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Progressing from first-of-a-kind to Nth-of-a-kind: Applying learning rates to carbon capture deployment in Sweden

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ABSTRACT

The deployment of CO_2 capture technologies presents opportunities to store fossil fuel emissions from industries and power generation (CCS) and to enable carbon utilization (CCU). However, the costs for early CCS projects are high, and this is a challenge in terms of their economic viability, requiring a strong climate policy with high carbon prices for implementation. This work details a techno-economic assessment of the cost of carbon capture based on a hybrid method and individual project approach, using first-of-a-kind contingency factors and learning rates to study the evolution of carbon capture costs as installed capacity increases over time. The work is based on a case study of 147 Swedish industrial and combined heat and power plants (total of 176 stacks). The results are presented as marginal abatement cost curves, with consideration of early mover CCS projects and learning rates. Deployment scenarios are also presented that take into account an expected increase in the CO_2 price. The findings indicate that when accounting for first-of-a-kind contingencies (100 % and 200 % increases in Nth-of-a-kind costs), 90 and 17 projects, respectively, of the total 176 emission sources studied have specific CO_2 costs of <300 €/t. However, high learning rates (12 %) can reduce the capture costs from first-of-a-kind to Nth-of-a-kind levels within some 30 project installations (100 % contingency). With lower learning rates (3 %), the first-of-a-kind costs are reduced by 10 %–20 %. With the expected increase in CO_2 prices, a peak in carbon capture deployment is observed around Year 2035, at a carbon price of 200 €/t.

1. Introduction

Carbon capture and storage or utilization (CCUS) is expected to play a key role in the efforts of industrial and power plants to reach net-zero CO_2 emissions targets; the IEA states that “reaching net-zero will be virtually impossible without CCUS” (IEA, 2023a). CCUS contributes to mitigation either by permanently storing captured CO_2 emissions (CCS) or by utilizing the captured CO_2 to produce new products so as to substitute for virgin fossil feedstock (CCU). When combined with biomass combustion, carbon dioxide removal (CDR) can also be achieved through bio-CCS (BECCS), provided that the biomass is sourced from forests in which the carbon stock is maintained over time. The net-zero emissions scenario presented by the IEA (2023b) suggests that by Year 2030 a CCUS capacity of 1 $GtCO_2$/a is needed, which increases to 6 $GtCO_2$/a by Year 2050 (although this will obviously depend on how many other measures are implemented). Estimates from Peters et al. (2017) suggest that up to 4000 CCUS facilities should be in operation by Year 2030 in many of the 2 °C scenarios. To meet these targets, rapid build-up of CCUS capacity is obviously needed worldwide. In terms of BECCS deployment, the proposed targets in Sweden (used as a case study in this work) are 1.8 Mt/a of biogenic CO_2 stored by Year 2030 and 3–10 Mt/a by Year 2045 (SOU, 2020). However, the cost of CCS is high, and this threatens to limit significantly the rate of CCS deployment, in particular in the absence of a strong climate policy.

The Nordic countries are close to an initial implementation of (BE) CCSU for different types of emission sources, for example the ongoing Norwegian full-chain project *Longship* (CCS Norway, 2024) and planned carbon capture installations at combined heat and power (CHP) plants in Denmark (Ørsted, 2023). In Sweden, more than 30 industrial and power plants have expressed an interest in CCUS and have carried out feasibility studies, research projects, and in some cases permit applications (Swedish Waste Management et al., 2022; The Swedish Energy Agency, 2022). CCU projects for the production of bio-methanol from captured biogenic CO_2 are also underway in Sweden (Liquid Wind, 2024). These may benefit the upscaling of CCS by spill-over learning effects, similar to the learning gained regarding photovoltaics from the semiconductor manufacturing industry (Nemet, 2006).

However, these early (BE)CCS projects are expected to be mainly government-funded. The cost of emitting fossil carbon within the EU

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Nomenclature

Abbreviation

BECCS	Bioenergy coupled with carbon capture and storage
BECCU	Bioenergy coupled with carbon capture and utilization
C	Cost
CAPEX	Capital expenditures
CCS	Carbon capture and storage
CCU	Carbon capture and utilization
CDR	Carbon dioxide removal
CHP	Combined heat and power
EU ETS	European Union Emissions Trading System
FOAK	First-of-a-kind
HOB	Heat-only boiler
LR	Learning rate
MAC	Marginal abatement cost
MEA	Monoethanolamine
MSW	Municipal solid waste
NOAK	Nth-of-a-kind
OPEX	Operational expenditures
P	Price
SMR	Steam methane reformer
SWOT	Strengths, Weaknesses, Opportunities, Threats

Subscripts

a	project number
b	factor based on learning rate
x	project number
y	year

emissions trading system (EU ETS) remains too low to incentivize CCS installations on economic grounds, as compared with the high cost of carbon capture. Industrial actors in trade-exposed sectors (e.g., steel-making, production of chemicals, and cement manufacture) are at the risk of carbon leakage (moving facilities abroad) and, therefore, are dependent upon reduced CCS costs for decarbonization to take place (Babiker, 2005). Findings from Wang et al. (2021) indicate that low carbon prices are linked to an increased hazard rate for CCS projects, and a risk of project failure. In the case of BECCS, financing systems other than the EU ETS are needed for the projects to attain economic viability (Zetterberg et al., 2021) and avoid an implementation gap (Fuss and Johnsson, 2021), as compared with targeted BECCS volumes. Sweden is soon to launch a system whereby the Government will buy negative emissions credits through an auction system (The Swedish Energy Agency, 2021).

Some first-of-a-kind (FOAK) (BE)CCS projects have been reported to over-run their budgeted cost estimations (Fyen, 2023), which threatens to reduce further the incentives to deploy carbon capture technology in the near-term. Previous reports have indicated that the cost for large-scale CCS demonstrations can exceed $1 billion, while the estimated cost of FOAK plants has exceeded $7 billion (Dubin, 2017). Nevertheless, technology-related costs often decline over time as more capacity is installed, from which learnings can be derived, so as to reduce the cost of future projects (Rubin et al., 2007). The developers of both the Boundary Dam and the Petra Nova CCS facilities have estimated that the capital costs could be 20 % lower if they were to build the facility again, based on learnings from the initial project (Global CCS Institute, 2021). Reiner (2016) has argued that "the eventual speed of deployment will not depend on the sheer number of projects but the success of learning at the demonstration phase". Bossink (2017) has further highlighted the impacts of learning from demonstration projects.

On the other hand, CCS projects are considered 'lumpy' (Markusson and Chalmers, 2013) and 'complex' (Grubler et al., 2016), and it remains unclear as to how much knowledge or learning can be transferred between projects. For example, larger cost reductions from learning can be expected for modular CDR technologies, such as direct air capture (Azarabadi and Lackner, 2020; Lackner and Azarabadi, 2021). The carbon capture technology has been commercially available for many years, and it is unclear as to how much of a reduction in cost can be expected in relation to the technology itself, even though the project costs and installation costs might decrease with expanded experience.

The need for increased carbon prices to incentivize CCS, in combination with the potential for cost reductions with an increased capacity of installed CCUS, raises the questions as to when in time CCUS deployment can be expected in relation to targets, and at what cost. Since FOAK cost data for CCUS facilities are limited, Nth-of-a-kind (NOAK) estimates are commonly applied in techno-economic studies of carbon capture systems (van der Spek et al., 2019). However, the NOAK costs cannot be seen as representative of early CCUS project costs and might lead to misconceptions about expected cost performance. A hybrid method has been demonstrated by van der Spek et al. (2017), in which FOAK costs and learning rates are applied to calculate NOAK cost levels.

