Techno-Economic Analysis and Optimization Models for Carbon Capture and Storage - A Survey

Yuping Huang, Steffen Rebennack and Qipeng P. Zheng

Abstract Carbon dioxide (CO_2) emissions are projected to increase significantly during the coming decades if effective environmental policies are not implemented, and the negative impacts of carbon emissions will eventually hinder economic and human development. Carbon capture and storage are proposed to mitigate the global climate change due to the increased concentration of carbon dioxide in the atmosphere. In this article, we focus on the technical developments and economic analysis of carbon capture and storage using optimization models and algorithms. The three main components of carbon capture and storage we discuss are: carbon capture, carbon dioxide transportation and carbon sequestration. In addition, to fulfill carbon dioxide reduction requirements, we also discuss the use of mathematical programming models solving energy expansion planning, CO_2 network design problems and CO_2 storage problems. Through the combination of technical and economic analysis of carbon capture and storage technologies, possible directions for sustainable developments of low-carbon energy economy can be evaluated.

Key words: carbon capture · carbon storage · CO_2 · CO_2 pipeline network · carbon sequestration · techno-economic analysis · energy system expansion planning · mathematical programming · optimization models

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1 Introduction

Carbon capture and storage (CCS), generally, is referred to as a method or integrated process available to capture CO_2 directly from large point resources and subsequently to sequester it into underground geologic formations for long-term storage. The major goal of CCS is to mitigate CO_2 emissions to the atmosphere. In this way, it hopefully lengthens human use of fossil fuels to provide more time to develop renewable and alternative energy technologies so as to ultimately combat climate change. With respect to the current energy infrastructure as shown in Fig. 1, it is expected that fossil fuels will remain the most important U.S. energy source for the next few decades. However, energy consumption worldwide shows that electricity and heat generation are responsible for 60% of the global CO_2 emissions as presented in Fig. 2. Since electricity and heat generation mainly consume fossil fuels (*e.g.*, coal, oil and natural gas), they are labeled as the major contributors of CO_2 emissions. Therefore, CCS is a critical component of a solution to mitigating global warming and a crucial component for a sustainable energy future.

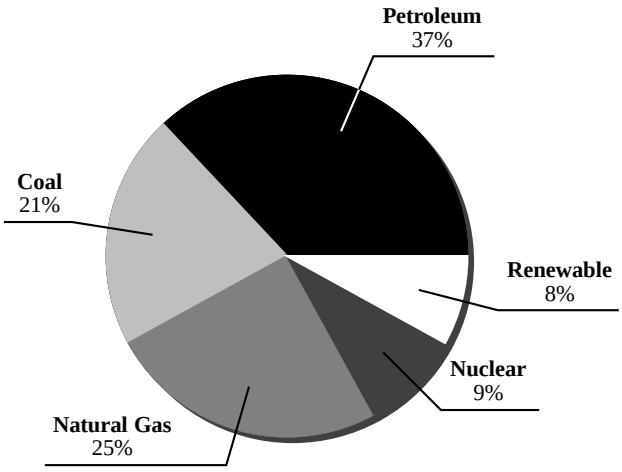

Fig. 1: U.S. energy supply from five types of resources. Data source: [1].

Over the past decade, many scientists have engaged in studies of carbon capture and storage. More than 45 CCS pilot projects in six countries have been proposed so far for further research and deployment of commercial projects over next 20-30 years [3].

However, as matters stand now, the large-scale deployment of CCS still requires demonstration of technical and economic feasibility. Moreover, the implementation of CCS technology unavoidably encounters a number of challenges, such as technical barriers, financing, climate policy, safety and environmental practices. The high

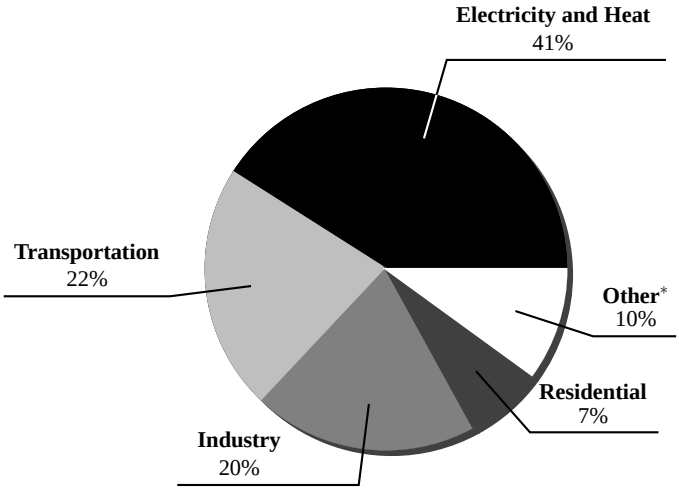

Fig. 2: World CO_2 emissions by sector in 2008. Data source: [2].
* *includes commercial/public services, agriculture/forestry, fishing, energy industries other than electricity and heat generation, and other emissions not specified elsewhere.*

investment costs and energy efficiency penalty of CCS in power generation is most likely to influence decision makers to agree with large-scale project deployment; a CCS project's lifetime spans 10 to 30 years. For long-term operations, the economic feasibility is still determined by both CO_2 market price and CO_2 allowance and exposure of their volatility. Successful projects' frameworks and energy policies are also expected to encourage participant contribution and to exert proper economic incentives during a project's lifetime.

To promote the employment of CCS in power expansion planning, this review discusses the current status of CCS development which involves three major components: carbon dioxide capture, transportation and sequestration. Generally, the groups concerning the CCS deployment include the government, industry, and many other non-governmental organizations, such as Carbon Capture and Storage Association, International Emissions Trading Association and World Coal Association. The major goal of this review is to help any CCS participant fill a CCS knowledge gap or evaluate the technologic and economic information for a particular purpose. Also, this review is able to help energy operation research analysts and decision makers better understand each part of CCS, and to apply optimization approach in the areas of energy expansion planning, CO_2 network transportation or storage problems to achieve the comprehensive economic evaluations.

The main contribution of this paper is the summary of state-of-art CCS technological analysis and economic analysis. So far, there is a limited number of comprehensive technological studies considering economic analysis, although some tech-

niques have been applied in the real-world applications. Thus, this review fills the gap between technical and economic analysis of CCS and builds a connection from technique research to project planning. In addition, the comparative discussion regarding optimization methods used in different parts of CCS provides the insights of CCS resource integration and viable project management.

The remainder of this review is organized as follows. We review all major carbon capture and storage technologies, which consists of three parts: carbon dioxide capture, carbon dioxide pipeline network and carbon dioxide sequestration. In Section 2, Each capture technology is described, relevant literature is reviewed and an engineering-economic analysis is provided. The first three sub-sections focus on CO_2 capture technologies in stationary emitters, *i.e.*, coal-based power plants. In subsection 2.4, we discuss energy expansion planning optimization models with a focus on CCS. Section 3 presents the design of a CO_2 pipeline network and its characteristics. The CO_2 source-sink optimization model available in the literature are presented. In Section 4, we not only discuss three geologic reservoirs for permanent CO_2 storage and their individual sequestration mechanisms, but also summarize the hazardous impacts from potential risks. Also, a brief introduction on modeling CO_2 storage with energy benefit is provided. We then conclude the current research of CCS and discuss future research in Section 5.

2 Carbon Dioxide Capture

Carbon capture is a process that separates the CO_2 from flue gas (*e.g.*, resulting from fossil fuel combustion) and then captures it to abate CO_2 emissions. The literature to date primarily focuses on three main technologies: post-combustion capture, pre-combustion capture, and oxy-combustion capture. All these CCS techniques are specifically targeted towards CO_2 emissions reduction in coal-fired power plants, steel plants, oil refinery, ammonia production and chemical industries, which are ranked at the top of the CO_2 emitter list.

When choosing a desirable carbon capture system, it is necessary to take the following three properties of the flue into account:

(i) CO_2 concentration in the flue gas,
(ii) pressure and temperature of the flue gas, and
(iii) flue type (gas or solid).

Combined with government incentives, the economic assessment of each specific capture system helps decision makers to choose a suitable carbon capture system.

The economics of CCS is very closely related to the energy market as well as regulations and taxes. The current economic studies mainly include partial or general equilibrium modeling, *e.g.* emissions prediction and policy analysis (EPPA) model, bottom-up/top-down energy market modeling with CCS and net present value analysis to determine the CO_2 tax levels and growth rates. However, the following two criteria are commonly used in economic analysis of carbon capture:

(1) cost of electricity (COE) [$/MWh] and
(2) cost of CO_2 avoidance (CO_2^{avoided}) [$/ton CO_2].

The COE is obtained by dividing the annual power plant cost (TC^{PP}) and the carbon capture cost (TC^{capture}) by the annual electricity generation (E), where TC^{PP} is the sum of the annual capital cost, the annual operation and maintenance (O&M) cost, as well as the annual fuel cost. This leads to the formula:

$$\text{COE} = \frac{\text{TC}^{\text{PP}} + \text{TC}^{\text{capture}}}{\text{E}}.$$

Once a capture process is added to conventional power generation processes, the output of power generation inevitably decreases (due to the carbon capture process) and the capture cost is introduced, resulting in an increase of the COE compared to the case in which no carbon capture process is present [4].

The second economic measure is to calculate CO_2^{avoided}, which is particularly suitable for comparing different carbon capture process configurations with respect to their CO_2 savings:

$$CO_2{}^{\text{avoided}} = \frac{\text{COE}^{\text{cap}} - \text{COE}^{\text{ref}}}{CO_2{}^{\text{ref}} - CO_2{}^{\text{cap}}},$$

with

COE^{cap} : electricity cost of the carbon capture component,
COE^{ref} : (known) electricity cost of a reference component,
$CO_2{}^{\text{ref}}$: CO_2 emissions from a reference component, and
$CO_2{}^{\text{cap}}$: CO_2 emissions from the carbon capture process.

Based on fossil fuel power generation, we next review the carbon capture progresses with respect to its capture principles, energy consumption and economic evaluations.

2.1 Post-combustion Capture

Technical Principle

Post-combustion capture has been the subject of many studies and is a relatively mature technology applied at coal-fired power plants. The post-combustion capture process is shown schematically in Fig. 3. In the boiler, air is injected to react with coal. The hot flue gas may then pass through the CO_2 system that has an electrostatic precipitator and a flue gas desulfurization unit. After leaving the desulfurization unit, most of the CO_2 is removed from the flue gas and compressed for storage. The chemical process does not require special equipment constructed with high-temperature resisting materials. This system has the potential for wide deployment in coal-fired power plants because of the relative ease of retrofitting existing systems.

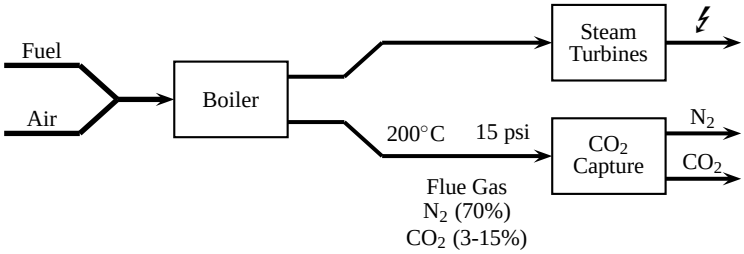

Fig. 3: Schematic of post-combustion CO_2 capture process, based on [5].

