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CARBON CAPTURE, STORAGE, AND UTILIZATION PROSPECTS IN THE POWER SECTOR OF UZBEKISTAN: A CASE OF TURAKURGAN THERMAL POWER PLANT

Captura, almacenamiento y utilización de carbono: Perspectivas en el sector energético de Uzbekistán. El caso de la Central Térmica de Turakurgán

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Dedicated to my family, my wife, and our kids

Nomenclature

IPCC	Intergovernmental panel on climate change
GHG	Greenhouse gases
COP26	Conferences of Parties
PCC	Post-combustion carbon capture
EOR	Enhanced oil recovery
ENGR	Enhanced natural gas recovery
EGS	Enhanced geothermal systems
F-T	Fischer-Tropsch
CCSU	Carbon capture, storage, and utilization
RES	Renewable energy recourses
NDC	Nationally determined contribution
GDP	Gross domestic products
TPP	Thermal power plant(s)
EGR	Exhaust gas recirculation
NGCC	Natural gas fired combined cycle
LCV	Lower calorific value
HRSG	Heat recovery steam generator
TEG	Triethylene glycol
MEA	Monoethanolamine
CAPEX	Capital expenditure
OPEX	Operational expenditure
SEGR	Selective exhaust gas recirculation
TAC	Total annualized cost
CAC	Cost of avoidance
LCOE	Levelized cost of electricity
FOC	Fixed operational cost
VOC	Variable operational cost
CRF	Capital recovery factor
TCC	Total capital cost
DC	Direct cost
IC	Indirect cost
WC	Working capital
CSU	Carbon storage and utilization
TRL	Technology readiness level
CO_2	Carbon dioxide
CH_4	Methane
N_2O	Nitrous oxide
N_2	Nitrogen
H_2	Hydrogen
CO	Carbon monoxide
H_2O	Water
O_2	Oxygen
NO_x	Nitric oxides
SO_x	Sulfur oxides

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Abstact

Climate change is one of the most pressing challenges of the 21st century, driven predominantly by rising levels of greenhouse gases in the atmosphere, particularly carbon dioxide (CO_2). Carbon Capture, Storage, and Utilization (CCSU) technologies have emerged as a crucial component in the global strategy to limit temperature rise to below 2°C as outlined in the Paris Agreement. CCSU offers a way to capture CO_2 emissions from large industrial sources and power plants, store it underground, or repurpose it for industrial use, thereby playing a vital role in sectors where decarbonization is otherwise difficult, such as energy, refinery, cement, and steel industries. Despite the global push towards renewable energy transition, fossil fuels are expected to remain a significant part of the energy mix for near decades, making CCSU technologies critical for mitigating CO_2 emissions and achieving climate goals. Thus, decarbonizing large-scale CO_2-emitting power sectors has become a key priority in the sustainable development plans of each nation around the world.

In the case of Uzbekistan, a country that relies heavily on fossil fuels, particularly natural gas, for over 85% of its power generation, the decarbonization challenge is particularly acute. Uzbekistan's power sector is responsible for 43% of the country's total CO_2 emissions, making it a key focus for emission reduction strategies. This doctoral thesis investigates the feasibility of integrating CCSU technologies into Uzbekistan's power sector, with a particular focus on the Turakurgan Natural Gas Combined Cycle (NGCC) power plant. The study is aimed at supporting Uzbekistan's commitment to reducing greenhouse gas emissions by 35% by 2030 and achieving carbon neutrality in its power sector by 2050.

In this context, initially, a detailed model of the Turakurgan NGCC power plant was developed using Aspen Plus® to assess its operational performance and potential for CO_2 capture. Modifications such as Exhaust Gas Recirculation (EGR) systems are proposed to increase CO_2 concentration in the flue gases, thereby optimizing the capture process. Monoethanolamine (MEA) absorption technology, a well-established method for CO_2 capture, was selected for detailed end-of-pipe CCSU integration analysis due to its maturity and long term reliability. The thesis also explores advanced separation techniques such as membrane separation, selective exhaust gas recirculation (SEGR), and hybrid technologies, combining membrane separation with MEA absorption, to enhance capture efficiency.

Beyond capture, the thesis conducts a spatial analysis to identify suitable CO_2 storage and utilization sites across Uzbekistan, including depleted hydrocarbon fields and saline aquifers. These storage options are evaluated based on their proximity to major emission sources, particularly power plants, ensuring the logistical feasibility of CCSU deployment. The potential for CO_2 utilization is also explored, with applications such as enhanced oil recovery (EOR) and the production of chemicals like methanol and urea offering additional economic incentives for CCSU adoption. These utilization strategies not only reduce emissions but also contribute to the development of a circular carbon economy, which is particularly relevant for Uzbekistan's industrial sector.

The techno-economic analysis in this research evaluates various CCSU integration scenarios, considering both their energy efficiency and economic feasibility. Among the methods analyzed, the SEGR-based absorption process emerges as the most viable option for Uzbekistan's power sector from techno-economic perspectives while SEGR with membrane system can compete with this method in the near term from both economic and environmental aspects. One of the key challenges identified is Uzbekistan's relatively low natural gas and electricity prices, along with the absence of a carbon tax, which creates significant barriers to make sharp decisions for the widespread consideration of decarbonization pathways such as CCSU technologies. The study underscores the critical role of government policy, international collaboration, and financial incentives in overcoming these economic barriers and enabling Uzbekistan's transition to a low-carbon economy.

In conclusion, this doctoral thesis provides a comprehensive analysis of the role of CCSU technologies in reducing CO_2 emissions from Uzbekistan's power sector, with a specific focus on the Turakurgan NGCC power plant. By integrating technical, economic, and policy perspectives, the research offers valuable insights into the potential for CCSU adoption and analyzes the alternative carbon reduction pathways in Uzbekistan, contributing to the global effort to combat climate change and achieve a sustainable energy future.

Resumen

El cambio climático es uno de los desafíos más complejos y urgentes del siglo XXI, impulsado predominantemente por el aumento de los niveles de gases de efecto invernadero (GEI) en la atmósfera, particularmente el dióxido de carbono (CO_2). Las tecnologías de Captura, Almacenamiento y Utilización de Carbono (CCSU, por sus siglas en inglés) han emergido como un componente crucial en la estrategia global para limitar el aumento de la temperatura a menos de 2°C, tal como se establece en el Acuerdo de París. El CCSU ofrece una manera de capturar las emisiones de CO_2 de grandes fuentes industriales y plantas de energía, almacenarlo en el subsuelo o reutilizarlo para usos industriales, desempeñando así un papel vital en sectores donde la descarbonización es más difícil, como las industrias de energía, refinería, cemento y acero. A pesar del impulso global hacia la transición a energías renovables, se espera que los combustibles fósiles sigan siendo una parte significativa de la matriz energética en las próximas décadas, lo que hace que las tecnologías CCSU sean fundamentales para mitigar las emisiones de CO_2 y alcanzar los objetivos establecidos. Por lo tanto, la descarbonización del sector de la energía se ha convertido en una prioridad clave en los planes de desarrollo sostenible de cada nación en todo el mundo.

En el caso de Uzbekistán, un país que depende en gran medida de los combustibles fósiles, particularmente del gas natural para más del 85% de su generación de energía, el desafío de la descarbonización es particularmente agudo. El sector energético de Uzbekistán es responsable del 43% de las emisiones totales de CO_2 del país, lo que lo convierte en un enfoque clave para las estrategias de reducción de emisiones. Esta tesis doctoral investiga la viabilidad de integrar tecnologías CCSU en el sector energético de Uzbekistán, con un enfoque particular en la planta de energía de ciclo combinado de gas natural (NGCC) de Turakurgan. El estudio está dirigido a apoyar el compromiso de Uzbekistán de reducir las emisiones de gases de efecto invernadero en un 35% para 2030 y alcanzar la neutralidad de carbono en su sector energético para 2050.

En este contexto, inicialmente se desarrolló un modelo detallado de la planta NGCC de Turakurgan utilizando Aspen Plus® para evaluar su rendimiento operativo y su potencial para la captura de CO_2. Se proponen modificaciones, como sistemas de recirculación de gases de escape (EGR), para aumentar la concentración de CO_2 en los gases de combustión, optimizando así el proceso de captura. La tecnología de absorción con monoetanolamina (MEA), un método bien establecido para la captura de CO_2, fue seleccionada para un análisis detallado de integración CCSU debido a su madurez y fiabilidad a largo plazo. La tesis también explora técnicas avanzadas de separación, como la separación mediante membranas, recirculación selectiva de gases de escape (SEGR) y tecnologías híbridas que combinan la separación mediante membranas con la absorción de MEA para mejorar la eficiencia de captura.

Más allá de la captura, la tesis realiza un análisis espacial para identificar potencialesemplazamientos para el almacenamiento y la utilización de CO_2 en Uzbekistán, incluyendo campos de hidrocarburos agotados y acuíferos salinos. Estas opciones de almacenamiento se evalúan en función de su proximidad a las principales fuentes de emisiones, particularmente plantas de energía, garantizando la viabilidad logística de la implementación del CCSU. También se explora el potencial para la utilización del CO_2, con aplicaciones como la recuperación mejorada de petróleo (EOR) y la producción de productos químicos como metanol y urea, que ofrecen incentivos económicos adicionales para la adopción del CCSU. Estas estrategias de utilización no solo reducen las emisiones, sino que también contribuyen al desarrollo de una economía circular del carbono, lo cual es particularmente relevante para el sector industrial de Uzbekistán.

El análisis tecnoeconómico de esta investigación evalúa diversos escenarios de integración del CCSU, considerando tanto su eficiencia energética como su viabilidad económica. Entre los métodos analizados, el proceso de absorción basado en SEGR emerge como la opción más viable para el sector energético de Uzbekistán desde perspectivas tecnoeconómicas, mientras que el sistema de SEGR con membranas puede competir con este método en el corto plazo desde los aspectos económicos y medioambientales. Uno de los principales desafíos identificados es el relativamente bajo precio del gas natural y la electricidad en Uzbekistán, junto con la ausencia de un impuesto al carbono, lo que crea barreras significativas para tomar decisiones drásticas respecto a la consideración generalizada de vías de descarbonización como las tecnologías CCSU. El estudio subraya el papel fundamental de la política gubernamental, la colaboración internacional y los incentivos financieros para superar estas barreras económicas y permitir la transición de Uzbekistán hacia una economía baja en carbono.

Resumen

En conclusión, esta tesis doctoral ofrece un análisis integral del papel de las tecnologías CCSU en la reducción de las emisiones de CO_2 del sector energético de Uzbekistán, con un enfoque específico en la planta NGCC de Turakurgan. Al integrar perspectivas técnicas, económicas y políticas, la investigación ofrece valiosas ideas sobre el potencial para la adopción del CCSU y analiza las vías alternativas de reducción de carbono en Uzbekistán, contribuyendo al esfuerzo global para combatir el cambio climático y lograr un futuro energético sostenible.

Chapter I - 1. Introduction

The part of this chapter is written based on the following published review papers:

1. Kamolov, A.; Turakulov, Z.; Rejabov, S.; Díaz-Sainz, G.; Gómez-Coma, L.; Norkobilov, A.; Fallanza, M.; Irabien, A. Decarbonization of Power and Industrial Sectors: The Role of Membrane Processes. Membranes 2023, 13, 130. https://doi.org/10.3390/membranes13020130

2. Turakulov, Z.; Kamolov, A.; Norkobilov, A.; Variny, M.; Díaz-Sainz, G.; Gómez-Coma, L.; Fallanza, M. Assessing Various CO_2 Utilization Technologies: A Brief Comparative Review. *J. Chem. Technol. Biotechnol.* **2024**, *99*, 1291–1307. https://doi.org/10.1002/jctb.7606

1.1. Climate change and its mitigation

Climate change is one of the most urgent and complex global challenges, disrupting the balance of ecosystems, economies, and human societies in profound ways. It refers to long-term alterations in temperature, precipitation patterns, and other climatic elements, which are driven by both natural processes and human activities. Over the past century, the Earth's climate has experienced unprecedented shifts, most notably a significant increase in global average temperatures. According to the Intergovernmental Panel on Climate Change (IPCC), the planet has warmed by more than 1 °C since the pre-industrial period, largely due to anthropogenic factors. This rise in temperature has triggered a cascade of environmental changes, including melting glaciers, rising sea levels, and more frequent and severe extreme weather events, such as hurricanes, floods, droughts, and wildfires [1,2].

Historically, Earth's climate has naturally fluctuated due to factors such as volcanic eruptions, variations in solar radiation, and shifts in the Earth's orbit, which affect long-term climate cycles. However, the rapid warming observed since the 20th century is primarily attributed to human activities, particularly the release of greenhouse gases (GHG) into the atmosphere [3,4].

GHGs are a group of gases that trap heat in the Earth's atmosphere, contributing to the greenhouse effect and global warming. The primary GHGs include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases, each with varying capacities to trap heat. These gases are released through different processes and activities. Among these, CO_2 is the most significant GHG due to its abundance and the scale of human-related emissions. CO_2 is responsible for over 75% of global GHG emissions, mainly as a result of burning fossil fuels for energy, transportation, and industrial processes [5]. While other gases like methane have a stronger heat-trapping potential, CO_2 remains the primary driver of climate change due to the sheer volume of its emissions and its long atmospheric lifetime. This makes it the central focus of global climate mitigation efforts aimed at reducing the overall GHG footprint.

CO_2 emissions arise from both natural and human activities, each contributing significantly to the carbon cycle in different ways. Natural sources of CO_2 emissions include volcanic eruptions, forest fires, the respiration of living organisms, the decomposition of organic matter, and the release of carbon dioxide from the oceans (Figure 1.1). In contrast, anthropogenic (human-caused) sources are predominantly linked to industrial activities and land-use changes. The combustion of biological materials such as wood, fossil fuels like coal, oil, and natural gas, and deforestation are the primary drivers of human-induced CO_2 emissions (Figure 1.1). Industrial processes, including manufacturing, transportation, and electricity generation, rely heavily on the burning of fossil fuels, releasing vast quantities of CO_2 into the atmosphere. The Figure 1.1 presents the main roots of both natural and human-related CO_2 emissions.

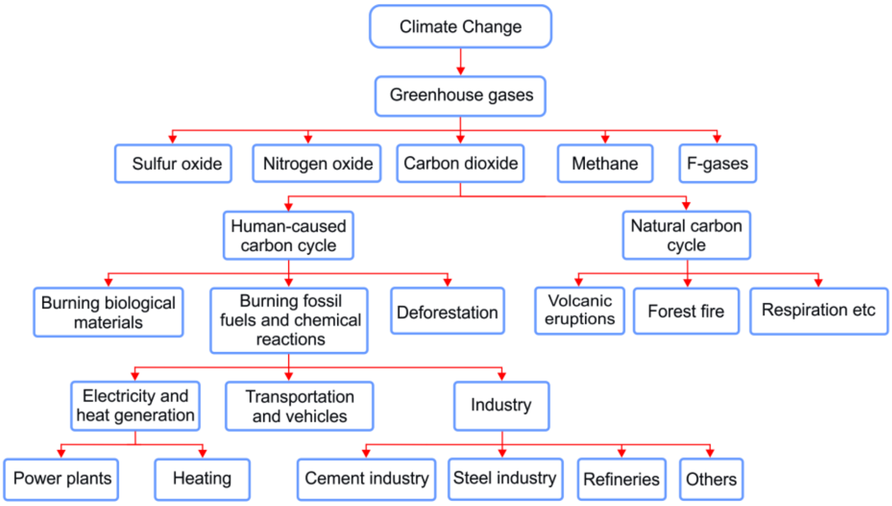

Figure 1.1. Overview of the main roots of human-related CO_2 emissions [3].

CO_2 is non-flammable, colourless, and odourless gas in the ambient conditions. Its greenhouse effect in the atmosphere plays an important role in maintaining the heat balance of the planet within the habitable range. CO_2 is also a key component for the existence of flora and fauna through the natural photosynthesis and respiration processes. However, excessive amounts of CO_2 in the atmosphere can lead to the retention of more heat on Earth, causing a rise in the average global temperature, thereby contributing to global warming, the main part of climate change [6]. Compared to the pre-industrial level, the concentration of CO_2 in the atmosphere increased by 50% reaching 421 parts per million (ppm), equivalent to nearly 1 °C increase in the global average temperature [7]. Those numbers can increase as high as above 1300 ppm and 4 °C by 2100 leading to catastrophic, devastating consequences of climate change, if no actions are taken to reduce the greenhouse gas emissions [8].

In response to the growing threat of climate change, the global community came together in December 2015 to adopt the Paris Agreement, a landmark accord involving 196 countries. This agreement established a collective commitment to limit the average global temperature rise to well below 2°C above pre-industrial levels, with the aim of reducing the most severe impacts of climate change. The 2°C threshold was seen as a critical limit beyond which the effects of global warming—such as more extreme weather events, rising sea levels, and ecosystem disruptions—would become significantly more dangerous [9]. However, scientific evidence and advocacy from climate-vulnerable nations prompted an even more ambitious goal of capping global temperature rise at 1.5°C. This lower target was officially introduced during the 26th Conference of the Parties (COP26) in Glasgow in 2021 [10], reflecting a growing understanding of the heightened risks associated with even a half-degree increase in global temperatures. The 1.5°C target is designed to minimize the most severe impacts of climate change, particularly for small island nations and other vulnerable regions that are disproportionately affected.

Since the fossil fuel-based energy, industry, and transportation sectors are principally the largest CO_2 emitting sources [11], the decarbonization of those sectors is considered the main target to meet the emission requirements of global consensus. In 2023, the global power industry emerged as the largest contributor to CO_2 emissions, accounting for approximately 38 percent of the total. Following closely, the transportation sector was the second-largest source of CO_2 emissions, responsible for just over 21 percent (Figure 1.2). From this perspective, transition to cleaner energy sources plays an important role to address climate change.

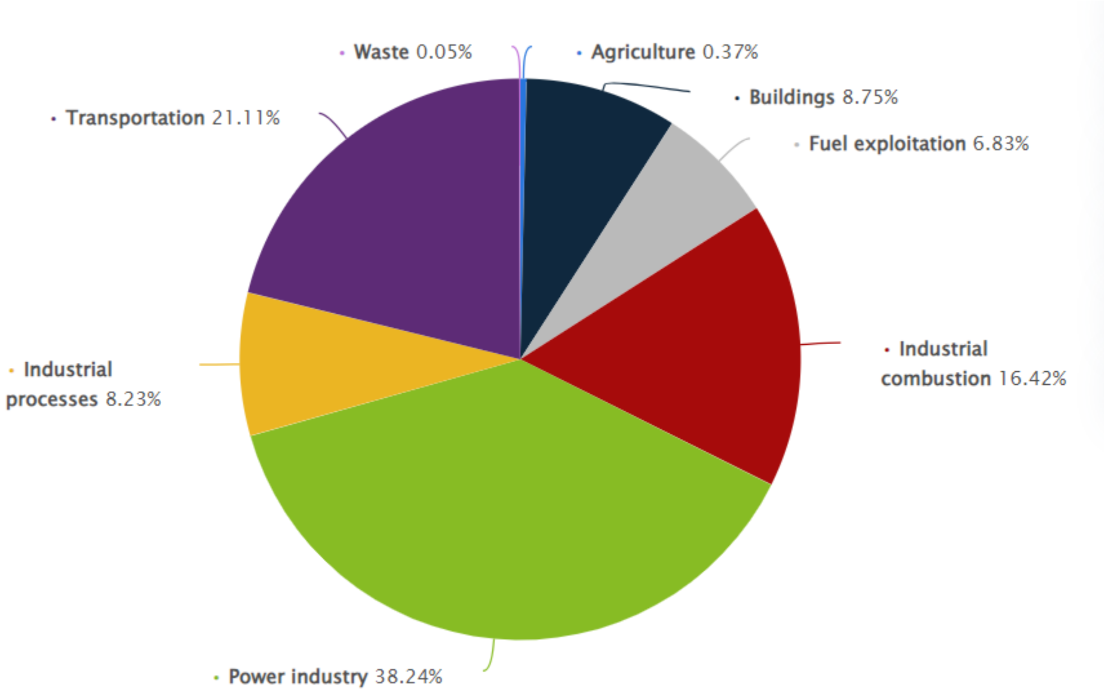

Figure 1.2. Global distribution of CO_2 emissions 2023, by sector [12].

Climate change driven by human activities is closely tied to the energy produced by burning fossil fuels [13]. As the global population continues to grow, so does the world's energy demand. To ensure a sustainable and healthy society, there is an urgent need for a reliable, environmentally friendly, and efficient energy supply, such as solar, wind, geothermal, hydro, and biomass energy. These renewable sources are more essential now than ever before [14]. However, transitioning from fossil fuels to sustainable energy will likely take several decades due to a number of challenges, including the mismatch between energy demand and the availability of renewable resources, price and supply fluctuations, technical limitations, and the need for new innovations [15].

Although solar and wind energy are free and clean, large-scale implementation presents challenges due to their variability over time and across seasons. There are also issues such as limited availability during certain periods, economic barriers, and instances where renewable energy cannot fully meet demand. Hydropower, while also free, clean, and the least expensive source of energy, faces challenges including water resource limitations, the displacement of local populations, disruption of ecosystems, and the lengthy time required to build large dams. Other renewable energy sources, such as biomass, geothermal, tidal, wave, and ocean energy, are currently limited to specific regions, and their technologies are relatively underdeveloped. More research and development are needed in these sectors to scale them up effectively [16–20].

Transitioning to renewable energy across all sectors of the economy will require time and long-term CO_2 emissions reduction efforts. In the near future, fossil fuel-based systems are expected to remain a significant part of power generation. Therefore, in the short and medium term, it will be crucial to integrate alternative technologies such as carbon capture, storage, and utilization with existing processes to reduce CO_2 emissions while the shift to renewable energy is underway.

1.2. CCSU methods and techiques in modern industry

CCSU is a methodology designed to combat climate change by reducing CO_2 emissions from large point sources such as power generation and industrial processes [21–23]. The typical CCSU process is based on three stages which include separating the CO_2 from gas mixtures in the power plants and industrial facilities, storing the captured CO_2 deep underground in geological formations, and using the CO_2 in other applications through physical and chemical CO_2 utilization pathways [24]. In the carbon capture stage, CO_2 is separated from the gas mixture through various methods, including direct air capture, chemical looping, pre-combustion, post-combustion, and oxy-fuel combustion. Among these, pre-combustion, post-combustion, and oxy-fuel combustion methods are widely investigated as they are more readily adaptable to existing power plants, offering a more practical and cost-effective approach to CO_2 capture [25].

In pre-combustion method, the process begins by heating fossil fuels with pure oxygen or, in some cases, air. This avoids introducing impurities like nitrogen (N_2), allowing for the formation of carbon monoxide (CO) and hydrogen (H_2). The mixture is then subjected to a water-gas shift reaction, where it reacts with steam (H_2O) to convert CO into additional CO_2 while producing more hydrogen. After this, the CO_2 is separated from the hydrogen, which can then be used as a clean energy source for power generation, heating, or other applications [26].

This method offers significant advantages, including higher efficiency in capturing CO_2 and requiring less fuel to generate the same amount of electricity compared to tranditional post-combustion method. The cleaner hydrogen energy it produces can also play a key role in transitioning towards a low-carbon energy system. However, one major limitation is that pre-combustion CO_2 capture cannot be easily retrofitted to existing power plants, as it requires complex modifications to the overall infrastructure. This makes it more suitable for new facilities rather than existing ones, limiting its current widespread application [27].

Oxy-fuel combustion approach involves burning fossil fuels using pure oxygen (O_2), which is provided by an air separation unit. This process results in a flue gas mixture with a high concentration of CO_2 and steam, along with very low levels of nitrogen oxides (NO_x) and sulfur oxides (SO_x). The high CO_2 concentration in the flue gas simplifies the process of separating CO_2 by cooling the gas stream, making it more efficient for capture [28].

While oxy-fuel combustion is more energy-intensive than post-combustion capture, it offers lower overall environmental impact due to reduced emissions of other harmful pollutants. However, challenges such as the high energy demand for oxygen production and the complexities of retrofitting existing plants continue to hinder its widespread commercial deployment [29].

Unlike pre-combustion and oxy-fuel combustion methods, post-combustion CO_2 capture (PCC) is the most mature and widely commercialized approach on a large scale. In this process, CO_2 is formed alongside water vapor, nitrogen oxides, and sulfur dioxide as a result of burning fossil fuels. The CO_2 is then captured from the flue gas before it is released into the atmosphere.

One of the key advantages of post-combustion capture is its ease of deployment, particularly in existing power plants, as it requires minimal alterations to the combustion system. This simplicity has led to increased recognition in the scientific community, making it a preferred method for CO_2 capture in retrofitting scenarios [30].

CO_2 storage is a critical component of CCSU technologies, aimed at reducing GHG emissions by safely containing CO_2 in geological formations. Once captured from industrial sources such as power plants, CO_2 can be injected deep underground into porous rock formations, depleted oil and gas fields, or saline aquifers, where it is stored for long periods to prevent its release into the atmosphere. These geological reservoirs, typically located several kilometres below the Earth's surface, provide the necessary conditions for trapping CO_2 through a combination of physical and chemical processes, including mineralization and cap rock sealing. This method of long-term storage helps mitigate the impact of carbon emissions on climate change by preventing CO_2 from contributing to global warming [31].

In terms of CO_2 utilization, the major purpose is to build a human-caused carbon cycle in which the captured CO_2 can be converted into useful products or raw materials for another industry. In this case, it is possible to capture and reuse the CO_2 multiple times in the cycle preventing the emission of a new CO_2 source into the atmosphere at the same time [32]. CO_2 utilization techniques are principally divided into two – conversion and non-conversion – categories [33]. Chemical (conversion) and physical (non-conversion) routes of CO_2 utilization are provided in Figure 1.3.

