REVIEW

Carbon Capture and Storage: How Green Can Black Be?

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The capture of carbon dioxide at the point of emission from coal- or gas-burning power plants is an attractive route to reducing carbon dioxide emissions into the atmosphere. To commercialize carbon capture, as well as transport of liquified carbon dioxide and its storage in exploited oil fields or saline formations, many technological, commercial, and political hurdles remain to be overcome. Urgent action is required if carbon capture and storage is to play a large role in limiting climate change.

Carbon dioxide emissions from fossil fuel combustion are a major contributor to climate change (*1*). The current low price of fossil fuel energy is partly subsidized by unpriced CO_2 emissions, exploiting the degradation of natural atmosphere and ocean. Even if the debate on climate change is over, the actions to limit CO_2 emissions have barely started.

One step toward reducing CO_2 emissions is to capture the CO_2 generated during combustion and store it in a suitable place. This process of carbon capture and storage (CCS) has the potential to reduce future world emissions from energy by 20% (*2*). CCS is already operating in trials, with 3 megatons of CO_2 (Mt CO_2) per year from power plants or natural gas cleanup being captured and stored. CCS technologies are now in a scale-up period. Worldwide, large demonstrations are planned on 36 power plants. However, there is a lamentable lack of financial commitment to real construction. If design and construction of these demonstration plants does not start now, they will not operate by 2014, and learning from these to provide commercial credibility will drift beyond 2020. The worldwide construction of many tens to hundreds of large CCS plants—necessary for a substantial impact on climate mitigation—will then be delayed beyond the deadline set by climate change predictions.

Will CCS actually deliver material reductions of CO_2 before 2030? Or is it instead a set of over-ambitious promises that act as an excuse for power generators to pollute with black coal and "clean" gas under a pretext of green development, locking the world into decades of high CO_2 emissions (*3*)? Here, I analyze the technical challenges associated with capture, transport, and storage of CO_2 and then look at what needs to be done for a viable CCS industry to be created between 2020 and 2030.

The Purpose of CCS

There is a broad political consensus that the global temperature rise should be limited to 2°C, compared with preindustrial temperatures. However, such declarations lack urgency, targets, or specified time scales. The scientific analysis has swung to define CO_2 limits not as a tonnage released per year, but as the total mass of fossil carbon released during this geologically short industrial time span (*4*). CO_2 emissions must therefore start to fall from 2020 onward. CCS is unavoidable if fossil fuels continue to be burned at more than 10% of the present rate. It is surprising, then, that so few CCS projects are underway.

Fossil fuel combustion supplies more than 85% of energy for industrial activities (*5*) and is thus the main greenhouse gas contributor. Coal is on a path to supply 28% of global energy by 2030, as part of a 57% increase in CO_2 emissions (*5*). CCS is a direct emissions mitigation option, usually considered as an interim system to enable a 50-year transition away from fossil fuels. Although current CCS technologies are only at the pilot stage, the scale of the main ambition is massive: to fit all coal and gas power plants with CCS by 2050 and reduce world CO_2 emissions from energy by 20% (*2*). Accordingly, CCS will incur incremental costs. For example, in the U.K., CCS may cost each household an extra 10% per year for electricity. That may seem expensive, but if CCS is developed now as part of a portfolio of global climate protection, the costs of CO_2 abatement required in 2050 are predicted to reduce from \$500 to \$50 per ton (*2*).

CCS strips out, purifies, and concentrates CO_2 emissions from fossil fuel combustion at large single sources such as power plants (Fig. 1). Three methods of CO_2 capture are currently being investigated (*1*). Postcombustion capture separates the CO_2 with the use of chemical solvents, precombustion capture chemically strips off the carbon, leaving hydrogen to burn, and oxyfuel combustion burns coal or gas in denitrified air to yield only CO_2 and water. After leaving the power plant, the captured CO_2 is pressurized to 70 bar, forming a liquid that can be transported to a storage site, where the fluid is injected into rock pores deeper than 800 m below the surface (*6*, *7*). Good choices of storage sites will retain CO_2 without appreciable seepage for tens of thousands of years. Monitoring will be required for decades into the future, combined with techniques to remediate deficient storage. In principle, CCS can be applied not only to power plants but also to large industrial sites, such as refineries, steel making, fertilizers, ethanol fermentation, and cement manufacture (*1*). However, these applications are proving to be quite slow to develop on a global level. The