In the present work, we apply a similar hybrid costing method to estimate the FOAK costs for CCUS using contingency factors and learning rates, to assess the carbon capture cost of the Nth plant to be built. The overarching aim is to derive marginal abatement cost (MAC) curves that enable refined assessments of the CCUS potential and cost development as the number of facilities increase. We also study the deployment of CCUS over time, given the cost reductions made possible by learning, and the estimated CO_2 price trends. Sweden is selected as a case study for this work, given the enormous interest in (BE)CCUS mentioned above, and the suitable conditions for BECCS (Fuss and Johnsson, 2021).

Marginal abatement costs have been criticized because, for example, they represent the cost distribution as static points in time (Kesicki and Ekins, 2012). Gallaher and Delhotal (2004) have provided a solution to this problem, presenting a range of curves for future points in time, including the effects of assumed technological change and projected cost reduction trends. However, MAC curves are often dependent upon exogenous assumptions regarding capacity installation rates. An example of this has been presented by van den Broek et al. (2009), where scenario data for capacity growth are used to project technology cost reductions with learning factors. Relying on scenarios might, however, limit the practical applicability of the results from such studies.

In the present work, we base the MAC curve and capacity growth estimations on individual projects that could realistically retrofit a carbon capture technology and contribute to technology learning. In this way, we avoid making assumptions as to capacity growth potentials, and incorporate elements of temporal dynamics, as technology learning effects are included. To the best of our knowledge, no previous study has adopted this approach of using existing plant portfolios to estimate potential cost reductions through learning, connected to MAC curves in which CCS, BECCS and (BE)CCU projects are all represented. We also present a method for deployment analysis, in which the effects of learning and CO_2 price trends are combined. Thus, the research gap and main motivation for this study can be defined by the need to develop methods that enable refined projections of the cost of carbon capture (and potential cost reductions) over time, based on announced projects and real possibilities (existing opportunities for technology installations) rather than externally imposed growth rates. In this way, this work contributes to the understanding of the economic conditions needed for carbon capture technology to contribute to emissions mitigation.

2. Method

The present work is based on techno-economic cost estimations of carbon capture retrofits to industrial and heat and power emissions sources, with the application of learning rates, to construct MAC curves, as described in Section 2.1. The cost estimations are also used to study carbon capture deployment scenarios (Sections 2.2). The cost estimations are applied to a case study of Sweden, as detailed in Section 2.3. Sweden represents a relevant case as there are a number of industrial CCS and CCU projects in various stages of planning. The MAC curves are envisioned as a reference point for the expected costs. Therefore, a standard, amine-based (MEA), post-combustion capture process is considered in this work.

2.1. Cost estimations and learning rates

The CO_2 capture cost is estimated in three steps, as visualized in Fig. 1, similar to the hybrid cost estimation method described by van der Spek et al. (2017, 2019). First, the NOAK capture cost of a plant/stack is calculated, followed by computation of the FOAK capture cost. Lastly, learning rates are applied to estimate how the FOAK cost of a facility declines over time, as increasing numbers of carbon capture projects are deployed.

2.1.1. CO_2 capture cost

The NOAK costs of CO_2 capture for industrial and CHP plants/stacks are estimated based on the methodology presented previously (Gardarsdóttir et al., 2018; Johnsson et al., 2020). The hourly flow rate of CO_2 to be captured, assuming a capture rate of 90 %, serves as the basis for capture plant dimensioning. CO_2 is assumed to be captured with a standard, post-combustion, amine-based (MEA) absorption process. The capital expenditures (CAPEX) of the MEA carbon capture plant are based on detailed, bottom-up techno-economic cost estimations for CO_2 concentrations of 5 %, 9 %, 13 %, 20 %, 24 % and 30 % (Gardarsdóttir et al., 2018). The costs for liquefaction and compression are based on a previous publication (Deng et al., 2019). The CAPEX is annualized assuming a project lifetime of 25 years (i.e., 3 years for construction and 22 years of operation) and a discount rate of 7.5 %. The operational expenditures (OPEX) are divided into fixed and variable costs. The fixed OPEX consists of annual maintenance (5 % of the absolute CAPEX cost) and labor costs [820 k€/a independent of plant size (Johnsson et al., 2020)]. The variable OPEX includes: steam to drive the CO_2 capture process, assuming a steam cost of 20 €/t_{steam} (Ali et al., 2018), corresponding to around 27 €/MWh with a reboiler duty of approximately 3.6 MJ/kgCO_2 captured; electricity for CO_2 compressors and solvent pumps at 60 €/MWh_{el}; cooling water (0.02 €/m^3); and MEA make-up costs (2000 €/m^3).

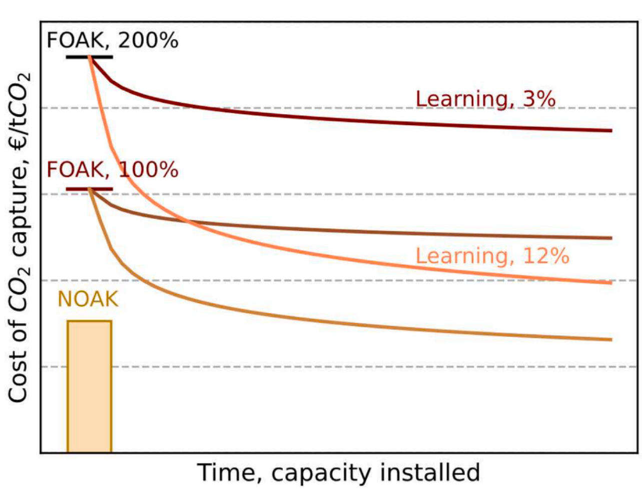

Fig. 1. Principal example of the cost calculation hybrid method and the use of learning rates.

Contingency factors are used to estimate the FOAK cost levels based on the NOAK values. Reported data from the Global CCS Institute (2017) indicate that there could be an up to 100 % increase in cost [$/t] from NOAK to FOAK. Evaluations of the Boundary Dam CCS project have concluded that costs could be reduced by up to 67 % if the same project was to be built again (IEA, 2020), corresponding to a cost increase of 200 % from NOAK to FOAK. Recent reports from ongoing CCS projects in Norway have indicated that project costs by June 2023 have over-run their budgets by 30 %–45 % (Fyen, 2023), corresponding to specific CO_2 costs that are 100 %–200 % higher than the corresponding NOAK estimations based on the method described above, as summarized in Table 1. The reported cost increases for the Norwegian projects are mainly due to significant project changes (e.g., localization of the shipping facility), infrastructure requirements, increasing energy and material costs, and reinforcement of the project organization (Fyen, 2023).

Thus, for each case study plant, the calculated NOAK CAPEX and OPEX are multiplied by a contingency factor of (i) 100 %, and (ii) 200 %, to represent the estimated FOAK costs. Note that both of the ongoing CCS projects in Table 1 are planned to capture 400 ktCO_2/a, although their costs differ substantially. Thus, significant variations in cost can be expected for different types of sites and industries. Therefore, and a wide range of cost escalations is considered in this work.

