A CCUS retrofit of a coal-fired power plant would involve adding a capture unit to separate CO_2 from the flue gases before they are released to the atmosphere. This is known as "post-combustion capture". The most cost-effective approach today is absorption of CO_2 by amine-based solvents that are regenerated by heating, which liberates the absorbed CO_2 to be compressed for transport. To avoid contamination of the solvent, the flue gas needs first to undergo flue gas desulphurisation (FGD).

Another approach to retrofitting CO_2 capture while upgrading the plant could involve replacing the boiler with a so-called oxy-fuel boiler whereby the coal is combusted in an oxygen-rich environment. This requires a more extensive and expensive upgrade of the plant and energy is required for the production of oxygen from air, but there is a cost saving in CO_2 separation because the resulting flue gas stream is almost 100% CO_2. A solution could come in the future from electrolysis-based hydrogen plants, which produce large amounts of oxygen as a by-product. This can represent a local opportunity not only for power plants but also for waste to energy plants to implement oxy-combustion. While oxy-fuel retrofits cannot be ruled out, the additional retrofit costs and less developed status of the technology are factors that favour post-combustion capture.

Adding CCUS to a power plant incurs an operational cost due to the reduction of efficiency caused by the energy requirements of CO_2 capture, transport and storage. CO_2 capture is responsible for the overwhelming majority of additional energy requirements which translate into fuel costs for the power plant operator. The efficiency penalty depends on the type of CO_2 capture technology used, but for current, state-of-the-art designs, it is usually considered to be in the order of 5-9%. Other additional operational costs like solvent purchases, have lower costs compared to the impact on fuel purchases per unit of output.

The retrofit at Boundary Dam involved adding an amine-based CO_2 capture plant to remove 90% of the CO_2 in the flue gas, compress it and inject it into a pipeline to an oil production operation. Most of the CO_2 is used for enhanced oil recovery (EOR)[2] and the power plant operator is paid for the CO_2 it supplies. Boiler modifications were also made: the old steam turbine was replaced with a new state-of-the-art turbine and an FGD system was added to remove virtually all of

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[2] CO_2-EOR is a proven technology for rejuvenating the production of oil at mature oilfields but can also provide a means of storing CO_2 permanently, as much of the gas injected is ultimately retained in the reservoir over the life of the project. For a CO_2-EOR/CCUS project to be considered a genuine climate mitigation measure, the CO_2 has to come from an anthropogenic source, such as a power station or natural gas processing plant. In practice, about 70% of the CO_2 used in the United States EOR projects today comes from naturally occurring underground reservoirs (not included here as CCUS). Several additional activities would also need to be undertaken before, during and following CO_2 injection, including additional measurement, reporting and verification of stored volumes.

the SO_2 from the flue gas. Energy requirements have been minimised by using a combined SO_2/CO_2 capture system and with selective heat integration. After allowing for the energy requirements of the capture plant, the net generating capacity of the retrofitted Unit 3 was reduced to 120 MW from 140 MW, and the refurbishment extended its life by at least 30 years.

The Petra Nova project retrofitted post-combustion amine-based CO_2 capture to a 240 MW slipstream at a 610-MW unit located at NRG Energy's Parish sub-bituminous coal-fired power station. This capture unit is designed to capture 1.4 $MtCO_2$ per year at a capture rate of up to 90%. The captured CO_2 was compressed and transported via a 130-km pipeline to the West Ranch oil field, for injection for EOR at a depth of 1-2 km. A key difference between the Boundary Dam and Petra Nova facilities is that steam and power for the capture unit at Petra Nova are provided by a 75-MW gas-fired co-generation unit that came online in 2013. As a result, the retrofit did not result in a de-rating of the existing asset because steam and power from the base plant was not redirected for CO_2 capture. Energy from the co-generation unit that is not needed for CO_2 capture can be sold to the grid at times of high electricity demand or supply shortage, due to the flexibility advantages of a single cycle turbine.

