PLANT DESIGN AND ENGINEERING   **SPECIAL**REPORT

Engineering and economics of CO_2 removal and sequestration

Using this technology will help facilities meet environmental regulations

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ncreased waste heat recovery from flue gases can minimize the capital and operating cost associated with post-combustion carbon dioxide (CO_2) capture and sequestration facilities. This can offer cost-effective technology and minimize CO_2 released to the atmosphere.

Due to CO_2's ability to trap solar radiation in the earth's atmosphere and the sheer quantity emitted, CO_2 is considered the principal greenhouse gas responsible for global warming by many in the scientific community. Approximately 7 giga (7 trillion) tons/year (tpy) of CO_2 is emitted worldwide and this is forecast to double between 2030 and 2050. Legislative action is anticipated to impose stricter emissions standards, financial penalties and/or incentives to sequester CO_2 emissions.

CO_2 emissions. Due to varied discharge levels and quantities, not all emissions can be economically separated and sequestered. CO_2 emissions sources include:
- Automobiles (>500 million vehicles worldwide)
- Normal CO_2 content in natural gas (~2% to ~30%) and coal (~8% to ~20%)
- Coal/gas-based boilers/turbines in large industrial and power plants

- Large diesel/gas engine driven generators for remote areas
- Gas turbine-driven machinery, including compressors and generators in refineries, petrochemical and chemical facilities, oil and gas plants, offshore platforms, floating production units and marine transport.

Currently, carbon credits are trading ~$30/ton. Values from ~$25/ton to $80/ton are quoted as the cost of CO_2 capture and sequestration. The Norwegian government taxes its energy business at a rate of $65/ton of CO_2 emitted. Emission taxes are being debated globally and the cost of CO_2 credits is expected to rise in anticipation of similar regulations and laws being passed elsewhere. Any differential between properly designed CO_2 sequestration project costs and emissions taxes will be an incentive for large CO_2 emitters to act.

All technologies necessary for CO_2 capture and sequestration are mature and have been in operation for more than 30 years. Comparative technologies include:
- CO_2 removal from process and flue gas streams using amine technology
- CO_2 compression in urea plants
- Hydrocarbon gas reinjection/underground storage in oil fields.

TABLE 1. Annual CO_2 emission comparison

Description	Thermal efficiency	Power, kWh	CO_2 emissions, tpy
1. 100-MW gas-based cogeneration power plant (gas + steam turbine-driven generators + heat recovery steam boilers)	~50% to 57%	100,000	~350,000
2. 100-MW gas turbine-driven compressor	~33% to 34%	100,000	~585,000
3. 100-MW coal-fired power plant (steam generation and steam turbine-driven generators)	~45% to 49%	100,000	~400,000 + @ 20% CO_2 content in coal
4. 10-MW gas turbine-driven compressor	~31% to 34%	10,000	~57,250
5. Gas engine-driven generator or compressor	~33% to 34%	1,000	~5,120
6. 1,000-cc standard car running 2 hours/day, 300 days/year = 600 hours	~30%	~50 to 52	~20 to 21

Notes: Annual equipment usage, 8,760 hours; ambient temperature, 40°C; relative humidity, 60%

TABLE 2. Flue gas specification, by volume, %

Gas	Gas turbine exhaust	Coal-fired boiler exhaust
CO_2	~2.75%	~9% to 15%
H_2O	~9% to 10%	~6% to 16%
Nitrogen	~72% to 73%	~70%
O_2	~4.5% to 18%	~21.5% to 3%

TABLE 3. CO_2 separation processes

Process	CO_2 concentration volume, %	Feed gas pressure, bar
Chemical absorption	>3	1
Physical absorption	>20	>20
Adsorption	>30	Moderate
Membrane	>15	>7

Sulfur dioxide (SO_2) removal is an integral part of CO_2 capture and sequestration. In a properly designed process or power plant, 85% to 90% of CO_2 and 98% of SO_2 can be removed.

Capturing CO_2 from large emitters. Due to economies of scale, capturing CO_2 from large emitters is potentially the most economical investment. A 100 MW/hour, clean hydrocarbon gas-based combined-cycle power plant generates ~350,000 tpy of CO_2. Removing and sequestering this CO_2 is equivalent to permanently taking 20,000 cars [1,000 cubic centimeter (CC) cars, running 2 hours/day for 300 days/year] off the road. Estimated emissions from various CO_2 emitters are given in Table 1.