CO_2 Separation Techniques

In the CO_2 capture process, the separation of CO_2 from N_2 to accumulate pure CO_2 is the primary operation. Because the CO_2 partial pressure is typically between 0.1 and 0.13 bar in flue gas, N_2 contributes approximately 75% partial pressure, in addition to the partial pressure contributed by other pollutants such as SO_2, NOx and trace metals [6]. Thus, large parts of the energy consumed during the separation process is wasted on the treatment of other components, leading to lower CO_2 capture efficiency and ultimately an increase in CO_2 separation costs. The flue gas with CO_2 is generally treated with conventional chemical adsorption technologies, *e.g.*, CO_2 wet scrubbing with aqueous amine solutions [7]. This nonselective solvent has the advantage of regeneration. When the solvent is heated to temperatures greater than 120°C, it releases CO_2. The solvent is then recycled and re-used in the absorption tower. Monoethanolamine (MEA) is a popular, cost-effective solvent.

Alternative separation technologies are constantly being sought. New solvents should be equipped with better performance, higher capacity for CO_2 capture, lower energy consumption for regeneration, higher sorption rates, lower volatility, better stability, less degradation and lower corrosivity [8]. Figueroa et al. (2008) [5] provide an overview of such developments of emerging CO_2 separation technologies.

Table 1 summarizes some traditional and state-of-the-art technologies, and their different properties. Enzyme-based systems and ionic liquids both are potentially novel technologies explored for CO_2 capture, having a low energy penalty as their greatest strength. However, these new technologies have only been tested in laboratories. The restrictions for enzyme-based systems result from technical factors, loss of enzyme activity, long-term operation and scale-up; the limitations of ionic liquid approaches include low capacity, high unit cost and high viscosity that gives rise to application issues [5].

Economic Analysis

During the process of capturing CO_2, energy in the form of heat and electricity is consumed. Typically, this amounts to an efficiency loss of at least 10%. The novel CO_2 separation technologies, or significant improvements over existing processes, are expected not only to improve CO_2 removal performance, but also to satisfy the economical production and regeneration. Among separation technologies, alterna-

Table 1: Summary of post-combustion CO_2 capture technologies.

Capture Technology	Type	Example	Separation Properties	Reference(s)
Solvent	Chemical solvent	MEA, DEA, MDEA, Amine blends, piperazine+MEA, piperazine+MDEA, diglycolamine	React rapidly, good selective capture at low CO_2 pressure, reverse reactions required, large energy requirement, corrosive, violative, degraded.	[9], [10], [4], [11], [12], [13], [14], [15], [16]
Sorbent	Chemical adsorption	Amine-enriched sorbent, carbonates, zeolites, alkali metal-based sorbents, MOFs	Lower regeneration temperatures, relatively high CO_2 absorption capacity, good for low CO_2 concentration, reduce heating and stripping	[12], [15], [5], [17]
	Physical adsorption	Solid alkalized alumina	Low cost raw material, Low regeneration energy requirements, suitable for high CO_2 concentration and pressure	[18]
Membranes		Polymeric membranes (rubbers, polyimides, cellulose acetate), amine membranes, siliceous membrane, zeolite membranes	Higher interfacial areas, independence of phases, difficulties in scale-up, low selectivity and permeability	[12], [15], [5], [19], [6]

tive configurations of the processes may also achieve lower energy requirements and power consumption.

Schach et al. (2010) [4] provide a techno-economic analysis of the post-combustion CO_2 capture processes. They analyze and compare four different configurations of CO_2 capture processes: the standard adsorption and stripping in addition with 30 weight% MEA solutions, absorber intercooling, matrix stripper, and two strippers. The authors' simulation results show that savings in CO_2 avoided cost of 2%-5% can be obtained, together with power savings of 4%-7%, by modifying the process configuration. Large scale adsorption by accommodating the adsorbent materials is not adequately capable of satisfying requirements of flue gas processing, although their energy needs are fairly low.

Liang et al. (2011) [20] study the improved performance of CO_2 capture system with bi-pressure stripper, where the CO_2 capture efficiency and the pressure of extracted stream location are adjusted accordingly to analyze the impacts of flue gas load on lean solution flow rate, energy penalty and plant efficiency. Compared to single-pressure stripper, the energy penalty of bi-pressure stripper can be reduced by up to 6.4% at 90% flue gas load, by operating simulation of a 600 MW supercritical coal-fired power plant using Amine based CO_2 capture technique.

With further developments of capture technologies, more comprehensive economic evaluations have to be performed to better understand the influence of cost on innovative techniques and correlated configurations; these evaluations aid in the adoption of suitable and feasible CO_2 capture processes in coal-based power plants.

2.2 Pre-combustion Capture

Technical Principle

Pre-combustion carbon capture is a promising technology to remove CO_2 from syngas (a gas mixture containing varying amounts of CO and H_2 before the fuel enters combustion turbine(s)), in order to increase the yield of chemical reaction along with energy generation. This CO_2 capture technology will most likely be integrated with gasification combined cycle (IGCC) or natural-gas-fired combined cycle (NGCC) systems. For a typical process of IGCC with CO_2 capture, gasification of fossil fuels is the first step in the gasifier to generate high pressure syngas (CO and H_2). The chemical reactions follow two main equations, accompanied by small amounts of SO_2 and NOx production:

$$2C + O_2 + H_2O \longrightarrow H_2 + CO + CO_2,$$

and

$$C + H_2O \longrightarrow H_2 + CO.$$

The syngas, mainly comprised of CO and H_2, requires moderate cooling and then undergoes further reforming, termed water-gas shift (WGS) reaction:

$$2CO + H_2O \longleftrightarrow H_2 + CO_2.$$

In a shift converter, gas mixture process is a reversible equilibrium reaction, where CO is converted to CO_2 and additional H_2 is generated in the forward reaction.

After the WGS reaction, the shifted gas with a high concentration level of H_2 and CO_2 is cooled and subsequently processed for the capture of a sulphur compound and CO_2, using physical solvents, Selexol or methanol-based Rectisol solutions [21]. After clean-up, the gas then becomes only hydrogen, optionally used for chemical synthesis or power generation. Fig. 4 shows the schematic for the pre-combustion CO_2 capture process.

Engineers are interested in the gasifiers' characteristics, which depend on several factors, such as reactants and products inlet, particle size, resident time, operating temperature, and operating pressure. Technically, these gasification-based processes are feasible for power generation. However, in the U.S., only four of 20 gasification-based plants have been operated for power generation so far, unavoidably increasing uncertainties regarding large-scale deployment of gasification-based power plants.

CO_2 Separation Techniques

The separation technology approaches for pre-combustion CO_2 capture known today are mainly divided into four types: solvents, sorbents, membranes, and water gas shift membranes. Most of these technologies have only been demonstrated via laboratory or bench testing. To rapidly deploy advanced technologies, DOE/NETL has been funding a series of research, development, and deployment (RD&D) projects based on the studies of physical solvents, solid sorbents and membrane-based sys-

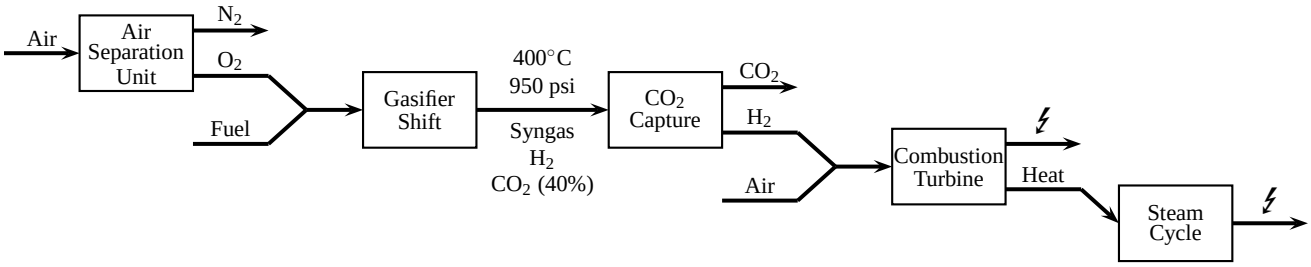

Fig. 4: Schematic of pre-combustion CO_2 capture process, based on [5].

tems (Composite Polymeric Membrane, Porous Membrane Contactor, Immobilized Liquid Membrane) to separate H_2 and CO_2 [21].

Researchers are primarily interested in the effective separation of the two gases, H_2 and CO_2, generated from WGS reactors. Moreover, there are a series of technical parameters collectively to drive the technical and economic considerations for the application of IGCC or NGCC, including the selectivity of gas mixture, permeance, the adsorption capacity for H_2 or CO_2, the undertaken temperature, regenerability, stability and energy requirements.

Table 2 summarizes the types of pre-combustion CO_2 capture technologies discussed in the literature. In addition to a few traditional technologies for commercial uses, most of the new separation technologies have been limited to feasibility studies in laboratories.

Economic Analysis

The economic analysis of IGCC combined with pre-combustion CO_2 capture is generally performed by comparing the base case (no capture) and the carbon capture case. Basic approaches and assumptions are made for calculating cost of electricity and CO_2 avoided cost.

Because N_2 is eliminated by air separation, it reduces energy consumption for the syngas treatment at later stages. However, most capture technologies require special materials that have not been produced on a commercial scale. Thus, when the special materials have commercial development, it may accordingly reduce capture costs. Meanwhile, the life cycle of the selected materials is still unknown and further long-term testing is required to establish quantitative measures.

To draw accurate economic conclusions, the specific investment and capital cost have to be known. These costs typically consist of solids reception, air separation, gasification, gas cleaning, gas turbines, heat recovery steam generators, steam turbines and water treatment. With CO_2 capture technologies, additional costs account for the shift section and catalyst, separation section and compression. Furthermore, the COE estimation is also impacted by discount rates, fuel cost, operating cost, maintenance cost and even insurance. International Energy Agency reports the levelized COE of pre-combustion CO_2 capture used in IGCC to be $104/MWh and

Table 2: Summary of pre-combustion CO_2 capture technologies.

Capture Technology	Type	Examples	Separation Properties	Reference(s)
Solvent	Chemical solvent	MEA, AMP, KS-1, Aqua Ammonia, Dual-alkali	Low or Moderate CO_2 partial, High acid gas selectivity, usage of thermal swing regeneration or pressure swing regeneration	[5], [12], [16], [22], [23], [24]
	Physical solvent	Selexol, Rectisol, Propylene Carbonate, Flutec Fluids	High CO_2 partial pressures, lower temperature, less energy for regeneration	[5], [12], [23], [24]
Sorbent	Chemical adsorption	Lithium Zirconate, Lithium Silicate, Amine-enriched sorbent	High removal efficiencies at low solvent concentrations, low ammonia losses	[5], [12], [16]
	Physical adsorption	Silica, SBA-1, SBA-15, MCM-41, MCM-48	Low energy requirement, quick regeneration by pressure change	[5], [12], [16]
H_2/CO_2 Membrane	H_2-selective membranes	Metallic, Porous Inorganic, Silica, Polymetric	Highly hydrogen selective at higher temperatures, high permeation of H_2,CO_2 product at high pressure	[5], [25], [19], [26]
	CO_2-selective membranes	Polymeric, Facilitated transport	High H_2 recovery rate, CO_2 product at lower pressure	[5], [25], [19]
Water Gas Shift Membrane	H_2-selective WGS-MR	Pd membrane, porous inorganic membrane	Near gasification pressure, relatively higher CO conversion, low temperature causing catastrophic failure, limited lifespan	[19]
	CO_2-selective WGS-MR	Aminoacid salt in polyvinylalcohol, Rubbery polymers (PDMS, PEBAX)	Low operational temperature, low pressure in CO2 generation, H2-riched products recovery at feed gas pressure	[19]

the average CO_2 avoided cost to be \$43/ton [27]. When COE is obtained, the CO_2 avoided cost measure presents a good comparison with carbon capture technologies. In the case of IGCC process using membrane technology, the CO_2 avoided costs are estimated within the range between 39€/ton and 43€/ton, based on different CO_2 recoveries [28].