From a broader economic perspective, retrofitting CCUS generally makes most sense for power plants and industrial facilities that are young, efficient and located near places with opportunities to use or store CO_2, and where alternative generation or technological options are limited. Other technical features that must be considered when assessing whether a retrofit is likely to make commercial or economic sense are capacity, availability of on-site space for carbon capture equipment, load factor, plant type, proximity to CO_2 transport infrastructure and confidence in the long-term availability of CO_2 storage.

If there is insufficient space available at the power plant site on which the CO_2 capture facility could be hosted, the plant may be technically unsuitable for a CCUS retrofit. The total land needed to accommodate a CO_2 capture facility, including compressors, has been estimated in different studies to range from 0.03 to 0.08 hectares per MW retrofitted for units of 300 MW to 600 MW.

Transport and storage requirements

After capture, a CCUS retrofit requires the CO_2 to be transported to suitable locations for use or permanent geological storage. Transport of large volumes of CO_2 in pipelines (average pipeline capacity range is 3-30 $MtCO_2$/year) is a known and mature technology, with significant experience from more than 8 000 km of

CO_2 pipelines in North America – mostly in the United States. CO_2 is transported 66 km from the Boundary Dam plant in Saskatchewan, Canada. There is also experience, albeit limited, with transport of CO_2 using offshore pipelines, for instance at the Snøhvit project in northern Norway. CO_2 is also transported by ship, but in small quantities.

Carbon capture retrofits at power plants require a high confidence in the availability of CO_2 storage or demand for use. Geological storage involves the injection of CO_2 into suitable geologic formations and the subsequent monitoring of injected CO_2. Suitable geologic formations include saline aquifers, depleted oil and gas fields, oil fields with the potential for EOR and, potentially, coal seams that cannot be mined with potential for enhanced coal-bed methane (ECBM) recovery.

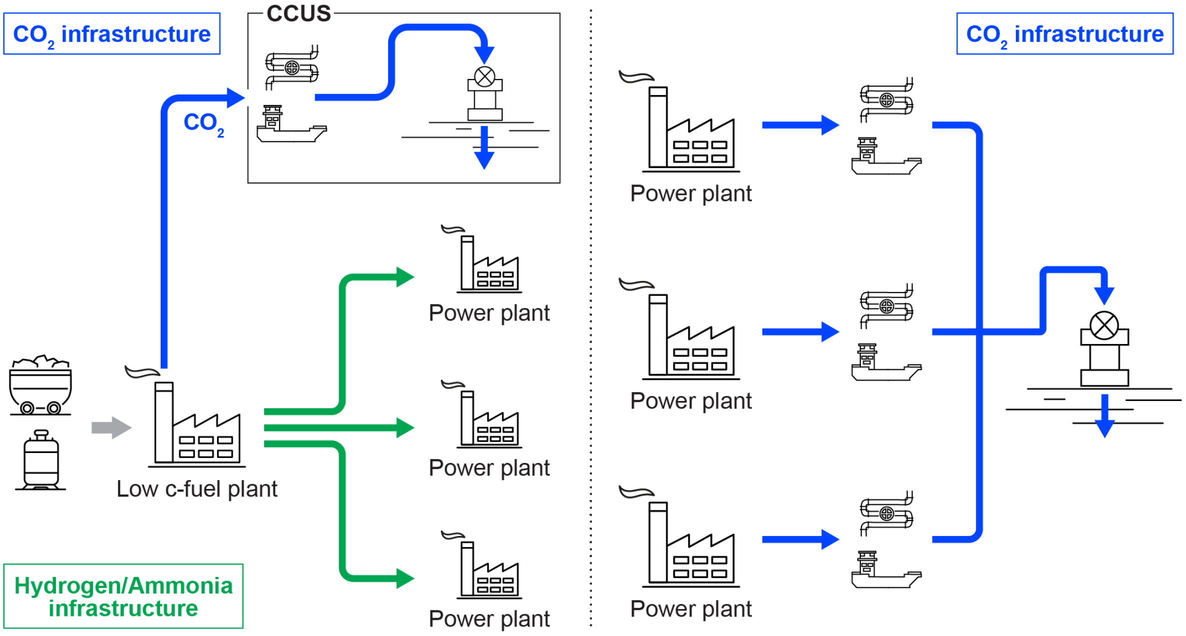
The fundamental physical processes and engineering aspects of geological storage are well understood, based on decades of experience. For example, the Sleipner project off Norway has been storing around 1 Mt CO_2/year in a deep saline aquifer under the North Sea since 1996, and six further projects around the world are now storing large volumes of CO_2 in dedicated geological formations (that is, not associated with EOR). This project experience is supported by decades of research and modelling, operation of analogous processes (e.g. acid gas injection, natural gas storage and EOR), studies of natural CO_2 accumulations and pilot projects.