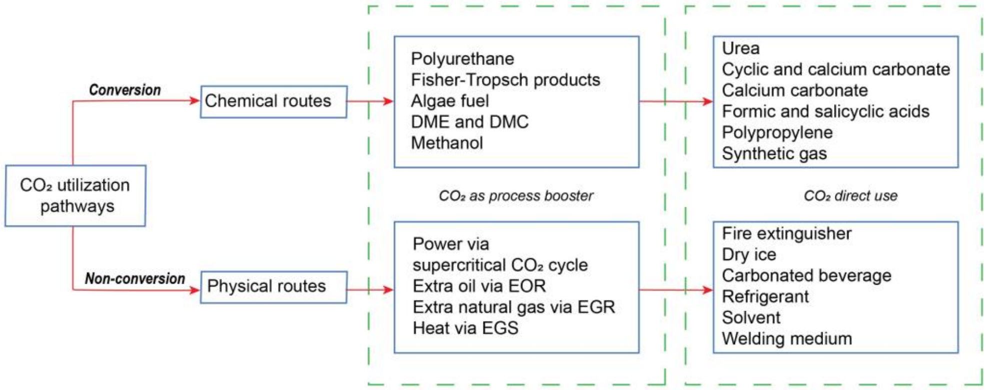

Figure 1.3. CO_2 utilization pathways by categories (Based on [34]).

In the non-conversion approach, the molecule of CO_2 physically remains in its state without any change and is used as pure or in mixtures. The application of the physical route of CO_2 utilization includes several direct and indirect uses including dry ice, refrigerant, fire extinguisher, carbonated beverages, solvent, welding medium, and power via supercritical CO_2 cycle, extra oil in enhanced oil recovery (EOR), enhanced natural gas recovery (EGR), heat via enhanced geothermal systems (EGS), enhanced coal bed methane (ECBM), etc. No matter how the majority of non-conversion use of CO_2 is limited in scale and small impact on CO_2 abatement, EOR using CO_2 has already been put into practice on a large scale, particularly in the USA and Canada [34].

In the conversion pathway, the CO_2 molecule is used in a chemical reaction as a feedstock, which converts the CO_2 into valuable chemical products and fuels. Various products come from CO_2 by catalytic or non-catalytic chemical reactions including calcium carbonate, polypropylene carbonate, formic acid, syngas, urea, cyclic carbonate, salicylic acid, acetylsalicylic acid for direct application, and indirect application involves polyurethane, algae biofuel, Fischer-Tropsch (F-T) products, dimethyl ether (DME), dimethyl carbonate (DMC). One of the main drawbacks of the conversion technique is that it is not mature enough and is significantly energy-consuming. Nevertheless, since this method is appearing as the key to a zero-emissions future, it is gaining progressive interest and support from manufacturers, investors, and governments [32,35].

1.3. Overview of the Research

1.3.1. CCSU assessment in regional scale

CCSU assessments are crucial not only at the global scale but also regionally, as they offer a significant understanding of local potential for CCSU integration. On a regional scale, assessing CCSU involves evaluating the area's specific emission sources, such as power plants and industrial facilities, along with identifying suitable geological formations for carbon storage and potential for utilization in industries like EOR. Regional assessments allow for tailoring CCSU strategies to match the local geography, industrial structure, and socioeconomic conditions, making them far more practical and economically viable than a one-size-fits-all global approach. In this context, Central Asia emerges as an ideal region for CCSU deployment due to its significant fossil fuel reserves and high carbon emission intensity. A thorough technical analysis of the CO_2 capture technologies, geological storage potential, such as deep saline aquifers and depleted oil fields, is crucial to ensure secure long-term storage. In addition, economic analysis is essential to evaluate the feasibility of capturing and utilizing CO_2, taking into account the costs of carbon capture technologies, infrastructure development, and the potential market for CO_2-derived products. The region's proximity to high-emission industrial hubs and the availability of oil and gas infrastructure make it well-suited for CCSU, particularly in Kazakhstan and Uzbekistan as they are two largest GHG emitting countries among Central Asia. However, integrating CCSU into these economies will depend heavily on policy support, financial incentives, and international collaboration, as well as overcoming technical challenges like CO_2 transportation and storage uncertainties.

1.3.2. Current state of Central Asian countries and their sustainability pathways

Green economy strategies in Central Asian countries have gained significant attention in recent years due to the region's rising carbon emissions and vulnerability to climate change. The geographical and site-specific conditions of these countries play a key role in shaping their decarbonization plans. Uzbekistan, located centrally in the region, shares borders with Kazakhstan, Tajikistan, Turkmenistan, Kyrgyzstan, and Afghanistan. Together, these six nations contribute approximately 423 million metric tons of CO_2 emissions annually. Among them, Kazakhstan is the largest emitter, releasing 212 million metric tons of CO_2 per year, followed by Uzbekistan at 121 million metric tons and Turkmenistan at 63.6 million metric tons. Tajikistan and Kyrgyzstan have significantly lower emissions, with 9.3 million metric tons and 9 million metric tons [36,37], respectively. These disparities in emissions reflect differences in industrialization, energy production, and economic development across the region. Figure 1.4 illustrates both the total annual carbon emissions and per capita emissions for five Central Asian countries.

Table 1.1. Current state of NDC plans for Central Asian countries [37].

Country	Base year	Deadline	NDC plan
Kazakhstan	1990	2030	1st scenario – 15% reduction 2nd scenario – 25% reduction
Uzbekistan	2010	2030	35% per unit of GDP
Turkmenistan	2010	2030	20% reduction (BAU)
Kyrgyzstan	BAU model	2030	1st scenario – 16% reduction 2nd scenario – 44% reduction
Tajikistan	1990	2030	1st scenario – not exceeding 60-70% of 1990. 2nd scenario – not exceeding 50-60% of 1990.

Kazakhstan not only leads in total GHG emissions but also has the highest per capita CO_2 emissions, averaging around 11.2 tons per person annually (see Supplemental Information in [37]). This is largely attributed to its reliance on fossil fuels, particularly coal, for energy. Renewable energy sources (RES), excluding hydropower, currently account for only about 3% of Kazakhstan's electricity generation [38]. The country's Green Economy Concept of 2013 envisions increasing this share to 50% by 2050, potentially incorporating nuclear power. It also targets a 15% reduction in GHG emissions from electricity generation by 2030, with a 40% reduction goal by 2050 [39]. According to Kazakhstan's 2016 Nationally Determined Contribution (NDC) plan (see Table 1.1), the country aims to reduce GHG emissions by 15% using its own resources, with the potential to raise this to 25% with international support [40]. However, this NDC is currently incompatible with the Paris Agreement.

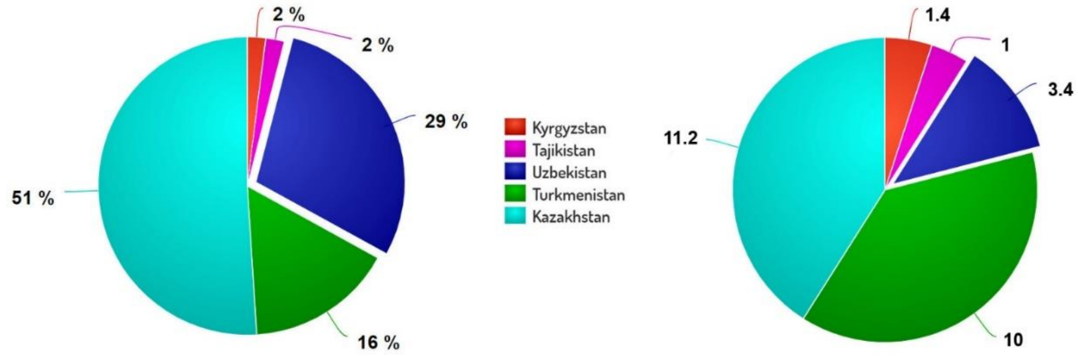

Figure 1.4. Annual CO_2 emissions of Central Asian countries (left) and CO_2 emissions per capita in tons (right) [37].

Turkmenistan is recognized as one of the most carbon-intensive economies, with a high per capita GHG emissions rate relative to its income. The country is also notable for its high methane emissions, primarily due to its vast natural gas reserves, which are the fourth largest in the world. In its NDC, Turkmenistan aims to reduce GHG emissions by 20% by 2030 compared to its 2010 levels under a Business-as-Usual scenario [41].

Kyrgyzstan and Tajikistan are the lowest GHG emitters in the region, both in terms of total and per capita CO_2 emissions. Their low emissions are primarily due to their geographical advantage, which allows them to generate most of their electricity from hydropower, as well as their limited industrialization. Kyrgyzstan's revised NDC plan, submitted in 2021, sets a target to reduce GHG emissions by 44% by the end of this decade with international investments, or by 16% without them [40]. This goal is largely based on shifting from coal to natural gas in the energy sector. Tajikistan, in its 2021 NDC, using 1990 as a baseline, aims to limit emissions to 60-70% above baseline levels with international support, or 50-60% without it [42]. However, Tajikistan is expected to prioritize climate adaptation and resilience over mitigation in its efforts to address climate change.

1.3.3. Decarbonization of the power sector in Uzbekistan

The Republic of Uzbekistan hereinafter called "Uzbekistan", like many other developing nations, faces the dual challenge of meeting its growing energy and urbanization demands while simultaneously mitigating environmental impacts, particularly in key sectors such as power generation and cement production. In line with international efforts to address climate change, Uzbekistan has undertaken significant steps to cut its GHG emissions, most notably CO_2. This commitment is embodied in the country's Nationally Determined Contribution (NDC) outlined under the Paris Agreement. A core element of Uzbekistan's NDC is the target of achieving a 35% reduction in GHG emissions per unit of Gross Domestic Product by 2030 in comparison with the level of 2010 [43]. This target reflects Uzbekistan's recognition of the pressing need to decouple economic growth from carbon emissions and transition towards a low-carbon development trajectory. On behalf of that promise, the government of Uzbekistan is presently dedicating significant endeavors to RES in order to alleviate GHG emissions. For instance, Uzbekistan plans to generate its 25% of electricity by RES by 2030 [44]. Apart from that, a further goal of reaching zero carbon emissions by 2050 in the power sector has been planned [39]. Within this framework, it is essential to analyze each CO_2 emitting sector and their sector by sector contribution towards the country's overall GHG emissions.

Energy production, transportation, industrial processes, and the residential sector are considered primary anthropogenic sources of CO_2 emissions in Uzbekistan. According to the previous study on the assessment of decarbonization measures in Uzbekistan [37], power and industrial sectors contribute significantly, accounting for more than half of the total CO_2 emissions being related to the mainly electricity generation and cement production processes. In terms of the CO_2 emissions by fuel type estimated in that study, natural gas is dominant, consisting of over 80%, followed by the coal, oil products combustions, and reaction-based CO_2 emissions of around 9%, 4%, and 5.5% respectively. Considering these facts, the decarbonization of power and industrial sectors, particularly cement production processes, are the first target for the evaluation of their potentials towards net zero emissions by 2050.

In Uzbekistan, achieving decarbonization goals requires a multi-pronged approach. This includes a significant shift towards RES like solar and wind power due to their high potential based on the site-specific condition of the country. Detailed analysis of RES generation is discussed in the IEA report [39]. Apart from RES switch, upgrading the existing power grid and implementing energy efficiency measures in buildings and industries are also crucial. Additionally, Uzbekistan is exploring regional cooperation through power trading and decarbonization agreements with neighboring countries in Central Asia [45]. In addition to those pathways, research and development of CCSU technologies offer promising avenues for capturing and utilizing carbon emissions, further reducing Uzbekistan's overall carbon footprint [46]. While progress is being made on the initial three options, which have already been initiated, the investigation of the CCSU potential of the country, existing CO_2 sources and sinks, their possible integration, and feasibility also play a vital role in the successful implementation of a low-carbon economy and subsequent zero carbon emission ambition by 2050 in power sector in Uzbekistan.

Uzbekistan's power generation is predominantly reliant on thermal power plants (TPP), which account for over 85% of the country's electricity, with natural gas being the primary fuel source [47]. For instance, in 2021, Uzbekistan produced 70.1 million MWh of electricity, with more than 91% generated from fuel-fired thermal power plants—86.3% from natural gas and 5.5% from coal [48,49].

To reliably assess the feasibility of integrating CCSU technologies in the power sector in Uzbekistan, it is crucial to develop a comprehensive CCSU model that evaluates the techno-economic and site-specific conditions under different scenarios. In this context, the Turakurgan TPP located in the province of Namangan region of Ferghana valley is selected for the case study in this research as it is the primary power source in the whole eastern part of the country. This selection is based on the following considerations:

- Natural gas is abundant in Uzbekistan and serves as the primary fuel for energy production.
- Compared to coal, oil, and other heavier hydrocarbons, natural gas produces cleaner emissions.
- Most of Uzbekistan's thermal power plants operate on the combined cycle principle.

- NGCC power stations are unlikely to be replaced by renewable energy sources in the near future.

1.4. Thesis objectives and outlines

The primary objective of this research is to evaluate the implementation of circular economy strategies aimed at reducing CO_2 emissions in Uzbekistan's power sector, ultimately contributing to the achievement of carbon neutrality by 2050. The study focuses on the application of CCSU technology. Turakurgan TPP, a NGCC power plant, has been selected as the case study to conduct a comprehensive techno-economic analysis of these strategies (Figure 1.5).

Figure 1.5. Turakurgan NGCC power plant, Uzbekistan.

Several specific objectives have been set on this research, as outlined below:

a) Identify CO_2 emission sources and evaluate decarbonization scenarios:

This objective involves mapping out the main sources of CO_2 emissions within Uzbekistan's power sector and assessing various decarbonization strategies. The analysis will place a special emphasis on the role and future prospects of CCSU technology as a critical tool for reducing emissions in the country.

b) Identify the potential CO_2 sinks and evaluate their capacity:

The study aims to identify potential CO_2 storage locations (sinks) and CO_2 utilization pathways across Uzbekistan, such as geological formations, and assess their storage capacity. A spatial analysis will be conducted to map the proximity and alignment between CO_2 emission sources and these potential sinks, particularly focusing on the power sector.

c) Simulate the Turakurgan TPP as base case study:

A detailed simulation of the existing infrastructure and operations at Turakurgan TPP will be carried out. The purpose of this simulation is to validate the results against the plant's project reports and refine the model through modification of the plant's operational conditions.

d) Modification through exhaust gas recirculation (EGR):

The research will explore and propose the implementation of the optimal exhaust gas recirculation (EGR) ratio at Turakurgan TPP. By increasing the concentration of CO_2 in the flue gas, this adjustment will help meet the necessary capture requirements, improving the efficiency of the CO_2 capture process.

e) Integrate carbon capture, storage, and utilization technologies:

A key aspect of this research is the integration of "end-of-pipe" CCSU technologies. The focus will be on the use of amine-based absorption technology, which is widely regarded as the benchmark due to its commercial viability and established performance in capturing CO_2.

f) Evaluate membrane based and hybrid carbon capture technologies:

The research will also explore advanced hybrid technologies by integrating both membrane and absorption-based CO_2 capture methods into the base case simulation of Turakurgan TPP. The performance and feasibility of this hybrid approach will be evaluated for its potential to enhance carbon capture efficiency.

g) Techno-economic analysis of different CCSU scenarios:

A techno-economic analysis will be conducted based on the different decarbonization and CCSU implementation scenarios developed in the study. This will provide a comprehensive assessment of the costs, benefits, and potential trade-offs associated with deploying these strategies in Uzbekistan's power sector.

By addressing these objectives, the research aims to offer actionable insights into how CCSU technology and circular economy principles can be effectively employed in Uzbekistan to reduce emissions and meet carbon neutrality goals by 2050.

In terms of the thesis outline, chapter 1 introduces the general problem and solution of the research focusing on CCSU in Uzbekistan's power sector, highlighting the importance of addressing CO_2 emissions to combat climate change.

Chapter 2 identifies the major CO_2 emission sources in Uzbekistan's power sector and explores decarbonization pathways. It focuses on integrating CCSU technologies to reduce emissions, providing an overview of the country's carbon profile and the potential for emissions reduction.

In chapter 3, a detailed model of the Turakurgan NGCC power plant is presented to evaluate its baseline performance. Modifications, including EGR, are proposed to improve CO_2 capture efficiency. The chapter sets the foundation for the techno-economic analysis of CCSU integration.

Chapter 4 studies the end-of-pipe technical assessment of conventional post-combustion MEA-based absorption technique through modelling and simulation. It focuses on detailed assessment of MEA absorption CO_2 capture method investigating the process optimal conditions using sensitivity analysis tools.

Chapter 5 conducts a comparative techno-economic analysis of amine absorption, membrane separation, and hybrid CCSU technologies at Turakurgan power plant. The costs, benefits, and operational efficiency of each method are assessed to determine the most viable option for carbon capture.

Chapter 6 evaluates potential CO_2 storage sites and utilization capacities in Uzbekistan, focusing on geological formations for long-term carbon storage. The suitability of these sites for Turakurgan power plant and the broader power sector is assessed, considering their capacity and proximity to emission sources.

The final chapter summarizes the research findings, emphasizing the feasibility of integrating CCSU technologies in Uzbekistan's power sector. It highlights key insights and offers recommendations for future research and policy development to achieve carbon neutrality by 2050.

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Chapter II - 2. Carbon sources and its reduction prospects in the power sector of Uzbekistan

This chapter is based on the following article:

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https://doi.org/10.1007/s41742-024-00578-6

Chapter II

Abstract

This chapter provides a comprehensive evaluation of Uzbekistan's current decarbonization efforts, future prospects, and potential pathways for CO_2 emission reduction, with a particular focus on the power sector. For the first time, a systematic estimation of Uzbekistan's CO_2 emission trends and their sectoral contributions is presented. The study places special emphasis on identifying reduction pathways through the integration of renewable energy sources (RES) and carbon capture, storage, and utilization (CCSU) technologies. The findings reveal that in 2021, Uzbekistan's CO_2 emissions amounted to approximately 116 Mt, with per capita emissions of 3.27 tons. The power and industrial sectors are the predominant contributors, accounting for 87% of total emissions. Over 80% of the country's CO_2 emissions originate from natural gas combustion, resulting in low-concentration flue gases, which increase the cost of CO_2 separation and constrain the feasibility of CCSU implementation in Uzbekistan.

2.1. Pressing need for carbon emission reduction in Uzbekistan

Uzbekistan, a Central Asian country and one of only two in the world that is double landlocked, has seen significant demographic and economic growth in recent years. This expansion has fueled a growing demand for industrial development, largely supported by the nation's vast natural resources, including natural gas, coal, and oil. However, as Uzbekistan works to bolster its industrial base, it also faces the challenge of aligning this progress with its environmental responsibilities [1].

In line with global climate change initiatives, Uzbekistan has set ambitious targets to reduce greenhouse gas (GHG) emissions. The country aims to achieve carbon neutrality in its power sector by 2050, a goal that will necessitate innovative technologies and decarbonization strategies. This objective forms part of a wider plan to transition toward a more sustainable energy future, in keeping with international climate agreements [2].

Considering Uzbekistan's reliance on fossil fuels for industrial and power generation, reducing CO_2 emissions from large-scale sources is a critical priority. In this regard, there is an increasing need to assess potential CO_2 emissions sources and its reduction pathways including carbon capture, storage, and utilization (CCSU) technologies. A comprehensive analysis of Uzbekistan's industrial CO_2 emissions and the feasibility of CCSU solutions will play a crucial role in achieving these ambitious climate goals. This analysis must take into account site-specific factors such as infrastructure readiness and economic viability. Understanding these elements will enable the development of realistic and effective CO_2 reduction pathways, essential for Uzbekistan's transition to a low-carbon economy.

2.2. CO_2 emission sources in Uzbekistan

In our study, we have implemented a comprehensive multi-stage approach. The first stage involves conducting a bibliometric study to gain an in-depth understanding of the existing research in the field. After the bibliometric analysis, we proceed with a data collection process to estimate the country's annual CO_2 emissions and distribute them across various sectors. Once the emission data is calculated and validated, we critically examine potential CO_2 reduction strategies and utilization options, focusing on Uzbekistan and its neighboring countries.

2.2.1. Bibliometric survey on CO_2 emissions in Uzbekistan

A brief bibliometric survey is carried out to gather existing knowledge and research on carbon emission reduction strategies, renewable energy technologies, carbon capture and storage methods, and utilization pathways. This step serves to provide essential information and insights into the latest advancements in the field. To achieve this, bibliometric analysis and data mining—both reliable methods for analyzing vast amounts of scientific data—are employed. These techniques help identify the areas that are receiving more attention within the scientific community, as well as highlight research fields that require further investigation. [3]. In this brief bibliometric survey, we aim to explore how GHG emissions and climate change mitigation are being studied in Uzbekistan by creating a keywords co-occurrence map using VOSviewer, one of the most widely used tools for such analysis. The SCOPUS web search engine is selected for quantifying the literature due to its broad coverage of research fields and its inclusion of a large variety of peer-reviewed journals, spanning over 44,000 titles. This makes SCOPUS an ideal platform for obtaining comprehensive insights into the research landscape on these topics.

Given the various techniques available for data searching, we utilized multiple relevant keywords in combination with the Boolean operator “or” to retrieve documents that contain any of the selected keywords and are affiliated with Uzbekistan.

2.2.2. Carbon emission estimation methodology

The next phase of the study involves estimating and validating CO_2 emissions in Uzbekistan by energy sources and sectors. This process is carried out using national statistics, industrial reports, and the 2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines and its refinement in 2019 for National Greenhouse Gas Inventories from the Intergovernmental Panel on Climate Change. [4]. Initially, data on energy sources, their locations, and annual production capacities are gathered. This includes determining the total exports, imports, and consumption of all fossil fuel types across the country. Additionally, the average calorific values of fuels such as natural gas, coal, and oil products (mainly gasoline and jet fuel) are identified through various statistical reports, archived information, and plant-specific data.

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories provide methodologies for calculating national inventories of anthropogenic emissions from various sources. These guidelines present three different approaches for estimating GHG emissions from stationary energy sources. The first method, Tier 1, calculates emissions using the total annual fuel consumption and its emission factor. This approach is straightforward and suitable when detailed data is unavailable. The second and third methods offer more rigorous assessments, requiring country-specific emission factors, information on combustion types, operational techniques, and equipment age.

In this study, we calculate CO_2 emissions in Uzbekistan using the Tier 1 method due to the absence of detailed statistical data. Furthermore, our analysis includes a comprehensive evaluation of estimated emissions from specific sectors such as power plants, cement production, urea manufacturing, iron and steel industries, agricultural activities, and households. This sector-based approach allows for a clearer understanding of GHG contributions from different industries, facilitating a more detailed examination of the country's overall emissions landscape. To assess the total CO_2 emissions, data on the combusted fuel and its corresponding emission factor are required.

$$\mathrm{TE_{fuel}} = \sum \mathrm{C_{fuel}} \cdot \mathrm{EF_{fuel}} \qquad (2.1)$$

where TE_{fuel} is total CO_2 emission by fuel combustion; C_{fuel} is the total amount of combusted fuel, TJ; EF_{fuel} is default emission factor of CO_2 by fuel type, Mt CO_2 /TJ. The amount of consumed fuel is calculated by total fuel consumption in the power, industrial, and other sectors.

$$\mathrm{C_{fuel}} = \mathrm{C_{fuel_{power}}} + \mathrm{C_{fuel_{industry}}} + \mathrm{C_{fuel_{other}}} \qquad (2.2)$$

Moreover, it is essential to consider CO_2 emissions resulting from chemical reactions, such as calcination in cement plants and urea production, when estimating the country's overall CO_2 emissions.

$$\mathrm{TE} = \mathrm{TE_{fuel}} + \mathrm{TE_{reactions}} \qquad (2.3)$$

At the conclusion of this stage, all calculated results are compared with international statistics, including data from British Petroleum [5], EDGAR [6], and Our World in Data [7] in order to validate the results. This comparative evaluation serves as a robust validation mechanism aimed at ensuring the reliability, accuracy, and credibility of the obtained results.

2.2.3. Preliminary assessment of CCSU possibilities in Uzbekistan

When evaluating the integration of CCSU with the major emitting sources in Uzbekistan, the primary focus is on economic and technical aspects. Given that the concentration of CO_2 in gas mixtures significantly impacts the efficiency and cost of the separation process, a preliminary assessment of CO_2 capture costs from various gas mixtures with different CO_2 concentrations is conducted. This is followed by a brief discussion on potential CO_2 utilization pathways specific to Uzbekistan, providing insights into the most viable options for the country. For the estimation of CO_2 capture costs, a power law equation (equation 2.4) is applied. The estimated costs are derived based on the CO_2 concentration in the gas mixture, using the Sherwood capture cost estimation data provided in reference [8]. The following equation can be utilized to provide an initial estimate of the capture cost based on the mole fraction of CO_2 present in the feed stream of the capture plant:

$$\text{Capture cost}\,\frac{\text{USD}}{\text{ton}} = 183.94 \cdot (\text{mole fraction of } \mathrm{CO_2})^{-0.555} \qquad (2.4)$$

The cost estimates presented here are based on those used for mature plant designs. This approach does not take into consideration the additional expenses involved in implementing new technologies in practical, real-world conditions. As a result, early carbon capture projects are expected to incur higher costs than those projected in this study.