CO_2 concentrations in flue gases depend on fuel properties. Coal from various global sources has an 18% to 20% CO_2 content and ash content between 2% and 30% by weight. Many natural gas reservoirs have a CO_2 content ranging from 2% to 30%. Pipeline quality gas specifications typically limit CO_2 content to less than 3% with treatment or mixing often required to meet this criterion. This CO2 content of the fuel has to be added to the equipment emissions in order to arrive at total plant emissions.

Any CO_2 sequestration project has three key processes:
1. CO_2 separation from the process or flue stream
2. Compressing the concentrated CO_2 to a pressure ranging from 80 barg to 180 barg and transportation to the sequestration site
3. Sequestration in selected locations such as depleted oil and gas reservoirs, deep saline reservoirs or onshore underground unmineable coal beds, etc.

CO_2 separation. Economics for separating CO_2 from flue gases is affected by the amount of CO_2 in the fuel and the air-fuel ratio used in that particular equipment. This air fuel ratio is ~2:1 in coal-fired boilers and ~45:1 in gas turbine-driven generators. Typical flue gas specifications for equipment firing clean hydrocarbon gas or coal are shown in Table 2.

Not all emissions can be captured for sequestration; however, CO_2 from large emitters can be separated and sequestered at relatively low cost. The power consumed by the CO_2 capture process can be substantially provided through higher heat recovery within the power generation plant due to a lower flue gas exhaust temperature.

Depending on the plant configuration typically, ~30% (~60% in simple cycle gas turbine/engine) or more fuel energy is lost through the stack. In coal- or gas-fired power plants with heat recovery steam generation (HRSG), exhaust flue gas temperatures, which typically range between ~175°C to ~220°C (>400°C for gas turbines without HRSG) depend on:
• Flue gas dewpoint. The exhaust gas temperature leaving the stack must be greater than the dewpoint temperature to prevent SO_2 and CO_2 forming corrosive acids combined with water (H_2O) vapor in the flue gas.
• Minimum stack height required to meet local emission stan-

dards for dispersion including SO_x, NO_x and soot.
• Heat recovery process availability.
Typical CO_2 separation processes also require pretreatment to remove SO_2 and soot precipitation, thus reducing the allowable flue gas dewpoint and permitting additional heat recovery from the exhaust stream. For example, in a flue gas with 3% oxygen (O_2) content, reducing the sulfur content by 0.5% can reduce the flue gas dewpoint by 15°C–35°C. By removing soot and the heavier CO_2 molecule from the flue gas, the discharge temperature and stack height required to achieve a desired dispersion as per local environmental regulations is reduced, thereby supporting greater flue gas heat recovery.

Post-combustion CO_2 removal technologies. These can be advantageous because they can be applied to existing plants and there is significant experience (>65 years, with amine plants) using this technology. However, the unique nature of flue gases presents significant engineering challenges for recovery:
• Flue gases have a relatively low CO_2 concentration requiring large gas volumes to be treated.
• Flue gases at low pressure limit options for CO_2 recovery process selection and require large equipment sizes. Pressure drops across the CO_2 separation process should be minimized to reduce:
  1. Turbine back-pressure losses
  2. Compression power required for sequestering the recovered CO_2 stream, i.e., in gas-fired turbines with HRSG, exhaust pressure losses are kept between 6 in. to 10 in. WG.
• Flue gas O_2 corrodes equipment and degrades liquid solvents.
• The SO_2 and nitrous oxide (NO_2) in the flue gas react with the amine solvent to form heat-stable amine salts that increase solvent losses and cause equipment corrosion.
• The flue gas stream fly ash and soot (coal-fired plants) cause corrosion, erosion, solvent degradation and loss, and sludge formation.

Commercial plants removing CO_2 from flue gases using proprietary solvents, with a capacity of up to 1,200 tons per day (tpd), were first built in the early 1980s for enhanced oil recovery (EOR) and various industrial applications. Process plants with CO_2 removal rates of 3,000 tpd from high-pressure process streams have been in operation since the mid-1990s. When compared with CO_2 production of approximately 10,000 tpd for a medium-sized 500-MW pulverized coal-fired power station, a 1:5 scaled-up plant is easily achievable.

