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IEA GREENHOUSE GAS R&D PROGRAMME

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CCS COST NETWORK

2019 WORKSHOP

ORGANISED UNDER THE AEGIS OF THE

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IEA GREENHOUSE GAS R&D PROGRAMME
CHELTENHAM, UK

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- CCS Costs in China: A Case Study for China Energy, *Surinder Singh, NICE*

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- Shand CCS Feasibility Study, *Mike Monea, CCS Knowledge Center*
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- An Updated View of the Role of CCS in the Australian National Electricity Market, *Andy Boston*, *Red Vector and Geoff Bongers, Gamma Energy Technology*
- What is the Value of CCS? *Niall Mac Dowell, Imperial College London*

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B. CCS Costs in Industry *(Co-chairs: Howard Herzog, MIT and Niels Berghout, IEA)*

C. Value proposition of CCS *(Co-chairs: Jon Gibbins, University of Sheffield and Sean McCoy, University of Calgary)*

12:30 Lunch

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14:30 General Discussion:

- What have we learned?
- Where should we be going?

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15:30 Adjourn

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INTRODUCTION

The sixth meeting of the CCS Cost Network Workshop was held on March 19-20, 2019 at the Electric Power Research Institute (EPRI) headquarters in Palo Alto, California, under the auspices of the IEA Greenhouse Gas R&D Programme.

The meeting was organized by a Steering Committee chaired by Howard Herzog (Massachusetts Institute of Technology), along with representatives from: Carnegie Mellon University (Ed Rubin), Electric Power Research Institute (George Booras and Abhoyjit Bhown), IEA Greenhouse Gas R&D Programme (Keith Burnard and Monica Garcia), International Energy Agency (Niels Berghout), University of Calgary (Sean McCoy), University of Sheffield (Jon Gibbins) and the USDOE National Energy Technology Laboratory (Jeff Hoffmann).

The purpose of the workshop is to share and discuss the most current information on the cost of carbon capture and storage (CCS) in electric utility and industrial process applications, as well as the outlook for future CCS costs and deployment.

The workshop also seeks to identify other key issues or topics related to CCS costs that merit further discussion and study.

As in past workshops, Day 1 was devoted to a plenary session addressing four general topics. Each session included two or three invited presentations, followed by a discussion among workshop participants. The second day began with a fifth plenary session topic, followed by three parallel breakout sessions pursuing selected topics in more detail. Reports of the breakout groups were presented in a final plenary session, followed by general discussion of lessons learned and planning for future events.

This document presents brief summaries of the five plenary session topics, together with the full set of presentations by invited speakers. The proceedings of this and all previous CCS Cost Workshop are available online from the IEAGHG.

PRESENTATION SUMMARIES

Session 1: CCS Costs in the Power Sector I

Rapporteur: A. Bhown

This session was the first of two that focused on the cost of CCS in the power sector. Two papers were presented, with key points summarized below.

New NETL Baseline Study

The U.S. DOE has published a series of widely-cited reports, titled "Cost and Performance Baseline for Fossil Energy Plants," that form the baseline against which all of their carbon capture R&D projects are compared. Tim Fout of DOE/NETL presented a summary of the newest update, Revision 4, expected to be published in 2019. This report provides performance and cost information of near-term commercial offerings for coal-fired and natural-gas fired power plants, both with and without current CCS technology.

The performance results that were presented included seven cases for IGCC plants (four with CCS and three without CCS); four cases for pulverized coal plants (two with CCS and two without CCS); and two cases for NGCC plants (one with CCS and one without). All cases were for a generic greenfield plant in the Midwestern U.S. providing baseload power. The net electric output of the plants was updated from 550 MW in previous versions of the baseline report to 650 MW in the new Version 4.

All cost estimates were calculated using the same general costing method used in previous releases of the baseline reports. Preliminary cost results were shared with the workshop attendees but were not yet finalized, hence, not included in these proceeding. Cost information for each of the cases analyzed will be available when the report is published.

CCS Costs in China: A Case Study for China Energy

Surinder Singh from the National Institute of Clean and Low-Carbon Energy (NICE) presented the results of a CCS cost study for power plants in China. NICE is part of China Energy, one of the world's largest power companies, with 180 GW of coal-fired capacity (163 plants with 477 units), 38 GW of wind capacity, and 19 GW of hydro capacity. Singh showed results of a study seeking to minimize the cost of CCS across a subset of China Energy's coal-fired power plants. For supercritical pulverized coal retrofits the cost of CO_2 avoided was estimated to be \$24-\$67/t CO_2 (compared to \$72-\$98/t CO_2 in the U.S.) For IGCC/coal-to-liquids, the avoidance cost was estimated to \$30-\$38/t CO_2 (compared to \$43-\$61/t CO_2 in the U.S.).

In China, plant efficiencies on an LHV basis ranged from 37.9% to 40.9% without CCS and from 25.5% to 28.6% with the addition of CO_2 capture. In comparison, the efficiency of a baseline plant in the U.S. fell from 42.2% without CCS to 31.8% with capture. Additional details of the China cost study will be published in a forthcoming paper by NICE.

Session 2: CCS Costs in the Power Sector II

Rapporteur: E. Rubin

Three additional studies on the cost of full-scale CCS projects were presented in this session.

Shand CCS Feasibility Study

Mike Monea of the International CCS Knowledge Center presented the highlights of a feasibility study of a second-generation CCS retrofit and life extension project at the Shand Power Station of Sask Power in Saskatchewan, Canada. The 300 MW coal-fired unit would have a CO_2 capture capacity of 2 Mt CO_2/yr employing a Mitsubishi amine-based system with a nominal capture efficiency of 90% and an overall parasitic load of 22.9%. Higher capture efficiencies of 95% at full load and over 97% at partial load are also possible.

For 90% capture the estimated cost is \$45US/tonne of CO_2 captured, with a reported reduction of 67% in capital cost relative to the Sask Power capture system at the Boundary Dam plant (BD3, which is a smaller unit with a different capture technology and a different project scope). Cost reductions were attributed to lessons learned from building and operating BD3; construction at a larger scale using extensive modularization; and integration advantages afforded by the bigger unit's steam cycle. It was also noted that the design capture rate substantially exceeds Canadian requirements. For lower capture efficiencies the total cost would decrease, although the cost per tonne captured would increase. A decision to implement CCS at the Shand plant is still pending.

Pre-Feasibility Study for a Carbon Capture Pilot Plant in Mexico

Haoren Lu of Nexant reported on results of a project funded by the World Bank to develop capacity for CCUS in Mexico. The Nexant Team was tasked to perform a feasibility study to evaluate and recommend the most appropriate commercially-available post-combustion CO_2 capture technology for NGCC power plants in Mexico. They were also tasked to develop a conceptual design for a CO_2 capture pilot plant to be located at the 250 MW Poza Rica generating station in the state of Veracruz. The conceptual design would then lead to a next phase of the project to develop a Front End Engineering Design (FEED) package for the capture pilot plant.

Six commercial vendors provided performance and cost estimates for the proposed project based on 85% CO_2 capture. Five of the six estimates were similar at \$35.0-36.2/MWh for the incremental cost of retrofitting the Poza Rica plant with amine-based post-combustion capture (PCC). These costs were lower than the \$37.4/MWh of Nexant's reference case using MEA. One vendor, however, estimated a cost of \$41.4/MWh. All costs appear to exclude CO_2 transport and storage costs.

All six proprietary PCC technologies also showed improvements in performance relative to the MEA reference, with energy penalties of 16% to18% reduction in net power export vs. 19% for MEA. Nexant then went on to design a PCC pilot plant that would treat 1% of the Poza Rica flue gas using MEA to capture 85% of the CO_2, with flexibility to test multiple types of amines. Cost estimates for the pilot plant are provided in the presentation slides.

Loy Yang A Power Station Retrofit for Carbon Capture

The final presentation of this session came from Bill Elliot of Bechtel, who shared results of a study of a post-combustion capture retrofit at the coal-fired Loy Yang A Power Station in Victoria, Australia. The plant was built during 1984-88 and burns lignite in four 600 MW units. The design PCC system employed two trains per unit (eight modules in total) using 40% MEA with a lean loading of 0.22 mol CO_2/mol MEA to capture 90% of the CO_2.

The capital cost reported for 2018 was 840 million US\$ per module (including total EPC cost, owner costs and commissioning costs). For a nominal 200 MW module size, this amounts to 4200 \$/kW. Over a 30-year life the associated cost of electricity and cost of capture were \$66/MWh and \$39/tonne CO_2, respectively, at an 80% capacity factor (CF), and \$105/MWh and \$63/tonne at a 50% CF. Costs were substantially higher for a 15-year project life with a higher discount rate. No information was reported on annual O&M costs or other elements of capital cost for any of the cases reported.

Session 3: CCS Costs in Industry

Rapporteur: Niels Berghout

Studies assessing CCS costs for industrial sources show large discrepancies. Some of these are due to case-specific characteristics, such as the CO_2 source, scale, technology, level of detail, and location. But some are also linked to issues of cost methodology, such as assumptions about new vs. retrofit facilities, energy supply strategy, data quality and cost metrics. The three presentations in this session sought to provide insights about cost variation, and to what extent they stem from the methodological framework vs. other factors, and how the cost analysis framework could be improved. Lastly, strategies were presented on how partial CO_2 capture can be used to reduce capture cost.

Methodological Costing Issues for CCS from Industry

Simon Roussanaly of SINTEF gave an overview of the activities of a group of experts from research institutes, academia and intergovernmental organizations that are developing a set of guidelines to do sound cost evaluations of CCS from industrial sources. The aim is to publish a new white paper building on the foundation established by the first white paper of the CCS cost network dealing with power plant applications of CCS.

Several methodological aspects have a large impact on the costs, especially assumptions about: (1) the type and costs of steam and electricity supply for carbon capture; (2) additional costs of retrofitting existing industrial plants with CCS, including required production stoppages and space limitations; and (3) CO_2 transport and storage costs, which can vary considerably for different industrial sources. Other costing issues to be addressed in the cost initiative include the transferability to industrial applications of experience with CCS cost studies for power generation, and the development of new costing metrics for the industrial sector.

Cost Review on CO_2 Capture in Cement and Steel Production: Key Findings

Monica Garcia of the IEAGHG presented the results of a joint study of the IEAGHG and IEA. This study aimed to develop a method that allows for a comparative assessment of CO_2 capture technologies for industrial sources. This included a clear definition of system boundaries, plant size, various cost elements as well as a set of values for key parameters (e.g., energy prices, plant size). Furthermore, the study reviewed and standardized literature studies assessing the costs of CO_2 capture from cement and iron and steel manufacturing using this method.

The factors causing the wide CO_2 capture cost ranges found in literature include the availability of waste heat for CO_2 capture, as well as the type and cost of energy supply. Consequently, CO_2 capture costs may vary widely by location. Standardization of cost data in the reviewed literature was able to reduce the reported cost ranges. However, the resulting cost ranges were still significant, due mainly to the lack of transparency in the methods and data used in the reviewed studies, which made full standardization impossible. Thus, better cost data and more transparency in reporting of cost studies are required to enhance our understanding of costs. The study also found that there is no universally "best" capture technology—the choice depends on many case-specific factors.

Highlights and Findings from the CO_2stCap project

This presentation by Nils Eldrup of SINTEF gave an overview of the CO2stCap project, currently nearing completion. The goal of the project was to identify a cost-effective carbon capture strategy for future CCS systems in energy-intensive industries, considering waste heat and energy availability, more efficient use of biomass resources, different capture technologies (and optimizations), and changes in market conditions. It further investigated the potential of partial capture to reduce capture costs for industry. Lastly, efforts were made to refine and implement modelling tools to calculate costs and optimize CO_2 capture systems.

The partial capture solutions focused on four industry cases: cement, pulp and paper, steel, and silicon (solar). The results showed that partial capture is a solution to reduce the cost for CO_2 capture for sources that: (1) have multiple stacks; (2) have a low to moderate CO_2 reduction requirement to meet regulations; (3) have access to low-cost energy to supply parts of the energy demand; (4) can vary their product portfolio, depending on market conditions; and (5) have large differences between base load and maximum load levels.

Session 4: What it Takes to Make CCS Economical

Rapporteur: K. Burnard

The 2015 Paris Agreement set out a global action plan to limit the average global warming to "well below 2°C" above pre-industrial levels to avoid dangerous impacts of climate change. Increased deployment of the full portfolio of low-carbon technologies is central to that plan. Amid mounting evidence from the scientific community, CCS has been identified as key to successfully mitigating climate change in the most cost-effective manner.

Despite the aims of the Paris Agreement and the growing realization that global action is critical, the deployment of CCS is not on track to meet these ambitions. While the reasons may be quite complex, the lack of CCS deployment is fundamentally a classic case of market failure, requiring government policies to address the problem effectively.

In recent years, many governments have enacted legislation to promote low-carbon energy, though few such measures offer a "level playing field" across the full range of low-carbon technologies. Explicit support for renewable energy technologies, for example, has been quite common. This workshop session was introduced to shine a light on some of the measures that have been introduced, or are planned, to encourage the deployment of CCS through economic and other incentives.

CCUS and 45Q

Tim Grant of DOE/NETL first discussed an initiative in the United States, which is implementing a revision to its "45Q" federal tax credit for capturing and sequestering CO_2. The goal is to improve the economics of CO_2 storage to make deployment of large-scale CCS significantly more attractive to investors and project developers alike. Successful projects would receive credits of about \$13/t for EOR storage or \$22/t for geological storage (as of 2017), increasing to \$35/t for EOR and \$50/t in 2026, with further increases tracking inflation. Projects must begin construction by January 1, 2024 and credits would be paid out for twelve years.

Grant described the nuts and bolts of the complex set of measures that must be in place before the credits can be claimed. For example, one of the outstanding issues that must be resolved is an agreement among the U.S. Department of the Treasury, Department of Energy, Department of the Interior, and the Environmental Protection Agency as to what constitutes "secure storage." Grant also explained the timelines that would have be met and approvals needed for credits to be claimed. The three critical components that would have be in place include CO_2 capture from a qualified source, a secure storage site with an approved plan for monitoring, reporting and verification, and a pipeline connecting the capture and storage sites.

CCUS in the Netherlands

Martijn van de Sande of the Netherlands Enterprise Agency told the workshop that CCS will play an important role in achieving emission reductions in the Netherlands, which has pledged to reduce its GHG emissions by 43% by 2030 (relative to 2017 levels). The country is firmly committed to a green future, with rapid growth in the deployment of renewable energy technologies. In 2017, renewables provided 6.6% of total Dutch energy consumption. The current focus for CCS is on reducing emissions from industrial facilities.

ds provides a very good fit for CCS because the majority of its CO_2 is emitted by a relatively small number of large companies with a clustering of point emission sources. The potential for re-use of natural gas infrastructure and ready access to storage sites in the North Sea also facilitates storage of captured CO_2. There are a number of smaller CCU/CCS projects currently in operation and some larger projects in development.

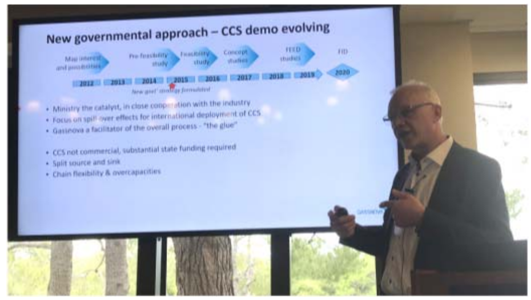
Martijn said that a national climate agreement was nearing finalization, with the government busy designing a CCS deployment stimulus. He then went on to describe in some detail the challenges faced by the Dutch government—and the Netherlands Enterprise Agency on the government's behalf—in developing the CCS stimulus package.

Norwegian Efforts Incentivizing CCS

Ståle Aakenes of Gassnova described the economic and environmental drivers for Norway to implement CCS, building on its long traditions, its large storage opportunities and its obligations to the Paris Agreement.

Norway was the first country to adopt a policy that led to the commercial application of CCS. In 1991, it introduced a CO_2 tax that led directly to the Sleipner Project (begun in 1996 and still in operation), where approximately 1 Mtpa CO_2 is separated from raw natural gas and injected into an offshore saline aquifer beneath the North Sea. Since then, Norway has continued to provide leadership in Europe by pursuing CCS via successful initiatives at Snøhvit (2008) and Test Center Mongstad (TCM) (2012), along with less successful projects at Kårstø and Mongstad. Aakenes discussed the reasons why some past initiatives succeeded while others stalled.

Drawing on this experience, the Norwegian government has developed its current approach to CCS, which (as in the Netherlands) is focused on the industrial sector. At present, Norway is hosting a competition to build and operate a full-scale industrial CCS demonstration plant, with the investment decision to come in 2020/2021.



Session 5: Value Proposition of CCS

Rapporteur: S. McCoy

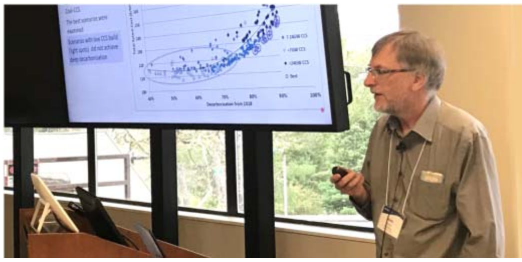
The goals of Session 5 were to assess the role of CCS deployment in the power sector; to characterize and communicate the full value of CCS; and to identify how such value propositions might affect directions for R&D.

The Potential Role and Value of CCS in the Decarbonization of U.S. Electricity

In the first presentation of this session Nils Johnson of EPRI presented findings from a recent EPRI analysis focused on decarbonization of the electricity system using their U.S. Regional Economy, Greenhouse Gas and Energy (US-REGEN) model. From this work, it was clear that deployment of low-cost renewables (i.e., onshore wind and solar photovoltaics) is shaping the future U.S. electricity market and will require increased flexibility from dispatchable (e.g., natural gas- and coal-fired) generation. However, the EPRI analysis also showed that the optimal response to an escalating carbon price is not only construction of additional wind and solar, but also natural gas with CCS to replace existing coal-fired generation. The value of CCS in the US-REGEN model results from a substantial reduction in the incremental investment required in the electricity sector. This reduction is driven largely by avoiding construction of renewable generating capacity that would otherwise be needed if dispatchable low-carbon generation (or energy storage) were otherwise unavailable.

An Updated View of the Role of CCS in the Australian National Electricity Market

Andy Boston of Red Vector and Geoff Bongers of Gamma Energy Technology next showed results from their modeling the Australian National Electricity Market using the Modelling Energy & Grid Services (MEGS) model. They found that the merit order for



emissions reductions in Australia was generally renewable deployment, followed by natural gas generation with CCS, and then coal with CCS—with the caveat that the starting point depends on the existing capacity mix in each state. The also noted that "new build [generation] does not pay for itself" in future scenarios, but is needed for system reliability. Thus, they found that reducing the capital and operating cost of CCS by half did not increase the construction of CCS-equipped capacity because the model was building CCS only for reliability. They also found that BECCS was required to offset uncaptured emissions from CCS in order to achieve the Australian net-zero emissions target in 2050.

What is the Value of CCS?

The final presentation from Niall Mac Dowell of Imperial College London was organized around four questions:

- Does CCS have any value?
- How helpful are cost targets?
- Should we believe in unicorns (i.e., miraculous innovation in capture)?
- Does CCS have other kinds of value?

Mac Dowell's answer to the first question was that CCS has value only insofar as it reduces total system cost for electricity generation under climate constraints that significantly limit carbon emissions from the power sector. The attribute that make CCS valuable in this context is not energy provision, per se, but the provision of low-cost, firm capacity to support reliability. Mac Dowell also went to length to show that the value of CCS is system-specific and thus not well represented by a traditional levelized cost of electricity (LCOE). In the context of the U.K. system, he found that targets for CCS-equipped plant efficiency had little impact on the deployment of CCS because CCS-equipped capacity is valued for reliability, not generation—much as in the Australian context. Similarly, in addressing the second question, he found that reductions in the capital cost of CCS-equipped generation had relatively modest impacts on total system cost.

This argument can then be generalized to the concept of "unicorn" technologies to conclude that only technologies that have very high efficiencies at very low capital cost would dominate in CCS deployment. Even then, they would have a relatively modest impact on total system cost.

To answer the final question, Mac Dowell presented results from an integrated modeling study to show that in the U.K. context one of the strongest economic arguments for CCS may be the preservation and creation of jobs across the economy. This is because the technologies that might replace CCS are less labor intensive, which has a ripple effect across the economy.

From these three presentations and the associated discussions, several general conclusions were drawn. First, deployment of CCS in the electricity sector in the U.S., U.K., and Australia is expected to reduce the overall cost of meeting stringent decarbonization targets at the power system level. Deployment of CCS tends to reduce total system costs by limiting low-utilization renewable capacity and enhancing system reliability. Furthermore, at least in Australia and U.K. contexts, substantial cost reductions for CCS were found to have little impact on the amount of CCS deployed, since CCS was deployed primarily to meet reliability constraints for low-carbon systems dominated by intermittent renewables. The presentations and discussions also underscored the need for R&D to develop and quantify general metrics for valuing CCS in a carbon-constrained system.

BREAKOUT SESSIONS

Day 2 of the workshop included three parallel breakout sessions to discuss selected topics in greater detail. Issues and discussion points arising in these sessions are outlined below.

A. CCS Costs in the Power Sector

Rapporteurs: A. Bhown and E. Rubin

This session focused on cost estimates for power plants equipped with CCS and the methods, research and data needed to improve such estimates for two applications. The first was power plants using current or near-term commercial capture systems. Motivating questions for discussion included:

- How consistent are the methodological approaches to cost estimation used by major R&D organizations such as DOE, EPRI, IEAGHG and others, as well as by various A&E firms who serve the power industry? Has there been any notable progress in arriving at a consistent framework for cost analysis?
- To what extent are improvements needed in the methods, assumptions and/or data used to quantify different elements of a CCS or power plant cost estimate? What are the priorities for such improvements and what methods and resources are available or needed to make progress in this area?

The session began with a brief summary of the 2013 White Paper prepared by a CCS Cost Network Task Force. That multi-national effort developed a standardized costing method and associated nomenclature that was endorsed and recommended by the Network. The paper, entitled "Toward a Common Method of Cost Estimation for CO_2 Capture and Storage at Fossil Fuel Power Plants," was published in the *International Journal of Greenhouse Gas Control*, and also by participating organizations including EPRI, the Global CCS Institute, and IEAGHG.

It was noted that many organizations and cost study authors have now adopted the proposed method, although some continue to prefer their own nomenclature for certain cost elements. The session then focused on ways to improve this costing methodology. Suggested improvements included:

- Expand on several of the major capital cost elements. In particular, the Bare Erected Cost needs to be broken down further in many cost estimates. More guidance also would be helpful for other items, such as engineering/home office fees, project management, process engineering, permitting types and costs, and various other "owner's costs," which are commonly estimated as a simple percentage of installed equipment cost.
- Better retrofit factors are desired for CCS and other types of installations at existing power plants. (NETL is working on a retrofit guideline.)
- Costs in other parts of the world should go beyond just a "simple multiplier" of U.S. costs. Some level of depth is needed. Also need more detail on construction labor-hours and productivity differences across regions and countries, not just total labor costs.
- Consider which factors change or don't change with scale, e.g., owner's costs.
- Process and project contingency cost factor ranges are too wide right now—must narrow and refine this guidance and make it more technology-specific.
- Guidance on capacity factor assumptions is needed. Current studies by NETL and EPRI assume capacity factor is equal to availability (e.g., 85% for PC plants) rather than actual capacity utilization, which historically is much lower. Lower capacity factors also may affect average plant heat rates.
- The International Standards Organization (ISO) is developing reporting performance standards for CO_2 capture, transport, storage and enhanced oil recovery (EOR).

The second topic for this breakout session focused on power plants using novel or advanced technologies that are still under development. Here, the motivating questions for discussion were:

- What are the strengths and limitations of methods currently used to estimate the future cost of power plants with novel or advanced CCS technologies?
- How can such cost estimates be improved? What new or improved methods, assumptions and/or data are needed to make progress in this area, and what are the priorities?

It was argued that the use of traditional "bottom-up" methods was not appropriate to estimate the expected future of novel or advanced technologies because designs typically change over time, as do the costs of unique materials and components that are not currently used at commercial scales. Suggested methodological improvements included the following:

- Use traditional "bottom-up" methods to first estimate the first-of-a-kind (FOAK) cost of an emerging technology based on its current state of development.
- Then use a "top-down" model based on learning (experience) curves to estimate future (NOAK) costs as a function of deployed capacity (and other factors, if available) based on experience with other similar technologies.
- Include an uncertainty analysis in the cost estimates. Early-stage technology costs have relatively large error bars, but the mature sub-components of overall plants have much smaller error bars.
- Recognize that the design of a technology or system will likely change over time, including from early-stage to FOAK.
- Need to develop guidelines for FOAK costs estimates, and for choices and applications of learning curves to estimate future cost trajectories.

B. CCS Costs in Industry

Rapporteurs: N. Berghout and H. Herzog

Compared to the power sector, studies of CCS costs and costing methods for the industrial sector are quite slim. Further complicating the situation is that the industrial sector is much more heterogeneous. This breakout session assessed the status of CCS costs and costing methods in industry and recommended activities to improve them.

Six questions were circulated prior to the workshop as a basis for discussions, with a seventh question added by the group. The first question was: What are the key industries of interest? The appropriate criteria for addressing this question included:

- Competition, because industry is exposed to global markets
- Cost of CO_2 capture
- Share in global CO_2 emissions
- Process vs. energy CO_2 emissions
- Exhaust gas clean-up vs. modifications of the core industrial process
- All emission sources within a complex plant vs. only easier-to-capture sources

The consensus of the group was that there are three primary industries of interest for CCS: cement, iron and steel, and chemicals. Research has shown that these industries have the highest energy demand and the highest CO_2 emissions among industrial emitters on a global basis.

Two additional industries were mentioned because of near-term interest for CCS: ethanol production, because the 45Q tax credits in the US may incentivize some CCS projects in that industry; and waste-to-energy, because of the interest in Europe and a probable project in Norway. Hydrogen production with CCS also was highlighted. While today this is considered to be part of the chemicals industry, in the future hydrogen may become an important carbon-free energy carrier that merits separate consideration.

Question 2 was: What are the seminal studies in industrial CCS costs? Three publically available studies were identified (an unpublished Abu Dhabi study for iron and steel also was mentioned):

- IEAGHG studies for different industries, including Report No. IEAGHG 2018-TR03 summarizing existing studies in the cement and iron and steel industries
- A 2016 SINTEF study on "Design and performance of CEMCAP cement plant with MEA post combustion capture"
- A 2014 DOE/NETL study on, "Cost of capturing CO_2 from Industrial Sources," DOE/NETL-2013/1602.

Question 3 was: How good is the currently available industrial CCS cost data (on both an absolute basis and compared to the power sector)?

The cement process is well-defined, but there are no publically available FEED studies on cement with CCS. Such information is important to obtain. The consensus was that cost estimates for post-combustion capture on cement plants are as good as for the power industry. However, integration issues are not clear—specifically, where does the steam come from and what level of flue gas clean-up is needed ahead of the capture unit.

Much less information exists on CCS costs for iron and steel plants, where integration is a major issue because of the multiple CO_2 sources. Since many other industrial processes also have multiple sources of CO_2, there was discussion as to whether these various effluents could be combined before entering a carbon capture process. The consensus was probably not, because there could be a wide variation in concentrations. The issues are not technical, but economic. Also, large-diameter ducting across a plant site might be problematic.

Questions also were raised as to whether there is a good alternative to solvents for industrial processes, such as membrane capture systems. However, it is likely that the relatively low capture rates of membranes could be a problem.

Question 4 was: How good do we have to get? The answer depends on the intended use of the cost estimate. It was agreed that the type of cost estimates we are discussing would be inadequate if one were actually going to build a plant. But this is not their intent. Rather, three major uses of the cost estimates were as inputs to:

- Various types of energy-environmental models, including those used by the IPCC to run decarbonization scenarios out to 2100.
- Analysis and design of policy options, such as incentives or targets, where it is important to have a good understanding of costs (while recognizing that policy decisions depend on other factors besides economics).
- RD&D program design.

Question 5 was: To what extent are cost data and methods for CCS costing in the power sector transferable to CCS in the industrial sector? What are the unique issues associated with cost assessments of CCS in industry?

Industry generally operates 24/7, as opposed to power plants that ramp up and down and sometimes turns off. Therefore, issues of flexibility (i.e., load following) are probably less of an issue for industry. On the other hand, integration is generally more complicated for industry than power, mainly due to the multiple and dispersed sources of CO2, as well as to a lack of on-site power generation and/or extraction steam sources at many industrial plants, in contrast to power plants.

The nature of these two sectors also is very different. Power plants typically serve local markets and are regulated (to various degrees), while industry operates in highly competitive markets, sometimes at the global level, and is very bottom-line driven. For one, this means there are different challenges and conditions for financing CCS projects. Industrial CO_2 emissions are generally much smaller in scale (tons per year) and therefore less able to take advantage of economies of scale. This can be especially challenging for the transport and storage components, and is one reason the concept of source clusters has been proposed for industrial applications of CCS.

Next, Question 6 asked: Which stakeholders should be involved in developing guidelines for costing of CCS in the industrial sector? How can we facilitate the stakeholders working together in furthering these efforts?

It was felt that the industries themselves are generally absent from these efforts, in contrast to the power sector, where there is utility involvement in cost methods development and applications. One route to encourage similar participation from the industrial sector may be to reach out to trade associations for cement, iron and steel, and other industries.

Finally, Question 7 asked: What are the top priorities to improve industrial CCS cost data and methodologies? Here, four priorities were identified:

- Better cost data, especially data from FEED studies. However, getting this type of data remains a challenge due to proprietary considerations.
- Emissions characterizations for various industries, with chemical composition (including trace components), flow rates, and physical properties (e.g., temperature and pressure).
- Development of a consistent, transparent costing method. One such effort is underway by a group of costing experts from academia, research institutes and industry working as part of the IEAGHG CCS Cost Network on a set of methodological guidelines for cost assessments of CO_2 capture from industrial sources.
- Actual capture system data from tests (e.g., pilot plants).

C. Value proposition of CCS

Rapporteurs: S. McCoy and J. Gibbins

Breakout group C focused on the "value proposition" for CCS, implicitly defined as the set of factors that would make CCS attractive to potential users, and the metrics by which this value would be measured. These factors and metrics may be different for each sector and might change over time. The questions that were proposed for the breakout were:

- Is there a simple, layman's description of what the value proposition for CCS means in different contexts?
- How different are these propositions? Can they be unified into a smaller sub-set?
- Which value propositions appear to gain traction with CCS funders and investors and how valid and comprehensive are they as metrics for CCS?
- Is current CCS R&D focused on the technologies that are best able to deliver the value proposition for CCS? Is something more needed?

The group began by identifying the decision-makers who CCS proponents might wish to address. The first were those in local government, for whom the most important factors might be jobs and other intangible benefits, such as a feeling of purpose in communities relying on fossil fuel extraction, or excitement about participating in a climate change solution. These decision makers need to know that CCS exists as a mitigation option and that it can be good for their constituents. Thus, they have "cover" to pursue this.

A second group was industry and trade associations, which can provide further support for CCS. These organizations need to know that CCS is affordable in their industries and are often less costly and less disruptive to business than other options to dramatically reduce emissions. Indeed, CCS has the benefit of maintaining or even growing jobs relative to alternative options. Most of these benefits stem from the continued use of fossil fuel while reducing climate-related impacts.

The breakout session also discussed the question of how CCS can be compared to alternatives, acknowledging that mitigation costs ($/t$CO_2$ avoided) or the levelized cost of electricity (LCOE) were not particularly helpful metrics when communicating with governmental decision makers. There was general agreement that better illustrations are needed of the employment and revenue-generating potential of continued fossil fuel use enabled by CCS in different sectors (relative to other mitigation options).

Recognizing that the value of CCS varies not only by audience, but also by sector, the group developed a matrix to categorize the potential value propositions where CCS might be deployed (Table 1). For local decision-makers, several potential values appear in addition to jobs, such as support for the local tax base, energy security, and a sense of leadership for early adopters. On the other hand, the potential value propositions for industrial audiences and investors vary widely.

Photo credits: G. Booras and E. Rubin

CLOSING PLENARY

Participants affirmed the continuing value of this workshop series, noting that this meeting had the greatest attendance in the series. The next meeting will be planned by the Steering Committee, with a tentative date of Spring 2021 at a location to be determined.

Table 1. Potential value of CCS for different sectors and decision makers

Sector		Industry & Investors	National Government Decision Makers	Local Government Decision Makers & Individuals
CO_2 Storage	Onshore	– Oil production from CO_2-EOR – Geologic storage as a service	– Domestic energy security – New national industry	– Safe, secure jobs – Local public and private revenues – Shared community benefits
	Offshore	– Oil production from CO_2-EOR – Geologic storage as a service – Out of sight, out of mind – Defer offshore facility decommissioning – “Closes the circle”	– Domestic energy security – New national industry – Values pore space – Support for existing fossil-fuel workforce	– Jobs for off-shore oil workers – Local public and private revenues – Shared community benefits
Coal-fired Electricity		– Low-cost of coal and low-carbon – Reliability of fossil-power – Extend generation lifetime	– Energy security – Maintain jobs – Emissions reductions	– Safe, secure jobs – Maintain local tax base
Gas-fired Electricity		– Enables coal-to-gas switching – Fast response for grid reliability	– Enable renewable deployment	– Safe, secure jobs – Maintain (or expand) local tax base – Enabling renewable deployment
Steel		– Premium markets for low-carbon products – Participation in low-carbon procurement schemes	– Meeting long-term emissions reduction targets – Supports domestic industry	– Maintain (or expand) jobs in domestic industry – Maintain (or expand) local tax base – Sense of leadership for early adopters
Cement				
Petrochemical				
Hydrogen		– Option to decarbonize most industry via H_2 – Lower cost H_2 than electrolysis – Natural gas replacement – Extend useful life of existing natural-gas infrastructure	– Opportunities for new export markets (e.g., Japan)	– Make use of existing infrastructure
Bioenergy		– Sell offsets to emitters or the state	– CDR as a public good	– Agricultural jobs in biofuel supply – Sense of leadership for early adopters
Direct Air Capture			– CDR as a public good – Cap on climate mitigation cost	– Sense of leadership for early adopters
CO_2-based Products		– Premium markets for low-carbon products – Launch pad for CCS	– Launch pad for CCS	– Potential for new industrial jobs – Sense of leadership for early adopters
Transport		– Negative emissions allow fossil-fuel consumption in high-value applications		

TECHNICAL PRESENTATIONS

This section of the Proceedings includes the fourteen presentations across the five plenary sessions of the workshop. Several presentations have been edited following the workshop as a condition for publication.

Session 1: CCS Costs in the Power Sector I

1.1. New NETL Baseline Study, *Tim Fout, NETL*

Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 4

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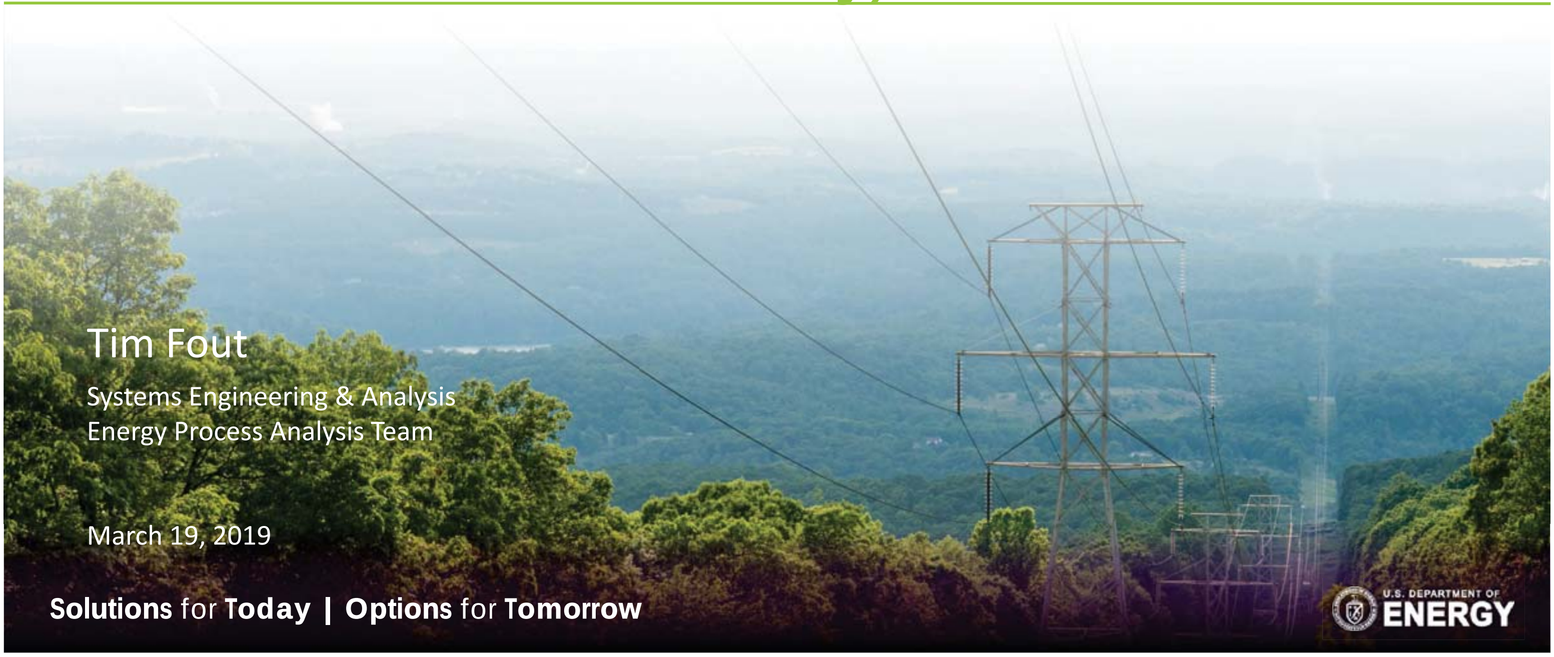

NETL Cost and Performance Baseline for Fossil Energy Plants: Bituminous Baseline

NATIONAL ENERGY TECHNOLOGY LABORATORY

- **Presents cost and performance estimates of near-term commercial offerings for coal- and natural gas-fired power plants, both with and without current technology for carbon capture and sequestration (CCS)**
  - —Integrated gasification combined cycle (IGCC) (7 cases, 4 with and 3 without capture)
  - —Pulverized coal (PC) (4 cases, 2 with and 2 without capture)
  - —Natural gas combined cycle (NGCC) (2 cases, with and without capture)
- ◦ Consistent and transparent design basis and analysis methodology
- ◦ Results represent an independent assessment of the power systems considered
- ◦ Significant vendor input for performance and capital cost estimates
- ◦ Black & Veatch “bottom up” approach to developing capital and operation and maintenance (O&M) estimates

https://www.netl.doe.gov/ea/about

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NETL Cost and Performance Baseline for Fossil Energy Plants: Purpose and Use

- **NETL internal uses**
  - Provides a consistent basis to compare existing and developing technologies
  - Informs development of research and development (R&D) goals and targets
  - Guides potential Department of Energy (DOE) investment by quantifying prospective benefits of successful R&D of advanced technologies within the DOE Office of Fossil Energy (FE) programs

https://www.netl.doe.gov/ea/about

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NETL Cost and Performance Baseline for Fossil Energy Plants: QGESS Documents

- **Quality Guidelines for Energy System Studies (QGESS)**
  - "Performing a Techno-economic Analysis for Power Generation Plants"
  - "Detailed Coal Specifications,"
  - "Specifications for Selected Feedstocks"
  - "Fuel Prices for Selected Feedstocks"
  - "Process Modeling Design Parameters"
  - "Cost Estimation Methodology for NETL Assessments of Power Plants"
  - "CO_2 Transport and Storage Costs in NETL Studies"
  - Others

https://www.netl.doe.gov/ea/about

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Study Matrix

Case Configuration

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	H_2S Separation	Sulfur Removal	PM Control	CO_2 Separation[A]	Process Water Treatment
B1A	IGCC	1800/1050/1050	2 x State-of-the-art 2008 F-Class	Shell	Sulfinol-M	Claus Plant/Sulfur	Cyclone, candle filter, and water scrubber	N/A	Vacuum flash. brine concentrator, crystallizer
B1B		1800/1000/1000			Selexol			Selexol 2nd stage	
B4A		1800/1050/1050		CB&I E-Gas™	Refrigerated MDEA		Cyclone, candle filter, and water scrubber	N/A	
B4B		1800/1000/1000			Selexol			Selexol 2nd stage	
B5A		1800/1050/1050		GEP Radiant	Selexol		Quench, water scrubber, and AGR adsorber	N/A	
B5B		1800/1000/1000						Selexol 2nd stage	
B5B-Q		1800/1000/1000		GEP Quench	Selexol		Quench, water scrubber, and AGR adsorber	Selexol 2nd stage	
B11A	PC	2400/1050/1050	N/A	Subcritical PC	N/A	Wet FGD/ Gypsum	Baghouse	N/A	Spray dryer evaporator
B11B								Cansolv	
B12A		3500/1100/1100		SC PC	N/A			N/A	
B12B								Cansolv	
B31A	NGCC	2400/1085/1085	2 x State-of-the-art 2017 F-Class	HRSG	N/A	N/A	N/A	N/A	N/A
B31B								Cansolv	

[A]IGCC cases consider nominal 90 percent removal based on total feedstock minus unburned carbon in slag. PC and NGCC cases consider nominal 90 percent removal based on total feedstock minus unburned carbon in ash (PC).

Bituminous Baseline Study, Revision 4

Technical Updates

- **Updated bituminous coal characteristics, reducing chlorine content to 1,671 ppmw**
- **Implemented ELG regulation compliance systems for PC and IGCC cases**
  - PC – spray dryer evaporator
  - IGCC – brine concentrator and crystallizer
- **PC net plant electrical output updated from 550 MW_{net} to 650 MW_{net}**
  - Size selection driven by updated NGCC output, and supported by Black & Veatch Updated CO_2 capture system cost and performance for PC and NGCC capture cases
- **Revised CO_2 compression model parameters for stable operation**
- **Updated combustion turbine (CT) and steam turbine (ST) performance estimates for NGCC cases (2017 vintage)**
- **Updates to IGCC cases include**
  - Water gas shift and COS reactor, air separation unit (ASU), steam turbine, Selexol system

Regulatory Drivers and Other Relevant Study Assumptions

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- **Cases configured to be compliant with key regulatory requirements**
  - Utility Mercury and Air Toxics Standards (MATS)
  - New Source Performance Standards (NSPS)
  - Effluent Limitation Guidelines (ELG)
  - Presumed Best Available Control Technology (BACT)
- **Cases presented are for a generic midwestern, greenfield site**
  - Site specific considerations (e.g., soil issues, water discharge and use restrictions, seismic data, local code for height/noise) are generalized and assumed to not be impactful
- **Performance and cost estimates assume baseload operation**
  - Plant designs do not specifically account for part load, ramping, or similar off-design considerations
  - Cost of electricity (COE) results do not account for market pressures relating to these plant operating conditions
- **NETL currently developing reference cases that specifically address flexible plant operation[1]**

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[1]NETL "Flexible Plant Baseline" Expected - 2019.

SubC and SC PC – w/o CCS

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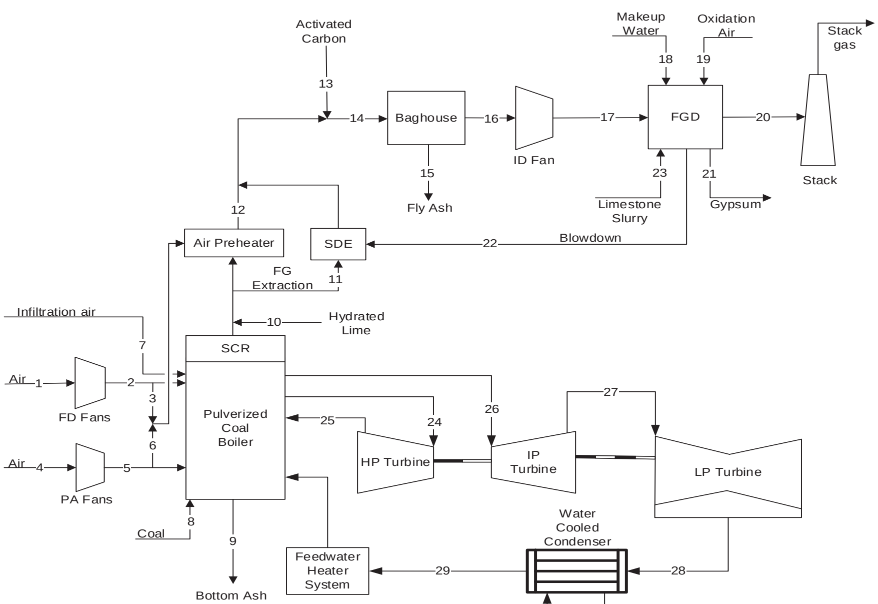

Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Source: NETL

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SubC and SC PC – w/ CCS

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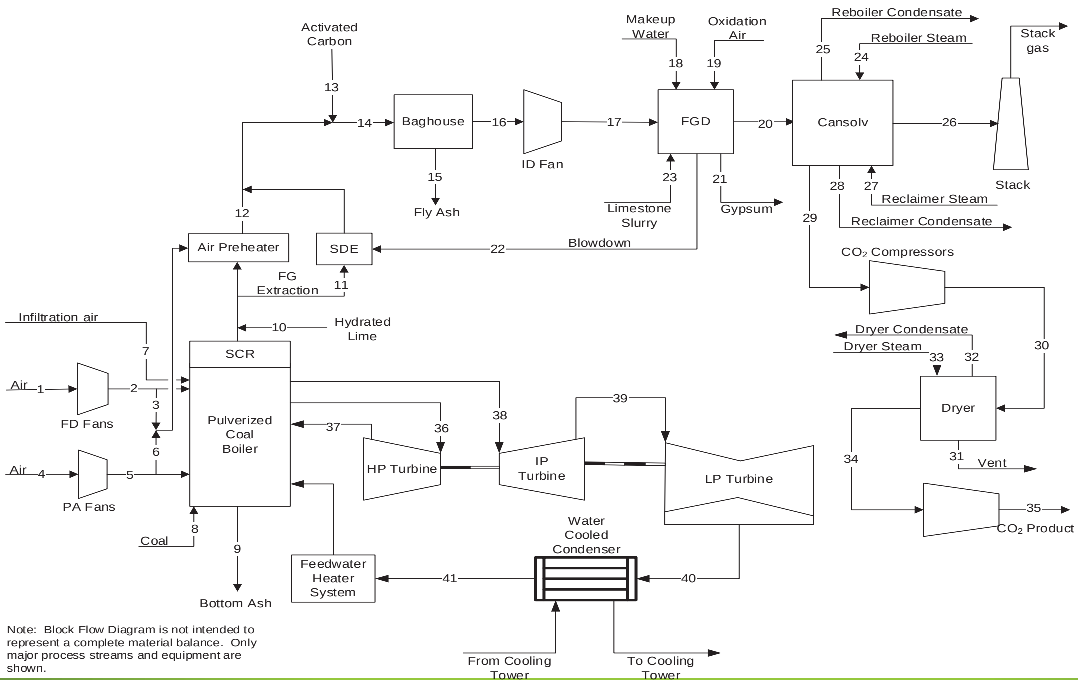

Source: NETL

NGCC – w/ CCS

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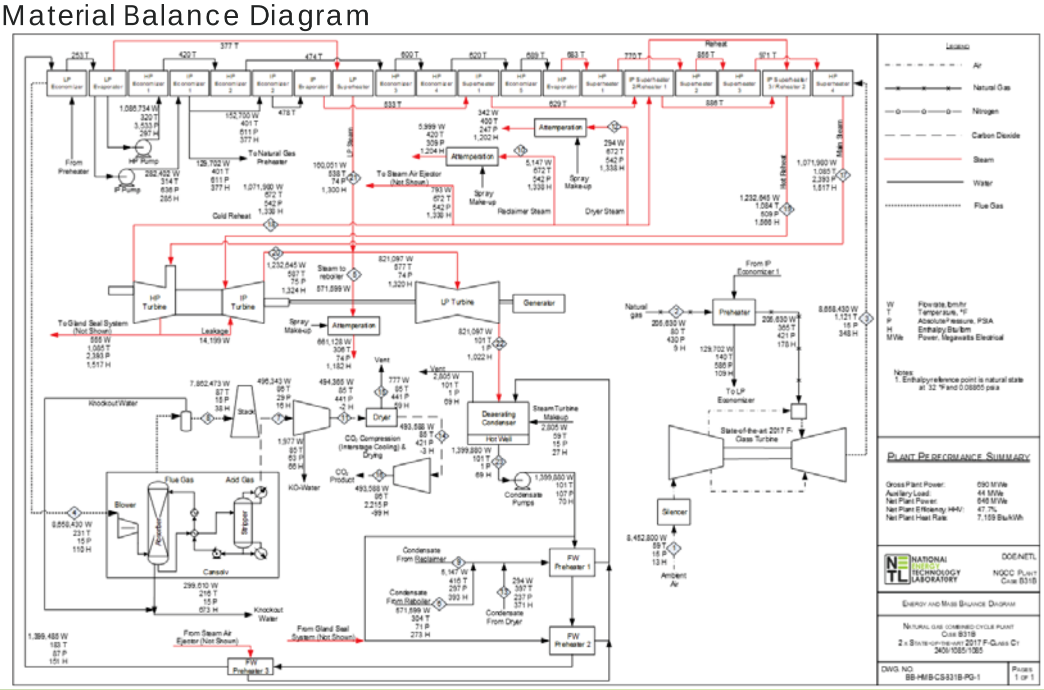
Energy and Material Balance Diagram



Source: NETL

CO_2 Compression Update

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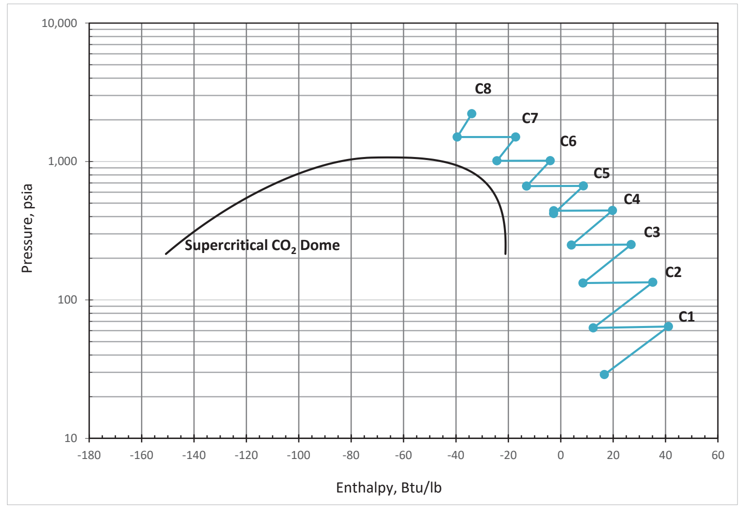
CO_2 Compressor Interstage Pressures

Stage	Outlet Pressure, MPa (psia)	Stage Pressure Ratio
1	0.44 (64)	2.22
2	0.92 (134)	2.14
3	1.73 (251)	1.90
4	3.05 (443)	1.78
5	4.59 (667)	1.58
6	6.99 (1,014)	1.53
7	10.38 (1,505)	1.49
8	15.29 (2,217)	1.47

PC CO_2 compressor enthalpy versus pressure operating profile



Performance Summary

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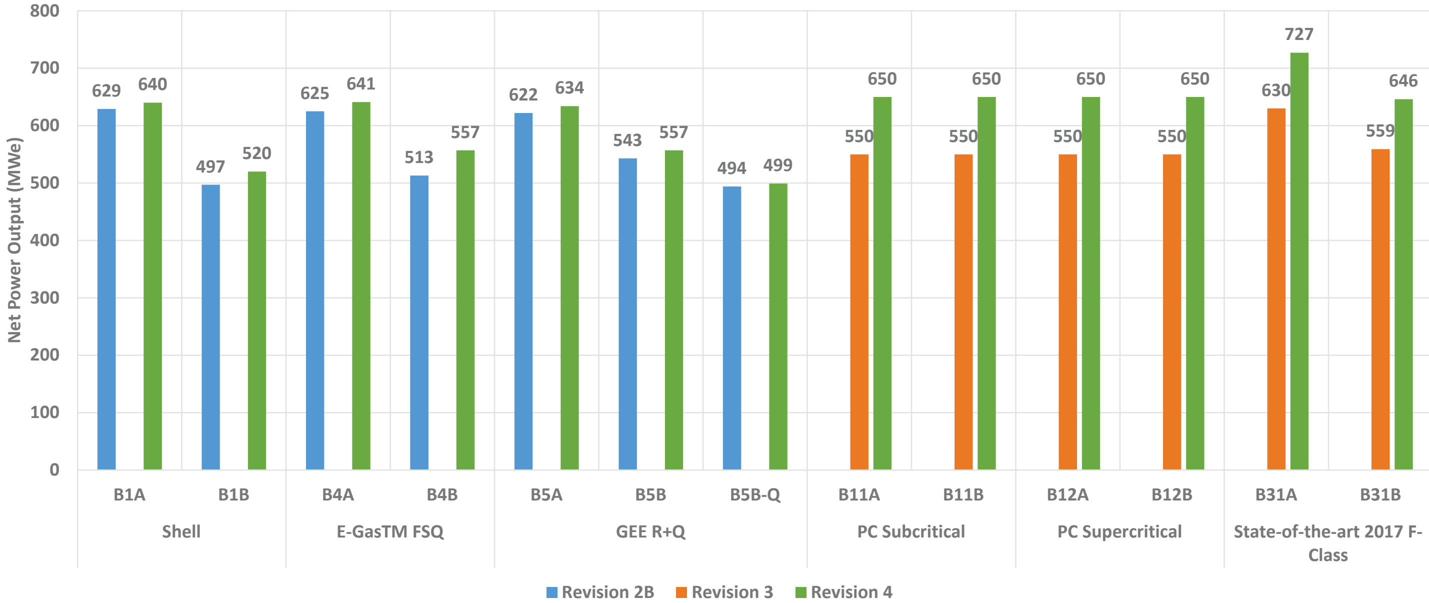
Case Name	IGCC							PC				NGCC	
	Shell		E-Gas™ FSQ		GEP R+Q			Subcritical		Supercritical		State-of-the-art 2017 F-Class	
	B1A	B1B	B4A	B4B	B5A	B5B	B5B-Q	B11A	B11B	B12A	B12B	B31A	B31B
CO_2 Capture Rate (%)	0	90	0	90	0	90	90	0	90	0	90	0	90
PERFORMANCE													
Gross Power Output (MWe)	765	696	763	741	765	741	685	687	776	685	770	740	690
Auxiliary Power Requirement (MWe)	126	176	122	185	131	185	185	37	126	35	120	14	44
Net Power Output (MWe)	640	520	641	557	634	557	499	650	650	650	650	727	646
Coal Flow Rate (lb/hr)	435,459	467,340	456,329	482,197	464,732	482,580	482,918	492,047	634,448	472,037	603,246	N/A	N/A
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	205,630	205,630
HHV Thermal Input (kW_t)	1,488,819	1,597,818	1,560,173	1,648,615	1,588,902	1,649,926	1,651,082	1,682,291	2,169,156	1,613,879	2,062,478	1,354,905	1,354,905
Net Plant HHV Efficiency (%)	43.0%	32.5%	41.1%	33.8%	39.9%	33.7%	30.2%	38.6%	30.0%	40.3%	31.5%	53.6%	47.7%
Net Plant HHV Heat Rate (Btu/kWh)	7,942	10,491	8,308	10,095	8,554	10,113	11,282	8,832	11,387	8,473	10,828	6,363	7,158
Raw Water Withdrawal (gpm)	4,128	4,927	4,357	5,039	4,798	5,355	6,128	6,480	10,427	6,053	9,719	2,902	4,704
Process Water Discharge (gpm)	922	1,040	944	1,068	1,033	1,087	1,182	1,333	3,044	1,242	2,850	657	1,655
Raw Water Consumption (gpm)	3,206	3,887	3,413	3,971	3,766	4,267	4,946	5,147	7,383	4,811	6,869	2,245	3,050