2.3. Results and Discussion

2.3.1. Insights from bibliometric survey

When searching for keywords like ‘carbon emissions,’ ‘climate change,’ ‘CO_2 emissions,’ and ‘decarbonization’ with Uzbekistan as the affiliation country, only a limited number of papers—223 in total—were found, including those with climate change as a keyword. However, this was insufficient to create a comprehensive network map for evaluating scientific trends in this area. To address this, a broader search was conducted, including all papers affiliated with Uzbekistan, with specific limitations. The search was confined to articles, conference papers, review papers, and book chapters published between 2018 and 2023 in the fields of Environmental Engineering, Energy, Chemical Engineering, Material Science, and Engineering. A total of 5,138 documents were used to generate the keyword co-occurrence map, as shown in Figure 2.1.

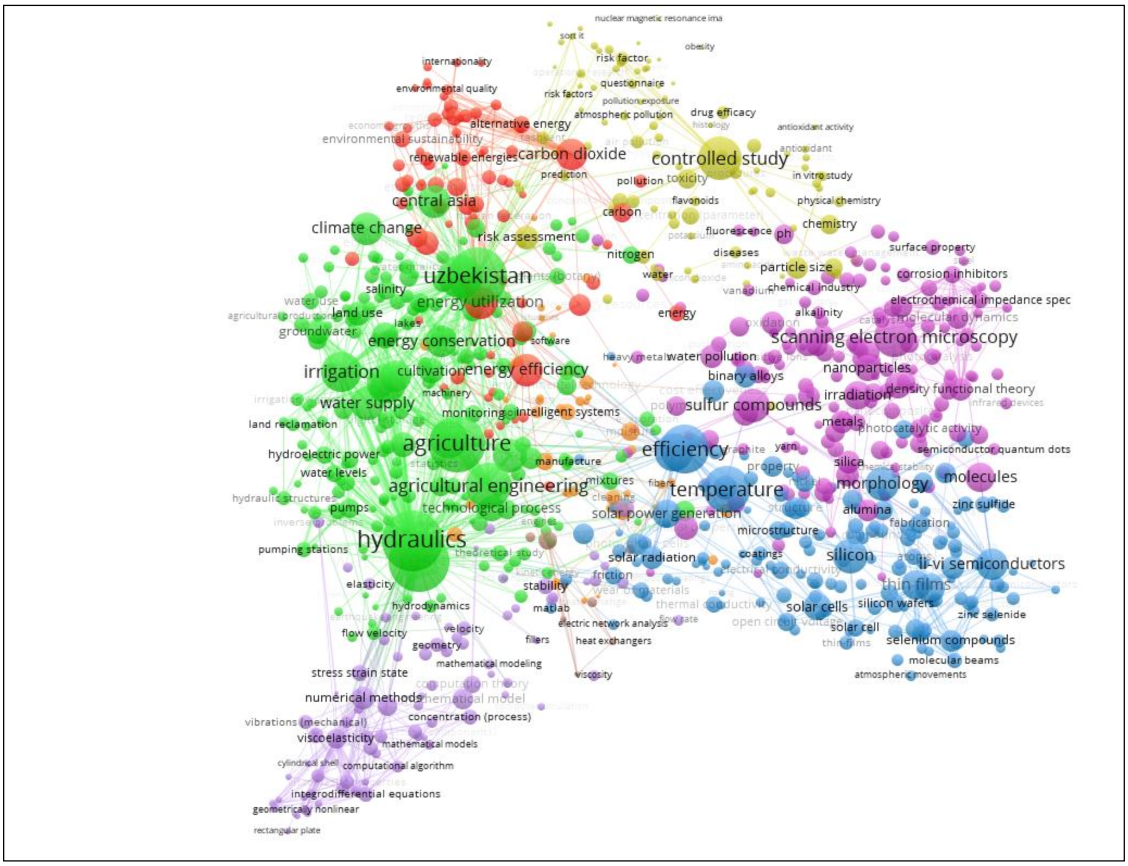

Figure 2.1. Keyword co-occurrence network visualization of the search.

Figure 2.1 reveals six distinct clusters, each represented by different colors, showcasing interconnected keywords. For instance, the keyword ‘climate change’ is closely associated with terms like ‘irrigation,’ ‘water use,’ ‘cultivation,’ ‘agriculture,’ and ‘hydraulics,’ highlighting the significant impact of climate change on Uzbekistan's water resources. Additionally, keywords such as ‘carbon dioxide,’ ‘environmental sustainability,’ and ‘pollution’ are linked to ‘renewable energies’ and ‘alternative energy,’ indicating that Uzbekistan’s decarbonization efforts, as reflected in the scientific community, are primarily focused on renewable energy sources. Overall, it is evident that there is limited interest in CCSU within Uzbekistan’s scientific circles, and there is also a notable gap in English-language literature regarding the country's representation in decarbonization initiatives.

2.3.2. CO_2 emissions in Uzbekistan

Accurately calculating CO_2 emissions relies on the reliability of the data available. Based on our calculations, Uzbekistan's annual CO_2 emissions for 2021 totaled 115.89 million metric tons (Mt). This equates to 3.274 metric tons of CO_2 emissions per capita. The average annual CO_2 emissions between 2016 and 2021 are estimated to be around 114.5 Mt, as illustrated by the dashed trend line in Figure 2.2.

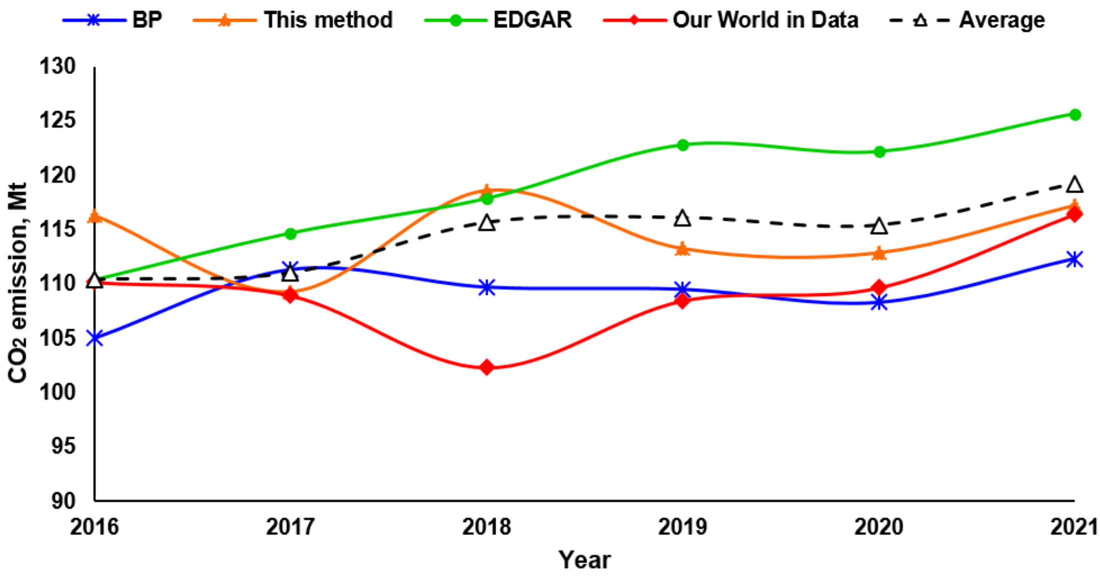

Figure 2.2. CO_2 emissions in Uzbekistan (2016-2021).

The discrepancies between statistical sources arise from variations in the methods used to calculate CO_2 emissions and the availability of reliable data. The increase in average CO_2 emissions over the years can be attributed to the rapid expansion of Uzbekistan's industrial and energy sectors. Notably, power production increased by 1.21 times [9], and cement production grew by 1.64 times [10]. During this period, existing power plants were modernized, and new combined cycle power units were introduced, contributing to the rise in emissions.

At the start of the last decade, Uzbekistan had only four large cement plants, but by 2022, this number had grown to 30 [11]. Additionally, a reduction in natural gas exports, which is Uzbekistan's dominant fuel (see Figure 2.3, a), has led to increased domestic consumption. This, coupled with the import of additional natural gas and rising fuel demands in agriculture and transport, has contributed to a rise in CO_2 emissions. The only notable exception occurred in 2020, during the COVID-19 pandemic, when the annual growth rate of CO_2 emissions slightly decreased, reflecting global trends. This reduction was primarily due to lower energy consumption in small to medium-sized industrial sectors, social facilities, and transportation during the pandemic.

The analysis covers all fuel-consuming industries in Uzbekistan to estimate CO_2 emissions by sector. Fuels responsible for CO_2 emissions are primarily utilized in power generation, residential use, and various industrial sectors. Figure 2.3 illustrates the yearly CO_2 emissions based on the source type (e.g., fossil fuels or chemical reactions) in part (a), and by sector in part (b). Natural gas, coal, and oil products contribute 81.7%, 9%, and 3.9% of the total CO_2 emissions, respectively, while the remaining emissions stem from calcination processes, urea production, natural sources, and other emitting activities.

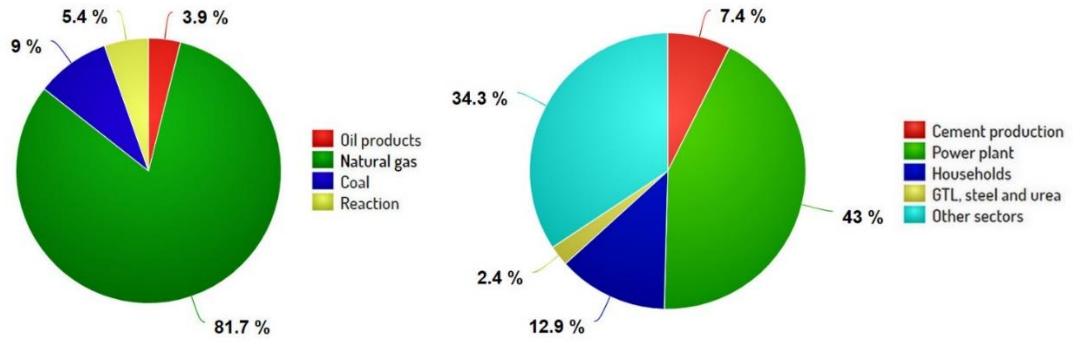

Figure 2.3. Annual CO_2 emissions by fuel type (left) and sector (right) in Uzbekistan (2021).

The basis of energy resources in Uzbekistan are natural gas, coal, and oil. The production and use of natural gas are higher than that of other fuels. On average, more than 50 billion cubic meters of natural gas is produced per year [12] (See Supplemental Information Table S1) and supplied to consumers through Joint-Stock Company (JSC) “Uztransgaz” (for large consumers and power plants) and JSC “Hududgazta’minot” (for households and small-medium industries) as shown Table S2 of Supplemental Information. As for coal, more than 4 million tons are mined on average per year (See Supplemental Information Table S3). In 2021, a total of 4.7 million tons of coal was produced [13]. Angren lignite with a low calorific value comprises 97.4 % of the total coal production [14] and is mostly used for Angren thermal power plant (TPP), Yangi Angren TPP, other production manufacturers, and domestic usage. The remaining 2.6 % of coal is hard coal and is mined from the Boysun and Shargun mines. Depending on the need, coal can be imported from neighboring countries, Kazakhstan and Kyrgyzstan. Oil production is much less than domestic demand, and it is covered by imports. Uzbekistan has three main crude oil refineries located in Ferghana (LLC “Sanoat energetika guruhi”), Alty-Arik (LLC “Sanoat energetika guruhi”), and Bukhara (“Bukhara Oil Refinery” unitary enterprise), with a total crude oil distillation capacity of about 80 million barrels annually [15].

In terms of emission sources, around 43% of annual CO_2 emissions come from the power sector. Residential use accounts for 12.9%, while cement production contributes 7.4%. Gas-to-liquid GTL production, steel, and urea plants together represent 2.4%. Other industrial sectors, including building material production (excluding cement), agriculture, transportation, and food production, account for 34.3%. The next sections focus on thermal power plants and the cement industry, which are the largest contributors to CO_2 emissions.

2.3.2.1. CO_2 emission in power sector

Uzbekistan’s potential for environmentally friendly power generation, especially from hydropower, is constrained by its geographical location and economic conditions. As a result, the country relies heavily on fuel-based power generation. In 2021, Uzbekistan produced 70.1 million MWh of electricity, with over 91% coming from thermal power plants fueled by natural resources, specifically 86.3% from natural gas and 5.5% from coal. [16,17]. Currently, Uzbekistan operates six natural gas-based thermal power plants, three natural gas-based thermal power centers, and two coal-fired power plants (see Supplemental Information Table S4). The map in Figure 2.4 (a) shows the locations of these power plants, which have capacities ranging from 57 MW to 3165 MW (Figure 2.4, b). The plants are depicted as rings, with red rings representing gas-fired power plants and blue rings indicating coal-fired plants. About 90% of CO_2 emissions from thermal power plants result from natural gas combustion, while 10% come from coal. The sector’s carbon footprint remains high due to the use of conventional gas turbine power units at some facilities.

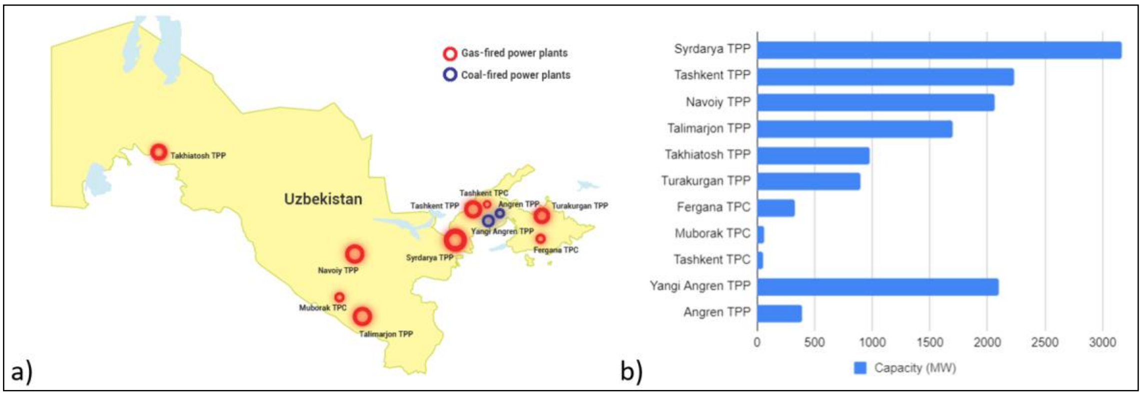

Figure 2.4. Power plant locations (a) and their capacities (b).

Given that current power production does not meet total demand, it is essential to increase output. To transition to a green economy and boost the annual production capacity of the power sector, the following planned initiatives are being implemented:

- Four natural gas-fired combined cycle (NGCC) TPPs with a total capacity of 3,520 MW are currently under construction [18–20]. Among them, the construction of the 220 MW TPP was completed at the end of 2022;
- Existing conventional thermal power plants are being modernized and combined cycle turbines are being installed;
- Four wind power plants with a total capacity of 2600 MW are being built in the Bukhara Region (1000 MW) and the Autonomous Republic of Karakalpakstan (1600 MW) [21];
- It is planned to build more than ten solar photovoltaic power plants with a total capacity of about 3000 MW [20].

2.3.2.2. CO_2 sources in power sector by regions

The data presented provides an overview of CO_2 emissions across various sectors in the region, highlighting the contributions of different industries. Below is a breakdown and analysis of how each sector impacts overall emissions.

Power plants emerge as the largest contributors, responsible for over 40% of total CO_2 emissions. This significant figure reflects the energy generation methods employed, which include gas-fired steam turbines, coal-fired power plants, hybrid systems, and NGCC plants. The variety of technologies used indicates differences in both efficiency and emission levels. With more than 13 facilities, the sector's heavy reliance on fossil fuels plays a crucial role in its considerable emissions footprint. The Tashkent economic region, which contributes around 19 Mt of CO_2, is likely home to a dense concentration of power generation plants, including larger and possibly older gas- or coal-fired units that typically produce higher emissions.

Similarly, Mirzachul, with emissions totaling 12 Mt, also has significant power generation activity. The use of similar technologies as in Tashkent suggests this region could benefit from energy efficiency improvements and carbon reduction measures. Regions like Zarafshan, Kashkadarya, Fergana, and Karakalpakstan produce moderate emissions from power generation, with 5.85 Mt, 5 Mt, 3.03 Mt, and 2.77 Mt, respectively, indicating a notable presence of industrial activity in these areas (see Figure 2.5). These regions, while emitting less than Tashkent and Mirzachul, still contribute meaningfully to the overall emissions profile and could also be targeted for emissions reduction efforts.

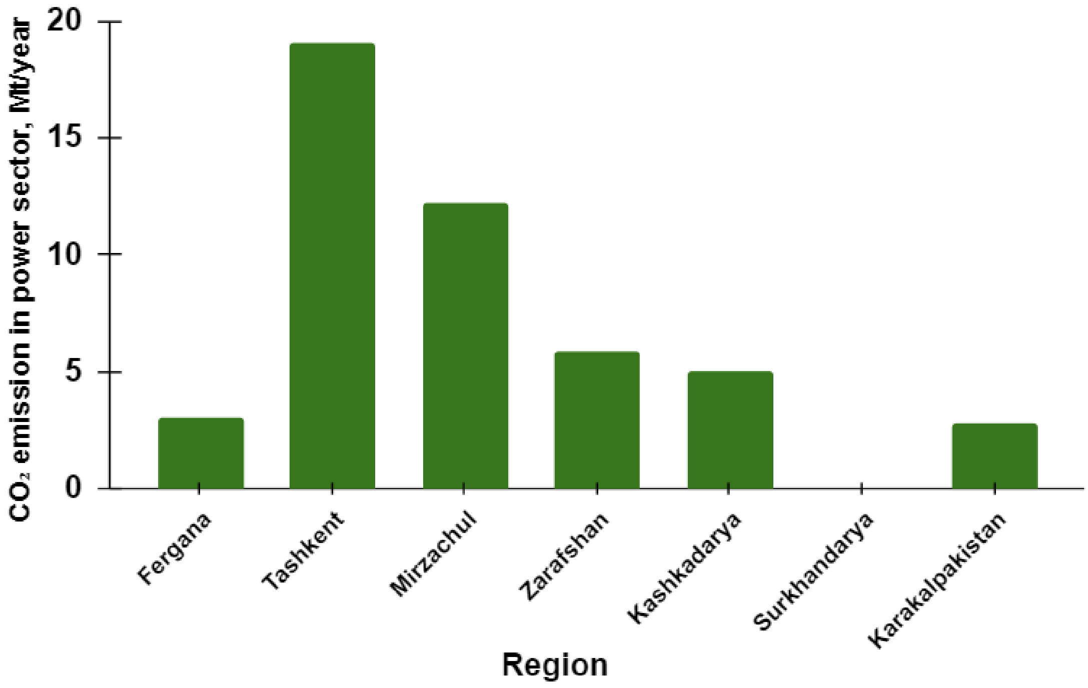

Figure 2.5. Annual CO_2 emission in the power sector by economic regions [22].

2.3.3. CO_2 emission reduction pathways for power sector of Uzbekistan

This section explores the main indirect strategies for reducing CO_2 emissions in Uzbekistan. These strategies focus on increasing the share of renewable energy sources (RES) in the overall energy mix, continuing reforms of the existing power transmission grid, and exploring power trading opportunities between Uzbekistan and other Central

Asian nations. Additionally, government policies and regulations aimed at promoting the adoption of clean energy, improving energy efficiency, and fostering sustainable practices are assessed.

2.3.3.1. Renewable energy transition

Renewable energy is a crucial avenue for reducing greenhouse gas emissions, offering the ability to generate electricity without harmful carbon outputs. By adopting sources like solar, wind, and hydropower, Uzbekistan can significantly curb its reliance on fossil fuels, helping mitigate their environmental impact and stabilize energy costs.

One of the key benefits of RES is decentralizing energy production, allowing localized energy generation, which increases energy security and resilience against power outages. The operational costs of RES are generally lower since they use abundant natural resources, and renewable energy systems also have the potential to reduce water consumption, which is a crucial benefit in regions with water scarcity.

However, renewable energy has challenges. Intermittent production, especially for solar and wind, means energy storage systems are essential to ensure a steady supply. Additionally, the high initial capital costs for infrastructure, resource limitations, and land requirements present obstacles. For instance, solar and wind energy systems need large land areas to generate power, and certain regions in Uzbekistan may not be suitable for renewable energy deployment due to inadequate sunlight or wind potential.

Uzbekistan has significant solar energy potential, with over 320 sunny days annually and technical potential far exceeding the country’s energy needs. Wind energy also shows promise, especially in designated areas where wind turbines can operate at full capacity for around 162 days a year—higher than the global average. Hydropower, although facing challenges due to decreasing water resources, remains the second largest renewable source, and small hydropower plants offer cost-effective solutions for remote areas.

The Uzbek government aims to increase the share of renewable energy in the country’s energy mix to at least 20% by 2025, up from 9.4% in 2018. To support this, numerous laws and policies have been enacted, including initiatives like the “Sunny House” program, which incentivizes households to sell electricity generated from RES back to the grid. Other decrees promote the development of hydrogen and nuclear energy, which are also being explored to diversify the country’s energy portfolio.

2.3.3.2. Improving Power Transmission Lines and Energy Efficiency

Uzbekistan's aging power transmission and distribution infrastructure has been a significant barrier to energy efficiency, with about 15.19% of electricity lost during transmission—almost double the global average. Much of the infrastructure, including main and distribution networks, substations, and transformer stations, is over 30 years old, contributing to frequent outages and inefficiencies [23].

The government has responded by launching the "Concept of Providing Uzbekistan with Electricity for 2020-2030," which seeks to reduce transmission and distribution losses to 8.85%, which is 1.85 times less than the value in 2019, by modernizing the power grid [23]. Key actions include upgrading existing substations, strengthening the power grid, and improving the electricity market through digitalization and decentralization. If fully implemented, these improvements could lower Uzbekistan's GHG emissions by about 4 Mt CO_2 annually, based on 2021 power generation levels.

This modernization will also help the power sector meet the increasing energy demands, particularly during peak periods in winter and summer. The upgraded infrastructure is expected to support the integration of more renewable energy into the grid, ensuring that the power generated can be delivered more efficiently with minimal losses. By addressing these transmission inefficiencies, Uzbekistan can enhance its energy security, reduce its environmental impact, and move closer to a carbon-neutral future.

2.3.3.3. Power trading with neighbouring countries

Power trading with neighboring countries can play a significant role in reducing GHG emissions by optimizing energy use across regions. Through regional power exchanges, countries like Uzbekistan can import cleaner, renewable energy when their domestic production falls short, especially during periods of low renewable generation. For instance, during times of high solar or wind energy production in neighboring countries, Uzbekistan could tap into surplus renewable power, reducing its reliance on fossil-fuel-based energy sources. This helps to lower overall GHG emissions by ensuring that a greater share of the energy consumed comes from low-carbon or carbon-free sources.

According to the modelling analysis results in 2020, Central Asian countries can save up from operational expenses as much as 6.4 billion USD in this decade by regionally power trading cooperation at full capacity [24]. Moreover, in March 2023, "The Central Asia

Energy Trade and Investment Forum 2023" took place in London where the policymakers of five Central Asian countries participated. During the forum, representatives of those countries highlighted their initial estimates of 20 billion USD of investments in Central Asia by 2030, including renewable energy and grid modernization for improved trade [25].

Furthermore, power trading can create economic incentives for investing in renewable energy infrastructure across the region, as countries with abundant solar, wind, or hydropower resources can sell excess electricity to their neighbors. By connecting to a regional grid, Uzbekistan can also avoid building additional fossil-fuel power plants to meet peak demand, leading to a more efficient and environmentally friendly energy system. Over time, this collaborative approach could drive significant reductions in GHG emissions across Central Asia while promoting energy security and economic growth.

2.3.4. Is it possible to implement CCSU technologies for the major CO_2-emitting sources in Uzbekistan?

The implementation of CCSU technologies in Uzbekistan presents an important opportunity to reduce CO_2 emissions from major industrial sectors, such as power generation, cement production, and chemical processing. Given the country's growing focus on sustainable development and its substantial reliance on fossil fuels, exploring the feasibility of CCSU in mitigating carbon emissions is essential.

In this line, the economic side is regarded as one of the most important aspects of evaluating the CCSU integration into the power and industrial sectors. In this context, CO_2 concentration in the exhaust gas plays a crucial role in the economy of the CCSU due to its inverse proportionality to the cost of CO_2 capture. Since the CO_2 separation process is responsible for the majority of the CCSU expenses, it is possible to make an initial estimation by CO_2 content in the flue gas. CO_2 capture cost from the point sources decreases in response to the increase in the concentration of the CO_2 in the flue gas or vice versa. For instance, CO_2 separation from the flue gas of natural gas-fired power stations costs significantly more than the flue gas of cement plants as the average CO_2 concentrations in these streams are 3-5 mole % and 18-30 mole % respectively (see Table 2.1).

Table 2.1. Preliminary CO_2 capture cost and its major CO_2 emitting sectors [26].

CO_2 source	CO_2 content, %	CO_2 process unit	Capture cost, $/ton	Temperature, °C	Flue gas components
Natural gas power plant	3-5	Gas turbine	75-100	90-110	CO_2, H_2O, O_2, N_2, Ar, trace amount of NO_X
	7-8	Steam boiler	58-62	90-150	CO_2, H_2O, O_2, N_2, Ar, trace amount of NO_X
Coal power plant	10-15	Steam boiler	41-51	40-65	CO_2, H_2O, CO, O_2, N_2, Ar, NO_X, SO_X
Cement production	18-30	Calciner	28-37	150-350	CO_2, H_2O, CO, O_2, N_2, Ar, NO_X, SO_X
Refineries	3-20	Process heaters, utilities, regeneration of catalyst	35-100	160-190	CO_2, H_2O, O_2, N_2, Ar, trace amount of NO_X
Iron and steel industry	20-27	Blast Furnace	30-35	~100	H_2, CO, CO_2, N_2, H_2S, H_2O

According to Table 2.1, CO_2 capture costs are highest for NGCC power plants. This is due to the large volume of air used in natural gas combustion, which lowers the combustion temperature but also dilutes the CO_2, making capture more expensive. In contrast, the industrial sector has the lowest CO_2 capture costs because emissions arise not only from combustion but also from calcination and other chemical processes, which release higher amounts of CO_2. From this perspective, power plants and cement factories are the main sources of CO_2 emissions, together accounting for more than 50% of the country's annual emissions (43% from power plants and 7.4% from cement plants). Given that natural gas, particularly in combined cycle gas turbines, dominates power generation, it is likely that the cost of CCSU for the power sector would exceed average expectations. However, coal-fired power plants like Angren and New Angren, as well as cement factories, could be prime candidates for early CCSU implementation, as the associated costs in these sectors are more manageable.