When CO_2 is injected into a reservoir, it flows through it, filling the pore space. The gas is usually compressed first to increase its density, turning it into a liquid. The reservoir typically needs to be at depths greater than 800 metres to retain the CO_2 in a supercritical state. The CO_2 is permanently trapped in the reservoir through several mechanisms: structural trapping by the seal, solubility trapping in pore space water, residual trapping in individual or groups of pores and mineral trapping by reacting with the reservoir rocks to form carbonate minerals. CO_2 storage can be undertaken safely – provided there is proper site selection, planning and operations – but it has to be recognised that all storage reservoirs are different and therefore need extensive dedicated characterisation.

Comparing CCUS-based pathways to decarbonise thermal plants

CCUS can support emission reductions from existing thermal power plants in two key ways: through direct retrofitting to the power plant or by enabling low-carbon production of hydrogen or ammonia that is subsequently co-fired in the plant (see Chapter 3).

Comparison of applying CCUS to different parts of the low-carbon electricity value chain



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Note: On the left side, CO_2 is captured from the concentrated process gases of the fuel conversion plant. Then the decarbonised fuel is shipped to the power plant. On the right side, CO_2 is captured from the dilute flue gases of the power plant. Then the CO_2 is shipped and stored.

The two pathways bring benefits and trade-offs when considering the potential for emission reductions across the value chain, the CO_2 transport and storage needs and the operation of the power plant.

Applying CCUS at the fuel production stage (upstream) to facilitate the co-firing of low-carbon ammonia and hydrogen can have several advantages over direct retrofitting of a thermal power plant. They include:

- lower cost CO_2 capture opportunities due to a more concentrated CO_2 stream,
- the potential to locate new production facilities near CO_2 storage resources or CO_2 utilisation facilities (reducing transport infrastructure requirements), and
- a more attractive business case for CCUS infrastructure investment where this investment can underpin the supply of low-carbon hydrogen or ammonia to

meet growing demand from a large number of customers (reducing commercial risk and creating economies of scale).

Moreover, fuel production facilities operate at baseload and do not have to follow a varying demand. Therefore, upstream CCUS can operate at baseload as well. However, the approach would require dedicated ammonia or hydrogen transport and handling infrastructure to supply the fuel to power plants, in addition to the CO_2 transport and storage infrastructure at the production site.

Retrofitting CCUS directly to a power plant (downstream) involves higher-cost CO_2 capture (per tonne of captured CO_2) relative to ammonia or hydrogen production due to the more diluted CO_2 concentration in the flue gas. The investment needs for CO_2 transport and storage infrastructure may also be greater where existing power plants are not located in close proximity to CO_2 storage resources or industrial clusters that can support shared infrastructure. Further, the utilisation (or load factor) for the capital-intensive infrastructure may be lower where CCUS-equipped plants are operated in a flexible manner, increasing costs. However, the overall efficiency of the value chain (in energy terms) is higher for CCUS retrofits as only one conversion step is needed from fuel to final output (electricity).

Both power plants retrofitted with CCUS, and plants co-firing ammonia or hydrogen can be run flexibly to help integrate renewables into the power system. Both could also be operated in a baseload capacity, but with higher costs for co-fired plants due to the higher-cost fuel. The plant modification requirements for CCUS retrofitting (discussed above) are greater than for co-firing.