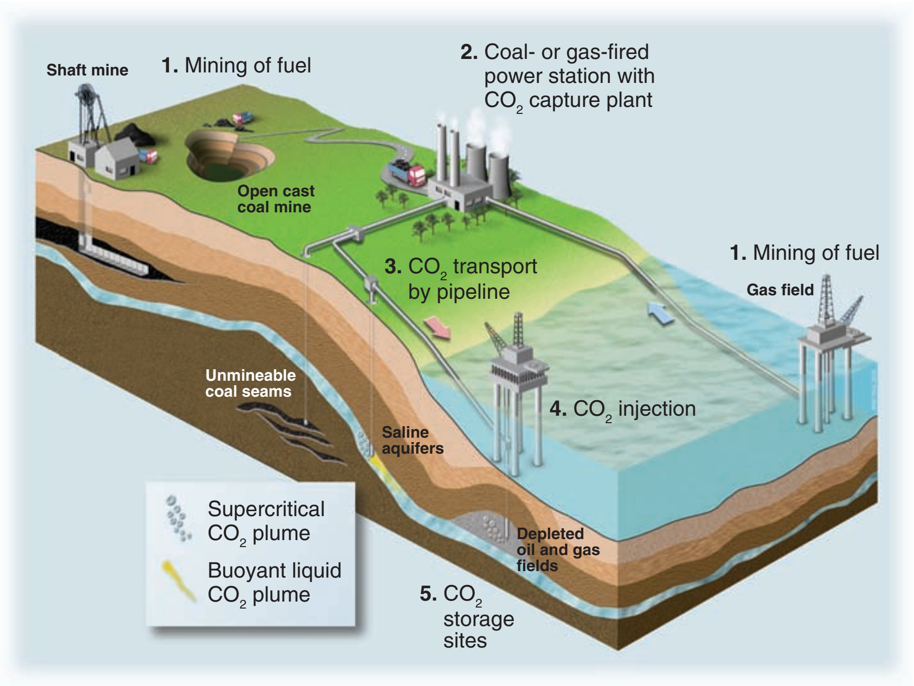

Fig. 1. Diagrammatic representation of the life-cycle chain of fossil fuel use. CO_2 separation and capture at power plants enables storage of CO_2 in porous rocks deep below ground.

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present CCS discussion focuses on power plants fired by fossil fuels (coal, gas, and oil) and sometimes co-fired with biomass.

Technical Challenges

Carbon capture. Separation of CO_2 is the step that consumes the most energy and results in the highest cost. Historical examples of CO_2 separation, if scaled-up, could consume 25 to 40% of the fuel energy of a power plant and be responsible for 70% or more of the additional costs in CCS (*8*). The developments currently under way should result in tangible improvements toward a 10 to 20% energy penalty. For commercialization, it is normal practice to construct progressively larger equipment from pilot to demonstration plants (Fig. 2). This practice enables learning to increase reliability and reduce cost. The three capture methods are currently indistinguishable in cost and efficiency.

In postcombustion capture, a solvent absorbs CO_2 from flue gas and is regenerated by heating for several hours in recovery columns at 150°C. In this case, the challenges are to scale up by a factor of 50 from the largest current operation while protecting the solvent from degradation by flue-gas impurities. Modified and new amine solvents are being tested in the European Union (EU) CO2CASTOR and SOLVit projects, which aim to halve energy penalties. Pilot plants up to 5 MW in the U.S. are investigating new ammonia-based processes, and in 2009, the U.S. Department of Energy (DOE) awarded \$100 million (*9*) to support a 1 Mt per year demonstration. The U.K. will fund a 400-MW commercial retrofit on coal plant, working in 2014 (*10*).

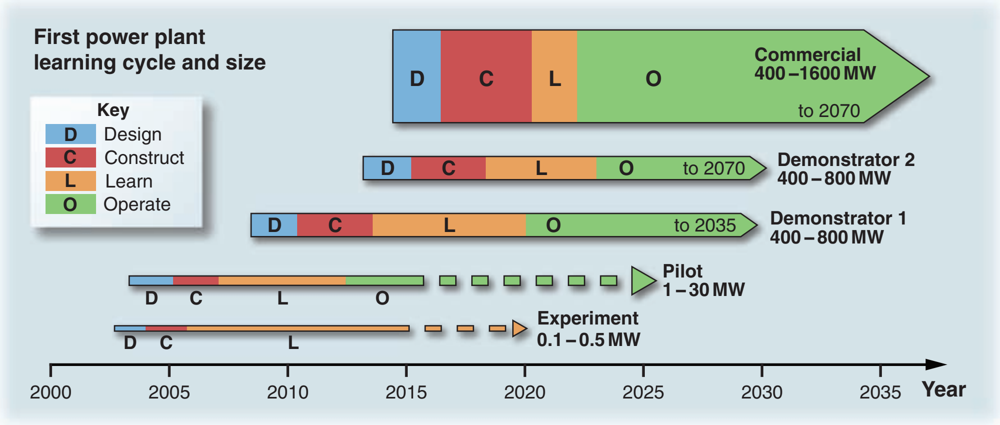

Fig. 2. Time chart showing how a CCS power plant can be increased to reliable and cost-effective commercial size by 2020, by means of progressively larger experimental equipment. Rapid information flow on the vertical axis is important from learning to subsequent design. This depends on industrialized nations providing financial support for CCS plant during the pilot and demonstration phases. Tens of large CCS demonstrators need to be built worldwide from 2009. Incentive systems (for instance, premium payments for decarbonized electricity) are needed to enable introduction, operation, and establishment from 2014 to 2020.