CO_2 removal technologies can be broadly classified as absorption, adsorption, membrane separation and cryogenic processes. However, as apparent from Table 3, not all technologies are suitable for removing CO_2 from exhaust gas streams. Based on CO_2 concentration and flue gas pressure, currently, chemical absorption is perhaps the most economically viable technology. Research

is expected to extend the range and commercial competitiveness of alternate technologies.

Chemical absorption. This involves contacting the exhaust gas with a solvent that removes CO_2 through an exothermic chemical reaction, which can be reversed upon heating. A number of patented solvents (primarily organic amine-based chemicals) are available. Various amines exhibit different properties in terms of its affinity for CO_2, the heat required for regeneration, corrosivity (function of the dissolved CO_2) and regeneration stability.

Alkanolamines—which are classified as primary, secondary or tertiary, depending on chemical structures—are the most common organic solvent for separating acid gases from natural gas process streams and for capturing CO_2 from flue gases (Fig. 1). Primary alkanolamines react more strongly with CO_2 but require more heat to regenerate and are generally more corrosive than secondary and tertiary amines due to higher CO_2 loading. Secondary and tertiary amines react less strongly, require less heat to regenerate but require greater amine circulation rates to achieve equivalent CO_2 capture levels.

Monoethanolamine (MEA) is the cheapest and most widely used alkanolamine for CO_2 absorption. It has the highest theoretical absorption but does not achieve this in practice due to corrosion limitations. It also has significant carryover during regeneration due to its high vapor pressure. Most industrial applications use an aqueous solution with MEA concentrations between 15% and 30%. Corrosion inhibitors are effective with carbon steel where the MEA concentration is less than 30% and CO_2 loading (moles of CO_2/moles of MEA) is less than 45%. Figs. 2 and 3 show typical amine absorption units removing CO_2 from exhaust gases.

Prior to entering the CO_2 recovery process, the exhaust gas is compressed (if required) to around 1.3 bar to overcome pressure drops in the system. To increase CO_2 capture rates, which may be required for large power plants, exhaust gases can also be compressed to a higher pressure level (say 5 bar) using axial compressors. It is cooled to around 50°C and fly ash, soot and other impurities removed as much as possible. Exhaust gas enters the packed column absorber at the bottom and contacts the alkanolamine absorbent in countercurrent flows as it rises up. The CO_2 is chemically bonded to the solvent and the treated exhaust gas leaves the adsorber with CO_2 content typically less than 2%. An H_2O wash system is used at the top of the absorber to minimize absorbent carryover in the exhaust flue gas.

The solvent, now rich in CO_2, is pumped from the bottom of the absorber through the lean rich heat exchanger to the packed column stripper. In the stripper, applying heat breaks the weak chemical bonds between the chemical absorbent and CO_2. H_2O vapor, O_2, CO_2 and evaporated solvent leaves the top of the stripper where the H_2O and solvent are condensed, accumulated in a reflux drum and returned to the top of the stripper column.

Predominantly pure CO_2 leaves the top of the reflux drum for drying, compression, transportation and sequestration. Energy for boiling the stripper column's bottom fluid is provided by a reboiler using low-grade/low-cost steam. The lean amine from the reboiler is pumped back to the top of the absorber column via the lean/rich heat exchanger where the CO_2-rich solvent cools it and the process is repeated. Reclaimers are used to remove degraded products (heat stable amine salts). Side
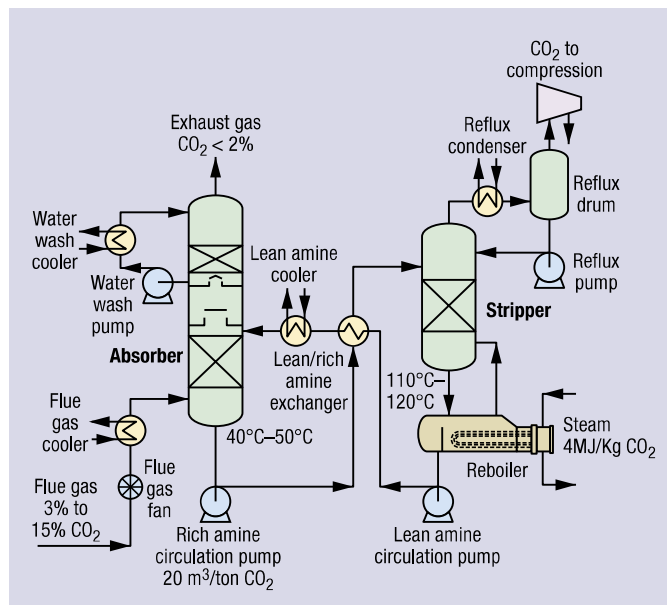