Comparison of CCUS-based pathways to decarbonise fossil fuel power plants

	Coal route		**Natural gas route**	
	CCUS retrofit of power plant	NH_3 co-firing with CCUS applied to fuel production	CCUS retrofit of power plant	H_2 co-firing with CCUS applied to fuel production
Value chain assessment				
Overall efficiency (fuel to electricity)	35%	22%	41%	38%
CO_2 storage needs (tCO_2 / MWh_e)	1.0	1.8	0.4	0.5
Capacity factor of CO_2 infrastructure	Variable	High	Variable	High

Power plant operation				
CO_2 emissions reduction	85-98%	Dependent on co-firing share	85-98%	Dependent on co-firing share
Cost impact of flexible operation	High	Low	High	Low
Modification requirements	Large	Small	Large	Small
Technology readiness level (power plants)	9	5-8	8	6-9

Note: “Overall efficiency (fuel to electricity)’’ for CCUS retrofitted power plants includes efficiency losses due to CCUS, while for co-firing it includes both CCUS-equipped fuel production efficiency and unabated power generation efficiency. Co-firing is not assumed to affect power generation efficiency, which is assumed to be 44% for ultra-super critical coal-based generation and 52% for combined-cycle gas turbine-based generation. Natural gas to hydrogen efficiency with CCUS is estimated at 74%, and for coal to ammonia with CCUS it is estimated at 49%.

Chapter 3. Production and transport of low-carbon hydrogen and ammonia

Highlights

- **Global hydrogen demand was 90 million tonnes (Mt) in 2020 and was responsible for almost 900 Mt of CO_2 emissions.** Hydrogen production is dominated by fossil fuels, with water electrolysis accounting for an estimated 30 ktH_2 in 2020, less than 0.03% of global production. With sixteen plants in operation, hydrogen production from natural gas with CCUS amounted to 0.7 MtH2 in 2020, 0.7% of global production.
- **Ammonia production was 185 Mt in 2020 and was responsible for around 450 Mt of CO2 emissions.** While CO2 capture is widespread in the ammonia industry, with more than 130 Mt CO_2 captured in 2020, only a small fraction of the captured CO_2 is geologically stored. Ammonia is already a widely traded commodity. Its global trade was about 20 Mt, or 10% of production in 2019.
- **Substantial GHG emission reductions can be achieved with low-carbon hydrogen and ammonia when compared to the unabated production from fossil fuels.** This means both maximising CO_2 capture from fossil fuels based hydrogen production and minimising upstream emissions from the production and delivery of natural gas and coal. Especially at high CO_2 capture rates, the emissions of the fossil fuel route become dominated by upstream emissions. For the electrolytic route, very low emissions can be achieved if electricity from wind, solar PV or other low-carbon sources are used. Capturing and permanently storing CO_2 from biomass-based hydrogen production would allow the production of carbon-negative hydrogen and ammonia.
- **The cost of low-carbon hydrogen and ammonia depends strongly on regional conditions.** Natural gas with carbon capture, utilisation and storage (CCUS) is currently the least-cost production route for low-carbon hydrogen and ammonia in regions with cheap natural gas, and access to CO_2 storage. Due to continuing reductions in the cost of renewable electricity and scale benefits in electrolysers, the costs of the electrolytic route are decreasing fast and are estimated to reach USD 13/GJ (USD1.5/kg) for hydrogen and 22/GJ (USD 400/tNH_3) for ammonia in regions with excellent wind and solar resources by 2030. Although the costs of low-carbon hydrogen and ammonia are becoming comparable with respective production costs from unabated fossil fuels for use as a chemical feedstock, they are still expected to remain significantly more expensive than coal and natural gas for energy use in 2030.
- **Marine transport costs can represent a significant share of the total supply costs of low-carbon fuels.** The cost estimate for marine transport of low-carbon fuels for a distance of 10 000 km is USD 14-19/GJ (USD 1.7-2.3/kgH_2) for liquid hydrogen, while for ammonia it is significantly lower at USD 2-3/GJ (USD 40-60/tNH_3)

Hydrogen market

In 2020, global hydrogen demand was around 90 megatonnes (this includes more than 70 Mt used as pure hydrogen and less than 20 Mt was mixed with other gases for methanol production and for a direct reduced iron [DRI] steel manufacturing process) and has grown 50% since the turn of the millennium. Around 72 Mt H_2 (or 79%) were covered by dedicated hydrogen production plants, while the remainder was by-product hydrogen (21%), i.e. hydrogen that is produced in facilities and processes that are designed primarily for other products.