2.3 Oxy-combustion capture

Technical Principle

Oxy-combustion capture is a modification of the post-combustion capture process. Instead of using normal air, oxy-combustion capture uses oxygen-enriched air or pure oxygen. However, if fuel burns in nearly pure oxygen, the resulting flame temperature is very high. To avoid unreasonably expensive equipment able to resist this heat, after the oxy-combustion, a portion of flue gas is resent to the boiler to control the flame temperature and enhance convective heat transfer.

Fig. 5 represents a general flowchart of oxy-combustion capture from a technical viewpoint. Pulverized Coal (PC) fired power plants are chosen as a typical example to illustrate the oxy-combustion capture process. The major difference between pre-combustion and oxy-combustion originates at the inlet gas, which is a mixture of gases entering a boiler to react with fuels. In oxy-combustion systems, the key cryogenic air separation unit is arranged prior to the PC boiler for the removal of N_2 and thereby produces highly concentrated O_2. The coal is then fed to a PC boiler and burned with oxygen. The resulting products primarily consist of highly concentrated CO_2 and large amounts of H_2O. Over 20% of the gas steam pass through steam turbines to generate power while the rest is required to pass through the particle removal and the sulfur removal units. After H_2O steam is condensed, pure CO_2 can be directly obtained. Meanwhile, the purified flue gas is compressed and then recycled in the boiler.

Oxy-combustion capture processes, as described above, are relatively mature technologies because the basic technical operations like oxygen separation and flue gas recycling have been widely demonstrated and employed in other industries, such as the steel, chemical & petrochemical, or metal industries. Furthermore, oxy-combustion capture technologies are suitable for existing conventional coal-fired power plants via retrofitting.

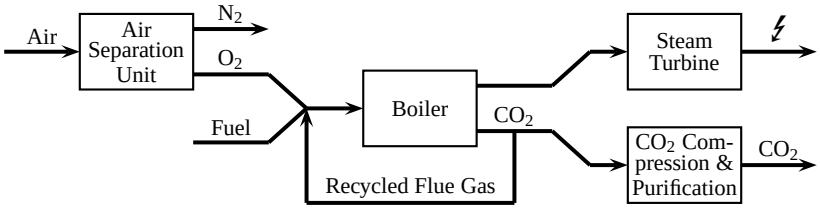

Fig. 5: Schematic of oxy-combustion CO_2 capture process, based on [5].

The general oxy-combustion capture process require air separation plant or external CO_2 separation equipment, but chemical looping combustion (CLC) technology has a feature of inherent CO_2 separation. The CLC typically applies metal oxide in a fluidized bed to provide oxygen for the combustion process in the boiler. The reduced material can be re-oxidized to metal oxide in the air sector and subsequently transferred back to the boiler for further reaction with fuel, the so-called "chemical looping." During such looping, the metal material undergoes oxidation and the redox reaction is expressed as [7]

$$O_2 + 2\mathrm{Me} \longrightarrow \mathrm{MeO},$$

$$C_nH_m + (2n + \frac{1}{2}m)\mathrm{MeO} \longrightarrow nCO_2 + \frac{1}{2}mH_2O + (2n + \frac{1}{2}m)\mathrm{Me}.$$

The final products are predominantly high concentrated CO_2 and water steam, without dilution of nitrogen gas. The biggest advantage of CLC process compared to the traditional oxy-combustion process is that it does not require air separation or additional CO_2 separation equipment, implying lower energy service cost.

CO_2 Separation Techniques

The final primary products of the oxy-combustion process are CO_2 and H_2O, but the mixture of gases also consists of excess O_2, a small portion of N_2, SO_2, NOx and other contaminants. To separate CO_2 and H_2O, the flue gas goes through cooling systems to condense the gaseous H_2O and consequently remove the water. Because flue gas is not diluted by nitrogen from the air, the gas volume of downstream processing (*i.e.*, processing after the air separation) shrinks significantly, which effectively lowers energy consumption as we do not have to deal with large volumes of the outlet gas. Other treatments for the removal of SO_2, NOx and Hg are also needed to improve CO_2 purity.

Improvements in the capture processes are expected to overcome several critical issues. To capture more than 95% CO_2 concentration from the gas mixture is more expensive compared to traditional technologies which have less than 65% CO_2 concentration. US DOE/NETL is funding advanced research to provide important breakthroughs in the reduction of more than 50% of the capture cost [29]. Additionally, emerging purification concepts are expected to achieve an advanced capture process associated with high CO_2 capture rates. Finally, optimizing the integrated oxy-combustion system is an effective means to eliminate uncertainty, for example, in the boiler and process air ingress.

Economic Analysis

The feasibility to retrofit oxy-combustion to coal-fired boilers has only been demonstrated theoretically. The investment cost mainly consists of coal and ash handing, boiler island, FGD plant, DeNOx plant, steam turbine island, air separation unit (ASU), CO_2 compression and purification for pulverized fuel (PF) air fired power plants without CO_2 capture, while only ASU and compression and purification are needed for typical NGCC air power plants without CO_2 capture.

The ratio of PF investment cost to NGCC investment cost under the condition of CO_2 capture installed is roughly equal to two. The total investment cost of an NGCC power plant is less than that of a PF power plant. However, there is a twofold difference in fuel costs between PF power plants and NGCC power plants. Thus, the generation load primarily determines the type of generation technology associated with CO_2 capture selected to achieve minimum electricity cost, as well as the efficiency and CO_2 capture loss percentage targets [30].

Air separation units and flue gas recirculation dominate the cost of the CO_2 capture in oxy-combustion. Due to a decrease in flue gas volume and an increase in concentration of CO_2, oxy-combustion processes are expected to be more economical than conventional PC plants [5].

Nsakala et al. (2004) [31] provide an economic analysis for CO_2 mitigated cost of \$37 – \$40/ton CO_2, based on a coal-fed circulating fluidized bed with ASU. Further-

more, large-scale technology, *e.g.*, Cryo-ASU, may consume up to 20% of a plant's gross power output. To further increase economic benefits of oxy-combustion CO_2 capture, the main target is to reduce the cost of oxygen production [32]. Instead of a Cryo-ASU, an oxygen transport membrane within a boiler can be used; as a result, the thermal efficiency for a natural gas system is estimated to increase from 87% to nearly 95%. The technology of ceramic autothermal recovery (CAR) for oxygen production is being developed to lower relative operating costs [5].

In addition to technical feasibility and operation costs considerations, choosing a right time point to invest carbon capture process is another question decision makers have to face. Due to the uncertainty of future electricity spot prices and CO_2 emission allowances spot prices, the timing to install or retrofit CCS with lower investment costs directly affects the short-term benefits of the power plants.

Rohlfs and Madlener (2010) [33] develop a multi-dimensional real options model to deal with the optimization problem of CCS investment. Their three-factor model has three stochastic prices: CO_2 emission allowance, electricity, carbon transportation and storage (CTS); their four-factor model has the previous three factors with the addition of the time-dependent investment cost. They aim to determine the approximate time lag between the initial investment and the upgrade to CO_2-free power plants. An investment comparison between CCS-ready power plants and conventional power plants with later retrofit is provided. Their study concludes that the low retrofit investment probability and the moderate rate of return for capture-ready investment result in lagging the CCS applications. Furthermore, the authors conclude that the replacement of mature power plants is more profitable than the retrofit of a CCS-ready plant.

2.4 Energy Expansion Optimization Models with CO_2 Reductions and CCS

Global energy demand is rising and, in addition, current power plants are retiring sometime in the future. Thus, the current power systems need to be expanded by additional power plants to satisfy future power market demands. Different power plant technologies, *e.g.*, hydroelectric and nuclear generation, provide an effective means to reduce the average CO_2 emissions per generated MWh. Through 2030, it is predicted that the largest energy source worldwide will continue to be fossil fuels [34]. As of today, renewable energy sources are not (with the exception of large hydro dams) able to serve as base-load plants, which typically are fossil fuel plants. Even if a generation mix is promoted widely, the amount of CO_2 emissions to the atmosphere inevitably increases if CCS is not used in fossil fuel burning plants. Therefore, energy expansion combined with pollutant mitigation should be adopted as a means to address political and environmental concerns.

Several studies examine optimal planning of electricity generation with CO_2 emission considerations [35]. On the one hand, power generation planning can be optimized by adjusting the structure of energy supply, for example, current gener-

ation technology retrofitted to new generation mix. On the other hand, the control of CO_2 emissions can primarily be achieved by fuel balancing, fuel switching, CO_2 capture, and renewable resources.

The general model for energy expansion planning with CO_2 reduction evaluates the effects of CO_2 reduction requirements on power generation cost and investment cost, based on a set of following assumptions:

- The fuel price as a main driver of power generation cost is assumed to be constant during the lifetime of a project but hardly affect any other decisions in most original models.
- The demand is considered to be a time-dependent parameter, which is given without involving any uncertainties.
- The plant capacity is separated into two groups based on the fuel type of generation units: fossil fuel and non-fossil fuel.
- Carbon emission limit is a pre-determined parameter that has been only applied in the evaluated generation systems.
- Both fuel switching and CO_2 capture work as optional strategies to meet the specified CO_2 emission target.

In the remainder of this subsection, we discuss the various objective functions and constraints present in existing energy expansion planning models. The objective functions model CO_2 emission credits / levels and the constraints model CO_2 emissions limits and selection of CO_2 capture processes.

2.4.1 Objective Functions of Energy Planning with CO_2 Reductions

Almost all objective functions seek to minimize energy (expansion) planning costs. Both economic and environmental factors provide decision makers with a screening criterion. The components of Objective cost mainly include retrofitting, electricity generation, O&M, capital investment, CCS, and purchasing CO_2 emission credits, which are listed in Table 3. We use small Roman letters for variables and capital as well as Greek letters for input data along with the following notation:

Sets

$\mathbb{J}$	Fuel types
$\mathbb{T}$	Time periods
$\mathbb{K}$	Carbon capture techniques
$\mathbb{F}$	Fossil fuel power plants
$\mathbb{F}^{\mathrm{C}}$	Fossil fuel power plants with CCS technology, $\mathbb{F}^{\mathrm{C}} \subseteq \mathbb{F}$
$\mathbb{N}$	Non-fossil fuel power plants
$\mathbb{W}$	New power plants, including fossil and non-fossil power generation, $\mathbb{W} = \mathbb{W}^{\mathrm{F}} \cup \mathbb{W}^{\mathrm{N}}$
$\mathbb{W}^{\mathrm{C}}$	New power plants with CCS technology, $\mathbb{W}^{\mathrm{C}} \subseteq \mathbb{W}^{\mathrm{F}} \subseteq \mathbb{W}$

Variables

h_{it}	[binary]	1 if retrofitting in generation unit i is performed at time t, otherwise 0
n_{it}	[binary]	1 if capital investment for unit i occurs at time t, otherwise 0
x_{ij}	[binary]	1 if fossil fuel generation unit $i \in \mathbb{F}$ with fuel type $j \in \mathbb{J}$ is operational, otherwise, 0
y_{ij}	[binary]	1 if generation unit i with fuel type j in new plant should be installed, otherwise 0
z_{ik}	[binary]	1 if carbon capture technology k is used in generation unit i, otherwise 0
e_{it}	[continuous]	Electricity generated from non-fossil fuel plant $i \in \mathbb{N}$
e_{ijt}	[continuous]	Electricity generated from plant $i \in \mathbb{F}$ using fuel $j \in \mathbb{J}$
e_{ikt}	[continuous]	The electricity required for unit i using carbon capture technology k
C_t^{Cre}	[continuous]	CO_2 credits at time t

Single Objective

Hashim et al. (2005) [36] propose an integrated model using CO_2 emissions cost coefficient conversion to combine economic and environmental factors. Their mixed-integer linear programming (MILP) model seeks solutions under CO_2 emission limits. The objective function has four components of costs. The first three components are presented as generation costs in fossil fuel plants, generation costs in non-fossil fuel plants, and retrofit costs for fuel type switching, respectively. The last component comprises CO_2 emission costs resulting from a fossil fuel plant using a specific fuel type.