Postcombustion amine capture has some major disadvantages: The equipment will be very large, comparable with the footprint size of a coal-fired power plant, large volumes of solvent are needed, heating to regenerate the solvent can produce toxic byproducts, emissions of solvents from recovery columns need to be scrubbed and eliminated, consumption of water needs to be reduced, and expired solvent needs to be disposed. However, postcombustion capture also has distinct advantages. It can be applied to already constructed plants, operated with the plant to capture CO_2, or disconnected to provide maximum power output at times of peak electricity price. Furthermore, components in the non-integrated equipment can be replaced, developed, and upgraded without fundamental impact on the power plant. Future developments may increase efficiency through closer integration of capture with the host plant, and novel membranes or microporous solids may help to separate N_2 and other minor gases from CO_2. Cryogenic capture has also been proposed at an experimental scale (*11*), including SO_x, NO_x, and Hg elimination, with the cost per ton of CO_2 capture reduced by 40%.

Oxyfuel combustion has not previously been developed for use in large-scale power plants. This process separates oxygen from air with the use of established cryogenic methods and then burns the coal or gas fuel in a mixture of that oxygen, combined with recycled flue gas to cool the combustion. Burners for oxyfuel have been demonstrated at 1-MW scale, and the world's largest experiments are developing 40-MW burners, intended to be commercially available from 2015 (*12*). Two pilot plants are in operation: Schwarze Pumpe in Germany has burned lignite or bituminous coal since 2008, and Lacq in southwest France has burned gas since 2009. Scale-up to a power plant involves the use of multiple burners and air separation trains.

Attractions of oxyfuel combustion are the much easier separation of CO_2, with no solvent, smaller physical size, and the potential to retrofit on existing plants (if the boilers are also reconstructed). Drawbacks are the very low SO_x required on leaving burners, as well as the higher-temperature materials that are also required. Future developments could improve high-temperature operation and reduce the energy costs of O_2 separation from air.

Precombustion capture involves constructing plants to gasify coal and chemically shift syngas or methane to hydrogen. Using this process, CO_2 capture is already proven to work at the megaton-per-year scale but has not been fitted to an operational power plant. The challenge here lies less in the basic technology and more in the reliability of all components for total continuous integration. In China, the GreenGen 250-MW project southeast of Beijing will potentially be the world's first Integrated Gasification Combined Cycle power plant with CCS, projected to be operating in 2011 (*13*). The U.S. FutureGen project will develop a 275-MW precombustion plant with CCS in Illinois; this project was reactivated in 2009, with \$1.7 billion from the DOE and commercial partners (*14*). Several commercial developments seem likely to operate before 2015 (*15*) in the U.S. (*9*, *16*); Alberta, Canada; Queensland, Australia; U.K., and Abu Dhabi, United Arab Emirates (*16*).

Advantages of precombustion capture are that multiple fuels can be used and multiple products produced, from electricity to hydrogen. The process is technically elegant, with efficiency gains from the integration. This could become a technology of choice for new-build plants supplying solely baseload electricity. Disadvantages are high construction costs and decreased short-term flexibility. Future gains may come from the development of high-temperature membranes that allow syngas to be catalytically reformed into CO_2 at the same time as hydrogen is separated.

For all capture technologies, the road to rapid commercial deployment is much less certain. At least two learning cycles are needed (Fig. 2) to demonstrate operation and enable commercial guarantees for construction, to begin globally in 2020 (*17*). This is a technically possible but politically optimistic pathway. With three major technologies, replication of each will be slower than if one type of capture becomes dominant. Consequently, promises to green the dirtiest fuel may be delayed.

Transport. CO_2 has been transported in pipes since the 1970s in the U.S. and Canada, where more than 3000 km of operational CO_2 pipes exist, transporting 30 Mt CO_2 per year. There are no known show-stoppers for pipeline developers, but there are many aspects for which more technical detail and safety criteria for populated areas would be helpful.

If the CO_2 is dry (less than 10 parts per million of water), conventional carbon steel can be used, greatly reducing the cost and also removing the risk of hydrate crystallization. CO_2 feed-in will contain impurities, depending on the plant type and capture system. These impurities could be N_2, O_2, H_2S, and/or SO_3. This multicomponent mixture increases the operational pressure needed to avoid dew-point condensation into liquids from ~73 bar in pure CO_2 to ~90 bar in CO_2 with impurities. To avoid costs of overcompression, a pipeline purity standard will be needed. If continental-scale transport is envisaged (e.g., across the EU or U.S.), standards need to be set early.

