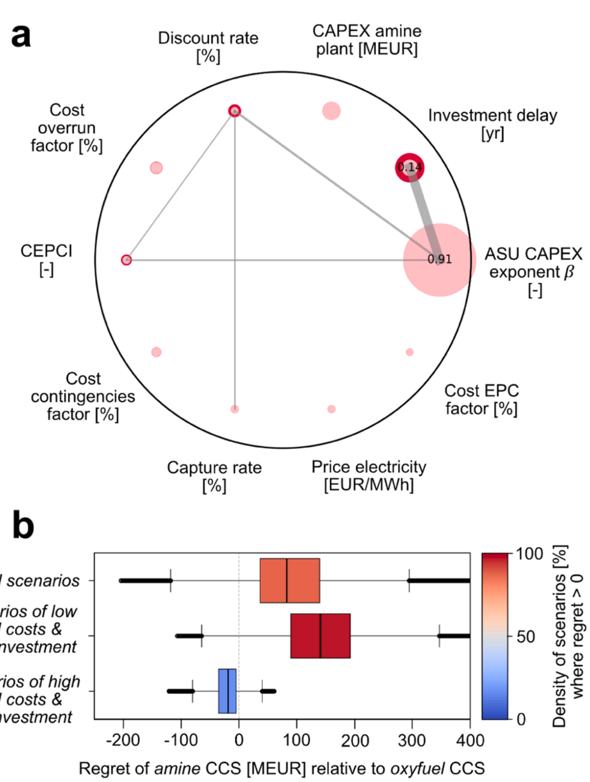

Fig. 7. Sobol sensitivity indices of 10 important parameters when regret is defined relative to oxyfuel CCS (**a**), and the explored ranges of regret illustrated in three boxplots (**b**).

4.3. Regretting amine CCS relative to chemical-looping CCS

Fig. 9 illustrates results when regret is defined relative to chemical-looping CCS, as in Eq. (3). Like previous cases, the upper radial convergence diagram displays sensitivity indices for the 10 parameters with the greatest influence on regret. Similar to the oxyfuel comparison, CAPEX and the timing of investments are the most influential factors when comparing the amine and chemical-looping decisions. Notably, the cost immaturity factor applied to chemical-looping CAPEX causes the largest variance in regret, which could be expected given its wide examined range (0 and 400 %).

The orange and red colors of the boxplots in Fig. 9 imply that amine CCS is regrettable in more than 86 % of evaluated scenarios, relative to chemical-looping. High-regret cases occur when the CAPEX immaturity factor is below 200 % and CCS investments occur early (5 or 10 years after the boiler), as shown in the middle boxplot. Here, regret ranges between −70 and 400 MEUR. Reverse conditions are visualized in the lowest boxplot, where the immaturity factor is above 200 % and investments occur late (15 or 20 years after the boiler). However, under these conditions, amine CCS is still regrettable in about 86 % of scenarios.

These high-regret scenarios are further unpacked in Fig. 10. Boxplots with grey outlines represent scenarios where the cost immaturity factor is below 270 % - a threshold identified by CART. Their red color indicates that amine CCS is regrettable in more than 90 % of cases and thus not robust. However, if the factor is above 270 %, regret mainly depends on the ASU CAPEX, as illustrated by boxplots with black outlines. Their density reduces as the CAPEX on the x axis increases. In these cases, and when β is higher than 0.98 (corresponding to an ASU CAPEX of 22 MEUR), amines frequently have lower regret than chemical-looping and could be considered more robust.

Similarly, the rightmost scatterplot visualizes how regret depends on the ratio between amine and chemical-looping CAPEX. Scenarios where the cost immaturity factor is below 270 % are marked in purple, and almost always result in positive regret.

4.4. Policy impacts across regret metrics

It is possible to compare the impact of the studied policies on different regret metrics. Fig. 11 provides an overview of regret when defined relative to the no CCS and oxyfuel cases. The upper row of boxplots clearly show the impact of specific policy measures on the robustness of E.ON's amine investment. It has negative regret in about 75% of scenarios if a subsidy is secured (panel **b**) or if the ETS, combined with a procurement scheme, is the main source of revenue (panel **e**). The inverse cases are shown in panels **c** and **d**, where regret is often positive. Conversely, when regret is defined between amine CCS and oxyfuel CCS (panels **f-j**) policy scenarios have little impact (the same holds true when defining regret relative to chemical-looping, which is why this case is not illustrated). This is a result of our assumption that the three technology cases capture and store the same volumes of CO2 across scenarios. Under this framing, policies make little difference for the technology choice.