Based on Hashim's previous work, Muis et al. (2010) [37] develop a MILP model with a comprehensive objective function in which O&M costs, retrofit costs and capital costs are included for both existing and new power plants. The minimum electricity cost is obtained by selecting plant shutdowns or new plant buildups following one or more schemes (IGCC, NGCC,and RE). The objective of the model is to select optimal power generation schemes for different CO_2 emissions reduction levels.

Mirzaesmaeeli et al. (2010) [38] consider time-dependent parameters related to energy demand, fuel price, construction lead time, conservation initiatives and O&M. Due to conservation initiatives and multiple time periods, the mathematical model becomes quite sophisticated. The objective function is to minimized total discounted present value of the total cost which includes investment cost for new power plants, fixed/variable O&M cost for existing/new power plants, fuel cost, retrofit cost for fuel switching, cost of purchasing CO_2 credits and CCS cost for existing/new plants.

Although all parameters assumed to be constant values for each time period, the general objective function can be formulated including generation cost involving fuel cost functions (1a), O&M cost (1b) and pre-operational costs (1c), shown as follow:

$$\min \quad F_1^1(\mathbf{e}) + F_2^1(\mathbf{x},\mathbf{y}) + F_3^1(\mathbf{h},\mathbf{n},\mathbf{C}^{Cre})$$

where

$$F_1^1(\mathbf{e}) = \sum_{t\in\mathbb{T}}\sum_{i\in\mathbb{F}\cup\mathbb{W}^F}\sum_{j\in\mathbb{J}} Cost_{ijt}^F(e_{ijt}^F) + \sum_{t\in\mathbb{T}}\sum_{i\in\mathbb{N}\cup\mathbb{W}^N} Cost_{it}^N(e_{it}^N) + \sum_{t\in\mathbb{T}}\sum_{i\in\mathbb{F}^C\cup\mathbb{W}^C}\sum_{j\in\mathbb{J}}\sum_{k\in\mathbb{K}} Cost_{ijkt}^C(e_{ijkt}^F, e_{ikt}^W) \tag{1a}$$

$$F_2^1(\mathbf{x},\mathbf{y}) = \sum_{t\in\mathbb{T}}\sum_{i\in\mathbb{F}}\sum_{j\in\mathbb{J}} M_{ijt}^F x_{ij} + \sum_{t\in\mathbb{T}}\sum_{i\in\mathbb{W}^F}\sum_{j\in\mathbb{J}} M_{ijt}^F y_{ij} \tag{1b}$$

$$F_3^1(\mathbf{h},\mathbf{n},\mathbf{C}^{Cre}) = \sum_{t\in\mathbb{T}}\sum_{i\in\mathbb{F}} R_{it}h_{it} + \sum_{t\in\mathbb{T}}\sum_{i\in\mathbb{W}} S_{it}n_{it} + \sum_{t\in\mathbb{T}} P_t C_t^{Cre} \tag{1c}$$

where $Cost(\mathbf{e})$ is the fuel cost function with respect to fossil fuel plant, non-fossil fuel plant and the plant with CCS, respectively. M_{ijt}, R_{it}, S_{it}, P_t are defined as O&M cost, retrofit cost, capital cost and cost for purchasing CO_2 credits, respectively.

Multi-Objective

Multi-objective optimization is an alternative approach of simultaneously optimizing at least two conflicting objectives in energy expansion planning problems. Most cases are anticipated to make optimal decisions in presence of trade-offs between minimizing power generation costs and minimizing total CO_2 emissions. Any renewable energy uses and CCS technologies, even power generation technology switching, generally produces relatively higher electricity costs than conventional coal-fired power generation. The conflicting objectives, therefore, are formed between generation cost and CO_2 emissions.

Bai and Wei (1995) [39] construct a multi-objective model to determine an effective and economic option that can significantly mitigate CO_2 emissions from the power sector. The first objective seeks to minimize new plant installation and operation costs subject to meeting three different levels of load; the second objective minimizes CO_2 emissions based on four types of power generation sources.

Mavrotas et al. (1999) [40] develop a mixed 0-1 multiple objective linear programming model for power generation planning in which a complete set of efficient solutions can be obtained. Their first objective function is expressed by minimizing the annual power generation cost based on the unit's lifetime and the market's discount rate. Besides, the second objective function is to minimize annual pollutant emissions, although the concerned pollutant is not CO_2. The model also identifies the number and output of each type of power unit to meet forecasted demand.

Tekiner et al. (2010) [41] integrate reliability analysis with expansion planning and dispatching decisions. A Monte-Carlo simulation-based optimization approach is proposed to determine optimal expansion plans to minimize cost (O_1), CO_2 emissions (O_2) and NOx emissions (O_3). The cost objective function not only includes essential investment costs, fixed operational and maintenance costs and generation costs, but also includes unmet demand cost and revenues from steam; all future costs are converted to net present values. The pollutant emission objective functions determine emissions amounts from existing and new generating units, and distributed units. Each sub-objective function (O_1, O_2 and O_3) is differently scaled; the composite objective function requires weighting to combine those three objective functions. The weights can be changed according to a decision maker's preferences.

Unsihuay-Vila et al. (2011) [42] proposed a multi-objective, multi-area and multi-stage model to optimize the electricity generation / transmission value-chain. The sustainable energy development criteria are expressed in the following three objectives: minimization of life-cycle GHG emissions, minimization of investment and operational costs, and maximization of the diversification of electricity generation mix. The three criteria are then substituted to a referenced comprise model and solved for comprise solutions.

The multiple objective function generally comprises at least two parts, one for the minimization of generation costs referred to (1) and the other for the minimization of CO_2 emissions (2). The objective of CO_2 emissions is determined by the emission rates of different units or plants, where non-fossil fuel plant is assumed to have zero emission

$$\min F^2(\mathbf{e}) = \sum_{t\in\mathbb{T}} \sum_{i\in(\mathbb{F}\setminus\mathbb{F}^C)\cup(\mathbb{W}^F\setminus\mathbb{W}^C)} Q_i^F(e_{ijt}^F) + \sum_{t\in\mathbb{T}} \sum_{i\in\mathbb{F}^C\cup\mathbb{W}^C} \sum_{k\in\mathbb{K}} Q_i^C(e_{ijkt}^F, e_{ikt}^W), \tag{2}$$

where $Q_i(\mathbf{e})$ is the CO_2 emission rate function corresponding to traditional fossil fuel plants and the plants with carbon capture techniques, respectively.

Table 3 shows and compares the components of different objective functions concerned in the above papers. The costs and emission targets are impacted by specific factors that are listed below, where the other component means unmet demand cost and revenue from steam. Most cost parameters are given based on the plant/generator type. Meanwhile, the fuel type corresponding to fuel prices is the dominant factor that influences generation costs and retrofitting costs for fuel switching. A part of studies also consider the effects of cost by time changes on fuel prices, retrofitting, capital investment, CO_2 credits and CO_2 emissions. Besides, there is a paper considering the different generation scenarios bounded by the available capacity, but no paper discusses parameter uncertainty on fuel price and other costs.

In sum, both single objective function and multi-objective functions account for the effects of economic factors and environmental factors on power generation planning. The key distinction between single objective function and multi-objective function for CO_2 emission considerations is that CO_2 emissions are deterministic and placed in the constraint set in single objective programming, while in multi-objective programming, CO_2 emissions become a variable to be minimized.

2.4.2 Constraints of Energy Planning with CO_2 Reductions

Power generation planning model formulations present in the literature account for various restrictions: electricity demand satisfaction, plant capacity, fuel selection and plant shut-down, operational changes, CO_2 emissions limits, selection of CO_2

Table 3: Summary of Objective Function for Energy Planning with CO_2 Reductions.

Component	**Single-Objective**			**Multiple-Objective**			
Paper	[36]	[37]	[38]	[39]	[40]	[41]	[42]
Fossil fuel generation	P, J	P, J	J, T	P	P, T	P, T	P, T
Non-fossil fuel generation	P	P	P, T				
Retrofit	P, J	P, J	P, T				
Capital investment		P	P		P	P, T	P, T
O&M		P	P, T		P, T		
CO_2 credits			T				
CCS technology			P				
CO_2 emissions	P, J			P	P, T	P, T	P, T
Other						T	

Note: P represents plant/generator; J represents fuel type, *e.g.* coal, oil and gas; T represents time/period.

capture processes, and capacity constraints on the capture process [36, 37, 38, 40, 43].

Electricity demand satisfaction: The total electricity supply has to be greater than or equal to the total electricity demand. Note that the total supply is the power generation excluding transmission and distribution losses. The power generation comes from existing fossil fuel power plants, existing non-fossil power plants and new power generation plants, excluding energy consumption for carbon capture.

The mathematical formulation is given as follows [38, 43]

$$(1-\rho)\Big(\sum_{i\in\mathbb{F}}\sum_{j\in\mathbb{J}} e^F_{ijt} + \sum_{i\in\mathbb{W}}\sum_{j\in\mathbb{W}} e^N_{it} + \sum_{i\in\mathbb{F}^C}\sum_{j\in\mathbb{W}} e^W_{ijt} - \sum_{i\in\mathbb{F}^C}\sum_{k\in\mathbb{K}} e^F_{ikt} - \sum_{i\in\mathbb{W}^C}\sum_{k\in\mathbb{K}} e^W_{ikt}\Big) \geq D_t \qquad \forall t\in\mathbb{T}.$$

Plant capacity: The power produced in each type of power plant should not exceed its maximum installation capacity. Binary variables represent the shut-down possibility of existing fossil fuel generation units or the possibility of new generation units to be built [36, 37, 38, 43].

Existing fossil fuel power generation:

$$e^F_{ijt} \leq E^{max}_{ij} x_{ij} \qquad \forall i\in\mathbb{F},\ j\in\mathbb{J},\ t\in\mathbb{T}.$$

Existing non-fossil power generation:

$$e_{it} \leq E^{max}_{i} \qquad \forall i\in\mathbb{N},\ t\in\mathbb{T}.$$

New power generation:

$$e^W_{ijt} \leq E^{max}_{ij} y_{ij} \qquad \forall i\in\mathbb{W},\ j\in\mathbb{J},\ t\in\mathbb{T}.$$

Fuel selection and plant shut-down: For existing fossil fuel power plants or generation units, conventional high carbon fuels are possibly switched to low carbon fuels in order to reduce CO_2 emissions, *e.g.*, gasoline or diesel is substituted by natural gas (CNG and LPG). In addition, the generation unit emitting high CO_2 emissions might be shut down completely, independent of the fuel type used [36, 38, 43]

$$\sum_{j\in\mathbb{J}} x_{ij} \leq 1 \qquad \forall i \in \mathbb{F}.$$

Operational changes: Generation for each type of power plant must adhere to a range over a period of time. For existing plants, the upper bound of this range is based on the sum of the allowable power production increment and current base load. For new power plants, the upper bound is the maximum installed capacity of the ith generation unit. The lower bound is influenced by the minimum annual capacity factor for ith generation unit. Minimum power generation must satisfy the demand of the power market; otherwise, the unit must be shut down, [36, 37, 38, 43].