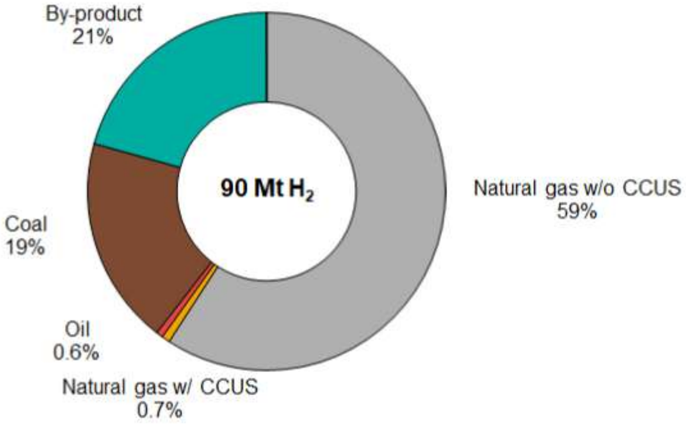
Practically all hydrogen demand comes from refining and industrial uses. Refineries consume close to 40 Mt H_2 to remove impurities (especially sulphur) and to upgrade heavy oil fractions into lighter products, whereas the industrial sector consumes more than 50 Mt H_2, mainly as a feedstock. Chemical production accounts for around 45 Mt H_2 demand, three-quarters of which are consumed in ammonia production and another quarter in methanol production. The remaining five Mt H_2 is consumed in DRI steelmaking. This distribution of hydrogen demand among end-uses has remained almost unchanged since 2000, with a slight increase in the contribution from DRI.

The vast majority of hydrogen production is based on natural gas reforming with some exceptions, like the use of coal gasification in Chinese refineries, which makes up close to 20% of dedicated hydrogen production in the country's refineries.

Hydrogen production

Around 240 billion cubic metres (bcm) of natural gas were used in 2020 for hydrogen production, accounting for 60% of annual global hydrogen production (representing 6% of global natural gas use). Coal comes next, due to its dominant role in China: it accounts for an estimated 19% of global hydrogen production and uses 115 Mt of coal (2% of global coal use). Oil and electricity account for the remainder of the dedicated production.

Sources of hydrogen production in 2020



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Source: Global Hydrogen Review 2021

As a consequence of the dominance of fossil fuel use, hydrogen production was responsible for almost 900 million tonnes of direct carbon dioxide (Mt CO_2) emissions in 2020 (2.5% of global CO_2 emissions in energy and industry), equivalent to the CO_2 emissions of Indonesia and the United Kingdom combined.

Various low-carbon pathways exist to produce hydrogen: from water and electricity through electrolysis, from fossil fuels with CCUS and from bioenergy. Production from water electrolysis accounted for an estimated 30 kt of hydrogen in 2020, less than 0.03% of global production. With 16 plants in operation, hydrogen production from natural gas with CCUS amounted to 0.7 MtH_2 in 2020, 0.7% of global production. These include facilities that produce pure hydrogen and capture CO_2 for geological storage or sale. CO_2 captured from ammonia plants for urea manufacturing is excluded.

Hydrogen from natural gas

Steam methane reforming (SMR) is the dominant process for the production of hydrogen. The SMR process usually starts by receiving the feed gas under pressure. Any sulphur compounds it may contain are transformed by reaction with hydrogen to hydrogen sulphide, which can be then absorbed in a bed of zinc oxide pellets at 300-400°C. The desulphurised feed is then mixed with steam and further preheated before entering the reformer, where it reacts at 800-900°C with steam to produce a mixture of carbon monoxide, carbon dioxide and hydrogen as the main constituents. The reaction takes place in furnace tubes packed with nickel catalyst, and the intense heat needed to drive this endothermic reaction is supplied by natural gas burners in the furnace radiation box.