5. Discussion

When would decision-makers regret deploying CCS? This overarching question was explored in this article, using the BECCS project of E.ON as our illustrative case. By systematically analyzing high-regret scenarios, our ambition was to strengthen decision-making on CCS. We consider this a useful contribution for researchers and CCS developers alike, given the uncertainties and urgency of upscaling CCS and durable CO_2 removal (Mahjour and Faroughi, 2023; Kazlou et al., 2024; Fridahl et al., 2023). While our practical findings are mainly relevant to European CHP and BECCS, our methodology can be usefully applied to other CCS cases.

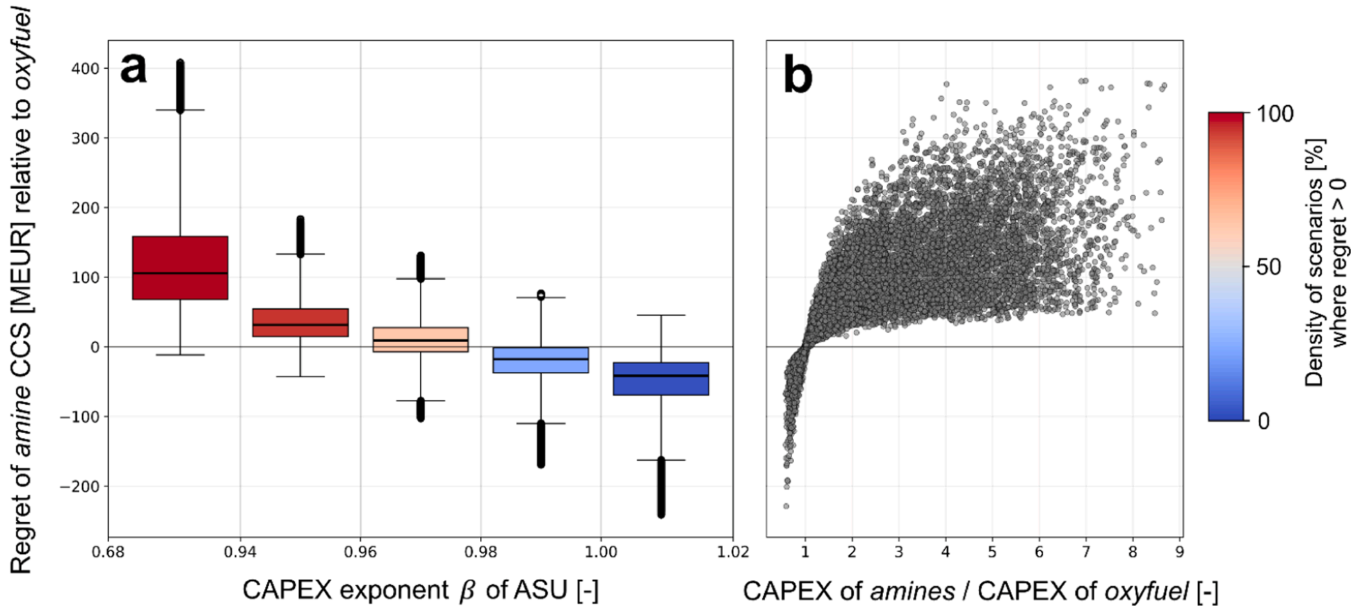

Fig. 8. The box and scatter plots illustrate ranges of regret values depending on the ASU CAPEX (**a**) and on the CAPEX ratio between amines and oxyfuel (**b**). If the ASU CAPEX exponent β is lower than 0.98, corresponding to a CAPEX of 211 MEUR, amine CCS is regrettable in more than 60 % of cases (left plot). If the total amine CAPEX is lower than for oxyfuel, amines have lower regret (right plot).