Existing fossil fuel power generation:

$$l_{ij}E_{ij}^{max}x_{ij} \leq e_{ijt}^{F} \leq (1+r_i)E_i^{current}x_{ij} \qquad \forall i \in \mathbb{F},\ j \in \mathbb{J},\ t \in \mathbb{T}.$$

Existing non-fossil power generation:

$$l_{ij}E_{ij}^{max} \leq e_{ijt}^{N} \leq (1+r_i)E_i^{current} \qquad \forall i \in \mathbb{N},\ t \in \mathbb{T}.$$

New power generation:

$$l_{ij}E_{ij}^{max}y_{ij} \leq e_{ijt}^{W} \leq E_{ij}^{max}y_{ij} \qquad \forall i \in \mathbb{W},\ j \in \mathbb{W},\ t \in \mathbb{T}.$$

Selection of CO_2 capture process: If the carbon capture technology is applied to existing fossil fuel power generation units or to new power generation units, it is capable of reducing CO_2 emissions with ε% of capture efficiency. The capture process can only be retrofitted on current operational fossil fuel power plants or installed on new CCS-ready power generation plants [38, 43]

$$\sum_{k\in\mathbb{K}} z_{ik}^{F} \leq \sum_{j\in\mathbb{J}} x_{ij} \qquad \forall i \in \mathbb{F}^{C},$$

$$\sum_{k\in\mathbb{K}} z_{ik}^{W} \leq \sum_{j\in\mathbb{J}} y_{ij} \qquad \forall i \in \mathbb{W}^{C}.$$

Further, it ensures that no more than one capture process is installed for the specific generation unit

$$\sum_{k\in\mathbb{K}} z_{ik}^{F} \leq 1 \qquad \forall i \in \mathbb{F}^{C},$$

$$\sum_{k\in\mathbb{K}} z_{ik}^{W} \leq 1 \qquad \forall i \in \mathbb{W}^{C}.$$

CO_2 emission limits: The total CO_2 emissions from the power system cannot violate pollutant emissions limits in any period. Carbon credits can be traded in the market, potentially impacting CO_2 mitigation. Generally, it is assumed that the amount of CO_2 emitted from non-fossil fuel plants is negligible in the power generation process, compared to emissions from fossil fuel power plants [36, 37, 38, 43].

The relationship is formulated as

$$\sum_{k\in\mathbb{K}}\sum_{i\in\mathbb{F}^{C}}\Big(\sum_{j\in\mathbb{J}} G_{ij}^{\mathrm{CO}_2,F} e_{ijt}^{F}\Big)\varepsilon_{ij}^{F} z_{ik}^{F} + \sum_{k\in\mathbb{K}}\sum_{i\in\mathbb{W}^{C}}(\sum_{j\in\mathbb{J}} G_{ij}^{\mathrm{CO}_2,W} e_{ijt}^{W})\varepsilon_{ij}^{W} z_{ik}^{W} - C_t^{Cre} \leq C_t^{Limit} \qquad \forall t \in \mathbb{T},$$

where $G_{ij}^{\mathrm{CO}_2}$ represents the CO_2 emission factor from an ith generation unit using the jth fuel type. CO_2 emission is calculated based on the chemical equations; meanwhile, it is affected by the quantity and quality of fuel burned.

Existing fossil fuel power generation:

$$G_{ij}^{\mathrm{CO}_2,F} = 0.03667\left(\frac{1}{\eta_{ij}^{F}}\frac{\%C}{HHV_{ij}}\right) \qquad \forall i \in \mathbb{F},\ j \in \mathbb{J}.$$

New power generation:

$$G_{ij}^{\mathrm{CO}_2,W} = 0.03667\left(\frac{\varepsilon_{ij}^{W}}{\eta_{ij}^{W}}\frac{\%C}{HHV_{ij}}\right) \qquad \forall i \in \mathbb{W}^{C},\ j \in \mathbb{J},$$

where η denotes the efficiency of generation unit; $\%C$ represents the percentage of carbon content and HHV_{ij} is the high heating value of specific fuel i used in unit j.

Capacity constraints on the capture process: The energy consumption of a carbon capture process directly impacts the energy generation output. The energy requirement of a capture process is valid only for the technology assigned to a fossil fuel power generation unit. The maximum supplementary energy required for the kth carbon capture process is also given [38]

$$e_{ikt}^{F} \leq z_{ik}^{F} E_k^{max} \qquad \forall i \in \mathbb{F}^{C},\ k \in \mathbb{K},\ t \in \mathbb{T},$$

$$e_{ikt}^{W} \leq z_{ik}^{W} E_k^{max} \qquad \forall i \in \mathbb{W}^{C},\ k \in \mathbb{K},\ t \in \mathbb{T}.$$

Nonnegativity constraints: The variables used in previous constraints are separated into two groups: binary variables and continuous variables. Binary variables:

$$x_{ij}, y_{ij}, z_{ik} \in \{0,1\} \qquad \forall i \in \mathbb{F}\cup\mathbb{N}\cup\mathbb{W},\ j \in \mathbb{J},\ k \in \mathbb{K}.$$

Continuous variables:

$$e_{ijt}, e_{ikt} \geq 0 \qquad \forall i \in \mathbb{F} \cup \mathbb{N} \cup \mathbb{W},\ j \in \mathbb{J},\ k \in \mathbb{K},\ t \in \mathbb{T}.$$

2.4.3 Comparison of Optimization Methods for Energy Planning with CO_2 Reductions

Although this survey has been discussed and compared mathematical models with respect to objective functions and constraints, the further comparison of optimization methods illustrates the focus area of current studies and the feasibility of CCS in power plants. Most of the above optimization models were applied in real cases and show positive economic evaluations on CCS deployment. Table 4 lists a comparison of optimization methods for energy expansion planning with CO_2 reduction, which contains types of models, solution techniques, percentages of CO_2 reduction and terms of objective function.

Table 4: Comparison of Optimization Methods for Energy Planning with CO_2 Reductions.

Reference	Type of Model	Solution Technique	CO_2 Reduction	Terms of Objective Function
Hashim et al. [36]	MILP	Benders' Decomposition	3%	generation cost, retrofit cost & CO_2 emission cost
Muis et al. [37]	MILP	Branch & Cut	30%, 50%	O&M cost, retrofit cost & capital cost
Mirzaesmaeeli et al. [38]	MILP	Branch & Cut	Approximately 30%	investment cost, O&M cost, fuel cost, retrofit cost, CO_2 credits & CCS cost
Mavrotas et al. [40]	Mixed 0-1 MOLP	Multi-criteria Branch & Bound	N/A	generation cost & pollutant emissions
Tekiner et al. [41]	MILP	Monte-Carlo simulation	N/A	investment cost, O&M cost, generation cost,unmet demand cost, revenue from steam retrofit cost, CO_2 emission, NOx emission
Unsihuay-Vila et al. [42]	MILP	Branch & Cut	62.16%	present value of investment & operation costs, GHG lifecycle & energy diversification
Elkamel et al. [43]	MINLP, linearized to MILP	Branch & Cut	Up to 3%, 6%, 60%	operation cost, capital and operational cost of carbon capture retrofit, sequestration cost
Genchi et al. [44]	LP	Simulation	16%	equipment & construction cost, operation cost
Noonan & Giglio [45]	MINLP	Benders' Decomposition with linearization technique	N/A	discounted investment cost & discounted operation cost

Note: LP abbreviates linear programming
MINLP abbreviates mixed-integer nonlinear programming
MOLP abbreviates multiple objective linear programming

Generally speaking, the mathematical models for power generation planning seek to optimize the power generation structure, satisfying power demands and environmental policy requirements. Three CO_2 mitigation strategies are fully considered in the model for existing fossil fuel power plants. Because they do not emit CO_2, non-fossil fuel plants have a promising future. New power plant constructions meet CO_2 zero-emission targets and maintain electricity demand at minimum cost. The models are mostly formulated as MILPs and solved using commercial solvers. Also, some developed algorithms have been proposed to solve stochastic MILP models more efficiently [46].

The current extension of optimization models includes the exploration of time-dependent factors on power generation planning, the influence of different load blocks, reliability analysis integrated with the expansion planning and dispatching problems, the consideration of CO_2 transportation and sequestration, and further system-level economic evaluation of geological CO_2 storage with uncertainty. CCS research and development will be continuously driven by commercialization to fulfill the requirements of energy demand and to achieve stable and sustainable economic development.

As the cases studied by above paper are not the same, the given data and research purposes are also different, we can still draw common conclusions regarding CO_2 capture integrated to energy expansion planning. Without national/regional energy policies to restricting CO_2 emission, CCS technology cannot be progressed quickly from being a concept to a key part of power generation systems. Meanwhile, without economic incentives on the implement of CCS system, generation companies or other organizations lack of economic justification and motivation to achieve the goal of abating CO_2 emissions. The results also indicate that renewable energy, fuel switching and CO_2 capture can contribute to CO_2 emission reduction. However, the availability of renewable energy resources is susceptible to geological locations and weather conditions. Fuel switching has an economic advantage only when it is used to satisfy lower-level of CO_2 emission reduction target. If the requirement of emission reduction is imposed greater than 40% [36], the carbon capture and storage will be applied as an essential approach to meet future long-term targets and become widespread.

3 Carbon Dioxide Transportation

Once CO_2 is captured in coal-based power plants, the transportation of CO_2 to disposal sites becomes the next challenge. There are three main common transportation types: pipelines, trucks and ships.

3.1 Pipeline Network

As of today, the pipeline networks provide a majority of CO_2 transportation. Topics present in the CO_2 transportation literature generally are divided into two groups: hydraulic design and techno-economic evaluations.

The determination of CO_2 pipeline diameter is the initial step to construct a pipeline network and to perform the economic evaluation. To calculate the CO_2 pipeline diameter, parameters considered include: temperature, pressure, CO_2 density, CO_2 viscosity, roughness height, velocity, pressure loss, pipeline length, Manning n-factor (the characteristic for roughness of pipeline material) and the last three factors of height difference, amount of bends and bend degree determined by the pipeline route [47]. Because CO_2 is compressed as a supercritical fluid for transportation, turbulent flow generally occurs in the pipeline systems. Most pipeline diameter calculations therefore are based on this condition and the hydraulic laws for turbulent flow in circular-shaped pipelines [48]. In the initial stage of pipeline design – the pipeline route is still to be determined – the inlet pressure, outlet pressure, temperature, viscosity and roughness height have to be assumed for the diameter calculations [48, 49, 50]. Based on the comparison of previous works, Vandeginste et al. (2008) [47] propose the employment of the Manning equation to obtain more accurate diameter values with the consideration of all parameters listed above.

For the economic evaluation of CO_2 transportation modes – different assumptions and methods for pipeline diameter calculations are used currently – the formula used naturally plays a significant role. Zhang et al. (2006) [51] use the optimum economic pipe diameter as a base to analyze supercritical fluid and subcooled liquid impacting energy efficiency and pump costs. The maximum safe pipeline distance between booster stations is also simulated to provide accurate values for varying CO_2 pipe inlet temperatures as a part of the system optimization. In McCoy's (2008) [52] research, the uncertainty with respect to pipeline and financial parameters yields a range of overall costs being calculated by using an engineering-economic model incorporating probabilistic analysis. Their model combining performance and cost could further help to more accurately estimate average costs of CO_2 transportation in different regions.