CO_2 can be gathered from multiple power plants (Fig. 3), transported through a shared system to the coast, compressed up to 150 bar, and transmitted to offshore nodes. From those, CO_2 can be redistributed to individual storage sites (aquifers, oil fields, or gas fields) at the appropriate pressure and rate (*18*, *19*). Targets for CCS tonnages are needed to predict the size of pipe needed. Commercial innovation is required if pipe operators function as the contractual links between operators of CO_2 capture (where risks are low and return on investment is also low) and subsurface storage operators (where risks are high, but return on investment is potentially very high). Diverse commercial solutions have been proposed. Norway will form a state company, but the U.K. expects a commercial pipe operation.

Injection and geological storage. To have an impact on worldwide emissions of fossil fuel–derived CO_2, extremely large volumes of geological storage are needed in the right places and at the right times. Injection of CO_2 for storage into microscopic pore space of sedimentary rocks is based on industrial experience of injection into hydrocarbon fields from enhanced oil recovery (EOR) activities since the 1970s. Commercial injection has been undertaken into saline formations at 1 Mt/year or more at Utsira and Snøhvit, Norway and In Salah, Algeria. Natural sites have stored CO_2 for tens of millions of years (*20*, *21*). However, efforts to scale-up injection face a fundamental problem: The subsurface contains no empty space. Any injection of CO_2 into a depleted hydrocarbon field or a saline formation has to displace or compress the existing pore fluid by raising the pressure.

In an oil or gas field, the pressure can be securely raised to return to the pressure at the date of discovery. The topographic hydrocarbon trap localizes the CO_2 so that pre-CCS boreholes can be monitored for leakage decades after injection. Yet even so, there are pitfalls. CO_2 is not an ideal gas and has a large Joule-Thomson effect (*22*, *23*). If CO_2 is injected at 140 bar into a reservoir, it will expand into depressurized gas reservoirs at 10 to 30 bar and then cool (*24*). The resulting risks include hydrate ice crystallization in reservoir pores, blocking injection around the borehole, and thermal fracturing of cement seals, inducing CO_2 leakage. Simulation suggests that heating injected CO_2 to 75°C may overcome the problem (*25*), but practical demonstrations are needed.

Injection into depleted oil fields can also be difficult because in many fields, water injected to undertake secondary oil recovery partially fills the space formerly occupied by oil. To take advantage of the oil field containment structure, it may be necessary to empty it by producing extra oil. In this EOR process, injection of fluid CO_2 reduces oil viscosity and pushes oil toward production boreholes (*26*). CO_2-EOR is established and viable onshore in several countries. The American Recovery and Re-investment Bill 2009 provides \$3.4 billion for CCS demonstration and reduced-tax incentives for CO_2-EOR already existing in several U.S. states. An assessment of EOR in the U.S. optimistically calculated that 88 billion barrels of oil could be recovered from 330 billion remaining, even though in 2004, CO_2-EOR production was only 75 million barrels per year (*27*). Although CO_2-EOR is plausible onshore, it has not been shown to be viable offshore. Since 2000, several fields evaluated in the North Sea by Shell, British Petroleum, Norsk-Hydro, and Statoil