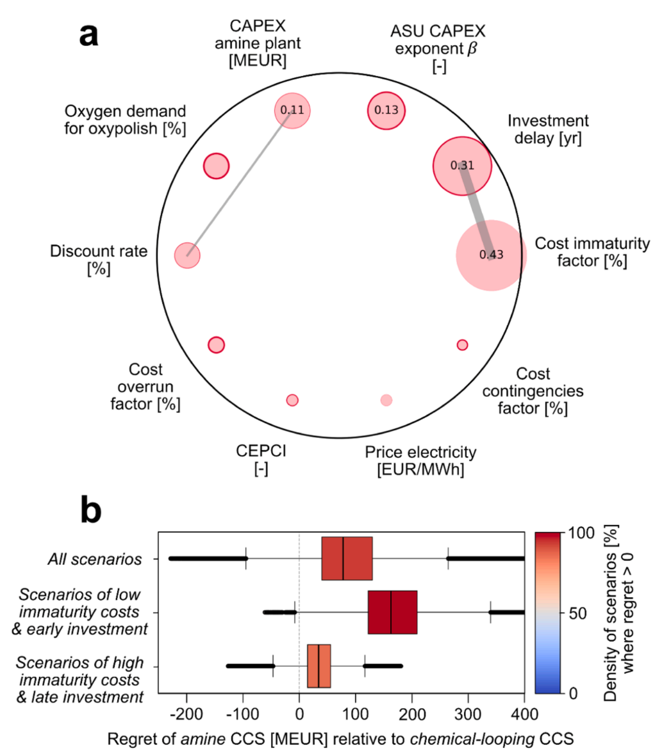

Fig. 9. Sobol sensitivity indices of 10 important parameters when regret is defined relative to chemical-looping CCS (**a**), and the explored ranges of regret illustrated in three boxplots (**b**).

Importantly, we introduced regret as the preferred performance metric when aiming for robust decision-making. Notably, the precise definition of regret is critical to the RDM methodology, as it shapes the whole analysis (Lempert, 2019). We chose to iterate definitions in consultation with the decision-maker of interest, in this case E.ON. While our chosen definitions quantify the economic performance of deploying amine CCS relative to three other decisions, they do not capture other potentially important performance metrics. A follow-up analysis could for example focus on environmental performance, life-cycle CO_2 emissions, or energy and exergy efficiency (cf. Fajardy and Mac Dowell, 2017; Roshan Kumar et al., 2023). Our narrow economic focus thus represents a limitation of the study.

That said, the economic focus lets us discuss conditions that are critical for CCS developers to commit to robust investment decisions. Given our model framing, these conditions mainly concern policy incentives for European BECCS, and the capture technology choice. We elaborate on these conditions below, ordered by research question.

Firstly, the decision-maker could regret amine BECCS relative to never deploying CCS. To reiterate, in our case, the BECCS investments would occur 5 to 20 years after the initial boiler investment. Notably, we found that a drastic change in full load operating hours causes great variance in regret, illustrated in Fig. 4. However, when specifying high-regret scenarios (Figs. 5 and 6), we focused on policy uncertainties. This focus was chosen because the risk of reduced full load hours was already intuitive to the decision-maker – reduced hours imply higher levelized costs – while the impacts of alternative policy scenarios were poorly understood, causing uncertainty and hesitation, and requiring detailed analysis.

Indeed, most high-regret scenarios occur when policy incentives are low. This finding is best visualized by the boxplots with grey outlines in Fig. 5. When voluntary CRC prices are below 220 EUR/tCO_2 and no auction subsidy is secured, amine CCS leads to high regret in more than 90 % of scenarios. These boxplots consider cases without a fixed reverse auction subsidy, but could in principle represent any price signal, be it from voluntary, ETS, or CO_2 storage markets. For amine BECCS to be robust relative to no CCS, E.ON could for example require CRC prices at or above 285 EUR/tCO_2, as in the rightmost boxplots. Notably, E.ON would then regret *not* deploying BECCS in more than 75 % of scenarios. Naturally, these price levels will vary depending on the decision-maker's risk appetite, including and beyond economic risks. Although not modelled, BECCS may for example become mandatory to comply with future EU bioenergy regulation, thus posing a regulatory risk (Stenström et al., 2024).

Other high-regret scenarios occur when specific policies are *not* in effect. As shown in Fig. 5, not securing a reverse auction subsidy – here 160 EUR/tCO_2 – often leads to regret. Likewise, if CRCs are integrated into the ETS without being procured from E.ON by some centralized