In fact, only a few studies focus on CO_2 pipeline transportation, although CCS technologies under physical conditions become mature. CO_2 transportation is a bridge function in the whole CCS system. However, most cost evaluations of CCS only refer to average CO_2 transport costs, based on arbitrary assumptions [53]. There is a Congressional Research Service report [54] that estimates the levelized cost of CO_2 transport to be approximately \$0.10/ton for 11 miles long trunck pipelines. For the hypothetical CO_2 pipelines averaging 234 miles, the average levelized cost increases to around \$2.00 per ton of CO_2 transport. It is important to note that average pipeline transportation cost can vary significantly depending on the scale of facilities and networks. Thus, the average cost estimate must account for the specific characteristics of each case.

For system-level infrastructure of CO_2 pipeline network, Kuby et al. (2011) [55] used a deterministic MILP model for CCS (*SimCCS*) to obtain an optimal CCS

system with trunk and feeder pipelines. They demonstrate a cost savings for the network systems with multiple sources and sinks, in which the savings on source costs, transport costs and sink costs are 2%, 34% and 22% respectively, and the total cost is reduced by 6.5% compared to direct systems. In addition, Middleton et al. (2011) [56] develop an MILP model called *SimCCS*^{CAP} and introduce an approach of five-step candidate network generation. The primary progress for the *SimCCS* is shown on the generation and refinement of a candidate network where candidate arcs can be optimized and further selected. The *SimCCS*^{CAP} MIP has the objective function that minimizes annual costs of CO_2 capture, transport and inject and store, subject to the following constraints, such as annual CO_2 flow between opened arcs, CO_2 capture amount, CO_2 injection and storage, mass balance and pipeline construction.

The design for CO_2 integrated pipeline networks is similar to that of natural gas (NG) pipelines. However, CO_2 pipeline transportation has its own specific characterizations, such as pollutant make-up, pipeline corrosion, CO_2 leaks, pipe and rupture. These factors impact CO_2 pipeline technical design. Additionally, future research on CO_2 transportation can't only focus on more comprehensive and accurate economic evaluations, but must also utilize a systems approach to optimize the whole network via combining CO_2 supply of carbon capture with CO_2 injection of carbon sequestration.

3.2 Trucks and Ships

Trucks and ships are flexible means of CO_2 transportation. Because CO_2 pipeline infrastructures are very capital intensive and their construction is time consuming, pipelines are mainly used to serve long-term storage sites. In contrast, trucks and ships can complement the needs of short-term storage and unreachable storage sites through pipelines.

For truck transportation, CO_2 gas is liquefied via compression. It is transported at a pressure of 1.896 to 2.068 MPa and at a temperature of -17.8 to -12.2°C [57]. The marine transportation performs the offshore delivery to ocean sequestration sites. The CO_2 cargo tank is an important carrier and designed to be pressure-type or semi-refrigerated. The technical design of cargo tanks usually satisfy the requirement of -54°C per 6 bar to -50°C per 7 bar [58].

Bakken and von Streng Velken (2008) [59] formulate linear programming models for CCS infrastructure optimization, which involve the selection of pipelines, intermediate storage, liquefaction plant and ship transport. The cost function of CO_2 ships is developed and applied to determine the types of lease and length, variable operational cost and energy penalty. The authors conclude that the ship transport is less profitable even if it has low chartering costs. The main reason is the high investment costs of liquefaction plants and additional temporary storage units, which are essential components of ship transportation.

Aspelund and Gundersen (2009) [60] discuss the cost effective liquefied energy chain, in which liquid CO_2 and natural gas are transported in the same ship to im-

prove ship utilization, because the transport pressures for each gas directly affects the thermodynamic efficiency and ship utilization. The authors perform a sensitivity analysis of ship utilization and energy efficiency. In these cases, ship utilization rates of 58%–85% and 48%–52% are obtained, respectively, and the total energy efficiency loss for the transportation can be reduced by 4.4%, compared to the traditional energy chain without CCS.

3.3 CO_2 Source-Sink Optimization Model in CCS systems

The normal CO_2 transportation links at least multiple CO_2 sources and sinks, which is an important part composed of CCS infrastructure. There are several studies investigating optimal CO_2 transportation problems, especially the design of CO_2 pipeline network through the mathematical optimization models. In general cases, the decision makers expect to determine which area to implement CO_2 capture, which sinks to allow CO_2 storage, pipeline network routes and capacities, and CO_2 allocation problems. Los Alamos National Laboratory performed the CO_2 pipeline routing studies, even taking into account the optimal pipeline diameter [61]. The rest of this subsection is organized to discuss the objective function and CO_2 transportation constraints used in the pipeline network design problems.

3.3.1 Objective Functions for CO_2 transportation problems

The objective function regarding CO_2 pipeline network is mainly to optimize the total cost of CO_2 pipeline network, including construction and maintenance costs, source or sink open costs, and flow costs. Benson and Ogden [62] applied a net present value method in the objective function to compute total cost over the lifetime of project, where the cost function is nonlinear determined by the flow over the pipe and its length. Tan et al. (2012) [63] develop optimal source-sink matching models to satisfy the objective of maximizing the total amount of CO_2 captured and stored. So the CO_2 flow rate as a significant decision variable directly determines the total cost of project.

Because of the different objectives achieved in various design problems, the CO_2 source-sink optimization models take assumptions mostly based on their case studies. For the minimum cost network problems, they minimize the costs on building and operating CCS pipeline networks under following major assumptions:

- All potential CO_2 sources and storage sites are accessible at the same time.
- Pure CO_2 is captured from plants or supplied from source nodes
- The target amounts of CO_2 captured and injected are determined by operating scheme.
- The effects of topography are not considered.
- The networks are specified with different transportation distances.
- All parameters involved are deterministic, not changed over time.

However, Tan et al. (2012) [64] discuss the optimal source-sink matching problem that breaks an assumption with respect to temporal issues. Since the time of operating CO_2 sources and the time of sink availability do not coincide, They focus on solving the duration of connectivity between two nodes. The assumptions they make in this model includes

- the CO_2 flow rate is constant over the project life,
- the plants with CO_2 capture are located sufficiently close to potential storage sites so as to match economically,
- the pipeline characteristics such as pipeline diameter, segments, booster stations are fixed and given,
- the minimum time of connectivity and the operation time at each nodes are provided.

We again use small Roman letters for variables and capital as well as Greek letters for input data along with the following notation:

Sets

$\mathbb{A}$ Pipelines
$\mathbb{R}$ CO_2 Sources
$\mathbb{S}$ CO_2 Sinks
$\mathbb{N}$ Nodes including CO_2 sources and sinks
$\mathbb{T}$ Planning horizon

Variables

x_i	[binary]	1 if CO_2 source $i \in \mathbb{R}$ is open; otherwise, 0
y_{ij}	[binary]	1 if CO_2 pipeline from node i to node j is open, $(i,j) \in \mathbb{A}$; otherwise, 0
z_j	[binary]	1 if CO_2 sink $j \in \mathbb{S}$ is open; otherwise, 0
f_{ij}^t	[continuous]	CO_2 flow rate in pipeline $(i,j) \in \mathbb{A}$

The general objective function for CO_2 transportation problems is to minimize the construction cost and operating cost regarding CO_2 sources (3a), transport processes (3b) and CO_2 sinks (3c), respectively. The construction cost mainly comprises the costs to open CO_2 sources and sinks and the costs to build CO_2 pipeline network. The operating cost is a variable cost reflected in regular operations to support the whole process of CO_2 transportation.

$$\min \quad F_1(\mathbf{x},\mathbf{f}) + F_2(\mathbf{y},\mathbf{f}) + F_3(\mathbf{z},\mathbf{f})$$

where

$$F_1(\mathbf{x},\mathbf{f}) = \sum_{i\in\mathbb{R}} C_i^R x_i + \sum_{t\in\mathbb{T}} \sum_{i\in\mathbb{R}} \sum_{j\in\mathbb{N}\setminus\mathbb{R}} V_i^t f_{ij}^t \tag{3a}$$

$$F_2(\mathbf{y},\mathbf{f}) = \sum_{(i,j)\in\mathbb{A}} Cost_{ij}^P(\mathbf{f},\mathbf{l}) y_{ij} + \sum_{t\in\mathbb{T}} \sum_{(i,j)\in\mathbb{A}} V_{ij}^t f_{ij}^t \tag{3b}$$

$$F_3(\mathbf{z},\mathbf{f}) = \sum_{j\in\mathbb{S}} C_j^S z_j + \sum_{t\in\mathbb{T}} \sum_{i\in\mathbb{N}\setminus\mathbb{S}} \sum_{j\in\mathbb{S}} V_j^t f_{ij}^t \tag{3c}$$

where $Cost^P(\mathbf{f},\mathbf{l})$ is the cost function for CO_2 pipeline network construction that depends on the flow over the pipe and its distance [62]. C_i^R and C_j^S are defined as the costs to open CO_2 sources and sinks, respectively. V^t represents the operating cost at time t.

3.3.2 Constraints of CO_2 transportation problems

Comparing to all constraints modeled in [61, 62, 63], we summarize some basic constraints to describe and restrict potential pipeline networks. We particularly define the CO_2 flow rate as time-dependent variables in order to highlight that it varies as the project in progress. Once the facilities and pipelines are decided to build, they are assumed to be permanent within the project planning.

Flow balance: The CO_2 flow balance constraint is formulated to handle all intermediate nodes $(i \in \mathbb{N} \setminus \mathbb{R} \setminus \mathbb{S})$ follow the mass conservation. Explicitly, the summation of CO_2 inflow that enters an intermediate node must be equal to the summation of CO_2 outflow that leaves that node, without any accumulation in the network

$$\sum_{j:(i,j)\in\mathbb{A}} f_{ij}^t - \sum_{j:(i,j)\in\mathbb{A}} f_{ji}^t = 0, \qquad \forall i \in \mathbb{N} \setminus \mathbb{R} \setminus \mathbb{S}.$$

Flow rate limit: Next, the flow rate limit constraints model physical pipeline capacities or restrictions. If one arc is selected to build pipeline, the corresponding flow rate is bounded; otherwise, there is no connection between node i and node j, shown in $f_{ij}^t = 0$

$$f_{ij}^t \le Q_{ij}^P y_{ij}, \qquad \forall (i,j) \in \mathbb{A},\ t \in \mathbb{T}.$$

CO_2 supply limit: This constraint states the total CO_2 outflow rate at CO_2 source i is restricted by available maximum CO_2 capture capabilities. The binary variable x_i is used to present the decisions whether CO_2 source is opened or not. This constraint will be useless when the objective function is to maximize the amount of CO_2 capture

$$\sum_{j\in\mathbb{N}\setminus\mathbb{R}} f_{ij}^t \le Q_i^{max} x_i, \qquad \forall i \in \mathbb{R},\ t \in \mathbb{T}.$$

CO_2 injection limit: Similarly, the summed CO_2 injection rate at sink j is also limited by the available maximum CO_2 injection capabilities. In fact, the physical condition is a main factor strongly impacting safe injection rate

$$\sum_{i\in\mathbb{N}\setminus\mathbb{S}} f_{ij}^t \le Q_j^{max} z_j, \qquad \forall j \in \mathbb{S},\ t \in \mathbb{T}.$$

CO_2 capture target: The target amount of CO_2 capture during a project planning horizon can be satisfied through adjusting the CO_2 capture rate at different source

i

$$\sum_{t\in\mathbb{T}}\sum_{j\in\mathbb{N}\setminus\mathbb{R}} f_{ij}^{t} \geq D_i, \qquad \forall i \in \mathbb{R}.$$

CO_2 storage capacity: The accumulation of CO_2 injection into sinks doesn't exceed the estimated storage capacity, as determined by the geological characteristics of selected storage sites

$$\sum_{t\in\mathbb{T}}\sum_{i\in\mathbb{N}\setminus\mathbb{S}} f_{ij}^{t} \leq M_j, \qquad \forall j \in \mathbb{S}.$$

Under normal circumstances, there is no branching allowed at sink node. The current studies generally assume that one sink can be linked to multiple source

$$\sum_{j\in\mathbb{S}} y_{ij} \leq 1, \qquad \forall i \in \mathbb{N}\setminus\mathbb{S}.$$

Most CO_2 pipeline network problems are formulated as mixed integer linear programming models. Although some models have the original forms of mixed integer nonlinear programming, they finally are converted into mixed integer linear program to obtain globally optimal solutions. The models proposed so far have been tested with small-size cases which have no more than 10 sources and sinks totally. The quantitative results gained from case studies illustrate that additional power supply or power generation facilities outside of CCS systems are needed to maintain the routine CO_2 transport operation, which lead to weaken the CO_2 reductions benefits for CCS systems. In addition, a network integrated compression strategy is more attractive due to less compressor units, and correspondingly reduce a total CO_2 pipeline network cost per tonne of CO_2 avoided [65].