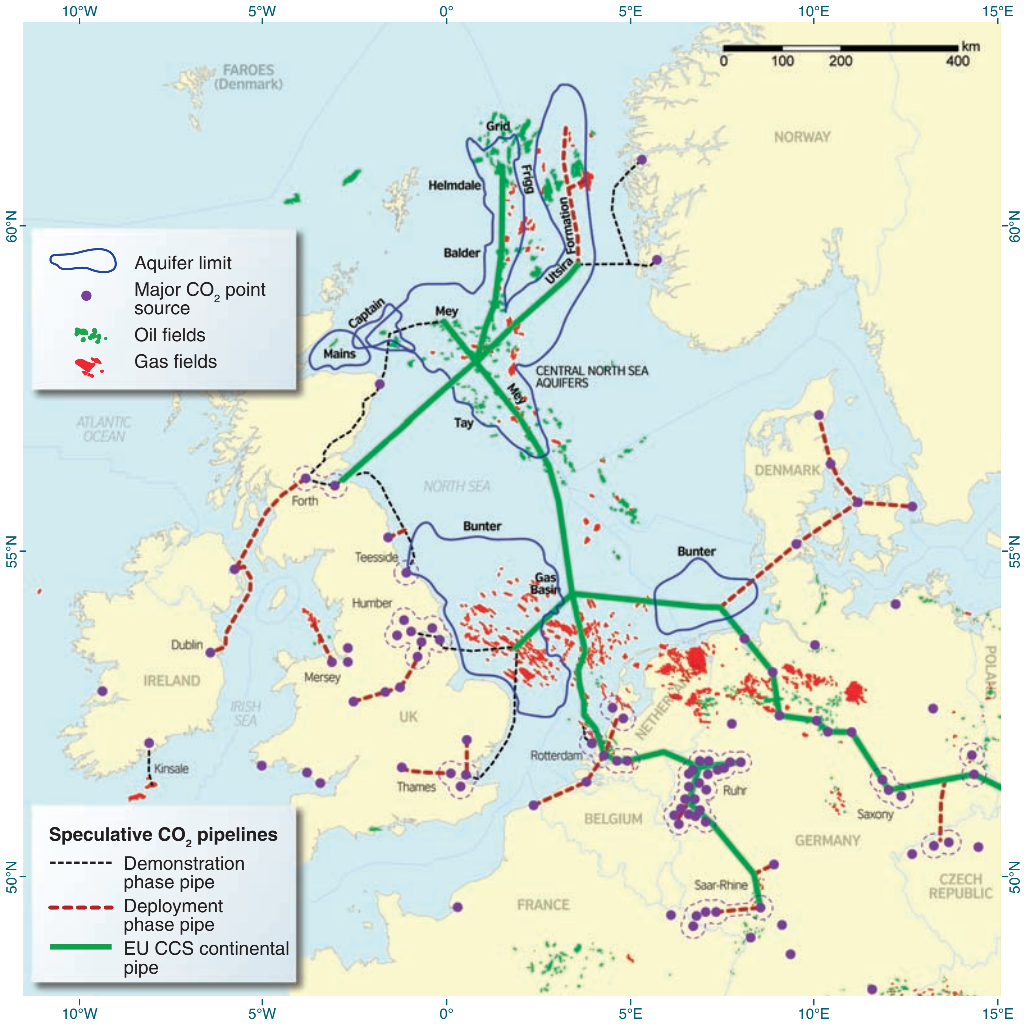

Fig. 3. Map of northwest Europe, showing sites of emissions, saline formations, gas fields, and oil fields. CO_2 can be collected from clusters of large power plants and transported to storage. This transport scenario visualizes pipelines built to offshore hubs accessing large-scale storage beneath the North Sea. Such sites can be evaluated with the use of legacy hydrocarbon data and may prove to be more reliable to develop and monitor than onshore storage. [Basemap of hydrocarbon fields supplied by M. Ricketts, Wood Mackenzie]

have failed commercial hurdles as a result of unreliable CO_2 supply, very large refit costs of offshore platforms, long times until positive cash flow, and much cheaper methods of additional oil production by drilling targeted and deviated boreholes. A sustained oil price of at least \$100 per barrel plus guaranteed availability of CO_2 are requirements for North Sea EOR viability (*18*).

Saline formations (aquifers) are not restricted to hydrocarbon provinces and have been calculated to provide, by far, the greatest storage volumes worldwide, equivalent to hundreds of years of present day power plant emissions (*1*). However, these calculations are probably too optimistic (*7*), because they do not consider that static storage volumes will be reduced as a result of inefficient dynamic sweep of CO_2 through a reservoir. Increased fluid pressure also imposes a limit on CO_2 injection volumes, because preexisting faults and fractures can be re-opened to form leakage conduits. Additionally, CO_2 in unconfined formations (without structure traps) may migrate tens of kilometers during a 30-year injection period, making prediction and monitoring more expensive. For example, the 25,000 km^2 North Sea Utsira formation can potentially store 50 gigatons of CO_2, with a static efficiency using 9% of pore space. Yet dynamic injection today fills only 0.2% of the pore space. Modeling of dynamic injection shows that large-scale extraction of deep water and disposal into the ocean is required if the larger volumes are to be achieved (*28*). For a smaller (4000 km^2) North Sea aquifer, a static calculation gave a capacity of 2% of porosity, but this amount dropped to 0.56% of porosity when dynamic reservoir heterogeneity was added, and it dropped further to 0.2% when a pressure limit was also applied (*18*).

Worldwide, the original static estimates of storage capacity are now being substantially downgraded to many decades rather than hundreds of years of emissions. Only after dynamic demonstrations in aquifers will true capacity values become apparent, to determine if CCS can provide a niche or a major mitigation of CO_2.

CCS Aspirations Versus Real Projects

Although no fully functioning CCS power plant has yet been built, more than 20 experiments and pilots (Fig. 2) are currently operating (*15*). Some of these pilots capture 0.001% of CO_2 emitted from a full-size power plant, and others capture all emissions from 1/10th-scale plants. Separate injections of CO_2 test aquifer or oil field storage. The ambition (*29*, *30*) is that multiple full-size demonstration plants (> 400 MW) will operate from 2014 (Fig. 4). A minimum of two cycles of demonstration plants are needed (*17*) to improve subsequent constructions before attempting to build commercial plants by the "climate deadline" of 2020. The overlap of learning into the next phase of construction will disappear if the first plants are not operational by 2015 (Fig. 2); thus, work on their design needs to start in 2009. Delay does not negate the utility of CCS, but it means that reductions of CO_2 emissions do not occur until after greenhouse gas forcing of climate progresses beyond the point of predictability (*31*). For the green aspirations of CCS to become real by 2020, funding and immediate building of real projects is needed.