After reforming, the process gas is cooled in a waste heat boiler and fed to a shift conversion step where the hydrogen content of the gas is maximised. The gas is then further cooled in a heat recovery train to about 30°C and sent to a pressure swing adsorption (PSA) unit for purification. The PSA process operates at about 18 – 30 bar and separates hydrogen from the gas mixture by adsorbing other compounds. The separation efficiency of the PSA unit is between 85-90% depending on the number of adsorbers in sequence and the operating conditions. The remaining hydrogen together with adsorbed impurities like carbon dioxide, carbon monoxide, methane and nitrogen forms an off-gas stream that is released from the PSA system at ambient pressure. The PSA off-gas has heating value and is used in the process as a reformer fuel. The CO_2 from the PSA off-gas can be further separated and used for other industrial processes or in food and beverages. While it could be compressed and transported for permanent storage, today almost all CO_2 that is not utilised is simply released into the atmosphere.

Autothermal reforming (ATR) is another example of a commercially available process for producing hydrogen from natural gas, although it is much less common today than SMR. A major difference from SMR is that the reaction heat needed for reforming is generated in the ATR by internal combustion with oxygen. Since this eliminates the need for heat from external burners, all the CO_2 formed in the process remains concentrated in the process gas and can be conveniently captured as a part of hydrogen purification.

Methane pyrolysis (MP), also known as methane cracking, is an alternative technology to conventional SMR for producing low-carbon hydrogen, which is rapidly approaching large-scale demonstration phase. It is carried out by cracking the fuel through high temperature heat to produce solid carbon and H_2 in a one-step process. This avoids the direct production of CO_2 (and hence the need for its disposal) and co-produces solid carbon. Its emissions depend on the source of energy needed to drive the endothermic reaction, the source of methane and end use of the carbon product. The competitiveness and positioning depend on future trends in gas prices and global market demand for solid carbon like carbon black and other value-added solid carbon products as each tonne of hydrogen produced results in around 3 tonnes of solid carbon co-product. The current market for carbon black is about 13 Mt per year, so producing the global pure hydrogen demand by methane pyrolysis would co-produce almost 20 times as much carbon black as the current market demand. Hence, new markets for carbon black would be needed to significantly decrease the cost of hydrogen production.

Full electrification of methane reforming, also known as e-SMR, is another emerging technology, presently in the early stage of development, but with potential for rapid upscaling. This technology offers the potential to reduce the formation of CO_2 by a third in comparison with conventional SMRs, and delivers all CO_2 in a concentrated stream that would be amenable to capturing. It also brings additional advantages including a more compact reactor design due to the absence of a firing section, faster response times and more uniform heating. However, to realise its full CO_2 mitigation potential, low-carbon electricity needs to be used, which might have added cost either in the form of electrical energy storage or due to intermittent operation.

Hydrogen from coal

Hydrogen can also be produced from coal via gasification. Coal gasification processes use pure oxygen, which is produced from air using a cryogenic air separation unit. The coal feed is milled and made into a slurry with water. The feed is then heated in the presence of oxygen to about 1200-1500°C to generate a gas mixture rich in carbon monoxide, carbon dioxide and hydrogen. The produced gas is then cleaned from impurities like soot and slag to protect downstream processes. The remaining process steps include a water-gas shift reaction for maximising the hydrogen content, CO_2 removal and sulphur removal. Hydrogen production via coal gasification is considerably more emissions-intensive than natural gas-based production.

Hydrogen from biomass

Biomass gasification for synthetic fuel applications was demonstrated a few times in the 2010s using fluidised-bed gasifiers followed by upgrading to different end-products like Fischer-Tropsch fuels, synthetic gasoline and biomethane. The largest demonstration plant to date was built as a part of the GoBiGas demonstration project in Sweden. It was commissioned in 2014 by Göteborg Energi in Gothenburg, and featured a 30 MW_{th} dual fluidised-bed biomass gasifier that converted pellets to raw synthesis gas. The syngas was purified with scrubbers and filters, and converted to synthetic methane over a nickel catalyst at elevated temperature and pressure.

Unlike coal, biomass feedstocks are characterised by a high content of volatiles that form a range of light hydrocarbons and tars during gasification. These impurities need to be treated before the gas can be further processed using commercially available technologies. Cost-effective and reliable treatment of tars from biomass gasification has for long been a key R&D challenge and as a result, two main approaches have been developed: scrubbing with organic solvents and catalytic reforming. The latter approach is especially suitable for synthesis