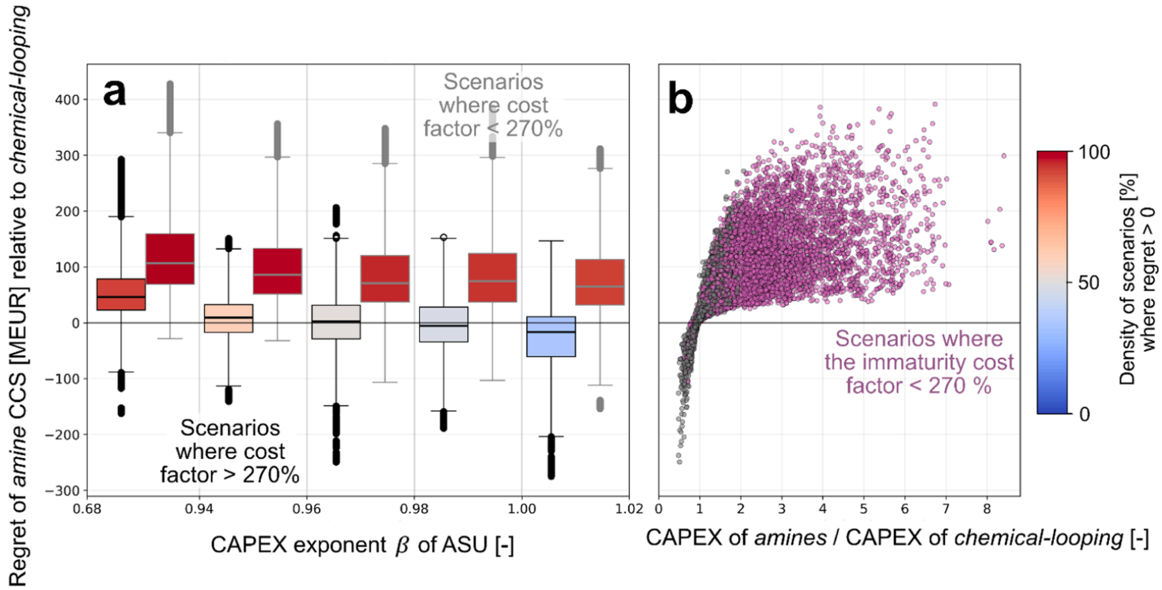

Fig. 10. The box and scatter plots illustrate ranges of regret values depending on the ASU CAPEX (**a**) and on the CAPEX ratio between amines and chemical-looping (**b**). Furthermore, both plots illustrate that amine CCS is almost always regrettable if the cost immaturity factor is lower than 270 %.

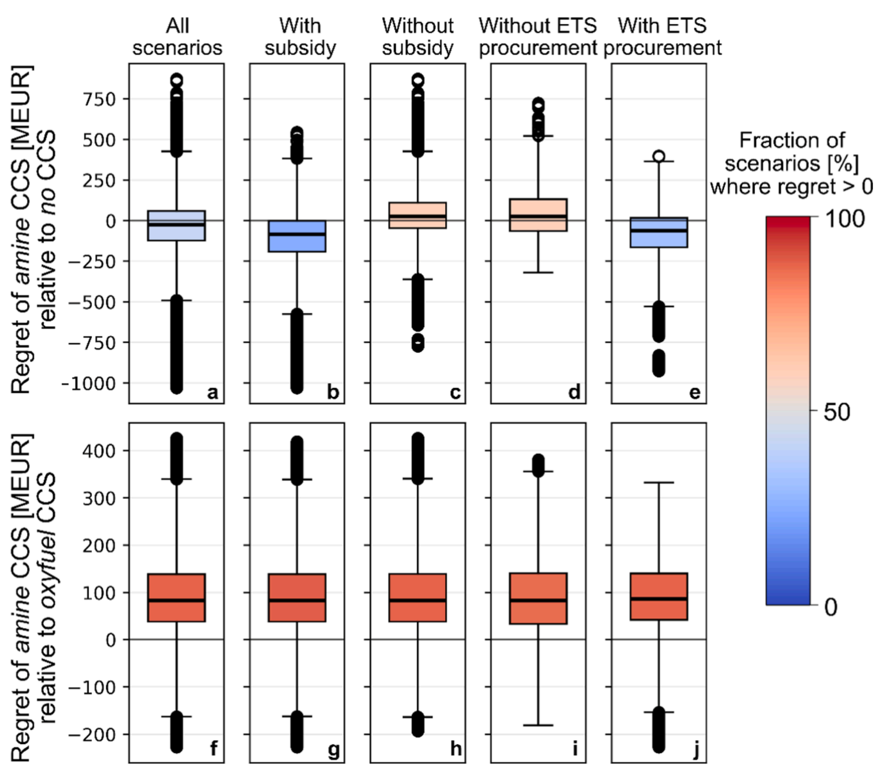

Fig. 11. Box plots of regret ranges depending on policy scenarios. In the upper row, regret is defined relative to the no CCS case, In the lower, regret is defined relative to the oxyfuel case.

agency (cf. Rickels et al., 2022) the price signal may be insufficient, as highlighted in Fig. 6. The explanation is likely that the modelled ETS prices increase too slowly to incentivize the studied BECCS project. Contrastingly, procuring CRCs in advance would provide an early and stable incentive and improves robustness across ETS price scenarios (Fig. 6). Although the ETS is commonly expected to provide sufficient BECCS incentives, this finding suggests that direct CRC integration is insufficient for the studied BECCS project, and the ETS may likewise prove insufficient for similar projects (of similar costs). This could be a hurdle to realizing Nordic BECCS from CHP.