FIG. 1   Amine removal system process schematic.

circulation rates are from 1% to 5% of the total solvent circulation rate.

Typical performance parameters for a CO_2 recovery system using conventional MEA solvents are:

1. Regeneration heat required 4 MJ/kg of recovered CO_2

2. Over a 25-year life cycle, total costs are split almost equally between capital and operating cost. For exhaust gas streams with low CO_2 concentrations, such as turbines (3%), the operating costs are expected to exceed the capital cost.

- The bulk of operating cost (70–80%) can be attributed to the regeneration costs determined by CO_2's partial pressure in the product.
- The bulk of capital cost (50–80%) is driven by the solvent circulation rates, which sets the absorber tower size, piping system, circulation pumps and regeneration facilities. Solvent circulation rate is set largely by CO_2's partial pressure in the feed gas.

3. The economical CO_2 recovery limit is approximately 85% for a 3% concentration of CO_2 in the exhaust gas and between 90% and 92% for an 8% concentration.

Chemical solvents that offer reduced energy requirements for regeneration and higher CO_2 solvent capacities have the potential to significantly reduce the chemical absorption system's cost. Chemically modified amines, known as sterically hindered amines, retard the CO_2 reaction rate with alkanolamine, produce an unstable intermediate carbamate solution, increase CO_2 loading and reduce energy requirements for regeneration. One commercial application captures 210 tpd of CO_2 at 99.95% purity. A performance parameters comparison between traditional MEA and sterically hindered amines is in Table 4.

Corrosion testing has demonstrated that sterically hindered amines, without corrosion inhibitors, offer significantly improved corrosion rates over MEA at typical stripper column operating temperatures and in the presence of O_2.

CO_2 compression and transportation for sequestration. CO_2 is a difficult gas to compress because it behaves like
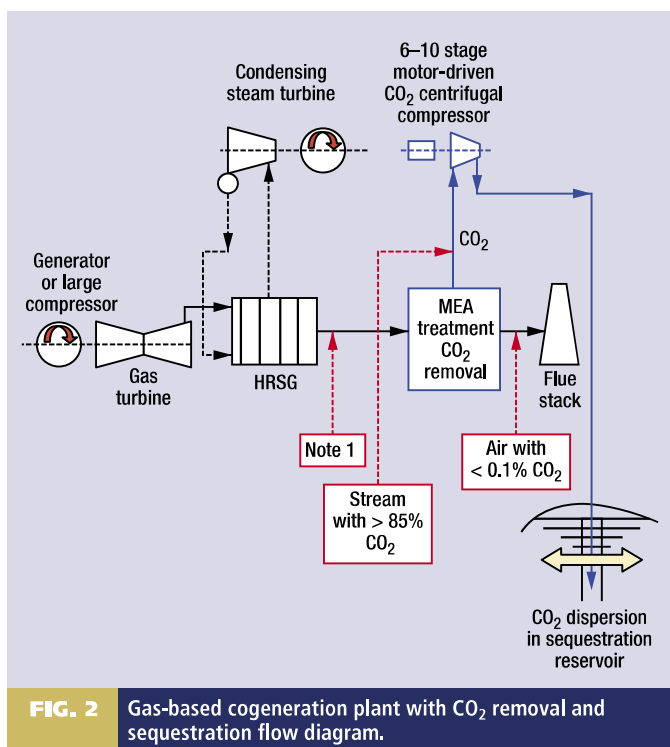
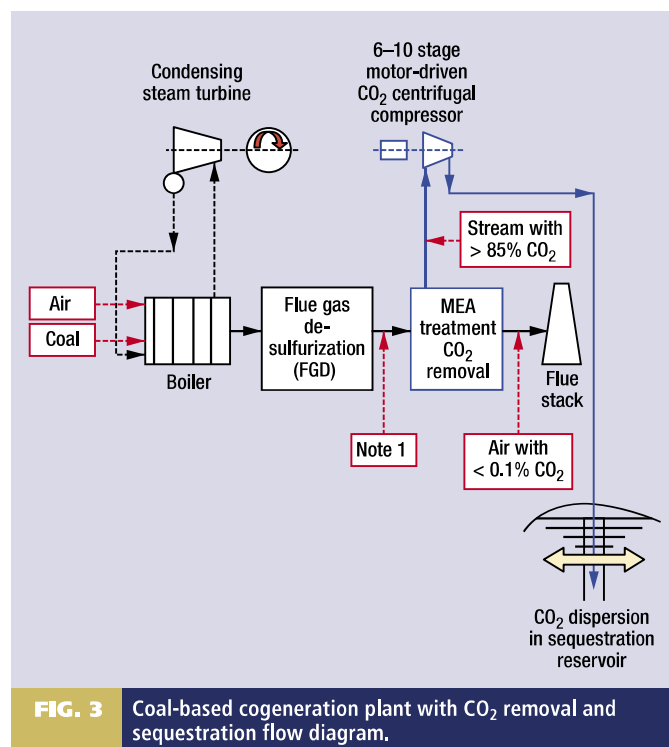**FIG. 2** Gas-based cogeneration plant with CO_2 removal and sequestration flow diagram.