2.1.2. Learning rates

The estimated FOAK costs are predicted to decrease over time as the number of deployed projects increases, as the learnings gained from finished projects can be of use for upcoming ones (Fig. 1). The reduction in FOAK cost over time (capacity build-up) is represented in this work by learning rates. Learning curves with the format shown in Eqs. (1) and (2) have been applied in a previous study of CCS cost estimations (Rubin et al., 2007). C_a is the cost of project number a, which is calculated from the FOAK cost C_0 and the factor b, whose value is adapted to a specific learning rate, LR. The learning curve assumes that the project cost is reduced by the learning rate each time that the installed capacity doubles.

$$C_a = C_0 a^{-b} \tag{1}$$

$$1 - 2^{-b} = LR \tag{2}$$

The learning curve is applied to the estimated FOAK costs for the construction of a MAC curve, as described in Section 2.2. Estimating the learning rate for a CCS technology is challenging, given that few projects have been completed globally. However, the analogy between the flue gas cleaning technology (wet scrubbers) and CO_2 absorption has been used in previous works to estimate learning rates, which were found to be in the range of 12 %–14 % for the period of 1970–2000 (Li et al., 2012; Lohwasser and Madlener, 2013; Riahi et al., 2004; Rubin et al.,

Table 1
Comparison of NOAK estimates, budgeted costs and cost over-runs for CO_2 capture projects in Norway.

Project data	Brevik CCS	Celsio CCS
Plant type	Cement Industry	Waste CHP plant
Planned capture [ktCO_2/a]	400	400
Estimated NOAK cost[a], Section 2.1.1 [€/tCO_2]	69.3	71.6
Gassnova estimated project cost[a] (Gassnova, 2020) [€/tCO_2]	104–120	152–163
Reported project cost over-run[b] (Fyen, 2023)	30 %	45 %
CO_2 cost with over-run[a] [€/tCO_2]	135–155	221–237
Project cost increase compared to NOAK	94 %–123 %	209 %–231 %

[a] Cost includes CAPEX and OPEX for capture and conditioning.
[b] Compared to the budgeted cost.

2007).

Lohwasser and Madlener (2013) have shown that the learning might not only be related to the technology itself (installed capacity), but also to knowledge building through research efforts, suggesting that the contribution of accumulated knowledge is as strong as accumulated capacity. Malhotra and Schmidt (2020) have stated that retrofits (as considered in this work) have relatively lower learning rates, due to the need for customization. For example, Kumar (2024) have found that site-specific factors, such as suitability for retrofitting, which is not related to the technology but rather to the ways in which it can be integrated into existing industrial systems, can increase cost estimations. On the one hand, it can be argued that CO_2 absorption is a mature technology, already used in industrial applications, and that little further learning is to be expected for the technology itself. On the other hand, learning related to the practical implementation of CCS can continue over time as actors in the supply chain gain experience, and this might bring down the project installation costs.

Given the uncertainties associated with the amount of learning and the cost reductions that are possible for the CCS technology, two learning rates are applied in this work: (i) a conservative rate of 3 %, which represents the case in which the level of learning from finished projects is low, i.e., it is difficult to transfer knowledge from one project to another, and learning occurs mainly on a national level (in this case, within Sweden); and (ii) a higher learning rate of 12 %, which represents the case in which a higher level of learning is feasible, and it is possible to learn from projects globally and not only from local projects in Sweden. As for the first limited learning level (i), it is not possible to say which factors are most likely to limit learning.

A learning and development scope that is limited to a specific country may be justifiable because CCS retrofits (as considered here) do not represent a mass-production technology. On the global level, a limited number of (retrofit) projects might be carried out. Thus, the technology-related cost reduction potential might be limited, although other factors, such as project execution and installation, could face cost improvements as complex retrofit projects are carried out. Cost reductions due to execution of the project are also more likely to be regionally limited, as workforce and project execution for these types of projects mainly occur in the national setting (as opposed to mass products with an international market). Thus, we consider it reasonable to assume that limiting the scope of our study to Sweden for the construction of the MAC curve does not lead to an underestimation of the learning rate.

2.1.3. *Marginal abatement cost curve – an individual project approach*

The MAC curve is constructed as follows. First, the plants in the considered system are ordered with respect to when in time the plants are targeting implementation. Plants that are assumed to be early movers, i.e., have announced ambitions to capture CO_2 and have initiated work towards this goal (i.e., start of construction, permitting processes, pilot studies or feasibility studies) are placed first in the MAC curve project order, based on the estimated start of operations. The remaining plants in the considered system are subsequently ordered according to their estimated capture costs, under the assumption that the lowest-cost projects will be carried out first. Second, based on the estimated NOAK costs, the FOAK costs are computed for each project and adjusted with learning factors (as detailed in Section 2.1.2), based on the plant order in the MAC curve. That is, the first plant in the MAC curve order will be assigned its FOAK cost, while the x-th plant in the order will receive cost $C_x = FOAK_x * x^{-b}$ (cf. Fig. 1). The projected cost after application of the learning factors, and after the addition of transport and storage costs (Section 2.1.4), is plotted in the final MAC curve.

2.1.4. *CO_2 transport and storage costs*

The CO_2 captured at a plant is assumed to be transported by truck or pipeline to a harbor with a CO_2-terminal, i.e., a CO_2 *hub*, where it awaits further shipping to an offshore storage location. The truck transport cost is calculated using the method described in (Beiron et al., 2022), although with a diesel cost of 2 €/l rather than the cost of 1.2 €/l in the referenced study. Pipeline transport can be considered for large-scale emission sources instead of trucks and are calculated based on the following cost data (Danish Energy Agency, 2023): Investment cost, onshore pipeline: 43 €/(tCO_2/h, m) for 30 tCO_2/h flow rates, 18 €/(tCO_2/h, m) for 80 tCO_2/h flow rates, or 13 €/(tCO_2/h, m) for 120 tCO_2/h flow rates. Fixed operational and maintenance costs: 20 €/(tCO_2/h, km). Variable operational and maintenance costs are neglected. Pipeline lifetime: 50 years. The investment cost is annualized with an interest rate of 5 %. Both the truck and pipeline transport costs are calculated for all emission sources and the lowest cost option is used for construction of the MAC curves.

The average ship transport cost is assumed to be 25 €/tCO_2, based on a study of the build-up of CO_2 infrastructure in Sweden conducted by Karlsson et al. (2023). The CO_2 storage price is set by the storage provider. Early estimations of the ship transport and storage costs by the Northern Lights project lie in the range of 30–55 €/tCO_2 (Sandberg, 2020). However, as CO_2 storage infrastructure is scaled up, cost reductions can be expected due to economy of scale and the learning acquired from the early phases of the storage projects (Rosjorde and Carpenter, 2020). Lohwasser and Madlener (2013) have argued that the cost reduction from technology learning can be expected to be low with respect to transport and storage, since the technology is already in widespread use within the oil and gas industry. For the present work, technology learning is neglected and a constant storage cost of 50 €/tCO_2 is assumed. It should also be mentioned here that the storage offers received by Swedish actors have so far been higher than the above-cited costs.