Secondly, the decision-maker could regret amine CCS relative to oxyfuel CCS. We found that this mainly depends on the CAPEX of the oxyfuel ASU. Using our cost functions and CART, various break-even costs could be identified, for example 211 MEUR when β equals 0.98. However, a more practical threshold was illustrated in the scatter plot of Fig. 8: regret mainly correlates to the ratio of amine CAPEX to oxyfuel CAPEX. The cheaper CAPEX alternative results in lower regret.

This finding is both unexciting and useful. It is unexciting because modelled external uncertainties, including CO_2 policies and energy prices, have minor impacts on the technology choice. The reason is likely that, for this CHP district heating application, oxyfuel and amine CCS have similar energy balances, and capture the same volumes of CO_2 to be conditioned, transported, and stored. Other uncertainties could naturally dictate which technology is preferrable, for example environmental risks of amine solvents in an urban context, or possible future synergies with electrolyzers generating O_2 as byproduct. However, these were not modelled.

Contrastingly, the finding is useful since it reduces the number of variables to consider when making the capture technology choice. Our study is academic and cannot accurately specify the ASU CAPEX. However, if E.ON knows that the CAPEX uncertainty dictates whether oxyfuel or amines is more robust, they may focus efforts to reduce this uncertainty as much as possible. For example, by requesting multiple ASU vendor quotes.

Thirdly, the decision-maker could regret amine CCS compared to chemical-looping CCS. We stress that this comparison assumes that a flexible chemical-looping design could be built and operated despite its relatively low TRL, as described in the background section. Below, we attempt to provide a balanced view by highlighting the conditions under which amine CCS performs better or worse than chemical-looping.

Principally, if chemical-looping is *not* unexpectedly expensive, E.ON would regret amine CCS. If the immaturity cost factor for chemical-looping is lower than 270 %, as exemplified in Fig. 10, amine CCS is regrettable in more than 90 % of scenarios. To reiterate, we applied this cost factor arbitrarily to an established cost estimate of chemical-looping, to discover the break-even point at which either capture technology dominates. Before applying the immaturity cost factor, this cost estimate already included base CAPEX estimates, scaled by EPC, project and process continency, owner's capital, and cost overrun factors (see Appendix A for details).

Contrastingly, Fig. 10 also illustrates scenarios when amine CCS is more robust. If chemical-looping would be more than 270 % more expensive than expected, the preferred capture technology mainly depends on the ASU CAPEX. This CAPEX refers to the small ASU for oxy-polishing downstream of the fuel reactor. If the CAPEX is above 22 MEUR, i.e., the β exponent is above 0.98, then the density of regrettable scenarios is only around 35 %. Simply put, multiple cost uncertainties need to add up to an unexpectedly high chemical-looping CAPEX for amines to be robust.

These findings imply that, if decision-makers want to reduce economic regret in their capture technology choice, they could focus on reducing uncertainty around chemical-looping design and cost estimates. The findings also indicate that for amine CCS to be more robust than chemical-looping, the immaturity cost factor may need to exceed 270 %. While we see potential in chemical-looping, we recognize that such high costs may occur for first-of-a-kind designs. However, we still conclude that relying on readily available technologies like amines may lead to regret if promising novel technologies are not explored, and eventually deployed by other actors.

A final note concerns the timing of CCS investments. Compared to oxyfuel and chemical-looping, amine CCS may lead to regret if implemented early (see Figs. 7 and 9). Implicitly, this suggests that amine CCS – and thus climate mitigation measures – should be delayed. However, this result stems from discounted cost comparisons. For example, if amines have higher CAPEX than oxyfuel, delaying the investment reduces the impact of that CAPEX difference on total NPV (Eq. (7)). Thus, our point is not that amine CCS generally benefits from delay, but that the higher-cost technology in any scenario appears less costly when postponed.