FIG. 3 Coal-based cogeneration plant with CO_2 removal and sequestration flow diagram.

TABLE 4. CO_2 capture performance comparisons between MEA and sterically hindered amines

	MEA	Sterically hindered amines
Steam for solvent, ton/ton CO_2	1.95 to 3.0	1.2
Regeneration [3 barg], GJ/ton CO_2	4.2 to 6.5	2.6
Solvent flow rate, m³/ton CO_2 estimated	17 to 25	11
Power for pumps and fans, kWh/ton CO_2	150 to 300	19.8
Cooling H_2O, m³/ton CO_2	75 to 165 (Delta T = 10°C)	150
Solvent consumption, kg/ton CO_2	0.45 to 2	0.35
SO_2 tolerance, ppm	10 to 100	<10

a liquid at its supercritical conditions [72.95 barg and 24.47°C], which are commonly encountered during compression. Large volumes of CO_2 are compressed in urea plants and significant experience exists among compressor manufacturers. In comparison with urea plants, where CO_2 is available from ~1 barg to ~6 barg (87 psig); the flue gases with CO_2 discharge pressure at about 0.25 barg (4.25 psig), posing significant compression challenges.

The discharge pressure required for sequestration depends on the reservoir properties in which CO_2 is to be stored. The expected pressures required for injection into various geological formations/reservoirs are:
• 80 barg–100 barg/1,160–1,450 psig for deep unmineable coal beds/seams
• 150 barg–160 barg/2,175–2,320 psig for EOR
• 150 barg–180 barg/2,175–2,610 psig for reinjection in saline subsea reservoirs/abandoned oil/gas wells both onshore and off-shore
• 310 barg/4,495 psig for deep-sea/ocean-bed storage at a dispersal depth of 3 km/2 miles.

While hydrocarbon gases have been compressed to 350 barg/5,075 psig, proven experience for compressing CO_2 is readily available up to 200 barg/2,900 psig. A large number of compressors in CO_2 service that have discharge pressures ranging from ~80 barg to 200 barg/1,160 to 2,900 psig exists in urea plants globally.

Selecting a compressor type for this service will have a strong impact on the sequestration facilities operating costs. Integral geared multistage centrifugal compressors (Fig. 4), which were initially developed to maximize compression efficiency in large air plants, are now used in urea plants for CO_2 service. An integrally geared multi-stage compressor with 4–10 stages and intercooling will minimize the required compression power. Post-treatment composition and physical properties of a typical concentrated CO_2 flue gas stream at the inlet to the compressor are given in Note 3 of Table 5.