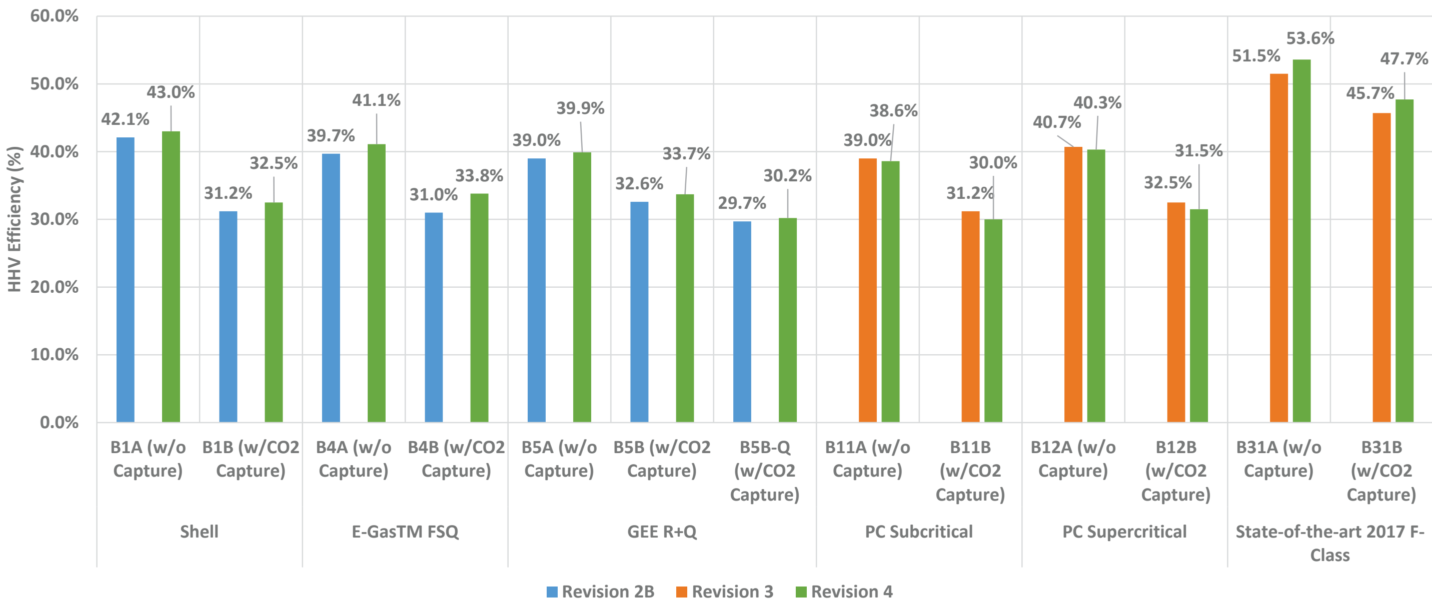
Bituminous Baseline Study, Revision 4

Rev2B and Rev3 Versus Rev4 – IGCC, NGCC & PC Net Power



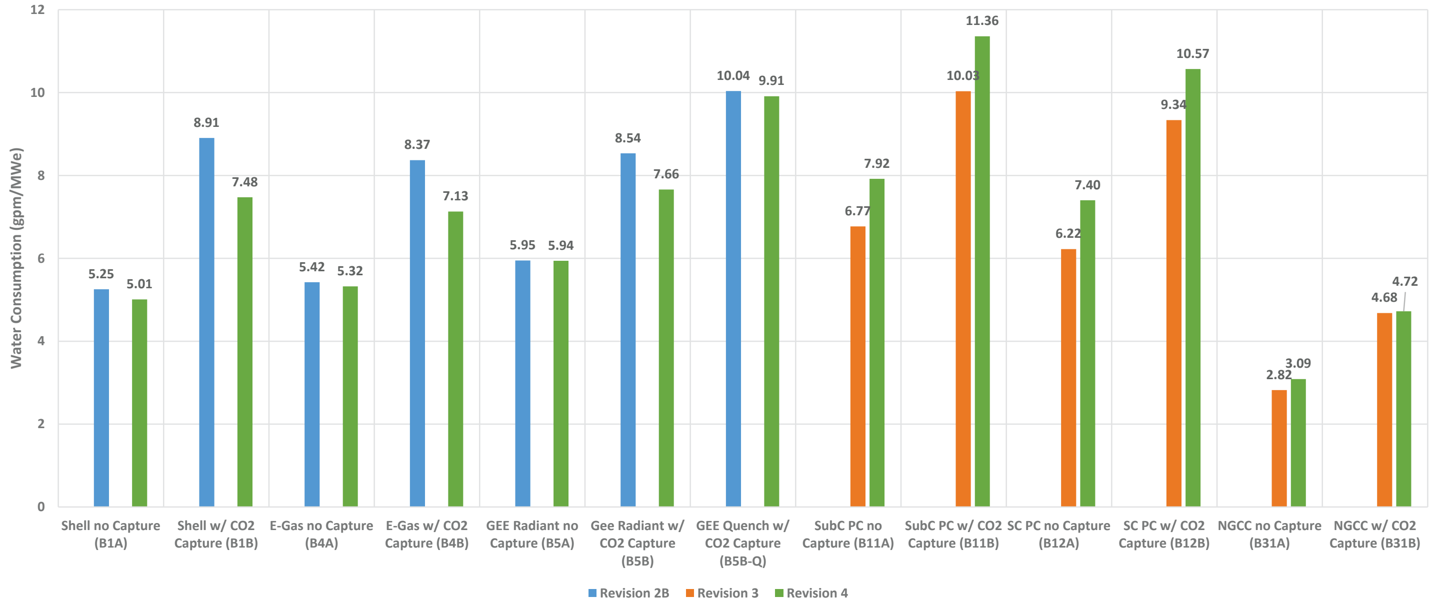
Bituminous Baseline Study, Revision 4

Rev2B and Rev3 Versus Rev4 – IGCC, NGCC & PC Net Efficiency



Bituminous Baseline Study, Revision 4

Rev2B and Rev3 Versus Rev4 – IGCC, NGCC & PC Raw Water Consumption



Emissions Summary – PC and NGCC

Case Name	PC				NGCC	
	Subcritical		Supercritical		State-of-the-art 2017 F-Class	
	B11A	B11B	B12A	B12B	B31A	B31B
CO_2 Capture Rate (%)	0	90	0	90	0	90
EMISSIONS						
CO_2 Emissions (lb/MWh-gross)	1,691	193	1,627	185	741	80
SO_2 Emissions (lb/MWh-gross)	0.67	-	0.65	-	0.01	-
NOx Emissions (lb/MWh-gross)	0.70	0.70	0.70	0.70	0.02	0.02
PM Emissions (lb/MWh-gross)	0.09	0.09	0.09	0.09	0.01	-
Hg Emissions (lb/MWh-gross)	3.00E-06	3.00E-06	3.00E-06	3.00E-06	-	-

IGCC Performance

- **For non-capture cases, the Shell gasifier has the highest (HHV) net plant efficiency (43.0%), followed by E-Gas™ (41.1%), and GE Radiant (39.9%)**
- **For IGCC cases with CO_2 capture (90%):**
  - Primary energy penalty drivers
    - Steam extraction for WGS
    - Auxiliary loads for Selexol CO_2 separation and compression systems
    - Slight derate of the combustion turbine due to higher moisture content of the syngas
  - Reduction in net plant efficiency due to CO_2 capture ~ 6 to 10 % points
    - Variability due to gasifier designs (e.g., slurry versus dry feed, syngas quench versus syngas heat recovery)
    - These also may vary between capture and non-capture
  - The lowest energy penalty is GE Radiant gasifier case (B5B)
    - W/O capture design (slurry feed, water quench) = high moisture content in the syngas
    - Results in CO_2 capture design needing little additional shift steam for WGS

IGCC Performance (cont'd)

  - The highest energy penalty is Shell gasifier case (B1B)
    - W/O capture:
      - Dry feed system + high heat recovery in the syngas cooler with no water quench = very low moisture content in the syngas
    - For Capture :
      - a water quench is added that increases the moisture content of the syngas for the WGS reaction but decreases the heat recovery in the syngas cooler
- **IGCC zero liquid discharge (ZLD) system**
  - Vacuum flash, Brine concentrator, and Crystallizer
    - treats 260-532 gpm of syngas scrubber blowdown
  - Case B5B-Q produces the highest flow rate to ZLD
  - Remaning 6 IGCC cases produce flow rates spanning 260-288 gpm
  - ZLD for ELG compliance results in a 0.1-0.2 % point decrease HHV net efficiency
    - Drivers for the efficiency reduction are the steam extraction and auxiliary load for the total ZLD system

PC Performance

- **SC steam conditions increase plant efficiency (HHV) by ~2 percentage points over SubC**
- **For PC cases with CO_2 capture (90%):**
  - Reduction in net plant efficiency of ~9 percentage points
  - Primary energy penalty drivers
    - —Steam extraction for solvent regeneration
    - —Auxiliary load for the capture and compression systems
- **All PC cases,**
  - Spray dryer evaporator treats 55-74 gpm of FGD blowdown
  - 0.25-0.27 % point (absolute) decrease HHV net plant efficiency
    - — Diversion of warm flue gas away from the air preheater and to the evaporator
    - — Small auxiliary load required by the spray dryer evaporator

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NGCC Performance

- **Highest net HHV efficiency**
  - Without CO_2 capture (53.6%)
  - With CO_2 capture (47.7%)
  - LHV net plant efficiency of non-capture NGCC is 59.4%
- **For NGCC with CO_2 capture (90%):**
  - Reduction in net plant efficiency of ~6 percentage points
  - Factors effecting NGCC penalty compared to PC
    - — Natural gas is less carbon intensive than coal
      - Study assumptions: natural gas 32 lb carbon/MMBtu; coal contains 56 lb/MMBtu
    - — NGCC non-capture plant is more efficient
      - Less total CO_2 to capture and compress
      - NGCC non-capture CO_2 emissions are approximately 56-58 percent lower than the PC cases*
    - — Offset slightly by the lower concentration of CO_2 in the NGCC flue gas (4% versus 13% for PC)

U.S. DEPARTMENT OF ENERGY

*when normalized to equivalent net power outputs

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Cost Estimation

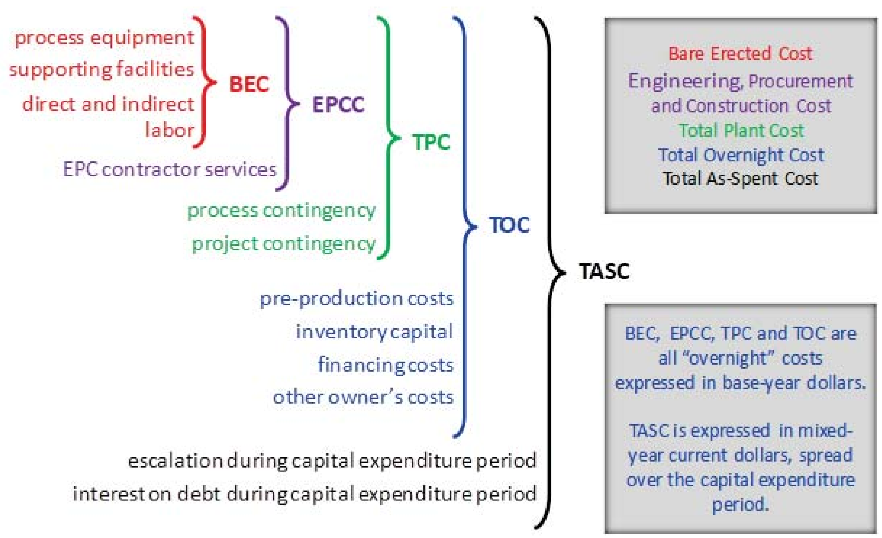
- **Capital cost results are broken into 14 accounts, and further partitioned by relevant sub-systems**
  - 2018$ estimation basis
  - Itemized owner's costs
- **Total costs for equipment through total as-spent costs are reported**
- **O&M tables breakout fixed, variable, and fuel costs, as well as initial and daily consumable rates**

	Case:	B12B	– Supercritical PC w/ CO_2			Estimate Type:		Conceptual			
	Plant Size (MW, net):	650				Cost Base:		Dec 2018			
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
4.13	Secondary Air System	$2,571	$0	$1,465	$0	$4,035	$706	$0	$711	$5,453	$8
4.14	Induced Draft Fans	$5,479	$0	$3,122	$0	$8,601	$1,505	$0	$1,516	$11,622	$18
4.15	Major Component Rigging	$93	$0	$53	$0	$146	$26	$0	$26	$197	$0
4.16	Boiler Foundations	$0	$399	$351	$0	$751	$131	$0	$132	$1,014	$2
	Subtotal	**$309,869**	**$399**	**$176,913**	**$0**	**$487,181**	**$85,257**	**$0**	**$85,866**	**$658,303**	**$1,013**
5	Flue Gas Cleanup										
5.1	Cansolv Carbon Dioxide (CO2) Removal System	$199,653	$86,357	$181,351	$0	$467,					
5.2	WFGD Absorber Vessels & Accessories	$79,398	$0	$16,976	$0	$96,					
5.3	Other FGD	$356	$0	$401	$0	$					
5.4	Carbon Dioxide (CO2) Compression & Drying	$41,405	$6,211	$13,844	$0	$61,					
5.5	Carbon Dioxide (CO2) Compressor Aftercooler	$455	$72	$195	$0	$					
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	$2,634	$579	$2,590	$0	$5,					
5.9	Particulate Removal (Bag House & Accessories)	$1,522	$0	$959	$0	$2,					
5.12	Gas Cleanup Foundations	$0	$198	$173	$0	$					
5.13	Gypsum Dewatering System	$764	$0	$129	$0	$					
	Subtotal	**$326,187**	**$93,417**	**$216,617**	**$0**	**$636,**					
7	Du										
7.3	Ductwork	$0	$747	$519	$0	$1,					
7.4	Stack	$8,767	$0	$5,094	$0	$13,					
7.5	Duct & Stack Foundations	$0	$210	$249	$0	$					
	Subtotal	**$8,767**	**$957**	**$5,862**	**$0**	**$15,**					
8	Steam Tu										
8.1	Steam Turbine Generator & Accessories	$73,354	$0	$8,175	$0	$81,					
8.2	Steam Turbine Plant Auxiliaries	$1,665	$0	$3,544	$0	$5,					
8.3	Condenser & Auxiliaries	$11,298	$0	$3,833	$0	$15,					
8.4	Steam Piping	$43,139	$0	$17,484	$0	$60,					
8.5	Turbine Generator Foundations	$0	$260	$430	$0	$					
	Subtotal	**$129,456**	**$260**	**$33,465**	**$0**	**$163,**					
9	Cooli										
9.1	Cooling Towers	$20,110	$0	$6,219	$0	$26,					
9.2	Circulating Water Pumps	$2,849	$0	$209	$0	$3,					

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$14,349	$22
1 Month Maintenance Materials	$2,323	$4
1 Month Non-Fuel Consumables	$3,322	$5
1 Month Waste Disposal	$999	$2
25% of 1 Months Fuel Cost at 100% CF	$2,859	$4
2% of TPC	$49,567	$76
Total	**$73,220**	**$113**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$28,691	$44
0.5% of TPC (spare parts)	$12,342	$19
Total	**$41,033**	**$63**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,612	$4
Land	$900	$1
Other Owner's Costs	$370,256	$570
Financing Costs	$66,646	$103
Total Overnight Costs (TOC)	**$3,023,041**	**$4,654**
TASC Multiplier (IOU, 35 year)	1.289	
Total As-Spent Cost (TASC)	**$3,897,002**	**$5,999**

Capital Cost Levels and Elements

- **Capital cost estimates are primarily reported using the following levels, which include the identified elements**



Source: NETL

Slides 23 – 28

Redacted pending NETL publication of final cost data within report titled "Cost and Performance for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 4

Conclusions and Takeaways

- NETL's Bituminous Baseline report presents a transparent and independent assessment of the cost and performance of near-term commercial offerings for coal- and natural gas-fired power plants, both with and without CCS
- The report serves many purposes including to benchmark SOA technology, guide DOE R&D, develop technology goals, identify opportunities for beneficial R&D investment, and others
- Performance estimates are based on significant sub-system vendor input
- Cost estimates are generated with a "bottom-up" approach, and based on recent and historical engineering, procurement, and construction (EPC) experience with power plant projects

Conclusions and Takeaways (cont'd)

- The report provides significant value in terms of the consistent approach and methodology applied to all technologies evaluated, as well as the extensive documentation via supplemental QGESS references that provide guidance on model development, parameter selection, cost evaluation, COE calculation methodology, and several other key areas
- The absolute capital estimates and COE results reported are not developed in an effort to match any single real-world project scenario; rather, the value of the results are that they are developed on a consistent basis, and facilitate technology comparison

Acknowledgements

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- NETL-Deloitte
  - Dale Keairns


Thank You
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1.2. CCS Costs in China: A Case Study for China Energy, *Surinder Singh, NICE*

China Energy

Corporate profile

神华集团 SHENHUAAGROUP + 中国国电 CHINA GUODIAN → CHN ENERGY 国家能源集团

- Over 1.8 Trillion RMB in assets + 330K employees
- Delivers 15% of China's electricity

World's largest …

500 MM MT/yr Coal production	180 GW Coal-fired power capacity	38 GW wind 19 GW hydro	15 MM MT/yr Coal-chemicals production

National Institute of Clean and low-carbon Energy (NICE)

Corporate RD&D lab

- *Mission ... To become a world-class R&D institute supporting China Energy's transition to a clean and low carbon energy supplier*
- Founded in 2009 ... ~600 researchers
- Sites ... Beijing, China; Mountain View, CA; Schwabisch Hall, Germany

Mission-driven research platforms

- Catalysis
- Clean coal
- Coal-based materials
- Distributed Energy
- Hydrogen Energy
- Water Treatment

- Advanced technologies
  ... Emissions/carbon management

Regulatory and market landscape for CO_2 in China

Paris agreement commitments

- 60-65% reduction in emissions intensity vs 2005 by 2030
- 30% share for non-fossil energy by 2030

13th Five year plan (2016-2020)

Generation mix

GW capacity	2016	2020
Coal	960	1100*
Hydro	330	380
Wind	149	210
Nuclear	34	58
Solar/PV	77	110

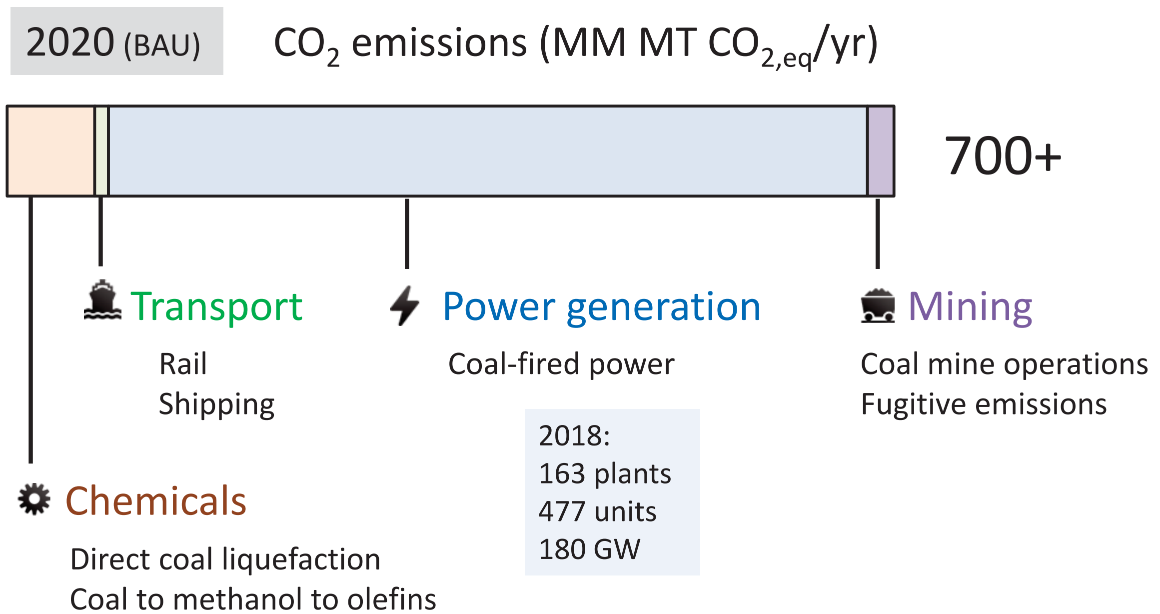
* 300 g sce/kWh ~ 40.9% LHV efficiency

Emissions trading market

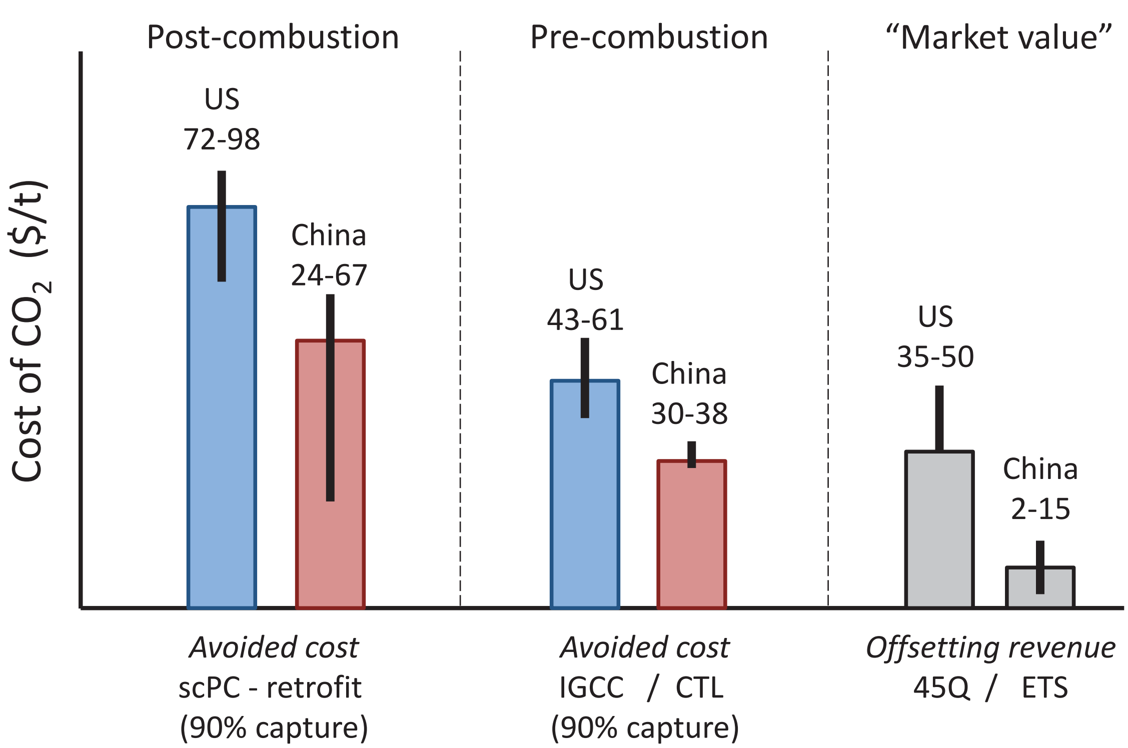
Ref: http://www.tanpaifang.com/tanhangqing/

2014 ... 7 regional pilots
2020 ... National market
Power sector ... 550 g/kWh

Estimated CO_2 footprint for China Energy



The challenge for CCS ... Affordability



Refs:
DOE, 2012/14; Singh, 2018

US and China Reference Power Plant Details

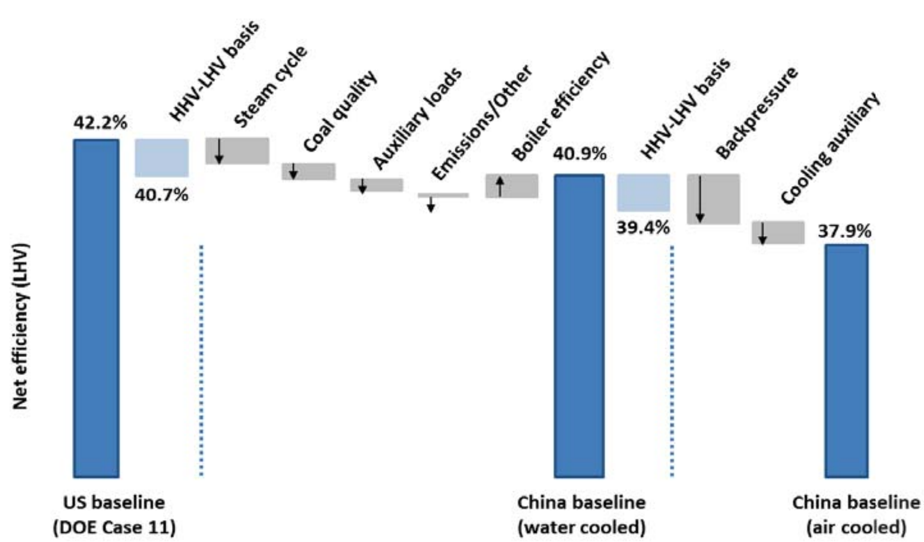
Differences between US and China can be systematically understood.

Table 1. Summary of key features and operating assumptions for the China reference cases (CN1 to CN4) and US DOE cases. [1]

Case	Case CN1	Case CN2	Case CN3	Case CN4	US DOE Case 11	US DOE Case 12R
Description						
Cooling type	Water	Water	Air	Air	Water	Water
CO_2 capture	None	Retrofit	None	Retrofit	None	Retrofit
Location	Henan, CN		Shanxi, CN		Midwestern US	
Output, gross (MW)	600	489.6	572	472.5	580	478.1
Output, net (MW)	565	395.6	524	352.8	550	414.4
Assumptions						
Coal type	China Anthracite		China Anthracite		Illinois No. 6	
Coal rate (kg/h)	208803		208803		179192	
Steam cycle (MPa/C/C)	25/566/538		25/566/538		24.1/593/593	
Condenser pressure (MPa)	0.005	0.005	0.015	0.015	0.007	0.007
Boiler efficiency (%)	93.8 (LHV)	93.8 (LHV)	93.8 (LHV)	93.8 (LHV)	88(HHV)/ 93(LHV)	88(HHV)/ 93(LHV)
CW/CA Temp to condenser (C)	20	20	15	15	16	16
CW/CA Temp from condenser (C)	31.1	31.1	39	39	27	27
Condenser duty (GJ/hr)	2406	1237	2420	1245	2202	1154
SO_2 control	Wet limestone forced oxidation		Wet limestone forced oxidation		Wet limestone forced oxidation	
FGD efficiency (%)	⩾95	⩾95	⩾95	⩾95	98	98
NO_x control	LNB+SCR		LNB+SCR		LNB w/OFA and SCR	
Particulate control	Electrostatic precipitator (ESP)		Electrostatic precipitator (ESP)		Baghouse	
Capacity factor (h, %)	5000 (57%)		5000 (57%)		85%	
CO_2 capture rate	0%	90%	0%	90%	0%	90%
Product CO_2 purity (%)	N/A	99.4	N/A	99.4	N/A	99.4
Product CO_2 pressure (MPa)	N/A	15.3	N/A	15.3	N/A	15.3

Fleet modeling … reference plant results

Performance (Baseline)



Cui et al, IJGGC 2018

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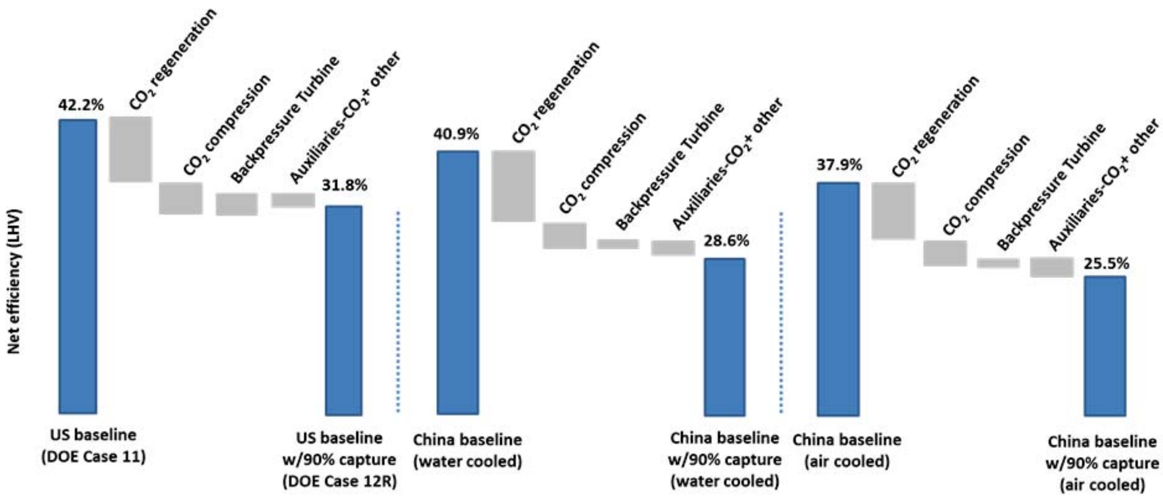
Fleet modeling … reference plant results

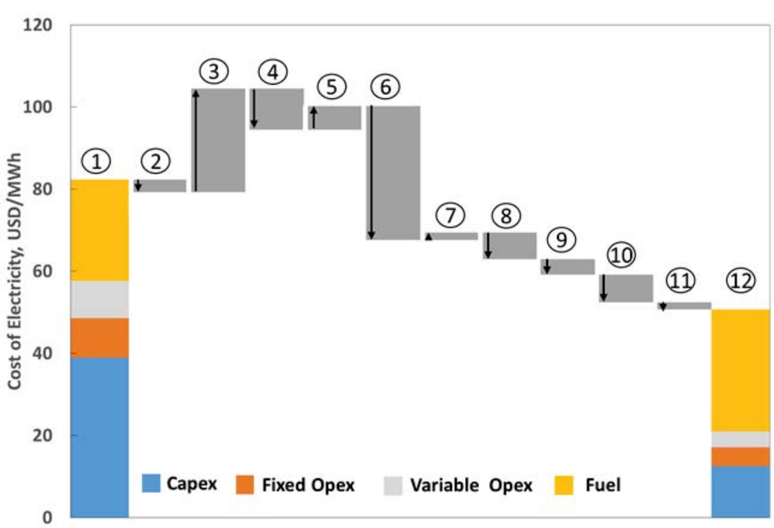
Performance (with Carbon Capture)



Cui et al, IJGGC 2018

Fleet modeling … reference plant results

Economics (Baseline)



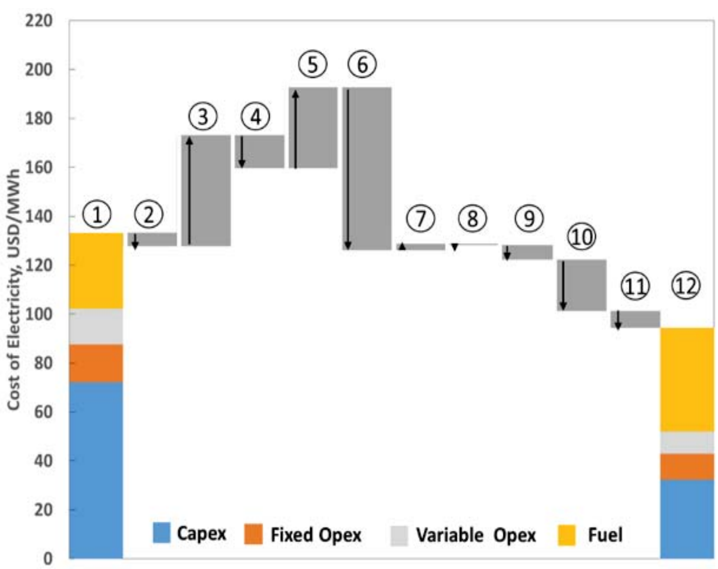
Singh et al., IJGGC 2018

Contributions to cost differences

1. US SCPC: 82.3 $/MWh
2. Currency basis 2011-2016
3. Utilization: 85% to 57%
4. Capacity scale up
5. Increased coal consumption
6. Capex savings in China
7. China coal price
8. China labor costs
9. Other fixed opex
10. Other variable opex
11. China economic returns
12. CN SCPC: 50.7 $/MWh

US-China differences ... Structural features

Reference plant comparison: Cost of Electricity



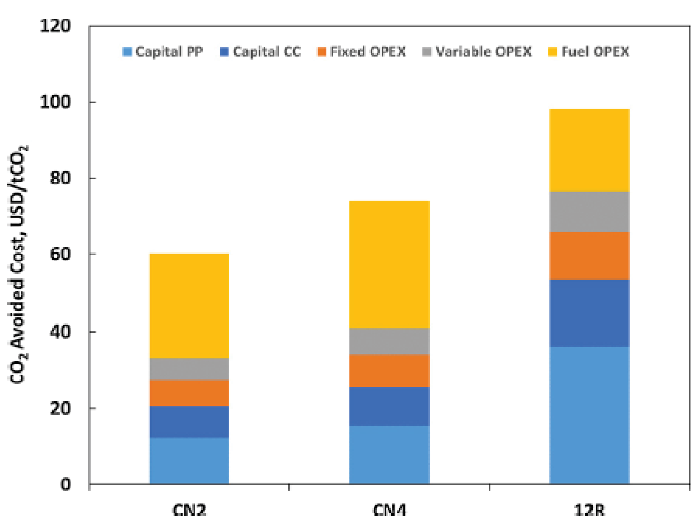
Ref: Singh, 2018

Contributions to cost differences

1. US SCPC: 133.2 $/MWh
2. Currency basis 2011-2016
3. Utilization: 85% to 57%
4. Capacity scale up
5. Increased coal consumption
6. Capex savings in China
7. China coal price
8. China labor costs
9. Other fixed opex
10. Other variable opex
11. China economic returns
12. CN SCPC: 94.3 $/MWh

US-China differences ... Structural features

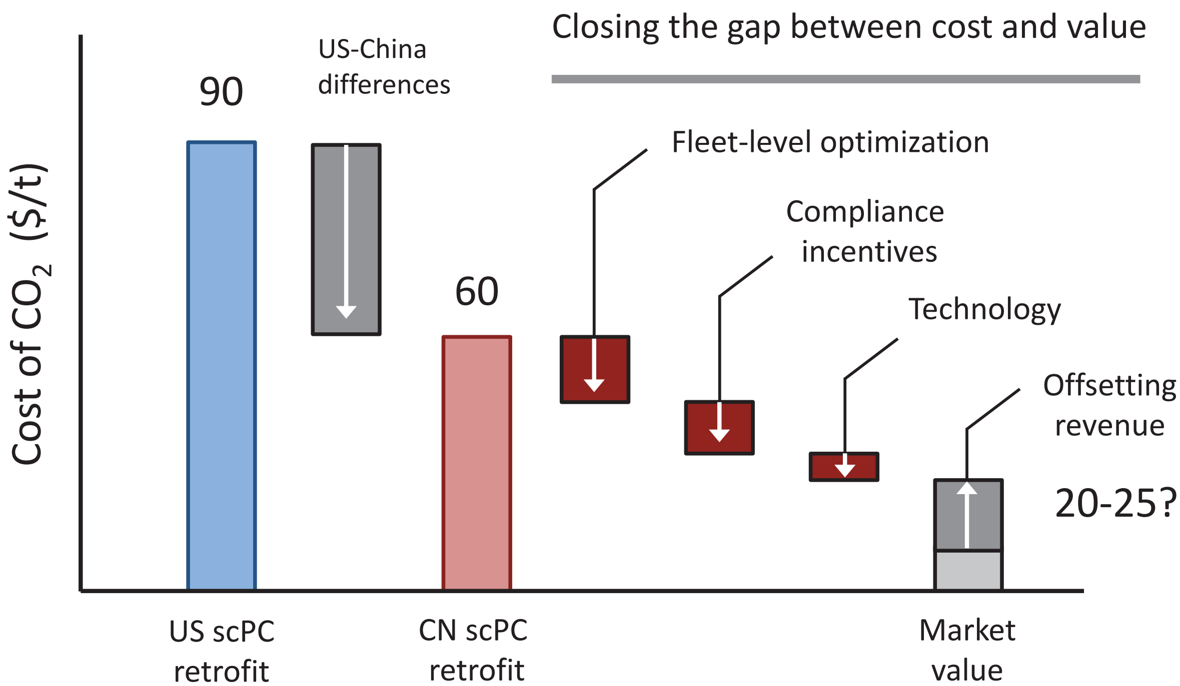
Reference plant comparison: Avoided Cost



Ref: Singh, 2018

1. US SCPC: 98.2$/tonne
2. CN SCPC (water): 60.2$/tonne
3. CN SCPC (air): 74$/tonne

A path towards affordability in China



Compliance incentives ... Lessons from ULE deployment

In response to urban air quality challenges, the Chinese power sector will have retrofitted all units larger than 300 MW capacity with ultra-low emissions (ULE) pollution controls in under a decade.

- State Council Action Plan (2013)

  ... Reduce urban $PM_{2.5}$ by 10% vs 2012 levels

  ... Reduce $PM_{2.5}$ in Jing-Jin-Ji by 25%, Pearl River Delta by 20% and Yangtze River Delta by 15%

  ... Reduce annual PM in Beijng to <60 ug/m^3

- Incentives for power plants

  ... up to 10 RMB/MWh for early adopters

  ... 100-200 h of increased dispatch

Ref: Liu, EST, 2019

Thank you

Session 2: CCS Costs in the Power Sector II

2.1. Shand CCS Feasibility Study, *Mike Monea, CCS Knowledge Center*

INTERNATIONAL
CCS KNOWLEDGE CENTRE

Presented by: Michael J. Monea, President and CEO

Shand CCS Feasibility Study

March 19, 2019

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Our Organization

THE INTERNATIONAL CCS KNOWLEDGE CENTRE

Facilitates in an advisory role

Based on expertise and lessons learned

Mandate:
Advance the understanding and use of CCS as a means of managing greenhouse gas emissions

Sponsored jointly by global resource leader, BHP and CCS pioneer, SaskPower

Sharing lessons learned from hands-on operations ensures for experienced-based decision making

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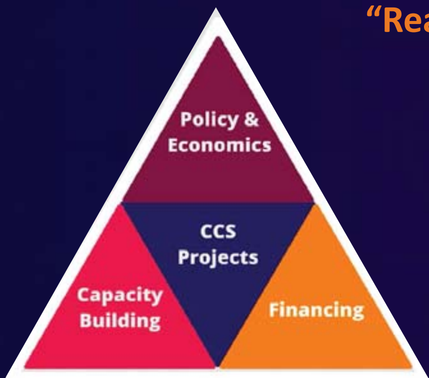
Operational Understandings: Sharing Lessons Learned



"Real world" considerations for using CCS are important.

We must COLLABORATE -
Not just talk about collaborating.

- Stimulate development
- Bring down costs
- Promote greater knowledge exchange

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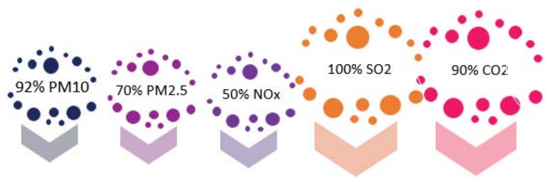
Overview of BD3 Project

The project consisted of two major parts:

Refurbishment included a complete replacement of the steam turbine and generator, which were at their end of life.

Capture involves taking out other components before the amine removes the CO_2.

- Design deficiencies and construction quality issues had to be managed, as well as amine issues.
- *Trend of higher capture rate and reduced outages over time*
- Has captured & stored over 2Mt



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Operational Understandings: Exceeding Federal Regulations

1100 t/GWh = Lignite Coal Plant

550-500 = Current Natural Gas Plant

420 = Canadian Regulations on Coal Plant

375-400 = New Natural Gas Plant

300-325 = Wind (with peakers)

120-140 = CCS on Boundary Dam 3*

*Name plate capacity

SECOND GENERATION DESIGN

SASKPOWER SHAND POWER STATION

HIGHLIGHTS OF FEASIBILITY STUDY:

- Designed to capture 2Mt
- 67% cost reduction (per tonne CO_2)
- Can capture up to 97% and integrates well with renewables

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About the Shand Feasibility Study

Feasibility Study evaluates the economics of a CCS retrofit & life extension on 300MW coal fired power plant in Saskatchewan

- Projected capture capacity of **2Mt/yr**
- Capital cost to be **67% less** per tonne of CO_2 captured
- Cost of capture at **\$45US/t CO_2**
- Capture rate can reach **up to 97%** with reduced load (i.e. renewables on grid)
- Fly ash sales can further reduce CO_2 (potential 125,000t CO_2/yr reduced)

Carbon neutral?

HOW DID COSTS COME DOWN?

- Lessons learned from building and operating BD3
- Construction at a larger scale using extensive modularization
- Integration of the bigger unit's steam cycle

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Introduction: *The Shand CCS Feasibility Study*

- The Shand CCS Feasibility Study was undertaken to evaluate the economics of a CCS retrofit and life extension on what was believed to be the most favorable host coal fired power plant in SaskPower's fleet.
- Collaboration between Mitsubishi Heavy Industries (MHI), Mitsubishi Hitachi Power Systems (MHPS), SaskPower and The International CCS Knowledge Centre (Knowledge Centre).

Figure 1. 3D model of the proposed Shand CCS facility

Table 1. Division of Labour by Scope of Work

MHI/MHPS Scope	Stantec/Knowledge Centre Scope
• SO_2 Capture System	• Steam Supply to Battery Limit
• CO_2 Capture System	• Feed-heating Modifications
• CO_2 Compressor	• Condensate Preheating
• Turbine Modifications	• Deaerator Replacement
	• Flue Gas Supply
	• Flue Gas Cooler
	• Hybrid Heat Rejection System
	• Waste Disposal

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The Cost of CCS

Capital Costs reductions of the next CCS facility are expected at *67%*

- The Shand CCS project would produce the second, full-scale capture facility in Saskatchewan with a design capacity of 2 million tons of CO_2 capture per year – twice the initial design capacity of BD3.
- Reductions in capital costs have been evaluated and are projected at 67% less expensive than they were for BD3 on a cost per tonne of CO_2 basis. This extensive reduction may be attributed to:
  a) lessons learned from building and operating BD3,
  b) construction at a larger scale using extensive modularization, and
  c) integration advantages afforded by the bigger 300MW units steam cycle.

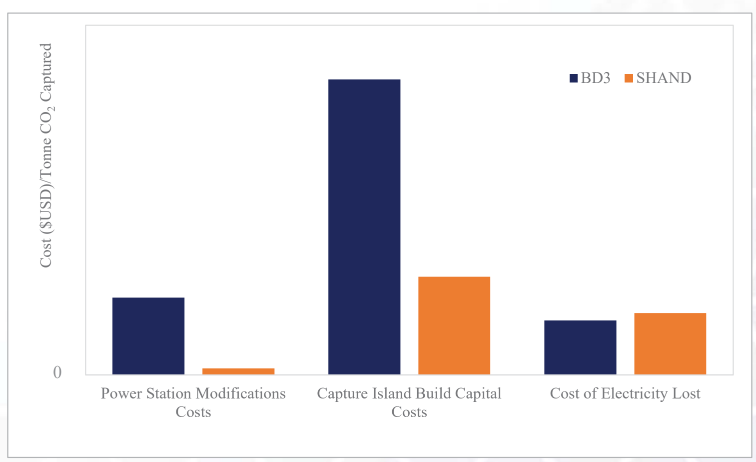

Figure 2. **Cost reduction of the Shand 2nd generation CCS facility as compared to the BD3 project**

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The Cost of CCS

The Calculated Cost of Capture from the Shand CCS Facility would be *$45US/tonne of CO_2*

- Economies of scale contribute to cost savings realized by moving to the larger 300 MW unit
- Factors considered when calculating the Levelized Cost Of Capture (LCOC) included:
    - 30-year sustained run-time of the power plant
    - capture island capital costs
    - capture island OM&A and consumables costs
    - power island modifications costs
    - cost of the power production penalty assuming purchasing of power lost due to CO_2 capture-related generation losses at costs consistent with new Natural Gas Combined Cycle (NGCC) power supply

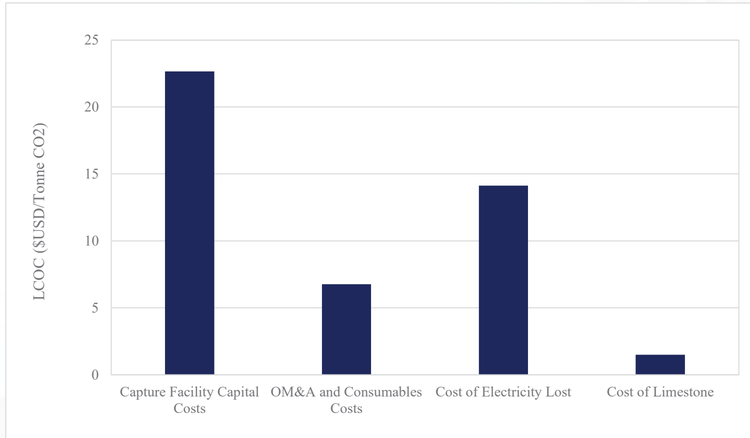

Figure 3. **Cost reduction of the Shand 2nd generation CCS facility as compared to the BD3 project**

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Drivers for CCS Implementation and Key Findings of the Study

Thermal Integration and Host Selection

- Steam extraction to reboiler sourced from IP-LP crossover; addition of butterfly valve enables continued capture operations at reduced loads
- Use of rejected flue gas heat for LP condensate preheating using a FGC and novel condensate preheating loop configuration (3 CPHs aligned in series with LP FWHs 1 and 2) helps to reduce the energy penalty
- Overall parasitic load was determined at 22.9%

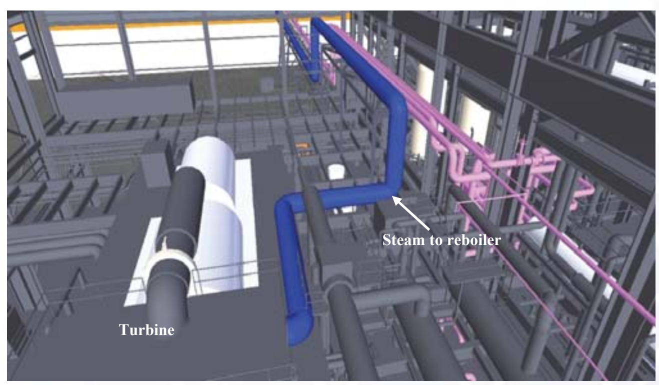

Figure 6. Proposed butterfly valve in IP-LP crossover

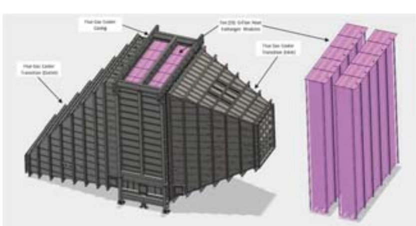

Figure 4. Proposed FGC and modules

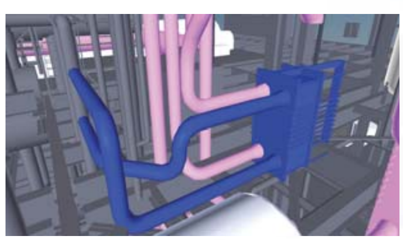

Figure 5. Proposed installation of CPH

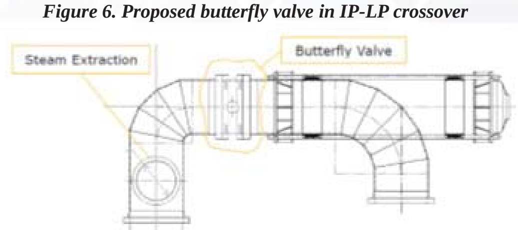

Figure 7. Proposed steam extraction line to the reboiler

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Drivers for CCS Implementation and Key Findings of the Study

Heat Rejection Design Considerations

- CCS retrofit of Shand increases the heat rejection requirement by 50%
- Shand operates as a Zero Liquids Discharge (ZLD) facility; additional water draw is not possible
- New hybrid wet surface air cooler heat rejection system consists of air cooled heat exchangers (ACHE) and wet surface air coolers (WSAC) connected in series
  - Water requirements satisfied solely by flue gas condensate
  - Designed at the 85 percentile of a 26 years survey of Estevan weather data
  - Dry cooling favored during summer months while wet cooling is dominant at cooler temperatures
  - Average colder climate in Saskatchewan shifts the annual average of heat rejection load in favour of wet cooling
  - Overall power consumption for the design case is **4.96 MWe;** the annual average of **2.58 MWe** which is **52%** of the design case

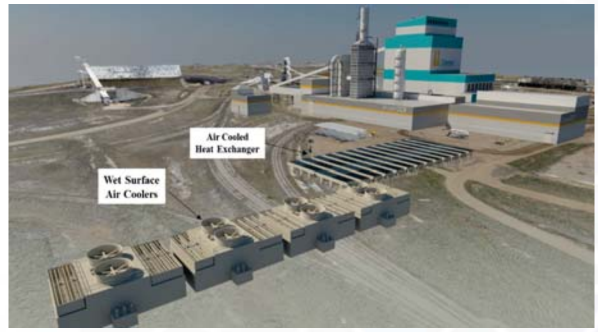

Figure 10. Proposed new hybrid heat rejection system

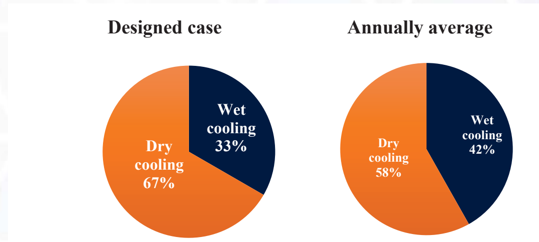

Figure 11. Variation in annual heat reject load

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Drivers for CCS Implementation and Key Findings of the Study

Fuel Pricing and Common Services

- High fixed costs in coal mining
- Scaling back on coal increases costs of fuel
- Shand and Boundary Dam feed from common mine
- Due to CCS conversion of BD3 this coal fuel source has the best long-term viability

Site Layout and Modularization

- Availability of space for the CCS plant footprint is a factor in determining a suitable location
- Distance between the power facility and the capture facility on BD3 resulted in significant capital expenditures for interconnections between the two plants
- Shand site is un-congested and open
- Modularization reduces onsite construction costs

Figure 13. Modularized facility

Drivers for CCS Implementation and Key Findings of the Study

Power Plant Reliability / Capture Plant Partial Capacity

- "Dual mode" is a risk mitigation strategy that allows continued power plant operations when experiencing issues with the capture facility
- Diverter dampers allows partial flue gas diversion

Grid Support and Ancillary Services

- Load adjustments of large thermal power stations are dictated by the supply-demand balance in the electricity grid
- Viable CCS would have to maintain the flexible operating range

Figure 14. Proposed flue gas supply to the capture facility

Plant Maintainability

- Current coal fired power plant designs are the product of multiple generations of revision
- This level of refinement has not yet been achieved with amine based CCS facilities
- Experience at BD3 highlighted key process isolations and redundancy at selected locations in the process; these have been considered in the Shand CCS design

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Drivers for CCS Implementation and Key Findings of the Study

CO_2 Market

- CO_2 EOR opportunities exist within 100 km of Estevan, Saskatchewan
- Economical development of these opportunities is key to a successful CCS retrofit
- Opportunity exists to join the Shand CO_2 pipeline to the BD3 pipeline; this would increased reliability of CO_2 supply and reduce penalties associated with delivery challenges
- CO_2 from BD3 that is currently not sold to off-taker(s) could be used to develop the CO_2-use market prior to the completion of the Shand CCS facility
- Excess CO_2 capture volumes could be sequestered within the capacity of the existing Aquistore dedicated geological storage project.

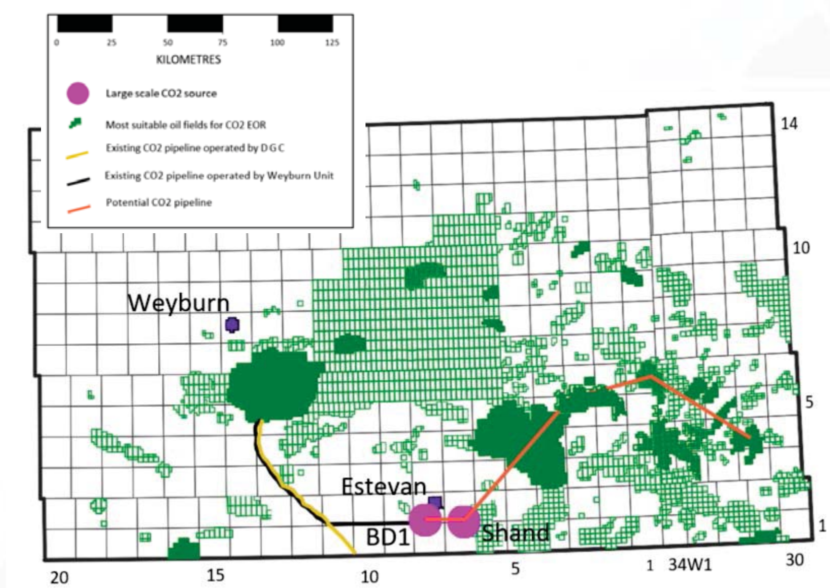

Figure 15. Location of potential CO_2 EOR in south east Saskatchewan

Drivers for CCS Implementation and Key Findings of the Study

Matching Capture Capacity to Regulatory Requirement

- *The Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations (July 2015), set performance standards at 420 tonnes CO_2/GWh*
- Designing a capture facility at minimum capture requirements increases the per ton cost of CO_2 capture
- Mitigating long-term risks of increased costs from tightening CO_2 policy is accomplished by implementing projects exceeding rates of 90% CO_2 capture

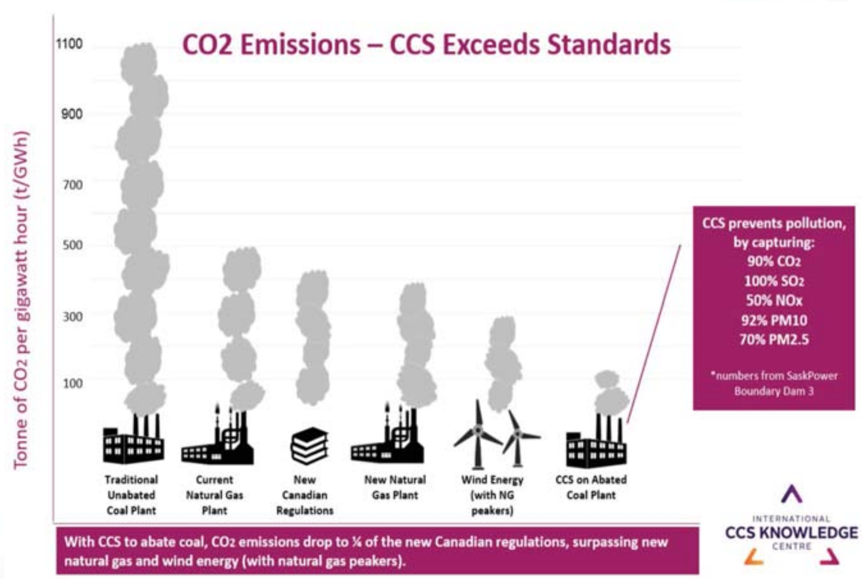

Figure 16. Summary of various industrial CO_2 emission intensities

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Drivers for CCS Implementation and Key Findings of the Study

Over-Capture at Reduced Load

- At lower loads the capture rate exceeds 90%
- Sensitivity analysis indicated capture rates reaching in excess of 97% at 75% fluegas flow (62% net electrical ouput)
- CCS equipped coal-fired power plant could be made responsive to variable renewable generation

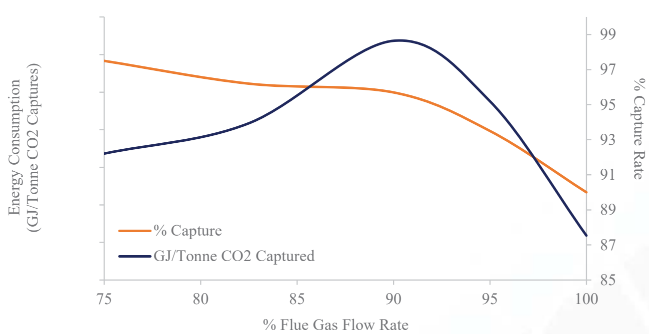

Figure 17. Summary of % capture rate and energy consumption with variation in flue gas flow rate

Increasing Capture Capacity From 90% to 95%

- 95% capture is possible
- Overall increase in capital costs required to facilitate the increase in capture produces a lower overall cost per tonne

Table 2. Average performance for Shand CCS with 90% and 95% design capture at full load

	Unit	90% Capture	95% Capture
Net Electricity Production	(MWh)	1,539,815	1,526,057
CO_2 Emissions	(Tonnes)	163,521	108,991
CO_2 Emission Intensity	(kg/MWh)	106.2	71.4

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Emissions Profile of a Shand CCS Retrofit

Flexible Load Operations - Integration with Renewable Energy Sources - Valuable Byproducts

- While renewable power sources lack CO_2 emissions, their variability requires a backup power supply for when the sun is not shining, or when the wind is not blowing
- Dispatchable fossil generation is used to firm the supply in these situations
- Proposed design of the Shand CCS retrofit considered planned curtailment; load following is a key design criteria of Shand CCS
- The proposed CCS integration of Shand would allow the unit to maintain its range of dispatch and loading rate with the CCS island operating, while allowing increased capture at lower loads
- Desirable scenario in which a capture plant supports the integration of renewable power sources, while further reducing its own CO_2 footprint; the opposite response is encountered at a traditional natural gas plant that supports VRE integration
- The emissions intensity profile for CCS coal integrated with wind and NGCC integrated with wind were compared; CCS coal offers the greatest gains in emissions reductions
- Up to 140,000 tonnes/ year fly ash would be saleable for the concrete market (valuable revenue stream, subject to demand) thanks to the replacement of the poorly performing lime injection system, resulting in a net effective CO_2 emission offset from fly ash sales would be approximately 0.9 tons of CO_2 reduction / ton of fly ash; potential net emission reduction of 125,000 tons / year.