Create Business, Make Learning Rapid

Expecting the translation of all 36 announced demonstrations (Fig. 4) into operation is overly optimistic for three reasons. First, the largest blockage is not technological, but rather the lack of a market to provide revenue that justifies large investment. Each demonstration coal plant requires a system for price support for many years to recover the \$1.5 billion extra capital and operational cost of generating decarbonized electricity. The pricing provided by the current carbon market is far too low and erratic. Price support systems are needed to introduce CCS, just as price support is given to introduce renewable energies. But this critical commercial help has been announced only for very few CCS projects. Paradoxically, in markets where renewables have price support to encourage deployment, cost compilations show that CCS will be a cheaper option to deploy (*32*).

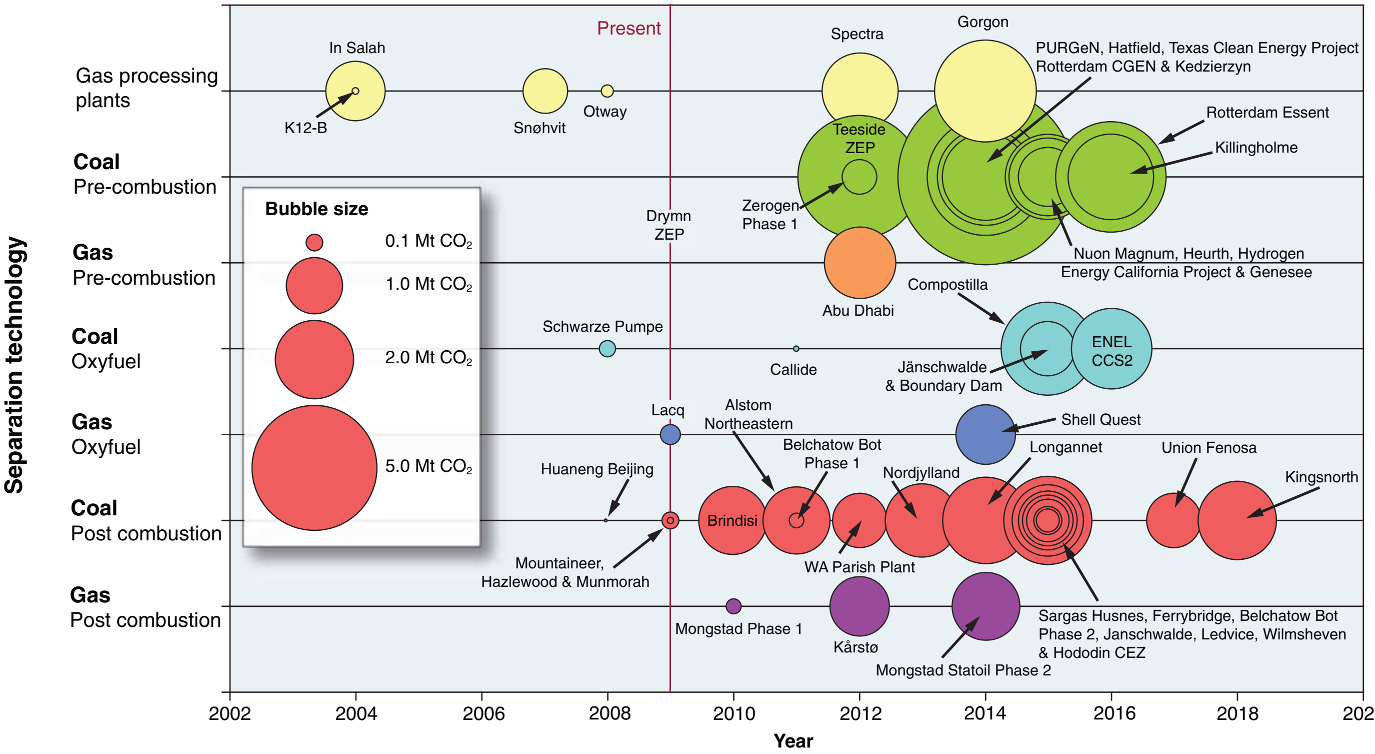

Fig. 4. Chart of large CCS demonstration projects planned worldwide, plotting calendar year against capture type and fuel. Coal and postcombustion power plants dominate. There is typically a 5-year lead time on design and construction (Fig. 2), so to operate these plants on schedule requires that projects commence spending on design now. Few of these projects have certain funding to assist construction, and even fewer have systems to enable commercial operation. National CCS targets with worldwide coordination and exchanges of learning are needed. [Compiled by Y. Bushby (*15*)]

Second, for insights from operating demonstration plants to be transmitted from the first to the second generation of plants, and to further generations (Fig. 2), detailed commercial information will have to be shared rapidly between companies. In a period of competitive development, such information is normally very tightly controlled by the owners. If these demonstration projects are enabled by public funds, then national governments have some ability to encourage the release of information. The Global CCS Institute in Australia will encourage such information release (*30*) but can enforce nothing. International agreements are required between governments from the present until 2020.