Table 5 shows typical operating parameters of a 9-stage, motor-driven, integrally geared compressor pressurizing approximately 500,000 tpy of CO_2 from 0.15 barg to 180 barg (2.18 psig to 2,610 psig). Such a compressor would cost ~$6 million per machine including the driver and inter-stage coolers. The principal benefits in selecting an integrally geared compressor are:
• A high compression ratio is achievable in one machine.
• Using multiple intercoolers minimizes power consumption.
• Using under-slung coolers minimizes the inter-stage pressure drop.
• 3-D impellers (Fig. 5) for each stage can be designed for high efficiencies.
• Rigid construction. Each impeller is supported by a bearing that minimizes rotor dynamics problems.
• These compressors leave the smallest machine footprint.
• Motor drive gives high reliability and availability. Alternatively a turbine drive may be selected.

FIG. 4   Type RG 80-8 8-stage integrally geared compressor (CO_2) for gas injection.

FIG. 5   High-pressure CO_2 integrally geared compressor impellers.

Sealing between the compressor and gear case is by labyrinth, mechanical contact or dry gas seals. Compressor control can be achieved using inlet guide vanes, speed variation and discharge pressure control or a combination of these. Considering the need for high turndown, a combination of hot and cold recycle (Fig. 6) decoupled from the capacity and speed control loop will assist in adequate protection against surge and hydrate formation.

Integral geared centrifugal compressors that have been successfully operating in CO_2 sequestration service include:

• Saskatchewan, Canada, Dakota Gasification Co.'s Weyburn's EOR project compressing 1.35 million tpy of CO_2, raising pressure from 0.15 barg to 187 barg (2.18 psig to 2,712 psig)

• Offshore Norway, Statoil's Sleipner saline reservoir CO_2 sequestration project removing 1 million tpy of CO_2 from a gas stream containing 9% CO_2. Since 1996, the captured CO_2 is injected into a confined saline aquifer at 800 m below the seabed and 2,500 m above the Sleipner West hydrocarbon reservoir.

Transporting CO_2 to a reservoir is expected to be less costly by pipeline. Transportation costs, including installation, operation and maintenance (for a 25-year project life) through a 50-km-long 6-in. pipeline, is expected to be less than $0.50/ton. One ton of CO_2 at 100 bar occupies ~4 m^3 of space. At this pressure a 1 km^2-sized reservoir with a 10-m gas column can hold 2.5 million tons of CO_2 which is equivalent to about 10 years of emissions from a 100-MW cogeneration power plant. Identifying such reservoirs for CO_2 storage within a suitable distance will minimize the capital cost of laying a pipeline and operating costs due to the minimized transportation pressure losses.

Sequestration. In the past decade, the scientific community has assessed various geological formations to act as reservoirs for CO_2 sequestration. A single geological structure (i.e., ultramafic body) can sequester many giga tons of CO_2. Some geological formations considered suitable for CO_2 injection/sequestration are identified in Table 6.

Significant research has been carried out worldwide to establish the geological properties of a reservoir required to hold CO_2 for long periods of time (>500 years). A typical reservoir can be characterized as an underground bed with an earth layer of significant depth acting as a cap with either porous rock or H_2O

level below the earth cap. Using in-situ stress and formation fluid pressure data available from drilling, geologists prepare a geomechanical model to:

• Estimate the maximum sustainable reservoir pressure that will not induce any fracture in reservoir faults resulting in CO_2 escaping in large quantities

• Determine reservoir static and dynamic behavior

• Decide the optimum injection scheme, for example, whether to inject at the top into the gas cap or below the H_2O table.

In addition to the geomechanical model, there is a need for geochemical and hydrological models to fully characterize the geological system's dynamics. This process should consider chemical reaction, fluid flow, mechanical stress/strain and its interdependencies.

Reservoir modeling can determine the following sequestration parameters:

• Approximate amount of CO_2 that can be sequestered

• CO_2 rate diffusion within the reservoir

• Reaction rate with salts and minerals, thus producing stable inorganic compounds.

The sequestration reservoir's containment integrity depends on the proposed site's geology. A primary concern is preventing leakage back to the environment. A reservoir's salinity and rock formation are also important in preventing leakage back to the atmosphere.