On one hand, Uzbekistan has significant CO_2 capture potential due to the widespread use of natural gas, the cleanest fossil fuel, across all CO_2-emitting sectors. However, capturing CO_2 through absorption would be costly because of the need for large columns and extensive solvent circulation. Additionally, Uzbekistan's geographic location as the world's only double-landlocked country poses logistical challenges for transporting materials and equipment. Furthermore, the absence of a carbon tax in Uzbekistan may reduce the motivation for CO_2 emissions reduction. As of October 1, 2023, electricity prices remain relatively low, with households paying 295 Uzbek soums (equivalent to approximately $0.025), government organizations 1000 soums ($0.082), and other consumers 900 soums ($0.074) per kWh, due to government subsidies [27]. If electricity tariffs are liberalized and a carbon tax is introduced, there would likely be increased pressure to pursue decarbonization efforts. Another obstacle to integrating CCSU is the lack of research from local institutions, creating a need for international expertise in this area.

On the other hand, these challenges are heavily influenced by national and international climate policies. If the government and global organizations implement strict climate regulations, companies—especially major emitters—will be compelled to adopt decarbonization strategies like CCSU. Moreover, advancements in CO_2 capture technologies, including innovative membrane materials, solvents, sorbents, and other methods, could significantly reduce the costs and complexity of CO_2 separation processes.

2.4. Conclusion and future work

In this chapter, a comprehensive sector-by-sector calculation and analysis of annual CO_2 emissions in Uzbekistan is presented for the first time, utilizing the 2006 IPCC guidelines and gathered statistical data. Additionally, pathways for CO_2 emission reductions through various strategies and other decarbonization measures in Uzbekistan are thoroughly examined. This information serves as a valuable resource for researchers and policymakers focused on reducing GHG emissions through the promotion of renewable energy sources, optimization of fossil fuel-based industries, and integration of CCSU technologies in Uzbekistan. Based on the findings, following several key conclusions are highlighted.

- ✓ A brief bibliometric survey reveals a scarcity of English-language literature on Uzbekistan's decarbonization policies and measures in international scientific databases.
- ✓ In 2021, Uzbekistan's annual CO_2 emissions amounted to approximately 115.89 Mt, with per capita emissions reaching 3.274 tons.
- ✓ As anticipated, the power and industrial sectors are the dominant contributors to the country's annual CO_2 emissions, accounting for 43% and 44.7% respectively, with the remaining emissions attributed to residential use and other sectors.
- ✓ Given the potential water shortages in Uzbekistan in the coming decades, transitioning to RES, particularly solar energy, is identified as a promising alternative to traditional fossil fuel-based energy and industrial sectors.
- ✓ The combination of low electricity and natural gas prices and the absence of incentives for businesses and households to adopt RES is increasing energy demand and hindering carbon reduction efforts.
- ✓ Modernizing and improving the existing power transmission infrastructure could potentially reduce the country's GHG emissions by up to 2 Mt.
- ✓ In terms of Nationally Determined Contributions (NDC) plans, Kazakhstan and Kyrgyzstan have set more ambitious decarbonization strategies compared to other Central Asian countries, while Uzbekistan has yet to outline substantial decarbonization actions.
- ✓ Central Asian countries stand to gain substantial economic benefits through regional power trade cooperation at full capacity, particularly in terms of reducing operational costs in power generation.
- ✓ Due to the low CO_2 concentration from natural gas combustion in major emitting sources, Uzbekistan will face higher costs to integrate CCSU technologies, emphasizing the need for further investments.
- ✓ Introducing a carbon tax and liberalizing Uzbekistan's energy market remain crucial drivers for advancing towards a more sustainable future.

Overall, Uzbekistan, as a developing country, possesses multiple pathways to achieve decarbonization. However, the limited public concern, absence of strong sustainability policies, and insufficient international investments are key factors hindering the acceleration of these decarbonization efforts. Future research will focus on evaluating the potential for both onshore and offshore CO_2 utilization, as well as examining end-of-pipe CCSU integration from environmental and techno-economic perspectives, using specific large stationary CO_2-emitting sources as case studies.

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SUPPLEMENTAL MATERIAL

Table S1. Natural gas production in Uzbekistan (2021).

Natural gas producers	Annual production, billion m^3 /year	Share, %	Gas reserve, billion m^3
Total	**53.8**		**1865.3**
"Uzbekneftgaz" NHC	34.1	63.383	934.1
"Lukoil Uzbekistan" LLC	13.8	25.651	413.1
Uz-kor gas chemical	2.1	3.903	109.6
Epsilon Development Company	1.4	2.602	50.2
Natural gas-stream	1.2	2.23	52.3
New silk road oil and gas	0.37	0.688	11.9
Jizzakh petroleum	0.28	0.52	84.9
Gazprom Uzbekistan	0.23	0.428	12
Gazli Gas storage	0.15	0.279	48.1
Gissarneftgaz	0.12	0.223	40.5
Kukdumaloq gaz	0.026	0.048	n/a
LLC “Surhan gas chemical complex”	n/a	n/a	108.6

Table S2. Natural gas distribution by sector in 2021

Power and industrial sector	Share, %
Thermal power plants	31.21
Uzkimyosanoat	4.99
Uzsanoatqurilishmateriallari	2.5
Natural gas station for transport	6.24
Households	23.84
Export	7.12
Storage	6.62

Other industrial sectors	7.36
Other consumption	10.12

Table S3. Fossil fuel production in Uzbekistan.

Year	Natural gas, billion m^3	Crude oil, Mt	Coal, Mt
2016	52.68	n/a	3.7
2017	46.1	0.806	4
2018	50.496	0.745	4.2
2019	47.26	0.696	4.1
2020	47.2419	0.774	4.2

Table S4. List of thermal power plants in Uzbekistan

	Thermal power plants	Capacity, MW	Main fuel	Alternative fuel
1	Syrdarya TPP	3165	Natural gas	Heavy fuel oil
2	Tashkent TPP	2230	Natural gas	Heavy fuel oil
3	Navoiy TPP	2068	Natural gas	Heavy fuel oil
4	Talimarjon TPP	1700	Natural gas	Heavy fuel oil
5	Takhiatosh TPP	980	Natural gas	Heavy fuel oil
6	Turakurgan TPP	900	Natural gas	Heavy fuel oil
7	Fergana TPC	329	Natural gas	Heavy fuel oil
8	Muborak TPC	60	Natural gas	Heavy fuel oil
9	Tashkent TPC	57.15	Natural gas	Heavy fuel oil
10	Yangi Angren TPP	2100	Coal	Natural gas
11	Angren TPP	393	Coal	Natural gas
Under design and construction				
12	New Syrdarya TPP	1500	Natural gas	n/a
13	Kibray TPP	240	Natural gas	n/a

Table S5. CO_2 emissions in Uzbekistan, Mt.

International statistics	2016	2017	2018	2019	2020	2021
British Petroleum (BP)	105	111.3	109.7	109.5	108.3	112.3
EDGAR	110.3	114.62	117.82	122.77	122.15	125.65
Our World in Data	110.14	108.93	102.29	108.43	109.63	116.39

Table S6. CO_2 emission calculation.

Tier 1	Estimation using fuel consumption, energy conversion and CO_2 emission factor				
	Energy consumption			CO_2	
Fuel type	Consumption, kt	Conversion factor, TJ/kt	Consumption, TJ	CO_2 Emission Factor, kt CO_2/TJ	CO_2 Emissions, Mt CO_2
Jet fuel	170.7	44.1	7527.87	71500	0.54
Motor gasoline	1288.3	44.3	57071.69	69300	3.955
Natural gas	34828	48.5	1689158	56100	94.76
Coal (brown)	4570	18.7	85459	107000	9.143
Coal (hard)	122	22.5	2745	98300	0.274
Coal (import)	47	20.5	963.5	1010000	0.97
Total CO_2 emission from combustion					109.6
CO_2 emission from other chemical reactions					
Calcination					7.1
Urea					0.314
Total:					**117.19**

Table S7. CO_2 emissions in the Central Asian countries.

	Country	**Total CO_2 emission, Mt/year**	**CO_2 emission per capita, t**
1	Kazakhstan	211.897	11.2
2	Turkmenistan	63.655	10
3	Tajikistan	9.329	1
4	Kyrgyzstan	9.080	1.4
5	Uzbekistan	117.190	3.4
	Total	**411.151**	

Chapter III - 3. Simulation of base case Turakurgan NGCC power plant and process modifications

The result of this chapter is presented at the 2nd International Electronic Conference on Processes: Process Engineering—Current State and Future Trends, Beijing, China, 17–31 May 2023, and published as proceeding paper as:

Kamolov, A.; Turakulov, Z.; Norkobilov, A.; Variny, M.; Fallanza, M. Decarbonization Challenges and Opportunities of Power Sector in Uzbekistan: A Simulation of Turakurgan Natural Gas-Fired Combined Cycle Power Plant with Exhaust Gas Recirculation. *Eng. Proc.* **2023**, *37*, 24. https://doi.org/10.3390/ECP2023-14648

Abstract

In Uzbekistan, reliance on natural gas for power generation is significant, with over 85% of the country's electricity stemming from natural gas, making natural gas-fired power plants a substantial source of national greenhouse gas emissions. To meet Uzbekistan's CO_2 reduction goals, carbon capture, storage, and utilization (CCSU) are critical. This study simulates one of the two 450 MW blocks at the 900 MW Turakurgan combined cycle natural gas-fired power plant located in the Fergana Valley, using Aspen Plus® software. This simulation is validated against publicly available project data, establishing a foundation for assessing the feasibility of integrating CCSU systems. To intensify the carbon capture potential, the study identifies a suitable level of exhaust gas recirculation (EGR) that enhances CO_2 concentration in the flue gas while reducing flow rate. Findings indicate that at a 90% CO_2 capture rate, over 2.16 Mt of CO_2 emissions could be avoided annually, when CCSU is integrated into the whole power plant. Additionally, An EGR integration of 45% is concluded to be the most suitable for effective CCSU implementation.

3.1. Introduction to modelling and simulation

The development of accurate models is critical in the evaluation, optimization, and simulation of complex systems such as power plants, especially when introducing advanced technologies and methodologies such as exhaust gas recirculation (EGR) and post –combustion carbon capture (PCC) technologies. This chapter provides an in-depth discussion of the modelling approaches, results, and validation used to develop simulation models for the Turakurgan natural gas-fired combined cycle (NGCC) power plant. The models span the power plant itself, its modification including optimal air/fuel ratio, EGR, and flue gas pre-treatment, units. A systematic methodology is applied to ensure that the models accurately reflect real-world conditions and are validated against open source project report data in the Turakurgan thermal power station preparatory project.

Modelling and simulation are powerful tools in engineering for the study of static and dynamic systems and processes. In this thesis, these tools are employed to analyze the performance and efficiency of the Turakurgan NGCC power plant and its associated components prior to post-combustion CO_2 capture plant integration. The process simulation of the power plant is developed using mathematical representations of the physical processes occurring within the power plant and auxiliary units employing commercial simulation tools such as Aspentech™. These developed models allow for experimentation and performance evaluation under various operational conditions without the need for expensive or disruptive real-life testing. In particular, this work focuses on modelling energy and mass balances, thermodynamic cycles, and chemical reactions.

3.2. Modelling of Turakurgan NGCC power plant

3.2.1. Background and Overview of Turakurgan NGCC

In line with Uzbekistan's climate goals of cutting greenhouse gas (GHG) emissions by 35% by the end of the 2020s, the Turakurgan NGCC power plant was selected as a case study to evaluate CCSU integration. The NGCC technology is favored due to its cleaner emissions compared to coal or oil-based power plants, and it operates with higher efficiency. However, most of Uzbekistan's thermal power plants, including Turakurgan, use the combined cycle principle, which combines gas and steam turbines to maximize energy output and still considered as the largest CO_2 emission sources in the power and industrial sectors of the country. Figure 3.1 below shows the overall thermal power plants and centers in Uzbekistan (left) and selected Turakurgan TPP (right).

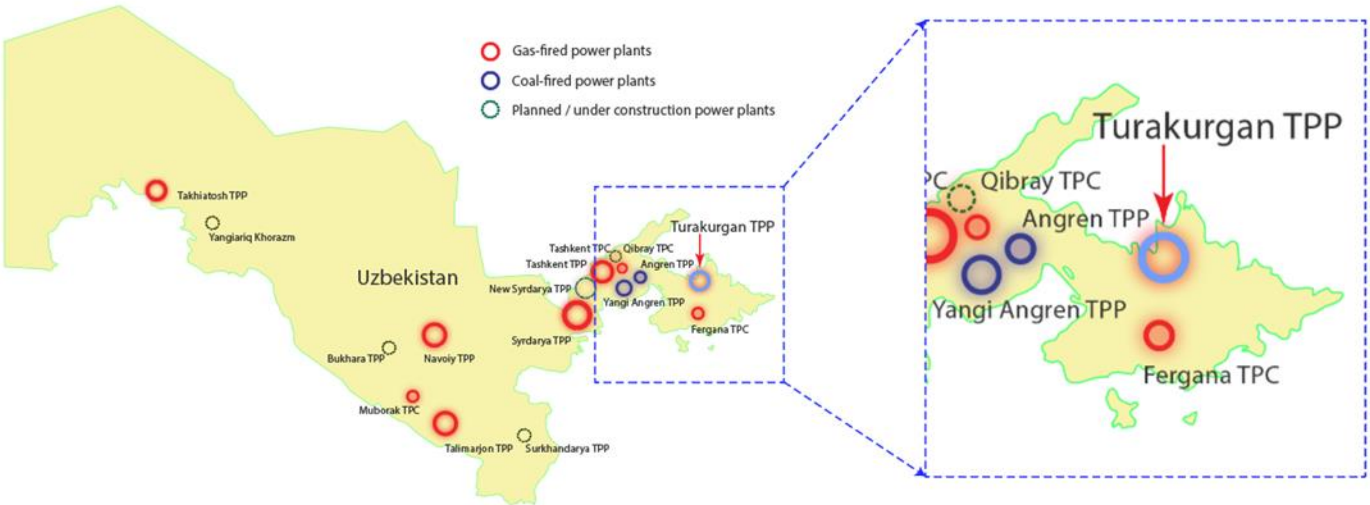

Figure 3.1. The site of Uzbekistan and Turakurgan thermal power plant [1].

The Turakurgan NGCC plant, located in the Namangan region in the northwest of the Fergana Valley, was selected for several following reasons [2]:

- Location: The power plant is situated 11 km west of Namangan city, and 4 km west of Turakurgan town, with the nearest settlement only 1 km away. Its proximity to the state boundary with the Kyrgyz Republic (35 km) also makes it a key infrastructure asset for regional energy needs.
- Fuel supply: Natural gas is the most abundant fuel in Uzbekistan, making it the most viable option for large-scale power generation. Turakurgan, being a natural gas-fired plant, aligns with the country’s reliance on NG for energy production.
- Operational Efficiency: The plant consists of two identical blocks, each with a 450 MW output, utilizing Mitsubishi-Hitachi M701F Series Gas Turbines. This combined cycle system enhances the plant’s efficiency and reduces emissions relative to single-cycle power plants.
- Decarbonization Potential: Given the challenges of fully transitioning to renewable energy in the near term, integrating CCSU technologies at Turakurgan offers a realistic pathway to decarbonizing the plant while maintaining its

operational efficiency. The implementation of CCSU, along with technologies like EGR, is being investigated as part of this study.

Overall, the Turakurgan NGCC power plant represents a vital part of Uzbekistan's current and future energy landscape. Its selection for this study is based on its strategic importance, reliance on natural gas, and potential for CCSU integration, which will help Uzbekistan meet its decarbonization goals while ensuring energy security.

3.2.2. Simulation Approach

The Turakurgan TPP operates with two identical power blocks, each producing 450 MW of output. These blocks are powered by Mitsubishi-Hitachi M701F Series Gas Turbines, which work in a combined gas and steam cycle to maximize efficiency. A basic diagram of NGCC power plant is illustrated in Figure 3.2 below (Figure 3.2). To better understand the performance of this system, a simulation model of one 450 MW block, including both the gas and steam turbines, was developed and validated using the commercial process simulation software, Aspen Plus®. Primary data on fuel and air composition is provided in Table 3.1.

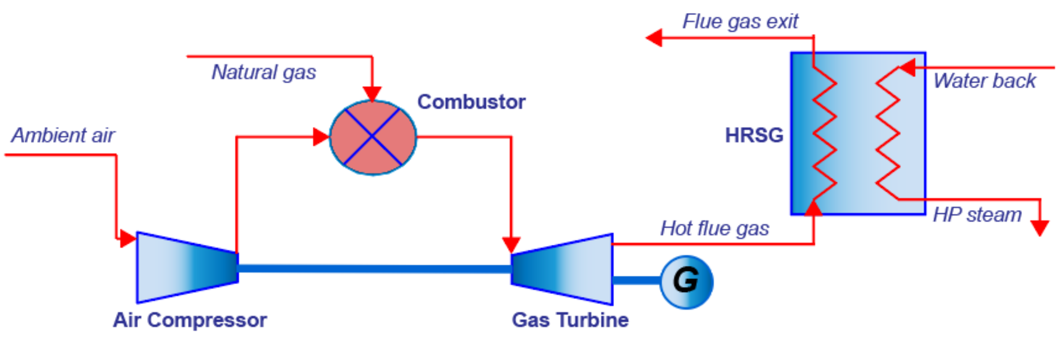

Figure 3.2. Turakurgan NGCC power plant's simplified schematic figure.

Table 3.1. The air and fuel compositions used in the Turakurgan NGCC power plant [2].

No.	Elements	%w/w
Air composition		
1	N_2	75.52%
2	O_2	23.13%

3	Argon	1.28%
4	Carbon dioxide	0.07%
Fuel composition		
1	CH_4	93.44%
2	C_2H_6	3.14%
3	C_3H_8	0.56%
4	n-C_4H_{10}	0.08%
5	i-C_4H_{10}	0.09%
6	n-C_5H_{12}	0.03%
7	i-C_5H_{12}	0.03%
8	n-C_6H_{14}	0.01%
9	N_2	0.54%
10	CO_2	2.08%
Lower calorific value (kJ/kg)		46750

The thermodynamic properties for the gas cycle are determined using the Peng-Robinson equation of state with Boston-Mathias modifications (PR–BM method), ensuring accurate prediction of gas behavior at high pressures and temperatures. Meanwhile, the steam cycle properties are modelled using the STEAMNBS property method, which provides reliable evaluation of steam properties under various conditions [3]. A key component of the gas turbine system is the combustor, which has been modelled using an RGibbs reactor block in Aspen Plus®. This block determines the equilibrium composition of combustion products by minimizing the Gibbs free energy [4]. Notably, the RGibbs reactor allows for the flexibility to define the extent of chemical equilibrium achieved in the system. While specifying the reactor's temperature and pressure is necessary, the precise stoichiometry of the reaction does not need to be input, offering greater flexibility in modelling.

Turbine blade cooling plays a critical role in enabling gas turbines to operate efficiently at high temperatures. For F-series gas turbines, such as the M701F, the cooling of turbine blades is essential to maintain the turbine inlet temperature at permissible levels, which can reach up to 1300°C due to metallurgical limitations [5]. This cooling is typically achieved by bleeding air from the compressor, which is then directed to cool the turbine blades. However, this process introduces two major challenges. First, the cooling air reduces the temperature of the gas expanding through the turbine, which in turn reduces the power output. Second, mixing the cooling air with the turbine's working fluid results in additional losses. To accurately capture these effects, the simulation applies a methodology suggested by [6], which quantifies the impact of turbine blade cooling on both temperature and power output.

In the power generation process of the Turakurgan TPP, ambient air enters the system at a rate of 664.5 kg/s with an initial pressure of 0.944 bar. This air is compressed to a pressure of 18 bar before being split into two separate streams. The first stream is directed to the combustion reactor after being mixed with 16.11 kg/s of natural gas, which has a lower calorific value (LCV) of 46.750 kJ/kg. The second air stream is utilized for cooling the hot flue gas that exits the combustion chamber. This cooling is critical due to the high temperature limits of the F-series gas turbines, which can only handle inlet temperatures up to 1300°C. To ensure the turbine inlet temperature remains within this limit, an additional 34 kg/s of air is introduced to cool the flue gas, although the exact amount of cooling air is dynamically calculated by Aspen Plus during the simulation based on the temperature constraints.

After combustion, the hot gas exits the gas turbine at a pressure of 1 bar and a temperature of 596°C. It then enters the Heat Recovery Steam Generator (HRSG), where the heat from the flue gas is transferred to a series of heat exchangers that generate steam. This steam is then used to power three steam turbines operating at different pressure levels: high pressure at 127 bar, intermediate pressure at 27.5 bar, and low pressure at 4.5 bar. These steam turbines further enhance the overall power generation efficiency of the plant. After the heat exchange process, the flue gas exits the HRSG at a temperature of 104°C and a pressure of 0.981 bar, significantly cooler than when it entered. Main inputs in the model and in the open source project data are provided in Table 3.2.

Table 3.2. Main inputs in the model and open source project data [2].

Parameters	Input
Air inlet mass flow (kg/s)	664.5[a]
Air temperature (°C)	13.7[a]
Air pressure (bar)	0.944[a]
Compressor discharge pressure (bar)	18[a]

Natural gas mass flow (kg/s)	16.11[a]
Natural gas inlet temperature (°C)	15[a]
Natural gas inlet pressure (bar)	14[a]
Circulation water mass flow (m^3/s)	138.5[a]
Compressor efficiency	0.90[b]
GT efficiency	0.89[b]
Three steam turbines efficiencies	0.91[b]
Cooling air kg/s	34[b]

[a] – these data are obtained from project report; [b] – these data are assumed in lack of specification in the project report;

3.2.3. Model results and validation

The simulation of a 450 MW Turakurgan NGCC power plant is developed and the simplified process flowsheet of the power plant is illustrated in Figure 3.3.

Table 3.3 provides a comprehensive summary of the simulation results in comparison with key parameters from the Turakurgan TPP project report. As the data shows, there is generally good alignment between the simulated results and the actual power plant data, indicating the reliability of the simulation model. However, a few discrepancies do exist, particularly in terms of the energy consumption for auxiliary systems, such as the compressors.

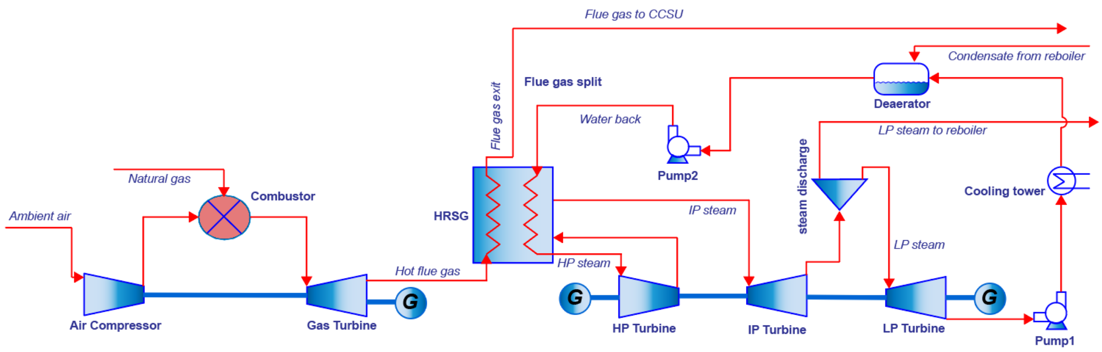

Figure 3.3. Base case Turakurgan NGCC power plant's flowsheet without EGR.

The energy requirement for auxiliary equipment is notably higher in the simulation than reported in the project data, with the simulation estimating an auxiliary consumption of 230 MW for the entire system and 12.6 MW specifically for the compressors. This elevated consumption is due to the fact that, in the simulation, the air compressors are modelled independently from the gas turbine, even though, in reality, the compressors are mechanically connected to the gas turbine on the same shaft. This connection means that the gas turbine must generate enough power to not only run itself but also to overcome the energy demands of the compressors. Despite this difference in modelling, the overall net power output of the TPP in both the simulation and project data remains comparable, showcasing the robustness of the system's design.

Table 3.3. A block of Gas Turbine tuning parameters and Aspen Plus simulation results.

Parameters	Project	Results
Flue gas out pressure (bar)	1	1
CO_2 content in flue gas (mol%)	N/A	3.96
O_2 content in flue gas (mol%)	N/A	12.3
Flue gas out temperature (°C)	100	104
GT power output (MW)	299.3	299.8
ST power output (MW)	134.5	132.8
Total power output (MW)	433.8	432.6
Auxiliary power (MW)	12.6	12.6
Net power output (MW)	421.2	420
Net power efficiency (%)	55.9	55.8
One Unit CO_2 emission (t/year)	1,177,177	1,202,000
Total CO_2 emission (t/year)	2,354,355	2,404,000

When it comes to CO_2 emissions, the simulation estimates a slightly higher emission rate—by around 2% more than the project data that can be due to the slight difference in the input parameters. The key focus of this analysis, however, is not just the absolute emission rate but also the characteristics of the flue gas, particularly in preparation for the design of a CCSU system.