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Conclusions

- A second generation CCS facility on coal is in sight
- Capital costs have been reduced by 67%
- Calculated cost of capture would be $45US/tonne of CO2
- Novel optimizations and lessons learned have de-risked aspects of CCS
- Emissions are significantly lower than Canadian regulations
- Carbon Neutral Coal Power is Possible

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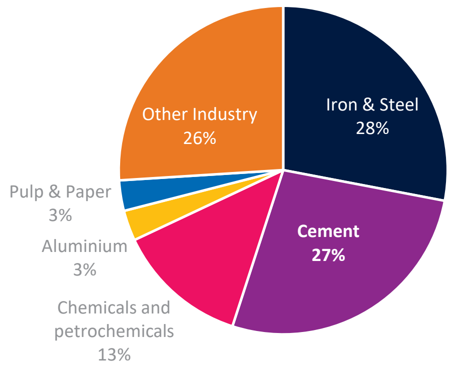
Second Generation Application to Industrial Emissions

Direct industrial CO_2 emissions (2014)



Information on this slide is sourced from International Energy Agency, Energy Technology Perspectives 2017

Industrial CO_2 emissions represent 24% of global CO_2 emissions at 8.3 Gt CO_2 (2014)

- Lessons learns from operational experience at Boundary Dam CCS Facility and findings from the Shand CCS Feasibility Study can be applied to other industrial sources of emissions
- Size and layout considerations / integration are key considerations
- Costs can be saved with CO_2 infrastructure hubs, cost recovery with EOR, modularization and byproduct sales decisions
- Optimization is still required for particular flue gas characteristics to save operating costs

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2.2. Pre-Feasibility Study for a Carbon Capture Pilot Plant in Mexico, *Haoren Lu, Nexant*

World Bank
Pre-Feasibility Study for Establishing a Carbon Capture Pilot Plant in Mexico

2019 IEAGHG CCS Cost Network Workshop

Haoren Lu

Mar 19, 2019

Acknowledgments

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The World Bank – Dr. Natalia Kulichenko, Dr. Frank Mourits, Dr. Moises Davila and Mr. Guillermo Hernandez Gonzalez; Professor Jon Gibbins of UKCCS as a Technical Advisor to the World Bank team

SENER (Department of Energy of Mexico) – Ms. Jazmin Mota Nieto

CFE (Comision Federal de Electricidad) – Mr. Agustin Herrera

IIE (Electrical Research Institute) – Mr. Jose Miguel Gonzalez

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While it is believed that the information contained in this report will be reliable under the conditions and subject to the limitations set forth herein, Nexant cannot guarantee the accuracy thereof. The views and opinions expressed herein and, in particular, in the documentation that constitute this study are specifically those of the authors of this study. The use of this report or any information contained therein shall be at the user's own risk.

Project Background

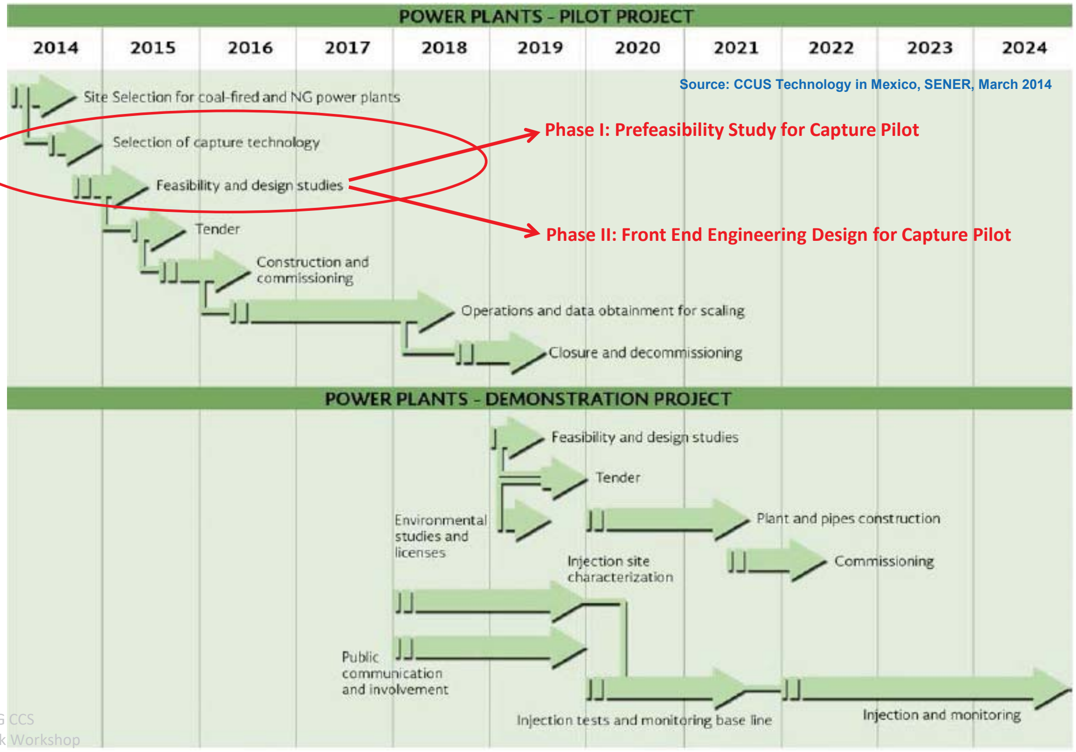
As part of the overall World Bank funded effort to develop capacity for carbon capture, utilization and storage technology (CCUS) in Mexico, the Nexant Team was tasked to perform a feasibility study to:

- Task 1: Evaluate and recommend the ***most appropriate commercially- available post-combustion*** CO_2 capture technology for NGCC power plants in Mexico, and
- Task 2: Develop a conceptual design for a CO_2 capture pilot plant to be located at the 250 MW Poza Rica generation station in the state of Veracruz

The conceptual design would then lead to a next phase (Phase II) of the project to develop a Front End Engineering Design (FEED) package for the capture pilot plant.

Project Background

Mexico's Technology Roadmap for CCUS in Power Plants



Task 1 – Approach and Activities Performed

Site Selection:

- ❑ 250MW Poza Rica NGCC Generating Station, located in State of Veracruz
- ❑ Preliminary site and plant data provided by CFE

Evaluate most appropriate commercially-available technology:

- ❑ Study will only focus on retrofit with post-combustion CO_2 capture (PCC)
  - o World Bank/SENER's interest in ***near-term technology deployment***
  - o Advanced amine-based absorption process for PCC nearest to commercialization
- ❑ Prepared and issued "Request for Information" (RFI) to ten (10) technology developers/vendors; Six (6) agreed to participate in the study.

Task 1 – Approach and Activities Performed

Site Selection:

- ❑ 250MW Poza Rica NGCC Generating Station, located in State of Veracruz
- ❑ Preliminary site and plant data provided by CFE

Evaluate most appropriate commercially-available technology

Participating PCC Technologies
Alstom Advanced Amine Process
BASF/Linde
Fluor
HTC
MHI
Shell Cansolv

Task 1 – Approach and Activities Performed (Cont'd)

Reference PCC Design:

- ❑ Established a ***full-size*** generic amine (30 wt% MEA) PCC plant design for Poza Rica NGCC at 85% CO_2 capture rate
    - o Estimated cost and overall power plant performance
    - o Serve as a reference, independently assessed CO_2 capture case on impact of PCC/NGCC integration for comparison with proprietary PCC technologies
    - o "Fill-in-the-blanks" for items that were not supplied by licensors

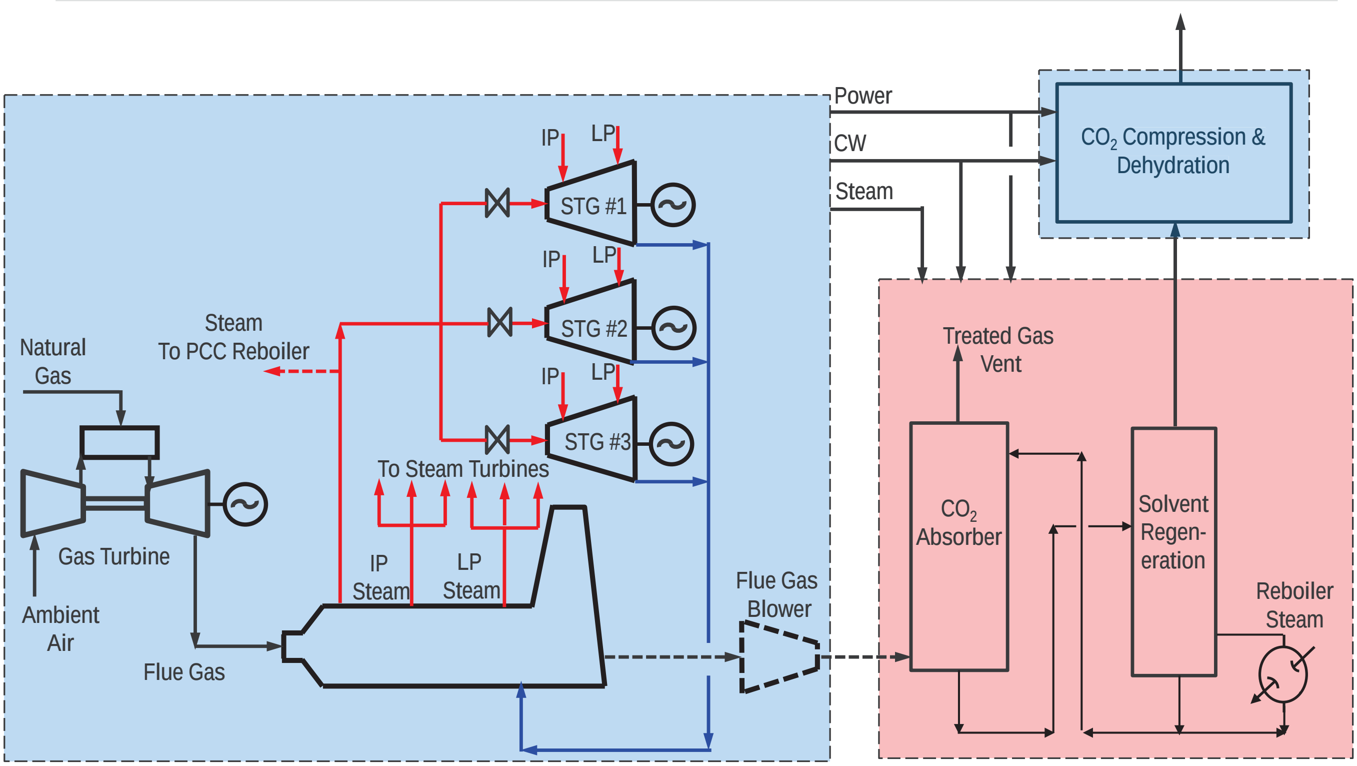
Task 1 – Approach and Activities Performed (Cont'd)

Integrated NGCC/Full-Scale Advanced Amine PCC Technology

Cases:

- ❑ Used PCC technology providers' RFI questionnaire responses as inputs into model
  - o Recovered CO_2 conditions
  - o Steam conditions and consumption rates
  - o PCC power consumption
  - o Capital costs
- ❑ Evaluated performance and cost (± 30%) for the six cases among one another and with the Reference PCC design
- ❑ Performed Cost of Electricity (COE) calculation consistent with DOE-NETL methodology

Poza Rica NGCC/PCC Division of Responsibilities



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Task 1 Findings: Full-Scale Poza Rica NGCC PCC Retrofit Performance Evaluation (All Licensors @ 85% CO_2 Capture)

See Note 1	No PCC
NGCC CO2 Emissions, STPD	2,532
Recovered CO2 Product, STPD	0
% CO2 Capture	0
Power Balance, MW	
Generation	
Gas Turbine Gross Output	166.6
Steam Turbine Gross Output	82.5
Back Pressure Turbine	0
Total Gross Output	249.1
Auxiliary Consumption	
Existing NGCC Plant Parasitic Loads	7.2
Flue Gas Blower	0
PCC + CO2 Compression + Plant Mods	0
Total New PCC Parasitic Load	7.2
Net Power Plant Export, MW	241.9
Δ Plant Export, MW	
% Plant Export Reduction	
Net Plant Heat Rate, Btu/kWh	6,584
Net Plant Efficiency, % LHV	51.8
Incremental Water Import, gpm	0

All show performance improvement over MEA

Note 1 - Values presented here are Nexant's interpretation of the data provided by the PCC licensors.
Note 2 - Fluor provided information for CO_2 capture rate of 90%. Nexant adjusted Fluor's performance to 85% to be consistent with the design basis

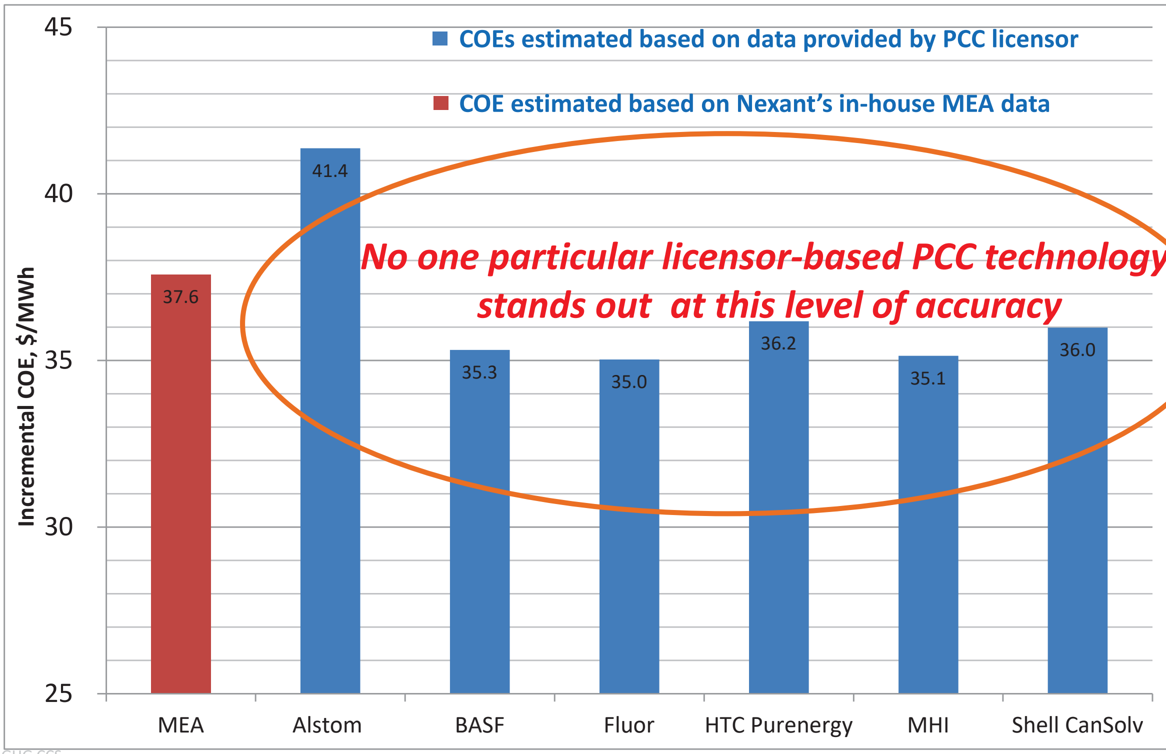
Nexant

Task 1 Findings: Full-Scale Poza Rica NGCC PCC Retrofit Economic Evaluation (All Licensors @ 85% CO_2 Capture)

Incremental Costs to Poza Rica NGCC without CO2 Capture [Note 1]	Estimated Post-Combustion CO2 Capture Costs						
	Generic 30% MEA PCC Design	Alstom	BASF / Linde	Fluor	HTC Purenergy	MHI	Shell CanSolv
CAPEX Estimate, $MM US USGC							
PCC Plant + CO2 Compression [Note 2]	181.4	234.7	187.7	174.0	194.5	178.8	194.9
Flue Gas Blower	14.2	14.2	14.2	14.2	14.2	14.2	14.2
Poza Rica Plant Modifications	32.8	32.4	30.4	31.4	29.1	30.9	30.4
TOTAL	228.4	281.4	232.3	219.7	237.8	223.9	239.5
O&M Estimate, $MM US							
Variable Costs [Note 3]	7.6	7.6	7.6	7.5	7.3	7.5	7.5
Fixed Costs	11.0	13.3	11.1	10.9	11.4	10.8	11.6
TOTAL	18.5	21.0	18.7	18.4	18.7	18.3	19.1
Estimated Cost of Electricity (COE), $/MWh [Note 4]	37.6	41.4	35.3	35.0	36.2	35.1	36.0

Note 1 - Values presented here are Nexant's interpretation of the data provided by the PCC licensors.
Note 2 - All except Nexant 'Generic 30% MEA Design' are based on vendor-provided data, which are considered proprietary.
Note 3 - Major component is the amine replacement costs, which are considered proprietary.
Note 4 - Incremental to estimated existing Poza Rica NGCC COE of $40.69/MWhr

Task 1 Findings: Full-Scale Poza Rica NGCC PCC Retrofit COEs for 85% CO_2 Capture



Task 1 – Conclusions

- ❑ **Retrofitting Poza Rica with PCC can incur significant thermal penalty to the plant**
  - ~19% reduction in the net MW plant output based on current state-of-the-art 30% MEA amine capture technology
- ❑ **All six proprietary PCC technologies evaluated show slight improvement in performance, 16%-18% reduction in power export vs 19% for MEA**
- ❑ **Estimated incremental capital cost for retrofitting Poza Rica for CO_2 capture is between $224 to $282MM US -**
  - Estimated CAPEX based on the study design of a 30% MEA amine capture is about $228MM of which breakdown as follows:
    - o Amine CO_2 capture plant 62%
    - o CO_2 compression plant 18%
    - o Flue gas blower 6%
    - o NGCC plant modification 14%
- ❑ **Estimated incremental O&M cost is between $18.3 to $21.0MM per year.**

Task 1 – Conclusions (Cont')

- Within the accuracy of the data provided, the performance of all six technologies are reasonable and comparable; no one technology is 'head and shoulders' above the rest
- Pilot plant testing would be needed to independently validate the claimed performances, in order to make sound choice of technology for large-scale commercial deployment
- Decided on an MEA-based pilot plant with design flexibility
  - Discussed in Task 2 of the World Bank report

Task 2 – PCC Pilot Plant Size Determination

- Provided charts of preliminary performance and cost estimates vs pilot plant size, as % of full-size CO_2 capture plant.
- Evaluated parameters included:
  - Quantity of CO_2 recovered
  - Estimated reboiler steam extraction rate
  - Estimated cooling water load and additional makeup water required
  - Column diameter (transportation limits)
  - Estimated NGCC export power loss
  - Relative capital cost
- Using the preliminary cost and performance estimates that Nexant provided, World Bank, IIE, SENER and CFE agreed on a pilot plant size to treat 1% of the full size Poza Rica plant flue gas, recovering 20 mTPD of CO_2.

Task 2 – PCC Pilot Plant Design Criteria

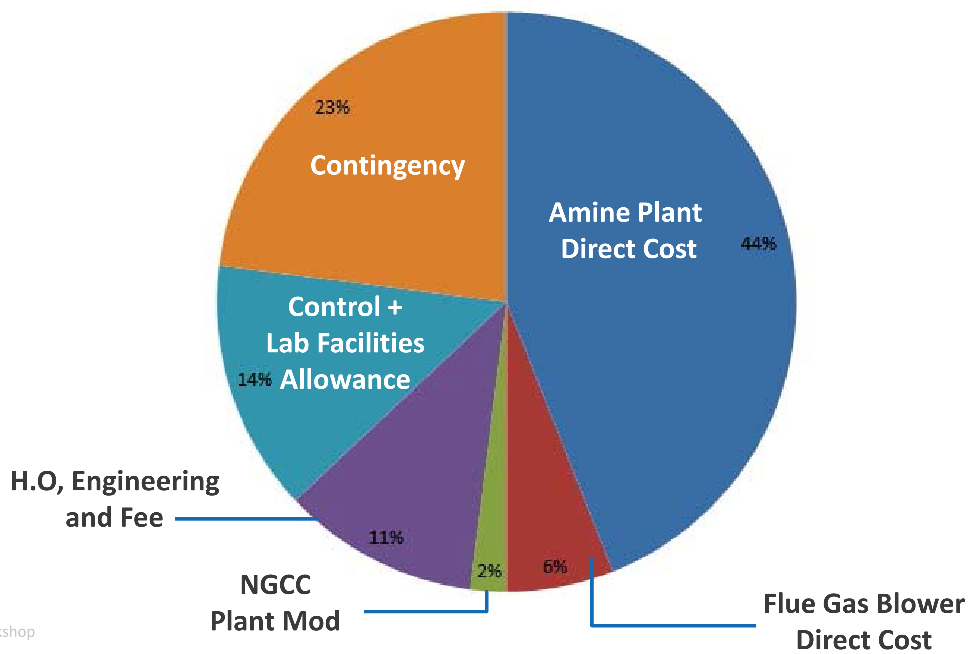
- Sized to treat 1% slipstream of total NGCC flue gas and recover 85% of CO_2
- Captured CO_2 is vented; compression facility excluded
- Designed with features to accommodate testing of multiple types of amines
  - Low-carbon stainless steel fabrication (304L & 316L)
  - Capable of separate chemical (caustic) scrubbing of feed gas
  - Capable of separate chemical wash of treated flue gas
  - Capable of absorber inter-stage cooling operations
- Minimize interference with existing plant operation
  - Motor driven actuators to avoid using plant instrument air
  - Separate trailer-mounted on-site control rooms and lab facilities with staff independent of Poza Rica NGCC operations
- Provide adequate sampling and monitoring systems
  - On-line analyzer (CO_2 and/or O_2 concentration) in gaseous streams
  - Grab-samples for lab analysis of liquid stream CO_2 and contaminant in liquid streams
  - Grab-samples for lab analysis of contaminants in vent and discharge streams

Task 2 – Post-Pilot Plant Retrofit Overall NGCC Performance

Overall NGCC Power Balance	No PCC	PCC Pilot (Exp)
Power Output, kWe		
Gas Turbine	166,570	166,570
Steam Turbine	82,500	82,300
Total Generation, kWe	**249,070**	**248,870**
Parasitic Loads, kWe		
Existing NGCC Loads	7,213	7,213
PCC Pilot Plant Loads	0	156
Total Parasitic Loads, kWe	**7,213**	**7,369**
Net Power Export, kWe	**241,857**	**241,501**
DPower Export, kWe (%)	**--**	**-357 (-1.5%)**

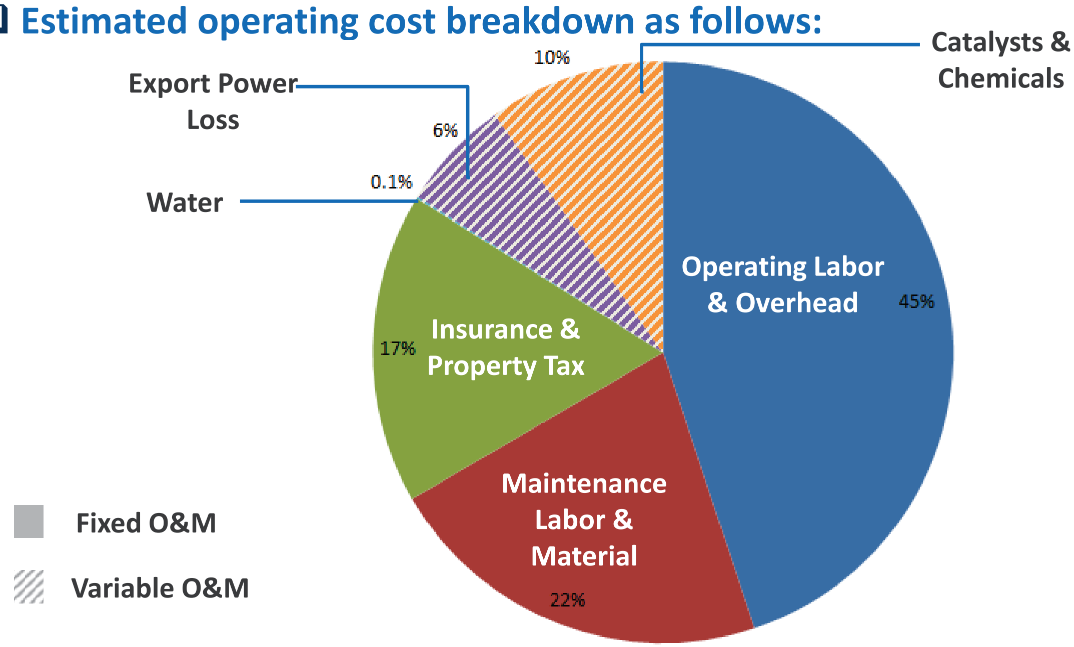
Task 2 – Post-Pilot Plant Retrofit Cost Estimate

- Estimated incremental capital cost for retrofitting Poza Rica with 1% MEA-based PCC pilot plant is $22MM (~10% of full size plant)
- Estimated CAPEX breakdown as follows:



Task 2 – Post-Pilot Plant Retrofit Cost Estimate

- Estimated incremental operating cost for retrofitting Poza Rica with 1% MEA-based PCC pilot plant is $2.5MM/yr
- Estimated operating cost breakdown as follows:



Thank you!

Questions?

2.3. Loy Yang A Power Station Retrofit for Carbon Capture, *Bill Elliott, Bechtel*

LOY YANG A POWER STATION RETROFIT FOR CARBON CAPTURE

LOY YANG A POWER STATION LOCATION

LOY YANG A STATION – POWER PLANT OVERVIEW

PLANT LOCATION – Latrobe Valley, Victoria, Australia

FUEL SOURCE – Adjacent open pit lignite mine

NUMBER OF GENERATING UNITS – 4

TOTAL GENERATION – 2400 MW (Nominal)

UNIT CAPACITY – 600 MW (Nominal)

ESP FLUES PER UNIT – 2 (Total 8 Flues for the Plant)

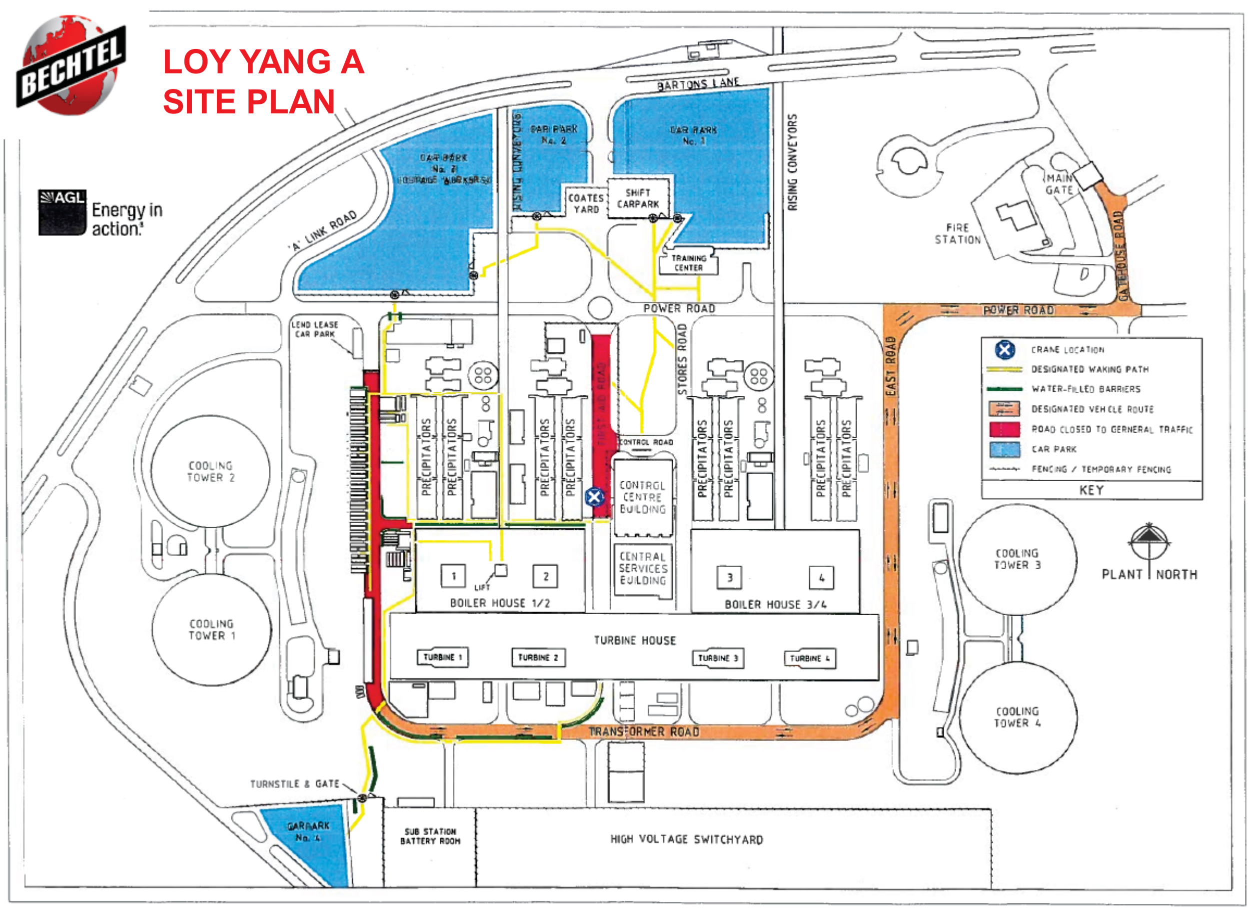
CARBON CAPTURE MODULES REQUIRED – 1 per Flue (= 2 per Unit; 8 Total for Plant)

PLANT OWNER – AGL Energy Limited

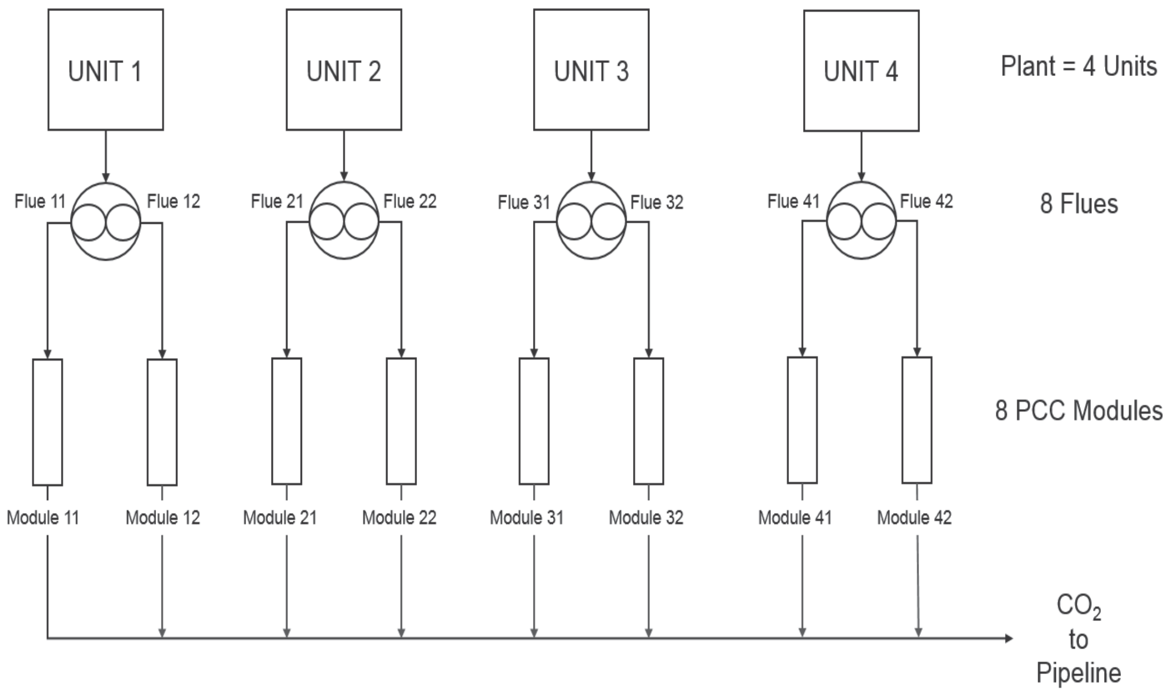
YEARS BUILT – 1984-88

ABSORBENT – 40% MEA @ 0.22 mol CO2/mol MEA lean amine loading

LOY YANG A SITE PLAN



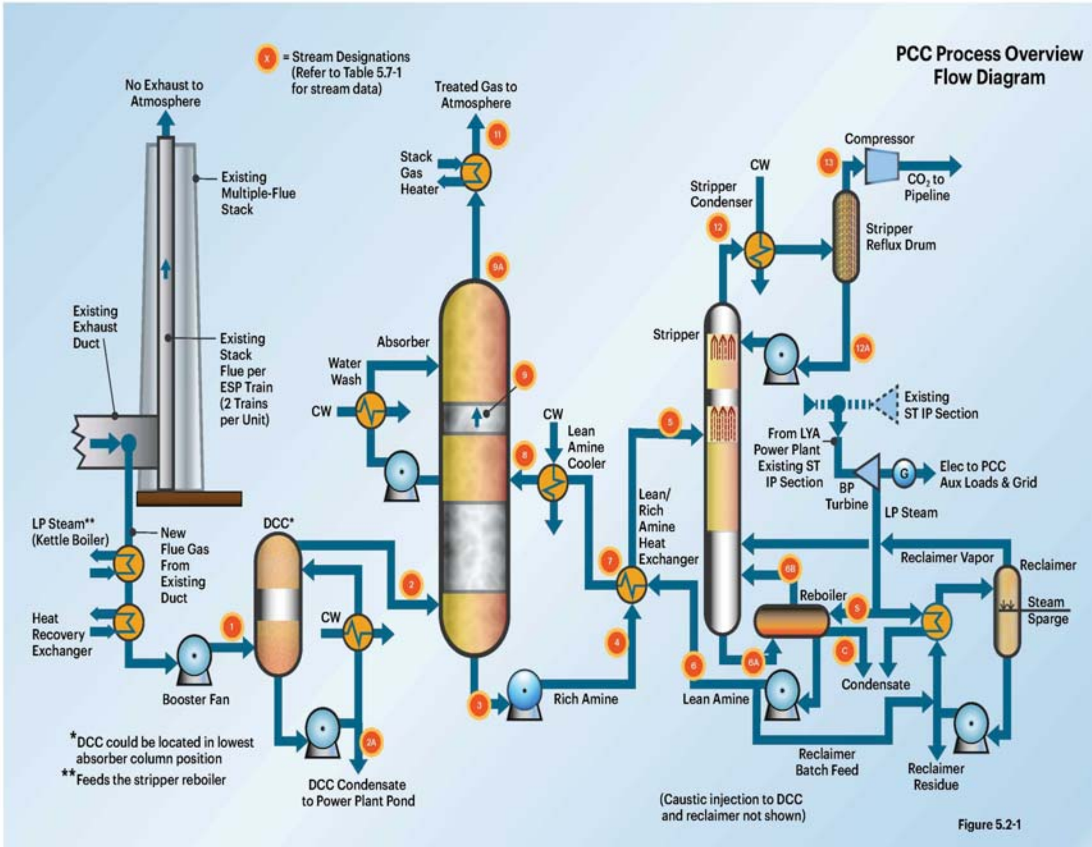
LOY YANG A MAJOR FLUE GAS PATH DESIGNATIONS



LOY YANG A STATION - RATINGS

RATING	Unit of Measurement	FOR THE PLANT (FOUR UNITS)	PER UNIT (TWO FLUES)	PER FLUE
CO_2 Emitted	Tonnes/day	58,400	14,600	7,300
CO_2 Captured	Tonnes/day	52,560	13,140	6,570
Flue Gas*	SCM/sec	3,120	780	390
	Tonnes/day	330,400	82,600	41,300
Net Elec Output	MW	2,064	516	258

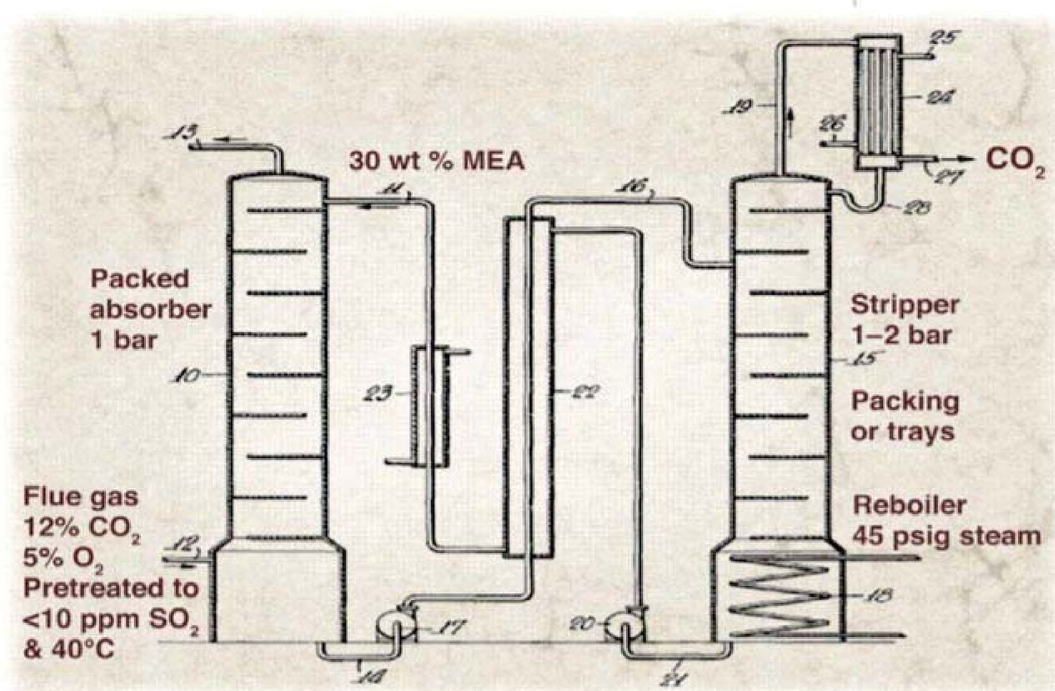
*Design inlet flue gas contains 11.2 vol % CO2, 4.3 vol % O2, 100 ppm NOX, 200 ppm SO2, and 0.5 g/SCM particulates.



AMINE SCRUBBING PROCESS ORIGIN

The amine scrubbing process invented by Bottoms in 1930

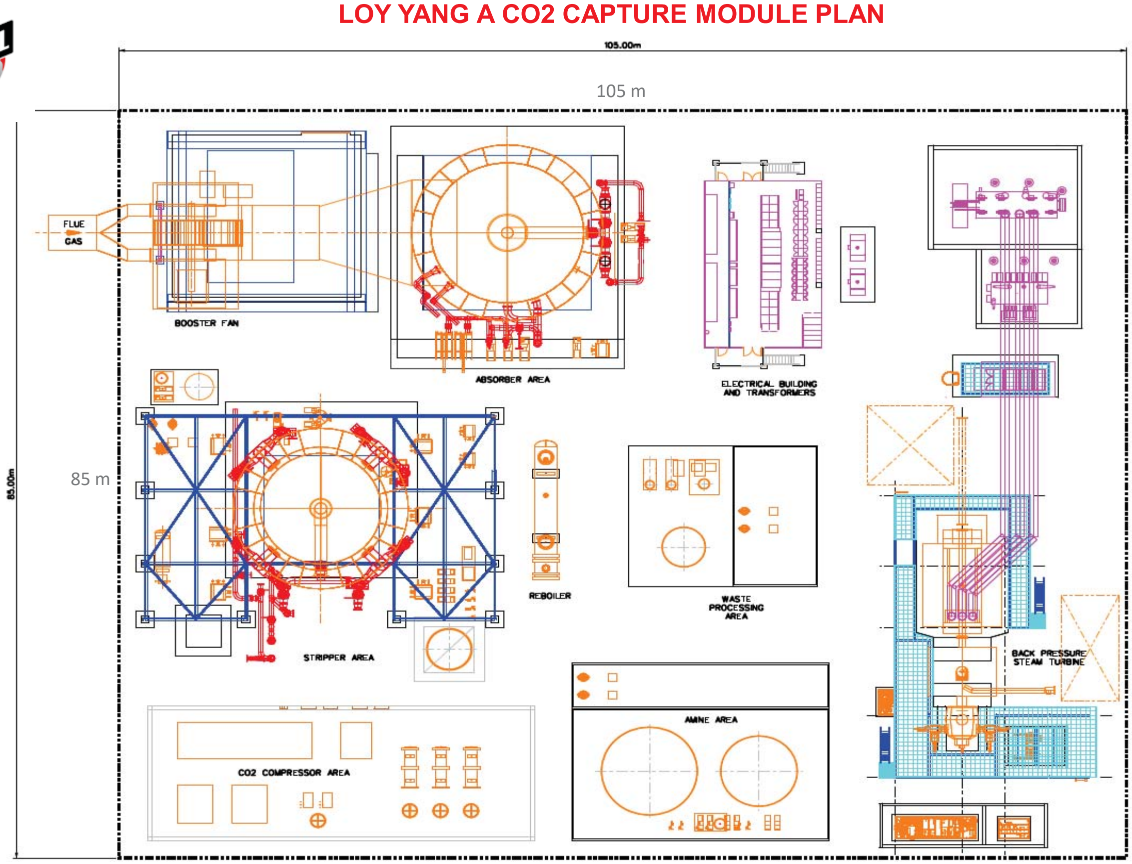
R. R. Bottoms (Girdler Corp.), "Separating acid gases," U.S. Patent 1783901, 1930



LOY YANG A STATION – CC DESIGN CHARACTERISTICS (per Flue/Module)

CC SECTION	SPECIFIC CHARACTERISTIC	UNIT OF MEASUREMENT	VALUE
Booster Fans	Number of Equipment Items	Each	1
	Capacity each	SCM/sec	400
	Delta P	cm H_20	150
Direct Contact Cooler (DCC)	Number of Equipment Items	Each	1
	Velocity	m/sec	3.0
	Area	m^2	180
	Packing Depth	m	2.16
	Diameter	m	15
	Vessel Height	m	4
Absorber	Number of Equipment Items	Each	1
	Velocity	m/sec	2.3
	Area	m^2	180
	Packing Depth	m	2 x 7.56
	Water Wash Packing Depth	m	1 x 1
	Diameter	m	15
	Vessel Height	m	29
Stripper	Number of Equipment Items	Each	1
	Pressure	bara	1.9
	Packing Depth	m	4
	Diameter at Bottom	m	14
	Diameter at Reflux Section	m	8.5
	Vessel Height	m	23.3
Compressors	Number of Equipment Items	Trains	1
	Stages	no. of	8
	Discharge Pressure	bara	150
	Power Consumption	kW	27,000

LOY YANG A CO2 CAPTURE MODULE PLAN



LOY YANG A STATION
CC OPERATING CHARACTERISTICS (PER FLUE/MODULE)

CHEMICALS CONSUMPTION

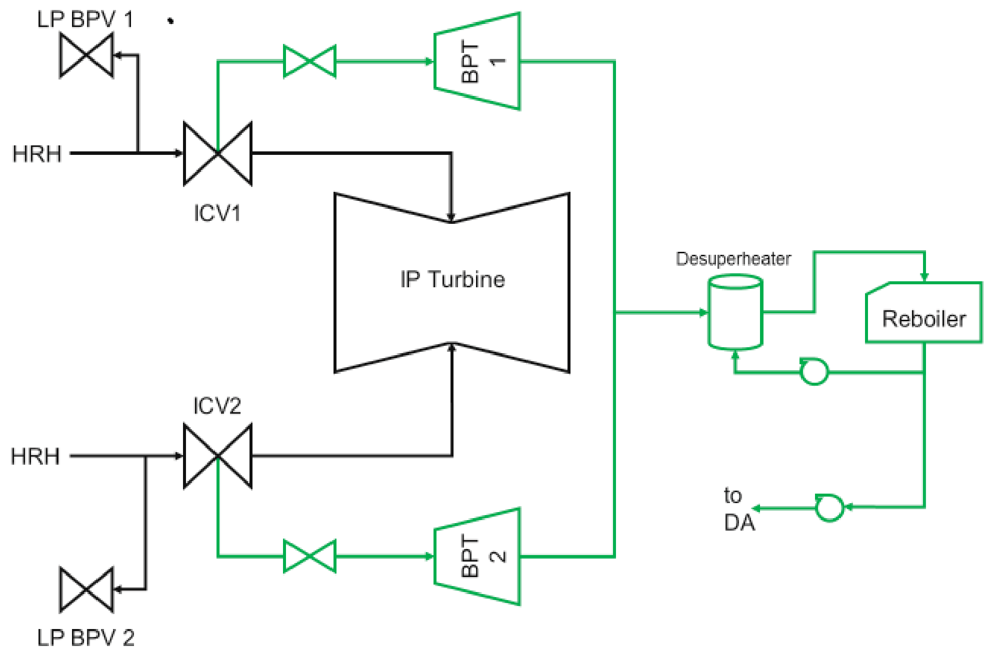
CHEMICAL	UNIT OF MEASUREMENT	VALUE
MEA (Initial Charge)	Tonnes	1,200
MEA (Annual Use)	Tonnes	649
Caustic (Annual Use)	Tonnes	**50**

LOY YANG A STATION
CC OPERATING CHARACTERISTICS (PER FLUE/MODULE)

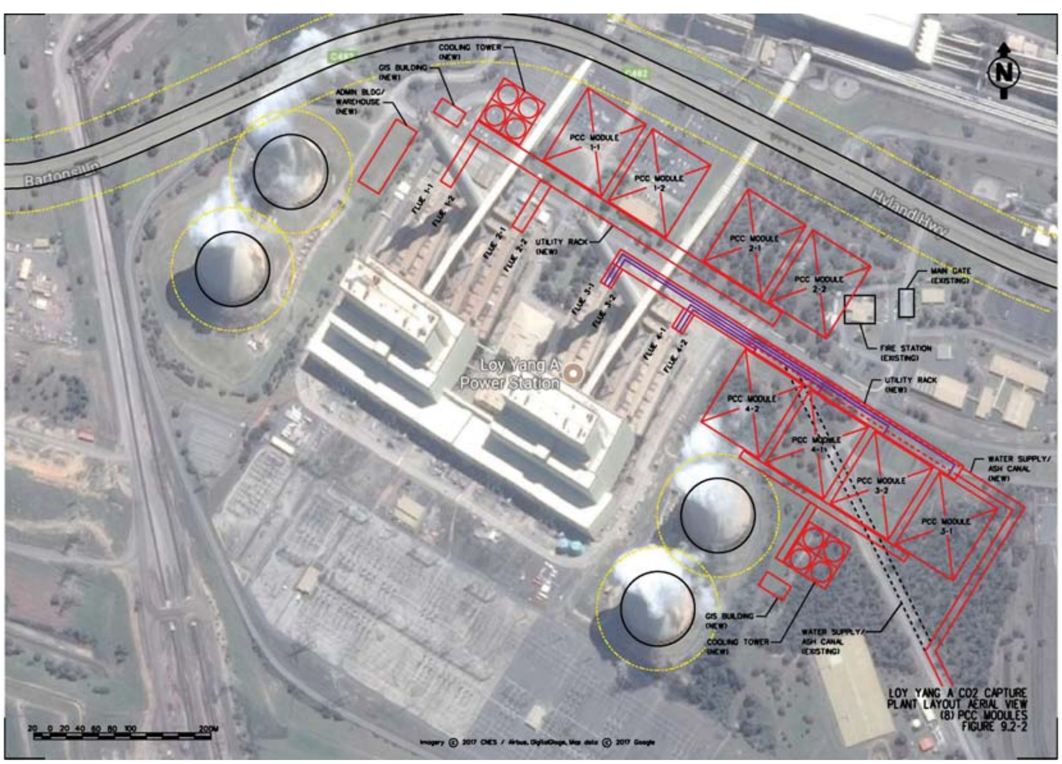
CC STEAM REQUIREMENT

RATING	UNIT OF MEASUREMENT	VALUE
BP Steam Turbine-Generator	MW (elec)	118.4
Steam in to B/P STG - Temperature	degC	539
Steam in to B/P STG - Pressure	bara	29
Steam in to B/P STG - Flow	kg/hr	749,300
Steam out to Reboiler - Temp	degC	251
Steam out to Reboiler - Press	bara	3.5
Steam out to Reboiler - Flow	kg/hr	749,300

LOY YANG A STATION
BP STG INTEGRATION
(PER UNIT = x2 FLUE/MODULE)



LOY YANG A WITH (8) CO2 MODULES PLACED



CARBON CAPTURE RETROFIT
FRONT-END SCHEDULE ASPECTS

SPECIFIC FRONT-END ACTIVITY	ACTIVE MONTHS	TOTAL MONTHS
Develop CO2 Project Ownership Structure	-55 to -45	10
Design/Erect Pilot Plant	-51 to -45	6
Run Pilot Plant	-45 to -30	15
Feasibility Study	-30 to -15	15
Engineering Systems Study	-15 to -12	3
Parallel FEED Studies	-12 to 0	12
BEA	0 to 6	6
EPC	6 to 36	30
Commissioning	36 to 40	4

NOTE: Above schedule applies to first CC module only.

LOY YANG A STATION
CC INDICATIVE COSTS (per Flue/Module)

EPC COST (US$ - 2018)

CC Cost Component	EPC Cost (US$)
Flue and Steam Connections, Including Fans	$60 mil
DCC and Absorber	$210 mil
Stripper, Reboiler, Reclaimer	$100 mil
Compressors	$125 mil
Backpressure STG	$85 mil
Engineering, Const Mgt, Distributables	$138 mil
Initial MEA Charge (1200 Tonnes, 99% Purity)	$2 mil

TOTAL EPC COST (Per Module)	$720 mil

LOY YANG A STATION
CC INDICATIVE COSTS (per Flue/Module) (2018)

- **OWNER COSTS (US$) 100 mil**
- **COMMISSIONING COST (US$) 20 mil**
- **ANNUALIZED COST (US$):**

CAPITAL COST	TERM	DISCOUNT RATE	ANNUAL COST	$/Tonne CO2 @ 80% CF	$/Tonne CO2 @ 50% CF
840 mil	15 years	15%	$144 mil	$75	$120
840 mil	30 years	8%	$75 mil	$39	$63

CAPITAL COST	TERM	DISCOUNT RATE	ANNUAL COST	$/MWh @ 80% CF	$/MWh @ 50% CF
840 mil	15 years	15%	$144 mil	$126	$201
840 mil	30 years	8%	$75 mil	$66	$105

Session 3: CCS Costs in Industry

3.1. Methodological Costing Issues for CCS from Industry, *Simon Roussanaly, SINTEF*

Methodological costing issues for CCS from industry

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[7] Delft University of Technology

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Why CCS from industrial sources?

- Seven large industrial sectors including cement, iron and steel, chemicals and refining account for one-fifth of the total of 31 $GtCO_2$ emitted globally
  - With current trends, these emissions are predicted to grow by around 35% up to 2050
- Without CCS, deep decarbonisation of these sectors will be challenging
  - Significant share of emissions are from use of non-energetic use of fossil fuels (feedstock)
  - Efficiency measures and non-fossil energy options only have the potential to reduce the specific emissions by around 30%
- CCS from industrial sources could be less costly due to for example higher CO_2 content in flue gas, integration with waste heat, clustering potential…
- As a consequence of this, the momentum for CCS from industrial sources has increased significantly
  - Especially in Europe due the ambitious mitigation targets of the EC (carbon neutral by 2050)

2

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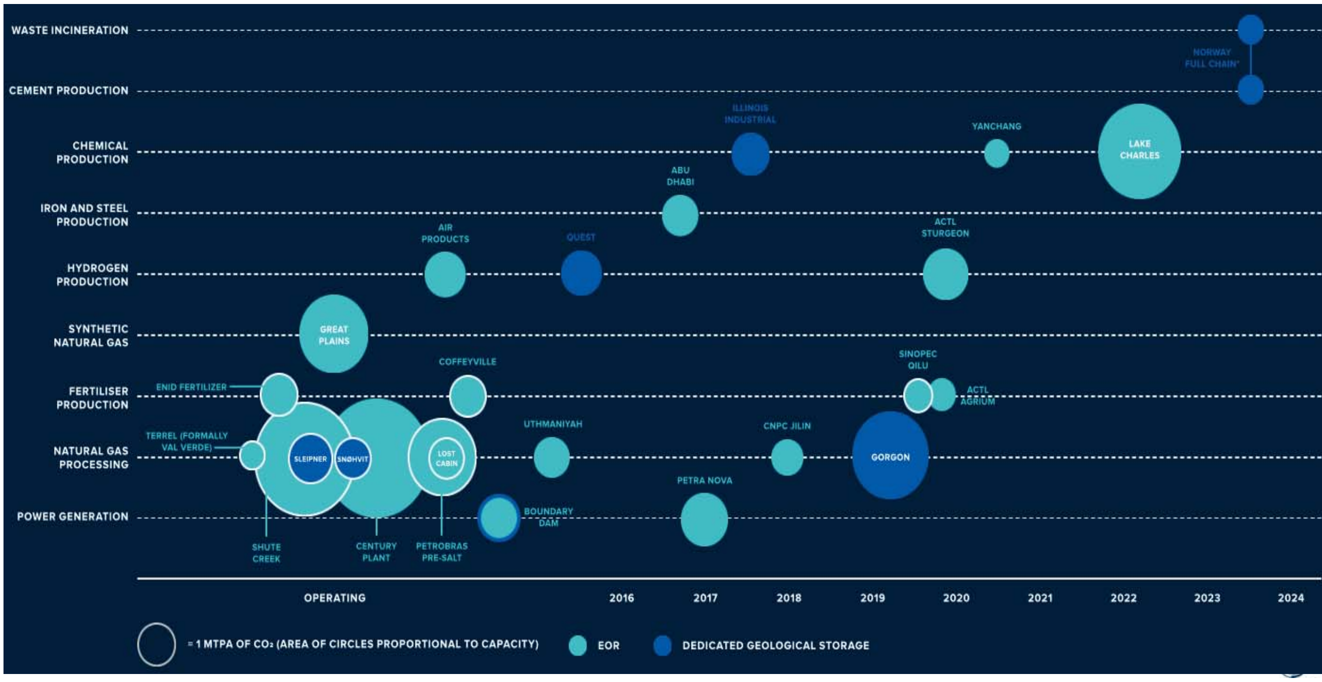
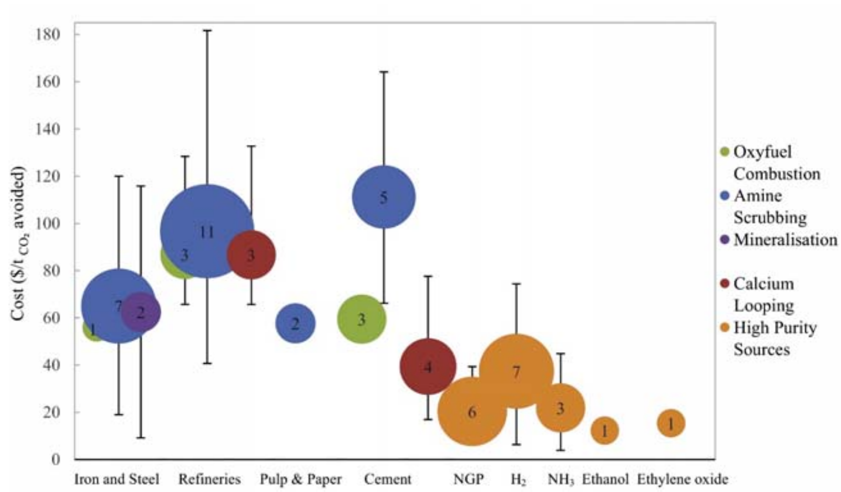
Why CCS from industrial sources?



Global CCS Institute (2017)

Cost of CCS from industrial emissions

- Large discrepancies in cost estimates between studies are often reported
- Part of these discrepancies are due to differences between the cases considered:
  - CO_2 source
  - Scale
  - Technologies
  - Level of detail
  - Location...
- Part of these are linked to cost methodology
  - New development vs. Retrofit
  - Energy prices and heat supply strategies
  - Data quality
  - Metrics definition...