We conclude this discussion by reflecting on the usefulness of the RDM methodology and by providing policy recommendations. As was shown, leveraging scenario analysis, sensitivity analysis, and data mining helps identifying critical conditions for CCS decision-making. For example, we identified robust break-even CO_2 revenue levels, assessed the impacts of tailored BECCS policies, and pinpointed what cost uncertainties could be reduced. We believe this contribution is both novel and useful, as not many studies have analyzed 1.000.000 scenarios tailored to an actual industrial BECCS case. Furthermore, we suggest that other researchers could adopt this methodology to support robust decision making in future CCS projects.

While the methodology is useful, our application has limitations. The precise levels of costs and incentives identified should be considered specific to the E.ON case (although similar CHP plants could achieve similar costs and require similar incentives). Another limitation is the choice of parameter intervals, listed in Table 2. We made assumptions to adapt literature values to uncertainty intervals, which may affect our results. For example, one reason CRC prices cause large variance in regret is that the modelled price range is wide. We consider this reasonable given current uncertainty about future CRC prices (in 2026), but we acknowledge that this and other interval assumptions influence our findings. Other limitations concern the model framing. Equal CO_2 capture rates were assumed, which is not necessary in practice, and we did not assume technological learning for capture, transport, or storage costs. Furthermore, as mentioned, difficulties arise when comparing low- and high-TRL technologies. The proposed chemical-looping design has not been built, so our findings should be interpreted as an indication of the technology's potential rather than its superiority.

We will now summarize policy recommendations for each considered policy instrument. Note that these are based on a single case study, while additional studies may be needed to make firm recommendations.

If policymakers expect early BECCS movers to commit to investment decisions based on voluntary CRC demand, then measures must be taken to ensure relatively high CRC prices. The studied case would require 285 EUR/tCO_2 for a robust investment. The need for high voluntary CRC prices can be reduced by subsidizing early movers, thereby improving the robustness of investments, but is likely not an economically sustainable solution given the limits of public funds. However, although not assessed in this study, such coupled public and private financing may risk environmental integrity since multiple actors may claim the same CRC for offsetting purposes (Dufour et al., 2024). Moreover, integrating BECCS credits into the ETS through procurement appears promising. With procurement, robustness increased substantially and the investment even achieved negative regret in over 71% of scenarios when ETS prices rose by 8.66 EUR/tCO_2 per year or more. Without procurement, the investment was not robust across most scenarios.

6. Conclusions

Our aim was to analyze high-regret scenarios when deploying amine CCS, with a focus on alternative capture technologies and policy scenarios. The BECCS project of E.ON was used as our case study and modelled across 1.000.000 scenarios. The following conclusions mainly concern the E.ON case, but could remain relevant for similar CHP cases of similar costs.

In terms of NPV, and relative to no CCS deployment, amine CCS leads to regret in more than 90 % of scenarios if CO_2 removal revenues fall below 220 EUR/tCO_2. Contrastingly, above 285 EUR/tCO_2, amine CCS is robust and the no CCS decision is regrettable in 75 % of scenarios.

The absence of BECCS policy leads to regret. For example, if no reverse auction subsidy is secured by the CHP owner. If CO_2 removals are integrated into the EU ETS without being procured ahead of demand, amine CCS leads to regret in most scenarios. Conversely, centralized ETS procurement schemes could ensure early and stable price incentives for a robust BECCS investment.

Deploying amine CCS may lead to regret relative to low-cost scenarios of oxyfuel or chemical-looping. If the oxyfuel ASU CAPEX is below 211 MEUR, amine CCS is regrettable in over 60 % of scenarios. If the chemical-looping CAPEX is 270 % higher than expected, amine CCS can be robust, but is otherwise regrettable in more than 90 % of scenarios. Therefore, while decision makers have historically preferred amines, reducing the uncertainties around alternative capture technologies could unlock their potential for low-regret CCS.

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Declaration of generative AI and AI-assisted technologies in the manuscript preparation process

During the preparation of this work the author(s) used the generative artificial intelligence chatbot ChatGPT in order to improve the readability and language of the manuscript. After using this tool/service, the author(s) reviewed and edited the content as needed and take(s) full responsibility for the content of the publication.

CRediT authorship contribution statement

Oscar Stenström: Writing – original draft, Visualization, Software, Methodology, Formal analysis, Data curation, Conceptualization. **Magnus Rydén:** Writing – review & editing, Supervision, Project administration, Methodology, Funding acquisition, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Supplementary materials

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Data availability

https://doi.org/10.5281/zenodo.17207218 (The data and models underpinning this research are openly available. Link to repository:)

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