In the current system, dilution air is introduced to cool the exhaust gases before they enter the gas turbine. This cooling has a noticeable impact on the composition of the flue gas, resulting in a lower CO_2 concentration of around 4 mol%. In contrast, the concentration of O_2 is relatively high at 12.3 mol%. This lower concentration of CO_2 in the flue gas poses a challenge for the efficient implementation of a CCSU system, as the higher O_2

levels and large mass flow rate of the flue gas could make the capture process more energy-intensive and costly.

Despite these challenges, the base case simulation of the Turakurgan TPP was successfully developed and validated. However, the study highlights that further optimization is needed to improve the feasibility of CCSU integration. One potential solution is the implementation of EGR, possibly with minor modification to the existing plant without deteriorating the system performance [7,8]. By recirculating part of the exhaust gas back into the combustion process, it would be possible to increase the concentration of CO_2 in the flue gas, which would significantly lower the overall cost of CO_2 capture.

3.3. Proposed process improvements for Turakurgan NGCC plant

The Turakurgan NGCC plant has been modified by integrating EGR to enhance its carbon capture potential. EGR is employed to increase the CO_2 concentration in the flue gas, facilitating more efficient separation in subsequent carbon capture stages. Other parameters, such as turbine efficiency, fuel utilization, and heat recovery, have not been considered for further optimization, assuming the plant operates within the optimal performance range typical of NGCC facilities. The plant's design already achieves low emissions, and EGR is implemented solely to enhance its readiness for CO_2 capture, with no additional need for further emission reduction.

Several studies have modelled and simulated PCC from the exhaust gases of NGCC power plants. For instance, Canepa et al. conducted a thermodynamic analysis of a 250 MW NGCC power plant integrated with CO_2 capture using the MEA absorption method. Their research showed that applying EGR increased CO_2 concentration in the flue gas from 4.1 mol% to 7 mol%, while also reducing the flue gas flow rate by 40%. These changes led to a smaller column size and a reduction in the specific reboiler duty from 4.97 to 4.68 GJ per tonne of CO_2 captured. [3]. Subsequently, the author further explored key operational parameters to determine the lowest achievable reboiler duty. The study found that the specific reboiler duty could be reduced to 4.1 GJ per tonne of CO_2 when achieving a 90% CO_2 capture rate. [9]. Additionally, Xiaobo Luo et al. examined the impact of MEA-based CO_2 capture on the operation of NGCC plants under different market conditions. Their findings indicated that a carbon price of €120 per tonne of CO_2

would be necessary to achieve a 90% capture rate. [10]. The study also revealed that rising fuel costs, along with increased CO_2 transport and storage prices, drive up the operating costs of carbon capture, necessitating an even higher carbon price to sustain the desired capture level. On the other hand, recognizing the critical role of CO_2 concentration in the flue gas for the energy efficiency of capture plants, Hailong Li et al. evaluated four methods to boost CO_2 levels in the exhaust stream: EGR, humidification, supplementary firing, and external firing [11]. The research indicates that EGR is the most effective method for simultaneously increasing CO_2 concentration and maintaining overall plant efficiency. EGR can raise CO_2 levels in the exhaust gas from 3.8% to 10%, and it also eliminates the need for a bottoming cycle, which can further reduce costs. Additionally, various studies have applied EGR in the range of 30-45%, demonstrating its ability to enhance CO_2 concentration while reducing the flow rate of flue gas and oxygen content. [12].

3.3.1. Exhaust gas recirculation integration

EGR is a technique used in power plants, particularly in NGCC plants, where a portion of the flue gas is recirculated back into the combustion process rather than being released directly into the atmosphere. This process helps to increase the CO_2 concentration in the flue gas while simultaneously reducing the volume of the exhaust gas that needs to be processed by a carbon capture system. EGR is essential for NGCC plants on the decarbonization pathway, especially when integrating CCSU systems. One of the main challenges with NGCC plants is the large volume of flue gas they produce, which contains relatively low concentrations of CO_2. This low concentration increases the complexity and cost of the CO_2 capture process. By recycling a portion of the exhaust gas, EGR can effectively increase the concentration of CO_2 and reduce the O_2 content in the flue gas. This leads to a more efficient CO_2 capture process, reducing the size and cost of the CCSU equipment required and improving the overall economic feasibility of carbon capture. The EGR ratio is calculated via the following expression (Equation 1):

$$\text{EGR ratio} = \frac{\text{volume flow of recirculated flue gas}}{\text{total volume flow of flue gas from HRSG}} \qquad (3.1)$$

Here, to maintain EGR ratio consistency in all parts of the system, both volumetric flowrates are recalculated to normal cubic meters per hour (Nm^3/h)

The optimal EGR ratio is a critical parameter in this process, as it must balance several factors, including maintaining adequate O_2 levels for stable combustion, managing the composition of flue gas components, and ensuring effective dehydration of the flue gas. In the literature, typical EGR ratios range from 0.3 to 0.45, depending on the specific conditions of the power plant [7]. The EGR ratio is calculated as the volume flow of recirculated flue gas divided by the total volume flow of flue gas from the HRSG, with both flowrates normalized to standard conditions (Nm³/h).

In this investigation, the performance of the power plant, specifically the changes in the concentrations of flue gas components and the power outputs of the gas and steam turbines, was studied across a range of EGR ratios, from 0% to 60%. This analysis was conducted to identify the optimal EGR ratio that would provide the best balance between enhancing CO_2 concentration and maintaining stable and efficient plant operations.

3.3.2. EGR integration results and discussion

EGR reduces the flowrate of flue gas exiting the plant by recirculating a portion of the exhaust gas back into the combustion process. This reduction in flowrate allows for the downsizing of critical components in the CO_2 capture plant, such as the absorber and stripper columns. Smaller equipment leads to a direct reduction in capital costs. Furthermore, by increasing the CO_2 concentration in the flue gas, EGR enhances the mass transfer rate in the CO_2 absorption process, which in turn lowers the solvent circulation rate. As a result, less energy is needed for solvent pumping, contributing to operational cost savings. Alternatively, it can reduce the required pressure ratio or membrane area size when it is captured by membrane separation technique. Basic flowsheet of the NGCC plant with EGR integration is illustrated in Figure 3.4.

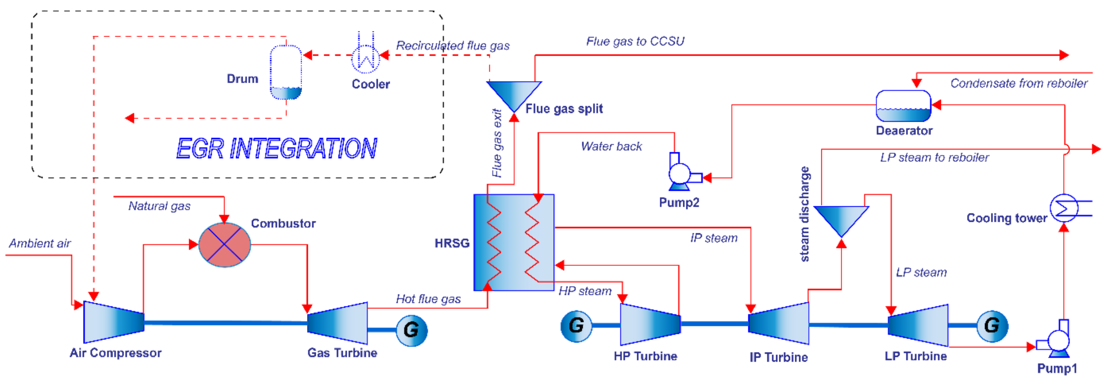

Figure 3.4. Turakurgan NGCC power plant with EGR.

Another significant benefit of EGR is its ability to reduce the O_2 content in the flue gas. In conventional CO_2 capture systems, O_2 is considered an impurity because it can lead to oxidative degradation of the solvent, particularly in amine-based capture systems such as those utilizing MEA. By decreasing the O_2 concentration, EGR helps minimize solvent degradation, improving the efficiency and longevity of the CO_2 capture process. The change in the flue gas composition and gas/steam turbines power outputs in different EGR ratios are shown in Figure 3.5 and Figure 3.6 respectively.

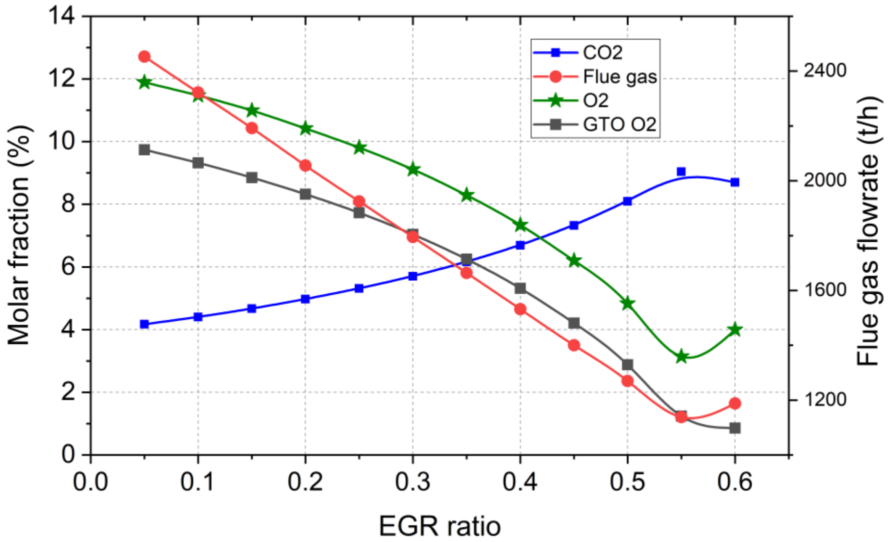

Figure 3.5. The effect of exhaust gas recirculation in different ratios on the exiting flue gas mass flowrate and the molar concentration of different compounds.

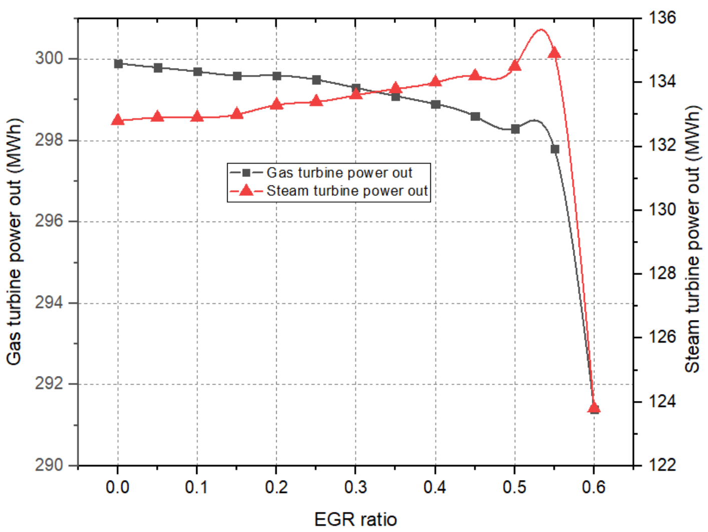

Figure 3.6. The effect of exhaust gas recirculation on the power output of the gas turbine and steam turbines.

According to the key Findings from Figure 3.4, the data indicates that the EGR ratio of 0.55 is the best operational point for many variables. At this ratio, the system achieves a near-optimal balance between reducing flue gas flowrate and increasing CO_2 concentration. However, increasing the EGR ratio beyond 0.55 leads to diminishing returns and potential operational issues. Specifically, further increases in recirculated flue gas do not significantly reduce the need for fresh air intake, as the O_2 levels in the combustor become too low to sustain stable combustion. This O_2 deficiency results in incomplete combustion and a rise in CO levels, which is undesirable.

For stable combustion, it is critical to maintain an O_2 concentration in the combustor outlet flue gas between 3% and 4% (molar basis). This ensures complete combustion of the fuel, avoiding issues such as flame instability and the formation of CO. Beyond an EGR ratio of 0.55, O_2 concentration drops below this critical threshold, which compromises the stability and efficiency of the combustion process.

As for the impact on Power Output from Figure 3.5, the introduction of EGR has differing effects on the power output of the gas and steam turbines. As the EGR ratio increases, the GT power output decreases slightly. This reduction is attributed to the higher flowrate of the air-gas mixture entering the compressor as a result of EGR. Maintaining the gas turbine inlet temperature at a steady 179-180°C across various EGR ratios leads to greater power consumption by the compressor. For instance, at an EGR ratio of 0.05, the flowrate of the air-gas mixture entering the compressor is approximately 1.15 kg/s higher than without EGR, and at an EGR ratio of 0.5, this difference increases to 10.1 kg/s. The additional mass flow through the compressor requires more energy, resulting in a slight reduction in GT power output.

Conversely, the steam turbine benefits from EGR integration. As the EGR ratio increases, the GT outlet temperature rises, leading to higher steam production in the HRSG. This increase in steam production results in higher power output from the steam turbines. For instance, at an EGR ratio of 0.45, the steam cycle generates approximately 1.05% more electricity compared to the case without EGR.

Based on the aforementioned findings, an EGR ratio of 0.45 is considered as the most suitable for this process. This ratio maintains a stable flame in the combustor, with O_2 concentrations in the outlet flue gas remaining above the critical threshold of 3 mol%. At this optimal EGR ratio, the CO_2 concentration in the flue gas increases from 3.96 mol% to 7.32 mol%, while the O_2 concentration drops from 12.28 mol% to 6.2 mol%. Additionally, the mass flowrate of the flue gas exiting the power plant decreases by approximately 45%, equivalent to roughly 389 kg/s.

While there is a minor reduction in GT power output (1.3 MW), this loss is offset by the additional 1.4 MW of electricity generated by the steam turbine, resulting in a net positive impact on overall power output. Importantly, EGR integration does not negatively affect the plant's overall performance and can be seamlessly implemented prior to the integration of a CO_2 capture plant. Final flow specifications and compositions of the flue gas leaving the NGCC plant with and without EGR is provided in Table 3.4 and Table 3.5 respectively.

Table 3.4. Flue gas specifications leaving the power plant with and without EGR.

Parameters	Without EGR	With EGR
Flue gas exit mass flowrate (kg/s)	707	389
Flue gas exit temperature (°C)	104	103
Flue gas exit pressure (kPa)	98.1	98.1

Table 3.5. Flue gas compositions leaving the power plant with and without EGR.

Compositions (mol%)	Without EGR	With EGR
N_2	0.76	0.770
O_2	0.12	0.062
CO_2	0.04	0.073
H_2O	0.077	0.085
Argon (Ar)	0.002	0.009
Nitric oxide (NO)	0.001	0.001

3.4. Flue gas pre-treatment

Before CO_2 can be captured from flue gas in power plants, the gas stream must undergo a series of pre-treatment steps to ensure optimal conditions for the capture process. Flue gas exiting from power plants, such as NGCC plants, contains a variety of contaminants and compounds that can hinder the efficiency of CO_2 capture, whether through absorption or membrane separation methods. These impurities, such as particulates, NO_x, SO_x, and moisture, need to be removed or reduced to protect the capture equipment and prevent degradation of solvents or membranes. Effective flue gas pre-treatment helps enhance capture efficiency, reduce operational costs, and extend the lifespan of CO_2 capture systems [13,14].

Flue gas often contains fine particulate matter, which can clog or damage downstream equipment, particularly in membrane-based separation systems. Additionally, particulates can cause foaming and increase solvent degradation in absorption processes. To avoid these issues, the flue gas typically passes through electrostatic precipitators, fabric filters, or cyclones to remove these solid particles before entering the CO_2 capture unit. Particulate removal is crucial for maintaining system integrity and performance in both absorption and membrane technologies [3].

On the one hand, SO_x and NO_x are common pollutants in flue gas [15], and their presence can have adverse effects on CO_2 capture systems, particularly in amine-based absorption processes. SO_x can react with amine solvents to form heat-stable salts, which can reduce the efficiency of CO_2 absorption and lead to excessive solvent degradation. NO_x can also contribute to the formation of harmful by-products that degrade the capture solvent and reduce its effectiveness over time [16].

To mitigate these issues, flue gas must undergo de-SO_x and de-NO_x treatment prior to CO_2 capture. This is commonly achieved through the use of flue gas desulfurization units, which remove sulfur compounds via wet or dry scrubbing techniques. For NO_x removal, selective catalytic reduction or selective non-catalytic reduction processes are used to reduce nitrogen oxides into N_2 and H_2O using a reducing agent such as ammonia or urea. These treatments help maintain the stability of solvents in absorption systems and prevent membrane fouling in membrane-based capture processes.

On the other hand, the presence of water vapor in flue gas can pose challenges in CO_2 capture, particularly in membrane separation. High levels of moisture can cause membrane swelling, reduce permeability, and lead to reduced separation efficiency. In absorption processes, excessive water vapor can dilute the amine solvent, reducing the solvent's ability to absorb CO_2 efficiently. To address this, moisture removal is typically performed using a gas cooler or a condensation unit to reduce the water vapor content. In some cases, dehydration units using adsorption techniques (e.g., with TEG or silica gel) are employed to further reduce the water content of the flue gas.

The temperature of the flue gas plays a significant role in the effectiveness of CO_2 capture, especially for absorption processes. High-temperature gas can reduce the solubility of CO_2 in the solvent, decreasing the absorption efficiency. Membrane-based systems also benefit from lower flue gas temperatures, as elevated temperatures can lead to reduced membrane selectivity and increased material degradation. As such, the flue gas is often cooled using heat exchangers to bring it to an optimal temperature before entering the CO_2 capture unit. For amine-based systems, the ideal temperature range for the gas is typically around 40-60°C, where the amine solvents can efficiently capture CO_2 without excessive degradation [16].

For membrane-based CO_2 separation processes, the pressure of the flue gas can greatly influence the separation efficiency. Membranes typically operate best under moderate to high pressures, which increase the driving force for CO_2 permeation through the membrane. Therefore, flue gas pre-treatment may involve compressing the gas to the required pressure level before it enters the membrane separation unit [17]. For absorption systems, the pressure is generally kept low, but the pressure loss throughout the absorber should be compensated with slight pressure increse using blower and to facilitate consistent CO_2 capture performance [18].

In this investigation, for simplicity, an ideal flue gas cleaning process has been assumed. As a result, all unwanted species, particularly SO_x and NO_x, have been removed, leaving only four main components in the flue gas. Moisture removal is considered effective enough at the cooling stage for both absorption and membrane-based CO_2 capture processes. Regarding pressure adjustments, they are applied individually based on the specific CO_2 capture technology and method used, which will be discussed in detail in the relevant chapters 4 and 5.

3.5. Conclusions

In this chapter, a comprehensive model of the Turakurgan NGCC power plant was developed and validated using the Aspen Plus® software. The model focused on one of the two 450 MW blocks, integrating both gas and steam turbines. Key aspects of the plant's operation, such as flue gas composition, power outputs, and turbine efficiencies, were simulated. Additionally, EGR was integrated into the model to analyze its effects on reducing flue gas flowrate and increasing CO_2 concentration prior to carbon capture.

The results demonstrated that EGR integration can significantly enhance the feasibility of CO_2 capture by increasing CO_2 concentration in the flue gas from 3.96 mol% to 7.32 mol%, while reducing the flue gas mass flow by 45%. Despite a slight reduction in gas turbine output, the overall plant performance remained stable due to increased power generation in the steam cycle. EGR optimization at a ratio of 0.45 was identified as the optimal scenario.

3.6. References

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Chapter IV - 4. End-of-pipe CCSU integration by MEA Absorption: A Complete Model Assessment

This chapter is based on the following article:

Kamolov, A.; Turakulov, Z.; Furda, P.; Variny, M.; Norkobilov, A.; Fallanza, M. Techno-Economic Feasibility Analysis of Post-Combustion Carbon Capture in an NGCC Power Plant in Uzbekistan. *Clean Technol.* **2024**, *6*, 1357-1388. https://doi.org/10.3390/cleantechnol6040065

Abstract

This chapter investigates the technical feasibility of incorporating post-combustion carbon capture (PCC) technology into natural gas fired combined cycle (NGCC) power plants for effective CO_2 mitigation in Uzbekistan. A detailed simulation and modelling of a 450 MW NGCC power plant block is conducted, alongside the integration of a first-generation, MEA-based CO_2 absorption plant. Additionally, the study evaluates CO_2 pressurezation, dehydration, and pipeline transportation to nearby oil reservoirs for storage. A parametric sensitivity analysis is carried out to optimize energy consumption in the solvent regeneration process. Results indicate that PCC implementation can achieve a 90% CO_2 capture rate, reducing emissions by over 1.05 million tonnes annually. However, the integration impacts plant efficiency, which declines from 55.8% to 46.8% due to the significant steam drawn off required for solvent regeneration, which consumes 3.97 GJ per tonne of CO_2. Furthermore, the multi-stage CO_2 compression system for pipeline transportation adds to the energy demand. While the economic aspects are considered, the focus of this study highlights the technical challenges and energy trade-offs associated with PCC implementation in NGCC plants, emphasizing the need for substantial low-pressure steam availability and advanced CO_2 compression techniques to minimize efficiency losses and optimize the capture process. This research demonstrates that PCC can be a viable solution for reducing emissions from NGCC plants but requires careful optimization of the associated energy demands. However, there is still room for development of alternative PCC technologies to further optimize the process efficiency.

4.1. Background to MEA absorption based PCC

For CO_2 separation from power plant flue gas, amine absorption, especially using MEA solvent, is the most prominent post-combustion carbon capture (PCC) technique. It is the most mature, technically proven, and widely available method in commercial applications [1]. The largest commercial-scale carbon capture, storage, and utilization (CCSU) projects to date, such as Petra Nova in the USA and Boundary Dam in Canada, which capture 1 and 1.4 million tonnes of CO_2 per year (Mtpa), rely on PCC using amine absorption. This method's high technical applicability and reliability are well-established, as it has been used for decades in industries like natural gas processing, making it relatively easy to retrofit for existing power plants. However, despite these benefits, challenges remain, including the high energy demand for solvent regeneration, significant capital investments in equipment, and issues with solvent degradation, both thermal and oxidative. [2].

Building on these factors, this study primarily focuses on modelling and comparing the natural gas-fired combined cycle (NGCC) integrated PCC plant without EGR. It then explores the optimal scenario with EGR and evaluates further improvements through sensitivity analyses. Lastly, the study examines end-of-pipe CCSU integration for NGCC power plants.

4.2. CO_2 capture plant design

Process simulation (modelling) is an essential tool in all process engineering operations, including research, process design, and process operation. Aspen Plus by Aspentech offers steady-state and dynamic modelling of a wide variety of processes, including chemical, hydrocarbon, pharmaceutical, solid, polymer, and petroleum tests and blend synthesis, among others [3]. In addition, Aspen Plus can provide industrial–scale modelling such as that of the NGCC power plant and integrated PCC plant, with good accuracy and an acceptable computational load.

A 900 MW Turakurgan NGCC power plant was divided into two identical 450 MW units (actual power output of 433.8 MW), each of which contained one gas turbine and one steam turbine. The plant consists of an M701F4 gas turbine by Mitsubishi Hitachi Power Systems and three pressure level steam turbines with a reheating cycle through the HRSG. The simulation of CO_2 CCSU plant is developed for one 450 MW unit of the power plant using Aspen Plus® commercial software and validated against the data provided in the report *"Preparatory Survey on Turakurgan Thermal Power Station Construction Project"* prepared by the Japan International Cooperation Agency [4]. Detailed information about modelling, results, and validation of the power plant is given in the Chapter 3.

4.2.1. Flue gas pre-processing prior to MEA absorption

To enhance absorption efficiency and minimize solvent evaporation in the capture plant, the exhaust gas exiting the heat recovery steam generator (HRSG) is pre-cooled to a target temperature range of 40–50 °C. This is achieved using a direct contact cooler (DCC), which employs water spray to directly cool the flue gas. Cooling water is sourced from the nearby Grand Canal Namangan, which has an average flow rate of 6.62 m^3/s and a temperature of 15 °C, to cool the flue gas to approximately 37 °C. After a slight pressure increase in the blower, the absorber inlet temperature is maintained at around 46 °C. The process was modelled using the Aspen Plus RadFrac block (Figure 4.1).

Cooling the flue gas results in water condensation, which not only reduces the water content but also increases the CO_2 concentration by about 0.2%. The condensed water, approximately 7.72 kg/s, plays an essential role in maintaining the overall water balance of the plant. To compensate for the pressure drop within the absorber column, including the water wash section, a pressure drop of 2 mbar/m is considered, as referenced from Sulzer Mellapak data. [5]. The blower subsequently elevates the cooled flue gas pressure above atmospheric pressure by 0.1 bar including gas distributor, headers, deminster, etc [6–8]. For the blower, an isentropic efficiency of 0.89 is assumed, leading to power consumption of 3786 kW for the scenario with EGR and 7293 kW without EGR.

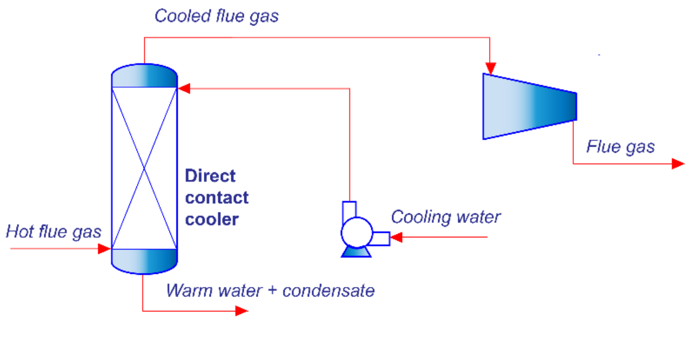

Figure 4.1. Flue gas pre-treatment unit.