Leeson et al., Int. J. of Greenhouse Gas Control (2017)

SINTEF

Methodological costing issues for CCS from industry

- As part of a larger joint effort towards the development of improved guidelines for cost evaluation of CO_2 capture technologies, we are looking at the following aspects in the context of TEA from CCS from industry:
  - Costing elements
    - Steam and electricity
    - Retrofit
    - Transport and storage
  - Transferability of experience from the power sector and impact of maturity on costs
  - Metrics for CCS from industrial sources

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Costing elements: Steam and electricity

- Steam and electricity supply strategies and costs aren't always carefully evaluated in the case of CO_2 capture from industrial sources
- Especially, steam characteristics (availability, cost and CO_2 intensity) will depend on supply strategy, energy prices, plant location, potential synergies with the industrial plant and nearby facilities

Steam characteristics for different supply strategies for a generic Netherlands-based application with an NG price of 6 €/GJ, a coal price of 3 €/GJ and an electricity price of 58 €/MWh

Source	Steam cost (€/GJ)	CO_2 intensity ($kgCO_2$/MWh)
Electrical	17.9	313
Natural gas boiler	7.1	205
Coal CHP plant	6.1	458
Steam extraction from an LP Turbine	3.7	175
Waste heat	1.9	0

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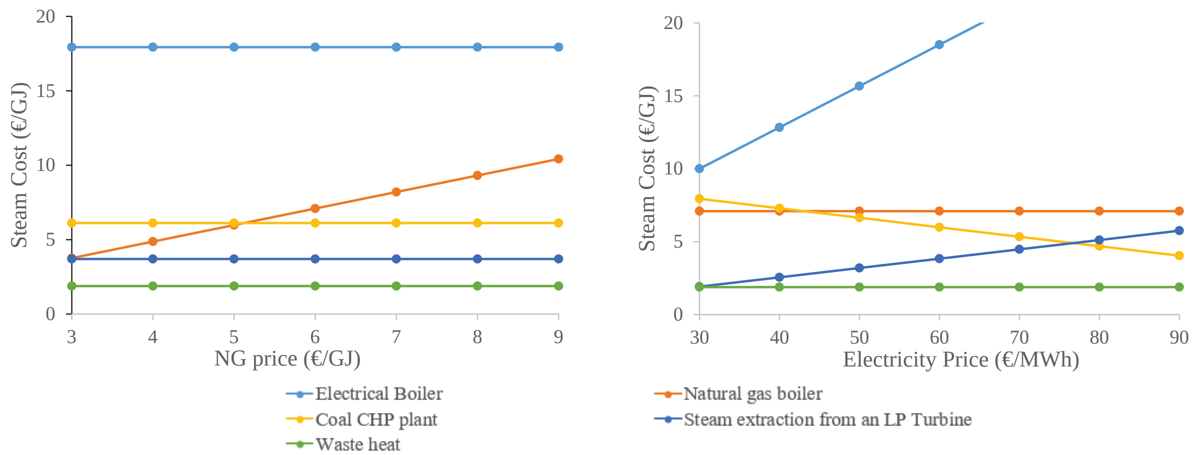
Costing elements: Steam and electricity

- Impact of energy prices on the cost of each supply strategies, for example:
  - Optimal steam supply will depend on energy prices
  - Steam extraction prior to the LP turbine will strongly benefit to capture technologies requiring steam
  - Steam from a coal CHP plant becomes cheaper with increasing electricity prices
  - At low electricity price, electrical boilers could become more attractive than NG boilers or CHP plant when taking into account the associated CO_2 emissions



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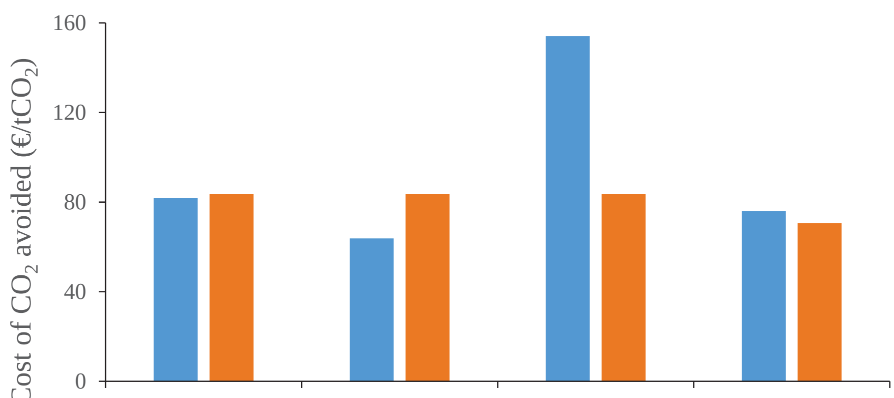
Costing elements: Steam and electricity

- Illustration of this for a case considering CO_2 capture from a cement plant
  - Case 1-3: Steam supply strategy
  - Case 4: Steam supply strategy and energy prices

- Heat supply strategy and energy prices will influence:
  - The cost performances of a given capture technology
  - The comparison of capture technologies
  - The design of the CCS system (for ex. partial capture to allow using only waste heat)

	NG Price (€/GJ)	Electricity Price (€/MWh)	Steam production option
Case 1	6	58	NG gas boiler
Case 2	6	58	Steam extraction
Case 3	6	58	Electric boiler (EU elec. mix)
Case 4	6	30	Electric boiler (Norwegian elec. Mix)



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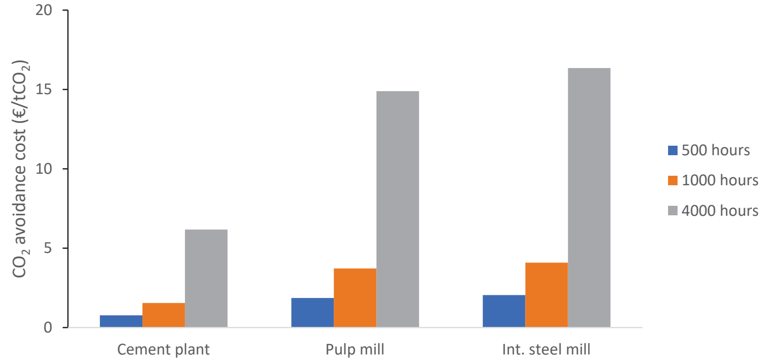
Costing elements: Retrofitting cost

- Economic impact of production stop
  - Retrofit will result in partial or full-shut downs of the industrial plant
  - Aligning shut-downs with maintenance/upgrade period will reduce this cost
    - May not be enough, especially in the case of capture technologies needing a tight integration with the plant
  - This can have non neglectable impact on the CO_2 avoidance cost but needs to be evaluated carefully

Impact of losing a "10% margin" on the CO_2 avoidance cost for different full plant production stop times



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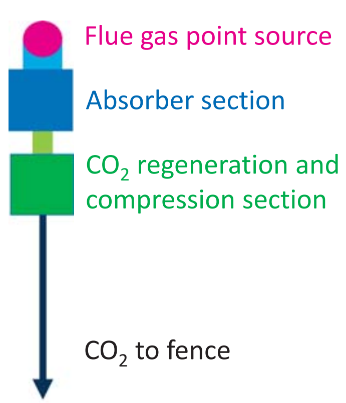
Costing elements: Retrofitting cost

- Space constraints
  - Finding available space for the CO_2 capture unit near the emission sources might be challenging
    - Alternative layouts are an option in such cases

Illustration of different layout alternatives for an amine unit in a space constraint case



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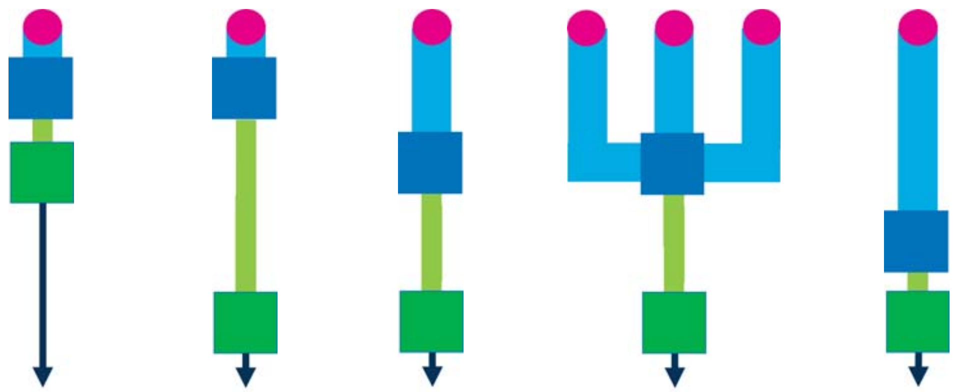
Costing elements: Retrofitting cost

- Space constraints
  - Finding available space for the CO_2 capture unit near the emission sources might be challenging
    - Alternative layouts are an option in such cases
    - Most industrial sources have several point sources, each with different qualities and quantities which may result in pooling strategies

Illustration of different layout alternatives that could be considered in space constraint cases



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Costing elements: Retrofitting cost

- Space constraints
  - Finding available space for the CO_2 capture unit near the emission sources might be challenging
    - Alternative layouts are an option in such cases
    - Most industrial sources have several point sources, each with different qualities and quantities which may result in pooling strategies

- In some cases, these alternative layouts can result in significant and costly transport of the flue gas
  - Flue gas and utilities interconnection costs were evaluated to be in the range of 16-35 €/t$CO_{2,avoided}$ for a refinery retrofit in the RECAP study
  - However these costs are often ignored in many studies

- To help to better account for this, cost of pipeline rack and ducting as a function of flow and distance will be provided in the guideline

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Costing elements: Retrofitting cost

- Utilities supply and integration
  - Similar issue as for space availability and ducting
  - Efficient use of spare capacities with the plant
  - Integration with the plant in term of utilities can be challenging
- Impact on product quality
  - Depending on the type, CO_2 capture can have an impact of the product quality of the main plant
    - E.g: oxyfuel with cement
  - Variation in plant product value vs. cost of post-treatment to keep the same product quality
- Flue gas pre-treatment
  - Wide range of possible impurity types and levels for industrial emissions
    - Pre-treatment costs are often not taken into account
    - Pre-treatment could also have additional cost impact, for example in space constraint cases

Costing elements: CO_2 transport and storage

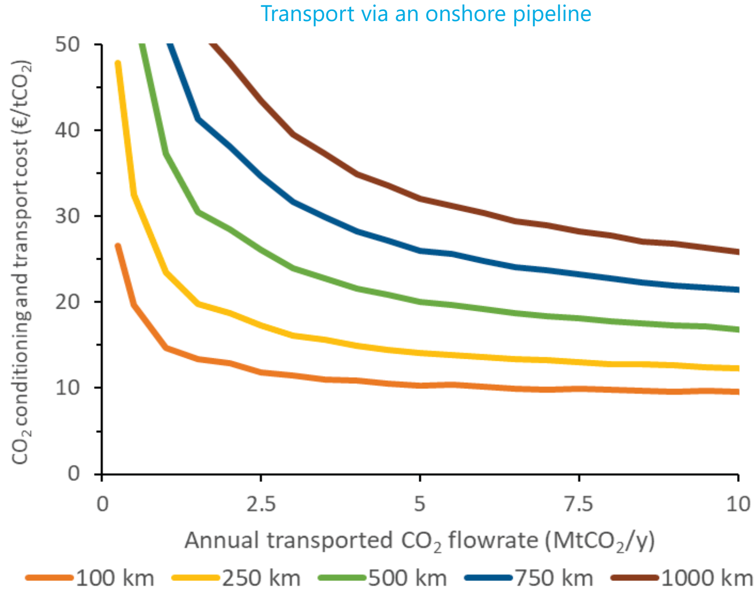
- Compared to power plants, industrial sources result in annual CO_2 emissions ranging from very low to very high (0.15 and 14 $MtCO_2/y$) depending on the plant type and the plant characteristics.

Industrial source	Average annual CO_2 emissions [$MtCO_2/y$]
Refinery	0.7-2.4
Cement plant	0.7-1
Iron and Steel mill	2-14
Pulp and Paper	1.3-2
Hydrogen plant	0.15-1.3
Offshore oil and gas platform	0.2-1

- In addition, other parameters can affect the amount of CO_2 to be transported and stored
  - All CO_2 sources within a plant may not be considered
  - Partial capture may also be considered
- As a result~~s~~ of this, CO_2 transport and storage cost might be very different from the traditionnal 10€/t commonly used in literature

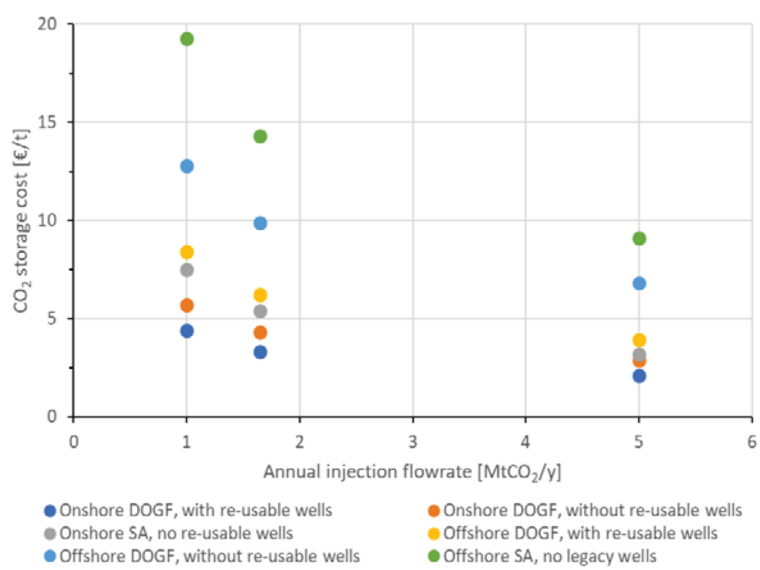
Costing elements: CO_2 transport and storage

- CO_2 conditioning and transport
  - Steep cost increase below 2-3 $MtCO_2/y$
  - Even stronger trend for offshore pipeline



Costing elements: CO_2 transport and storage

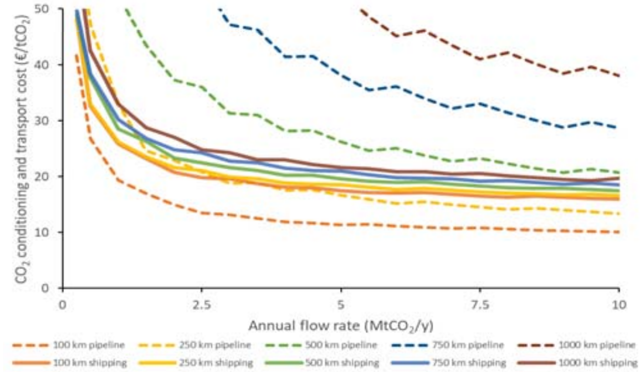
- CO_2 conditioning and transport
  - Steep cost increase below 2-3 $MtCO_2/y$
  - Even stronger trend for offshore pipeline
- CO_2 storage
  - Similar trends have also been reported for storage (ZEP)
  - In Europe, where CCS from industry is of particular relevance, the more costly option of offshore storage usually is be the main option
- To improve the quality of these estimates
  - Costs depend on flowrate, distance and storage type
  - Development strategy: Stand-alone vs. cluster basis

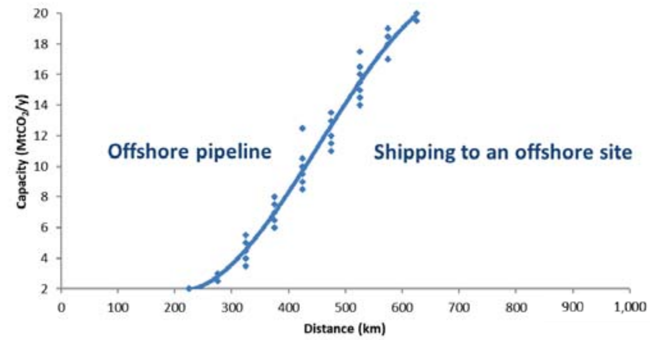


Costing elements: CO_2 transport and storage

- Ship transport can be a viable alternative to pipeline for industrial emitters
  - Efficient for small volumes
  - Efficient for long distances
  - Reduces investments and increases flexibility

- Other aspects of importance for cost
  - Distance to harbour
  - Impact of impurities
  - Regional costs





Roussanaly et al., Int. Journal of Greenhouse Gas Control (2014)

Transferability of experience from the power sector and the impact of maturity on costs

- A significant amount of data considered in TEA of CCS from industry comes from the power sector
  - Model validation, design procedure, flexibility, cost escalation, sparing, etc.
  - However, these may not be easily adaptable for industrial applications
  - These may introduce additional uncertainties in underlying data/models and on overall cost estimates

- While contingencies reflecting technology maturity level are rarely used, their use can raise questions in the case of CCS from industrial sources
  - The most important one being the transferability of TRL from one application to the other
  - Using, for example, System Readiness Level (SRL) approaches might be more suitable to take into account the level of maturity from the CCS for the application considered

Metrics for CCS from industrial sources

- As in the case of CCS from power plants, several metrics are relevant for CCS from industrial sources
  - Levelised Cost of Key Product (cement, hydrogen, steel) or service (crude processing) with and without CCS
  - CO_2 avoidance cost
  - Cost of CO_2 capture
- However, in some cases, additional metrics could make sense and allow to take into account different perspectives
  - End-user cost
    - While the post-combustion CCS from a cement plant has been shown to nearly double the cost of cement, the impact on the cost of a building or a house is limited (<5%)
  - Decarbonisation cost
    - When CCS is part of a "deep" sector change (e.g. H_2 for transport sector), CO_2 avoidance cost may bring only a limited value unlike the decarbonisation cost

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Metrics for CCS from industrial sources

- Compared to power sector cases, CO_2 avoidance cost can sometimes be calculated in simplified ways:
  - "Exhaustive" method (same principle as for power plants)

$$\mathrm{CO_2\ avoidance\ cost} = \frac{(\mathrm{LCOKM})_{\mathrm{CCS}} - (\mathrm{LCOKM})_{\mathrm{ref}}}{(\mathrm{t_{CO2}/U_{KM}})_{\mathrm{ref}} - (\mathrm{t_{CO2}/U_{KM}})_{\mathrm{CCS}}}$$

  - "Net present value" method

$$\mathrm{CO_2\ avoidance\ cost} = \frac{\text{Net Present Value of CCS implementation cost}}{\sum_i \frac{\text{Amount of } \mathrm{CO_2} \text{ emissions avoided by CCS implementation(i)}}{(1+d)^i}}$$

  - "Annualisation" method

$$\mathrm{CO_2\ avoidance\ cost} = \frac{\text{Annualised investment due to CCS implementation + Annual operating cost due to CCS implementation}}{\text{Annualised amount of } \mathrm{CO_2} \text{ emissions avoided}}$$

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Metrics for CCS from industrial sources

- These methods lead to identical results when the conditions of validity are met but present different advantage(s)/drawback(s)"
  - However, "users" aren't always aware of them

Summary of assumptions, advantages and drawbacks of each CO_2 avoidance cost calculation methods

Calculation method	"Exhaustive"	"Net present value"	"Annualisation"
Necessary assumptions for validity			
Production of industrial plant not affected by CCS implementation	-	Yes	Yes
Additional costs and CO_2 emissions avoided due to CCS implementation can be assessed separately	-	Yes	Yes
Annual operating costs and CO_2 emissions avoided must be constant over project duration	-	-	Yes
CO_2 emissions linked to construction can be neglected or excluded	-	-	Yes
Advantage(s)/Drawback(s) of the method			
Always valid	Yes	No	No
Valid for all combinations of CCS technologies and industrial plant	Yes	No	No
Requires limited technical data concerning the industrial plant considered	No	Yes	Yes
Does no require cost estimates for the industrial plant considered	No	Yes	Yes

Roussanaly, Carbon Management (2019)

Summary

- While the interest for CCS from industrial sources is rising, there are still more efforts required to better understand and estimate the costs from such systems

- Several methodological cost aspects relevant for CCS from industry were discussed to
  - Raise awareness on important issues often ignored in literature
  - Provide direct support to improve the quality of cost estimates

- Despite this, it is also important to recognise that the CCS cost may still vary significantly across a given industry due to, for example, site specific aspects

- Finally, it is important to realise that there are other issues relevant for both CCS from power and industry which deserve further work

Towards improved guidelines for cost evaluation of CO_2 capture technologies

- This work is part of a wider collaborative effort aiming to develop improved cost guidelines on three areas of TEA
  - Evaluation of CO_2 capture technologies that are not yet commercial, and the evolution of CO_2 capture costs beyond demonstration projects
  - Need for transparency, data quality and uncertainty evaluations of both the data and models used in CCS cost analysis
  - Evaluation of CO_2 capture, transport and storage for non-power industries

- This collaborative effort should result in a new white paper building up on the foundation established by the first white paper of the CCS cost network

Towards improved guidelines for cost evaluation of CO_2 capture technologies

- Collaborative effort between different types of organisation dealing with TEA

Research institutes

SINTEF

EPRI

Intergovernmental organisations

iea

ieaghg

Governmental laboratories

NETL NATIONAL ENERGY TECHNOLOGY LABORATORY

Universities

Carnegie Mellon University

ETH zürich

NTNU

TU Delft

THE UNIVERSITY OF SYDNEY

Methodological costing issues for CCS from industry

Simon Roussanaly[1,*], Niels Berghout[2], Tim Fout[3], Monica Garcia[4], Stefania Gardarsdottir[1], Minh Ho[5], Shareq Nazir[6] and Andrea Ramirez[7]

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3.2. IEAGHG-IEA Cost Review on CO_2 Capture in Cement and Steel Production: Key Findings, *Monica Garcia, IEAGHG and Niels Berghout, IEA*

IEAGHG-IEA cost review on CO_2 capture in cement and steel production: key findings

- **Monica Garcia**

Technology Analyst, IEAGHG- Carbon Capture

- **Niels Berghout**

Energy Analyst, IEA- CCS Unit

International Energy Agency
Secure
Sustainable
Together

What I am going to talk about

- The problem
- The objective
- The proposed solution
  - Quantifying CAPEX
  - Quantifying OPEX
  - Key cost indicators
  - Homogenisation of scenarios
- Overview and sensitivity analysis

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Together

The problem

- There are substantial differences between cost methods used by different organisations and initiatives to evaluate CCS technologies for the industrial sector.
- The communication of results varies from one organisation to another (CO_2 capture costs, CO_2 avoided costs and manufacturing costs)→ confusion, misunderstanding, unfair comparison.

Cost Categories	CEMCAP (2017)	NETL (2014)	IEAGHG (2013)	Kuramochi (2012)
BEC				
	Total equipment costs Installation costs	Process equipment	Civil, steelworks, erection others	Installation costs
		Supporting facilities		
		Direct and indirect		
		Labour		
EPC				
	Indirect costs	EPC contractor services	EPCC	Engineering services
	Project contingency	Process contingency	Project contingency and fees	
		Project contingency		
	Owner Costs	Owner Costs	Owner Costs	Owner Costs
	Total Plant Cost (TPC)	Interest during construction	Working capital, start-ups, spare parts	Total Plant Cost (TPC)
			Interest during construction	Interest during construction
		Total as spent cost (TASC)	Total Capital Requirement (TCR)	Total Capital Requirement (TCR)

Capital Cost Element	CEMCAP (2017)	NETL (2014)	IEAGHG (2013)	Kuramochi
Process equipment cost (PEC)	Process simulation with optimized design	Summing up individual equipment	Summing up individual equipment	From Original Study *
Supporting facilities cost	NA	NA	NA	130% of PEC
Others	NA	Initial solvent and corrosion inhibitor : 0.035+0.02% TPC	Civil, steelworks, erection others: 108% PEC	
BEC**				
Engineering service cost	Quantified as indirect costs (14%), with a breakdown	8.50% of BEC	EPCC: 6.87% of BEC	
EPC		NA		
Process contingency	From 0 to 40% depending on the technology status	21.70% of BEC	10% of Installed costs (here EPC) as contingencies and fees	
Project contingency	Owner costs and contingencies vary from 19 % to 40% l of the total EPC cost, depending on maturity level			
Others	NA	NA	NA	
Total Plant Costs (TPC)				
Owner costs	NA	24.31% TPC	7% of TPC	10% of TPC
Others	NA	NA	4.7% of TPC	
Total Overnight Cost (TOC)	NA			
Interest during construction (IDC)	NA	9.9% of TOC	3.8% of TPC	
Total Capital Requirement (TCR)				

The objectives

- To develop a method based on a bottom-up analysis which allows for a comparative assessment of CO_2 capture technologies in the industrial sector
- Conduct a consistent assessment of the techno-economic performance of CO_2 capture technologies applied to the cement and iron and steel industries

The objective

- IEAGHG & IEA joint efforts to:
  - Provide a **tentative set of parameters and assumptions** to take into account on the evaluation of the cost of CCS in the cement and iron and steel sectors.

  - To **homogenise** CCS costs reported in the literature for the cement and iron and steel sectors
  - **Perhaps:** A number of assumptions are onsite specific and cannot be extrapolated → how to communicate transparent evaluations by describing technical and economic parameters to include in future studies. Limitations are given

The objectives

- IEAGHG & IEA joint efforts to:
  - Compare the set of cost assumptions given in transparent studies and this work → Partly explain the cost differences reported in the literature.
    - ✓Identify cost-methods
    - ✓Identify assumptions: process configurations, energy supply/demand,

Phases of this study

Thanks to the external reviewers

Screening of publications

- Selection of transparent studies

Standardization of key input parameters

- North West European context
- Materials and energy flows for an average plant (plant size, capacity factor, grid CO_2 intensity, CO_2 compression outlet)
- CAPEX, OPEX
- Cost metrics

Assessment of technologies under three scenarios

- As in the literature
- No waste heat
- No selling electricity to the electricity grid

Sensitivity analysis

- Select technologies to go under analysis
- Under basic scenario: still differences on how the technologies were assessed

The proposed solution

- To standardize cost measures and metrics
- To define and homogenise boundaries
- To define and quantify elements of CCS cost: CAPEX, OPEX
- To define and homogenise technical and financial parameters

Limitations

- The **underlying data** and process designs of the manufacturing and carbon capture systems differ between the reviewed studies. Different process designs selected by the authors of the studies
- Several studies provided **insufficient information** required for the standardisation process
  - Additional assumptions were made
  - Detailed cost estimations tend to present higher costs
- **Technological improvements** in capture technologies that have taken place **over recent years** are not necessarily reflected in the quantitative results
- The **energy or steam production technologies** differ among studies, affecting the CAPEX and fixed OPEX
- In the cases of steelmaking, the **blast furnace and basic oxygen furnace route (w/o CO_2 capture) was used as the reference** case against the costs of all other cases, including configurations with advanced steelmaking processes
- The results should be corrected using **location** cost factors, as presented in IEAGHG (2018), to determine the techno-economic performance for specific locations.

Assumptions for alternative scenarios

- NO waste heat
  - If required, a new natural gas-fired boiler was assumed to be built to supply the steam, with a CAPEX of 85€/KW and an additional 2% of such CAPEX as operational cost.
  - From the results, it helped to homogenise the "most optimistic" studies on waste heat recovery
- If there is electricity surplus, that cannot be sold to the electricity grid, neither obtaining "environmental" revenue

RESULTS AFTER APPLYING THE COST METHOD

More information in: *IEAGHG 2018-TR03, Cost of CO_2 capture in the industrial sector: Cement and Iron and Steel industries* , Sept 2018

COST PARAMETER	SCENARIO	Cement						Iron and Steel[g]			
		Traditional chemical absorption	Advanced chemical absorption	Membrane	Oxy-	Solids-based	Hybrid[d]	Traditional chemical abs.	Advanced chemical abs.	VPSA	Hybrid[e]
CO_2 avoidance cost ($\$_{2016}$/ t CO_2 avoided)	BASIS	72-180	61	69-78	69-86	38-86	199	56-82	52-80	34-52	65-135
	No-heat-recovery	77-215	91	69-78[a]	69-86[a]	64-348	261	56-119	28-70	34-52[a]	81-135
	No electricity export	72-215	61	69-78[b]	69-86[b]	38-91	199[b]	69-93	12-37[f]	34-52[b]	52-90
CO_2 captured cost ($\$_{2016}$/ t CO_2 captured)	BASIS	34-79	45	51-57	50-63	11-63	146	16-21	7-16	11-14	23-66
	No-heat-recovery	34-93	59	51-57[a]	50-63[a]	21-68	171	17-30	7-18	11-14[a]	33-66
	No electricity export	36-101	45	51-57[b]	50-63[b]	20-67	146[b]	7-23[f]	3-9[f]	11-14[b]	33-44
Increase of manufacturing cost [c] ($\$_{2016}$/ t cement or steel)	BASIS	46-116	20	39	38-39	26-40	94	54-93	74-76	30-45	69-86
	No-heat-recovery	46-116	26	39[a]	38-39[a]	37-65	110	54-117	77-78	30-45[a]	69-86[a]
	No electricity export	49-116	20	39[b]	38-39[b]	40-74	94[b]	39-117[f]	36-37[f]	30-45[b]	69-86[b]

Let’s summarize

- Main differences found on the literature review
  - ➢Waste heat available for the Capture process / Heat integration
  - ➢Energy production/ Energy cost
  - ➢Steam production/ Steam cost
  - ➢Revenue from selling electricity to the electricity grid

➢We provided a cost-review method to homogenise the CO_2 capture/avoidance costs and increase on the manufacturing cost

➢Still, our method has limitations

➢Best technology? **Difficult to choose one**. Based on specific conditions

ASK US FOR MORE INFORMATION!

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3.3. Highlights and Findings from the CO_2stCap project, *Nils Eldrup, SINTEF*

CO_2stCap

18 march 2019

Nils Henrik Eldrup

Participants

Four year project
Total budget: 2,7 MEUR
Start up : August 2015
Planned final event: June 2019
3 PhD candidates
13 companies

Research partners

- SINTEF
- USN
- Chalmers
- RISE Bioeconomy
- Swerim AB

Industry partners

- SSAB
- Norcem Brevik AS
- Elkem AS
- Aga Gas AB

Other partners

- Gassnova
- The Swedish Energy Agency
- GlobalCCSInstitute
- IEAGHG

What is partial capture?

CO_2 capture below 85-90% of the emission

Continuous capture

– the capture plant follows the operational time of the base plant

- The size of capture plant is adjusted to the available amount of waste heat
- The size of capture plant is adjusted to the base or average production scenario instead of peak production
- Capture from some of the stack/sources

Discontinues capture

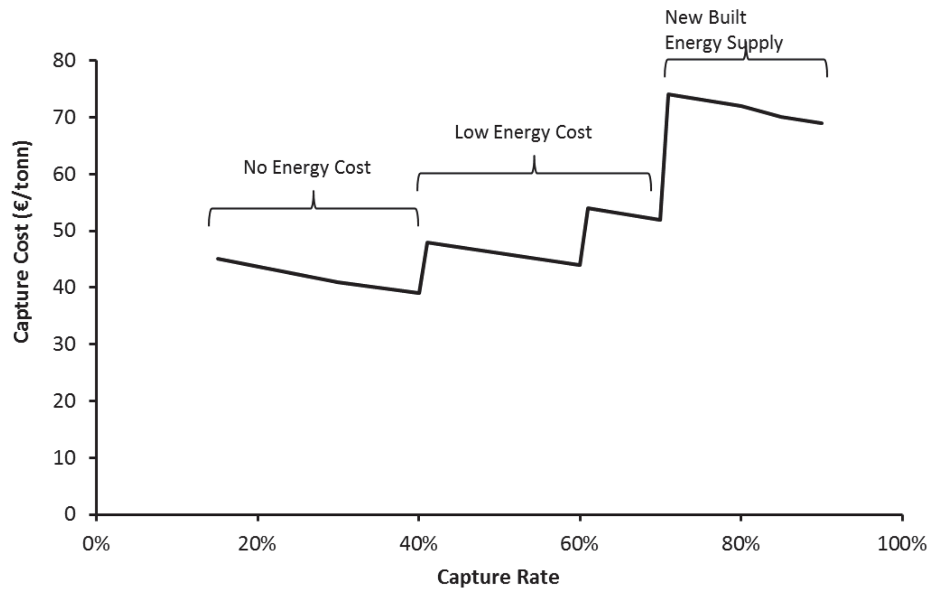
– the capture plant operates when the conditions is favourable

- Day/night and summer/winter variations of the plant
- Steam supply varies
- Electricity price varies

Questions

- Why do we try to have a high capture rate
- Is there industries which have "free steam"
- How much will it cost to "catch" the free steam?
- How shall we present the result
- (cost estimating tool)

Utilization of waste heat



CO2stCap

The project investigates where and how CCS, particularly partial CO_2 capture, may be applied cost efficiently to emission intensive industry.

Partial capture solutions with focus on 4 industry cases

- Cement
- Pulp and paper
- Steel
- Silicon (solar)

Further development and implementation of modelling tools to calculate costs and optimize CO_2 capture.

The overall aim of CO_2stCap

To suggest a cost effective carbon capture strategy for future CCS systems in industry, considering

- utilization of waste heat/energy
- a more efficient use of biomass resources
- different capture technologies and optimization
- Changes in market conditions

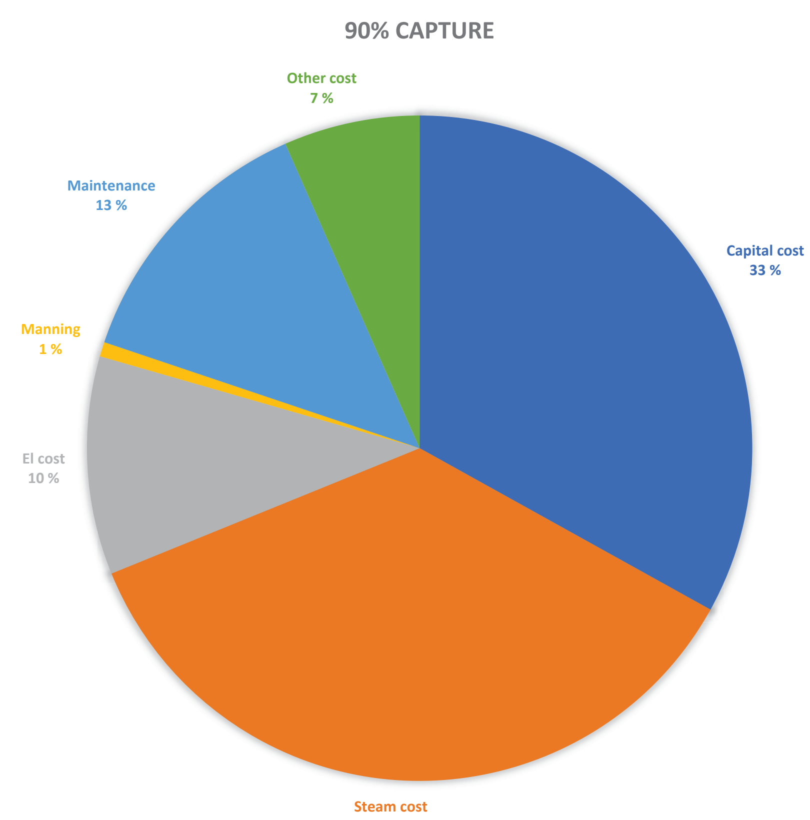
Investigate if partial capture will reduce the capture cost for industry !

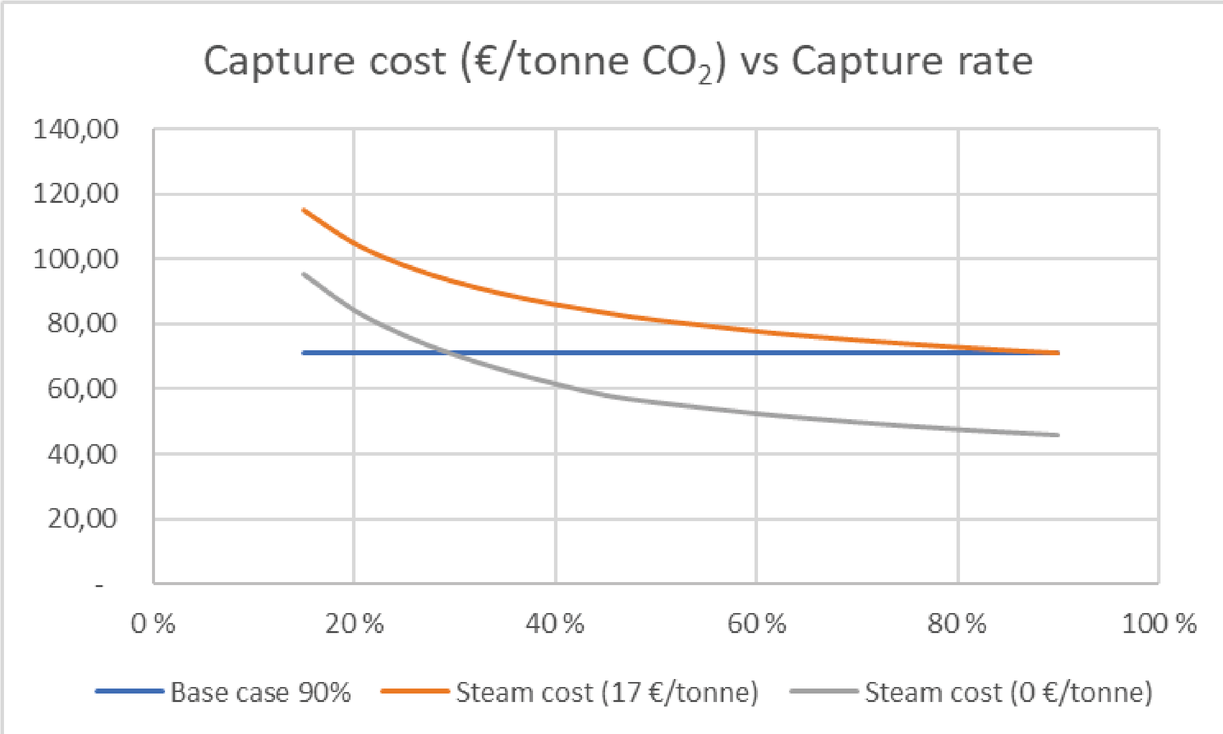
The idea

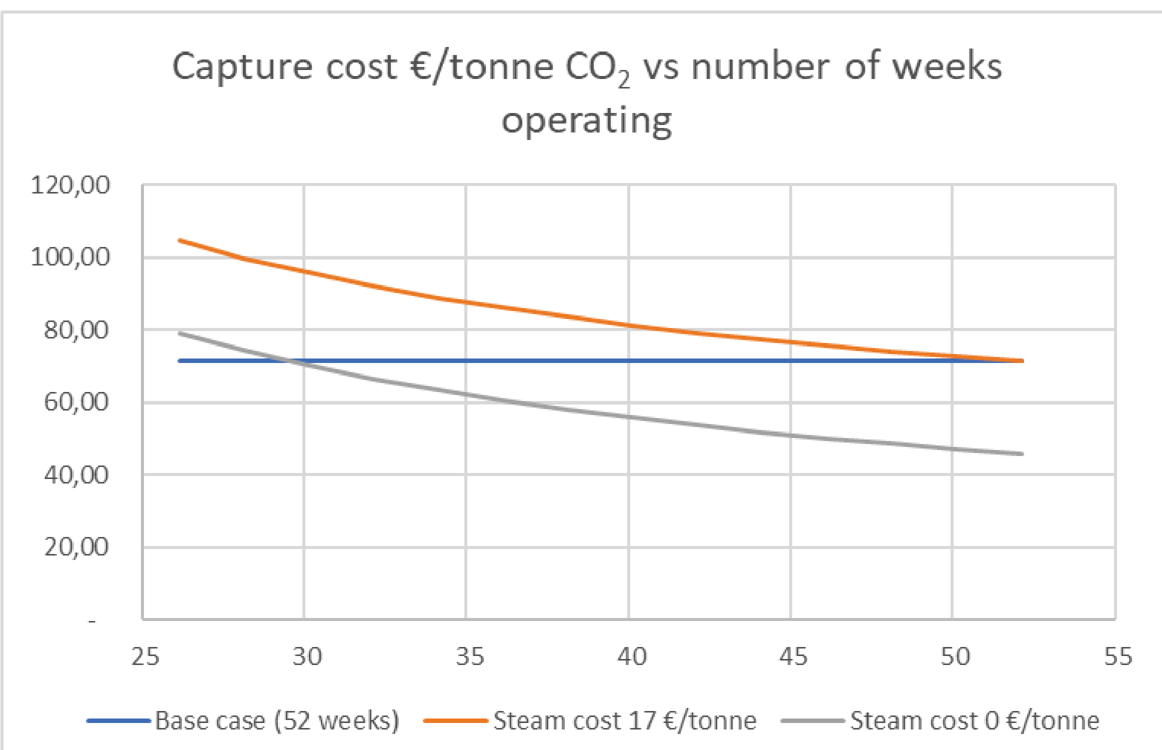
Why 90%

€/tonne CO_2

	90% capture
Capital cost	23,56
Steam cost	25,50
El cost	7,56
Manning	0,50
Maintenance	9,42
Other cost	4,71
Total cost	**71,25**




Capture cost (€/tonne CO_2) vs Capture rate
140,00
120,00
100,00
80,00
60,00
40,00
20,00
-
0 %
20 %
40 %
60 %
80 %
100 %
Base case 90%
Steam cost (17 €/tonne)
Steam cost (0 €/tonne)

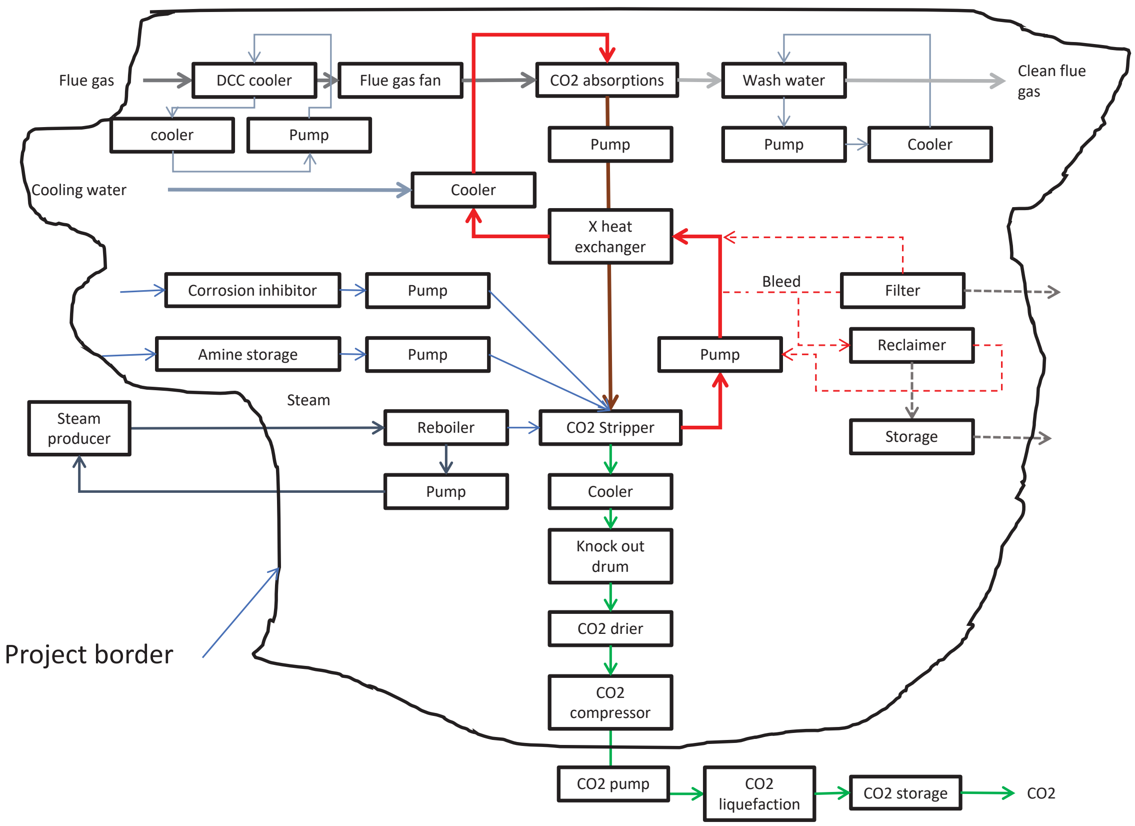

Capture cost €/tonne CO_2 vs number of weeks operating
120,00
100,00
80,00
60,00
40,00
20,00
-
25
30
35
40
45
50
55
Base case (52 weeks)
Steam cost 17 €/tonne
Steam cost 0 €/tonne

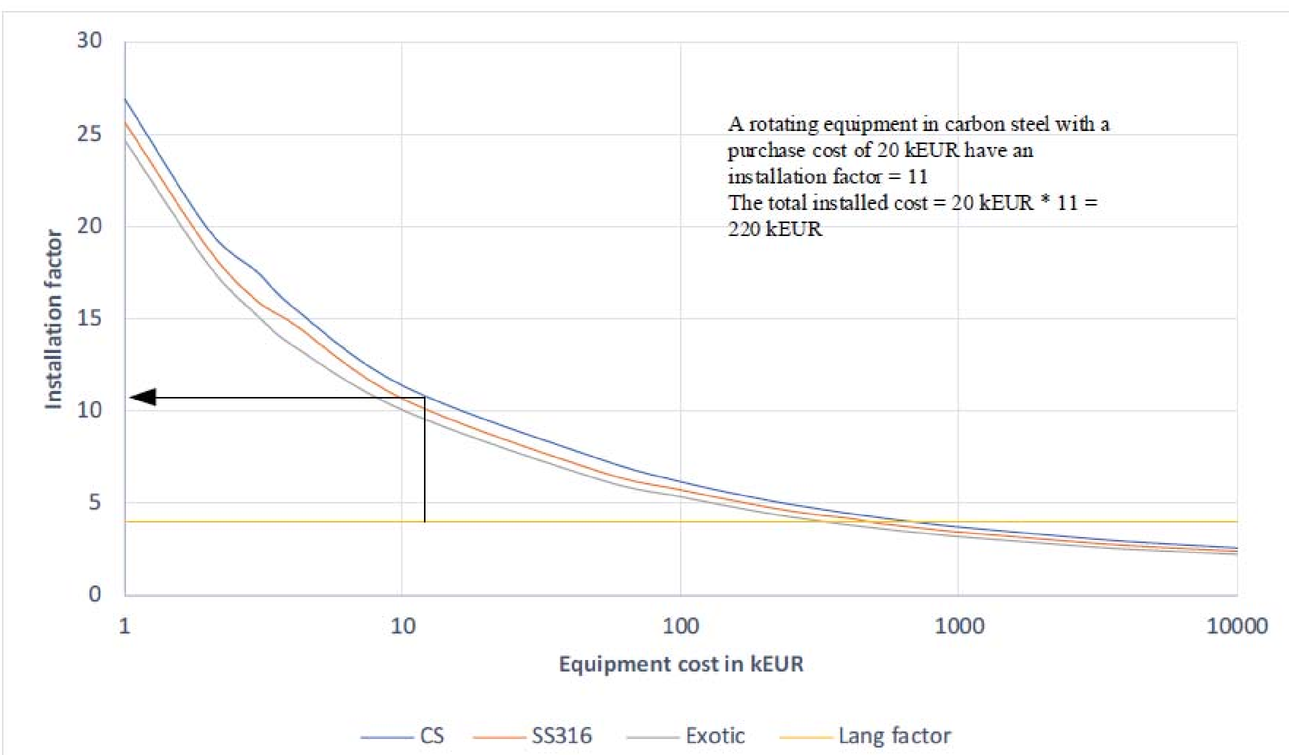
Cost estimation tool owned by SINTEF Industry

- Early phase cost estimation
- Detail factor estimation method
- Based on simulation from ASPEN
- Equipment cost from databases
- Gives installed costs based on equipment cost, material, plant type ect
- Sensitivities
- Benchmarking

The main elements of the workflow are;

- Identify the scope
- Establish equipment list
- Find equipment cost
- Calculate installation factors
- Establish final cost estimate
- Combine CAPEX and OPEX to provide indicators


Flue gas
DCC cooler
Flue gas fan
CO2 absorptions
Wash water
Clean flue gas
cooler
Pump
Pump
Pump
Cooler
Cooling water
Cooler
X heat exchanger
Bleed
Filter
Corrosion inhibitor
Pump
Amine storage
Pump
Pump
Reclaimer
Steam
Steam producer
Reboiler
CO2 Stripper
Storage
Pump
Cooler
Knock out drum
CO2 drier
CO2 compressor
Project border
CO2 pump
CO2 liquefaction
CO2 storage
CO2


A rotating equipment in carbon steel with a purchase cost of 20 kEUR have an installation factor = 11
The total installed cost = 20 kEUR * 11 = 220 kEUR
Installation factor
0
5
10
15
20
25
30
1
10
100
1000
10000
Equipment cost in kEUR
CS
SS316
Exotic
Lang factor

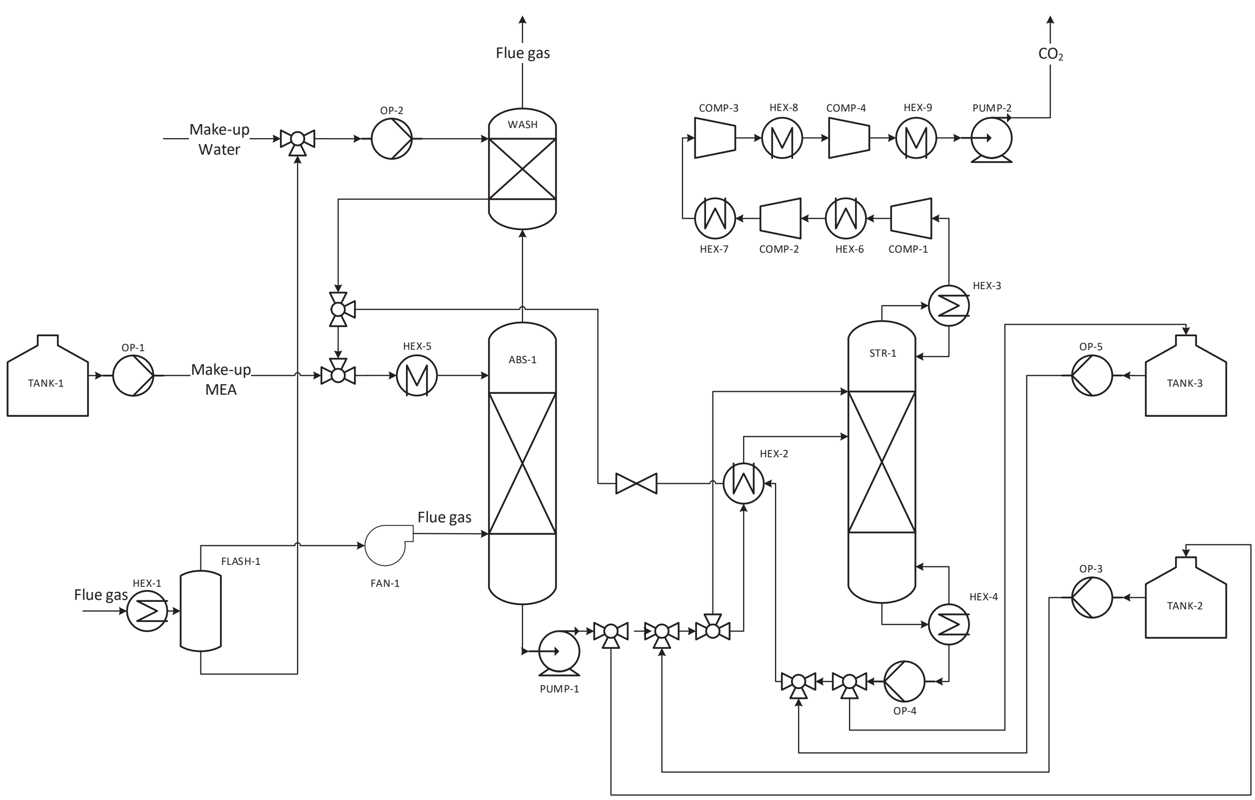
The installation factor is calculated as a function of:

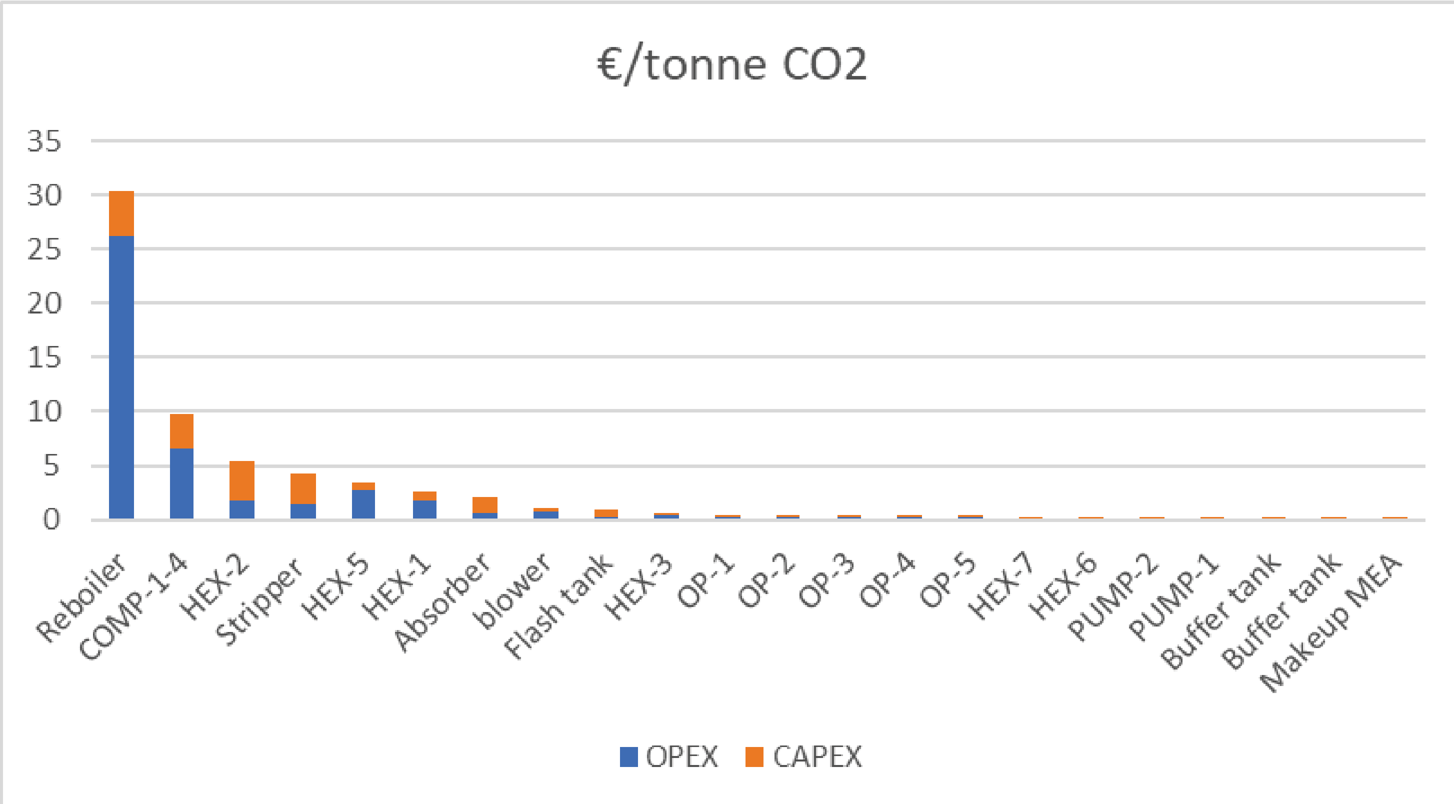
- Plant description
  - Piping
  - Ground preparation
  - Building type
  - Control system (instrument)
  - Electrical supply
  - Insulation

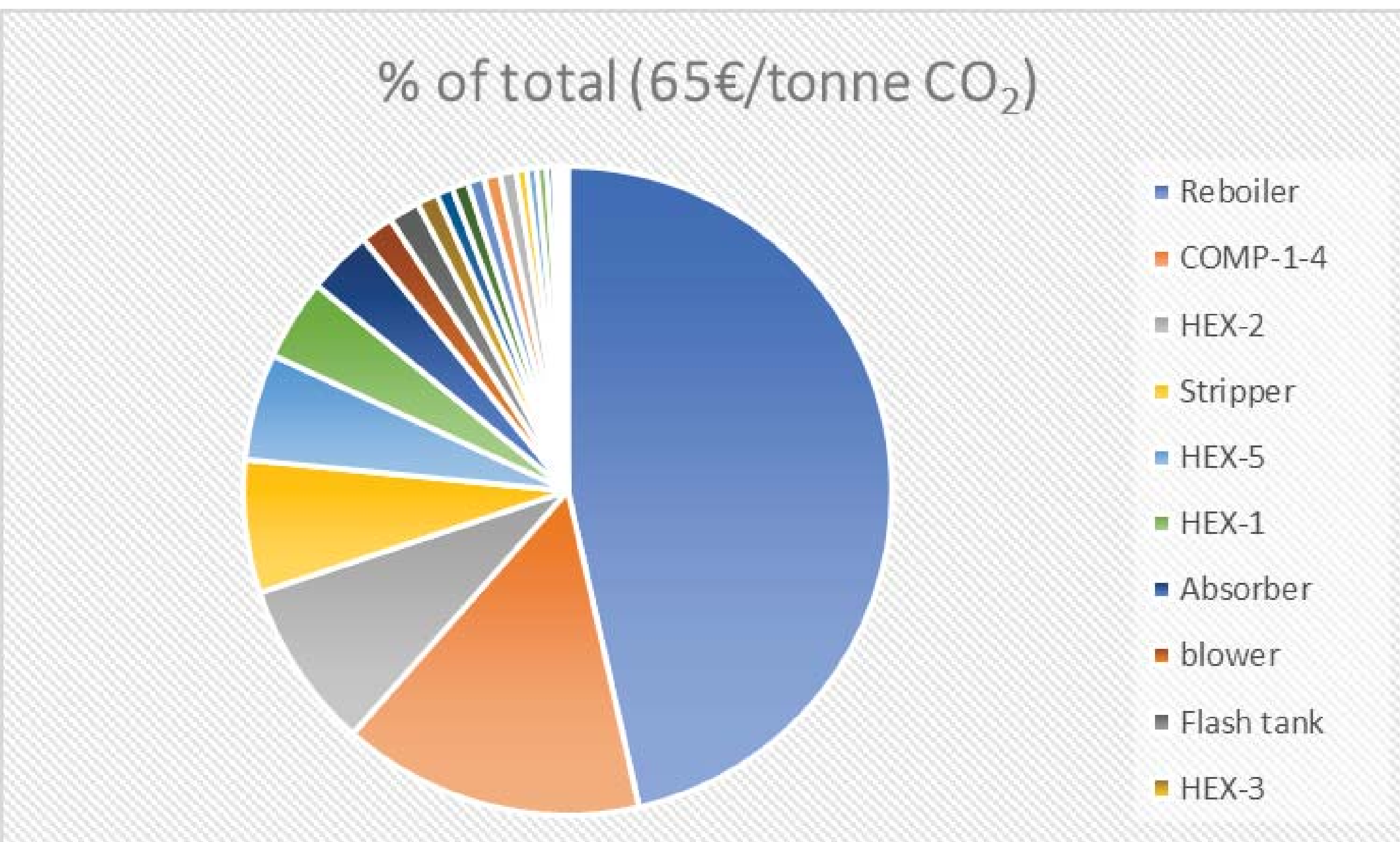
- Equipment type
- Material
- Size/cost

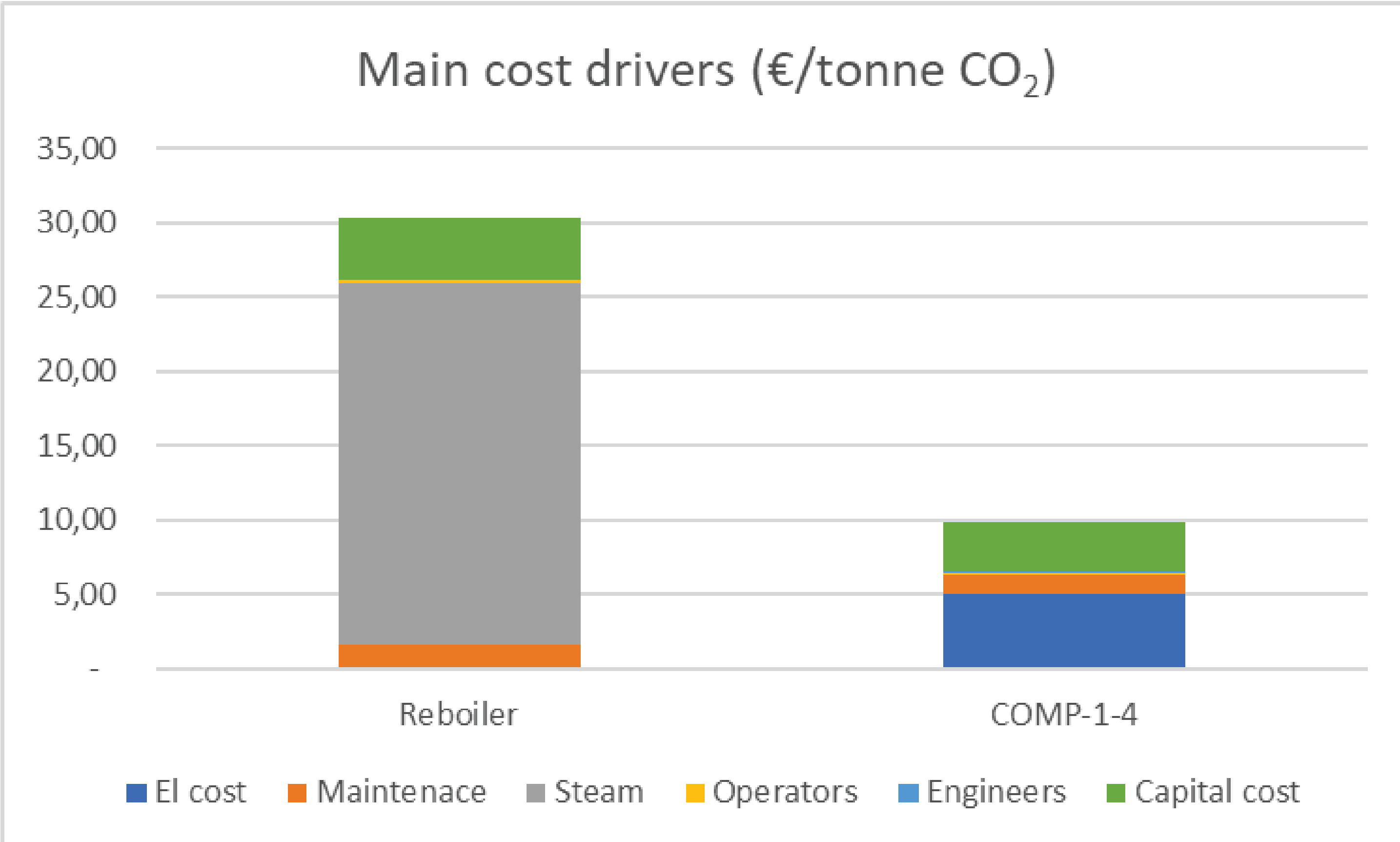
Equipment description	Equipment Cost (kEUR)	Installation factor	Detailed factor installed cost (kEUR)	Lang factor cost (kEUR)
CO_2 compressor	3300	3.19	10 527	15 642
CO_2 water removal	1260	3.81	4 801	5 972
CO_2 product pump	510	5.68	2 336	2 417
1st stage CO_2 cooler	226	5.53	1 250	1 071
2nd stage CO_2 cooler	211	5.63	1 186	1 000
3rd stage CO_2 cooler	226	5.53	1 250	1 071
1st stage K.O. drum*	16	11.22	177	76
2nd stage K.O. drum	24	9.92	235	114
3rd stage K.O. drum	38	8.68	333	180
Sum	5811		22 094	27 544