2.2. *Deployment scenarios*

The learning rates for carbon capture costs are applied to analyze when in time carbon capture would be a competitive investment for a plant, as compared to paying an estimated EU ETS CO_2 price or a selling price for CDR (BECCS). The EU ETS CO_2 price is estimated for the period of 2025–2055 using Eq. (3), where $P_{CO2,y}$ is the estimated CO_2 price in year *y*, and P_{2024} is the CO_2 price at the outset of Year 2024 (80 €/tCO_2).

$$P_{CO2,y} = P_{2024} * 1.09^{y} \quad (3)$$

The resulting curve is plotted in Fig. 2 and compared with other published estimates of the future CO_2 price (Enerdata, 2023; GMK Center, 2023; Simon, 2023). The selling price for negative emissions

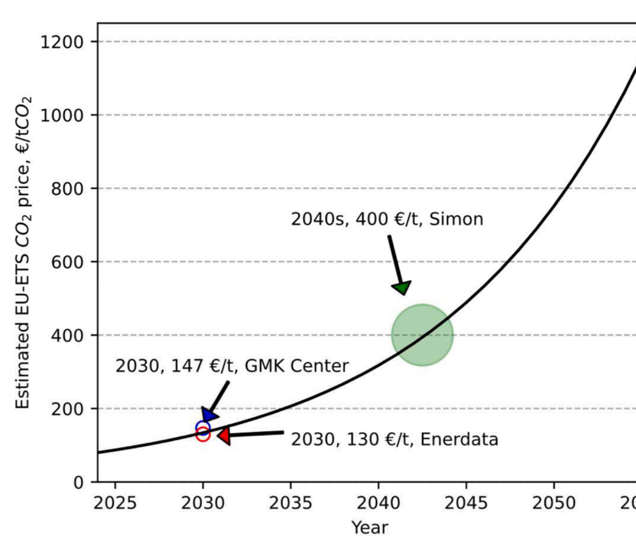

Fig. 2. CO_2 price estimation curve.

(BECCS) is assumed to equal the EU ETS CO_2 price. This is a reasonable assumption given that the reward for creating negative emissions should not exceed the cost of emitting fossil fuel emissions – as that would risk the creation of a moral hazard, and also considering that biomass is a limited resource.

The estimated cost of a project [C_a, Eq. (1)] is evaluated for the period of 2025–2055, assuming a learning curve in which two carbon capture projects are deployed each year that contribute to cost reductions for CCS plants (Fig. 1). During the period of 2000–2023, 4–5 industrial-scale projects (new CHP plants or pulp mill reinvestments) per year have been commissioned in Sweden (the country in focus in this work). Thus, the assumption of two projects completed per year is realistic for Sweden, and aligns with the stated ambitions of the early movers in the country (Section 2.3), as noted by Fuss and Johnsson (2021).

For each year, the estimated CCS project cost of a plant is evaluated against the estimated CO_2 price. When the CO_2 price is higher than the calculated project cost ($C_{a,y}$) for a year, the project is assumed to be built in the corresponding year. Thus, an investment is made if:

$$C_{a,y} \leq P_{CO2,y} \tag{4}$$

The exception to this is early movers, which are assumed to finalize their projects by the respective target commissioning year, independent of competitiveness. Summarizing these deployment estimations for all plants in a studied system, a scenario describing the build-up of carbon capture installations over time can be derived.

2.3. Case study – Swedish industrial and CHP plants

The case study includes all major emitters of fossil and biogenic CO_2 in Sweden, including industrial plants and CHP plants. The industrial sectors considered are: iron and steel, pulp and paper, refineries, chemicals, and cement (minerals). For the Swedish iron and steel industry, CCS is currently not the main decarbonization pathway, although these plants are still included in the case study because the carbon capture technology could be a feasible option for the industry sector in general. In total, 37 industrial plants that emit >200 $ktCO_2/a$ are included in the study. While there are some plants in other industrial sectors (e.g., metallurgical industry) that emit >200 $ktCO_2/a$, it is unclear as to whether CO_2 capture is a suitable option for the decarbonization of these plants, as the pertinent data are missing; therefore, they are excluded from the present work. In contrast, 108 CHP plants are included in the case study, regardless of their annual emissions and fuel types. Two large (>200 $ktCO_2/a$) heat-only boilers (HOB) are also considered. In total, the case study covers 147 plants emitting 40.1 $MtCO_2/a$ (fossil and biogenic). This can be compared with the total Swedish fossil greenhouse gas emissions of some 45 Mt in Year 2022 (Statistics Sweden, 2023). A list of all the case study plants and hub locations is provided in the *Supplementary Materials*, and Fig. 3 shows a map of their geographical distribution in Sweden.

Industrial plant data are obtained from the Chalmers Industrial Case Study Portfolio (Svensson et al., 2019). The CHP plant data are based on (Beiron et al., 2022). All the annual CO_2 emissions data are updated to Year 2022 based on data reported in the Swedish Pollutant Release and Transfer Register (The Swedish Environmental Protection Agency, 2024). The register contains emission data (fossil and biogenic CO_2) for all sites that emit >100 $ktCO_2/a$ and/or have a thermal capacity >20 MW_{th}. This implies that if several plants or stacks are located at the same site, their CO_2 emissions are aggregated; and CHP plants that emit <100 $ktCO_2/a$ do not necessarily report data. If emissions data are missing for a CHP plant, the plant CO_2 emissions are estimated based on annual fuel use data reported in (Swedenergy, 2021), assuming that the combustion of 1 MWh of biogenic fuel corresponds to 355 $ktCO_2$-generated.

Aggregated emissions are divided between plants/stacks according to the following method. For industries, the emissions are allocated to stacks based on assumed percentages (see Table 2). Each stack is

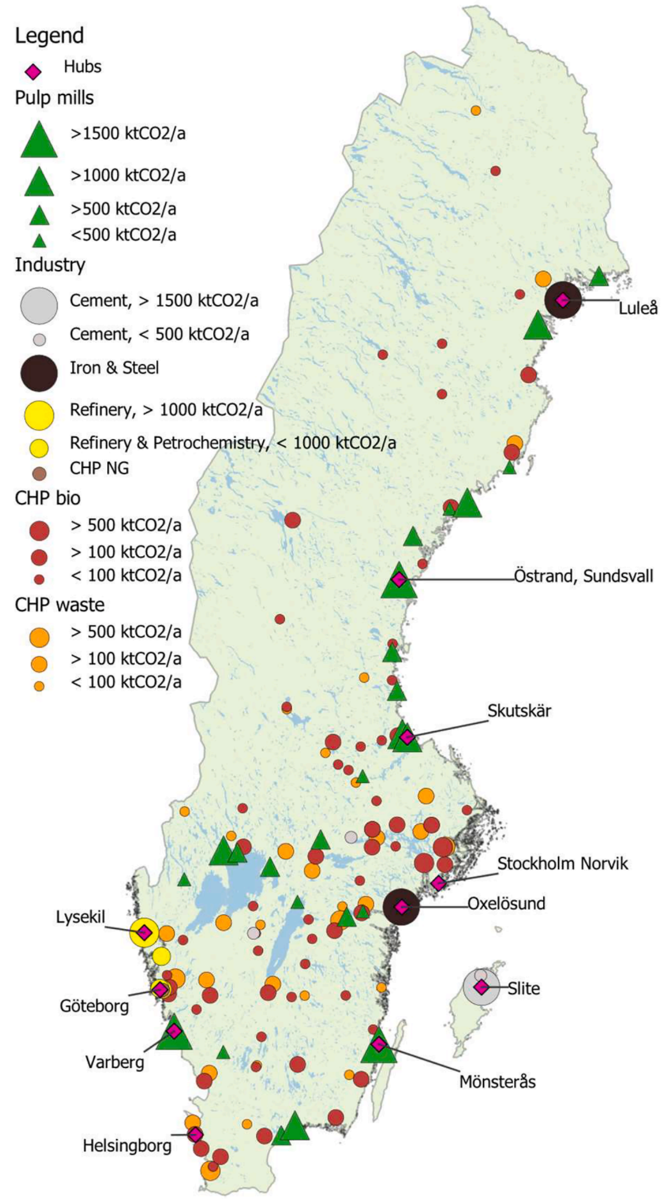

Fig. 3. Map of the locations and scale of emissions for the Swedish plants and hubs included in the case study. The hub locations are marked with labels.

individually considered for CO_2 capture retrofitting. For CHP plants located at the same site, emissions are allocated based on either fuel use data, or if the fuel use data are not sufficient to allocate emissions, boiler capacity data, with an assumption made as to the annual number of full-load hours. It is assumed that installing CO_2 capture at a plant does not impact the plant operation or annual CO_2 generation level.