4.2.2. Extracting steam for regeneration energy requirement

The solvent regeneration process in the CO_2 capture plant relies heavily on thermal energy, with the reboiler requiring significant heat input to break the chemical bonds between MEA and CO_2 within the stripper. Steam extraction for solvent regeneration has a direct impact on the overall efficiency of the power generation system, as it diverts steam that would otherwise be used for electricity generation. In this process, low-pressure steam is extracted from the power plant's steam cycle, specifically between the intermediate-pressure and low-pressure steam turbines, at 470 kPa and 290 °C. This extraction results in a significant reduction in power output from the low-pressure turbine.

To prevent solvent degradation caused by high temperatures, the incoming steam is cooled by spraying water onto it, reducing the temperature to just above its saturation point. This controlled cooling ensures that the solvent is not exposed to temperatures that could cause degradation while still providing sufficient heat for the regeneration process. Once the steam has transferred its heat to the reboiler, the condensed steam is returned to the HRSG for reuse in the power cycle.

4.2.3. MEA absorption model set-up

The commercial-scale CO_2 capture plant was modelled using Aspen Plus®, a software grounded in chemical engineering principles. The model employs the electrolyte nonrandom two-liquid (NRTL) method to describe the liquid phase, while the Redlich–Kwong (RK) equation of state is applied for the vapor phase. For both the absorber and stripper, the rate-based mode with packing was selected, as it provides a more detailed and accurate representation of the process compared to the equilibrium mode. [2,9]. As a starting point, the CO_2 capture process follows the MEA absorption model outlined in the AspenTech guidelines [10]. This model, originally designed for flue gas from coal-fired power plants, was adapted with only minor modifications to suit the conditions of the current study. Since the process occurs in a reactive environment, it is crucial to define the appropriate reactions in the reaction panel. For this model, three ionic equilibrium reactions ((R1), (R2), (R3)) and two reversible kinetic reactions ((R4), (R5)) were included.

$$2H_2O \rightleftharpoons H_3O^+ + OH^- \quad \text{(R1)}$$

$$MEA^+ + H_2O \rightleftharpoons H_3O^+ + MEA \quad \text{(R2)}$$

$$HCO_3^- + H_2O \rightleftharpoons H_3O^+ + CO_3^{2-} \quad \text{(R3)}$$

$$CO_2 + MEA + H_2O \rightleftharpoons MEACOO^- + H_3O^- \quad \text{(R4)}$$

$$CO_2 + OH^- \rightleftharpoons HCO_3^- \quad \text{(R5)}$$

To calculate the equilibrium constants for the ionic reactions, the standard Gibbs free energy (as provided in Equation 4.1 from the Aspen Plus properties database) was used. For the kinetic reactions, the model employed the default power law kinetic expressions built into Aspen Plus (as described in Equation 4.2), ensuring accurate representation of the reaction kinetics:

$$K_{eq} = \exp\left(-\frac{\Delta G^0}{RT^L}\right) \quad (4.1)$$

ΔG^0 is obtained from the Aspen Properties database.

$$r = kT^n \exp\left(-\frac{E}{RT}\right) \prod_{i=1}^{N} (x_i y_i)^{a_i} \quad (4.2)$$

All kinetic constants used in the model are summarized in Table 4.1.

Table 4.1. Coefficients of kinetic parameters [10].

Reaction No.	k	E (cal/mol)
R5[1]	1.33E+17	13249
R5[2]	6.63E+16	25656
R4[1]	3.02E+14	9855.8
R4[2] (Absorber)	5.52E+23	16518
R4[2] (Stripper)	6.50E+27	22782

Note: [1] – forward reaction; [2] – reverse reaction;

In the Aspen Plus simulation environment, a rate-based MEA absorption model was constructed using various unit operation blocks from the model palette. Both the absorber and stripper columns were modelled using the RadFrac block, with structured packing from the Mellapak Sulzer 250x series. This packing was chosen due to its excellent performance, offering a low-pressure drop and a large surface area for liquid-gas contact. The rate-based setup for both columns was configured with a mixed flow model, employing the Bravo-85 method for mass transfer coefficients and interfacial area calculations. The reaction condition factor was set to 0.9, and the film discretization ratio was adjusted to 10. For calculating holdup, the Bravo-92 correlation method was utilized, while the Chilton and Colburn analogy was applied for heat transfer coefficient calculations in both column packings. Among the available film resistance models, "discretize film" was chosen for the liquid phase and "consider film" for the vapor phase, with the number of discretization points set to 10 and the interfacial area factor to 1.2, as in the reference. [9].

Due to the large scale of the capture plant, multiple absorber columns are required, which can significantly increase computational time. To manage this, a multiplier/divider from the manipulators section was used to create a rigorous closed-loop system by adjusting stream distributions. A pump with an overall efficiency of 0.80 was incorporated to raise the pressure of the rich solvent to between 150 and 220 kPa, as regeneration occurs at pressures above atmospheric.

The cross heat exchanger in the system was replaced by two standard heat exchangers connected via a heat stream, with a user-defined temperature approach at the cold end of the heat exchanger ranging from 5 °C to 10 °C. A flash separator was used to condense any evaporated solvent from the CO_2-rich gas exiting the stripper, while a cooler was implemented to reduce the temperature of the lean solvent to 40 °C before reuse.

4.2.4. Process description

The flue gas from the power plant, cooled to 40 °C after pre-treatment, is fed into the absorber column from the bottom. Inside the column, CO_2 from the flue gas reacts chemically with the MEA-based liquid solvent, which flows counter-currently from the top through the packing material. As this reaction is exothermic, a small amount of solvent evaporates along with the CO_2-free purge gas at the top. The evaporated solvent is recovered in a water wash cycle. The CO_2-rich solvent exiting the bottom of the absorber is pumped to the stripper column via a cross-heat exchanger, where it is preheated by the lean solvent returning from the stripper, lowering the overall energy needed for regeneration. However, to simplify testing for sensitivity analysis later, the cross-heat exchanger is replaced with two heater and cooler blocks connected through a heat stream, providing the same heat exchange but avoiding the complexity of a closed-loop system.

In the stripper column, the hot, CO_2-rich solvent flows from top to bottom, where it is further heated using steam extracted from the power plant. This breaks the chemical bond between CO_2 and the MEA solvent. The CO_2-rich vapor stream is then directed to a flash separator, which acts as a condenser to recover any evaporated solvent and concentrate the CO_2. The regenerated solvent is recycled back to the absorber after makeup and cooling, closing the loop for the process.

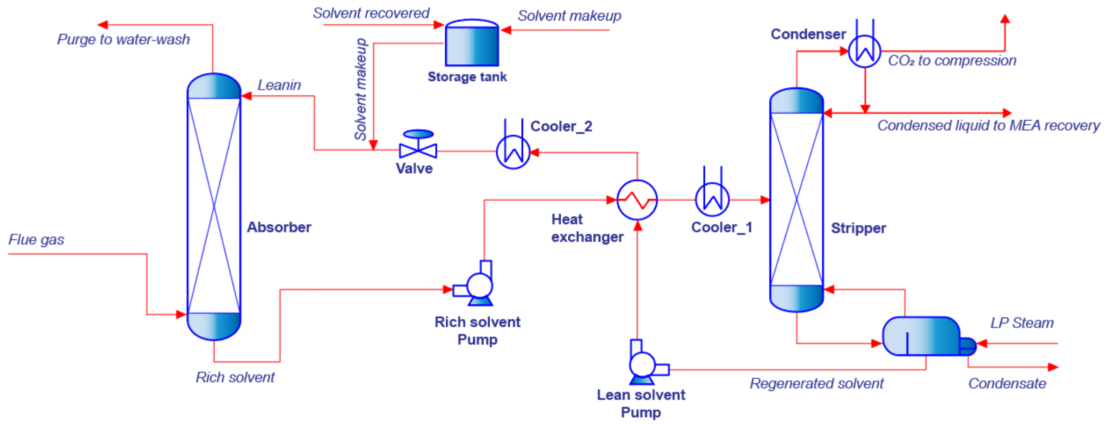

Figure 4.2. The general flowsheet of the MEA absorption-based PCC plant.

4.2.5. Capture plant scale-up

To scale up the CO_2 capture plant model and integrate it with a 450 MW power plant, general chemical engineering principles are applied. As noted earlier, the initial development of the MEA absorption model follows the AspenTech reference with several key assumptions [10]. The MEA concentration in the solvent is set at 35% by weight, and the CO_2 capture rate is assumed to be 90%. Both columns are assumed to operate under adiabatic conditions, ignoring heat losses. The absorption process is set at atmospheric pressure, while the stripper operates at a slightly elevated pressure of 210 kPa.

To scale up the capture plant, the number of absorber and stripper columns, their dimensions, and the required solvent flow rate must be determined. An initial estimate of the solvent flow rate indicated that 564 kg/s would be sufficient based on the flue gas flow rate, the CO_2 concentration in the gas, a 90% capture rate, and an assumed MEA absorption capacity of 0.19 mol CO_2 per mol MEA. For estimating column dimensions, the operation should aim for the highest economic pressure drop, which is set at 42 mm of water per meter of packing, as recommended by reference [11]. To determine the column's cross-sectional area and thus the required diameter, generalized pressure drop correlations are used (Equations (4.3) and (4.4)):

$$F_{LV} = \frac{L_w^*}{V_w^*}\sqrt{\frac{\rho_V}{\rho_L}} \tag{4.3}$$

The flow parameter F_{LV} can be calculated easily via expression (4.4) once the liquid-to-vapor ratio and the ratio of their densities are provided. The flow parameter is then used to identify the modified gas load K_4 via generalized pressure drop correlation, as previously mentioned, followed by the calculation of V_w^*, which is the amount of flue gas per m^2 of cross-sectional area.

$$K_4 = \frac{13.1(V_w^*)^2 F_p\left(\frac{\mu_L}{\rho_L}\right)^{0.1}}{\rho_V(\rho_L-\rho_V)} \tag{4.4}$$

where F_p is the packing factor and where μ_L is the liquid viscosity as well as the densities of the liquid solvent ρ_L and flue gas ρ_V.

This approach is used to calculate the diameters of both the absorber and stripper columns. Due to the low partial pressure of CO_2 and the high flow rate of flue gas, the column dimensions need to be large enough to achieve the desired capture efficiency. To address these challenges, multiple absorber columns with smaller diameters were chosen, offering several advantages: better fluid distribution, improved operational flexibility, redundancy, and avoidance of the difficulties associated with constructing and operating a single, large-diameter column.

One of the most important factors influencing this choice is the part-load condition of the power plant. As mentioned in the manuscript's introduction, Uzbekistan aims to reduce carbon emissions primarily through the integration of renewable energy. Given the country's strong potential for solar photovoltaic and wind energy, there is a high likelihood that NGCC power plants will operate under part-load conditions in the future. In this scenario, opting for three smaller absorber columns (two absorbers with EGR integration) would be a more practical solution than a single large-diameter column. Figure 4.3 illustrates the relationship between the required column diameter and the number of columns needed for the absorber and stripper.

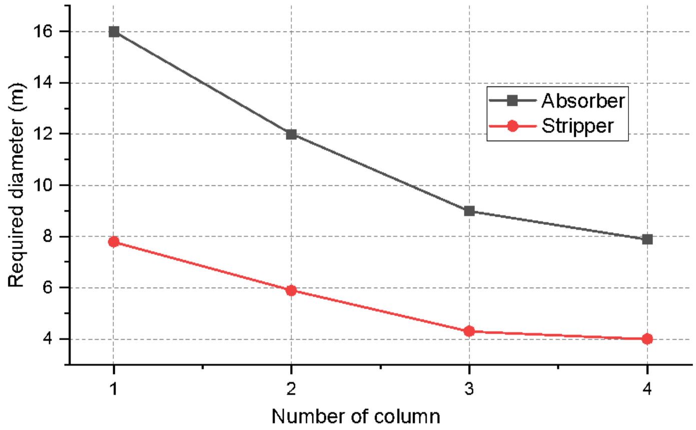

Figure 4.3. Absorber/stripper diameter versus the number of column.

In addition, an overall summary of the assumptions used in model development is presented in Table 4.2 below.

Table 4.2. Overall assumptions of the power station and PCC plant models.

Assumed parameters	Units	Value
Ambient pressure in the power plant side	bar	0.981
Ambient temperature in the power plant side	°C	20
Cooling water temperature	°C	15
Gas and steam turbines isentrophic efficiency	%	90
Gas and steam turbines mechanical efficiency	%	99
Compressor isentrophic efficiency in power plant	%	89
Compressor mechanical efficiency in power plant	%	99
Pressure ratio in the compressor of power plant	bar/bar	18
Blower isentrophic efficiency in the capture plant	%	89
Blower mechanical efficiency in the capture plant	%	99
Pressure drop estimate per meter of packing	mbar	2
Total pressure drop of column with water-wash section	mbar	90
Overall efficiency of the pumps	%	80
Total pressure drop estimate for base case capture plant	mbar	90
Heat exchanger minimum approach temperature	°C	19
Column flooding in columns	%	70

4.3. Water wash section integration for MEA and water recovery

Since the reaction between MEA and CO_2 in the absorption column is exothermic, a significant amount of solvent is lost during the process. To mitigate this, the water wash section of the CO_2 capture unit is essential for recovering evaporated MEA and water vapor, maintaining the system's solvent balance. In addition to solvent recovery, the water wash section ensures compliance with environmental and health regulations, which limit amine emissions. Excessive amine emissions, including MEA and its degradation products, can lead to the formation of harmful compounds like nitrosamines, which are carcinogenic [12]. Thus, the water wash section not only aids in solvent recovery but also reduces harmful emissions, protecting both the environment and public health. Regulations strictly limit solvent emissions, often in terms of Threshold Limit Values. For MEA, the permissible Time-Weighted Average exposure is set at 3 ppm [13], and increasingly stringent regulations may drive emissions below 1 ppm. Other amines, like piperazine, are subject to even more rigorous standards, with European regulations limiting its emissions to below 0.1 mg/Nm^3 [14]. Complying with these standards is critical for the sustainable operation of CO_2 capture plants, ensuring they meet regulatory requirements and reduce their environmental impact.

To address this, the water-wash section consists of two separate beds (Figure 4.4) located at the top of the absorber column, designed for MEA and water recovery. In the Aspen Plus model, this section is simplified as a separate block with two columns—one for MEA recovery and one for water recovery—using the same packing type and diameter as the absorber column. The MEA recovery section uses part of the liquid from the regenerator condenser, while fresh water is used for the water recovery section. As the water-wash section is within the same vessel as the absorber, the only parameter that requires computation is the effective packing height, which was determined via sensitivity analysis, shown in Figure 4.5.

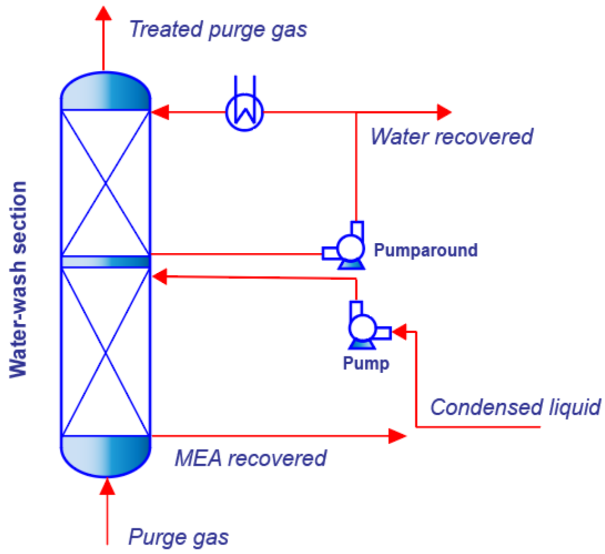

Figure 4.4. Water-wash section flowsheet of the absorber column.

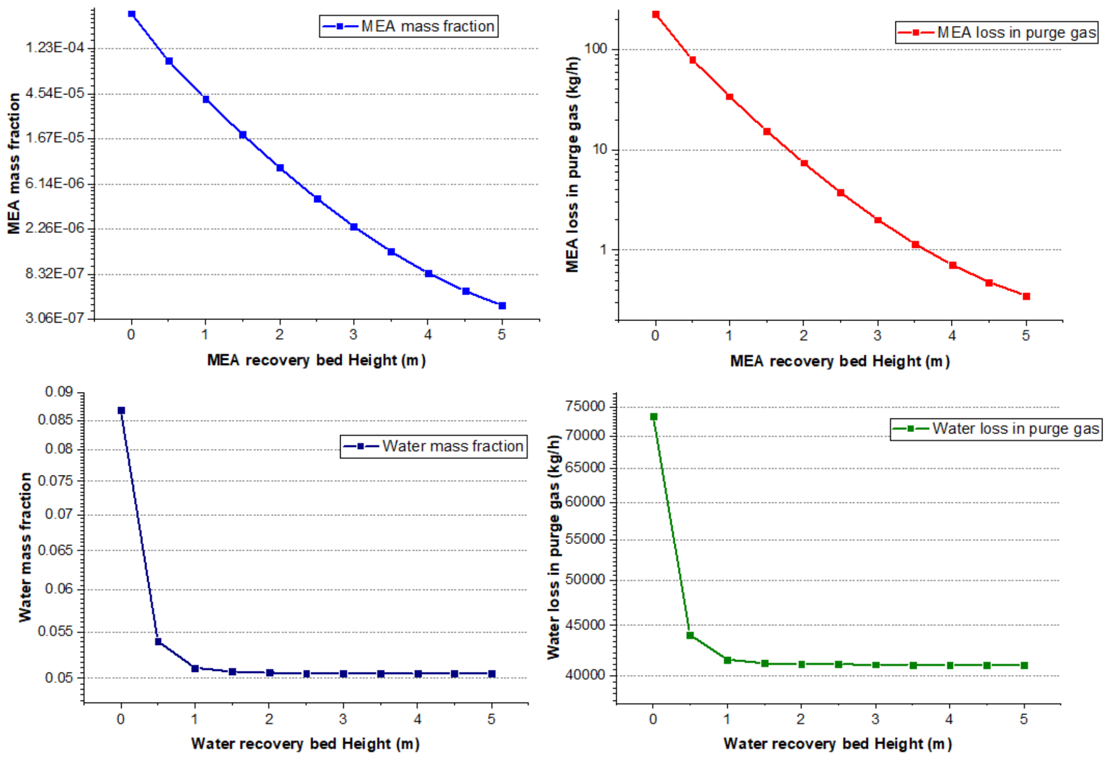

Figure 4.5. Effect of water-wash section packing height on MEA and water reduction in purge gas.

Based on the sensitivity analysis, the packing height for MEA recovery was selected at 3 m, which ensures compliance with the regulatory limit of <3 ppm MEA emissions. This is close to the 2.15 m selected by Gilardi et al. to maintain residual MEA content in the purge gas at 5 ppm [15]. For the water recovery section, a packing height of 1.5 m is selected, and the total height of the water-wash section is 4.5 m.

4.4. CO_2 compression, dehydration, transportation

4.4.1. CO_2 pressurization

CO_2 transportation over long distances requires pressurizing the captured CO_2 to over 10 MPa. Single-stage compression, though simple, becomes inefficient at high pressures due to the significant temperature increase, which raises compressor work, risks material degradation, and may cause liquefaction issues. To address these challenges, this work utilizes multistage compression with intercooling, modelled using the Peng–Robinson equation of state as recommended by [16] (Equation 4.6). The number of compression stages is determined by keeping each stage's pressure ratio below 3, resulting in a total of 6 stages with a final pressure ratio of 2.3. After stage 5, a CO_2 dehydration/purification unit is integrated to meet pipeline quality standards. The average intercooling temperature is set to 40 °C, with further cooling to 25 °C for water condensate removal via knockout drums at each stage. To optimize energy consumption, the last-stage compressor operates at an outlet pressure of 80 bar, after which the CO_2 is cooled and liquefied. A final pressure of 120 bar is achieved using a pump, reducing the energy consumption by around 588 kW. Table 4.3 provides detailed CO_2 compression model specifications, and Figure 4.6 illustrates the flow diagram of the multistage compression unit.

$$\mathrm{R_s} = \mathrm{R_t}^{\frac{1}{\mathrm{N_s}}} \tag{4.5}$$

where R_t is the total pressure ratio of the compression plant, R_s is the stage pressure ratio, and N_s is the number of stages [16].

Table 4.3. CO_2 compression model tuning parameters.

Parameter	Value
Mass flowrate of CO_2 (kg/s)	39.5
Plant exit pressure (MPa)	12
Final outlet temperature (°C)	25
Intercooling temperature (°C)	40
Isentropic efficiency for all stages (%)	80

4.4.2. Water knockout

CO_2 captured from flue gas contains significant moisture, which must be dehydrated to prevent carbonic acid formation and potential pipeline clogging. Dehydration is essential to avoid hydrate formation under high pressure and protect infrastructure from corrosion. Common methods include using triethylene glycol (TEG) systems, where the glycol absorbs moisture from the CO_2, adsorption with molecular sieves, or membrane-based separation for selective water vapor removal. Another method involves adsorption using solid desiccants such as molecular sieves, which trap water molecules from the CO_2 stream.

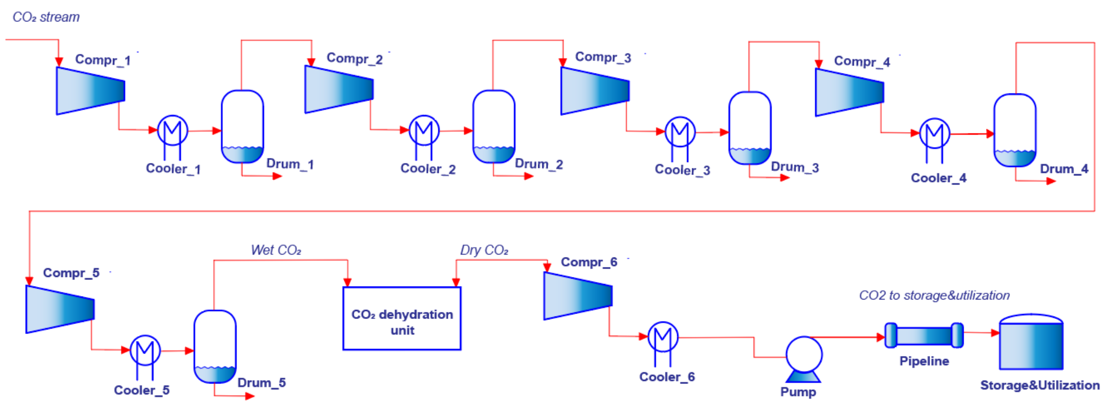

Figure 4.6. The flowsheet of CO_2 dehydration, compression, and pipeline transportation to the enhanced oil recovery storage site.

In this model, a TEG-based CO_2 dehydration unit is integrated after the fifth compression stage (Figure 4.6). TEG is used at an L/G ratio of 0.05, with approximately 2% of CO_2 dissolving into the TEG due to high pressure. This dissolved CO_2 is recovered via a flash tank for recirculation. The TEG dehydration unit reduces the CO_2 stream's water content to below 100 ppmv, meeting US pipeline standards [17].

4.4.3. CO_2 transportation

Pipeline transportation is the most common and cost-effective method for moving captured CO_2 to storage sites. In this study, a portion of the captured CO_2 is assumed to be used for CO_2-enhanced oil recovery (EOR) and underground storage, technologies that have been well-established and widely available for many years [18]. Previous studies [19,20], have provided preliminary estimates of CO_2 utilization options and potential in

Uzbekistan. Given that the average distance to nearby oil fields is approximately 100-120 km from the plant, the total length of the CO_2 transportation pipeline is set at 120 km. Transporting CO_2 over long distances at pressures exceeding 10 MPa, as considered in this research, requires careful attention to several factors to ensure safe and efficient operation. Key considerations include the selection of suitable pipeline materials and determining the most economical pipeline diameter, both of which significantly affect the annualized cost of the transportation system. Finding the optimal pipeline diameter is a cost-minimization process: while larger diameters increase capital costs, they also reduce pumping costs due to lower pressure drops. Therefore, the most cost-effective diameter is where the combined capital and pumping costs are minimized. In this work, the optimal internal diameter for the pipeline was determined to be 0.25 m, based on a CO_2 mass flow rate of 39.5 kg/s and a density of 707 kg/m³, using the equation provided in [11] (Equation 4.6):

$$d_i = \left(\frac{m}{\rho}\right)^{0.5} \tag{4.6}$$

where d_i – pipeline internal diameter (m), m – mass flow rate (kg/s), and ρ – fluid density (kg/m^3).

Maintaining pressure above the critical value throughout the CO_2 pipeline is essential for efficient transportation. To achieve this, the inlet pressure at the pipeline entrance must be determined by accurately estimating the pressure drop along the entire length of the pipeline. According to the principles outlined in reference [21], the pressure drop over a 120 km pipeline is calculated to be 2.1 MPa. This necessitates an inlet CO_2 compression of around 12 MPa to ensure that the fluid remains above its critical point during transport. The pipeline is designed with a wall thickness of 8 mm, using carbon steel as the material.

4.5. Sensitivity analysis

To proceed deeper insights into the behaviour of the CO_2 capture plant model, a sensitivity analysis was conducted by varying key input parameters from a baseline case and observing their effects on model outputs. The primary objective of this analysis was to evaluate how sensitive the model is to parameters that influence the reboiler duty and column design. This was done through an open-loop process flow diagram. Once key operational parameters were identified, they were incorporated into the process flow diagram before transitioning to a closed-loop system, as optimization is more complex in closed systems due to interdependent material balances.