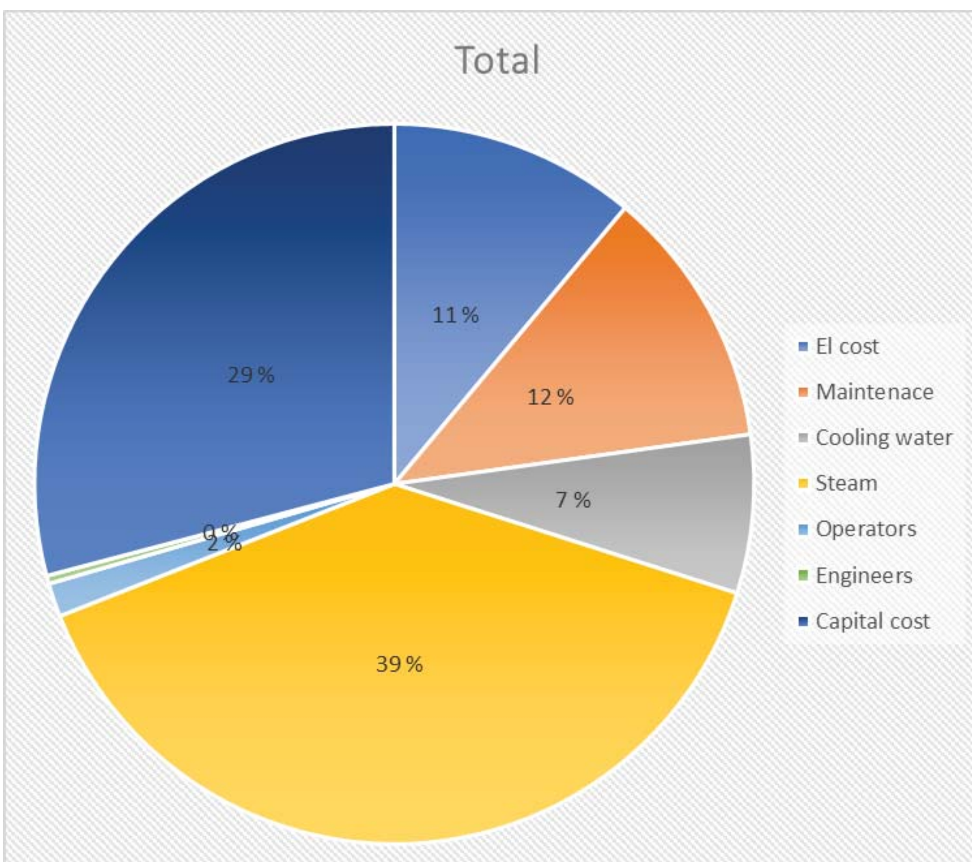
	Detail factor	Lang factor
Effect of material selection	Impacts on results	Little impact on results
Plant type (size)	Works well for both small, mid-sized and large plants	Works best for mid-sized plants
Pilot scale	Suitable	Underestimates
EPC package cost	Suitable	Overestimates
Benchmarking	Suitable for all types of plants	Suitable for midsized plants
Updating	Must be continuously updated	No need for updating
Plant description	Must be defined (Default)	Can be adjusted
Applicability	Needs experienced personnel	Simple




€/tonne CO2
35
30
25
20
15
10
5
0
Reboiler
COMP-1-4
HEX-2
Stripper
HEX-5
HEX-1
Absorber
blower
Flash tank
HEX-3
OP-1
OP-2
OP-3
OP-4
OP-5
HEX-7
HEX-6
PUMP-2
PUMP-1
Buffer tank
Buffer tank
Makeup MEA
OPEX
CAPEX

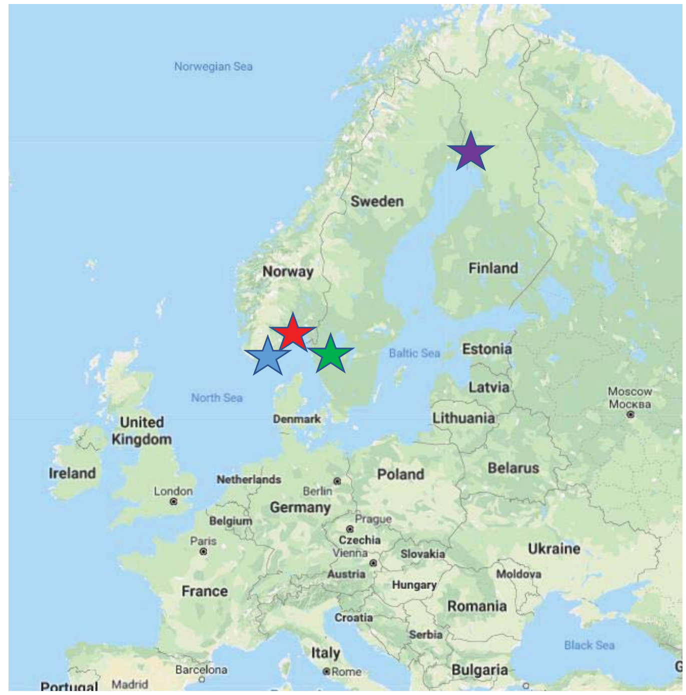

% of total (65€/tonne CO2)
Reboiler
COMP-1-4
HEX-2
Stripper
HEX-5
HEX-1
Absorber
blower
Flash tank
HEX-3


Main cost drivers (€/tonne CO_2)
35,00
30,00
25,00
20,00
15,00
10,00
5,00
-
Reboiler
COMP-1-4
El cost
Maintenace
Steam
Operators
Engineers
Capital cost


Total
11 %
12 %
7 %
39 %
2 %
0 %
29 %
El cost
Maintenace
Cooling water
Steam
Operators
Engineers
Capital cost

4 industrial cases

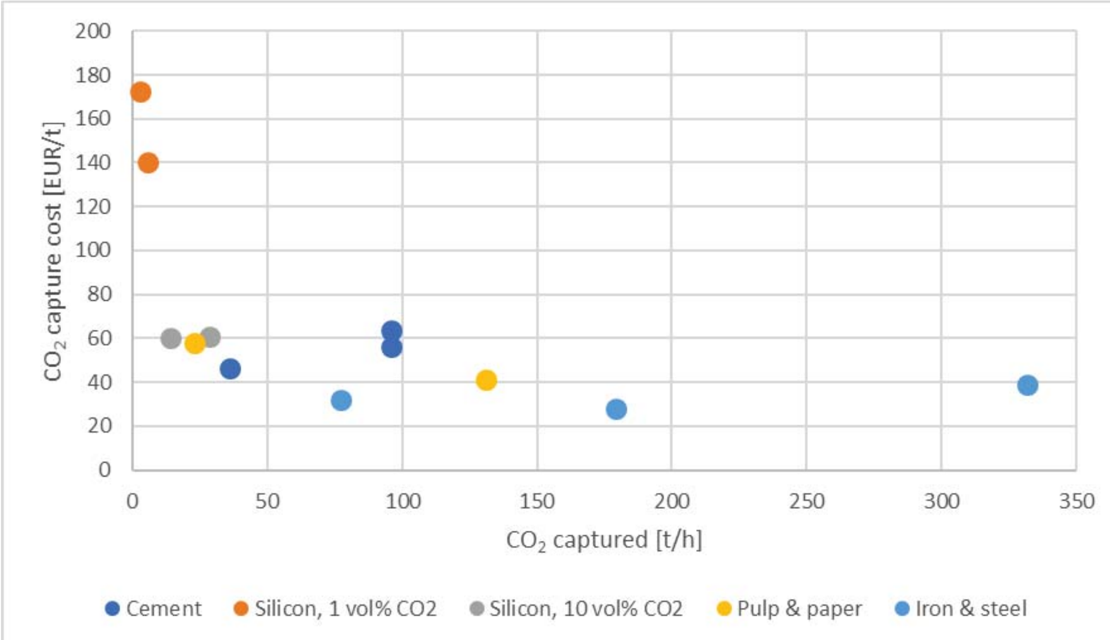
1. Cement production at Norcem Brevik, Norway
2. Pulp production at a generic pulp mill in Sweden
3. Silicon production at REC in Kristiansand, Norway
4. Steel production at SSAB in Luleå, Sweden



Case introduction

- Have focused on available energy
- Retrofit- MEA capture technology have been investigated, and also Oxyfuel.
- Large differences in size (50 kt up to near 2600 kt CO_2 pr year) and consentration
- Some utilize available energy for production of green electricity and district heating

Results



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Results

Cement case:

- Have looked at MEA and Oxyfuel for two emission point sources, the calciner and the kiln.
- With MEA, a reduction of 17 % in capture cost (EUR/t) with partial capture.
- The most favorable case was to reduce the capture plant in size according to available steam.
- Oxyfuel was even lower, but these numbers have high uncertainty due to retrofit costs.

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Results

Solar case:

- Have enough waste heat to capture 90 %.
- Have looked at season variation and different concentrations
- High capture cost, but can reduce the capture cost by 35 % with increased CO_2 concentration from 1-3.7 % and using a WHSG instead of electric boiler.

Results

- **Steel case:**
  - Have a lot of excess heat- divided in 5 heat levels.
  - 3 emission sources with varying concentration and volumes
  - Partial capture reduces capture cost with up to 27% if capture from only blast furnace gas.

Results

- Pulp case:
  - Reduction of 26 % in capture cost (EUR/t)
  - Capture 2 out of 3 emissions (lime kiln and recovery boiler), with the capture rate of steam available.
  - Production of green electricity/green sertificates is an issue, but included

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Summary

Partial capture is a solution to reduce the cost for CO_2 capture if the source:

- have multiple stacks
- must reach a certain level to meet emission regulations
- have access to low-cost energy to cover parts of the energy demand.
- can vary their product portfolio depending on market conditions
- Have large differences in base load and max load

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Acknowledgement

The authors wish to thank the CO_2stCap project partners :

SSAB, Global CCS Institute, IEAGHG, Elkem AS, Norcem Brevik AS, USN, Chalmers, SINTEF, Swerim AB, RISE Bioeconomy and AGA Gas AB.

The project is funded by the Norwegian CLIMIT–Demo programme via Gassnova, The Swedish Energy Agency and participating industry and research partners.

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Thank you for your attention!

CO_2stCap

Cement case

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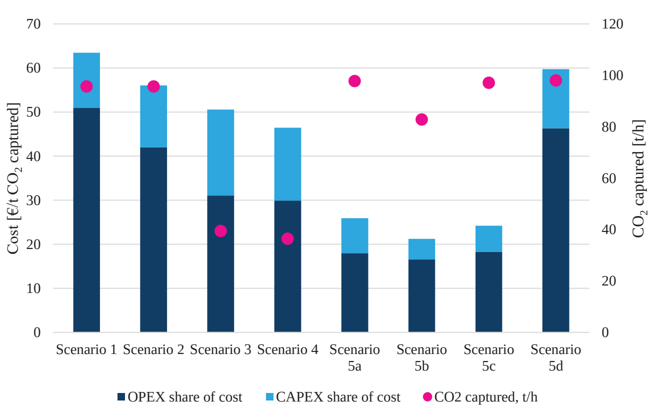
Cost estimation results - all



1 – Reference case, all steam bought, 90% cap
2 – 33 MW steam from WHSG, rest bought, 90% cap
3 – 33 MW steam from WHSG, full size plant, reduced cap rate
4 – 33 MW steam from WHSG, reduced size plant, reduced cap rate
5a – Calciner oxy-comb, kiln MEA
5b – Calciner only oxy-comb
5c – Full oxy-comb
5d – Calciner oxy-comb mixed with kiln to other capture

- The results presented on oxy-combustion are most valuable when compared with each other, but it seems to be worth pursuing even for retrofit
- It is clear from the results, Scenario 5d, that the increased CO_2 concentration in the flue gas to amine scrubbing does not give any advantages compared to Scenario 2

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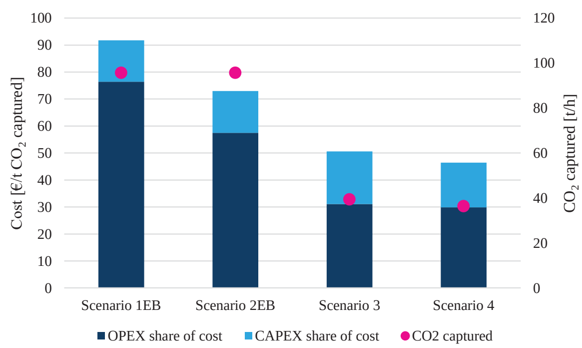
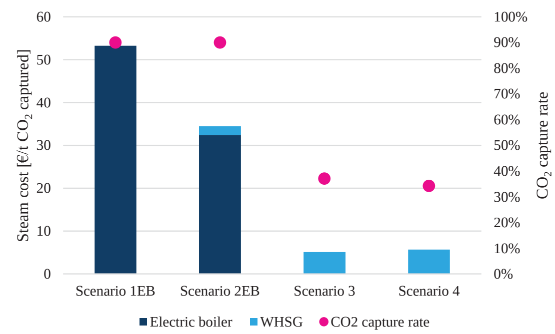
Amine scrubbing – electric boiler results



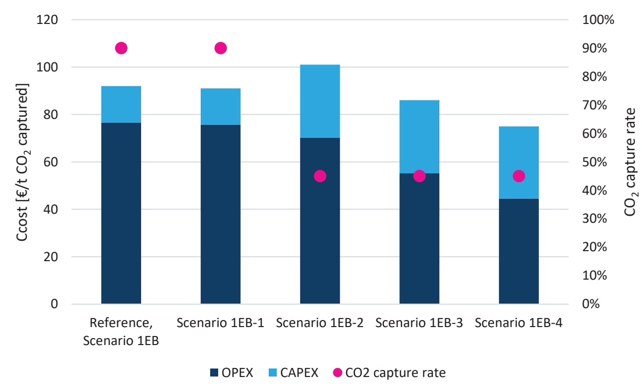


Amine scrubbing - seasonal capture

- Until now
  - The operational time of the capture plant coincides with the uptime of the cement plant
  - The investigations are based on a fixed electricity price independent on season
- Seasonal capture
  - Electric boiler
  - Capture plant can be left idle for six months
  - Seasonal variation in electricity price

Amine scrubbing - seasonal capture

Scenario	CO_2 capture technology	Electricity price summer (€/kWh)	Electricity price winter (€/kWh)	Steam supply	CO_2 capture details
Ref. 1EB	MEA scrubbing	0.055	0.055	All steam from electric boiler, 85.5 MW	90% capture, all year
1EB – 1	MEA scrubbing	0.045	0.065	All steam from electric boiler, 85.5 MW	90% capture, all year
1EB – 2	MEA scrubbing	0.045	-	All steam from electric boiler, 85.5 MW	Summer capture only, full size plant
1EB – 3	MEA scrubbing	0.03	-	All steam from electric boiler, 85.5 MW	Summer capture only, full size plant
1EB – 4	MEA scrubbing	0.02	-	All steam from electric boiler, 85.5 MW	Summer capture only, full size plant



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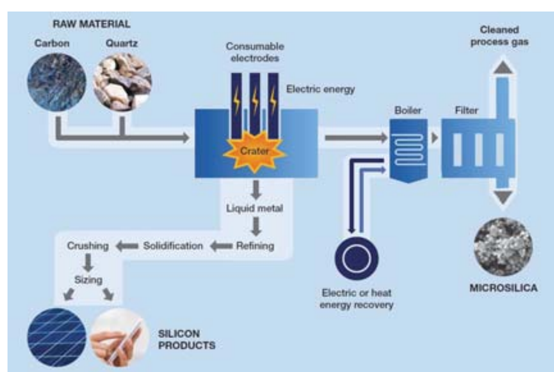
Final remarks

- Amine scrubbing
  - Utilisation of waste heat highly beneficial
  - Steam generation on site is costly
- Oxy-combustion
  - Seems promising
  - Requires considerable changes in the existing process
- Seasonal capture
  - Could be an option at favorable conditions, low electricity price during summer months

Solar case

REC Solar - Process

- The plant produced close to 10 kt Si in 2015
- Corresponding CO_2 emission
  - 43 kt from fossil energy sources,
  - and 12 kt from bio based sources



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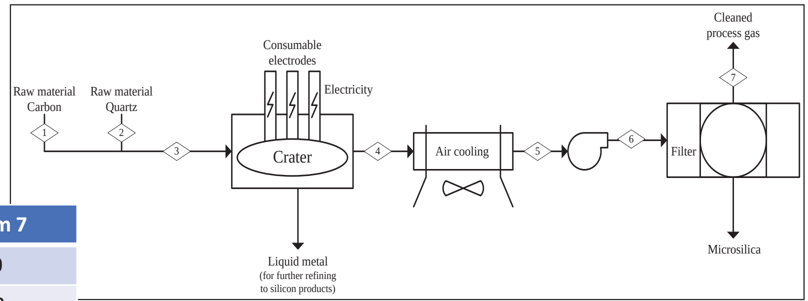
REC Solar - basis

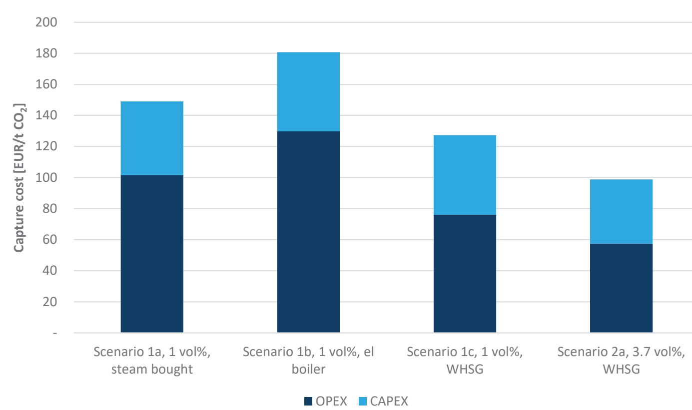


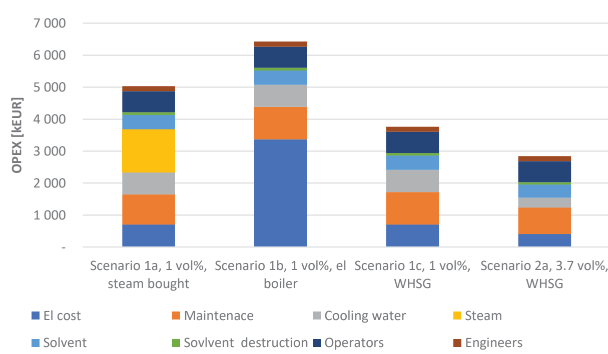
Parameter	Unit	Stream 4	Stream 7
Temperature	˚C	600	100
Flow rate	m^3/s	77.0	97.3
CO_2	**Vol%**	**3.7**	**1.0**
H_2O	Vol%	1.0	7.4
N_2	Vol%	77.2	74.1
O_2	Vol%	18.1	17.5

Excess energy sufficient to capture 90% of the produced CO_2

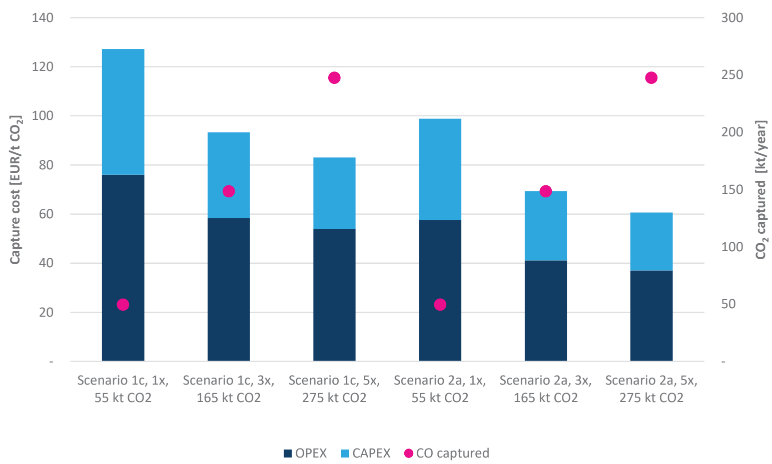
REC Solar - results

Scenario	CO_2 capture technology	CO_2 capture details	Specific reboiler duty, SRD	Steam supply
1a (ref. case)	MEA scrubbing	1 vol% CO_2 in off-gas, 90% capture rate	3.53MJ/kg CO_2 captured	All steam bought, 5.6 MW
1b	MEA scrubbing	1 vol% CO_2 in off-gas, 90% capture rate	3.53 MJ/kg CO_2 captured	All steam from electric boiler, 5.6 MW
1c	MEA scrubbing	1 vol% CO_2 in off-gas, 90% capture rate	3.53 MJ/kg CO_2 captured	All steam from WHSG, 5.6 MW
2a	MEA scrubbing	3.7 vol% CO_2 in off-gas, 90% capture rate	3.34 MJ/kg CO_2 captured	All steam from WHSG, 5.3 MW





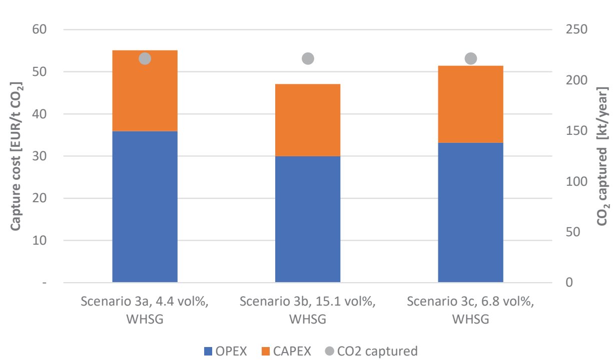
REC Solar –increased plant size results

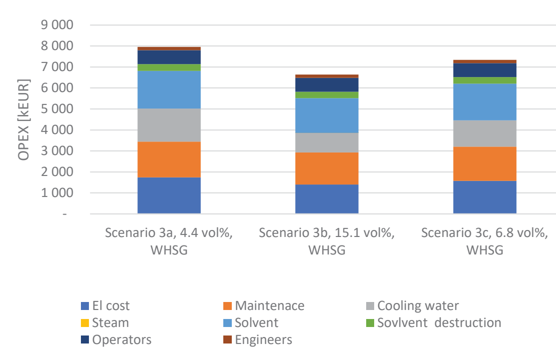


All steam from WHSG

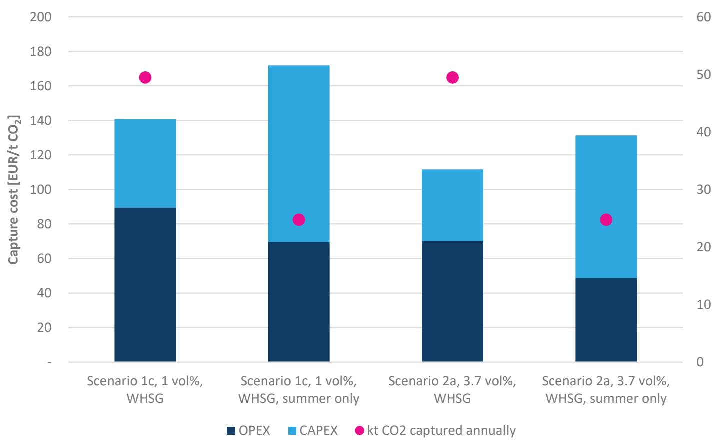
Generic plant - flue gas recycling, WHSG

Assumed that sufficient steam can be generated from the WHSG in all scenarios





Amine scrubbing - seasonal capture results



Scenario 1c and 2a all year capture now includes a loss of revenue from district heating sales

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Final remarks

- REC Solar
  - The combination of low CO_2 concentration and small source makes CO_2 capture costly
  - A relatively small increase in CO_2 concentration, ~ 4 vol%, is beneficial in regard to cost as expected, the same is found for increased plant size
  - Utilisation of waste heat is highly beneficial
  - Seasonal capture is likely not to be an alternative as the combination of low CO_2 concentration and small source results in a high CAPEX, however if the value of steam as district heating is high enough it might become favorable
- Generic plant
  - Current CO_2 concentration ~4 vol% CO_2, flue gas recycling can result in a CO_2 concentration of ~ 15 vol%
  - The increase to 15 vol% does not have a huge impact on CO_2 capture cost for amine based post-combustion capture
  - However, higher concentrations make other capture technologies attractive and the difference in cost is expected to be more significant
  - Utilisation of waste heat is highly beneficial

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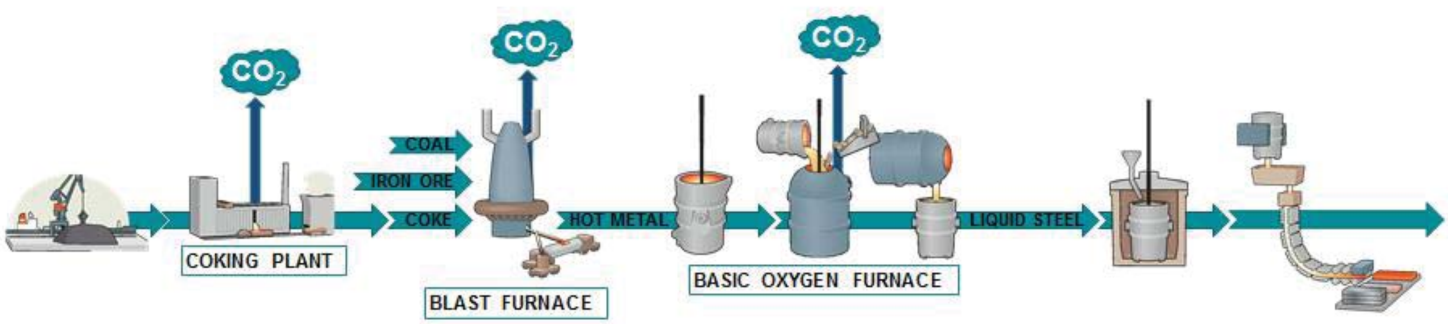
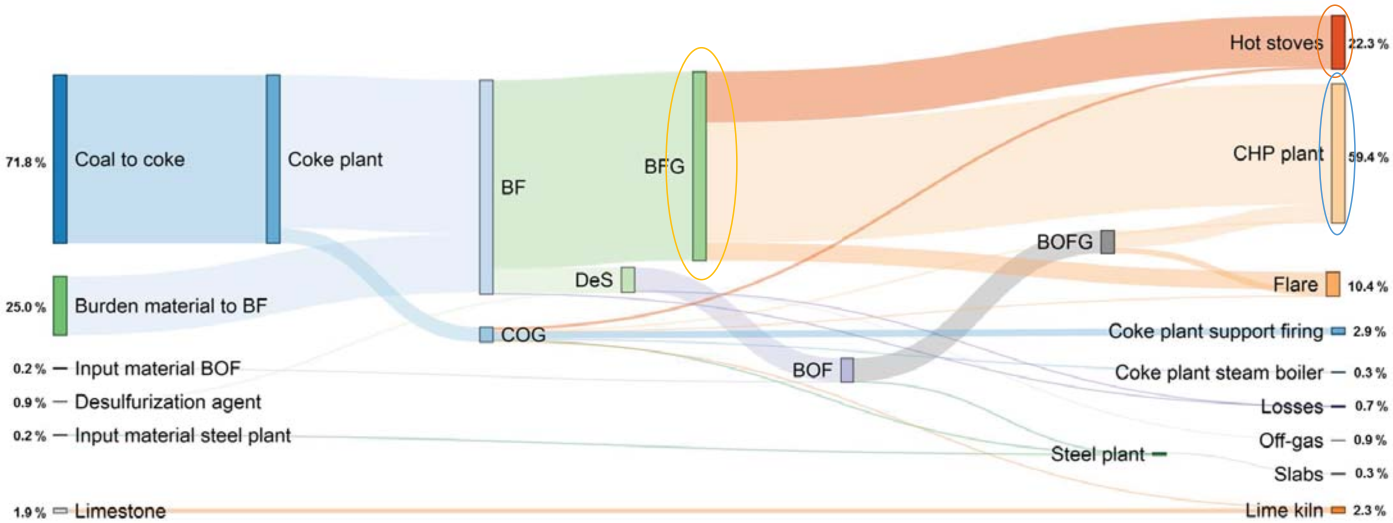
Steel case

Steel industry

- Carbon (C) enters the system with coke and coal (Reducing agent, Fuel, Bed material structure)
- Limited amount of point sources

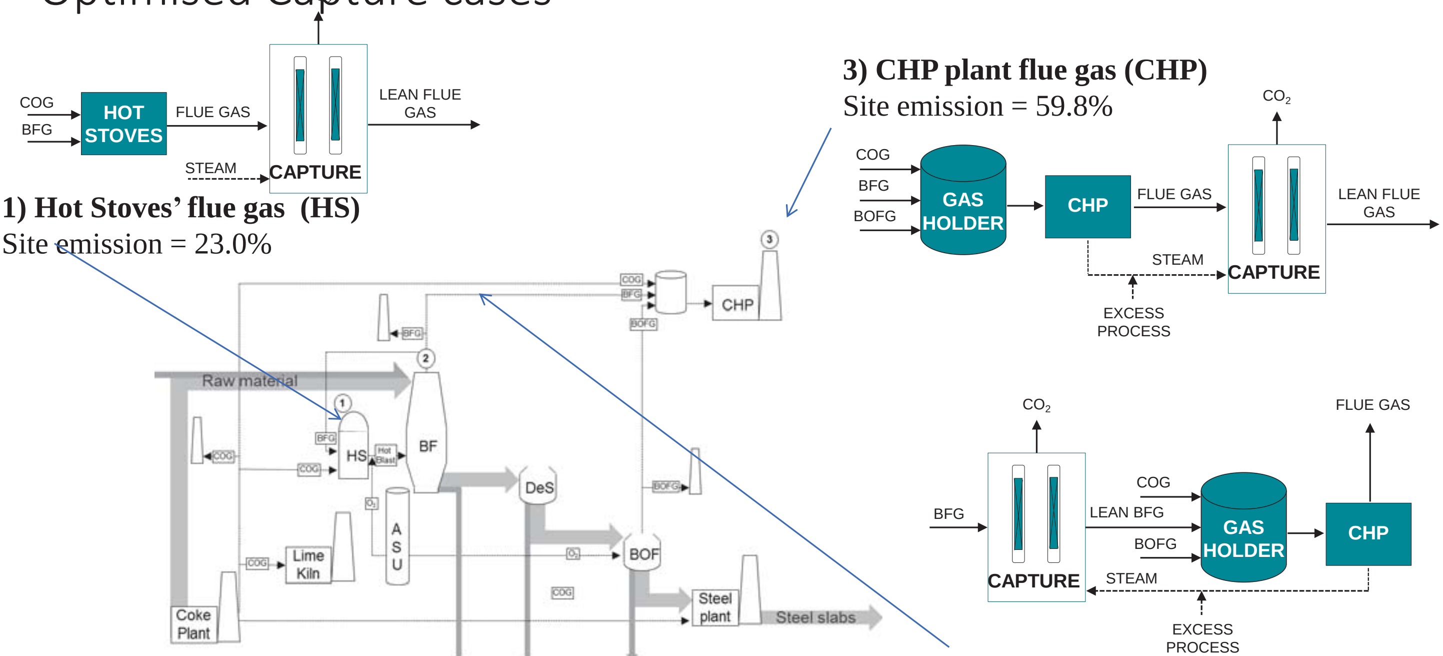


Carbon balance



Important to find cost efficient ways to reduce the emissions of green house gases

Optimised Capture cases



1) Hot Stoves' flue gas (HS)
Site emission = 23.0%

3) CHP plant flue gas (CHP)
Site emission = 59.8%

2) Blast furnace gas (BFG)
Site emission = 44.5%

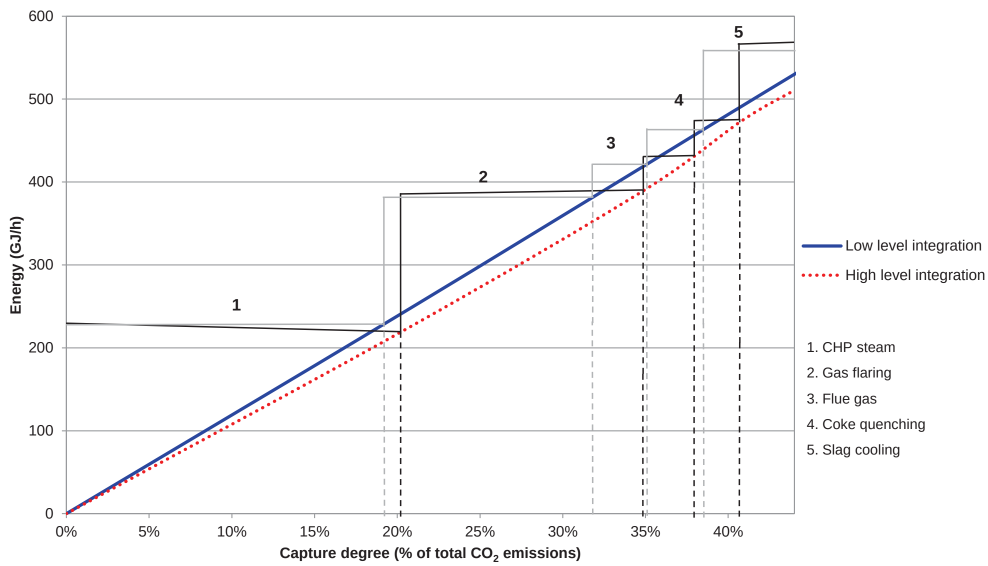
Status on results: Aspen simulation case 2 & 3

BFG vs CHP – high vs low level of integration

Scope: Highest possible capture from BFG or CHP depending on leve of excess energy

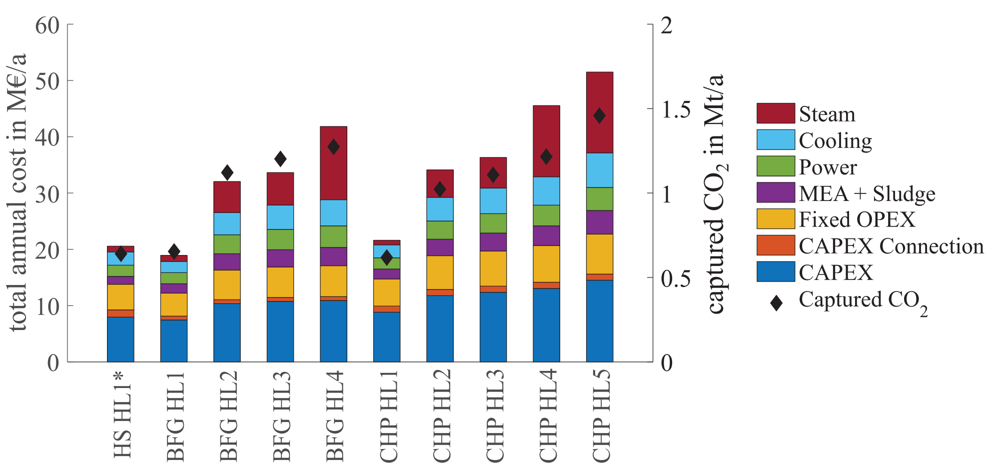
→ Capture from BFG is more energy efficient however limitec in the total amount of captured CO_2 compared to CHP case

Dissemination: TCCS-9 presentation & paper submitted into Int. J. Greenh. Gas Control



Results

(Capture cost)



Specific cost €/t CO_2 captured

HS	BFG				CHP				
HL1*	HL1	HL2	HL3	HL4	HL1	HL2	HL3	HL4	HL5
32.1	28.9	28.6	**28.0**	32.8	35.1	33.4	32.7	37.4	35.3

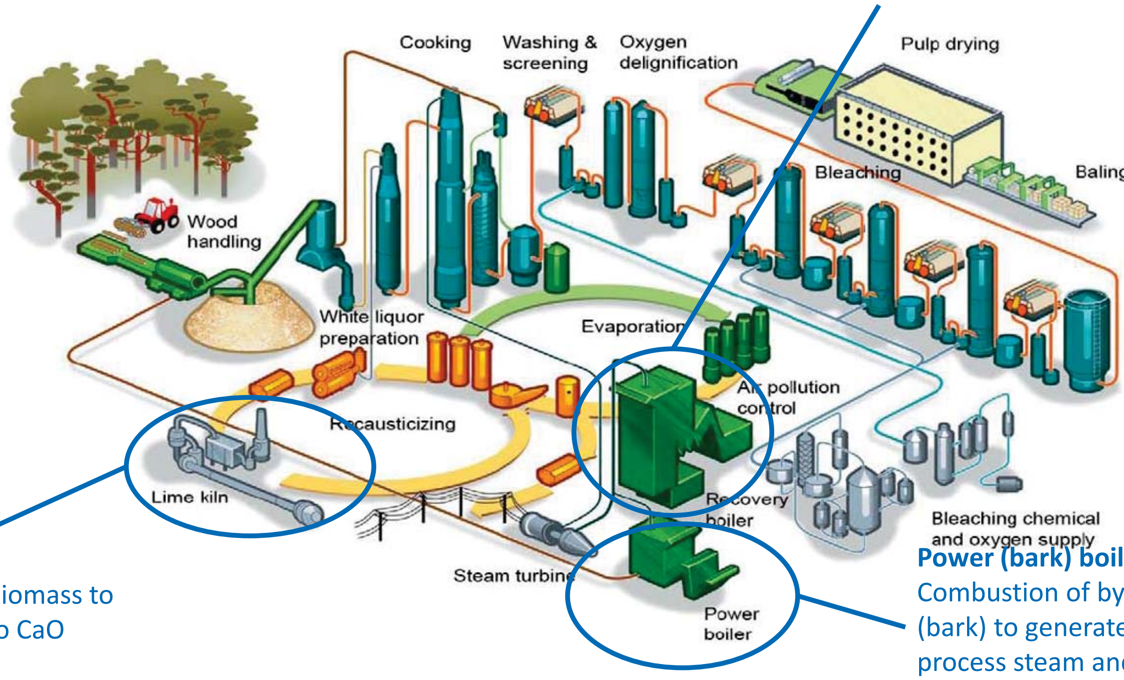
Conclusions

- Three different capture options evaluated (hot stoves flue gases, blast furnace gas, CHP flue gas)
- Capture cost is in the range of 27-37€/ton CO_2 captured **(are costs verified)**
- Most cost efficient when capturing CO_2 from blast furnace gas
- Utilisation of excess heat mean to reduce capture cost (way to reduce steam cost)
- Higher capture rates require more expensive energy (steam)
- There are alternative solutions to mitigate CO2 on different maturity level

Pulp & paper

The modern Nordic kraft pulp mill

Recovery boiler:
Combustion of black liquor to recover chemicals and generate process steam

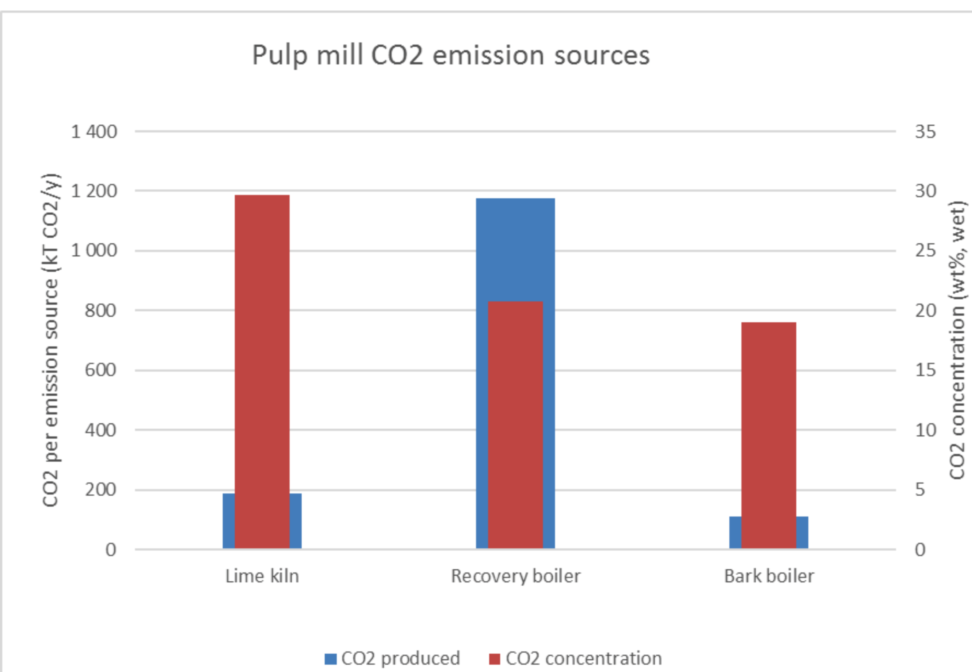


Lime kiln:
Combustion of biomass to transfer $CaCO_3$ to CaO

Power (bark) boiler:
Combustion of by-products (bark) to generate additional process steam and power

P&P case study goal: to investigate hypothetical technical and economic potential of full and partial CO_2 capture

Total yearly emission of CO_2: 1.5 Mt



Modern Nordic kraft pulp mill (BAT 2010) (hypothetical)

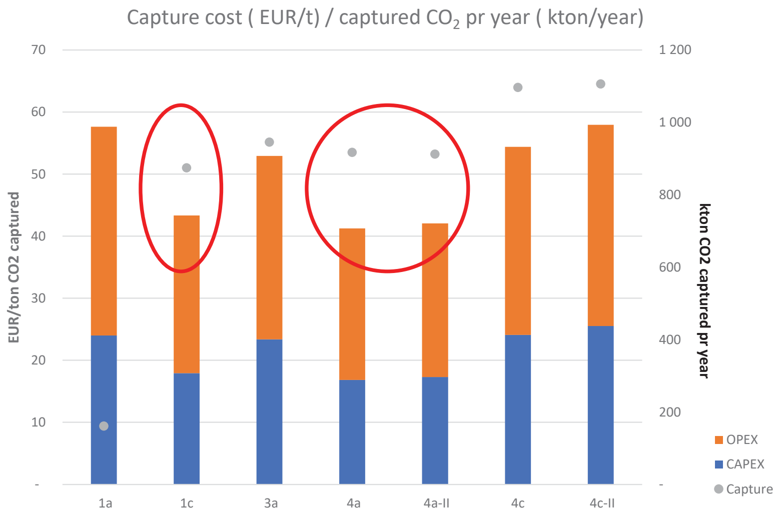
- 700 000 Adt/y of pulp
- 355 days of planned operation, 92% combined availability = 7840 h/y
- Bark powder as fuel in lime kiln
- Condensing turbine for electricity generation from excess energy
- 68 MW exported green electricity

Capture plant and Economic assumptions

- MEA, split flow configuration
- The capture plant is treated as an extension to the existing plant
- Rate of return: 7.5 %
- No of years: 25 (3 year of construction and 22 years in operation).
- Electricity: 0.03 EUR/kWh
- Green electricity certificates: 0.015 EUR/kWh
- Bark 16 EUR/MWh
- Cooling water 0,02 EUR/m^3

RISE

Economic results

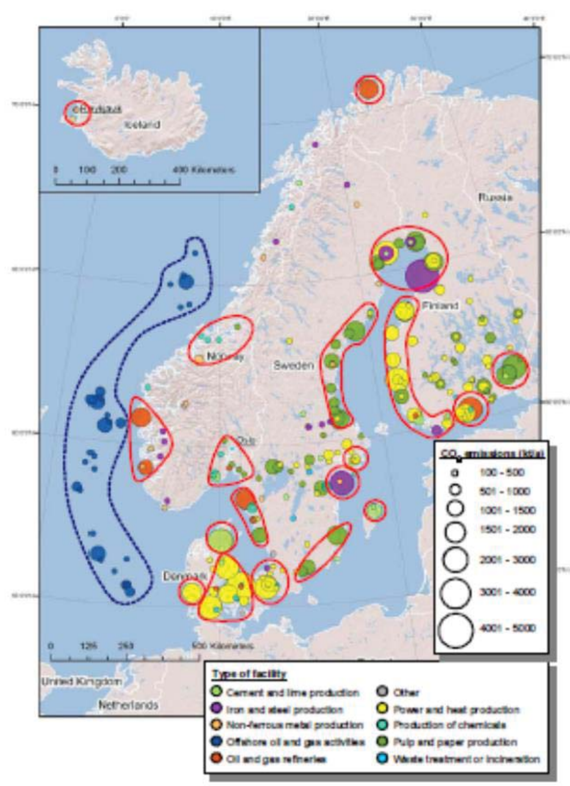


Parameter	Unit	Case 1a	case 1c	Case 3a	Case 4a	Case 4a-II	case 4c	Case 4c-II
CAPEX	kEUR	42 800	172 900	243 900	170 500	174 300	291 500	312 900
OPEX	kEUR/an	6 100	24 900	31 300	25 100	25 300	37 200	40 200

- OPEX per ton correlates with the energy requirement for solvent regeneration
- Bark boiler has a high impact on CAPEX and OPEX (ref 1c vs. 3a and 4a vs. 4c)
- Lowest CO_2 capture cost with maximum partial capture (1c and 4a)
- High investment costs entail high risk

Large potential BECCS…

- Sweden
  - 22 Mtonne CO2/y in 2007
  - About 10 mills with emissions of 1-2 Mtonne/y
- Finland
  - 17 Mtonne CO2/year 2007
  - 9 mills with emissions from 1-3 Mtonne/y
- Expansion in capacity since 2007
  - Change to biofuels
  - Expansion in a number of mills (ongoing)

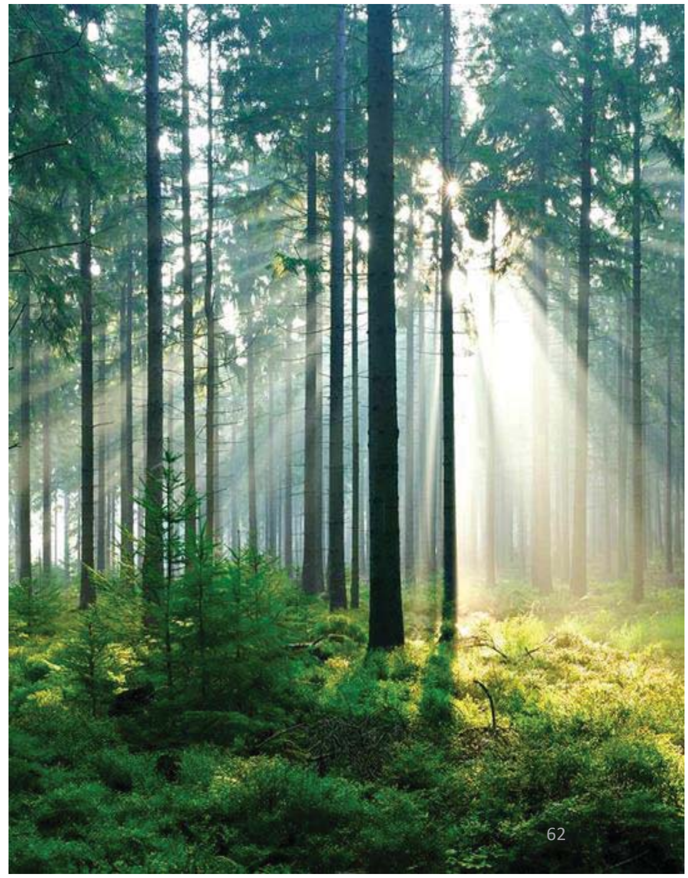


Conclusions

- There is a potential for capture of biogenic CO_2 in the pulp and paper industry to compensate for emissions in other sectors;
  - 1-2 mill ton from state of the art pulp mill sites at a couple of locations in Sweden and Finland
  - Non-integrated, stand alone pulp mills are the primary target as they have an excess of energy

- The CO_2 capture cases investigated for the pulp mill result in specific cost of CO_2 capture in the range of 41-58 EUR/t CO_2 captured
  - **The lowest costs are obtained with max partial capture** (about 65-70% of total emissions) utilizing excess energy otherwise used to generate electricity in a condensing turbine
  - Investing in a new bark boiler to reach full CO_2 capture increases the specific capture cost significantly (10-12 EUR/t)

- The CO_2 capture cost is low compared to other industrial sources
  - Economy of scale, large plant with 1 main stack (recovery boiler)
  - Excess energy and fuel (by-products such as bark) available
  - However, additional cost of loss of green electricity certificates in the order of 1-3.5 EUR/t CO_2 captured
  - Few incentives for CO2 capture; requires new financial measures to stimulate investments!
- CCU with lignin production results in less BECCS but reduces the climate footprint the lignin product and its cost
  - Only a very small amount of CO2 can be re-used



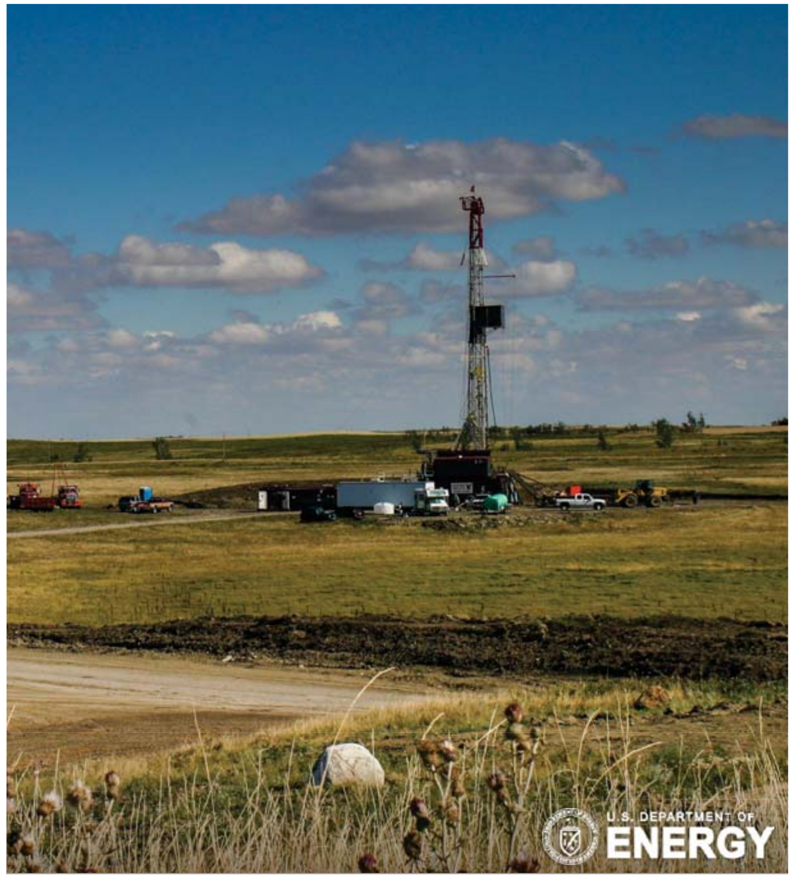
Session 4: What it Takes to Make CCS Economical

4.1. CCUS and 45Q, *Tim Grant, US DOE*

CCUS and 45Q

Tim Grant
National Energy Technology Laboratory

IEAGHG CCS Cost Workshop
March 19-20, 2019



Disclaimer

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45Q

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Introduction

- Components of 45Q
- Timing
- Secure Storage

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45Q: 2008 - 2018

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- A tax credit for capturing and sequestering CO_2
- Value of the credit:
  - $20 per metric ton captured and disposed of in secure geologic storage
  - $10 per metric ton captured and used in a qualified EOR or EGR project and disposed of in secure geologic storage
- Credits available for a total of 75 million tonnes captured and sequestered
  - for projects placed in service before 2-9-2018
  - 59,767,924 captured and sequestered as of May 14, 2018
- Only sources capturing more than 500,000 tonnes per year qualify.
- Only available to those who capture, not transferable

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45Q: 2018 Revision

What does it take to claim the tax credit under the current 45Q?