In-depth sequestration process studies have been conducted evaluating the migration and reaction of CO_2 in subsoil. Downhole seismic (cross-well and vertical profiling) can help evaluate the migrating CO_2 plume's geometry. Diffusion coefficients are difficult to measure at the high pressures and temperatures normally encountered in sequestration. However, it is possible to estimate diffusion coefficients from laboratory measurements. These can be used to evaluate the expected CO_2 trap time, which will allow its reaction and formation into stable salts.

A number of drilling technologies are available to evaluate injected CO_2 movement, dispersion and reaction, for example, wireline logging for saturation, downhole geochemical sampling, reservoir 3D-simulation and pumping fluids to the surface to monitor geochemical changes. Observing the overlaying sandstone, groundwater and air for trace elements injected in CO_2 can help determine the system's effectiveness in retaining CO_2.

In aquifers without a shale layer, the CO_2 plume rises quickly to the aquifer's cap-rock and migrates laterally with some CO_2 possibly escaping. Unconsolidated rock formations, such as geologically young shale having hydration (expanding clays-smectites) and plastic properties, are expected to be excellent CO_2 storage sites.
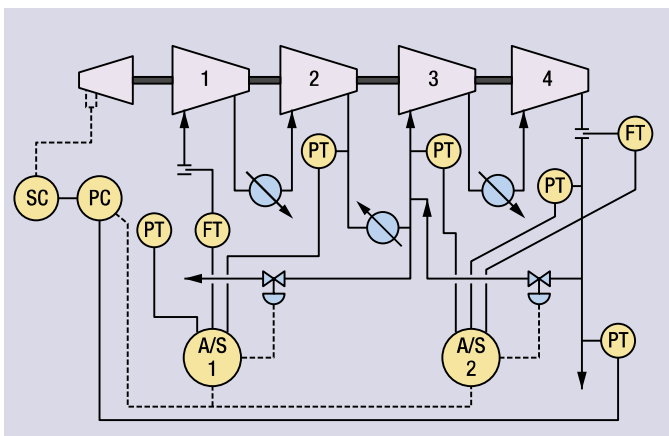
TABLE 5. Typical parameters for a 9-stage motor-driven compressor compressing 500,000 tpy of CO_2—approximate calculations

Compression stage/unit	1	2	3	4	5	6	7	8	9
Actual inlet flow, m³/hr	30,411	16,755	9,029	4,780	2,544	1,390	763	406	198
Suction pressure, kPaa	115	208	384	714	1,321	2,323	3,984	6,700	11,111
Discharge pressure, kPaa	216	392	722	1,329	2,331	3,996	6,713	11,123	18,000
Pressure ratio	1.881	1.881	1.881	1.861	1.765	1.720	1.685	1.66	1.62
Operating speed, rpm	4,975	4,950	4,950	9,880	11,850	11,800	14,560	14,625	14,000
Discharge temperature, °C	97	97	97	96	92	89	89	87	87
Differential head, kNm/kg	42.1	42	41.7	40.5	36	32.9	29.7	25.7	19.5
Compression efficiency, %	85	85	85	85	83	83	80	78	78
Power required, kW	786	783	777	755	688	628	588	523	395
Motor power required, kW	6,610 (including losses and 10% power margin)								

Note 1. CO_2 properties; molecular weight, 44.01; gas density, 1.98 kg/m³; liquid density, 960 kg/m³ at minus –6°C; density at super-critical condition, 467.74 kg/m³; critical temperature, 31.1°C; critical pressure, 73.85 bar abs; gas-to-liquid ratio, 485:1.
Note 2. Dry super-critical CO_2 is inert; however, it is very reactive in the presence of water or sodium chloride brines and, though compressible, behaves like a liquid.
Note 3. Gas flow, 57,077 kg/hr; suction temperature for each stage pre-intercooled, 40°C; gas properties in mole percentage, CO_2 = 89.95; carbon monoxide = 3; O_2 = 2; nitrogen = 3; H_2O water = 2; SO_2 = 0.05; mol weight of gas = 42.3; Cp at 15°C = 36 kJ/kmol K; Cp at 100°C = 38.81 kJ/kmol K.

FIG. 6 Suggested control loop for controlling a multistage centrifugal compressor.