The main goal of the sensitivity analysis was to minimize the techno-economic performance of the CO_2 capture process. The analysis focused on CO_2 capture using flue gas from the NGCC power plant with 45% EGR. Given the complexity of optimizing absorption/regeneration-based CO_2 capture, where many process parameters are interlinked, a multi-objective optimization approach covering variables such as MEA concentration, absorption temperature, lean loading, L/G ratio, heat exchanger approach temperature, column dimensions, regeneration pressure, and reboiler duty would be ideal. However, due to the broad scope of the study, a simplified two-stage sensitivity analysis was conducted instead of a full optimization, as commonly used in other studies [8,15,22–26]. The process optimization in this study was carried out in two stages. In the first stage, since equipment size and reboiler duty directly affect capital and operational costs, these two factors were chosen as objective functions, with solvent circulation rate as a key parameter (Figure 4.7). In the second stage, the optimal process parameters identified from the first stage were used to vary the fixed column heights to assess their impact on performance. This stage involved adjusting the absorber and regenerator heights to find the optimal configuration that maintains a 90% CO_2 capture rate while minimizing energy consumption. This fine-tuning aimed to achieve the best balance between system performance and energy efficiency (Figure 4.7).

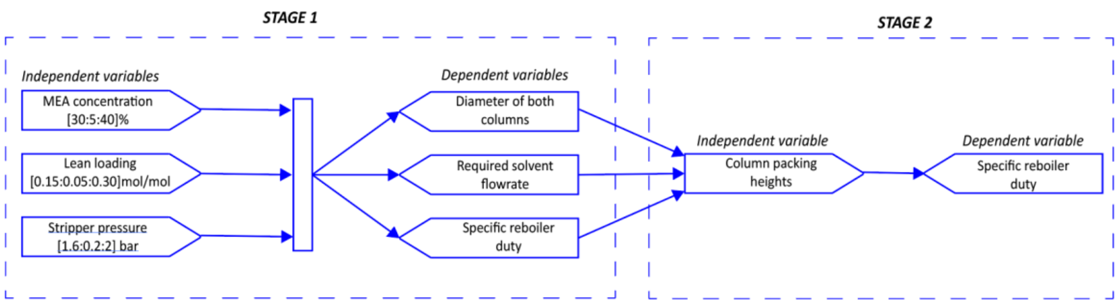

Figure 4.7. Sensitivity Analysis Workflow (Two Stages).

Stage 1: Independent variables are MEA concentration (30–40 wt%), lean loading (0.15–0.30 mol/mol), and stripper pressure (1.6–2.2 bar). These impact dependent variables such as column diameter, solvent flow rate, and reboiler duty.

Stage 2: Using Stage 1 results, the independent variable is the packing height of the absorber and stripper, affecting the specific reboiler duty.

Initial assumptions for the sensitivity analysis:

- CO_2 capture rate: 90%
- Column flooding limited to 68% (±1%) for both columns
- Mellapak Sulzer 250x packing for both columns
- Heated rich solvent from heat exchanger conditionally set at 100°C
- Initial absorber and regenerator heights set at 25 m and 20 m, respectively.

4.6. Results and Discussion

4.6.1. Initial model results and comparison

Accurate modelling of CO_2 capture plants is crucial for optimizing their design and operation. To assess the model's performance, the results are compared with data from open and partially open access reference cases, including the Canepa et al. [27] reference case and the Cesar project case [28], provided in summary data in Table 4.4, which both analyze the PCC MEA-based model for the NGCC power plant with similar capacity.
Table 4.4. Model input and output comparisons against two similar reference cases.

Parameter	Model value	Canepa et al [27]	Cesar project [28]
Plant gross power output (MW)	433	427	430.3
Flue gas mass flow rate (kg/s)	717.5	702	690.6
Flue gas temperature (°C)	45	40	40
CO_2 capture efficiency (%)	90%	90%	89%
CO_2 content in flue gas (mass%)	6.14	7.60	6.03
CO_2 mass flow (kg/s)	44.05	43.35	41.54
MEA concentration (%)	35	32.5	30
L/G ratio (mol/mol)	0.86	0.97	1.71
Lean solution temperature (°C)	40	40	37
Lean loading (mol CO_2/mol MEA)	0.20	0.20	0.26
Number of absorber columns (-)	3	3	-
Absorber column pressure (kPa)	98.1	105	-
Flooding in absorber/stripper (%)	68	65	-

Absorber column packing type	Sulzer 250x	IMTP no. 40	-
Absorber pressure drop (kPa)	9	5	-
Packing height of absorber (m)	25	25	-
Packing diameter (m)	8.7	10.3	-
Number of regenerator columns (-)	1	1	-
Regenerator column pressure (kPa)	210	210	-
Regenerator column packing type	Sulzer 250x	Flexipack 1Y	-
Regenerator packing height (m)	18	15	-
Regenerator column diameter (m)	7.1	7.4	-
Captured CO_2 (kg/s)	39.3	38.75	37.22
Rich loading (mol CO_2/mol MEA)	0.48	0.477	0.46
Reboiler duty (kW)	160000	158800	149000
Specific reboiler duty (GJ/tonne CO_2)	4.07	4.10	4.01

Overall, the data in the tables indicate that the model values align well with the reference data in most cases. As shown in Table 4.4, the model case has a slightly higher net power output, which leads to increased flue gas and captured CO_2 flow rates compared to the other two cases. However, the CO_2 concentration in the flue gas of the developed model is somewhat lower than in the reference values. This discrepancy may be attributed to variations in gas turbine specifications, air and fuel compositions, fuel calorific values, and air/fuel ratios across different NGCC power stations. Additionally, while the L/G ratio was initially estimated, it was later adjusted to optimize column dimension and packing selection. Minor differences in specific reboiler duties could also be linked to variations in the mass transfer surface area and MEA concentration.

Furthermore, as seen in Table 4.4, model design values are primarily compared with those from Canepa et al.[27], as the Cesar project report [28] does not provide equipment sizing or specification details. However, a comprehensive comparison of the model with the literature is presented in the next section (4.6.2), along with a summary and brief discussion. One notable difference is the absorber column pressure, which is higher in the model due to the plant's altitude above sea level. The lower column diameters observed in the model are likely influenced by the differences in packing type. During simulation testing, Mellapak, despite all packings being structured, outperformed IMTP and Flexipack due to its superior mass transfer efficiency and lower pressure drop.

4.6.2. Results and discussion of the sensitivity analysis

4.6.2.1. Stage 1 sensitivity analysis

The results presented in Figures 4.8 and 4.9 were obtained by testing the model in 36 different cases, adjusting key input parameters to optimize the performance of the CO_2 capture plant. In this first-stage sensitivity analysis, it is notable that the L/G ratio was adjusted based on variations in MEA concentration and lean loading, but remained constant when the stripper pressure was modified. This approach differs from conventional procedures, as discussed in subsection 2.7. Throughout the analysis, column flooding was kept below the 75-80% threshold, a widely accepted safe operating range for absorption columns.

For a detailed technical analysis of the MEA-absorption CO_2 capture process, lean loading was selected as the primary parameter to visualize its impact. Figure 4.8 illustrates the effects of lean loading on the required solvent flow rate (L/G ratio) and rich loading across different MEA concentrations. Figure 4.9 shows the impact of lean loading on specific reboiler duties and the size of the absorber and stripper under varying MEA concentrations and stripper pressures.

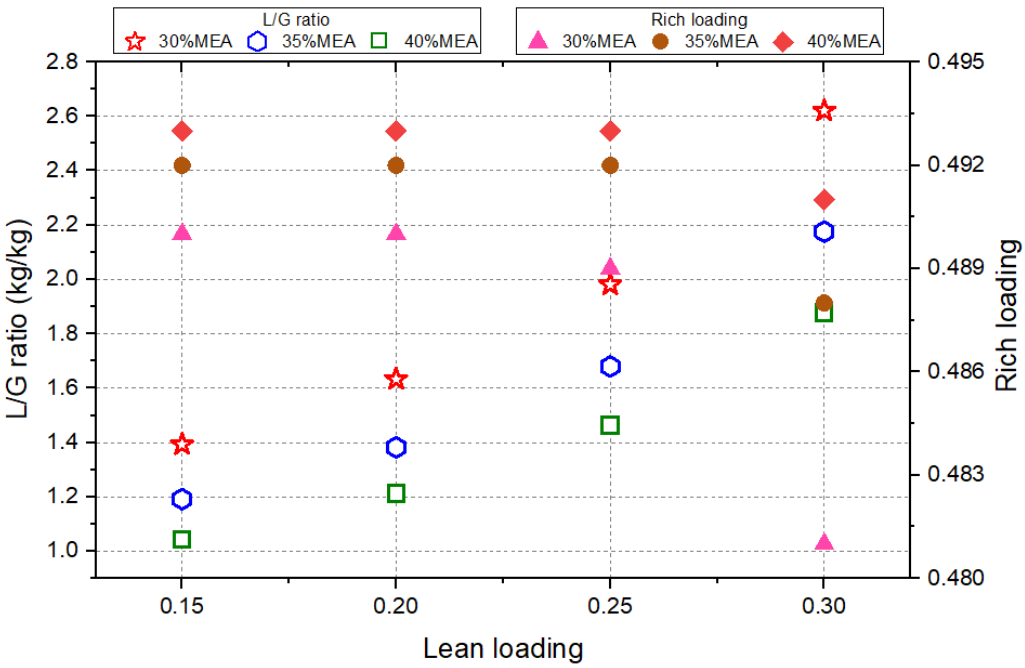

Figure 4.8. Relationships among lean loading (mol/mol), the required solvent flow rate, and rich loading (mol/mol) at different MEA concentrations.

Generall, with EGR integration, the flow rate of flue gas entering the capture plant was almost halved, resulting in a reduction in the size of key equipment, such as absorbers, strippers, heat exchangers, flash separators, and reboilers, which in turn lowered capital costs. A key change in the modified plant was the reduction of absorber columns from three to two. The increase in CO_2 concentration due to EGR—from around 4 mol% to 7.3 mol%—significantly improved the CO_2 absorption process.

EGR integration also impacted blower power consumption, reducing it from 7293 kW in the base case to 3786 kW in the optimized case. The higher CO_2 concentration in the gas stream enhanced the driving force for mass transfer, increasing the efficiency of CO_2 absorption. This improvement in mass transfer allowed the solvent to capture CO_2 more effectively, potentially reducing energy requirements and minimizing the need for additional solvent regeneration.

Overall, higher MEA concentrations in the solvent led to greater efficiency in terms of both solvent circulation rate and CO_2 absorption capacity (see Figure 4.8). Conversely, higher lean loading resulted in lower solvent absorption capacity and a higher solvent requirement to maintain a 90% capture rate. For example, the difference in rich loading between lean loads of 0.15 and 0.30 at 30% MEA was only 0.009, but the required solvent flow rate increased by more than 470 kg/s (a 1.39 increase in the L/G ratio) under the same conditions.

As for Figure 4.9, it highlights the complex relationship between reboiler duty, lean loading, and column diameter in optimizing the CO_2 capture system. Across all scenarios, reboiler duty initially decreases with increasing lean loading, but beyond a certain point, it begins to rise again, forming a U-shaped curve. This pattern indicates the existence of an optimal lean loading value where reboiler duty is minimized. The exact position of this minimum shifts depending on MEA concentration and stripper pressure. For example, at lower lean loading, the L/G ratio is also lower, leading to a reduced solvent circulation rate and a corresponding decrease in reboiler duty. However, the system remains complex due to the additional energy required in the reboiler to strip the solvent down to the initial low CO_2 load.

As column flooding is fixed at 68%, the diameters of both the absorber and stripper columns adjust based on changes in lean loading and the L/G ratio. The absorber diameter increases as lean loading rises, reflecting the need to handle larger liquid flow rates at higher lean loadings. This effect is more pronounced at lower stripper pressures, indicating that lower pressures require larger absorber columns to maintain performance. Conversely, the stripper diameter tends to decrease with increasing lean loading, particularly in the mid-to-high lean loading range. However, the interaction between stripper pressure and solvent flow rate makes this trend less consistent, requiring individual case assessment.

From the nine panels in Figure 4.9, it is evident that a 40% MEA concentration delivers the most favourable outcomes, particularly in terms of reboiler duty. Higher MEA concentrations result in improved CO_2 capture performance due to the solvent's increased absorption capacity. However, these higher concentrations also raise concerns about corrosion, which can be mitigated using stainless steel, protective coatings, or anti-corrosion inhibitors [29]. The lowest combined absorber and stripper column diameters, totalling 15.3 m, were achieved in test case 30 (panel i, Figure 4.9), where the stripper pressure and lean loading were 200 kPa and 0.20, respectively. This case also resulted in the smallest combined diameters for two absorbers and one stripper column, totaling 24 meters.

Test case 34 (panel g, Figure 4.9) demonstrated the lowest specific reboiler duty at 3.86 GJ/t CO_2, achieved with 40% MEA concentration, a lean loading of 0.30, and a stripper pressure of 160 kPa. Although the MEA concentration of 40% was most effective, reducing it to 35% still provided reasonable energy consumption at 3.93 GJ/t CO_2, with a combined column diameter of 25.8 m for two absorbers and one stripper (panel d, Figure 4.9). In contrast, cases with 30% MEA consistently showed lower competitiveness, with reboiler duties exceeding 4 GJ/t CO_2 compared to the higher MEA concentrations.

As the MEA concentration and lean loading increase, the required solvent flow rate decreases, which reduces the L/G ratio and the column diameters. These results suggest that for a given stripper pressure, an optimal lean loading exists that minimizes reboiler duty. However, this optimal point varies with MEA concentration and impacts column diameters, indicating the need for adjustments based on these variables.

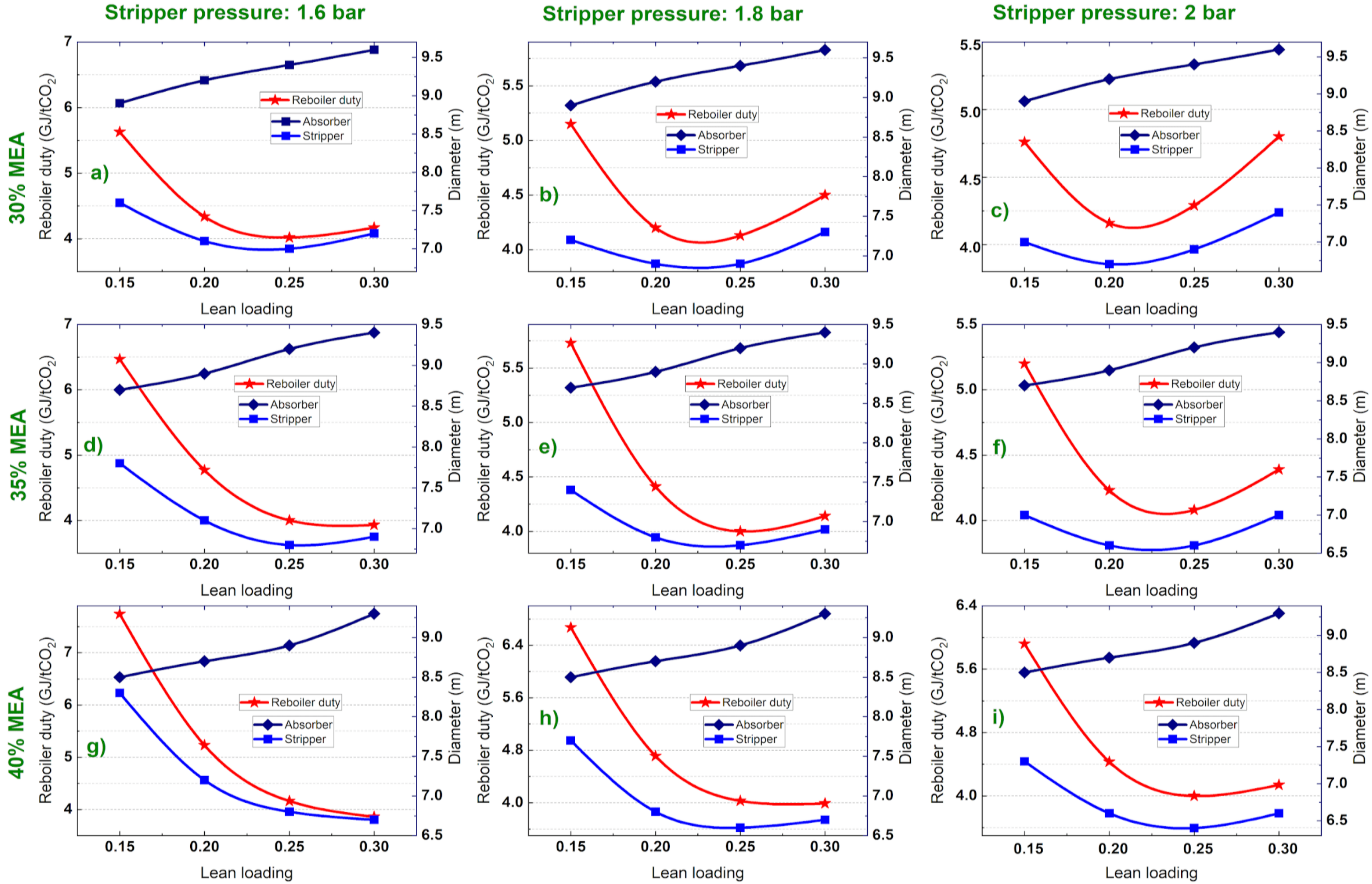
Stripper pressure: 1.6 bar
Stripper pressure: 1.8 bar
Stripper pressure: 2 bar
30% MEA
35% MEA
40% MEA
a)
b)
c)
d)
e)
f)
g)
h)
i)
Reboiler duty
Absorber
Stripper
Reboiler duty (GJ/tCO_2)
Diameter (m)
Lean loading

Figure 4.9. Relationship between lean amine loading, reboiler duty, and column diameter (absorber and stripper) for various MEA concentrations (30%, 35%, 40%) at stripper pressures of 1.6, 1.8, and 2 bar. Each subplot (a–i) represents a specific combination of these conditions.

To achieve the best performance, comprehensive system optimization must consider both operational parameters like pressure and MEA concentration, as well as design parameters such as column diameters and packing heights (addressed in the second stage of sensitivity analysis). Based on the findings, test case 34 (panel g, Figure 4.9), with the lowest specific reboiler duty and reasonable column diameters, is selected for the second-stage sensitivity analysis due to its minimal impact on overall plant costs.

4.6.2.2. Second stage of sensitivity analysis

The design and optimization of the absorber packing height are critical in determining the energy consumption and overall effectiveness of CO_2 capture systems. In this study, a range of absorber packing heights (12 to 30 m for the absorber and 6 to 25 m for the stripper) were tested to assess their impact on system performance, with a primary focus on heat requirements for CO_2 capture. The heat requirement, defined as the energy needed to separate 1 tonne of CO_2 from the flue gas mixture, was used as the key performance metric. The results, illustrated in Figure 4.10, show that as the packing height increases, the gas-liquid contact area improves, leading to better mass transfer efficiency and potentially reducing the reboiler heat duty. However, taller packing heights also increase pressure drop and capital costs due to the larger column size. These findings are essential for identifying the optimal packing height that strikes a balance between enhanced CO_2 absorption and manageable energy consumption and costs.

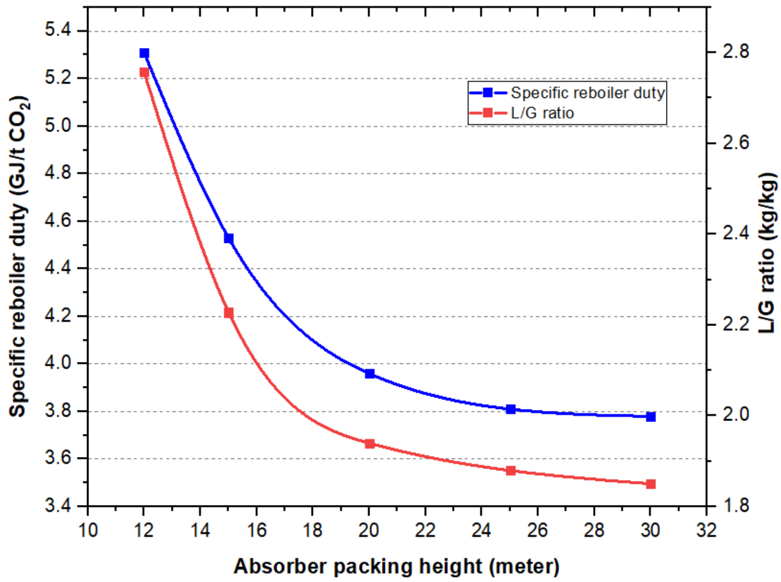

Figure 4.10. Relationships between the absorber packing height and specific booster duty and L/G ratio at 90% CO_2 capture efficiency.

Reducing the column height directly lowers CO_2 capture efficiency, which can be compensated by increasing the L/G ratio. This, in turn, raises the column diameter to maintain flooding below 70%, as set in the study. Moreover, increasing the solvent flow rate elevates the pump energy consumption and the reboiler duty. A reduction in column height also indirectly increases the stripper diameter and the cross-heat exchanger area due to higher solvent circulation rates. For example, in the modified model with EGR, reducing the absorber diameter from 25 m to 15 m led to a 6% drop in CO_2 capture efficiency. This was compensated by increasing the solvent flow rate by 480 t/h, which slightly increased the column diameter from 9.3 m to 9.6 m. While the smaller absorber packing height reduced column volume by approximately 35%, thereby lowering CAPEX, it also raised the specific reboiler duty from 3.81 to 4.53 GJ/t CO_2.

Overall, an absorber packing height that maintains a specific reboiler duty (SRD) below 4 GJ/t CO_2 seems optimal from a techno-economic perspective. Beyond this point, increasing the packing height offers only marginal improvements in energy consumption. According to Figure 4.10, a packing height of 20 m strikes a favorable balance between performance and cost. At this height, the SRD shows a marked reduction compared to lower heights, indicating improved energy efficiency. Additionally, the L/G ratio is reduced, optimizing solvent use without requiring excessive liquid flow. Although further increasing the packing height could yield slight efficiency gains, the trade-off in terms of larger column volume and higher CAPEX makes it less attractive. By selecting a 20 m packing height, the system achieves strong CO_2 capture performance while keeping column size and costs manageable.

For the stripper packing height, the optimal design follows a similar principle, targeting an SRD below 4 GJ/t CO_2. A height of approximately 13 m was found to be optimal for the final techno-economic evaluation, as shown in Figure 4.11. At this height, the SRD approaches its minimum, indicating near-optimal energy efficiency for CO_2 regeneration. Beyond 13 m, the decrease in SRD becomes negligible, suggesting that further increases in packing height would offer diminishing returns in energy savings. Therefore, a 13 m stripper packing height strikes the right balance between operational efficiency and cost-effectiveness in the CO_2 capture process.

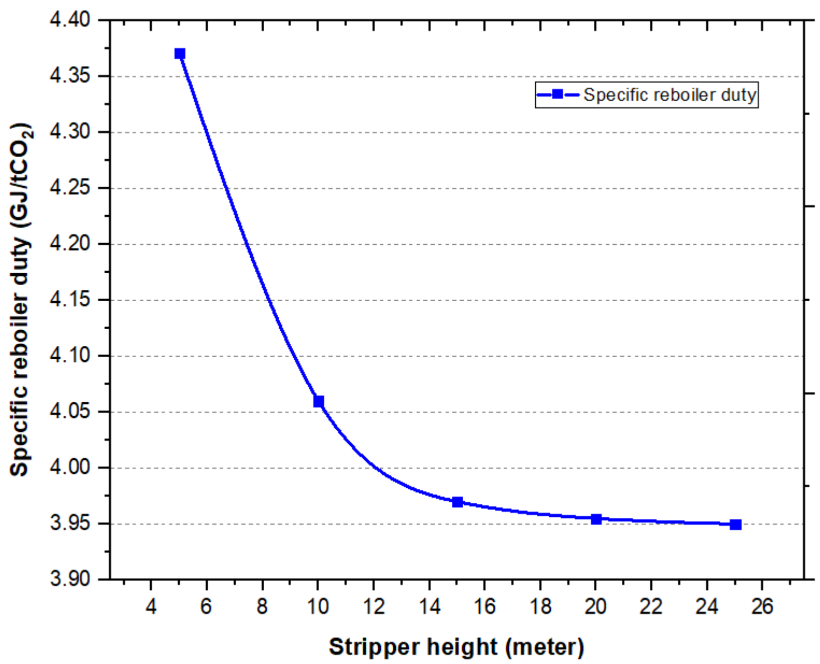

Figure 4.11. Relationship between the stripper column packing height and specific reboiler duty.

Considering the plant modifications with 45% EGR integration and the results of the sensitivity analysis, the final specifications for the techno-economic evaluation are summarized in Table 4.5.

Table 4.5. Final specifications and results for technical evaluation.