The analysis considers captured emissions rather than avoided emissions, under the assumption that the captured and avoided emissions have similar magnitudes. For CHP plants and the pulp and paper industry, the energy required to drive the capture process might be taken from existing steam production. Excess heat utilization could be feasible for refineries (Biermann et al., 2022), pulp mills (Skoglund et al., 2023) and steelmaking (Eliasson et al., 2022). Thus, capture plant integration might not necessarily increase site emissions, and even if fuel use increases due to capture plant integration, the retrofit might be designed to capture also these additional emissions. For CHP plants, it might be possible to recover low-grade heat from the capture process for use in district heating systems, thereby reducing the need for increased fuel use

Table 2
Assumptions as to industrial and CHP plant data related to CO_2 emissions. Note that there might be several CO_2 sources of the same type at a specific site, as well as smaller CO_2 sources/stacks that are not included in the study (e.g., bark boilers in pulp mills).

Plant type	Capacity factor	CO_2 source	% of site emissions	Vol% CO_2
Iron and Steel	0.91	Power plant	40	30
		Hot stoves, coking plant, other	17	24
Refinery	0.95	SMR for hydrogen production	30	24
		Combined stacks	15	8
Pulp and Paper	0.91	Recovery boiler	75	13
		Lime kiln	10	20
Cement	0.95	Combined stack	90	20
Chemical	0.95	Cracker	78	5
CHP, HOB	Plant-specific	Boiler	100	13

SMR, steam methane reformer; CHP, combined heat and power; HOB, heat-only boiler.

(Beiron et al., 2022; Roshan Kumar et al., 2023).

Table 3 lists the case study plants that are assumed to be early movers with respect to CCS deployment in Sweden, based on their activities in relation to permit application processes, pilot studies, feasibility studies and/or an expressed interest in CCS. While some of the announced projects aim to capture less than the full potential of the plant, the full potential capture rate is shown in the MAC curve to illustrate the theoretical potential. Note that three of the announced projects in Table 3 target CCU applications (methanol production).

3. Results and discussion

The results are presented in two parts followed by discussion. Section 3.1 describes the estimated MAC curves derived from the case study and the impacts on project costs of learning rates. Section 3.2 presents an analysis of the modeled carbon capture deployment over time in Sweden. Section 3.3 evaluates the methodological approach of the study. Section 3.4 discusses the use of BECCS as a CDR measure using a SWOT (strengths, weaknesses, threats, opportunities) analysis.

3.1. Marginal abatement cost curves

3.1.1. Nth-of-a-kind costs and plant order

Fig. 4 shows the NOAK-based MAC curve for the Swedish case study plants, distinguishing between industrial and CHP plants, as well as between biogenic and fossil CO_2 emissions. The early mover plants (Table 3) are placed furthest to the left, as stated in Section 2.1.3 and together they correspond to the capture of 8.7 $MtCO_2$/a of which almost all (6.3 Mt/a) is captured from the combustion of biomass or waste in CHP plants. If all case study plants deploy carbon capture, the total potentials for fossil and biogenic carbon capture are 10.6 and 29.1 $MtCO_2$/a, respectively, with an additional 0.44 Mt/a of bioenergy coupled with carbon capture and utilization (BECCU) planned. This can be compared to the total fossil greenhouse gas emissions in Sweden in Year 2022, which were around 45 $MtCO_2$ (Statistics Sweden, 2023). It should, however, be noted that some of the BECCS projects indicated in Fig. 4 could be deployed as CCU projects, depending on the levels of willingness in different sectors to pay for biogenic CO_2 and CDR. The potential for BECCS might, thus, be lower than the numbers indicated here, if competition for BECCU increases over time. It should be noted that three of the early mover plants are targeting CCU for methanol production (yellow shading in Fig. 4, total of 440 $ktCO_2$/a for CCU). Therefore, carbon utilization, rather than carbon removal, is seen as the main driver for early carbon capture projects, and it competes with CDR and BECCS targets. It should, however, be possible to learn from both CCU and CCS projects, as they are based on the same type of capture technology.

Interestingly, it is clear from the cost calculations that the early movers in Table 3 are not the plants with the lowest estimated capture costs. Instead, the estimated early mover capture costs can be up to two-fold higher than the corresponding values for the lowest-cost plants in

Table 3
Early mover (BE)CCUS actors in Sweden.

Plant/project	Type	Ambition [Year]	CO_2 emitted 2022 [kt/a]	Biogenic/fossil	Status (as of April 2024)
Liquid Wind FlagshipONE, Örnsköldsvik	CHP plant + CCU	2025	270	Biogenic	Construction started in 2023.
BECCS Stockholm	CHP plant	2027	800	Biogenic	Pilot study complete. Permit granted.
Liquid Wind FlagshipTWO, Sundsvall	CHP plant + CCU	2026	200	Mix (MSW) – fossil to be stored	Construction start in 2024.
Öresundskraft, Helsingborg (Filborna)	CHP plant	2027	210	Mix (MSW)	Pilot study. Procurement process.
Liquid Wind FlagshipTHREE, Umeå	CHP plant + CCU	2027	170	Mix (MSW) – fossil to be stored	Construction start in 2024.
Skellefteå Kraft (Hedensbyn)	CHP plant	2027	170	Biogenic	Environmental permit granted.
Vattenfall, Jordbro	CHP plant	2028	220	Biogenic	Early phase of project. Permit application.
Växjö (Sandviksverket)	CHP plant	2028	260	Biogenic	Pilot study completed. Detailed engineering study.
Söderenergi, Södertälje (Igelstaverket)	CHP plant	2029	520	Biogenic	FEED study start in 2024.
Heidelberg Materials, Slite	Cement Industry	2030	1800	Mix of fossil + bio	Project planning and establishment 2024–2025.
Malmö (SYSAV)	CHP plant	2030	250 + 250	Mix (MSW)	Pilot study.
Preem, Gothenburg	Refinery, SMR	N/A	300	Fossil	Pilot project completed. Considering CCS vs CCU.
Vattenfall, Uppsala	CHP/HOB plant	N/A	400	Mix (MSW)	Pre-study.