Third, for rapid learning to help cost reduction, successive generations of equipment have to evolve and improve from the same design. For CCS, there are at least seven different combinations of fuel with the three capture technologies (Fig. 4). Each demonstration project may have distinct transportation systems and individual geological storage sites. Consequently, learning progress in one technology has limited relevance to that of another, and the progress of the "CCS fleet" could be inhomogeneous. So, will CCS globalize? With no price support or communication, CCS will remain limited to interesting but isolated demonstrations. A coherent national and international approach is required to create a new industry that disrupts the status quo.

CCS on a Renewables Electricity Grid

The electricity grid systems of industrialized countries have been developed to distribute reliably from large centralized power plants. Increasing the supply of variable output from wind power to 30% or more produces greater risks of supply interruptions (*32*). This means that CCS systems will need to be continually responsive to demand, along the whole CCS chain from capture to transport to storage. At extreme times of no wind, 100% reserve capacity will be required from fossil fuel generation.

Periods of no wind are infrequent, but not rare. For example, predictions of the U.K. electricity market price have been made, with a scenario based on an historical calm and cold period during several days in late January 2000 (*33*). If wind generation in 2030 ceases for a week, then backup gas and coal generation will be needed, at a very high cost. The short-term electricity wholesale price will reach £500 per megawatt hour, compared with a normal price of £50.

For some power plants, the periods of operation could be just months in one year or as few as alternate years. Will CCS expense on such a plant be financially viable? Will CCS be required to operate, even when it may be more profitable to switch off postcombustion CCS to achieve greater electricity output?

Outlook

Power plant capture of CO_2 can technically be enacted now, but with low efficiency and many energy losses. Current R&D on capture holds very good promise of 20 to 60% improvements in energy efficiency and cost and also of adapted or entirely new capture processes. Transport of CO_2 by pipeline can also be undertaken now. Costs can be reduced if clusters of power plants feed CO_2 into shared transport pipelines. Injection into hydrocarbon fields or aquifers uses established methods and can commence immediately, although the total storage capacity in aquifers is highly uncertain. Worldwide, demonstration projects must use diverse types of storage to test capacity predictions. Public acceptance is also an issue: Opposition has halted several feasible test sites for CCS in Europe. Governments must require heart-and-mind action from developers, several years ahead of applications.

Climate change predictions show that CO_2 reduction must be operating by 2020. Mainstream economic assessments state that CCS is a medium-term, low-cost option that needs to be prepared now (*34*) and that even a 10-year delay in tackling climate change will be economically serious (*35*). Yet there is a lack of policies or funds worldwide to support profitable operation of demonstration plants. In the future, industry needs to see and believe in secure, long-term underpinning revenue from low carbon fossil energy, similar to the way that renewable energies have been helped to emerge.

On the 10-year time scale, it is not technology, but legal permission, business development, and public opinion that will determine whether CCS experiments and demonstration plants are built sufficiently rapidly for CCS to be deployed in 2020. On the 20-year time scale, these initial demonstrations must enable a new CCS industry to be born. Low-cost reliable capture at clusters of CCS power plants must emerge, and national pipe networks must be developed, delivering to aquifer storage capacity that must have been validated. CCS also needs to be built and operated in developing economies with high national but low per capita emissions. If CCS is difficult to afford now in Western economies, then it is even more so in India and China. Additional payments for CCS demonstrations will accelerate the above-mentioned actions.

Simply pricing carbon in a market is not enough to encourage CCS or to enforce decarbonization. During peak demand, venting of CO_2 will be commercially beneficial. If the price of carbon is set very high to avoid such effects, that taxes the whole economy, not just dirty electricity. Additional policy levers will be needed to enforce CCS operation. Lessons from previous clean-up technologies applied to power plants—such as SO_x and NO_x removal from flue gases—show that voluntary codes do not work, but clearly signed and enforced rule changes do.

New power plants can now be built "capture ready," to be converted when CCS is established. This is the death-or-glory test of governments, as there is industry pressure to build new coal and gas plants now, increasing CO_2 emissions, and perhaps convert to CCS later. Substantial difficulties can be anticipated in government-enforced plant-by-plant conversion. Another regulatory route is the introduction of emissions performance standards, expressed as amount of CO_2 per kilowatt-hour of electricity produced. These standards are conceptually simple and directly address the issue. Care will be needed to avoid unintentionally incentivizing gas-fuelled plants, which are not fitted with CCS but lock-in CO_2 emissions. A permitted emission amount decreases through time, enforcing innovation. A key difficulty is that firm rules and dates cannot be applied to technologies that do not yet exist.

Coal and gas combustion can become more sustainable. To change black fuel into green energy, the acceleration and scale-up of CCS is required, from tens of power plants within 5 years, to hundreds of large plants by 2025, and then to thousands of small power plants by 2035. This progression can defer climate change problems and buy time. To do this, bold policies of clear vision to include CCS emissions reductions must be explicit. CCS may be the single most effective and direct climate action available. It is not yet too late, but good words need to be matched by hard actions and good money; the present level of committed funds is too low and needs a 4- to 10-fold increase in order for this climate mitigation to be successful.