4 Carbon Dioxide Sequestration

Studies show that CO_2 sequestration promises to be an effective and direct technique to achieve significant reductions of atmospheric CO_2 concentration. Although the technology of CO_2 sequestration cannot fundamentally change the tendency of global warming, it mitigates the negative effects from greenhouse gases and buys civilization time to develop alternative clean energy techniques.

Large quantities of industrially produced CO_2 are transported by pipelines and then injected into the subsurface for permanent storage. Geologic reservoirs consist of depleted oil and gas reservoirs, unmineable coal seams, saline aquifers, ocean water and carbon sinks.

Geologically, CO_2 storage can be divided into two parts: offshore fields and onshore fields. Economically, potential CO_2 geological storage can be distinguished as follows [66, 67]: One group is the storage without energy benefits, including sequestration in depleted gas or oil reservoirs, in saline aquifers and ocean storage. The other is the storage with energy benefits, including oil or gas recovery and coal bed

methane production. As commercial exploitation emerges, the latter group shows more attractive aspects and a promising development direction because energy incomes produced from oil or gas recovery can be increased. Thereby generated revenues can partially offset CO_2 sequestration operational cost. In other words, the prevention of CO_2 emissions provides an added value, and its cost effectiveness may present additional opportunities for CCS implementation.

The following paragraphs provide an overview of three common reservoir types implemented in the United States over the last decade:

(i) oil and gas reservoirs,
(ii) unmineable coal seams, and
(iii) saline formations.

4.1 Oil and Gas Reservoirs

Oil companies have extensively studied the increase of oil recovery from aging reservoirs. In addition to the recovery enhancement via water flooding, the CO_2 injection into depleted oil and gas reservoirs can also help to improve oil production. Furthermore, depleted oil and gas reservoirs offer potential storage sites for CO_2 sequestration. Therefore, oil recovery with CO_2 injection is a win-win approach to mitigate global climate change and generate additional benefits from current resources.

The employment of enhanced oil recovery (EOR) technology with CO_2 increases unrecovered oil production in the form of CO_2 miscible flooding. The mechanism uses the solubility of CO_2 in oil to increase the bulk volume and to reduce the oil's viscosity, thereby improving the mobility ratio of the phases, facilitating oil flow to wellbores, increasing well productivity [67]. Over the past decade, the gas methods with CO_2 flooding apply to medium and light oil production, whereas enhanced heavy oil recovery mainly uses the chemical method of polymer flooding or the thermal method of steam injection [68].

Regional Carbon Sequestration Partnerships (RCSPs) have recently reported that almost 143 billion tons of CO_2 storage resources pervade 29 States in the U.S. [69]. As of 2010, some commercial operations of CO_2-EOR production are located in Alberta and Williston Basin oilfield in Canada, Rangely oil field in Colorado, Monell field in Wyoming, Rock Creek Field in West Virginia and Permian Basin in New Mexico [70].

The economics of CO_2-EOR dictates the feasibility of CO_2-EOR projects. The economic sensitivities originate from oil price, CO_2 purchase price and the cost of CO_2 handling and recompression. In addition, in the U.S., federal tax credits and specific allowances in some states could encourage the utilization of CO_2 injectants to tertiary oil production.

Fig. 6 shows average crude oil wellhead prices for the last ten years and forecasts oil prices for the next ten years. Future oil prices are estimated to have 1.10% growth

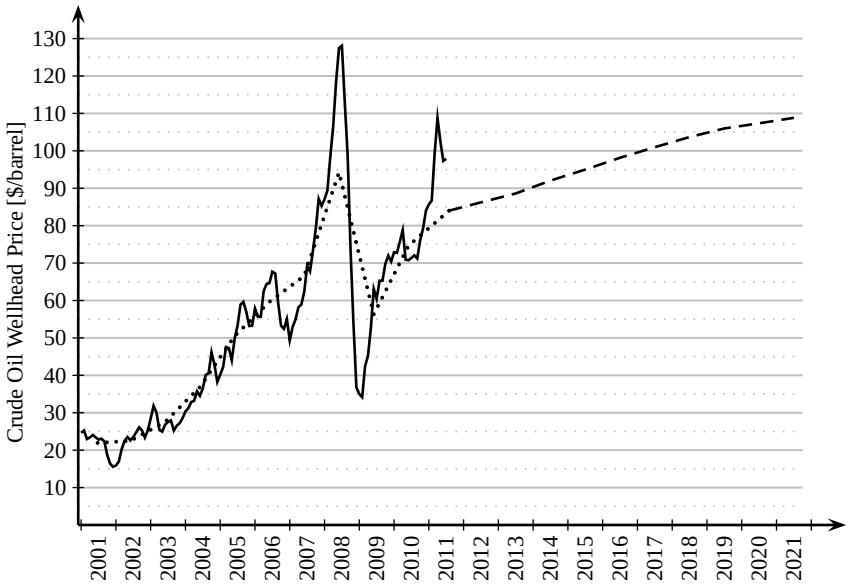

Fig. 6: Crude oil wellhead prices in the U.S. from 2001-2021.
Data source: [71, 72]
— historic data (monthly average)
· · · historic data (annual average)
- - forecast (annual average)

rate and stay above $80 per barrel, which also includes unpredictable oil field cost increases [71, 72].

The base case can be referred as 45 billion barrels of incremental oil to recovery, and the total CO_2 storage cost is estimated approximately $45 per metric ton [73], where the CO_2 purchase cost is $20 to $25 per barrel. Furthermore, it is estimated that pre-tax economic margins may be greater than $35 per barrel. There still exists market attractiveness to implement CO_2-EOR projects. The U.S. Department of Energy [69] verified that CO_2 flooding after primary and secondary recovery adds an additional 10-15% to the reservoir's original oil in place (OOIP), on average. The economic sensitivity analysis from NETL has reported estimates and evaluations of economically recoverable domestic oil by CO_2-EOR employment with expected financial hurdle rates [73]. Their conclusions support a promising economic outlook for conducting CO_2-EOR projects. In addition, there are other economic evaluations about whether the CO_2-EOR project is worthy of investment with considerations of oil and CO_2 prices.

Fleten et al. (2010) [74] use a stochastic dynamic analysis for understanding the profitability and timing of CO_2 storage investment used for EOR. They conclude that the possibility of making large profits still exists, when the risk of future price

uncertainty is high. The driver of CCS investment is identified as the income from oil sales, rather than CO_2 avoided costs.

4.2 Unmineable Coal Seams

Unmineable coal seams present another option for storing CO_2. These coal seams are too deep or too thin to satisfy mining requirements. During a recovery process, several value-added byproducts are produced, such as coal bed methane (CBM) and other hydrocarbon gases.

The CO_2-CBM mechanism is more complex than CO_2-EOR mechanisms, though both share similar operational processes. Wells are initially drilled or reworked to reach unmineable coal seams, usually at depths greater than 2000m. Next, dewatering lowers reservoir pressure, which allows CH_4 release from coal matrix. With CO_2 injection and diffusion, CO_2 molecules replace CH_4 molecules absorbed on the surface of coal. Typically, 2-4 mole CO_2 are adsorbed for one mole CO_2 desorbed, dependent on the coal rank [75]. The pressure difference existing between injection wells and production wells forces the escaped CH_4 to flow from a high pressure area to a low pressure area through fractures before it is extracted.

This adsorption-desorption process is described by Langmuir and extended Langmuir models (ELMs) for single and multi-component systems, respectively. The limitations of ELM are reflected in strict assumptions. ELM is also not thermodynamically correct for a large difference in Langmuir volumes [76], leading to large errors in estimations. Nevertheless, it is still suitable for reservoirs with low or medium pressure in most cases [77, 78]. Existing coal reservoir simulators are mainly based on ELMs which estimate produced gas composition, gas in place, production rate and reserves. In addition, other adsorption isotherm models, such as the Two-Dimensional Equation of State, Simplified Local Density model and IAS with D-A, offer accurate process prediction; some researchers have investigated the impact of model differences on the simulation results and assessed their implications on CBM production [79].

Similar to oil and gas reservoirs, only parts of unmineable coal seams have been examined and classified. RCSPs have estimated the CO_2 storage volume for unmineable coal areas at about 60 billion to 117 billion metric tons, covering 21 States in the U.S. The areas available for CO_2 storage in unmineable coal beds include Texas, Alaska, Louisiana, Mississippi, Wyoming, Alabama, Arkansas, Illinois, and Florida [69]. Some pilot CBM projects and operational large scale projects have been conducted, *e.g.*, San Juan Basin in New Mexico, Marshall County in West Virginia, MGSC in Illinois Basin, and Fenn-Big Valley, Alberta, Canada.