TABLE 6. Geological formations for CO_2 sequestration

Reservoir type	Global estimated storage capacity
Deep saline aquifers	1,000 to 10,000 giga tons or more
Empty natural gas/oil field	1,000 giga tons
Existing oil fields for enhanced oil recovery	See above
Un-mineable deep coal beds	No estimates available

m³ (sm³) to 560 sm³ [5,000 standard ft³ (scf) to 20,000 scf] of CO_2 is required to recover an additional barrel of oil. Reservoir-specific evaluation will optimize CO_2 storage vs. oil recovery.

Deep unmineable coal beds are also an attractive option for CO_2 sequestration with coal-bed affinity for CO_2 being well established. Natural mined coal contains ~18% CO_2. Methane is being successfully recovered from coal beds in Alabama, the US and Queensland, Australia. This recovery can be further enhanced by injecting additional CO_2 into the reservoir's unmineable section improving the methane recovery rate.

The future. Geologically, a large number of structures exist globally that can be used to sequester CO_2 stably for very long periods. Many reservoirs have the ability to sequester multiple giga tons of CO_2 and finding suitable storage capacity within a reasonable distance of CO_2 generation is not expected to be a constraining factor.

Similarly, dispersal of captured CO_2 on the ocean bed (>3 kms deep) to form stable carbonate compounds could be a commercially viable alternative. Though expected to be minimal, detailed studies are underway to evaluate the impact on marine and microbiological life. The estimated/expected cost of various utilities for CO_2 removal using an MEA process is shown in Table 7.

High energy costs are expected to drive the opportunity for improved plant thermal efficiency and environmental concerns are expected to drive the need for CO_2 capture and sequestration. Engineers have the technology to meet our environmental needs, and CO_2 sequestration can succeed in minimizing man's impact on our planet. Companies that act early on CO_2 sequestration could also be the ones to gain the maximum from an early investment. **HP**

Such geologically young and unconsolidated sediments tend to slough and swell. Drillers have reported that uncased boreholes will commonly squeeze shut in a matter of hours, resulting in natural borehole closure.

This natural closure is an important mechanism in preventing upward movement in unconsolidated rock areas. The permeability of such mud plugs is usually less than surrounding formations, which, combined with the hydrostatic head of an overbalanced mud column, is sufficient to counterbalance increased formation pressure due to injection, thus creating an effective barrier to vertical fluid flow.

CO_2's solubility in H_2O increases with increasing pressure and decreasing temperature. However, solubility can be reduced by up to 50% due to the presence of dissolved salts in the injection aquifer or subsea reservoir.

A typical depth for a sequestration or EOR reservoir is expected to be grater than 800 m, requiring CO_2 injection pressures between 80 bars to 180 bars. Early CO_2 injection is considered most useful in EOR projects, whereas later injection is expected to provide the highest storage capacity in saline aquifers or depleted oil wells. As CO_2 diffuses into the reservoir's oil phase, oil swelling occurs, assisting in EOR. Laboratory and field tests estimate that 140 standard

TABLE 7. Economics for 500,000 tpy of CO_2 sequestration

Operating cost	Cost
MEA makeup (~1 kg/ton of CO_2)	$1/ton of CO_2
Compression cost/ton of CO_2 at $0.1 per kWh	$10/ton of CO_2
Cooling H_2O (~makeup 10 m³/ton of CO_2 at $0.15/m³), power (~225 kW/ton of CO_2 at $0.1 per kWh), low-quality steam (~2.5 tons/ton of CO_2 at $1.5/ton), miscellaneous utilities and other management costs (~$2/ton of CO_2)	$30/ton of CO_2

Installation/first cost	
MEA facility ($21 million) + additional utility ($4 million)	~$25 million
CO_2 compressor (6,000 kW motor driven) facility	~$8 million
Pipe line cost (50 km, 6-in. pipe line, 150 bar pressure)	~$15 million
Sequestration well drilling cost	~$3 million
Amortizing this first cost over 25 years at 6% rate of interest, the installation cost per ton of sequestration	$8/ton of CO_2

Recovered energy value	
Cost of additional energy recovered from flue gases per ton of CO_2 emitted (conservatively assuming 15% waste heat recovery)	$25/ton of CO_2

Actual cost of CO_2 capture is ~$24/ton of CO_2 captured.

Additional cost burden on end user is ~$0.0135/kWh.

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