- Begin construction before January 1, 2024
- Capture of a minimal amount of CO_2 from a qualified facility
- A pipeline connected to secure storage
- A geologic storage site or EOR project with an approved Subpart RR MRV plan

45Q: 2018 Revision

- **Bipartisan Budget Act of 2018:**
  Section 41119 Enhancement of Carbon Dioxide Sequestration Credit

- **New 45Q Credit Period:**
  - CO_2 capture equipment placed in service on/after February 9, 2018 (passage of bill)
  - Credit reaches full value in 2026
    - Geologic Storage: $22.33 (2017) to $50.00 (2026) and continues to track inflation
    - EOR (EGR): $12.83 (2017) to $35.00 (2026) and continues to track inflation
  - Construction has to begin before January 1, 2024
  - Credit paid out for 12 years
    - As long as maintain minimum capture and secure storge

45Q: 2018 Revision

- **Expand types Carbon Oxide Sources that qualify under 45Q**
  - Electric generating facility (not covered in next bullet point):
    - capture not less than 500,000 tonnes during the taxable year
  - Facilities with <500,000 tonnes emissions,
    - capture not less than 25,000 tonnes during the taxable year
  - Direct air capture or other facility not covered above –
    - capture not less than 100,000 tonnes during the taxable year
- **CO_2 measured at point of capture and verified at the point of disposal/injection/use**
- **Excludes gases recaptured during EOR process**
  - Don't count produced and recycled CO_2
  - Only count purchased CO_2

45Q: 2018 Revision

- **Who claims credit? –**
  - Taxpayer who captures the CO_2 (various business structures)
  - Transferable to Taxpayer who sequesters the captured CO_2
  - Split between the two – not specifically prohibited; will IRS approve?
  - Not applicable to transportation
- **Secure Geological Storage**
  - An approved Subpart RR MRV plan (IRS Form 8933)
  - Required for Class VI permit, optional for Class II permits
  - Three MRV plans approved for EOR to date:
    - Occidental Petroleum Denver Unit and Hobbs Unit in Permian Basin
    - Core Energy Niagaran Pinnacle Reef EOR in Michigan Basin
- **Utilization**
  - Photosynthesis or chemosynthesis
  - Chemical conversion to qualified material or compound
  - Isolate permanently from atmosphere
  - Amount claimed for credit based on lifecycle analysis

45Q: 2018 Revision

- Some details needed
- Sec. of Treasury (DOT) with DOE and DOI and EPA Admin to determine what is secure storage.
- DOE letter to DOT December 2018 – clarification on issues:
  - Requirements for commencement of construction, including what activities constitute commencement of construction
  - Transferability of 45Q tax credit
  - Treatment of partnerships, definition of "secure geological storage"
  - Requirement for lifecycle analysis for CO_2 utilization
  - Recapture of 45Q tax credits

45Q

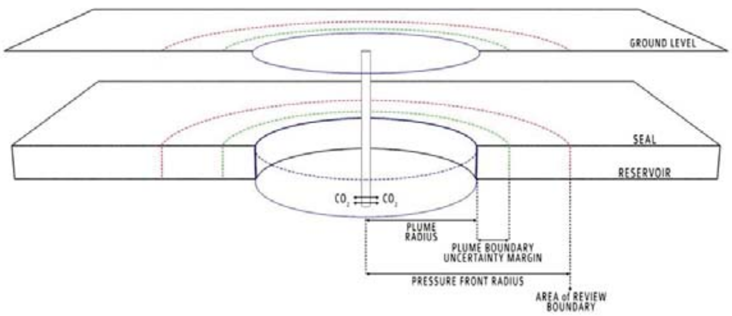
To Claim Credit - Timing

							Begin CCS Place Equipment in Service										
Facility		2 to 5 Year Capital Expenditure Period depending on size of source						30 years of Power Generation Operations									
Transportation				3 Year Capital Expenditure				30 years of Pipeline Operations									
Geologic Storage	Regional Evaluation	Site Characterization New wells, seismic data, res. Modeling, etc.			Permitting, well drill & completion, etc.			30 years injection operations, MVA						50 years post-injecton site care and site closure			
EOR					Permits, wells, plant, etc.			20 to 50 years of operations									
Project Year	1	2	3	4	5	6		7	8	17	18	35	36	37	38	85	86
Calander Year	2018	2019	2020	2021	2022	2023		2024	2025	2034	2035	2052	2053	2054	2055	2102	2103
45Q Tax Credit	Begin Construction Period							1	2	11	12						

- Begin construction of capture facility before January 1, 2024
- To place equipment in service* means capturing CO_2
  - * in service may be declared before capture begins
- Pipeline ready to transportation to secure storage
- Approval for injection granted by EPA for Class VI operations
- Facilities and injection wells ready for EOR

45Q – Secure Storage

Secure Storage: Sec of Treasury, Energy, Interior & EPA

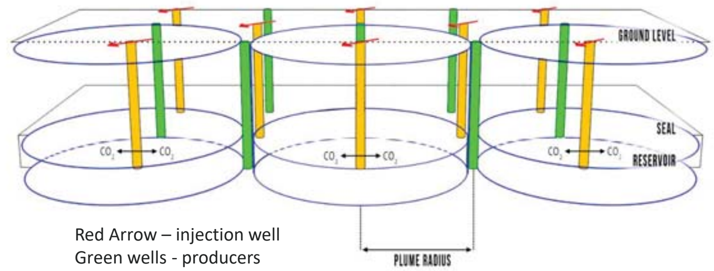


Geologic Storage:

- Continuous injection over a period of time
- Class VI permit
- Subpart RR MRV Plan required
- Financial Responsibility

EOR – Associated Storage

- Injection of CO_2 until economic limit
- Produced CO_2 separated and recycled,
  - Mixed with newly purchased CO_2
  - New CO_2 replaces trapped CO2
- At some point only recycled CO_2 injected
- Class II permit, Subpart RR MRV optional



45Q - CO_2 Geologic Storage

FutureGen 2.0 (First-of-a-kind)

- September 2010: DOE commits $1B funding for FutureGen 2.0[1]
- March 2013: Class VI permit application to EPA[2]
  - Site selected, characterized, plans prepared and permit application submitted in 4th year of project
- March 31, 2014: EPA completes technical evaluation and issues draft decision
- May 7, 2014: Public Hearing
- August 29, 2014: Issue Permit
  - Permit with authorization to drill injection wells in 5th year of project
  - Permission to inject required to begin injection

Plant		3 to 5 Year Capital Expenditure Period					Begin CCS	30 years of Operations							
Transportation				3 year Capital Expenditure Period				30 years of Pipeline Operations							
Storage	Regional Evaluation	Site Characterization			Permitting & Inj Well Drill			30 years of Operations (MVA)				50 years for PISC & Site Closure			
Year	1	2	3	4	5	6		7	8	35	36	37	38	86	87

Source: NETL[3]

[1]NETL. FutureGen 2.0. DOE/NETL, Found at: http://www.netl.doe.gov/research/coal/major-demonstrations/futuregen
[2]FutureGen Permit Documents, Attachment H: FutureGen Financial Responsibility FINAL (PDF). Found at: http://www.epa.gov/region5/water/uic/futuregen/
[3]NETL. Table, Exhibit 2-1, page 11, from QGESS: Carbon Dioxide Transport and Storage Costs in NETL Studies. DOE/NETL-2014-1653. Found at: http://www.netl.doe.gov/research/energy-analysis/quality-guidelines-qgess

45Q - EOR associated storage

Petra Nova

- May 2010 – CCPI Project Selection
  - DOE $190 million
  - Total cost ~$1 billion
  - 60 MWe expand to 240 MWe project
    - Make EOR effective
- June 2014 – Financing in place, begin construction Carbon Capture facility
- Dec 2016 – Plant Operations begin
  - CO_2 pipeline commissioned
  - Capture up to 1.4 Mt/yr
- Jan 2017 – 1st EOR production well
  - Class II permit operation

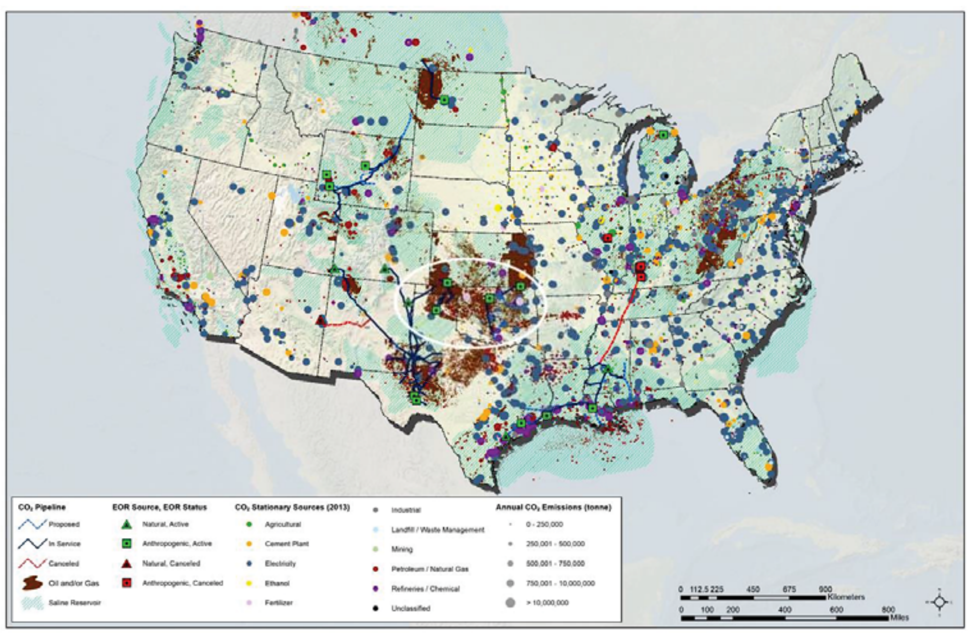
45Q

Small Sources

- **Small Sources**
  - <500 Kt annual emissions, capture >25 Kt CO_2
- **Pipeline**
  - 414 mi (712 km)
  - 2 Operators
- **15 EOR Projects**
  - 3 Operators

CO_2 Source

- **Anthropogenic**
  - Coffeyville Fertilizer Plant
    - 24 mo. to connect plant and North Burbank Field
  - Enid Fertilizer Plant
  - Agrium Fertilizer Plant
  - Arkalon Ethanol Plant
  - Bonanza Ethanol Plant



Kuuskraa, V., and Wallace, M., 2014. CO_2-EOR set for growth as new CO_2 supplies emerge. Oil & Gas Journal, April 7, 2014.
NETL, 2014, A Review of the CO_2 Pipeline Infrastructure in the U.S. DOE/NETL-2014/1681

45Q

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Conclusions

- 45Q credit provides significant financial opportunity
- Three critical components have to be in place to claim this credit
  - Capture from a qualified source
  - Pipeline connection to secure storage
  - A secure storage site with approved Subpart RR MRV plan
    - Geologic Storage – Class VI
    - EOR – Class II
- Begin construction of capture site before January 1, 2024
- Place equipment in service
  - All three components ready to go at the same time.
- Secure Geologic Storage may require the longest lead time of these components

45Q

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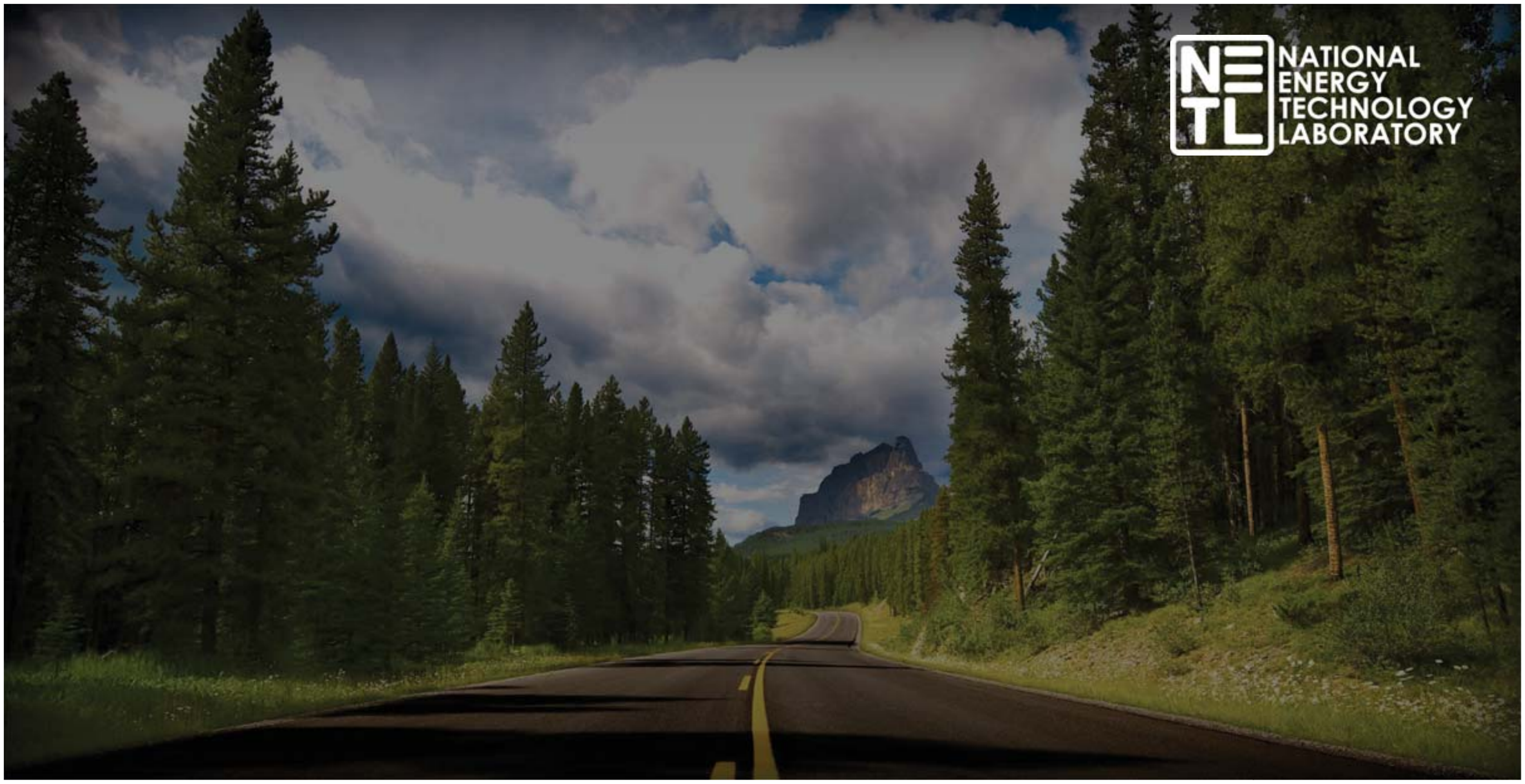
Questions?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LABORATORY

4.2. CCUS in the Netherlands, *Martijn van de Sande, Netherlands Enterprise Agency*

Netherlands Enterprise Agency

CCUS in the Netherlands

Challanges faced in developing measures to stimulate CCS deployment

Martijn van de Sande
martijn.vandesande@rvo.nl

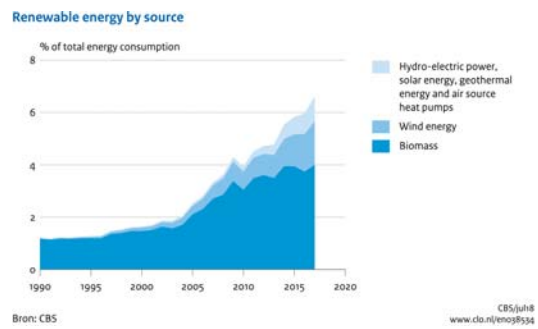
19 March 2019

Contents

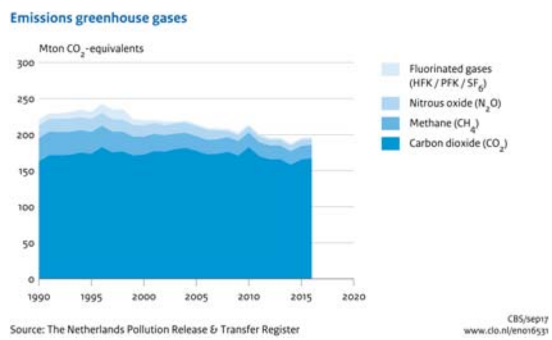
Part I

Context and CCS in the Netherlands

Netherlands



- GDP: 331,8 billion euros
- Size: 41,5 km²
- Population: 17,3 million (15 times as US)
- Renewable energy share: 6,6% (2017)
- GHG emissions: 193Mtpa (ex LULUCF, 2017)



National GHG statistics and objectives

Year	GHG emission in Mt (ex LULUCF)
1990	221
2015	195
2030	*113 (49% GHG reduction relative to 1990 emissions)*

Sector \ 2030	Reference reduction	Additional reduction objective	Total objective
Electricity	20,2	20,2	40,4
Build environment	5,7	0,8	6,5
Industry	5,1	14,3	19,4
Agriculture	3,2	3,5	6,7
Transport	3,1	4,5	7,6

Policy developments on CCS

- Coalition agreement (Oct 2017): 20Mtpa in 2030
- Climate agreement negotiations
  - Preliminary result, CCS: 7Mtpa in 2030
  - Joint Fact Finding
  - All in industry and waste sectors
- Development of a policy framework for division of tasks and stimulation.

Netherlands is a good fit for CC

- Few big pollutants; 10% of the ETS companies, emit 85% of the NL ET emissions.
- Mostly concentrated in clusters nea shore.
- Elaborate gas infrastructure that c used.
- Numerous potential storage sites (depleted gas fields) at the North Sea (estimated at 1700Mt storage capacity).

RD&D tenders in 2018

- 3 national tenders and participation in ERANET-ACT call, spending 16,6 EUR mln
- Application analysis:
  - Much interest of waste incinerators
  - Two large CO2-grid projects: PORTHOS & ATHOS
  - Focus on capture and CO2 applications
  - ACT: focus on capture and CO2 storage
- 2019: again 3 national RD&D tenders

Projects under development

❖ AVR Duiven

Waste incinerator producing electricty and heat adding CO2 capture for summer CO2 supply to greenhouses, 60Ktpa from 2019

❖ Porthos

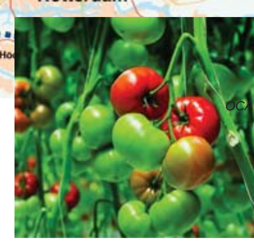
Rotterdam Harbour area, 2-5 Mtpa in 2030 from various emitters, start operation in early ’20

❖ Athos

Amsterdam Harbour area, aim to capture emissions from the Tata Steel plant (1,5-5Mtpa) and AEB (Amsterdam waste incinerator, 1,5Mtpa), start operation in 2026

9

Projects operating



❖ OCAP delivering CO2 from two emitters

in Rotterdam harbour to three horticulture area’s

❖ WARMCO delivering CO2 from Yara

(fertilizer production) to nearby greenhouses

❖ Several utilisations ‘compensation stone’

containing 250kg CO2/m3 (5.000kg per average house), production sodium bicarbonate at waste incinerator (Twence)

❖ Offshore storage in K12-b use of CO2

for offshore enhanced gas recovery, ± 100kton since 2004

10

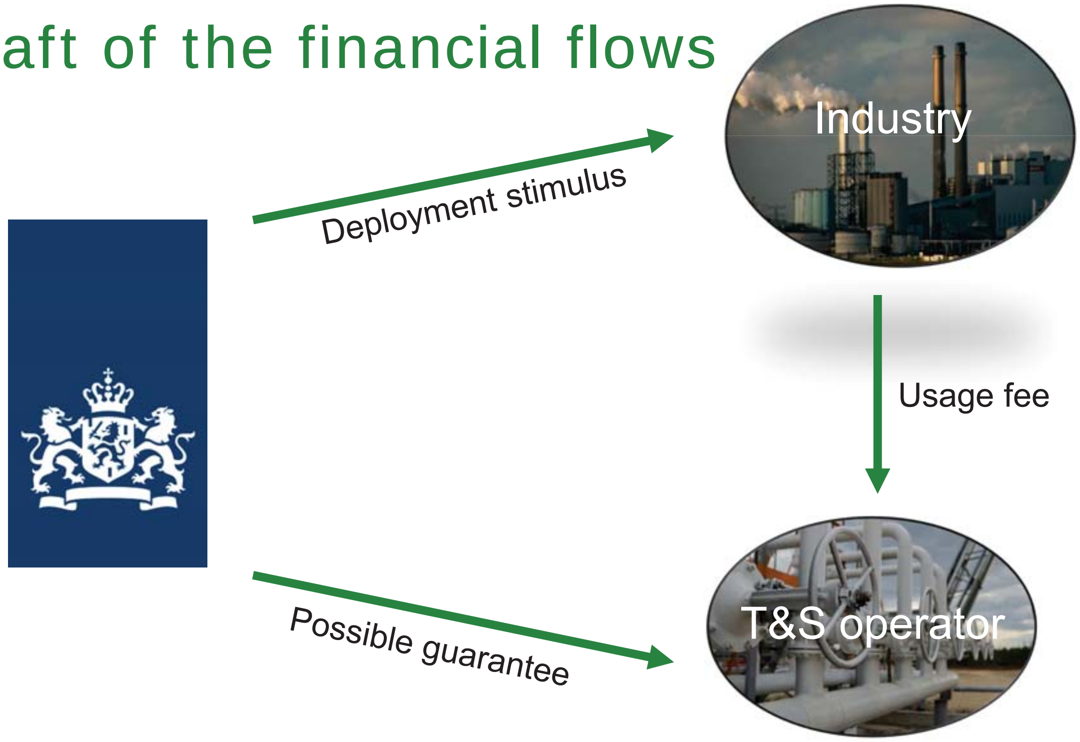
Upcoming developments

- New round of RD&D tenders in 2019.
- Finalisation of the national climate agreement.
- From 2020 onwards tender scheme for stimulation of deployment of CO2 reduction (including CCS).

Part II

Design of the CCS deployment stimulus

Draft of the financial flows

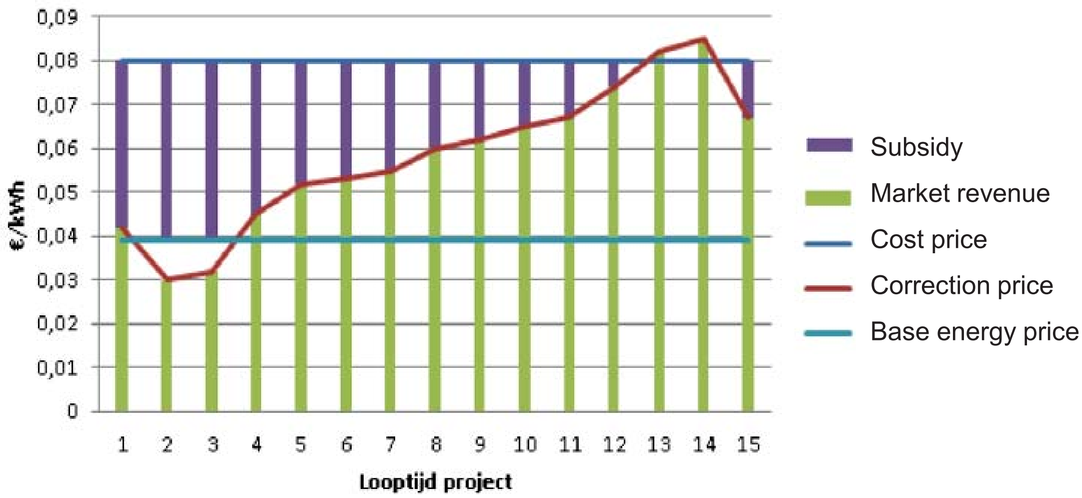


Current RES deployment: SDE+

Point of departure: the current sliding feed-in premium that is designed for RES generation

- Subsidies awarded in a reverse clock auction.
- All renewable energy technologies compete equally, based price.
- Payment of a feed-in premium, per unit of energy produced, corrected for market price of energy.

Current RES deployment: SDE+



Embedding CCUS: SDE++

- Tender: ranking based on euro/ton CO2 reduction.
- Tender: all technologies for production of renewable energy and CO2-reduction for industry compete based on this criterium.
- Subsidy: CO2-reduction premium based on cost price and possible ‘revenues’.

Selection of CCUS pathways

- Criteria for selecting eligible CCUS pathways
  1. Close to market introduction
  2. Measurability
  3. There needs to a substantial potential

- Pathways currently considered
  - Capture at industry (refining, H2 production) and waste incinerators
  - Transport through pipes or trucks
  - End use: storage or supply to greenhouses

Accounting of the CO2 reduction

- Primarily look at the reference scenario.
- Include or not include ‘scope 2’ emissions
  - Pro: higher use of electricity will (currently) depend for the largest part on fossil fuels
  - Con: Creates another uncertainty for projects and bad fit with current negotiations/sector objectives
- CCS seems manageable, CCU more complex.

Further challanges

- Lack of information of realised projects makes it hard to calculate the cost price (maximum bid price).
- Industry projects are heterogenous, the scheme is generic and open to any project, possible windfall profits.

Thank you for your attention!

Martijn van de Sande
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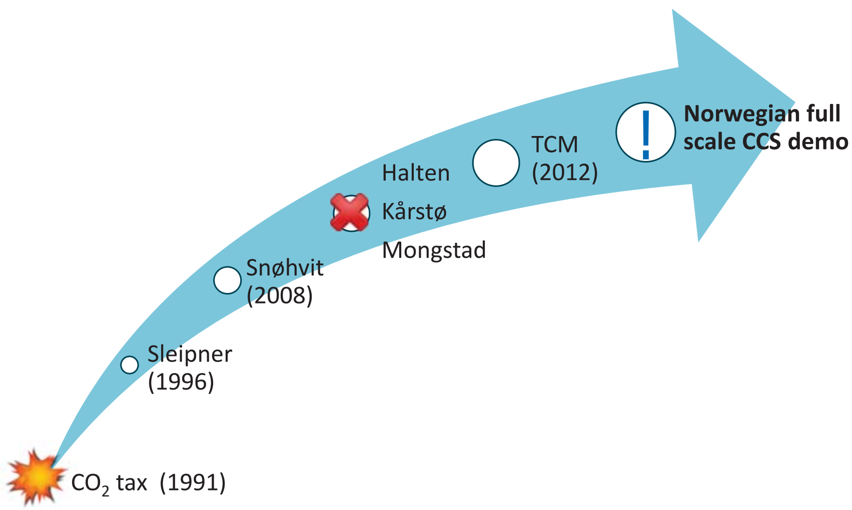
4.3. Norwegian Efforts Incentivizing CCS, *Ståle Aakenes, Gassnova*

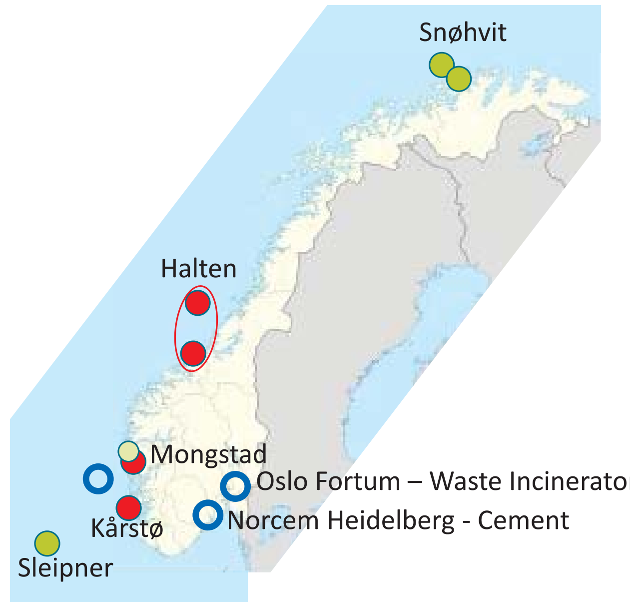
Gassnova

- State enterprise – Owned and funded by the Ministry of Petroleum & Energy
- Pursuing the State's strategy on CCS since 2005
- Facilitator for technology development and demonstration
- Full scale demo / TCM / CLIMIT / Adviser to Ministry on CCS
- ~€50m – mainly state aid; 40+ employees

GASSNOVA

Norwegian CCS story





GASSNOVA

Why Norway?

- Building on long traditions
- Large storage opportunities
- Obligations from Paris agreement

GASSNOVA

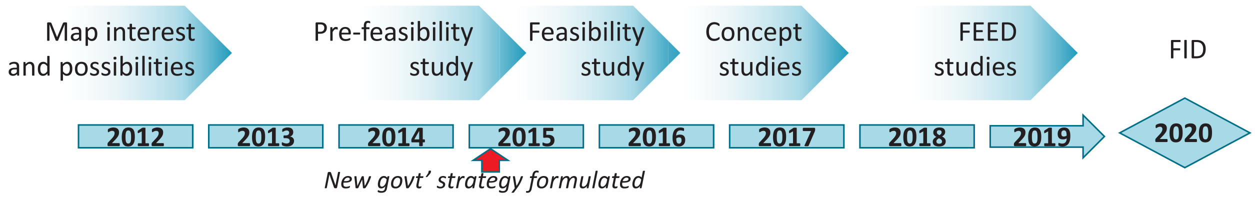
The Mongstad CCS project (2006-2013)

- No emission permit on new NGCC, unless CCS
- Agreement Statoil-Government; Share cost & risk
- State responsible for establishing solution for T&S
- Amine – NGCC – separate projects

- Misalignment risk-reward → driving costs
- Project complexity → Emission of amines
- Refinery business uncertainty, heat demand reduced
- Agreement on operations/ownership never reached

- FEED for capture almost finalised, no technical showstopper
- TCM test facility succeeded, verifying relevant technologies

New governmental approach – CCS demo evolving

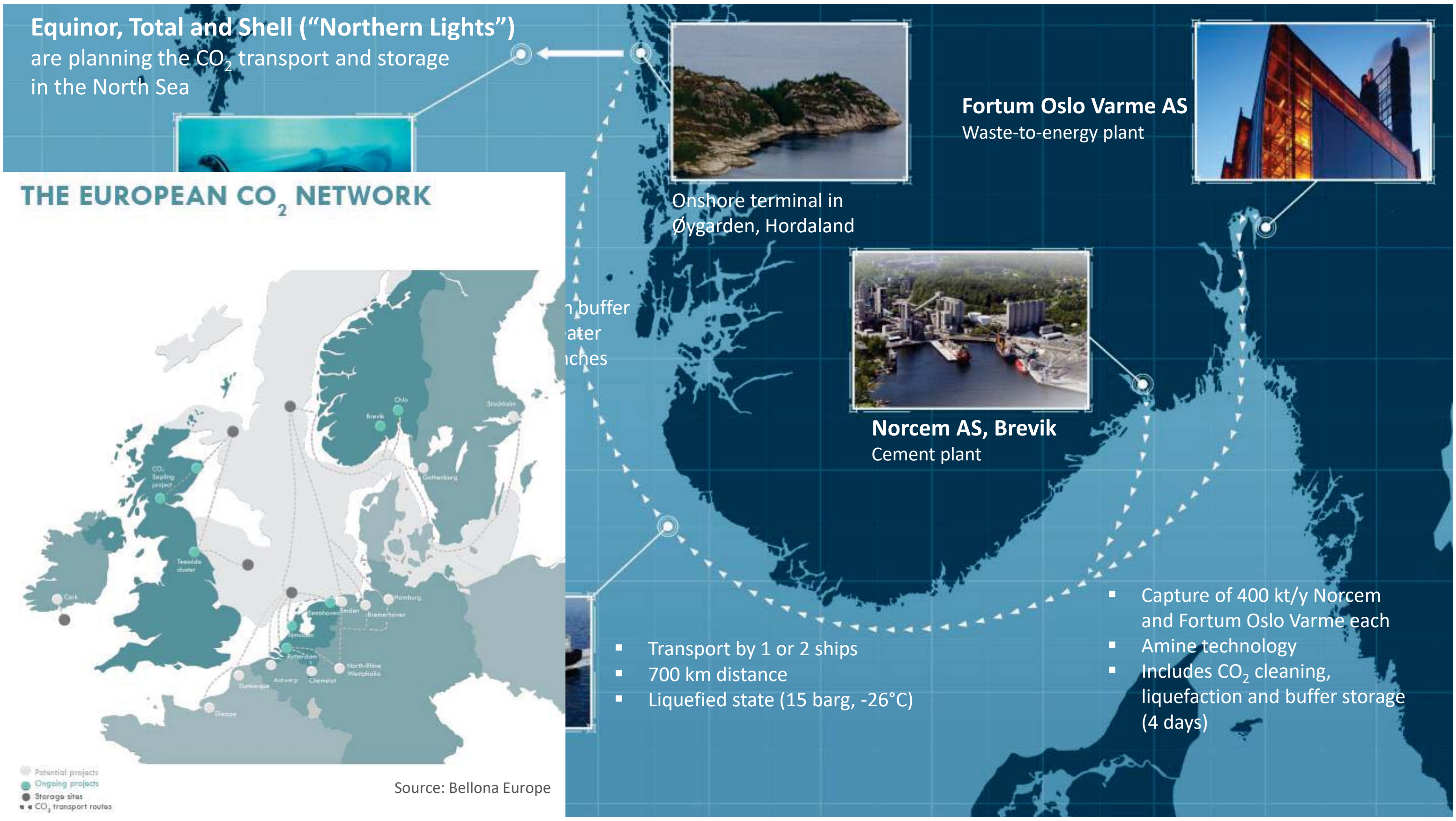


- Ministry the catalyst, in close cooperation with the industry
- Focus on spill-over effects for international deployment of CCS
- Gassnova a facilitator of the overall process - "the glue"

- CCS not commercial, substantial state funding required
- Split source and sink
- Chain flexibility & overcapacities

- The companies responsible for own projects
- State aid, based on competition
- Commercial agreement between Ministry and each company

GASSNOVA



1:1 commercial agreement – What and how?

- Capex support
- Opex support incl ETS
- Profitability / risk-reward

- Knowledge dissemination
- Regularity / capture rate

- Third party access to storage
- Liability issues
- Excess capacities

- Cross chain risk
- Timeframe

GASSNOVA

Norwegian CCS demo – What is and what's not?

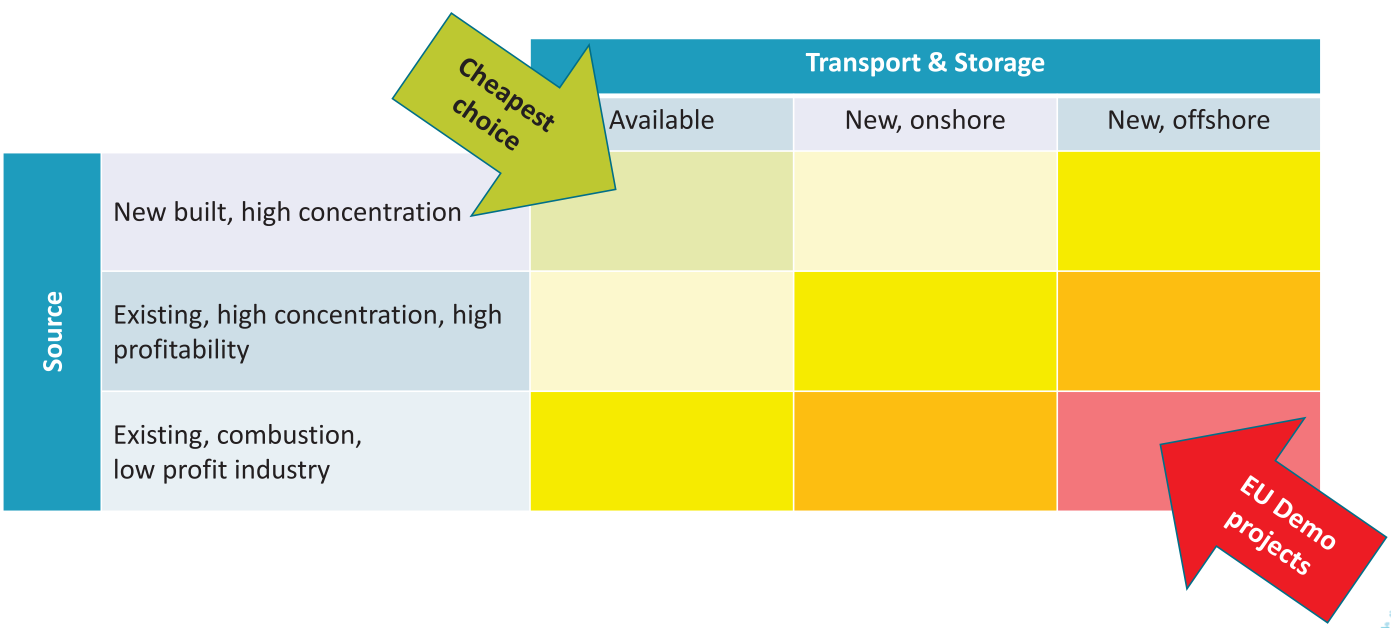
To be achieved

- Demonstrate a full-scale CCS is possible and safe
- Spill-over to future projects – learning and scale effects
- Learning on how to regulate and incentivise future CCS projects
- Promote low carbon business development

For the future

- Need for post combustion CCS in EU on cement / WTE? – Or at all?
- Replicability of the support scheme?
- Business case for commercial investments in CCS
- Arrangements for further Norwegian CCS projects

CCS à la carte



Thank you!

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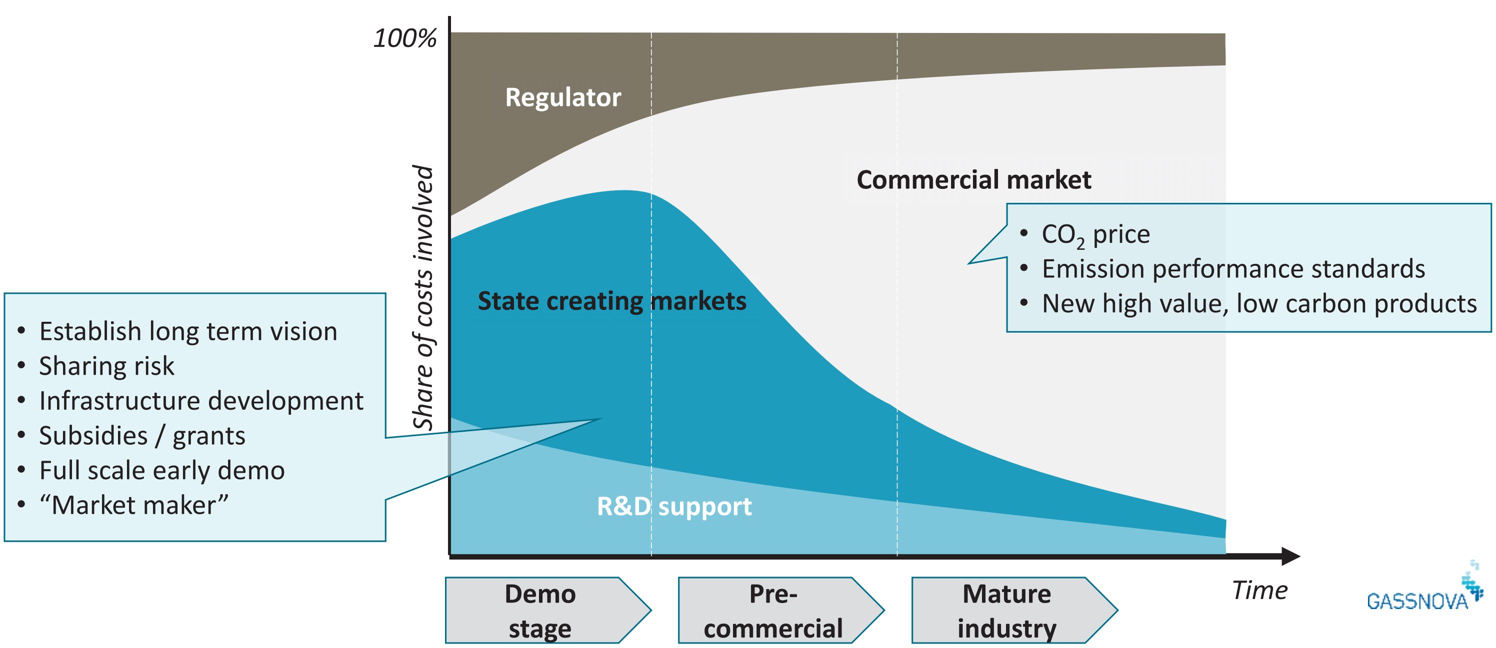
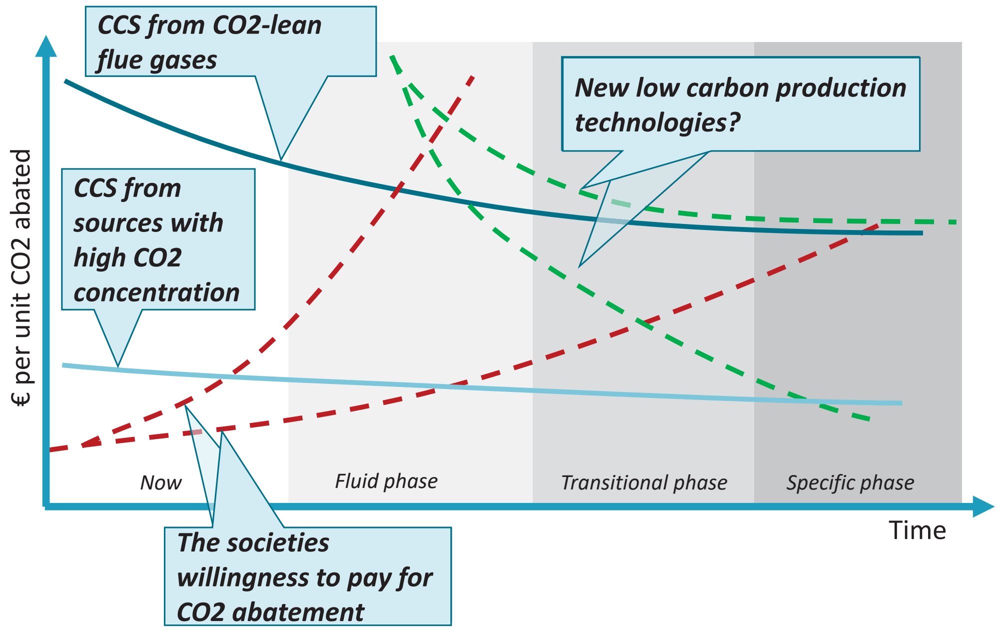
ADDITIONAL SLIDES

Early mover projects in CCS
A perspective on the role of governments



CCS Outlook – An illustration



Industries: Drivers for innovation in production technologies

- Energy efficiency
- Electrification
- Fuel switching
- Outdated plants

Possible side effect: Remaining flue gases have higher CO2-concentrations

GASSNOVA

The Kårstø CCS project (2005-2009)

- Politically and environmental driven project
- Purpose to reduce CO_2 emissions (and possibly EOR)
- Role of state; "To ensure start and funding of project"
- Amine – NGCC – separate projects

- No commercial incentives – PP to "deliver flue gas"
- No agreement on operations and ownership reached
- Basis for profitable NGCC lapsed

- FEED for capture almost finalised
- No technical showstoppers

GASSNOVA

Future; A decarbonised Norwegian industry?

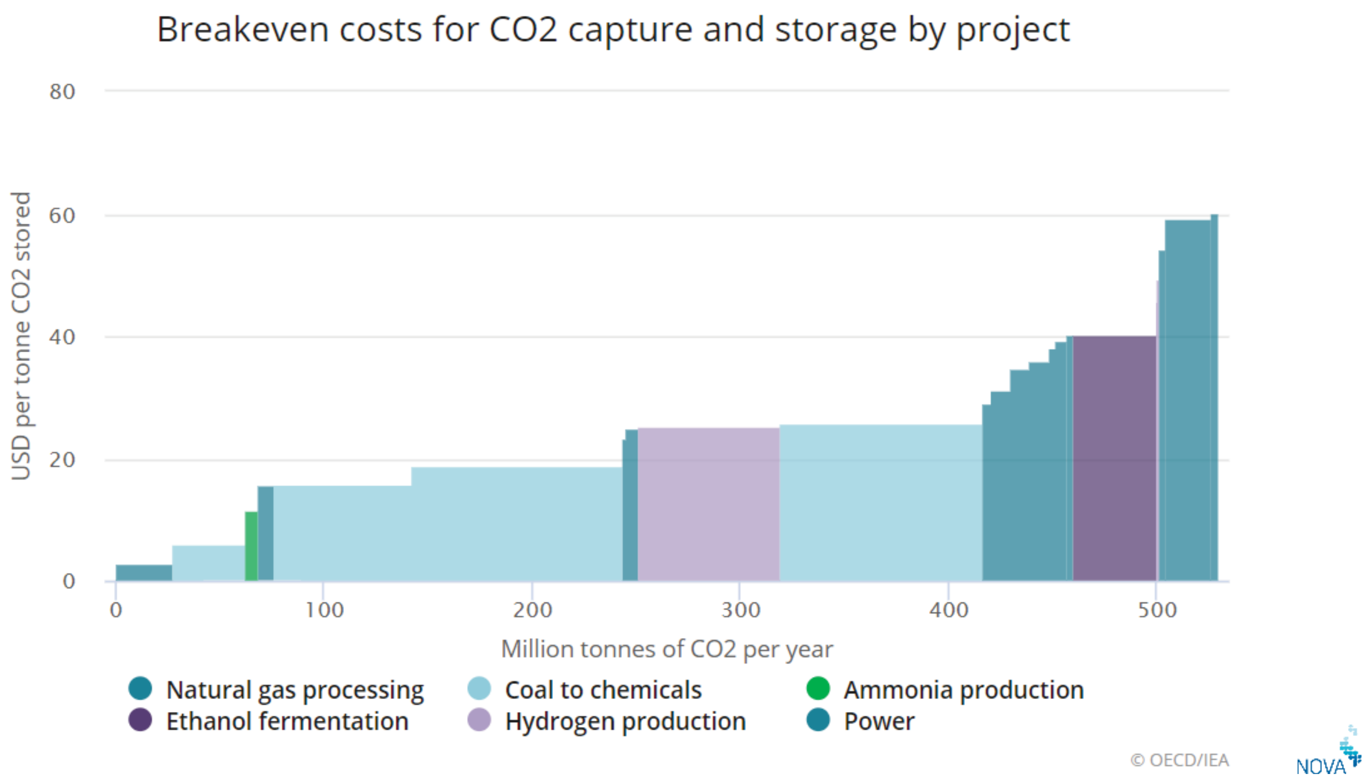
- Federation of Norwegian Industries – ROADMAP for decarbonisation
- Smaller industrial sites – Cornerstone in local communities
- Clusters; Close co-opetition established
- CCS synergies; Learning & infrastructure
- CLIMIT funded projects: Local solutions

→ CCS made possible for minor emission points?

Difference EOR driven CCS vs climate driven CCS

	EOR-CCS	cd-CCS
Driver	Diversification – added revenue stream	Avoid cost increase - Stay in business
Alternatives	Not produce, lost opportunity	Emit CO2, low cost, no risk! Switch to low carbon fuel!
Long term concern	Business as usual	Outlook for industry? Will CCS help anyway?
Storage	Market exists - that may purchase and care for CO2	No storage provider exists Insurance difficult
CO2 sources	Utilise available & cheap CO2	Most valuable process, least replaceable, with relevant volumes

SNOVA


Breakeven costs for CO2 capture and storage by project
80
60
40
20
0
USD per tonne CO2 stored
0
100
200
300
400
500
Million tonnes of CO2 per year
Natural gas processing
Coal to chemicals
Ammonia production
Ethanol fermentation
Hydrogen production
Power
© OECD/IEA
NOVA

Session 5: Value Proposition of CCS

5.1. The Potential Role and Value of CCS in the Decarbonization of U.S. Electricity, *Nils Johnson, EPRI*

The Potential Role and Value of CCS in the Decarbonization of US Electricity

Nils Johnson, Geoff Blanford, and John Bistline
Energy & Environmental Analysis, EPRI

CCS Cost Network Workshop
Palo Alto, CA
March 20, 2019

ELECTRIC POWER RESEARCH INSTITUTE

Initial Comments

- **LCOE is not a good indicator of the value of a technology in the power market.**
  - Market value depends on the generation mix, prices, policy, etc.
  - Systems models are useful tools for exploring technology value
- **CCS deployment in the power sector requires carbon constraints**
  - CCS will coexist with significant renewable deployment
  - Flexible CCS technologies will likely be important
- **CCS does have a significant role in decarbonization pathways**
  - Success will depend on fuel prices, policy, and the generation mix

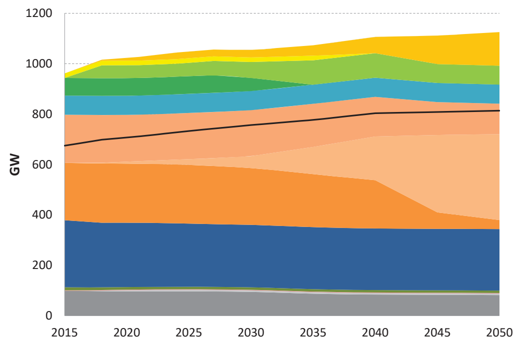
US-REGEN: EPRI's In-House Electric Sector and Economy Model

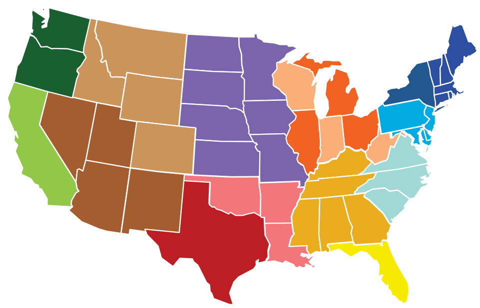
U.S. Regional Economy, GHG, and Energy

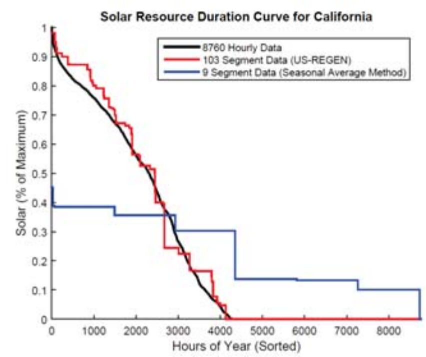
Capacity Expansion Economic Model, Long Horizon to 2050

Customizable State/Regional Resolution for Policy and Regulatory Analysis

Innovative Algorithm to Capture Wind, Solar, and Load Correlations in a Long-Horizon Model

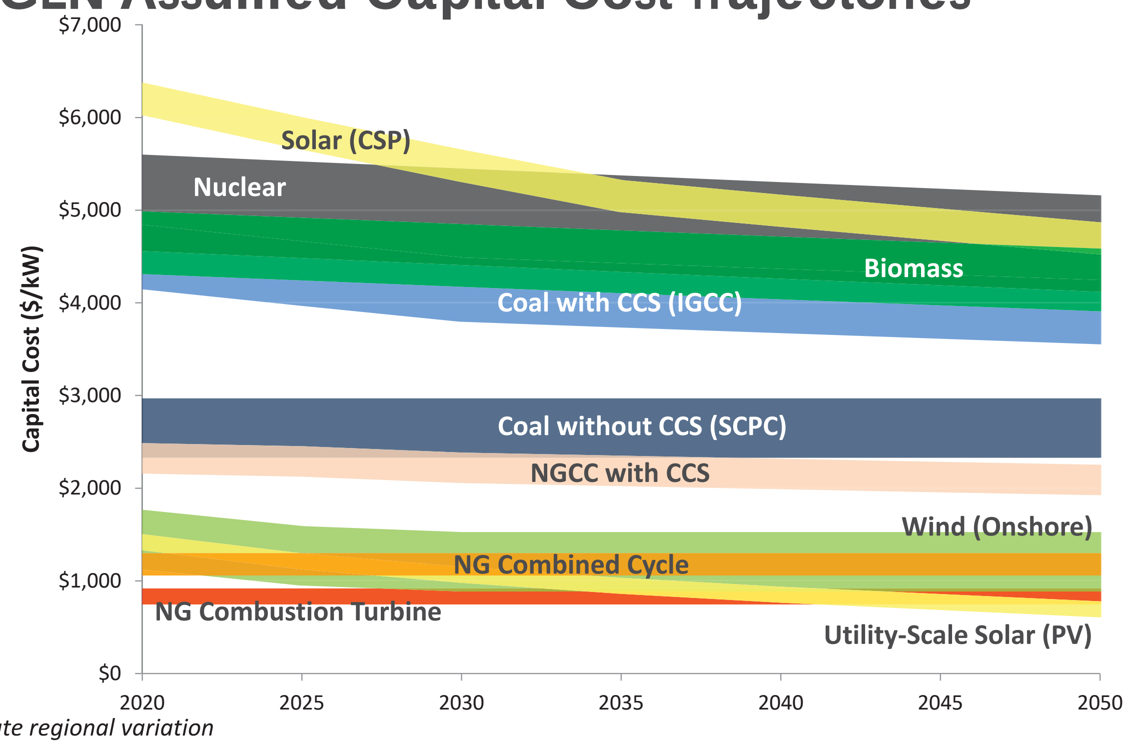






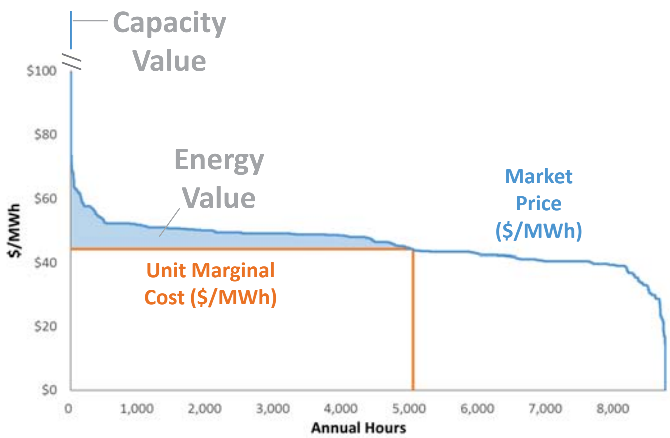
For more information, see our website at http://eea.epri.com

US-REGEN Assumed Capital Cost Trajectories



Ranges indicate regional variation

US-REGEN Captures Energy and Capacity Markets



Energy value
(dispatch when price exceeds short-run marginal cost)

Capacity value
(availability to meet peak demand)

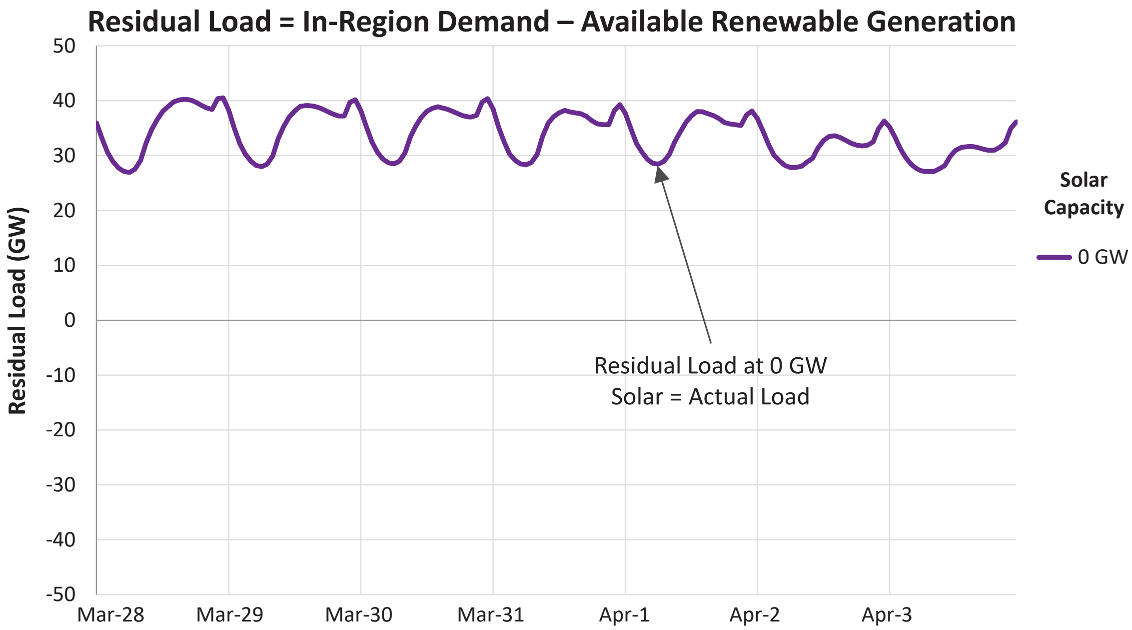
Modeled in US-REGEN

- Short-term responsiveness / inertia / grid management
- Becomes more important as share of intermittent generation increases
- "Thin" markets, value tends to saturate quickly
- Generally omitted from dynamic REGEN simulations (included in more detailed studies)

Ancillary service value
(e.g. frequency regulation, spinning and quick-start reserves)

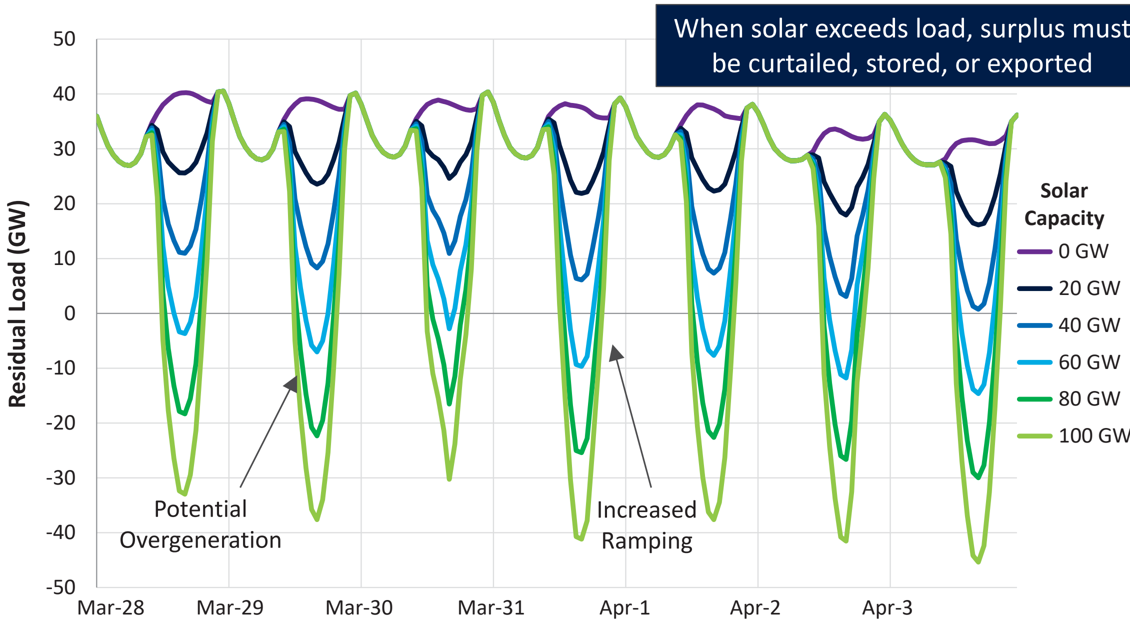
Why might CCS technologies be important in a carbon-constrained power market?