Plants that have conducted feasibility studies and shown interest in CCS (plant type, CO_2 emitted ín Year 2022) (Borglund, 2023):

- Gävle Energi (CHP, 130 kt/a)
- Renova, Göteborg (CHP, 540 kt/a)
- Skövde Energi (CHP, 100 kt/a)
- Boden Energi (two CHP, 160 kt/a)
- Falu Energi och Miljö (CHP, 180 kt/a),
- Tierp Energi (HOB, 23 kt/a)
- E.ON, Högbytorp (CHP, 260 kt)
- E.ON, Örebro (CHP, 340 kt/a)
- E.ON, Händelö, Norrköping (CHP, 470 kt/a)
- Mälarenergi, Västerås (two CHP, 450 + 290 kt/a)
- Tekniska Verken Linköping (CHP, 250 kt/a)
- Katrinefors, Mariestad (CHP, 60 kt/a)
- Halmstad Energi (CHP, 170 kt/a)
- Kraftringen, Örtofta (CHP, 230 kt/a)
- Jönköping Energi (two CHP, 350 kt/a)
- Stora Enso (pulp mill, 1300 kt/a)
- Södra (pulp mill, 1800 kt/a)
- Preem, Lysekil (refinery, 600 kt/a)

FEED, Front-End Engineering Design; MSW, municipal solid waste; SMR, steam methane reformer; N/A, data not available.

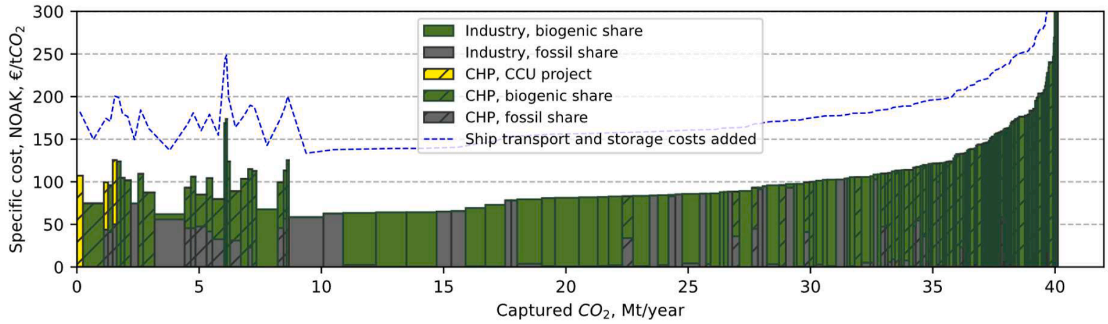

Fig. 4. Marginal abatement cost curve for industrial and CHP plants in Sweden, based on Nth-of-a-kind-costs. Cost components included in the bars are carbon capture and truck/pipeline transport to the nearest coastal transportation hub, while the dashed line indicates added costs for ship transport (25 €/t) and storage (50 €/t). Plants that are categorized as early movers are placed left-most in the figure, ordered by target year of deployment. Colors distinguish between biogenic (green) and fossil (gray) CO_2, while CCU projects are marked in yellow. Note that the y-axis is cut at 300 €/tCO_2.

the case study (steel mills). The early movers mainly consist of CHP plants of varying sizes, both biomass- and waste-fired, one cement plant, and one pulp mill. These trends imply that scenarios for the deployment of decarbonization projects should not necessarily be based on the principle of lowest cost first, or the volume of CO_2 captured. Business models, ownership, and public demands might better explain why relatively small municipal CHP plants are identified as early movers in the Swedish CCS deployment.

Industrial plants generally achieve lower costs than CHP plants, due to economy of scale and, in some cases, higher flue gas CO_2 concentrations. The industries also constitute greater potential in terms of the volume of CO_2 captured. As indicated by the dashed line in Fig. 4, none of the projects are economically viable with the NOAK costs, relative to current EU ETS carbon prices (around 80 €/tCO_2 in January 2024). Based on the NOAK costs, carbon prices above 135 €/tCO_2 are required to incentivize CCS at the lowest-cost plant (in this case, a steel mill power plant).

3.1.2. *First-of-a-kind costs and learning rates for cost reduction*

Fig. 5 compares the MAC curves for the estimated FOAK costs and learning rates with the corresponding NOAK values. The costs cover the capture, transport and storage of CO_2. The fluctuations in the cost curves above 15 MtCO_2/a-captured are due to truck transport costs not being scaled by the FOAK contingency factors. With FOAK contingency factors, the specific CO_2 costs are considerably higher than the NOAK costs. In total, 39 plants have specific CO_2 costs of <250 €/tCO_2, for the 100 % FOAK contingency factor without the application of learning rates (together capturing 24.3 MtCO_2/a). At 300 €/tCO_2, the corresponding numbers are 90 and 17 plants, respectively, for the 100 % and 200 % contingency cases.

However, the learning rates (3 % and 12 %) have the potential to reduce significantly the specific capture cost, especially in the case of the higher learning rate. For the 100 % contingency case (Fig. 5a), the NOAK capture cost levels are almost reached by the time the early mover projects are installed, given a learning rate of 12 %. For the 200 % contingency case (Fig. 5b), the 12 % learning rate is not sufficient to bring the costs down to the NOAK level for the capacity installations considered in the case study, although capture cost reductions of around 45 % (compared to the FOAK levels) are observed following the commissioning of early mover projects. With the lower learning rate (3 %), the impact on specific capture cost is weaker and cost reductions are in the interval of 10 %–20 %, as compared to the FOAK capture costs.

Clearly, a low cost reduction potential through technology learning threatens to keep CCS costs high, irrespective of how many projects are implemented. In this regard, the application of the hybrid cost-evaluation method in CCS contexts might not be needed, as it may suffice to simply use FOAK contingency factors without applying learning rates to reach an approximate estimation of the cost for CCS. If higher learning rates can be expected, the method has greater significance, and can be used to estimate at what time the NOAK cost levels might be reached. It can also be discussed as to whether the project contingency factor will retain its magnitude over time, or how much it

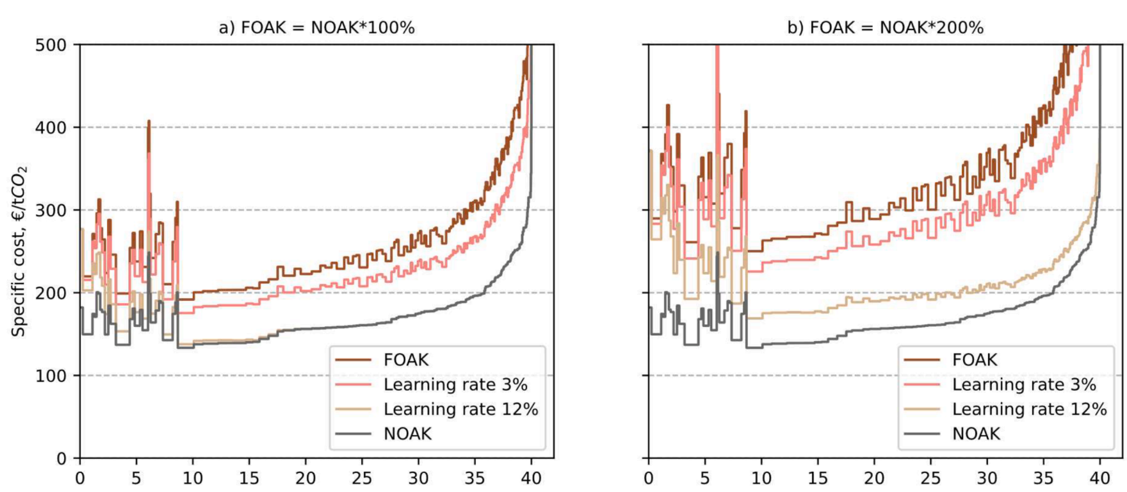

Fig. 5. MAC curves based on FOAK cost estimations and different learning rates for the case study plants. The cost includes capture, transport, and storage. a) 100 % FOAK contingency. b) 200 % FOAK contingency. The NOAK cost curve is included for comparison (see Fig. 4). The plant order is the same as that plotted in Fig. 4.

could be reduced as additional projects are deployed. As shown in Fig. 5, the contingency factor itself has a marked impact on the cost, so it must not be neglected. Therefore, the relevance of NOAK cost estimations often seen in academic publications should be evaluated.