To demonstrate the economic feasibility of CO_2-ECBM, NG prices, the CO_2 purchase price and the cost of CO_2 handling and recompression are required. Fig. 7 represents natural gas wellhead prices over the last decade and predicted annual prices for the next ten years. The historical NG wellhead prices are volatile with a peak appearing over 2-3 years. NG prices are assumed to have a 2.10% growth rate

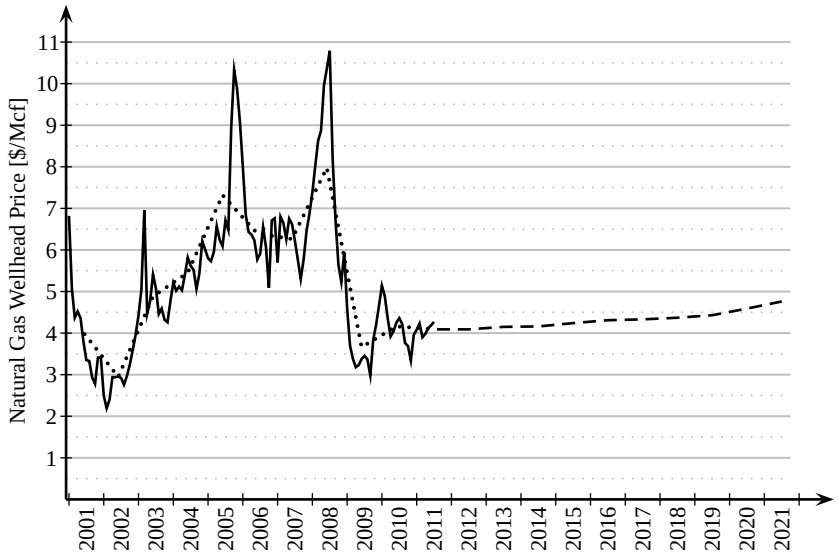

Fig. 7: Natural gas wellhead prices in the U.S. from 2001-2021.
Data source: [80, 72]
— historic data (monthly average)
· · · historic data (annual average)
- - forecast (annual average)

and remain within the range of $4 to $7 per thousand cubic feet (Mcf) [80, 72], and total CO_2 storage cost is assumed to be $2.38/Mcf (equivalent to $45 per metric ton) [73]. Considering the exchange ratio of CO_2 and CH_4, the injection of three Mcf CO_2 is usually needed to produce one Mcf of methane (1.013 bar and 15°C). The following equation suggests that there is no profit generated in a period of "stable" prices:

$$\text{CFBT} = \text{Revenue}^{\text{CH}_4} - \text{Cost}^{\text{CO}_2} - \text{Cost}^{\text{O\&M}}.$$

CO_2-ECBM commercial developments are unlikely to occur, because the CH_4 revenues do not compensate for the CO_2 storage cost and O&M costs, based on current CCS technologies. The policies of CO_2 credits and allowances were proposed and became the determinate tools to assure that CO_2-ECBM carry-out successfully. Under these circumstances, the project cash flow before tax can be estimated through the following equation:

$$\text{CFBT}^{\text{credit}} = \text{Revenue}^{\text{CH}_4} + \text{Credit}^{\text{CO}_2} - \text{Cost}^{\text{CO}_2} - \text{Cost}^{\text{O\&M}}.$$

Government incentives can transform negative cash flows into positive ones. Additionally, an increase in profit should be considered relative to the following two aspects: the improvement of CCS techniques so as to reduce CO_2 costs, and the

optimization of CO_2-ECBM production scheduling, which aims at increasing CH_4 revenues and decreasing CO_2 costs by management methods. The former has been discussed in previous sections, while the latter has not been addressed in the literature to date. Due to the fluctuation of NG wellhead prices in each period, the CBM production rate can be adjusted to satisfy demand while maximizing profits. This study may provide more comprehensive economic assessments for CO_2-ECBM production coupled with new opportunities and challenges.

4.3 Saline Formations

Saline aquifers for CO_2 sequestration have been identified as an alternative to effectively store and mitigate atmospheric CO_2 concentration. According to the latest data published from US DOE NETL, the CO_2 storage resource for saline formations is estimated to range from 1,653 billion metric tons to up to 20,213 billion metric tons [69]. This enormous potential for the storage of CO_2 has prompted researchers and the government to investigate saline formations.

Saline formations saturated with aquifer brines, at a wide range of depths (600-2800m) [81], provide potential CO_2 storage space. When liquid-like CO_2 is injected into saline formations, there are many storage mechanisms occurring to irreversibly trap CO_2 underground. These storage mechanisms have four main categories, including physical trapping, structural trapping, hydrodynamic trapping, and geochemical trapping [82]. Fang et al. (2010) [83] summarizes the characteristics of these trapping mechanisms and compares their different natures, capacity limitations and potential storage capacity.

The technical evaluation of saline aquifers suitable for CO_2 storage takes two criteria into account: storage capacity and injectivity [84]. The process of storing CO_2 in saline aquifers is very complex; therefore, a series of factors affecting CO_2 storage capacity are investigated, including CO_2 density at reservoir, porosity, fluid property, reservoir heterogeneity, and structural closures [83]. Both CO_2 solubility in brines and geochemistry reactions that happen among CO_2, brines and formations also directly cause the difference in the estimations of storage capacity. For the calculation of the CO_2 storage capacity, DOE provides a simple volumetric equation, considering only gas occupation in pore space. Liao et al. (2009) [84] present two storage capacity calculation models that depend on static trapping and hydrodynamic trapping. More recently, analytical expressions of storage efficiency were proposed by Okwen et al. (2010) [85] to establish the technical validity of CO_2 storage projects.

Saline formations occur worldwide, but there are only a few pilot and demonstration projects for CO_2 sequestration in saline aquifers in developed nations. In the United States, as part of the seven U.S. DOE RCSPs, the pilot and demonstration projects have been carried out in locations such as Decatur, IL; Shadyside, OH; Hancock County, KY; Gaylord, MI; Escatawpa and Cranfield, MS; Rio Vista, CA;

and Joseph City, AZ. Canada, Norway and Australia already implement commercial projects primarily focusing on industrial CO_2 sources [81].

The economic driver of CO_2 storage in saline aquifers is quite different from those of CO_2-EOR and CO_2-ECBM. Lacking value-added byproducts, the CO_2 injection amount in each well is maximized to lower the average storage cost and shorten injection time. The two major economic factors, capital cost and CO_2 injection rate, directly reflect the economic feasibility of commercial projects. Eccles et al. (2009) [86] develop an average cost function for CO_2 sequestration on a single-well basis, which is constructed from a relationship between the two factors mentioned above. They obtained the predicted range for cost per ton of CO_2 storage, *i.e.*, \$2-\$7/ton, depending on the range of depth and basin characteristics. In addition to the costs discussed above, the costs from brine displacement should also be considered in an economic assessment. This expense is generated from potential usages of brine after drain-off or compensations for direct disposal.

In CO_2-EOR and CO_2-ECBM projects, CO_2 is purchased as raw material to employ gas production. By contrast, CO_2 sequestered in saline aquifers becomes a major revenue source in a commercial project, while coupling with federal CO_2 credits and other allowances. Because on-going CO_2 saline projects are limited, recent practical experience and research inadequately support building comprehensive economic models. As research progresses, it is expected that the economic advantages from CO_2 saline projects will be gradually visualized and will present commercial opportunities.

4.4 CO_2 Leakages

While the benefits of CO_2 geologic storage are being investigated, it is important to recognize that CO_2 leakage is a serious risk. Because CO_2 is heavier than air and accumulates in low lying areas, CO_2 release from a blow-out at injection wells can produce a concentration (7%-10%) of gas sufficient to threaten human life. Therefore, the risk identification and risk assessment is significant and valuable for long-term management of CO_2 sequestration.

Though huge amounts of CO_2 is sequestered successfully every year, CO_2 leakages can hardly be avoided on geological storage sites. The following recently published articles discuss CO_2 leakage:

- Zwaan et al. (2007) [87] perform a sensitivity analysis for the CO_2 leakage rate through the entire energy systems model. They confirmed the acceptable leakage level as feasible climate change mitigation options.
- Chiaramonte et al. (2008) [88] report seal integrity associated with the goal of estimating potential risk of CO_2 leakage from a geomechanical perspective.
- Qin et al. (2008) [89] contribute to an integrated decision support system for CO_2 storage, where hybrid fuzzy-stochastic risk assessment was selected to quantify the risk level of CO_2 leakage.

- Kopp et al. (2010) [90] address a risk analysis for CO_2 leakage through abandoned wells. They developed methods for quantitative risk assessment, which identified independent primary parameters and secondary parameters that affect the risks.
- Zhang et al. (2010) [91] estimates the probability of CO_2 leakage along conduits with fuzzy logic rules and the proposed method also computes the uncertainty range of estimated probability, incorporated with the uncertainty of system parameters.

Monitoring CO_2 migration and leakage is very important to ensure that our health, safety and environment will not be threatened. Monitoring CO_2 migration, for example, is to protect drinking water sources not contaminated. Therefore, regulation is a tough but effective way to reduce or prevent risks of underground injection and storage. Policy makers also should recognize that the successful deployment of CCS technology is built on the safety of CO_2 transport and sequestration.

4.5 CO_2 Sequestration Optimization Models in CCS Systems

Currently, the economic studies of CO_2 storage focus on pure CO_2 storage without consideration of energy benefits, such as CO_2 storage combined with transportation [61, 62, 63]. In such a case, the operation of CO_2 injection could only be considered as a capital expenditure process, which is difficult to provide positive promotions for this CO_2 storage technique. Meanwhile, there is limited literature that studies the economic feasibility of CO_2 storage with energy benefit, no mention made of the economic optimization of gas storage and recovery process. However, there is one working paper to investigate the optimal scheduling of enhanced coal bed methane through CO_2 injection (CO_2-ECBM recovery) [92]. This study explicitly incorporates the project incomes with normal CO_2-ECBM recovery by selling coal bed methane and trading CO_2 credits in the carbon market, so as to verify the economic validity for long-term CO_2 sequestration.

The deterministic optimization model proposed by Huang et al. aims to maximize the total profit of CO_2-ECBM production over a planning horizon and seeks the optimal CO_2 injection and methane production schedules. Also, the multistage stochastic programming model developed from the deterministic model involves the uncertainties in methane wellhead prices and CO_2 trading prices in order to maximize the total expected profit. What's more, the stochastic model integrated with conditional value-at-risk is formulated to provide project risk measure on different risk levels of implementation strategies.

These models make a series of assumptions in physical conditions and geological conditions, with particular emphasis on the two-component system of methane and CO_2. The constraints model CO_2 supply capability, methane supply limit, composition of sorbed phase, composition of gas phase, variations of gas contents, methane and CO_2 extraction, respectively. The feasibility of optimization approach on CO_2-

ECBM recovery has been confirmed by case studies using historical data. This study provides a solid foundation for further CO_2 sequestration economic studies.

5 Conclusions and Future Research

After a few years of continued research, CCS technologies have enjoyed significant development. However, most research and applications for the new materials, technologies and processes needed are still at the laboratory stage or in pilot phases. The economics of CCS is the primary concern of all decision-makers. If CCS projects become profitable, then carbon capture technologies can be successfully promoted and widespread.

Carbon capture is the first step in the implementation of CCS. However, this step is very costly and energy intensive. Additionally, carbon capture facilities, the supplement and replacement of gas separation materials during power generation, energy consumption, operation and maintenance of carbon capture process come with huge expenses. Although governments are expected to provide moderate subsidies, reducing operation costs and lowering energy consumption are critical for successful CCS implementations.

Pipeline transportation connects carbon sources and carbon storage sites. CO_2 pipelines have unique features, slightly different from those of natural gas pipeline networks. Average cost depends on actual facility locations and the scale of the network, hence an optimal CO_2 pipeline network can help minimize the infrastructure costs and operating costs over a project planning.

Carbon storage is the ultimate purpose of carbon capture. If a suitable storage site cannot be found or confirmed for CO_2 generation sources, large amounts of CO_2 captured will suffer disposal issues and CO_2 pipeline networks become redundant. Carbon sequestration is the essential step of CCS to generate additional income for power plants. CO_2 physical properties are exploited to enhance oil or gas recovery as well as to achieve the goal of permanent sequestration. So far, CO_2 storage has proven to be technically feasible, but the overall economic analysis still needs to be explored and discussed. This economic analysis involves petroleum or natural gas engineering, mining engineering and other practical considerations. At the same time, the volatility of energy market prices directly affects the investments in CO_2 sequestration and oil and gas production operations.

The experience of CCS gained from pilot projects or commercial programs can influence technology developments. Core research areas mainly focus on precombustion capture, geologic carbon storage, monitoring and verification, simulation and risk assessment, and CO_2 utilization. Once the cost of CCS is reduced to an appropriate level and storage factors are understood, carbon capture technologies will probably be promised to new and existing fossil fuel power plants and other high-carbon industries. Moreover, before CCS technologies are adopted or new projects are carried out, decision makers are recommended to carefully consider a series of economic factors such as future power demand, CO_2 emission lim-

its, new policy implementation, investment capacity, energy prices volatility, energy expansion planning, and operations & maintenance, and also perform new economic analysis on optimize resource allocation, investment portfolio and operations planning.

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