High renewable shares lead to adverse system impacts…



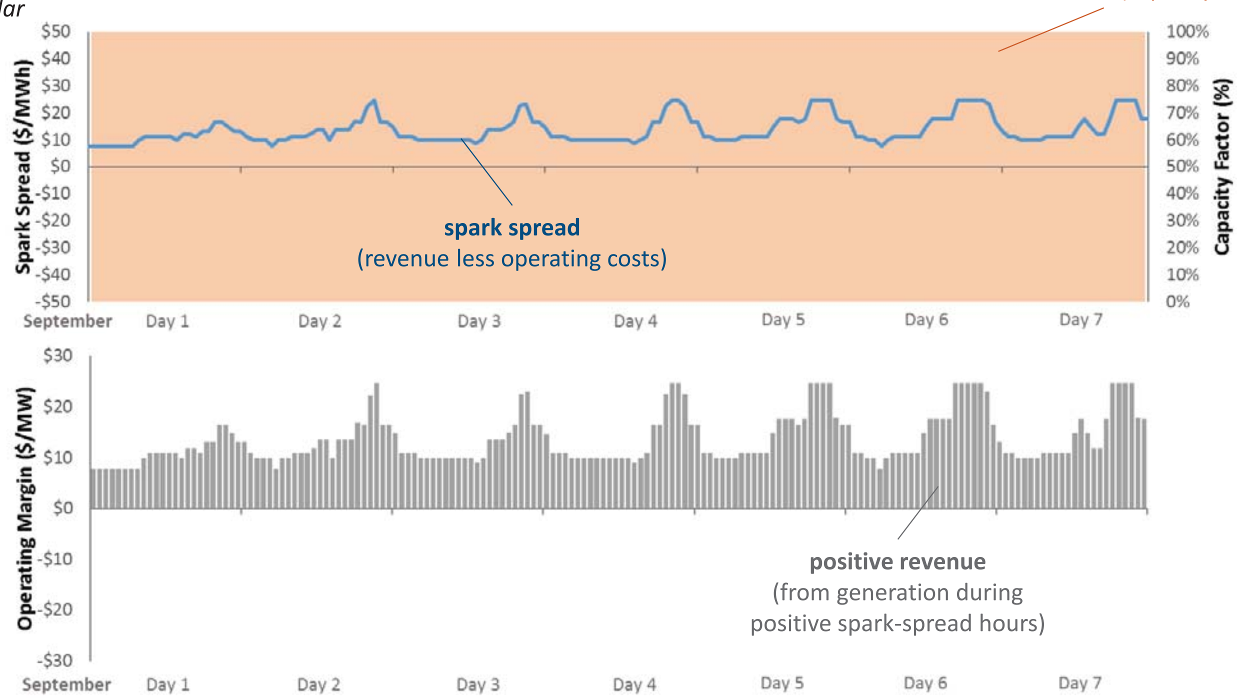
High renewable shares lead to adverse system impacts…

When solar exceeds load, surplus must be curtailed, stored, or exported



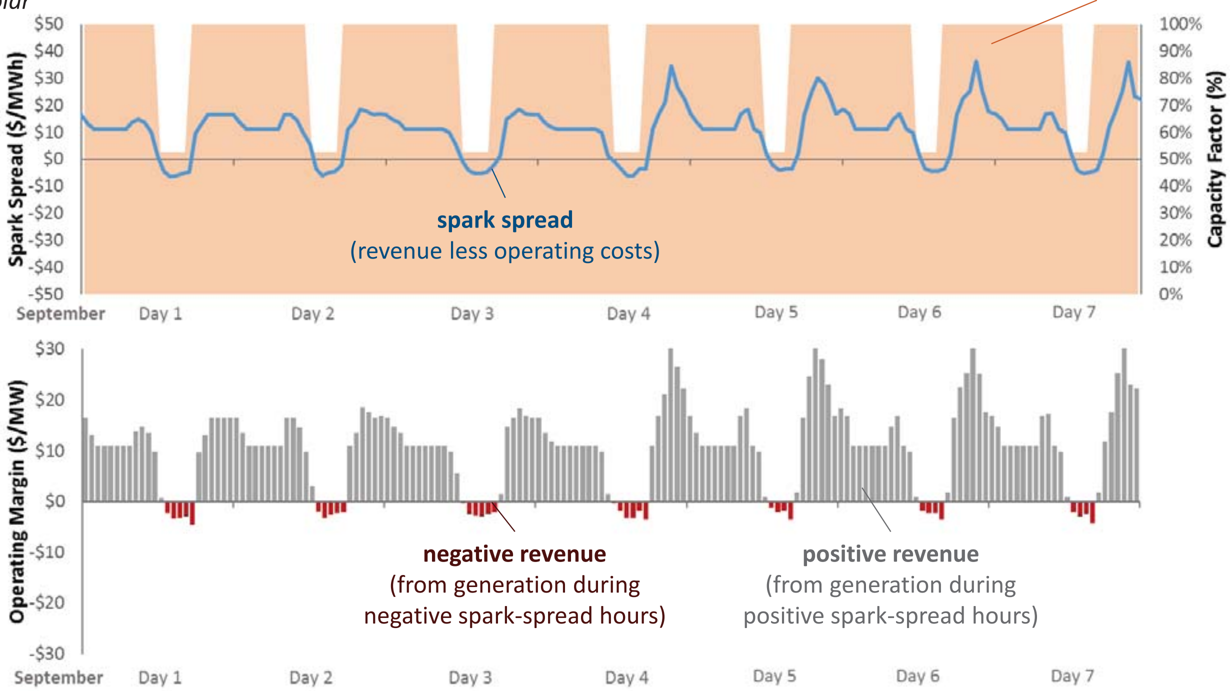
... with implications for dispatchable generators

0 GW Solar

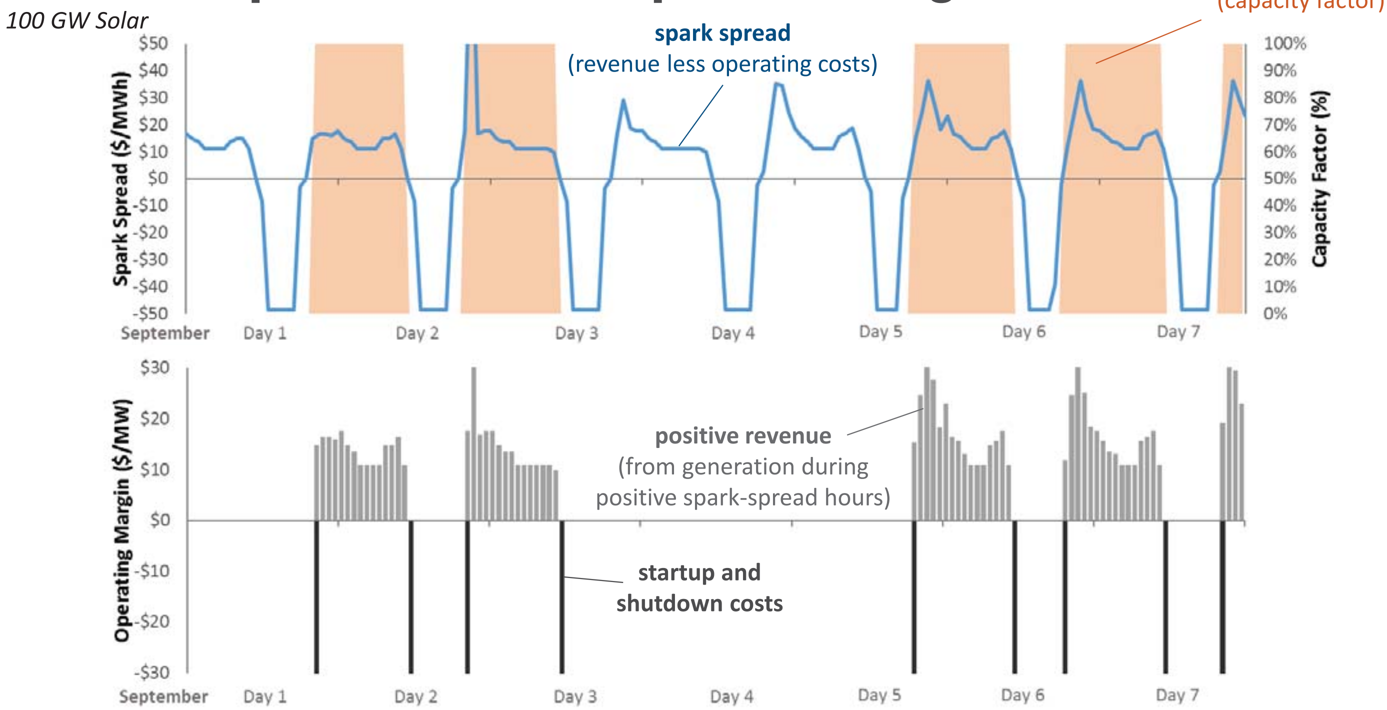


... with implications for dispatchable generators

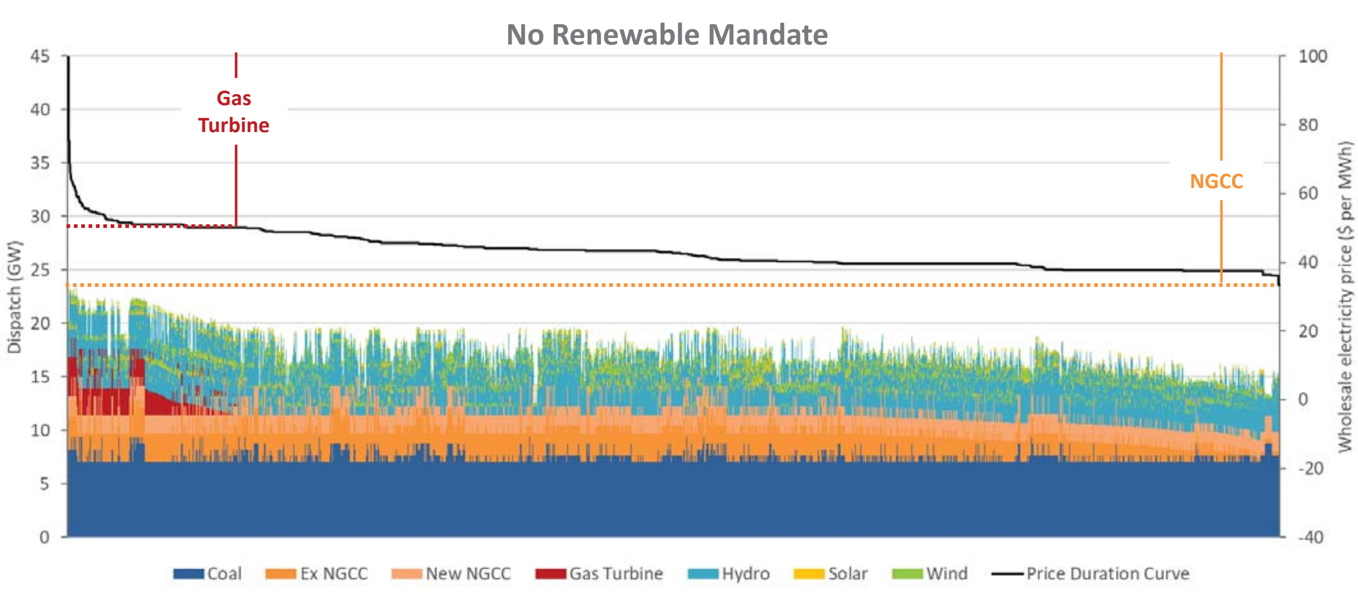
40 GW Solar



… with implications for dispatchable generators

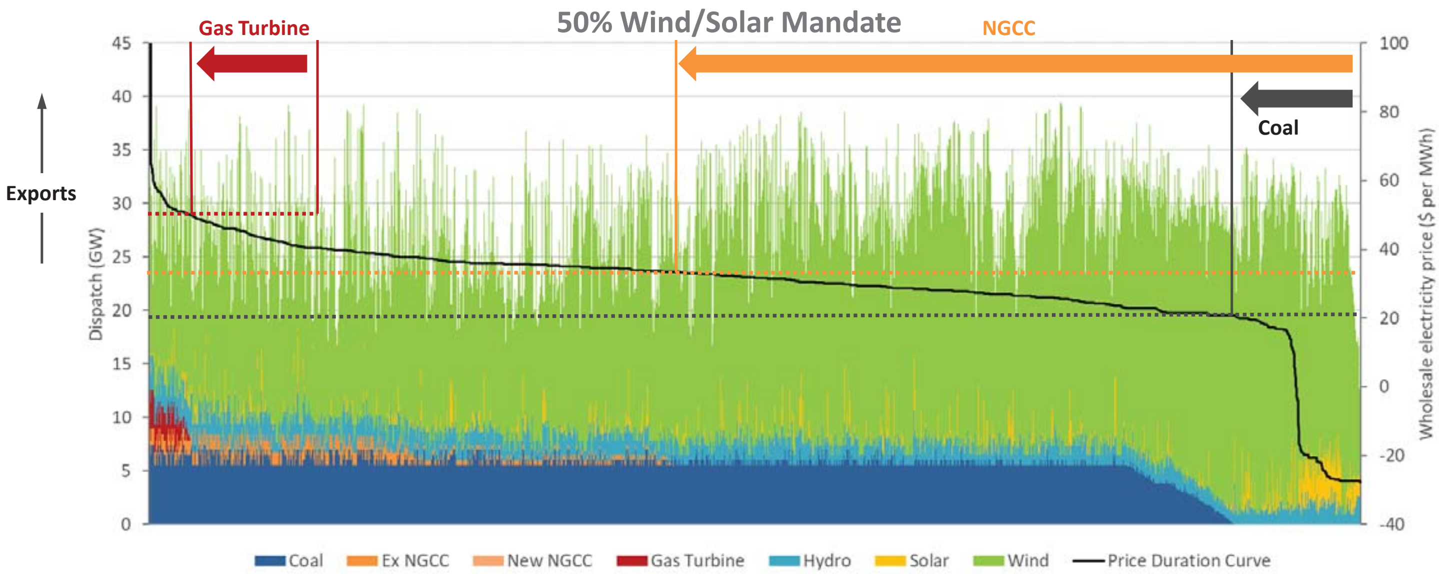


High renewable shares erode both prices & utilization



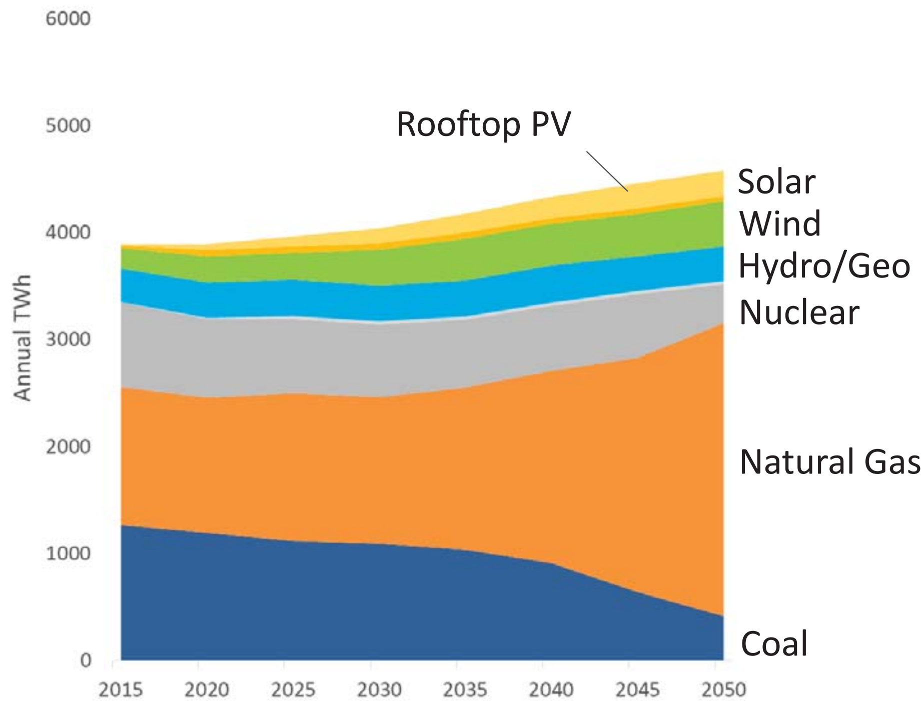
High renewable shares erode both prices & utilization

- **Very large renewable shares** displace generation at both gas and coal units
- **Price cliff** begins when all thermal units are offline (reduced portfolio diversity)

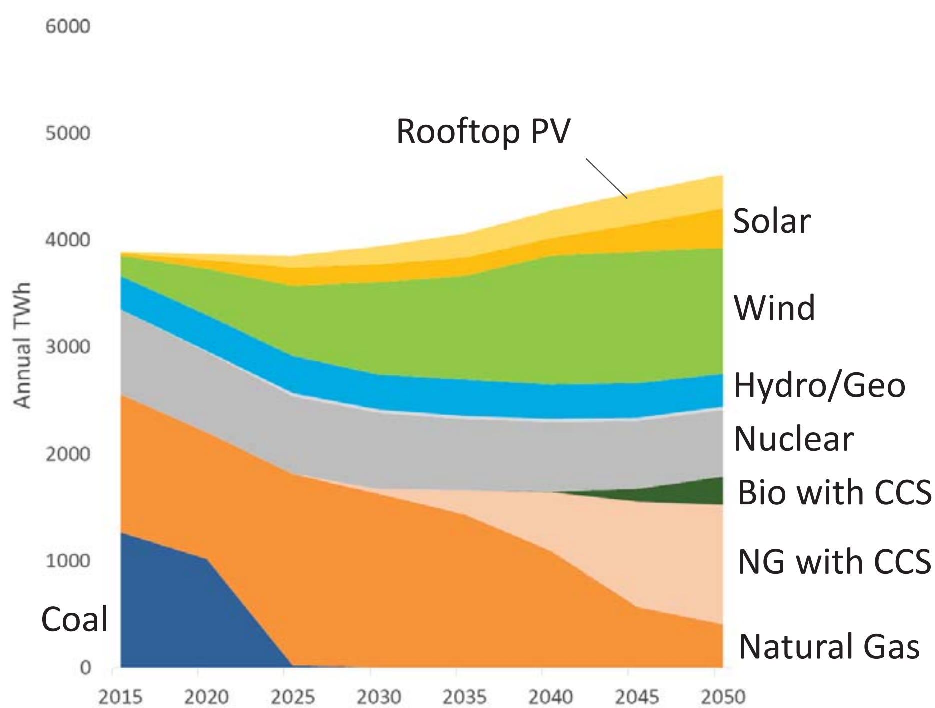


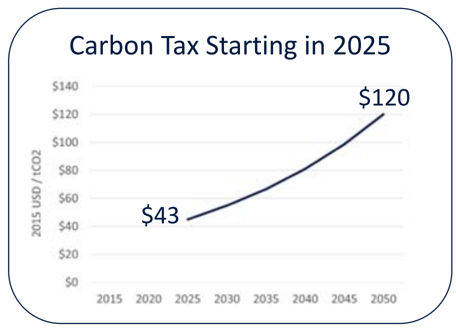
Optimal decarbonization pathways include CCS

Reference Electric Generation (low gas price)



Carbon Policy Electric Generation



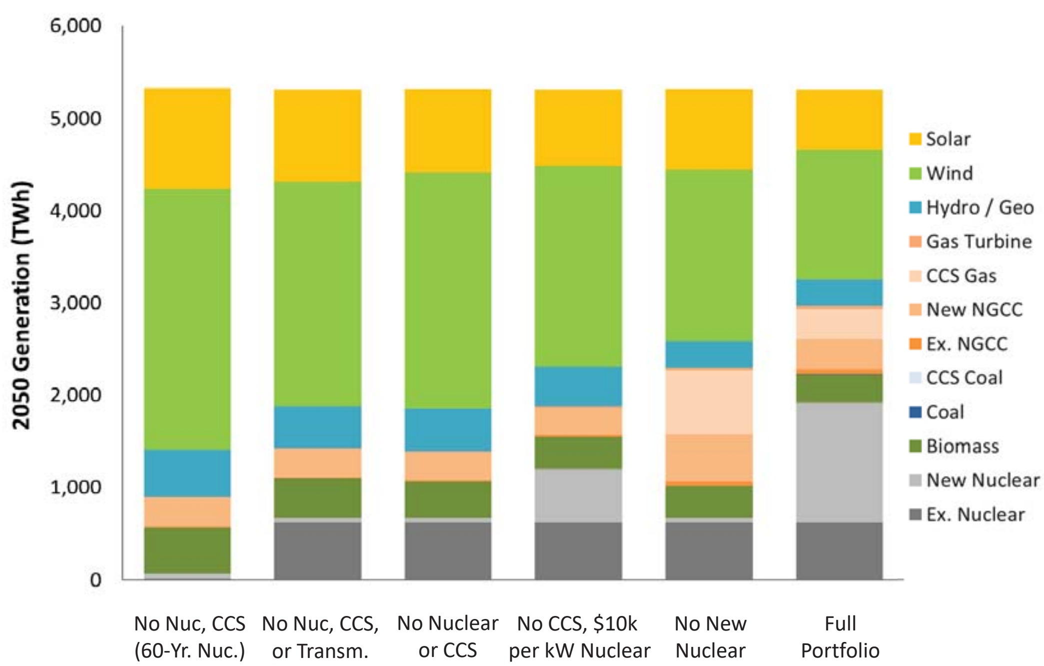


- Existing coal is retired rapidly (no CCS retrofits)
- New NGCC and wind/solar initially replace coal
- As carbon price rises, wind/solar saturates due to declining value and gas with CCS begins to replace NGCC
- Bio with CCS enters as a negative emissions option

Measuring Technology Value in terms of Policy Costs

How Valuable Is a Full Portfolio in Meeting Long-Term Goals?

95% Cap on US Power Sector CO_2 Emissions by 2050

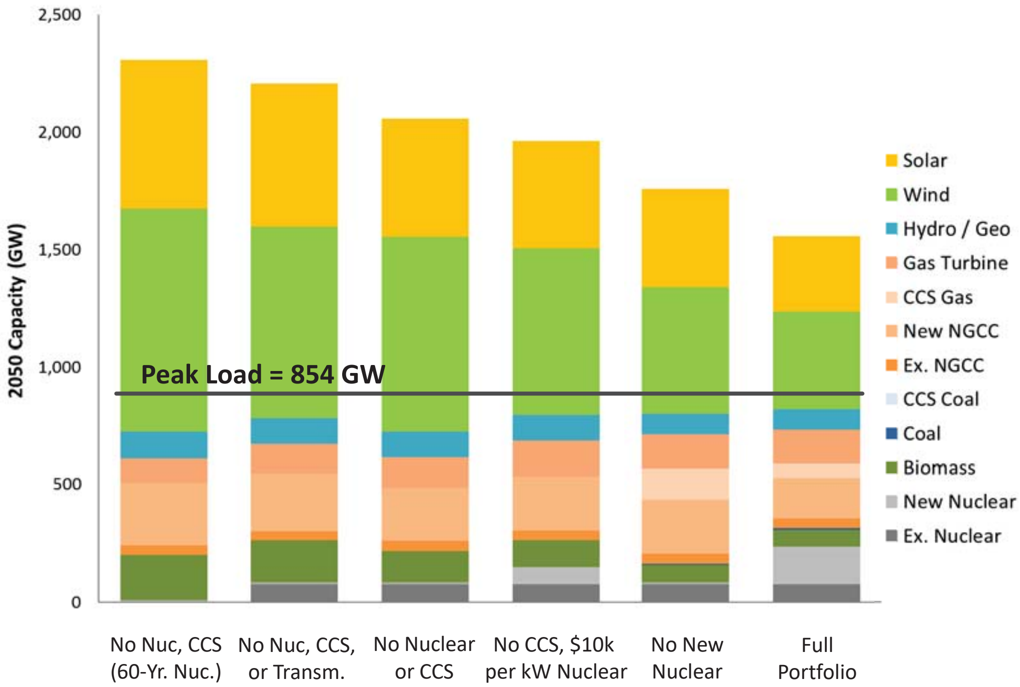


Observations

- Tradeoff between cost and technological preferences
- Important role of dispatchable low-carbon power
  - o Options: Existing nuclear and hydropower, gas (without/with CCS), new nuclear, biomass, geothermal
  - o Region-specific solutions
- Value of new and existing nuclear
- Gas likely to use the remaining emissions budget

Capacity Needs Increase under Limited Technological Portfolios

95% Cap on Power Sector CO_2 Emissions by 2050

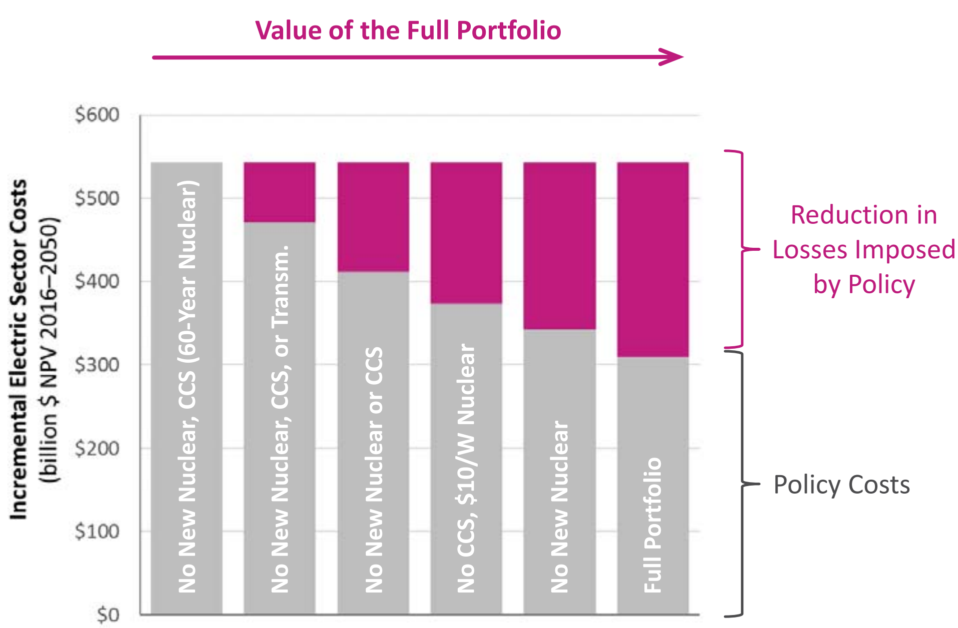


Observations

- Constrained portfolios require greater capital investments
  - o Decreasing returns to variable renewable energy
  - o Total capacity for the most limited portfolio scenario is almost three times peak load
- Dispatchable generation falls faster than installed capacity: Questions about markets, capacity needs, and financing high-cost, low-utilization assets under high renewable energy systems
- Caveat: No new storage investments in this analysis

Technological Cost and Availability Determine Policy Costs

95% Cap by 2050



Summary

- **CCS technologies can play a significant role in meeting long-term power sector decarbonization targets, but …**
  - … they will coexist with significant renewable generation and likely have high dispatch costs relative to other technologies
- **Flexible operation will be important as significant revenue will be derived from capacity and potentially ancillary services**
  - R&D needed to improve flexibility of these technologies
- **Success of CCS will depend on fuel prices, generation mix, and policy**
  - Low gas prices in the U.S. render coal w/ CCS unlikely unless supported by subsidies (e.g., 45Q)
  - CCS investors will face risks associated with uncertainties around fuel/CO_2 prices and renewable deployment

Together…Shaping the Future of Electricity

5.2. An Updated View of the Role of CCS in the Australian National Electricity Market, *Andy Boston, Red Vector and Geoff Bongers, Gamma Energy Technology*

MEGS Modelling of the Australian National Electricity Market

An Updated View of the Role of CCS

Andy Boston

Geoff Bongers

Gamma Energy Technology
EXPERIENCE THINKING INNOVATION

REDVector

Background

This work is focused on **Australia's NEM** and was undertaken by:

Prof Geoff Bongers CPChem GACID
Director of Gamma Energy Technology
An Australian Energy Consultancy

Andy Boston CEng
Director of Red Vector
A UK Energy Consultancy

Steph Byrom
Gamma Energy Technology

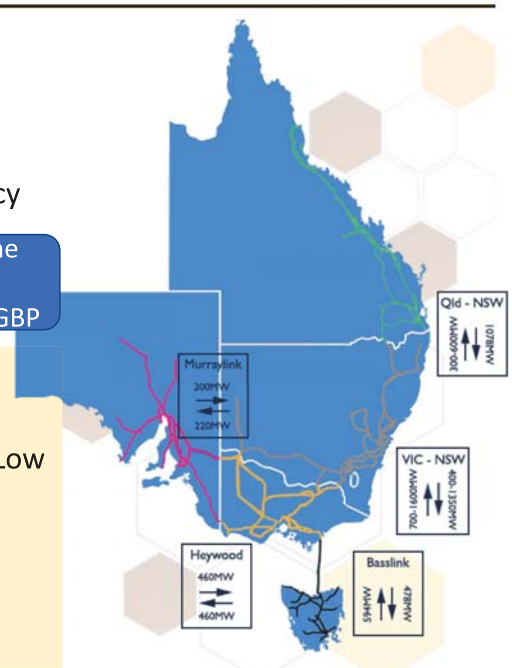
This presention uses the Australian dollar.
1 AUD = 0.7 USD = 0.53 GBP

The authors wish to acknowledge financial assistance provided by:

Australian National Low Emissions Coal Research and Development (ANLEC R&D). ANLEC R&D is supported by Australian Coal Association Low Emissions Technology Limited (ACALET) & the Australian Government

Coal Innovation New South Wales which is part of the government of New South Wales

University of Queensland through the UQ-SDAA Project which is supported by ACALET.



MEGS: Modelling Energy & Grid Services

Gamma Energy Technology
EXPERIENCE THINKING INNOVATION
REDVector

- Energy must balance. — **Conservation of Energy**
- There is sufficient supply of reserve and response services. — **Managing imbalances**
- There is sufficient inertia — **Stability: time to react**
- There is sufficient reliable capacity to meet peak demand — **Keeping the lights on!**

Whilst minimising short run cost
- **Fuel**
- **Carbon Storage**
- **Variable**
- **Start-up**

And optimising storage

Adjusts capacity to maintain Loss of Load Hours

And it's FAST **1,700 time-steps for NEM in 5 minutes**

MEGS Methodology

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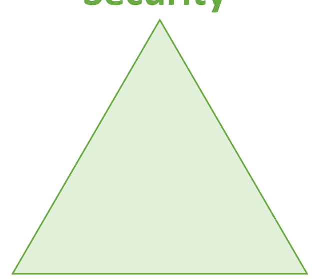
REDVector

MEGS takes care of most important grid services (sufficient frequency response, reserve, system strength, inertia, firm capacity) **so the lights stay on**

Security



Run MEGS, add a technology
Run again…

… -Delta TSC gives the **value** of that technology to the system

Carbon **Cost**

MEGS **reports total system carbon emissions** and State by State emissions

… -Delta TSC/ Delta Carbon gives the **abatement cost** of that technology in $/t

MEGS minimises short run costs and **reports Total System Cost (TSC)**

Abatement Cost Curve Comparison

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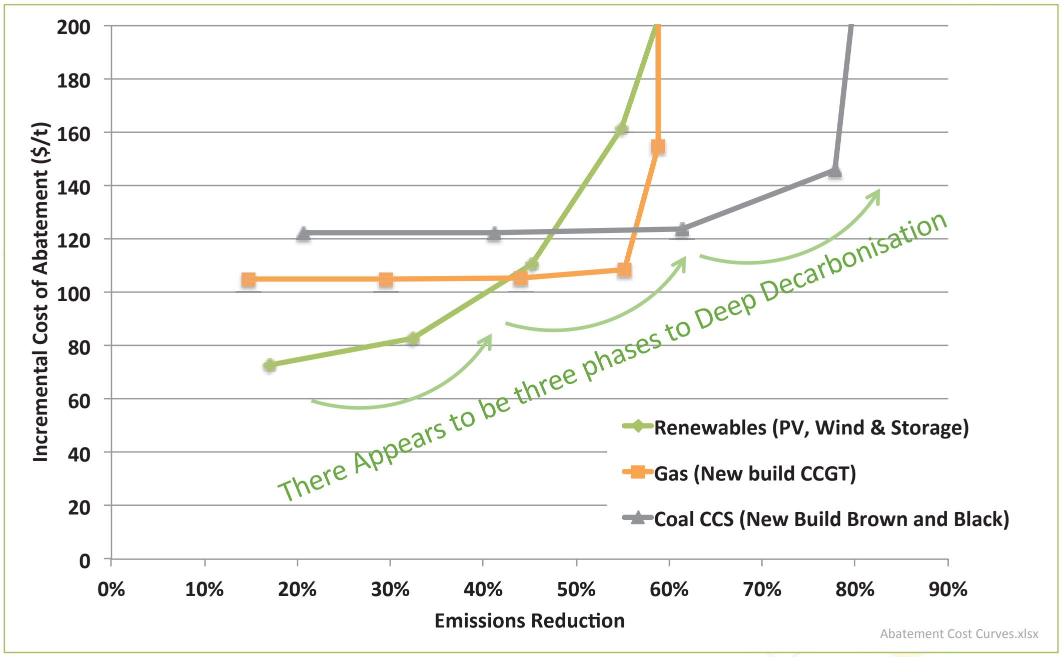
MEGS explored 3 pathways to decarbonisation by either building just renewables, just gas or CCS alone.

The plot shows the cost of getting to that emissions reduction on each path.

- Renewables starts low cost but soon becomes expensive.
- Gas cannot pass 60%
- CCS starts more expensive but can access 80%



Phase 1 Messages

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It is important to consider the whole system

- The value of a technology depends on how much of that technology has been added already

A secure grid requires a range of essential services

- To survive existing plant will have to become flexible
- New CCS will have to load-follow

The solution will be diverse and includes renewables, storage, CCS and unabated gas.

- Each State is different!

Providing reliable low carbon electricity comes at a cost

- New build does not pay for itself!
- System planners must minimise TSC

Recent Modelling

New Questions

How does CCS Cost reduction help?

What is the role of BECCS?

What do the Renewable Energy Targets do?

Does Concentrating Solar Power have a role?

What are nuclear spiders? !!

What if CO_2 storage is limited?

Competition for CCS in the Decarbonisation Race??

Methodology

MEGS was run stochastically for 250 scenarios.

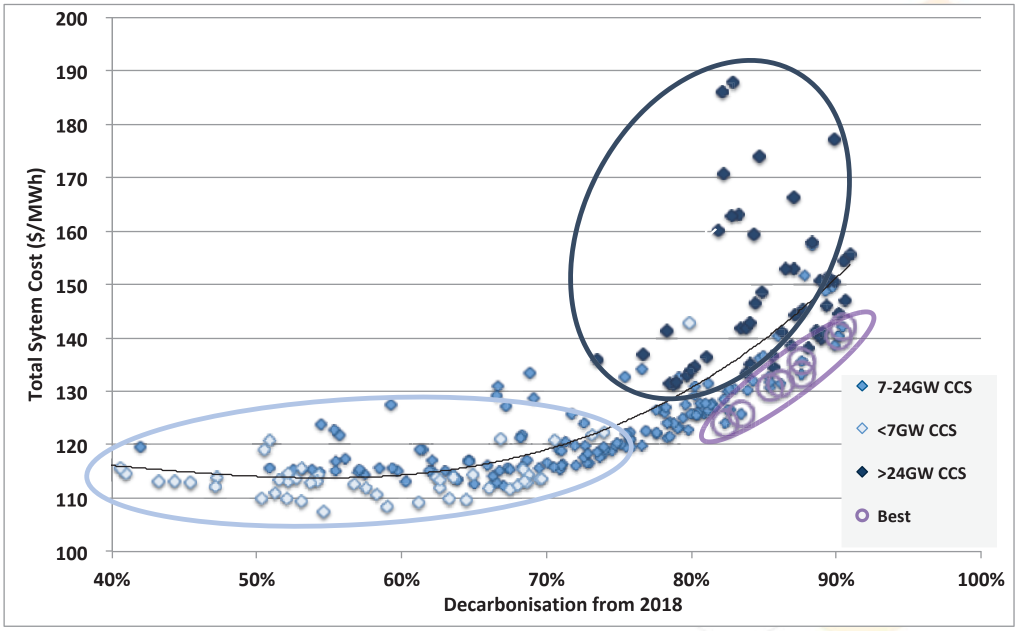
Each scenario chose a random build of Renewables, Gas and Coal-CCS.

The best scenarios were examined

Scenarios with low CCS build (light spots) did not achieve deep decarbonisation

Scenarios with high CCS build (dark spots) were mostly very expensive

The "Goldilocks" scenarios all had close to 20GW of CCS



CCS cost sensitivity

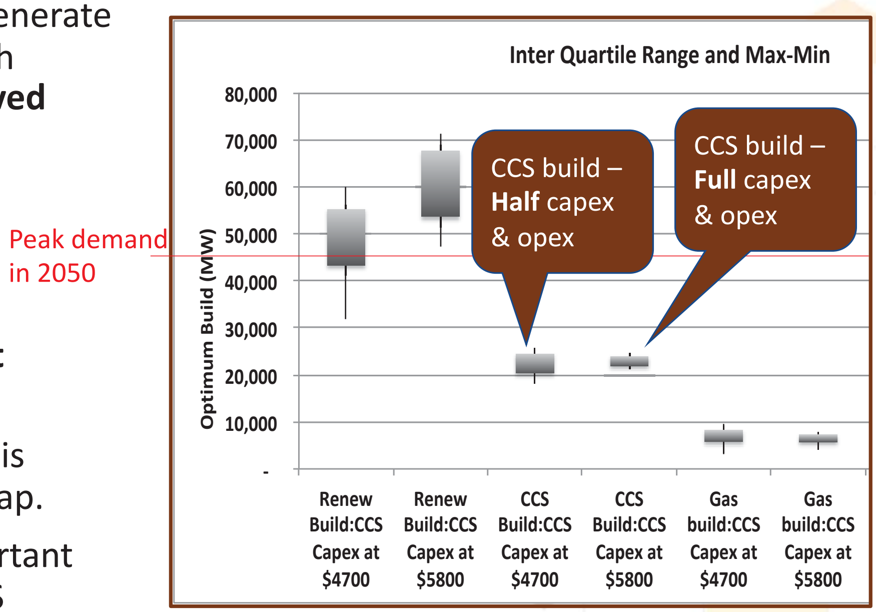
MEGS was run a second time to generate stochastic scenarios, this time with capture plant capex and opex **halved**

Halving CCS cost **reduced cost to consumer** by $20/MWh

However the plant mix remained consistent, **no more CCS was built because costs were lower**

20GW of CCS was built because it is necessary, not because it was cheap.

Renewables still have a very important role to play alongside "cheap" CCS



Analysis of best scenarios

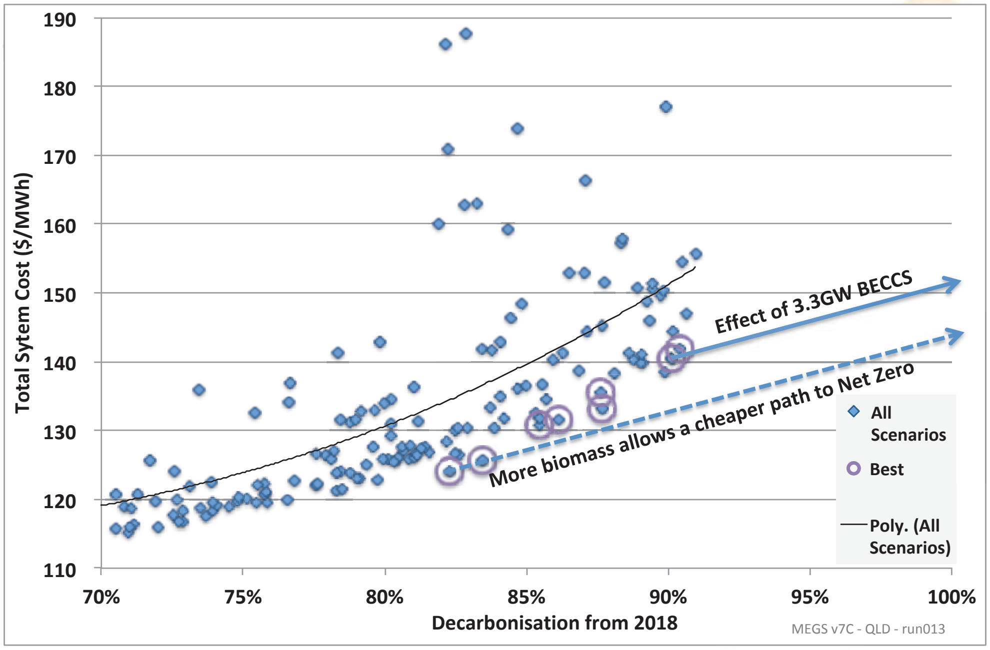
A Role for BECCS

Australian State emission targets are for Net Zero by 2050

The slippage from post combustion capture and the residual emissions from gas mean negative emissions are required.

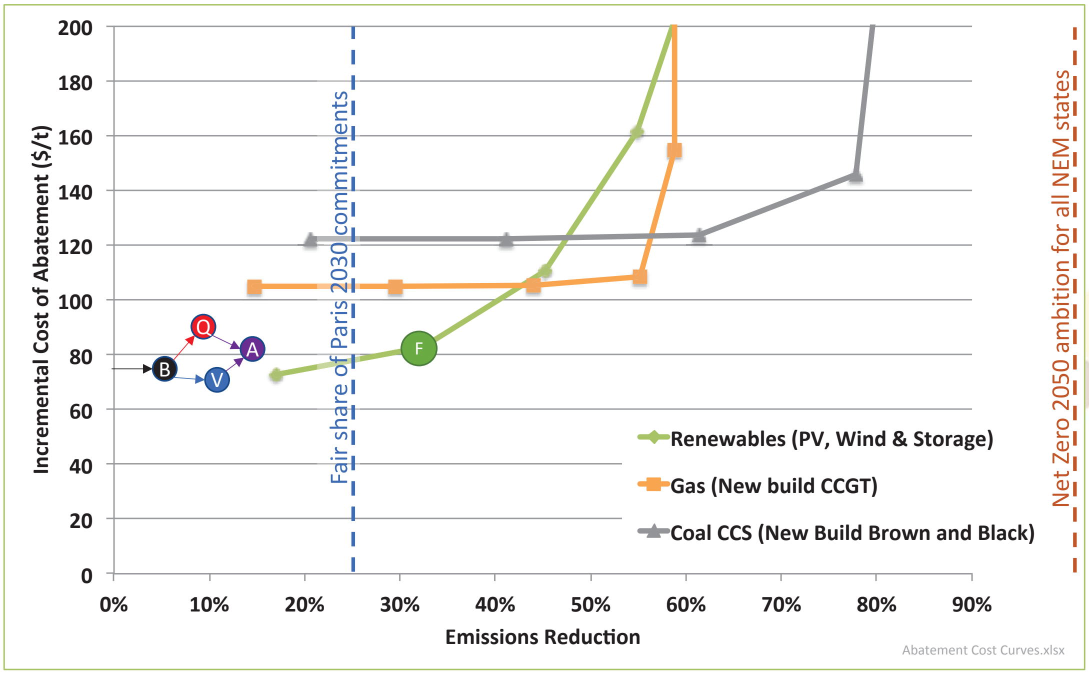
Substituting biomass for coal in 3.3 GW moves our current optimal solution to Net Zero.

If more biomass were available at assumed costs (Drax quote £75/MWh) there are potentially some cheaper solutions to Net Zero



Are Renewables and Nuclear Competitors?

What do the RETs do for us?



B Base case (National targets)

Q Base + Queensland RET

V Base + Victoria RET

A Base + All RETs

F Finkel 2030 (The Chief Scientist's Proposal)

The RETs are relatively small steps, much more will need to be done to meet Paris 2030

To achieve the Net zero ambition by 2050 requires deployment of CCS in the early 2030's.

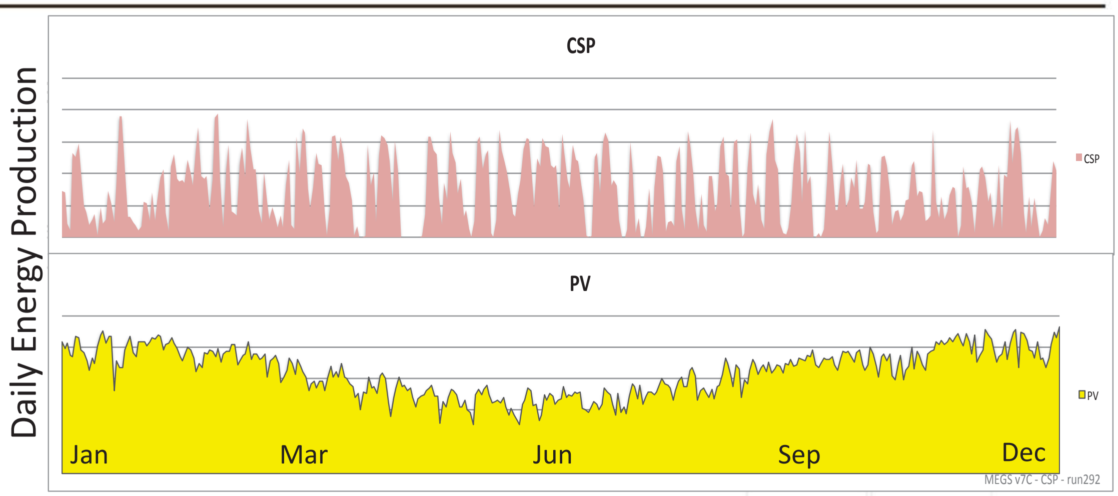
What About Concentrating Solar Power?

CSP Benefits

- **Delivers grid services**
- **Higher load factor**
- **Can generate overnight**

PV Benefits

- **Cheap**
- **Can deploy near demand**
- **More consistent – it generates every day**



On balance MEGS chooses PV over CSP, CSP isn't consistent enough to be a threat to CCS in Australia
With aggressive cost reductions for CSP it may play a role, but is no substitute for CCS

Nuclear Options from 2030

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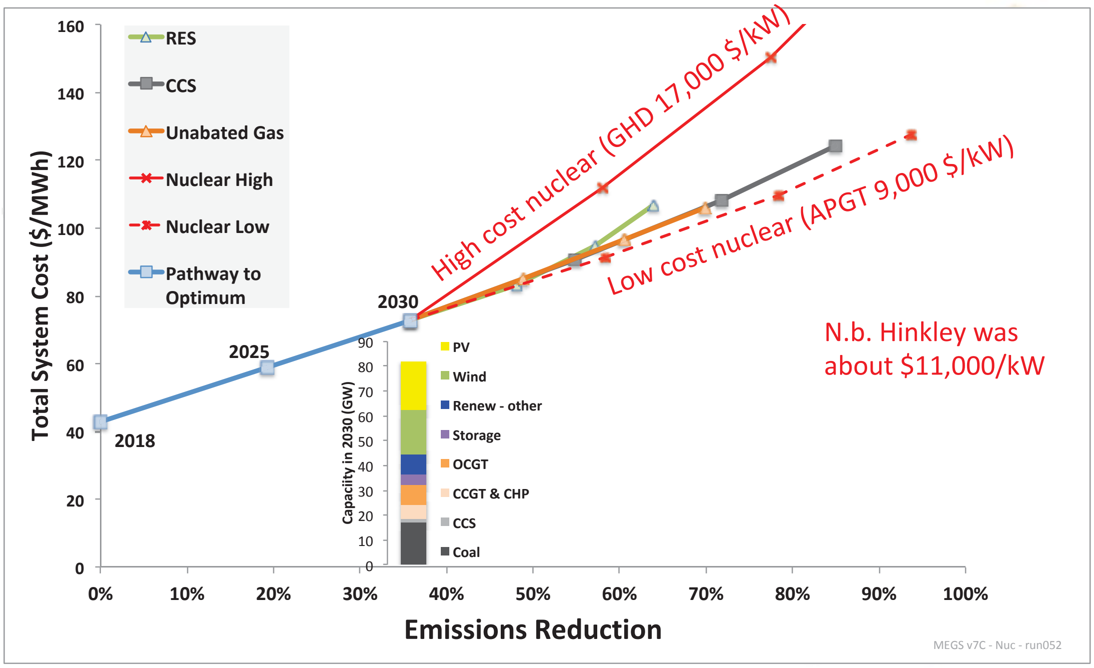
Assume the pathway to 2050 optimum is followed until 2030

Post 2030 tracks are for single options

All conventional options are bracketed between the lowest (APGT) and highest (GHD) estimates of nuclear

Nuclear Low competes head to head with CCS, and can decarbonise further

However nuclear before 2040 is very unlikely, by which time CCS should be established



Injection Rate Constraints

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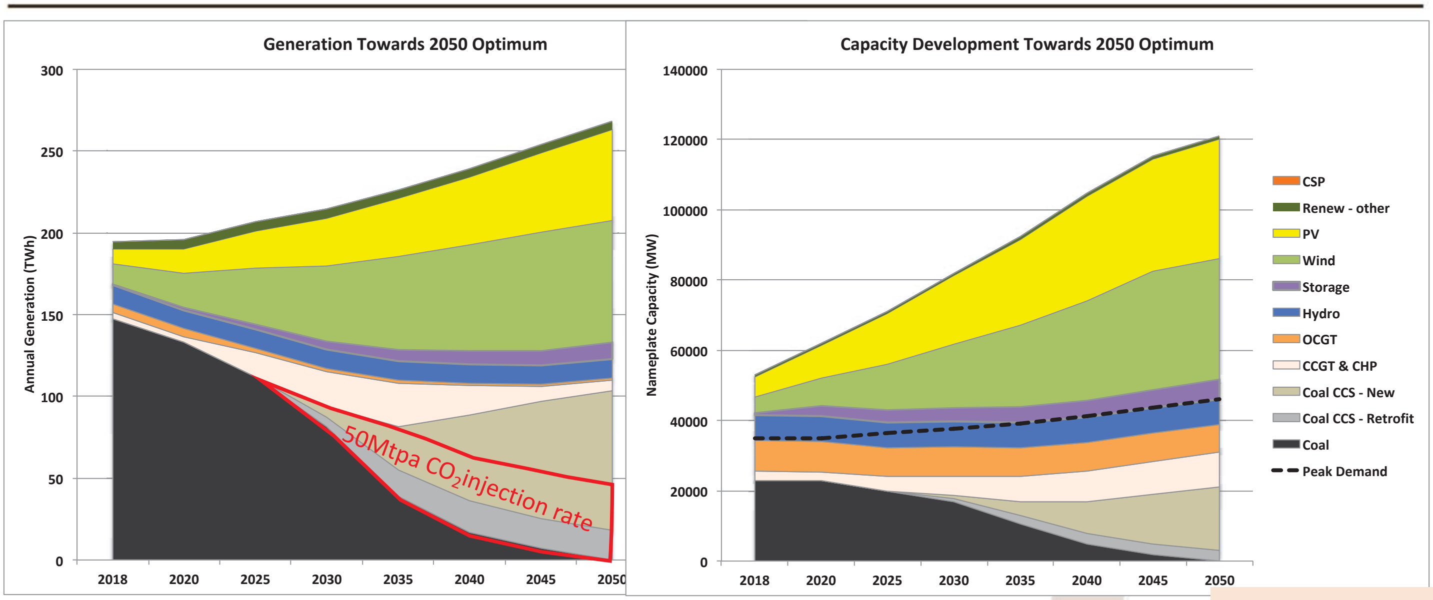


The Energy and Capacity pathways are illustrated
but what if the currently estimated 50Mt/year were the limit?

May need nuclear
May need BECCS
May need gas CCS

Conclusions

MEGS is ideal for modelling value of CCS vis a vis other technologies

It consistently chooses 20GW of CCS in its optimum scenarios

Cost reductions do not increase role for CCS, but significantly help consumer

If biomass is available 3-4 GW of BECCS could help achieve Net Zero

The current Federal and State Renewable Targets are only very small steps and do not threaten CCS

CCS development does not threaten renewables, both are essential

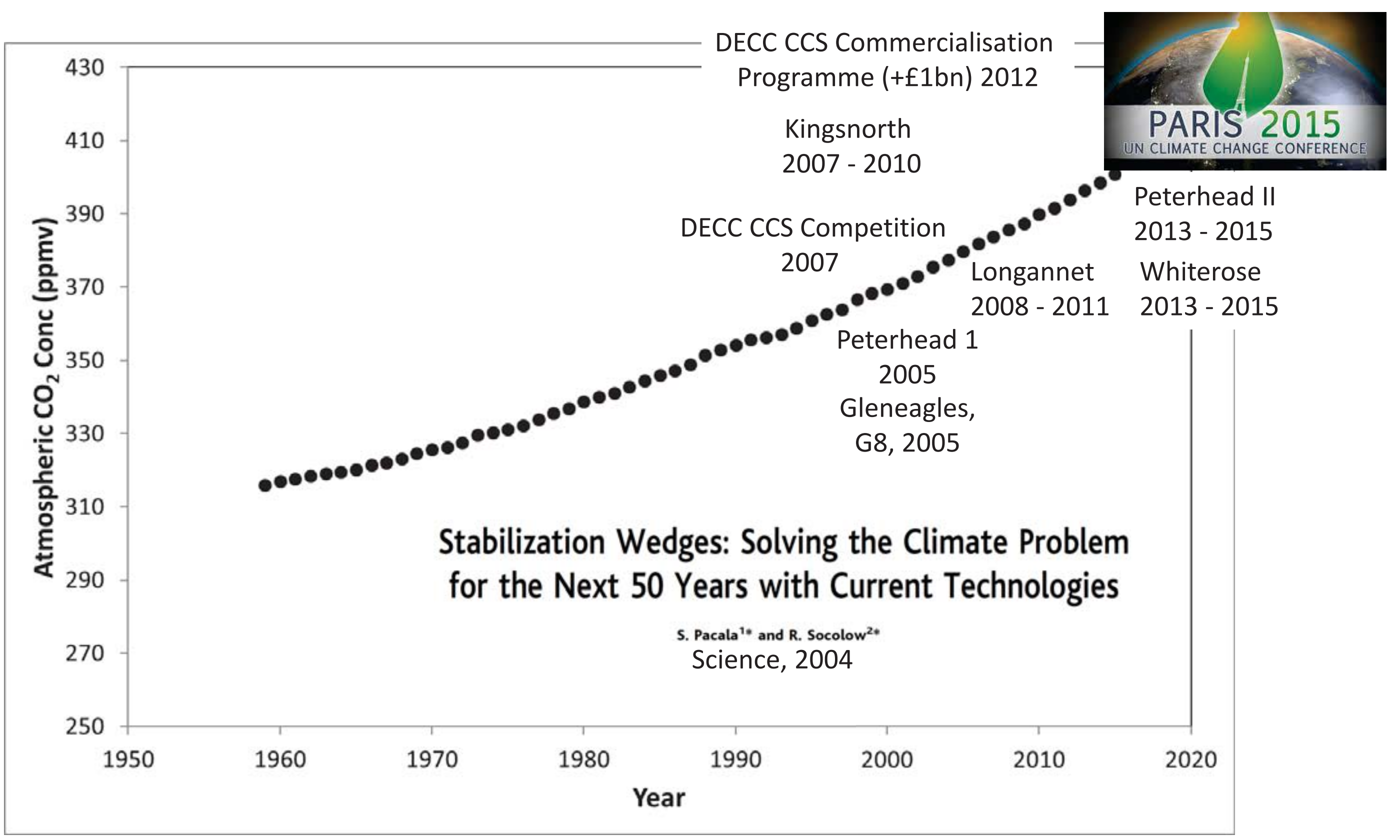
Nuclear could compete head to head with CCS, but unlikely before 2040

If optimal Coal CCS is to be realised then more injection sites need to be found

5.3. What is the Value of CCS? *Niall Mac Dowell, Imperial College London*

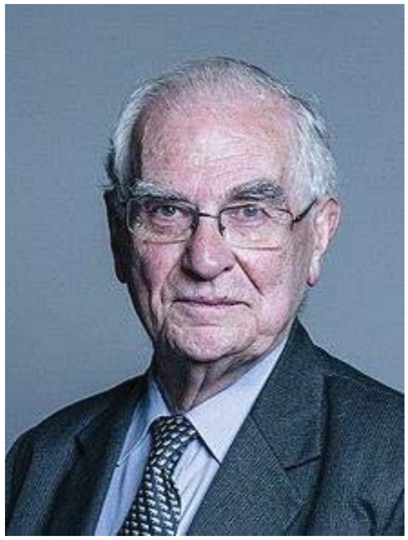
What is the value of CCS?