3.2. Carbon capture deployment scenarios

Fig. 6 shows the modeled deployment of carbon capture installations in Sweden over time, as a function of increasing carbon price [Eq. (3)], and the cost reductions achieved through learning rates as the installed capacity increases. Fig. 6a assumes a 100 % FOAK contingency factor, while Fig. 6b is based on a 200 % FOAK contingency. In both cases, the deployment of early mover CCS projects until Year 2032 (Table 3) is based on target commissioning years, rather than an economic evaluation [Eq. (4)]. There is a steep ramping up in modeled CCS deployment in the 2030s. By Year 2060, carbon capture is economically viable at all the case study plants, given the expected increase in carbon price. With these assumptions, the proposed Swedish targets (SOU, 2020) of 1.8 Mt/a of BECCS by Year 2030 and 3–10 Mt/a BECCS by Year 2045 are met.

With the 100 % FOAK contingency, a peak in carbon capture deployment is observed around 2034–2038, which coincides with estimated increases in CO_2 prices [around 200 €/t by Year 2035, Eq. (3)], and the planned phase-out of free allowances from the EU ETS by Year 2034. It should be noted that BECCS is not included in the EU ETS, although it is in this work assumed to be priced at the same level as fossil CCS (Section 2.2), i.e., the reward for achieving negative emissions is the same as the cost to emit fossil-fueled CO_2 emissions. A 200 % FOAK contingency factor shifts the deployment peak to later in time, to around 2037–2042 (Fig. 6b), as higher carbon prices are needed to incentivize investments in the capture projects if costs increase. Estimates of the development of EU ETS allowance prices show a steep increase in prices around Year 2040 (Simon, 2023).

The planned early mover project deployments are fixed to their target timelines, regardless of cost levels, providing opportunities for later installations to learn from the early mover projects. A high learning rate from early projects implies a greater cost reduction potential (Fig. 5), and this suggest that the point of economic viability can be moved forward 3 years. However, caution should be exercised regarding the movement of deployment scenarios forward in time, as it takes time to apply for permits, conduct detailed engineering studies, and construct plants. Large-scale implementation of CCS requires that planning is started well in advance of targeted deployment, which might not be the case for actors that are not among the early movers. The maximum CCS capacity installed per year in Sweden is around 7 $MtCO_2$/a for the deployment scenarios shown in Fig. 6. Thus, for the deployment to be practically feasible, it is crucial that also the necessary infrastructure requirements (CO_2 transport, storage capacity, engineering and construction competence) are put in place by 2030–2035.

With regards to BECCS deployment in Sweden, a government-funded support system based on reverse auctioning is being planned. The initial plan is that the proposed target of 1.8 Mt/a of BECCS will receive support for the first 15 years of operation (The Swedish Energy Agency, 2021). Considering the list of ongoing projects in Table 3, it is likely that the proposed BECCS target can be met by Year 2030, since roughly double the volume of BECCS could be operational by then if all the planned projects (Table 3) are successfully implemented.

The governmental budget for the reverse auctioning system is set at 36 billion SEK for the period of 2026–2046 (approximately 3600 M€, at the currency exchange rate of 1 € = 10 SEK). With the FOAK costs estimated in Section 2.2.2, the cost of capturing the first 1.8 $MtCO_2$/a would amount to 300–450 M€/a (range depending on FOAK contingency factor and learning rate) plus ship transport and storage costs of around 140 M€/a, under the assumptions listed in this work. Supporting the first 1.8 Mt/a for 15 years would cost 6600–8800 M€, which would exceed the proposed budget. With FOAK costs, the budgeted 3600 M€ would barely be sufficient to fund the first early mover BECCS project of 0.8 $MtCO_2$/a. If NOAK cost levels (Section 2.1.1) are applied, covering the costs for 15 years for 1.8 Mt/a would require 4600 M€ in state support, which is closer to, but still more than, the allocated budget. The use of NOAK or FOAK cost estimations in budget propositions, therefore, needs careful consideration, as they might lead to significantly different expectations as to total costs and captured CO_2 volumes.

3.3. Discussion of method and assumptions

The methodological approach taken in this study enables the computation of potential cost reductions over time for CCS based on an existing portfolio of point-source emitters. One underlying assumption of using learning rates to represent cost reductions, is that the same project is constructed multiple times and that the cost is reduced for every doubling of installed capacity (Rubin et al., 2007). While all plants in this case study are assumed to retrofit the same type of carbon capture process, the plants differ in several aspects (such as the scale of the plant, flue gas characteristics and opportunities for heat integration of the capture process) and the projects would, thereby, not be exactly the same. For instance, previous work has shown that the type of fuel (recycled wood vs fossil coal) could impact the capture plant reboiler duty (lower for recycled wood given a higher concentration of CO_2 in the flue gas), and that a higher flue gas oxygen concentration (fossil coal

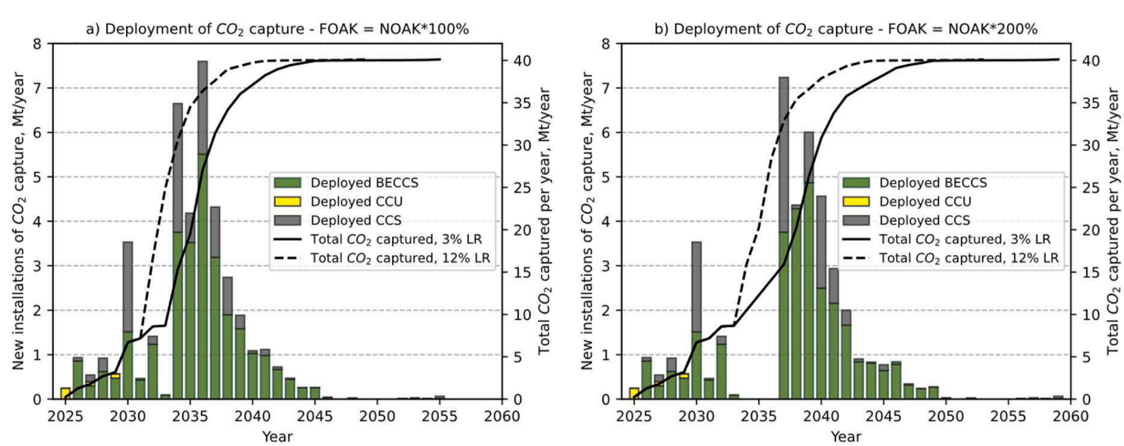

Fig. 6. Modeled deployment over time of carbon capture projects in Sweden given the carbon capture costs with learning rates and an increasing CO_2 price according to Eq. (3). a) Deployment scenarios based on: 100 % FOAK contingency; and b) 200 % FOAK contingency. The lines showing the total carbon captured per year refer to learning rates (LR) of 3 % and 12 %, respectively, while the bars correspond to the 3 % learning rate.

combustion) might lead to increased levels of solvent degradation (Nookuea et al., 2020). Additionally, another study found that accumulation of potassium and chlorine in the solvent was higher when capturing CO_2 from biomass (corn stover) combustion than coal combustion (Strege et al., 2022). These factors might impact the design and operating characteristics of the capture process and lead to differences in cost. Given the varying plant scales, in this work we also deviate from the assumption that all capture processes installed have the same capacity, and rather assume that the cost is reduced every time the number of capture processes installed doubles. The impact on the results of aspects that limit the learning that can be transferred between projects might be a higher estimated cost of captured CO_2, that may be closer to the case with a 3 % learning rate.