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PERSPECTIVE

Amine Scrubbing for CO_2 Capture

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Amine scrubbing has been used to separate carbon dioxide (CO_2) from natural gas and hydrogen since 1930. It is a robust technology and is ready to be tested and used on a larger scale for CO_2 capture from coal-fired power plants. The minimum work requirement to separate CO_2 from coal-fired flue gas and compress CO_2 to 150 bar is 0.11 megawatt-hours per metric ton of CO_2. Process and solvent improvements should reduce the energy consumption to 0.2 megawatt-hour per ton of CO_2. Other advanced technologies will not provide energy-efficient or timely solutions to CO_2 emission from conventional coal-fired power plants.

Existing coal-fired power plants in the United States have more than 300,000 MW of power capacity, providing about 50% of the total power generated nationally and representing more than 30% of CO_2 emissions. Any reasonable strategy for ameliorating anthropogenic climate change must reduce these emissions without closing these plants. Amine scrubbing is probably the only technology for postcombustion capture of CO_2 that is available to address this problem.

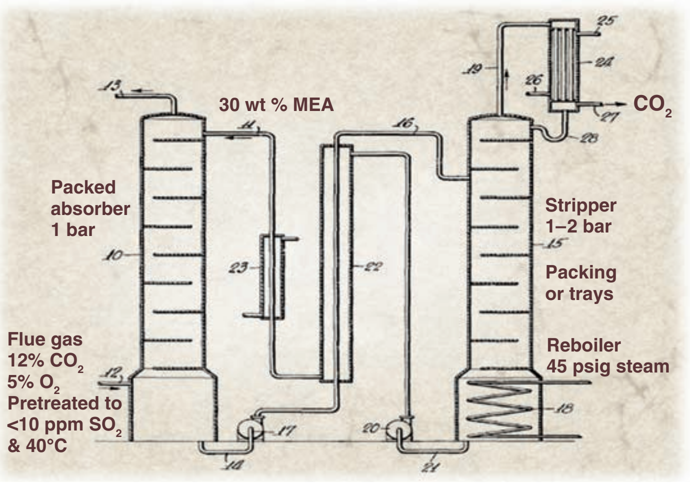

Fig. 1. The amine scrubbing process invented by Bottoms in 1930 (*7*).

The history of flue gas desulfurization should teach us what to expect in the development and deployment of technology for CO_2 capture. Lime or limestone slurry scrubbing for flue gas desulfurization was first applied at two British plants in 1936 (*1*), and was identified as an effective technology as early as 1965 (*2*). However, it was deemed to have unacceptable capital cost, poor reliability, and poor environmental performance, as well as being too commercial, and therefore was considered an unworthy candidate for government-funded research and development. Work on limestone slurry scrubbing continued, nevertheless, gaining increasing attention through the 1970s [e.g., (*2*, *3*)] and beyond, and now it is the dominant technology for flue gas desulfurization.

Amine scrubbing, the technology of choice for CO_2 capture, was first evaluated in 1991 (*4*) and—like flue gas desulfurization—was deemed to have unacceptable energy use and costs. It had been successfully applied to gas- (*5*) and coal-fired plants (*6*) on a small scale in the early 1980s, but was perceived to be too commercial and not worthy of government support. Since 2000, the U.S. Department of Energy has primarily supported R&D on other advanced technologies for CO_2 capture. However, amine scrubbing will probably be the dominant technology for CO_2 capture from coal-fired power plants in 2030.

CO_2 removal by absorption and stripping with aqueous amine is a well-understood and widely used technology. The basic process, patented in 1930 (*7*), is one in which CO_2 is absorbed from a fuel gas or combustion gas near ambient temperature into an aqueous solution of amine with low volatility (Fig. 1). The amine is regenerated by stripping with water vapor at 100° to 120°C, and the water is condensed from the stripper vapor, leaving pure CO_2 that can be compressed to 100 to 150 bar for geologic sequestration.

Hundreds of plants currently remove CO_2 from natural gas, hydrogen, and other gases with low oxygen. Four coal-fired plants with power outputs of 6 to 30 MW separate CO_2 from flue gas using 20% monoethanolamine (MEA). More than 20 plants use 30% MEA on gases with substantial O_2 content, including a gas-fired turbine with a flue gas rate equivalent to that of a 40-MW coal-fired power plant that produces flue gas with 15% O_2. More than 10 plants use a proprietary hindered amine, KS-1, with flue gases produced by combustion of clean fuels. Four other demonstration projects using MEA, KS-1, and another proprietary amine at coal-fired plants of 5- to 25-MW capacity will start up in Germany and Alabama, USA, in 2010 and 2011 (*8*, *9*).

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