Niall Mac Dowell
Imperial College London
niall@imperial.ac.uk
@niallmacdowell



Data: NOAA, https://www.esrl.noaa.gov/gmd/ccgg/trends/index.html

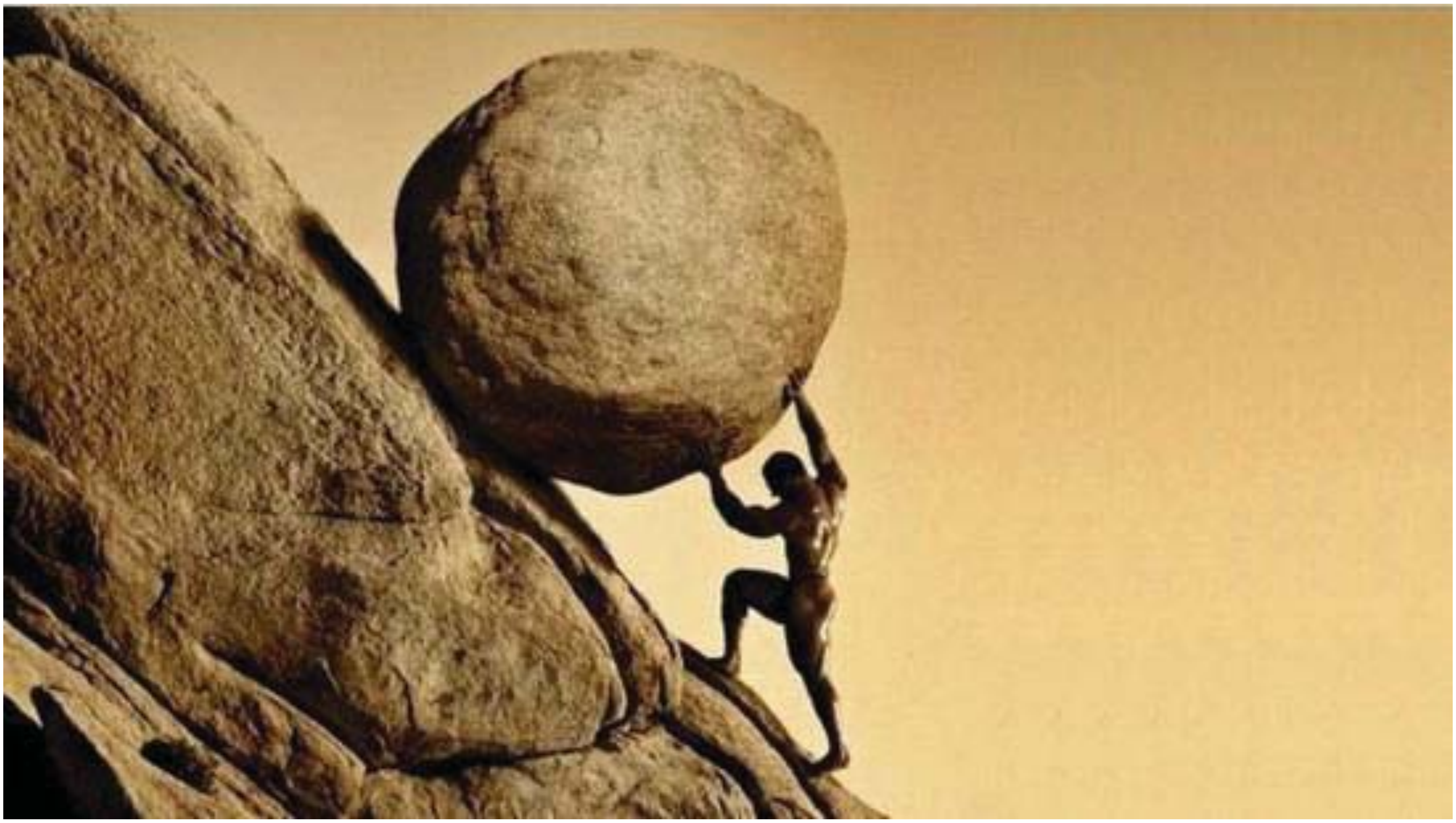
The Lord Oxburgh

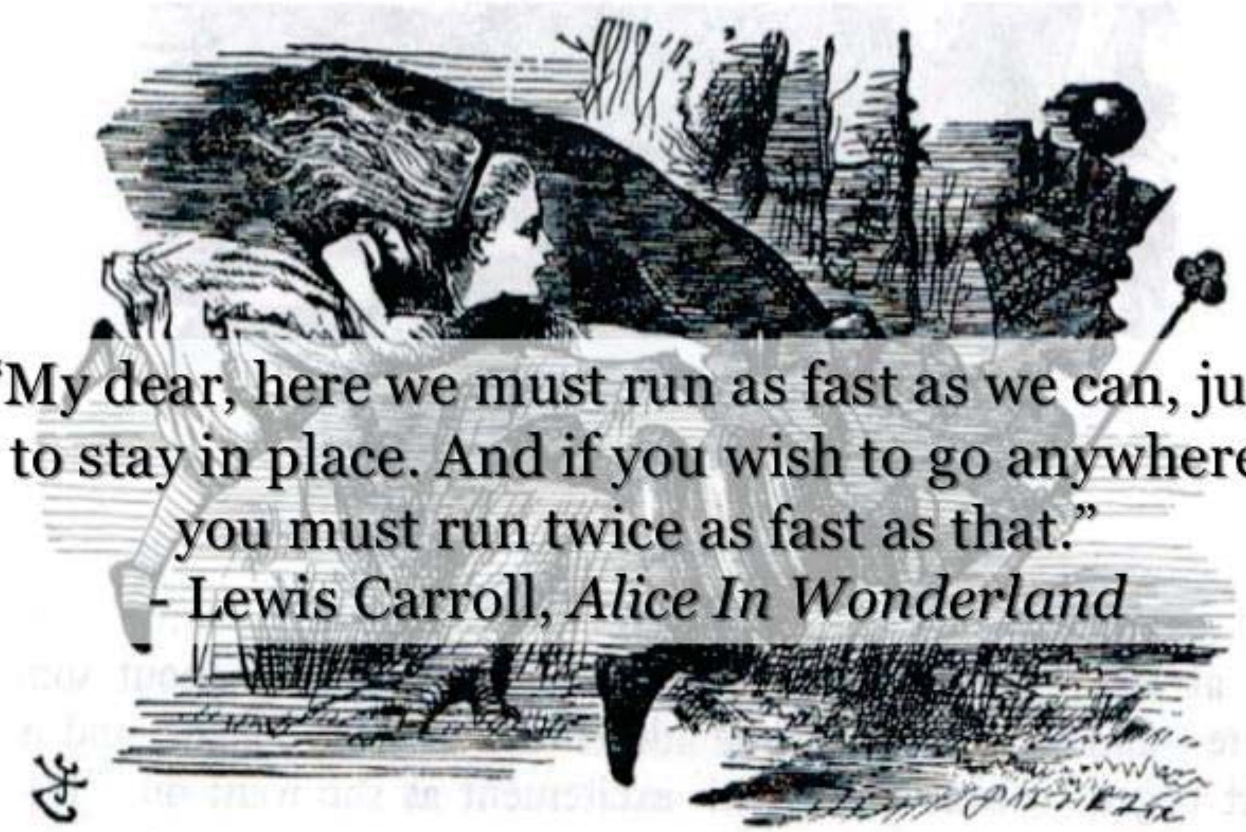


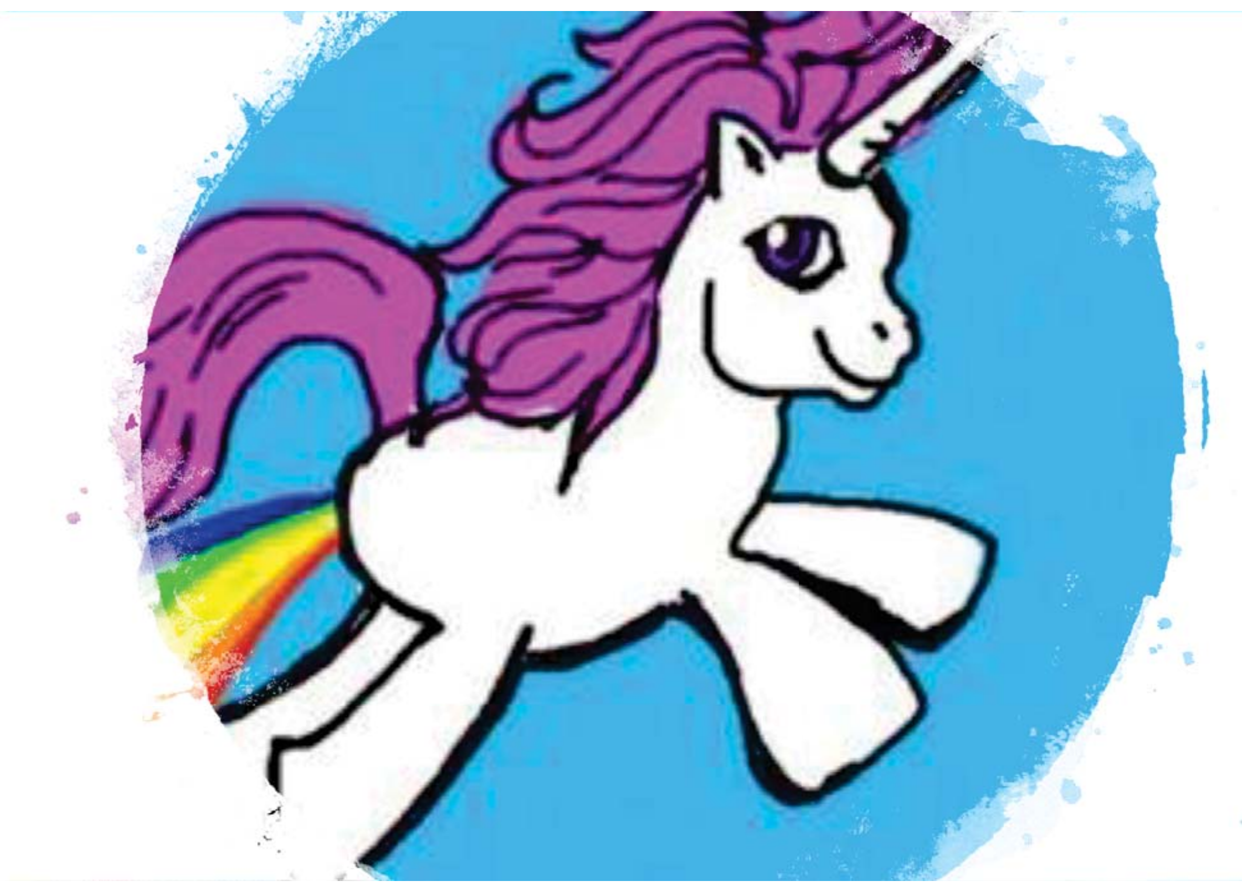
"CCS is an orphan technology. It has numerous well-meaning aunts and uncles but no parents."

The Right Hon. Claire Perry MP

"We need CCUS, [but] it remains a pre-commercial technology. [In the UK], we want to have the option to deploy CCUS at scale during the 2030s, subject to costs coming down "



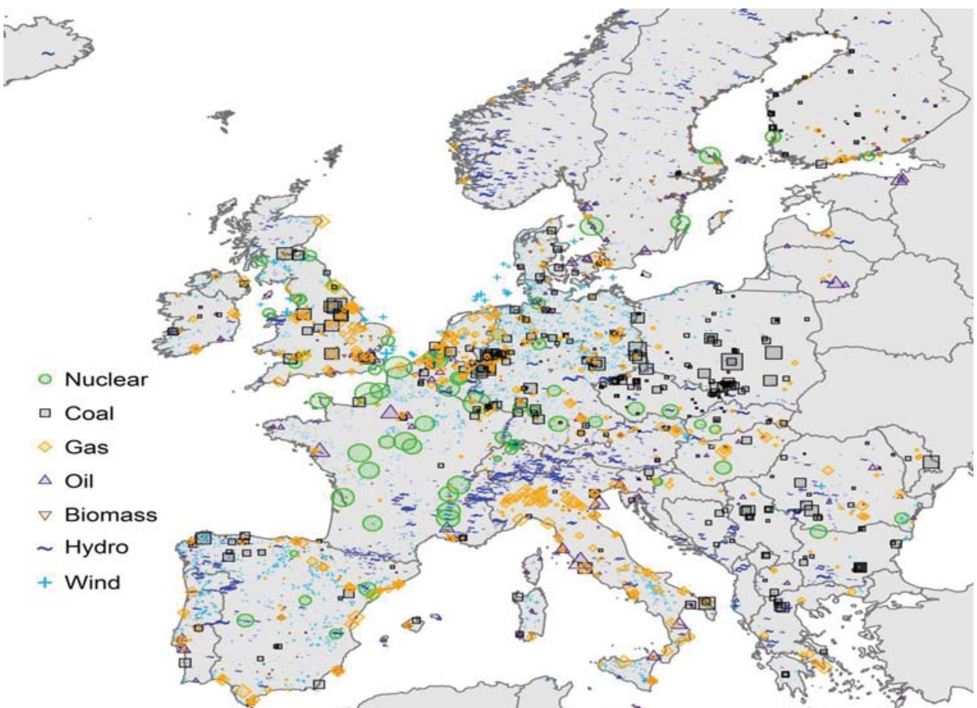

"My dear, here we must run as fast as we can, just
to stay in place. And if you wish to go anywhere
you must run twice as fast as that."
- Lewis Carroll, *Alice In Wonderland*



Some key questions

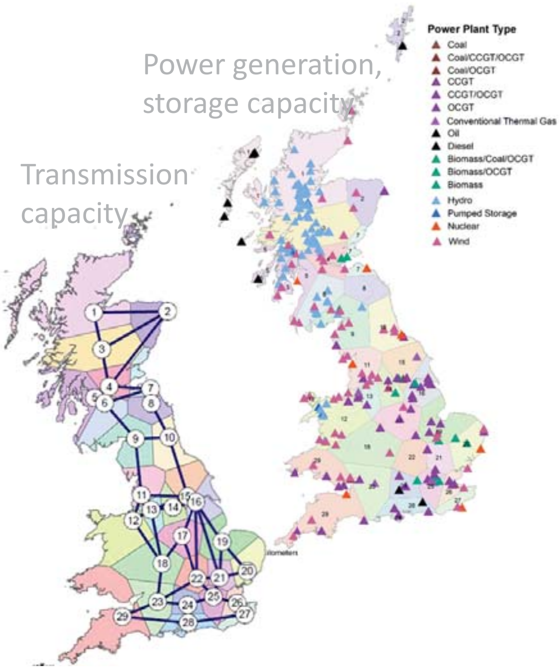
1. Does CCS *have* any value?
2. How helpful are cost targets?
3. Should we believe in unicorns?
4. Other kinds of value?

One ring to rule them all…?



Bassi et al., "Bridging the gap: improving the economic and policy framework for carbon capture and storage in the European Union", 2015

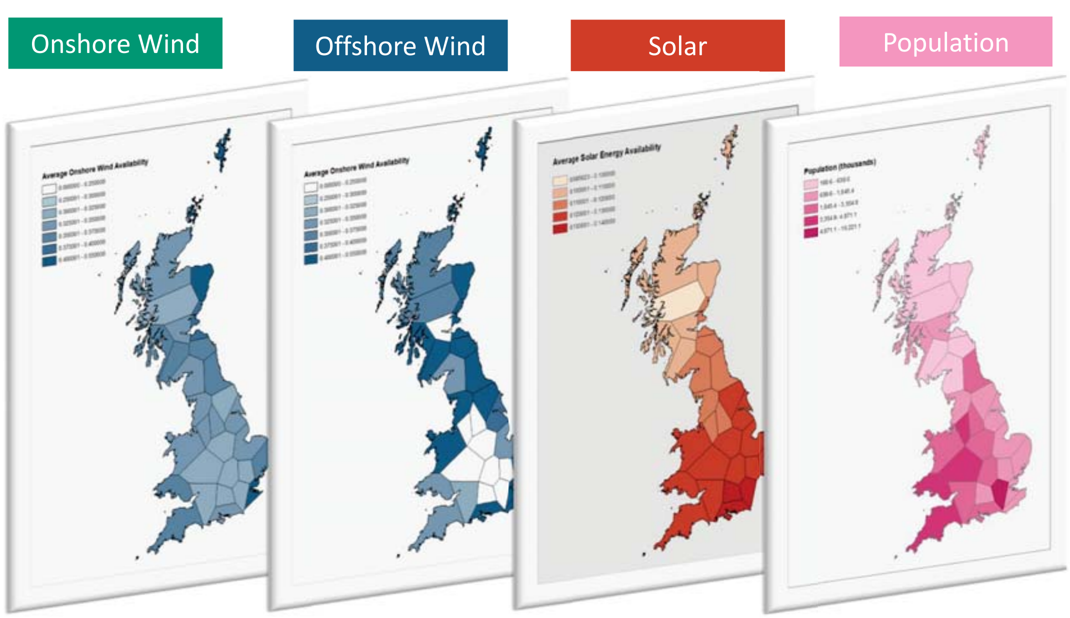
Electricity Systems Optimisation



$\forall i \in I$ $\forall a \in A$	Capacity expansion	• Initial supply and transmission capacity • Build rate constraints (supply, store, transmission) • Life time constraints • Maximum resource constraints
$\forall c \in C$	System-wide constraints	• Electricity demand • Reserve requirements • Inertia requirements • Emission target
$\forall z \in Z$	Transmission	• Transmission between zones
$\forall t \in T$	Tech.-wise constraints Integer scheduling	• Power, Reserve, inertia provision • Flexibility of generation/storage units • Carbon emissions by technology • Uptime and downtime
sum	Objective	min { CAPEX + mode-specific OPEX }

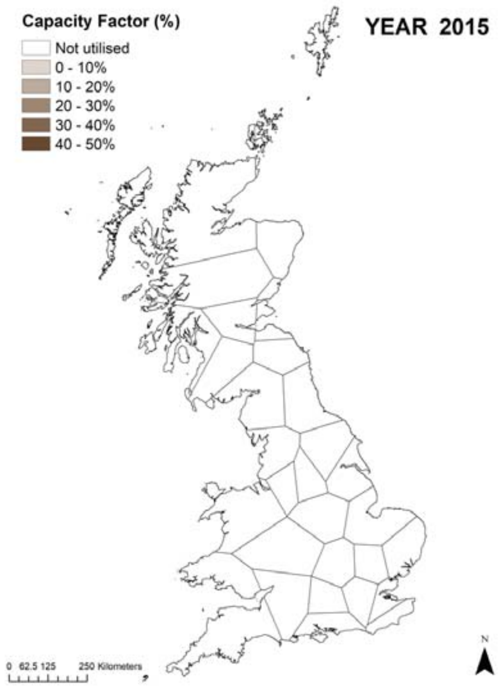
Building on: CF Heuberger, E Rubin, I Staffell, N Shah, N Mac Dowell, *Applied Energy*, 2017, 204: 831–845

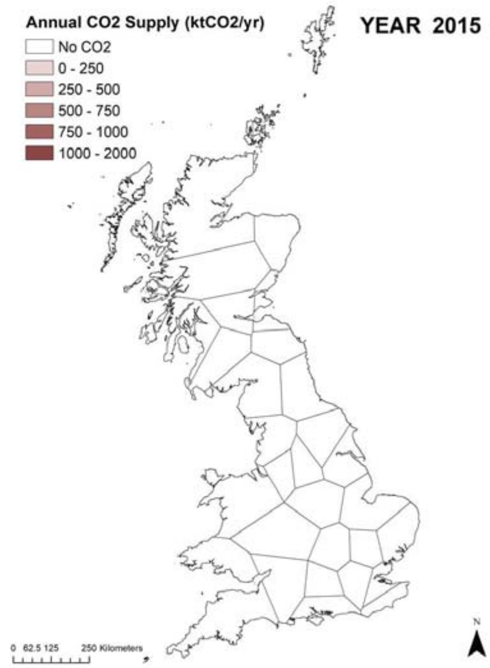
Spatial resource availability and demand data



Raw data solar, onshore wind, offshore wind: www.renewables.ninja; UK BEIS National Statistics Population estimates 2018

The evolving role of CCS

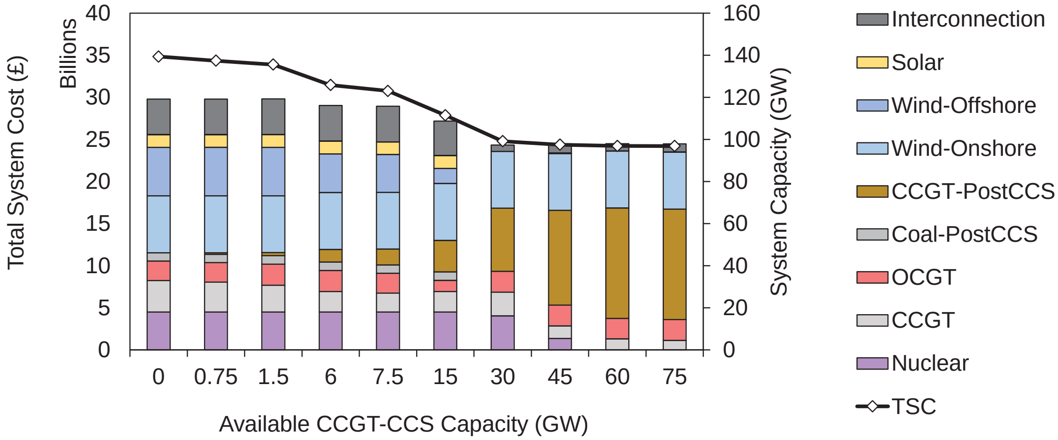




Some key questions

1. Does CCS *have* any value?
2. How helpful are cost targets?
3. Should we believe in unicorns?
4. Other kinds of value?

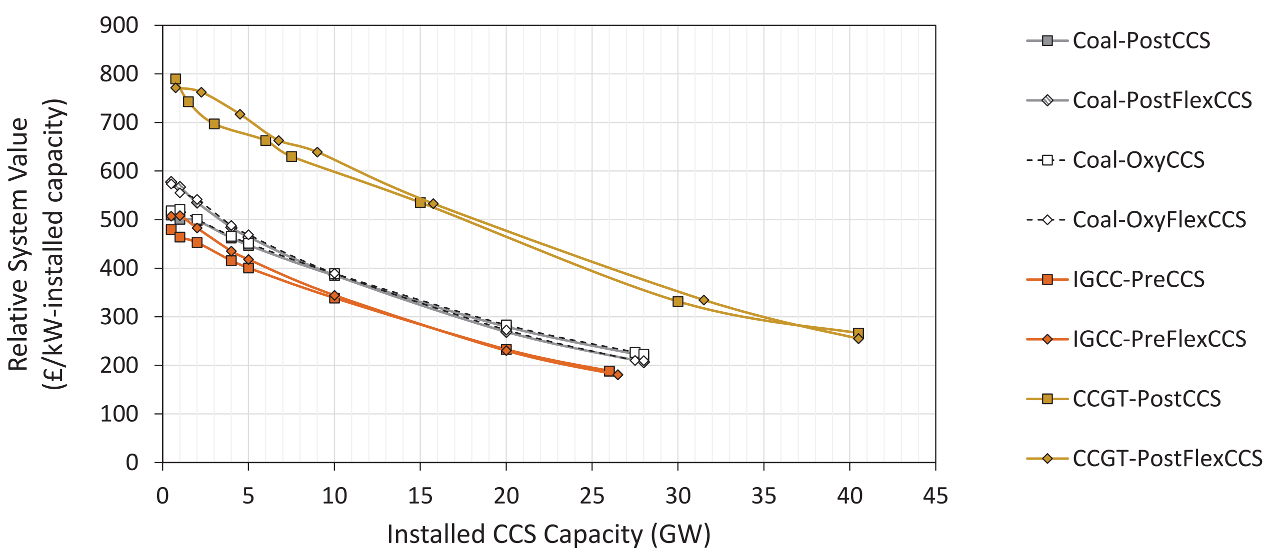
The value of CCS



- The deployment of CCS capacity can reduce total capacity requirements and TSC.
- CCS utilisation increases as unabated and intermittent capacity is replaced.

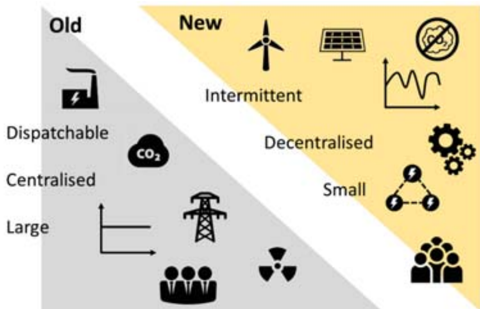
CF Heuberger, *et al*, Computers and Chemical Engineering, 2017

CCGT-CCS technologies provide the greatest value



CF Heuberger, *et al*. Valuing Flexibility in CCS Power Plants – FlexEVAL project for the IEAGHG, 2016

Which technology parameters matter?



Technology Feature	Value in future power systems
High Efficiency	+
High Flexibility*	++
Low CAPEX	+++
Dispatchability	+++
Firm capacity/ancillary service provision	+++
Low OPEX	+
High Rate of Deployment	++

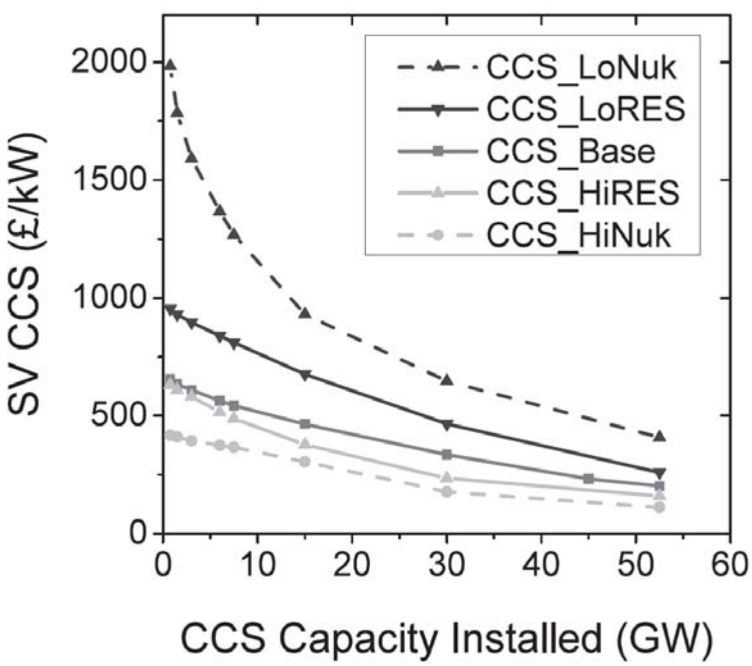
The power system is changing…

"+" → "+++" = low → high value

*modelled as minimum stable generation point, up-/down time

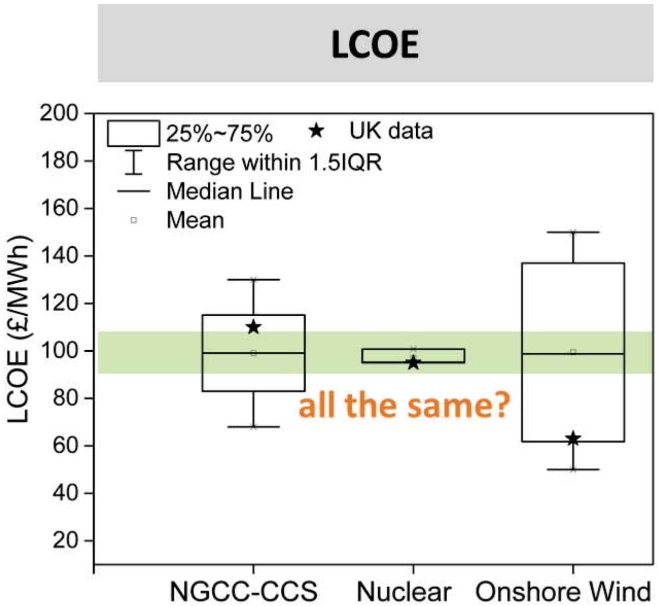
M Schnellmann, CF Heuberger, SA Scott, JS Dennis, N Mac Dowell , 2018, Int J GHG Con, Accepted

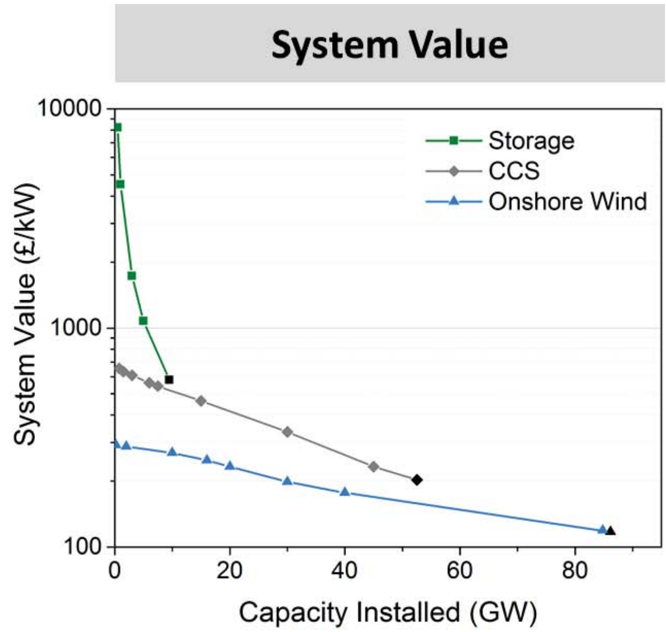
Value of CCS is context specific



CF Heuberger, *et al*, Computers and Chemical Engineering, 2017

Value ≠ cost





CF Heuberger, *et al*, Computers and Chemical Engineering, 2017

Some key questions

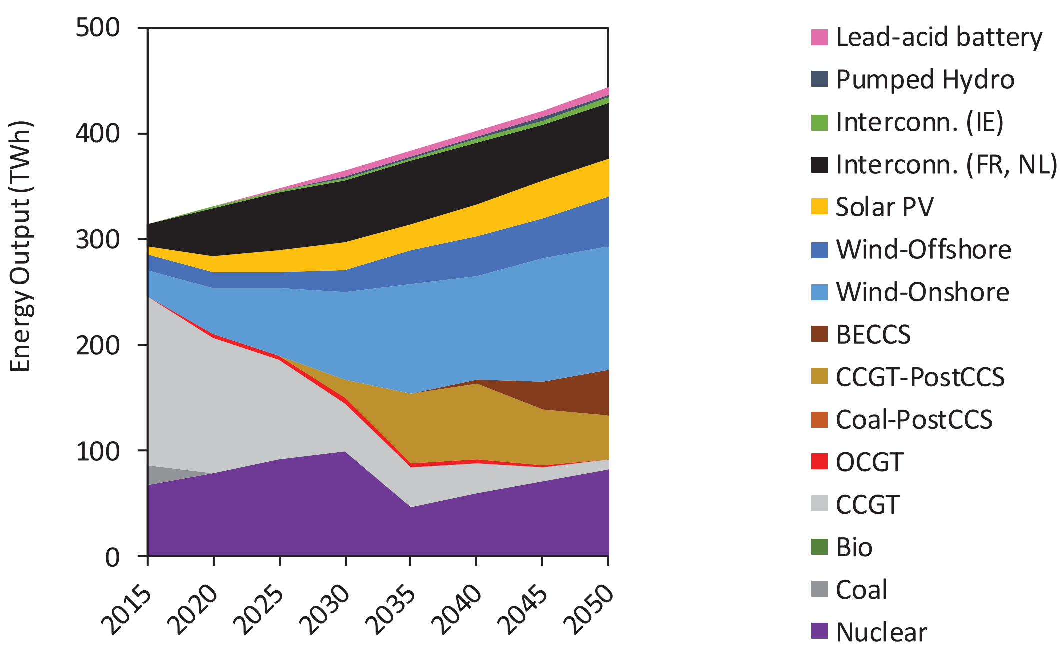
1. Does CCS *have* any value?
2. How helpful are cost targets?
3. Should we believe in unicorns?
4. Other kinds of value?

How helpful are cost targets?

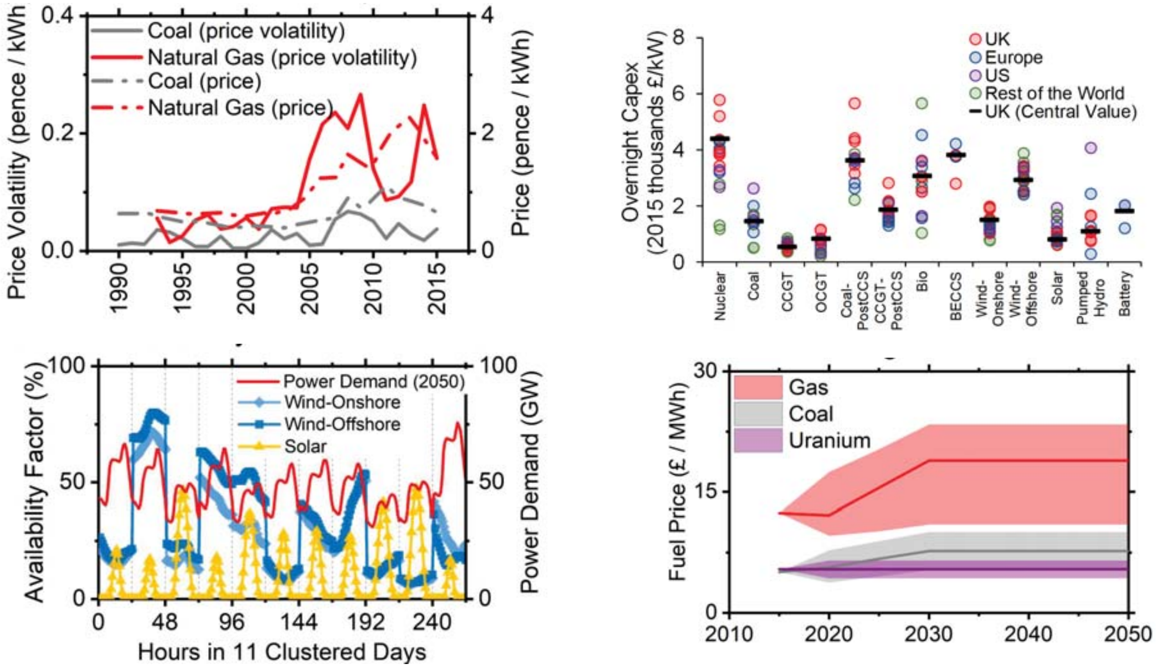
- We know that CCS
  - Is integral to least cost decarbonisation targets
  - Provides value to the electricity system
  - Is vital to decarbonising industry

- Yet we persistently
  - Hear that the “cost must come down”
  - Wait on new technologies
  - Set isolated cost targets

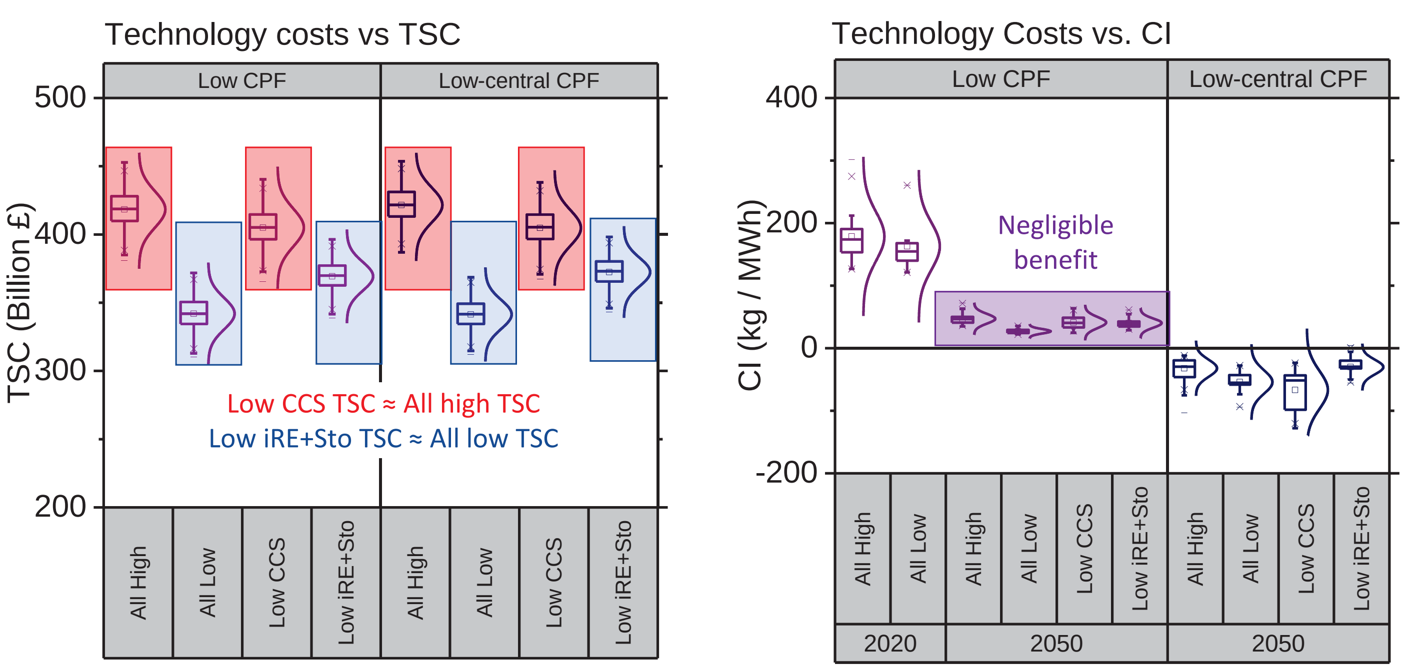
Limited uncertainty..?



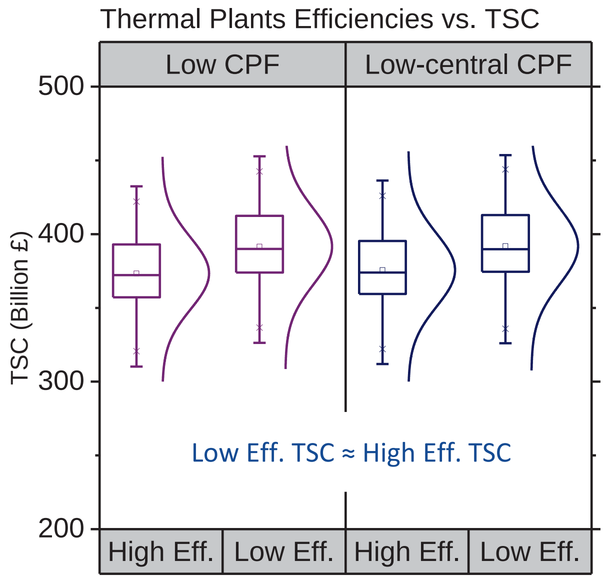
A wide range of possible futures…

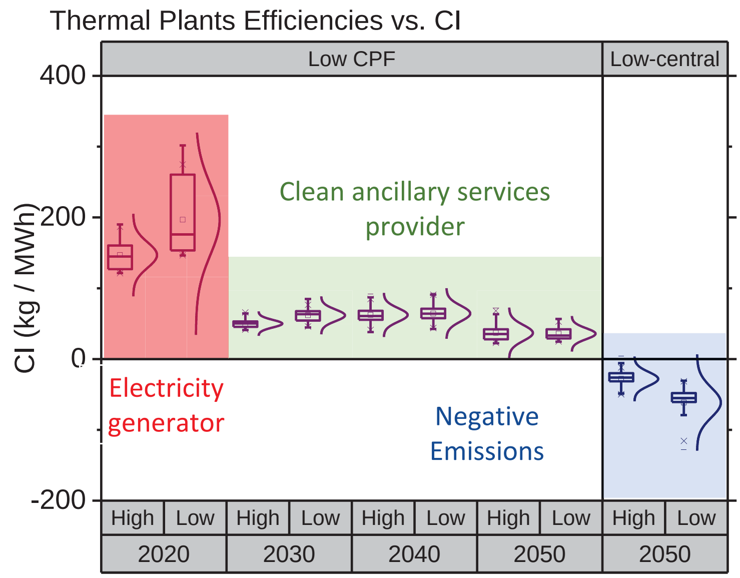


How important are individual technology costs?



The key metric is efficiency…





Some key questions

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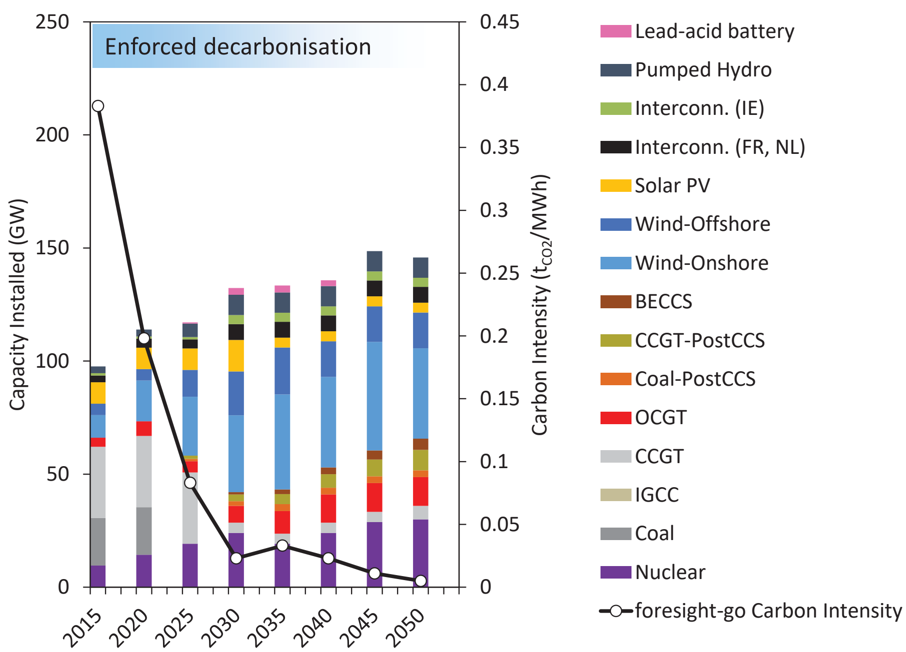
Should we believe in unicorns?

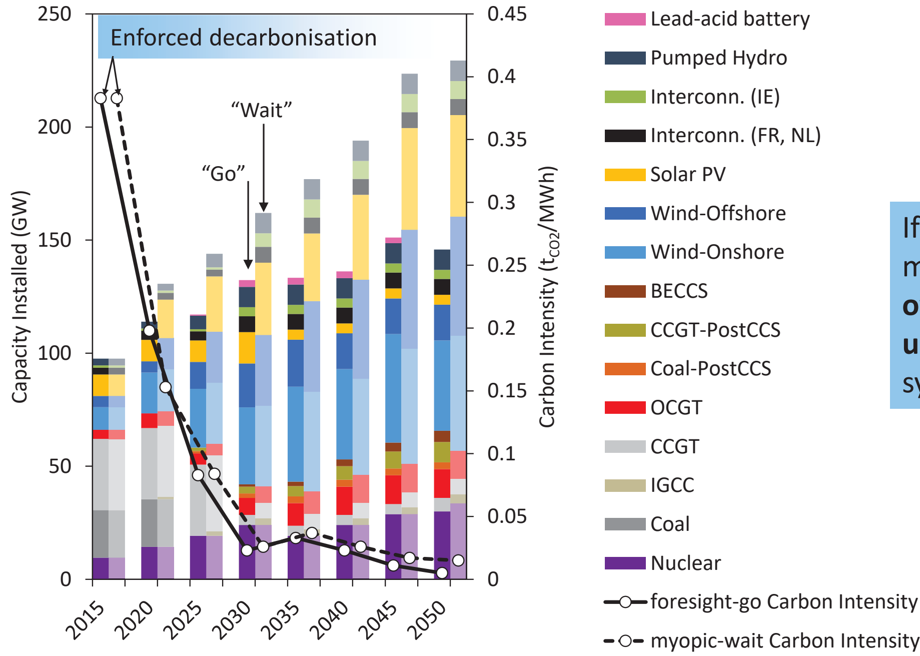
- We typically assume perfect foresight
- This is not the world we live in…
- Can we trust in technological optimism?
- What is the least regrets strategy?

Perfect foresight capacity expansion



CF Heuberger, *et al.*, Nature Energy, 2018

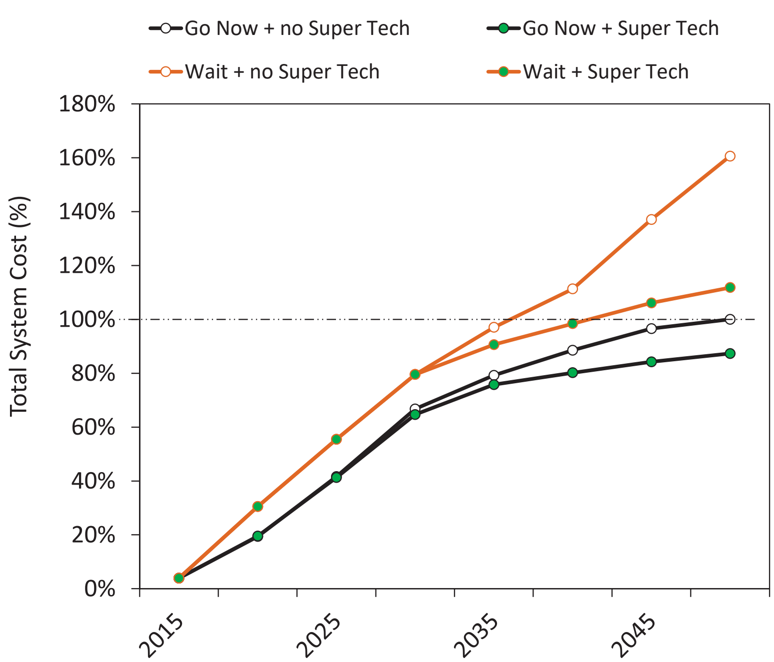
Imperfect foresight capacity expansion



If the "super tech" fails to materialise, we have an **overbuilt and underutilised** power system.

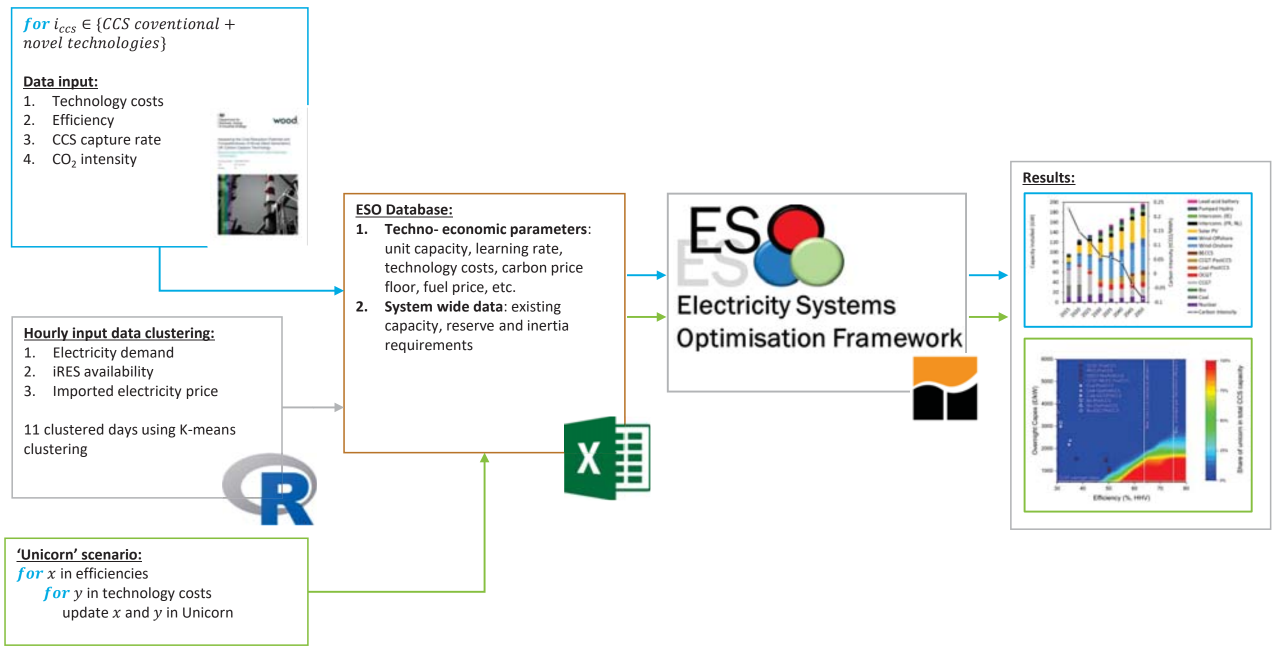
CF Heuberger, *et al.*, Nature Energy, 2018

Myopia in planning affects operation and cost

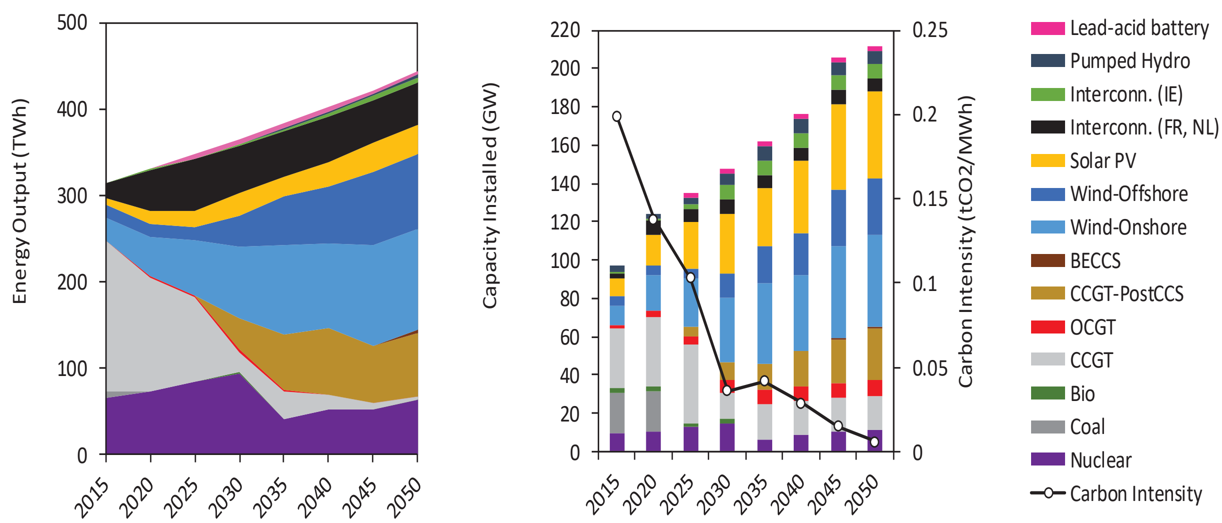


CF Heuberger, *et al.*, Nature Energy, 2018

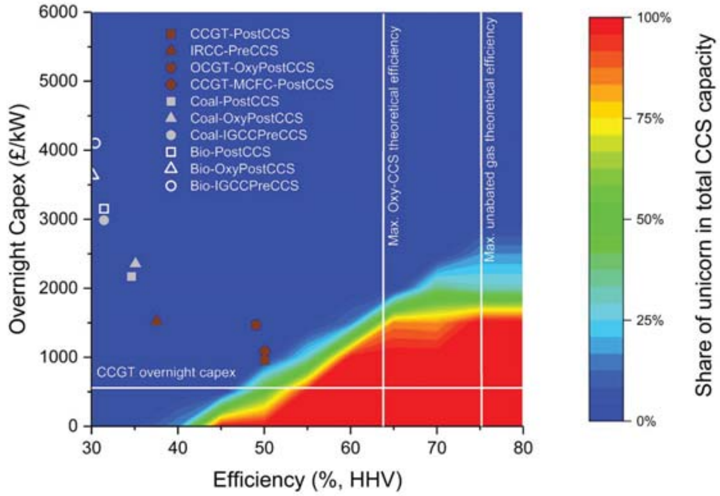
Unicorn hunting

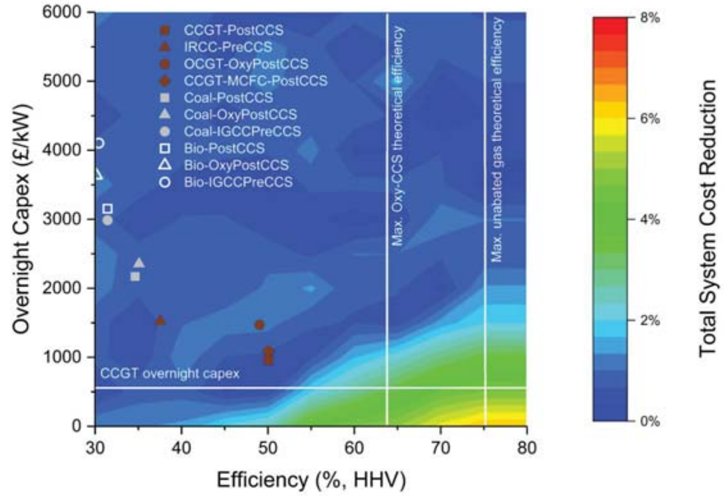


CCGT-CCS still appears to be a dominant technology



Is there a unicorn worth waiting for?





Some key questions

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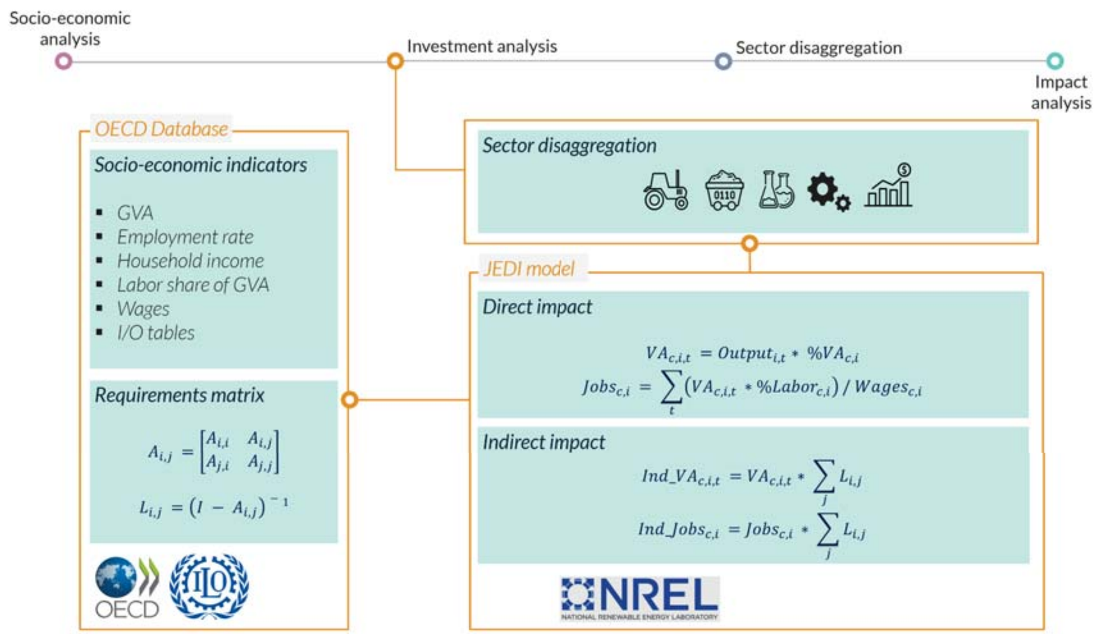
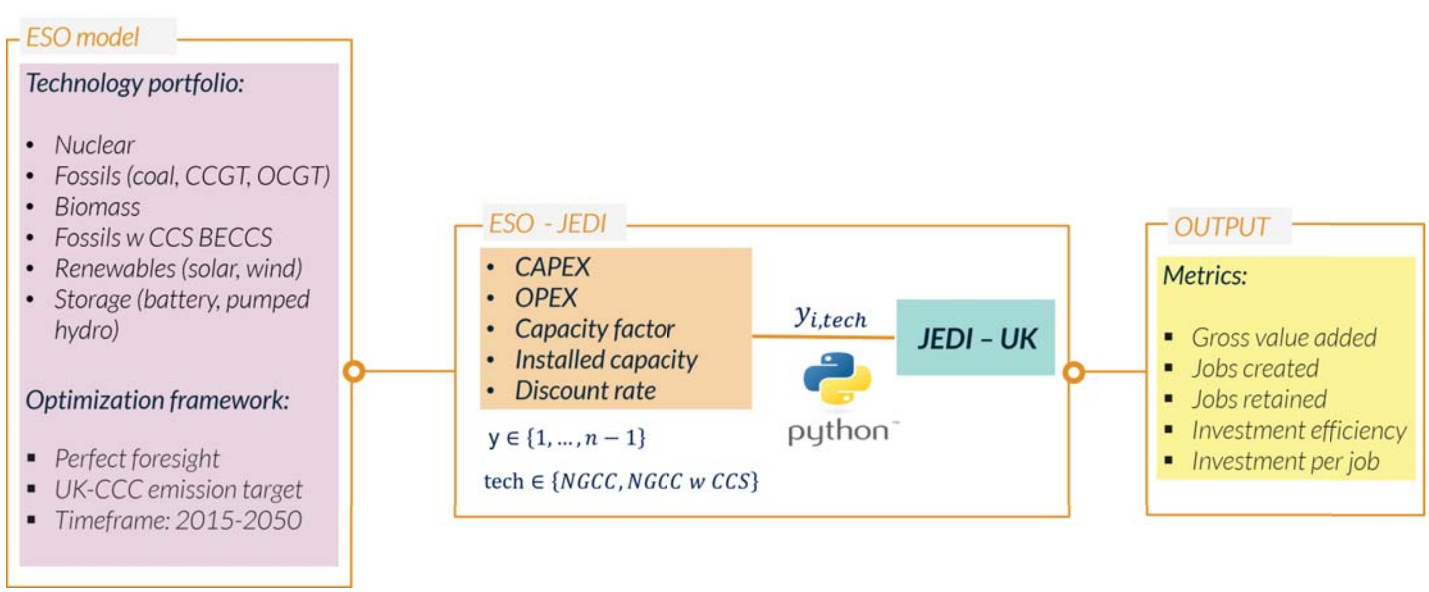
2. How helpful are cost targets?
3. Should we believe in unicorns?
4. Other kinds of value?

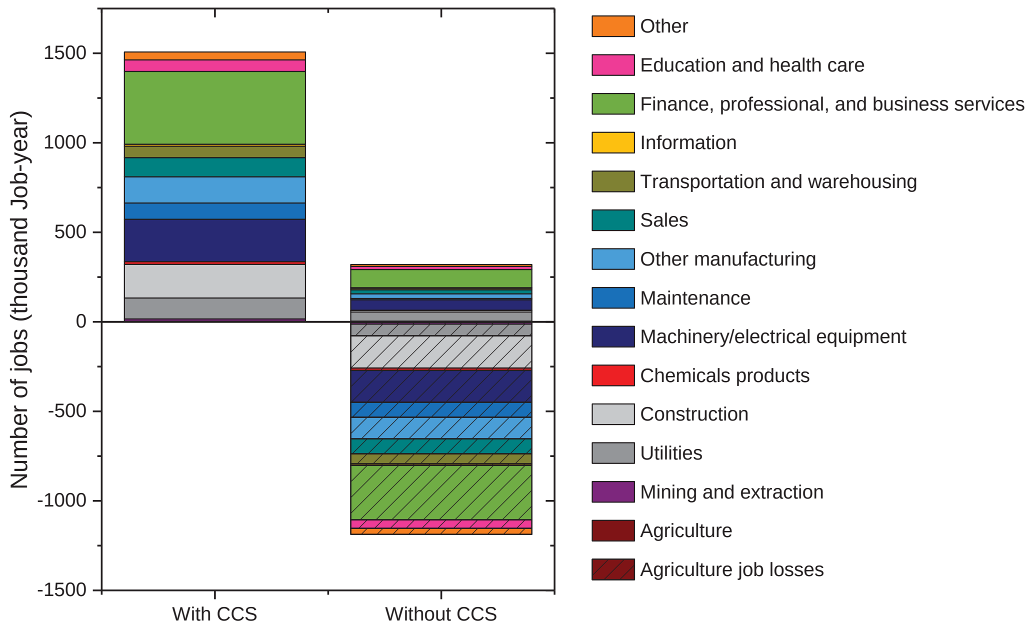
Jobs and Economic Development Impact (JEDI)



ESO -JEDI framework



Cumulative jobs preservation and creation from CCS in the UK (2020-2050)



Some key questions

1. Does CCS *have* any value? YES!
2. How helpful are cost targets? Unhelpful, and simplistic…
3. Should we believe in unicorns? No!
4. Other kinds of value? Jobs; across all levels of the economy…

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