The potential for BECCS is estimated assuming that the current portfolio of Swedish bio-energy plants remains over time and that plants are replaced when reaching end-of-life. For industrial sites, this might be a valid assumption given that re-investments are commonly made to replace or extend the life of key equipment, rather than building new industrial projects from scratch which would require significant capital investments. For CHP plants, it has historically also been common that end-of-life plants are replaced with similar technology. However, CHP plants are competing with other technologies for the supply of district heating and electricity, and biofuel prices are expected to increase over time (Section 3.4). Thus, the continued practice of using biofuels for district heating supply is, to some extent, uncertain and could reduce the BECCS potential somewhat.

3.4. SWOT analysis of BECCS

While fossil CCS can act as a decarbonization measure for industries and power generation and could be economically motivated by a higher carbon price, the situation is different for biogenic CO_2. For Sweden, it is foreseen that most CO_2 capture will come from BECCS. Yet, the economic conditions for BECCS are still uncertain, as is the long-term access to biogenic fuels. Thus, investing in a long-term project that uses biomass for BECCS might entail an economic risk, considering that the willingness to pay for biomass (as a fuel or feedstock for the production of materials) might be higher in those industrial and/or transport sectors where it is difficult to shift away from carbon-based fuels or feedstocks (e.g., aviation and maritime fuels, chemicals, biochar for steel production).

Fig. 7 presents a SWOT (strengths, weaknesses, opportunities, threats) analysis of BECCS in a Swedish context, and summarizes the key aspects to consider when evaluating investments in BECCS installations. On the positive side, BECCS remains one of few commercially available options to achieve cardon dioxide removal with high permanence, and there appears to be broad political support available through the above-mentioned governmental funding scheme for BECCS. In addition, voluntary markets for offsetting fossil greenhouse gas emissions by means of BECCS are emerging. The end-of-pipe nature of the post-combustion capture technology also enables the continued use of biomass for societal services and energy purposes, such as process heat, district heating and dispatchable electricity generation. However, the high costs for capture, transport and storage of CO_2, as well as the associated energy penalty, clearly limit the competitiveness of BECCS; to date, no projects have yet entered operation. Political initiatives in the EU may also mean that the harvesting of biomass from forests will be restricted, which might increase even more the competition for the available biomass.

4. Conclusion

This work applies a hybrid method for a techno-economic assessment that is based on first-of-a-kind contingency factors and learning rates to estimate the cost of CO_2 capture from 147 industrial and CHP plants in Sweden, which together constitute a CO_2 capture potential of 40.1 $MtCO_2/a$ (fossil and biogenic) from 176 stacks. The results of the work are presented in MAC curves and deployment scenarios over time. The main conclusions of the work are that:

- When accounting for first-of-a-kind contingencies high CO_2 price levels are required to incentivize CO_2 capture projects. Without learning rates, 90 (100 % contingency) and 17 (200 % contingency) of the 176 emission sources have specific CO_2 costs of <300 €/t.
- Learning from early mover CCS projects can reduce carbon capture costs from first-of-a-kind levels to Nth-of-a-kind estimated levels after some 30 projects are deployed. However, this requires a high learning rate (12 %). With a lower learning rate (3 %), cost

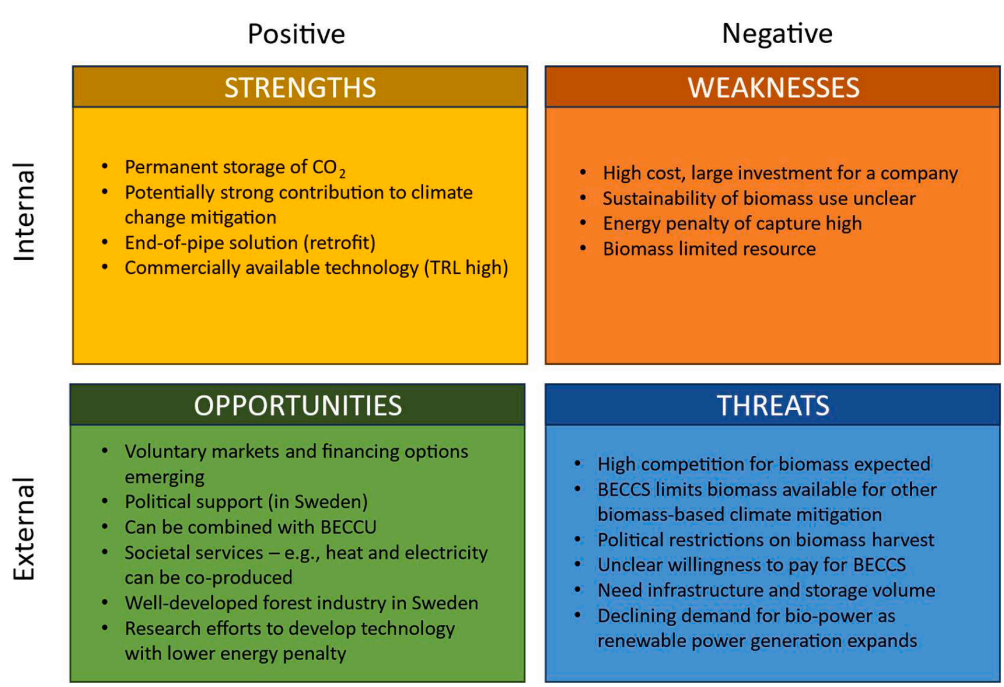

Fig. 7. SWOT analysis of BECCS in a Swedish context.

reductions amounting to 10 %–20 % of the first-of-a-kind values are obtained.

- Ongoing early mover (BE)CCS projects do not correspond to lowest-cost-capture plants. This indicated that factors other than cost alone explain the deployment of CCS.
- Given a modeled increase in the EU ETS carbon price over time (reaching around 200 €/tCO_2 by Year 2035), a peak in CCS deployment occurs around 2035–2040. CO_2 transport and storage systems need to be put in place by then, so as to enable project completion.

Biogenic emissions are assumed to be permanently stored in this work (unless early movers have expressed utilization as the main target). However, the identified potential for BECCS in Sweden (29 Mt/a) is subject to competition from other sectors that may have a high willingness to pay for biogenic carbon (for example, aviation and maritime transportation fuels). Future work should investigate the climate benefits of BECCS in comparison with the utilization of biogenic carbon to substitute for fossil fuel use.

CRediT authorship contribution statement

Johanna Beiron: Writing – original draft, Methodology, Conceptualization. **Filip Johnsson:** Writing – review & editing, 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.

Data availability

Data is available in the Supplementary Materials.

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Supplementary materials

Supplementary material associated with this article can be found, in the online version, at doi:10.1016/j.ijggc.2024.104226.

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