Parameter	Value	Parameter	Value
Plant gross power output (MW)	433	Plant net power output (MW)	420
Flue gas mass flow rate (kg/s)	389	Flue gas temperature (°C)	45
CO_2 capture efficiency (%)	90%	CO_2 content (mol%)	7.6
CO_2 mass flow (kg/s)	43.71	MEA concentration (%)	40
L/G ratio (mol/mol)	1.88	Lean solution temperature (°C)	40
Lean loading (mol CO_2/mol MEA)	0.30	Number of absorber columns (-)	2
Absorber column pressure (kPa)	98.1	Flooding in absorber/stripper (%)	70
Absorber column packing type	Sulzer 250x	Absorber pressure drop (kPa)	9
Packing height of absorber (m)	20	Packing diameter (m)	9.5
Water-wash packing height (m)	4.5	Number of regenerator columns (-)	1
Regenerator column pressure (kPa)	160	Regenerator packing height (m)	13
Regenerator column packing type	Sulzer 250x	Regenerator column diameter (m)	6.7
Captured CO_2 (kg/s)	39.1	Reboiler duty (kW)	154886
Rich loading (mol CO_2/mol MEA)	0.491	Specific reboiler duty (GJ/tonne CO_2)	3.97
Compression power (kJ/kgCO_2)	344	Compression energy consumption (kW)	13443
Blower power consumption (kW)	3451	Compression pump power (kW)	274
Plant efficiency (%)	55.8	Plant efficiency drop (%)	8.99
Total energy consumption (kW)	67699	Energy penalty with CCSU (%)	16.12%

4.6.2.3. Comparative analysis with literature

This study focuses on optimizing the standard MEA absorption CO_2 capture process in an NGCC power plant by integrating EGR and fine-tuning key design parameters. A critical evaluation of the sensitivity analysis results, compared with those reported in the literature, reveals both the advantages of the current approach and areas needing further improvement. A comprehensive comparison of key design data and assumptions for the MEA-based CO_2 capture process with the literature is summarized in Table 4.6.

The base case and optimized case specific reboiler duty values were 4.07 GJ/t CO_2 and 3.97 GJ/t CO_2, respectively. This reduction demonstrates an enhanced thermal efficiency in the optimized case owing to the increased content of CO_2 with EGR integration and optimized system parameters. When compared with other studies, such as those by Biliyok et al. [30] and Agbonghae et al. [26], which reported reboiler duties of 3.96–4.003

GJ/t CO_2, our findings are in close agreement. The similarity in reboiler duty values across these studies suggests that the optimization approach and process adjustments implemented in our study are consistent with best practices in the field. The significant reduction in reboiler duty in the model optimized case compared to Luo et al. [31,32] and Canepa et al. [33] indicates that the process is both competitive and effective as well as suggests that the combination of EGR and optimized solvent flow rates can achieve competitive thermal efficiency. However, in comparison to the work of Sipöcz et al. [34], there is still space to improve the process implementing additional strategies, such as the absorber interval cooling applied in their study. Nevertheless, this falls outside the scope of the current investigation.

In the optimized design, integrating EGR led to a more than 35% reduction in packing volume compared to the base case. Literature commonly reports absorber and stripper column packing heights in the ranges of 12-30 meters and 10-30 meters, respectively. In line with this, the optimized model in this study uses packing heights of 20 meters for the absorber and 12 meters for the stripper, ensuring the results remain within these typical ranges. Further reductions in column heights could potentially be achieved through multi-objective optimization, considering all variables and their interactions, though this is beyond the scope of the current study.

The liquid-to-gas (L/G) ratio is also a crucial factor in the absorption process, as it affects both CO_2 capture efficiency and the energy needed for solvent regeneration. In the optimized case, the L/G ratio was increased to 1.88, a significant rise from the base case of 0.86. This adjustment was necessary to maintain high CO_2 capture efficiency despite the increased CO_2 concentration resulting from EGR. This ratio aligns with findings from other studies, which show that higher L/G ratios are often needed to achieve greater CO_2 capture efficiency, particularly in NGCC plants with EGR. For instance, Biliyok et al. [30] reported an L/G ratio of 1.04 in their NGCC studies, emphasizing the importance of balancing solvent flow rates to minimize both reboiler duty and pumping energy.

Table 4.6. Comparison summary of key design data and assumptions for the standard MEA-based CO_2 capture process with the literature.

	Base case	Optimal case	Agbonghae et al. [26]		Biliyok et al. [30]	Luo et al. [31]	Luo et al. [40]	Canepa et al. [27]	Gilardi et al. [15]	Canepa et al. [33]	Sipöcz et al. [34]
Flue gas supply	NGCC	NGCC + 45% EGR	NGCC plant 1	NGCC plant 2	NGCC plant	NGCC + EGR	NGCC	NGCC	Irving oil refinery	NGCC + 40% EGR	NGCC + 40% EGR
Gross power output (MW)	433	433	400	450	440	453	453	427	-	250	448
Flue gas flowrate (kg/s)	717.5	389	622.2	725	693.6	408.8	673.57	702	77.86	213.6	370.28
L/G ratio (kg/kg)	0.86	1.88	0.96	0.96	1.04	2.75	1.79	0.97	1.91	3.32	1.13[b]
Number of absorber	3	2	2	2	4	1	1	3	1	2	-
Absorber packing	Mel.250X	Mel.250X	Mel.250Y	Mel.250Y	Mel.250X	Mel.250Y	IMTP.40	IMTP.40	Mel.250X	IMTP.40	Mel.250
Absorber diameter (m)	8.7	9.5	11.93	12.88	10	16.2	9.9[b]	10.3	5.86	8	6.87
Absorber packed height (m)	25	20	19.06	19.99	15	20	25	25	12	30	22.7
Absorber pressure drop (mbar)	100	90	36.2[a]	38[a]	-	54	69	50	230	123[a]	140
Number of stripper	1	1	1	1	1	1	1	1	1	1	1
Stripper packing	Mel.250X	Mel.250X	Mel.250Y	Mel.250Y	Mel.250X	Mel.250Y	Flex.1Y	Flex.1Y	Mel.250X	Flex.1Y	Mel.250
Stripper diameter (m)	7.1	6.7	6.76	7.74	9	8.6	5.1[b]	7.4	3.12	8	3.8
Stripper packed height (m)	18	13	28.15	28.15	15	20	15	15	10	30	18
Lean loading (mol/mol)	0.20	0.30	0.20	0.20	0.234	0.32	0.32	0.20	0.24	0.30	0.125
Rich loading (mol/mol)	0.48	0.491	0.483	0.483	0.4945	0.461	0.461	0.477	0.506	0.466	0.481
CO_2 content in flue gas (vol%)	4[d]	7.6[d]	4.04[d]	4.04[d]	3.996[w]	7.32[d]	4.5[d]	-	7.2[w]	7[d]	7.3[d]
MEA concentration (%)	35	40	30	30%	30%	30	32.5	32.5	30	30	30
CO_2 capture rate (%)	90	90	90	90	90	90	90	90	90	90	90
Stripper pressure (bar)	2.1	1.6	1.62	1.62	1.5	2.1	2.1	2.1	1.9	1.62	1.92[c]
Reboiler duty (MW)	160	154.89	138.9[b]	161.8[b]	156.91	176.23	186.81	158.77	33.05	114.16	126.17
Specific reboiler duty (GJ/t CO_2)	4.07	3.97	3.96	3.96	4.003	4.31	4.54	4.1	3.78	4.68	3.25

Table notes: [a] – packing height pressure drop based on the data provided in the corresponding references as pressure loss per meter. [b] – is calculated based on the data provided in the refer-ence. [c] – based on the stripper pressure of 122 °C reported. “-“ – no data is found in the corresponding parameter. w – CO_2 content in wet basis; [d] – CO_2 content in dry basis; Mel. – Mellapak; Flex. – Flexipack;

4.9. Conclusions

This chapter explored the integration of CO_2 CCSU technology with a NGCC power plant in Uzbekistan through full-scale modelling and simulation of an end-of-pipe approach. Key findings include:

- The model predicts an annual CO_2 emission reduction of 1.05 Mt with a 90% capture rate.
- A 40% MEA concentration in the solvent resulted in lower energy consumption compared to lower concentrations.
- Using compressors to liquefy CO_2 at 80 bar and then a pump to reach 120 bar saved around 588 kW in compression and transportation energy.
- The water wash section ensured compliance with environmental standards while maintaining the solvent and water balance.
- CO_2 dehydration is critical for safe pipeline transportation over long distances.
- Reboiler duty was reduced to 3.97 GJ/t CO_2, keeping the plant size manageable.
- CO_2 capture integration led to a drop in power plant net efficiency from 55.8% to 46.8%.

Despite the reduction in reboiler duty, the energy demand for regeneration remains high, presenting a challenge for widespread commercial deployment, particularly given current low CO_2 market prices. Future research should focus on optimizing capture processes using alternative PCC technologies including absorption, membrane separation, and hybrid technologies to reduce energy consumption and improve economic viability in Uzbekistan’s energy sector.

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Chapter V - 5. Techno-economic comparative analysis of different carbon capture technologies

This chapter is based on the completed manuscript titled "Techno-Economic Comparative Analysis of Absorption, Membrane, and Hybrid Carbon Capture Technologies in NGCC Power Plant", that is planned to submit to the *Journal of Chemical Technology and Biotechnology*.

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Chapter V

Abstract

This chapter provides a comprehensive techno-economic comparative analysis of post-combustion carbon capture (PCC) technologies, specifically conventional absorption, membrane separation, and their combinations in hybrid systems for CO_2 capture in the Turakurgan natural gas combined cycle (NGCC) power plant in Uzbekistan. The aim of the chapter is to evaluate different PCC configurations from techno-eonomic perspectives and identify the most viable options from both techno-economic and environmental contexts. Based on this, in this study, eight configurations are analyzed, including conventional MEA-absorption method, commercial polymeric membrane separation systems, and advanced process modification techniques like exhaust gas recirculation (EGR) and selective exhaust gas recirculation (SEGR). Results highlight the SEGR with amine absorption as the most cost-effective, energy-efficient option, showing the lowest energy consumption with minimal plant efficiency drop of 4.91%, and high CO_2 capture rate of 90% at 98% purity. Membrane-only systems with SEGR exhibit a bit higher energy consumption but it can be more favourable from environment concerns, while hybrid configurations, though promising, have operational complexities and significant energy intensity. The study emphasizes the potential of SEGR-enhanced setups for NGCC plants, especially in Uzbekistan, and suggests prioritizing SEGR-absorption for near term application while investing in membrane technology advancements for future competitiveness.

5.1. Importance of alternative carbon capture technologies

Decarbonization is achieved by boosting the proportion of low-carbon energy sources, mainly renewables, while simultaneously decreasing the reliance on fossil fuels. Alternatively, carbon capture, storage, and utilization (CCSU) is another pathway to decarbonize the power sector which allows the use of fossil-fuels and preventing the majority part of CO_2 release into the atmosphere at the same time [1]. As there are mainly three CO_2 capture technologies—pre-combustion, post-combustion, and oxy-fuel combustion—post-combustion carbon capture (PCC) is particularly advantageous due to its ability to be retrofitted onto existing power plants, making it a more flexible and cost-effective option for reducing emissions without the need for significant modifications to current infrastructure. In terms of the PCC techniques, conventional amine absorption is benchmark and technically proven technology to implement such a large scale CO_2 capture process [2].

Absorption-based PCC integration into NGCC power plant has extensively been investigated in the literature [2–6]. The main challenge in CCSU integration in NGCC power plants is the relatively low concentration of CO_2 around 4 vol% in the flue gas making the process more costly and unfeasible. To overcome this, exhaust gas recirculation (EGR) modification is investigated in several studies [7]. Overall, when EGR is usually applied at 30-45%, the CO_2 concentration in the flue gas increased on average from 4% to around 6.5-7.5%, substantially reducing capital expenditure (CAPEX) of the PCC plant due to lower flowrate of flue gas with higher concentration of CO_2. Apart from that, EGR has additional impact on the plant's operational expenditure (OPEX) by slightly reducing the solvent regeneration energy requirement and subsequent increase in the plant efficiency around 0.5-1% [8]. However, the energy required for solvent regeneration process is still high with specific reboiler duty of reported average 3.5-5.5 GJ/CO_2 tonne reducing the plant efficiency significantly around 7-15% and subsequent making this method techno-economically less favourable. In this regard, in order to make CCSU commercially feasible, it is important to develop alternative PCC techniques that is more techno-economically viable than conventional absorption process enabling its large scale global implementation.

From this perspective, membrane separation CO_2 capture technology has attracted significant attention among scientists due to its potential to reach lower CAPEX and OPEX compared to conventional amine technology. Membrane technology also offers numerous advantages, such as ease of operation, modular design, compact size, absence of hazardous by-product emissions, and no alterations to the power plant's steam cycle [9]. Globally, there are several research groups working on the improvement various applications of membrane technologies. For instance, a pilot scale testing campaign has been investigated for Polaris™ membrane processing up to 20 t CO_2 per day from coal-fired power plant flue gas. This factor, coupled with the favourable environmental performance of CO_2 capture membrane technology, make membranes as the most potential candidate for future CCSU application [10].

As for the PCC integration by membrane separation to NGCC power plant, with the current characteristics (permeability & selectivity) of commercial membranes [11], it is difficult to achieve 90% capture rate that is standard for many CCSU technologies. Besides, low concentration of CO_2, even after EGR integration, makes membrane separation process challenging. In this context, Merkel at al. proposed a novel process configuration of selective EGR (SEGR) [10]. This process uses membrane contactor for selectively separate CO_2 from recycled flue gas with the air sweep stream flowing counter currently in the permeate side. By doing this, the combustion air sweep strips the CO_2 back to the compressor with minimal energy input which is used to compensate the pressure loss across membrane. One of the main advantage of SEGR technology is that it maintains the enough oxygen flow (16-19%) to the combustion chamber keeping the flame stability. SEGR processes typically follow two main configurations: parallel and series design. In parallel configuration, up to 70-80% of exhaust gas recycled back to the compressor through CO_2 selective membrane mixing with combustion air, while rest of the flue gas with increased CO_2 content goes to PCC plant [12]. In terms of series design, the CO_2 in the flue gas from the power plant is partially captured in the PCC plant and rest of the CO_2 in the flue gas passes through the membrane contactor back to the power plant compressor with air sweep. According to the several studies, SEGR integration can increase the CO_2 content in the flue gas as much as 19 vol% [12,13], by reducing the flue gas flowrate by almost three-quarter.

SEGR application into NGCC power plant has been well studied in the literature [14–17]. Laura Herraiz et al. proposed regenerative adsorption for SEGR instead of membrane and comprehensively assessed for CO_2 recycling in gas turbines, demonstrating significant potential for reducing absorber size in CO_2 capture systems by up to 50% and increasing CO_2 concentrations to improve capture efficiency. Experimental results highlight a marginal efficiency decrease and operational challenges in small-scale turbines. Additionally, a design of regenerative adsorption technology is conceptually proposed for SEGR and an advantage of relatively small pressure drop is reported compared to membrane contactors [12,18]. Apart from that, PCC with SEGR technology for NGCC power plant has been investigated by Yamina Qureshi et al [15]. in different part load conditions of the plant. The findings indicate that SEGR maintains stable combustion with a reduced flue gas flow rate, enhancing the feasibility of CO_2 capture and reducing specific reboiler duty. The hybrid SEGR configuration shows the least efficiency penalty during part-load operations, making it a viable option for integrating CO_2 capture in NGCC plants. Diego et al., introduces a hybrid CO_2 capture system integrating amine scrubbing and a selective membrane, enhancing CO_2 concentration to 18% vol. and reducing absorber size by 77%. It achieves a net electrical efficiency of 50.3%, with a significant impact from membrane system pressure drop. 6% reduction in energy demand for reboiler was also reported. A techno-economic evaluation reveals that the membrane system's cost significantly impacts the plant's capital costs, cost of electricity, and cost of CO_2 avoided, ranging between $81.9-$93.9 per MWh and $82.6-$121.8 per tonne of CO_2 avoided for S-EGR cases. Reducing the costs of the hybrid S-EGR system through advancements in membrane technology is essential for competitiveness against current benchmarks [16].

However, to best of author's knowledge, majority of the PCC with NGCC flue gas studies have focus on single PCC method either with absorption or membrane. Many research and investigations assessed EGR, SEGR, hybrid absorption-membrane CO_2 capture cases individually. Besides, there is a knowledge gap in the scientific database for through techno-economic evaluation of different mix cases and their comparative analysis based on absorption and membrane separation technologies for NGCC power plant integration with CO_2 capture. Apart from that, it is well understood that, due to a very large energy penalty and cost factors, there is limited recent techno-economic investigations for standalone membrane and absorption technology integration for NGCC power plant without any process intensification techniques such as EGR and SEGR. Regarding those, this paper provides a techno-economic comparative analysis for different absorption and membrane PCC cases with and without process intensification methods in order to make a thorough evaluation of which technology is more feasible for NGCC power plant in a global context. Besides, this study is, for the first time, evaluates specific NGCC power plant with various PCC integrations located in Uzbekistan, Central Asia.

5.2. Model development

5.2.1. Power plant modelling, EGR, SEGR integration

A detailed procedure for the modelling and analysis of Turakurgan TPP and EGR integration has been developed in Chapter 3. This involves using advanced simulation tools to represent the key components of the power plant, such as the gas turbine, heat recovery steam generator, and steam turbine, as well as the EGR system. For a complete step-by-step procedure of the modelling process, refer to Chapter 3 of this work and previously published proceeding paper [19], where the technical aspects of NGCC plant modelling are discussed in detail, including the parameterization of the gas turbine, heat exchanger networks, and integration of EGR for the increase of CO_2 concentration in flue gas prior to CCSU integration. The same principles and methodologies have been applied to the Turakurgan TPP, ensuring accurate simulation of the plant's performance under different EGR configurations.

As for the SEGR integration in NGCC power plants, is an innovative approach for enhancing CO_2 capture. In this study, commercial polymeric membrane by Membrane Technology & Research characteristics are employed [10]. In terms of the process, SEGR involves recirculating a significantly higher portion of the exhaust gases between 60-80%, compared to conventional EGR, back into the combustion chamber to further increase the CO_2 concentration in the flue gas, which facilitates more efficient CO_2 capture. Flue gas circulates on one side of the membrane, while air flows through the other. The membrane selectively allows CO_2 to pass through, separating it from oxygen and nitrogen. This process results in CO_2 entering the air stream and feeding the compressor. Instead of directly mixing CO_2 with air, this method selectively recycles CO_2 from the flue gas. The difference in CO_2 partial pressure between the air and flue gas drives the selective exhaust gas recycling. By using the combustion air stream as a sweep, CO_2 is separated and enriched with minimal energy consumption. Figure 5.1 shows the sensitivity analysis results for SEGR integration.

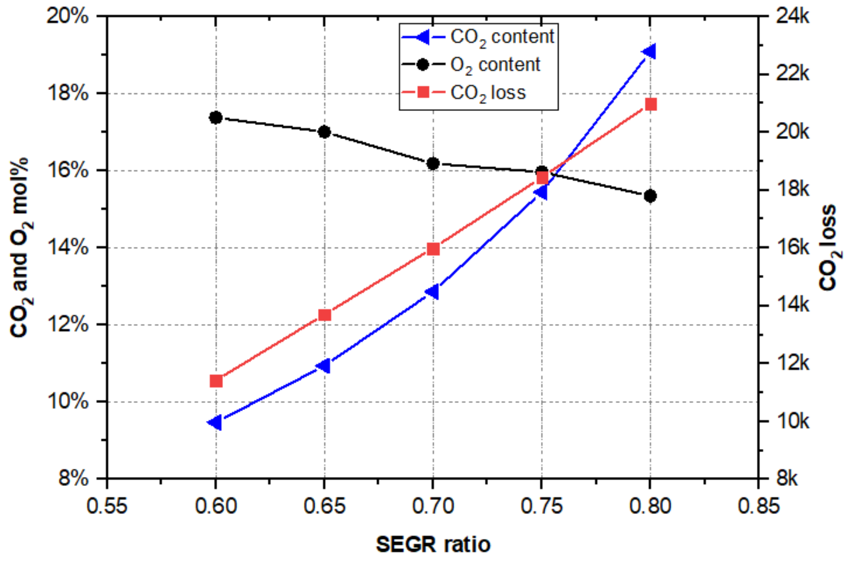

Figure 5.1. The effect of SEGR in different ratios on CO_2 molar fraction in the flue gas leaving the HRSG to PCC, O_2 molar fraction before the combustion chamber, and CO_2 loss in SEGR unit.

The analysis demonstrates that the CO_2 content in the flue gas increases to a maximum of approximately 19% when the required membrane area is 90,000 m² at a SEGR ratio of 0.80. Assuming this membrane area remains constant across different SEGR ratios, the CO_2 content decreases as expected with lower ratios. Concurrently, the O_2 content in the combustion chamber gradually decreases as the SEGR ratio increases, reaching a safety minimum of 16% at a SEGR ratio of 0.75. Furthermore, CO_2 loss in the SEGR unit rises with increasing recirculation ratios, which subsequently reduces the overall CO_2 capture rate. Therefore, considering both the need to maintain flame stability and to achieve a higher capture rate, an SEGR ratio of 0.75 is identified as more viable compared to 0.80.

5.2.2. Membrane separation model development

Integrating an CO_2 capture unit into a NGCC power plant involves several steps and components to ensure efficient carbon capture and minimal disruption to the power generation process. The flue gas from the NGCC power plant must be conditioned before entering the amine absorption unit. This involves cooling – the flue gas is cooled to an optimal temperature (40-50 °C) for CO_2 capture using a DCC. In this study, flue gas pre-treatment process is modelled with RadFrac block using equilibrium mode for both CO_2 capture standalone absorption/membrane and ERG/SEGR integration case. When the portion of flue gas is recirculated back in DCC out, it is further cooled down by 10-20 °C passing through knockout drum and bag filter. The rest of the DCC out flue gas is sent to CO_2 capture unit.

Membrane separation offers a promising solution for CCSU application, boasting several advantages over traditional technologies. These systems are compact, easily scalable, and compatible with existing infrastructure, potentially resulting in lower operational costs and energy consumption. In the CCSU field, membrane separation is emerging as a competitive alternative to benchmark absorption processes. Membrane separation is a process that utilizes a specialized module to separate gas mixtures. The membrane selectively permits the flow of desired components (permeate) while retaining impurities (retentate), as illustrated in Figure 5.2. In this application, pre-treated flue gas containing CO_2 is introduced to the high-pressure side of the membrane, with CO_2 recovery occurring on the low-pressure side. Membrane materials are generally classified into three categories: organic (polymeric), inorganic (non-polymeric), and hybrid (mixed matrix) membranes. Detailed information on different types of membranes, their TRL, scalability, pros and cons, and comparative techno-economic, environmental analysis can be found from previously published work [9].

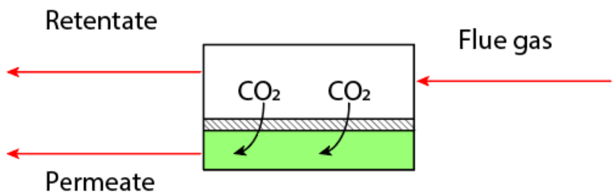

Figure 5.2. Basic flowsheet of membrane-based CO_2 separation process.

However, since the majority of high-performance membranes are still under development with low TRL, making it difficult to predict their large scale implementation, this study considers commercially available membranes for techno-economic evaluation provided in Table 5.1.

Table 5.1. Performance comparison of commercial membranes exposed to flue gas [11].

Manufacturer	Membrane	Permeance (GPU)	CO_2/N_2 selectivity	Polymer
Air Liquide	Medal	Referred only normalized	50	PI
Air Products	PRISM™	760	13	PSf
MTR	Polaris™ gen 1	1000	50	PE-PA copol.
	Polaris™ gen 2	2000	49	PE-PA copol.
Helmholtz-Zentrum	PolyActive™	1480	55	PEO-PBT
PermSelect	PermSelect®	32.5	12	PDMS

As can be observed from the data in Table 5.1, the diverse options available for membrane-based CO_2 capture from flue gas, showcasing variations in permeance and selectivity based on the polymer material used. Helmholtz-Zentrum's PolyActive™ shows the highest selectivity (55) and high permeance (1490 GPU), making it a strong candidate for effective CO_2 separation. Besides, MTR's Polaris™ gen 2 membranes also performs well with high permeance (2000 GPU) and selectivity (49). On the other hand, Air Products' PRISM™ has moderate permeance (760 GPU) but lower selectivity (13), indicating it may be less effective for CO_2/N_2 separation but potentially useful in other applications. The differences in polymer types reflect the tailored design of these membranes for specific performance characteristics, such as higher permeance or selectivity, depending on the capture requirements and operational conditions. The references indicate that these findings are supported by experimental data, providing reliability to the presented performance metrics.

Taking all aspects of commercial scale membranes into consideration, it can be summarized that permeability and selectivity is the most crucial factors while modelling the membrane separation processes. Thus, the membrane module with permeance of 2500 GPU and CO_2/N_2 selectivity of 50 which is close to the second generation of MTR's

Polaris™ is considered in this simulation, as same with Baker et al. from MTR Institute [10]. Further details on the practical aspects of fabricating such membranes are provided in Baker et al.

Modelling CO_2 capture from NGCC power plant flue gas using membrane technology requires a different approach compared to amine absorption modelling in Aspen Plus. Since Aspen Plus does not include a pre-built membrane block within its Model Palette, a custom membrane module had to be developed using Aspen Custom Modeler. This development involved applying specific equations, such as Equation 1, to accurately represent the membrane separation process. Once created, this custom module was directly integrated into the base-case Aspen Plus model to enable comprehensive process simulation and analysis (Equation 5.1).

$$\begin{cases} \frac{dF_{p,i}}{dx} = \frac{p_i}{\delta} \cdot S \cdot (P_r \cdot x_i - P_p \cdot y_i) \\ \frac{dF_{r,i}}{dx} = \frac{p_i}{\delta} \cdot S \cdot (P_p \cdot y_i - P_r \cdot x_i) \\ F_{rt} = \sum F_{r,i}, \quad F_{pt} = \sum F_{p,i} \end{cases} \tag{5.1}$$

where, p_i is the permeability of the membrane material for the i component, $m^3/m^2 \cdot h \cdot bar$; δ - membrane material thickness, m; P_r, P_p - retentate and permit pressures, bar; F_r, F_p – volumetric flowrates of the i component in the retentate and permeate side, m^3/h; x_i, y_i – the concentration of component $_i$ on the retentate and permeate side, kmol/kmol; x is the width of the membrane material, m; S is the surface of the membrane module, m^2.

Upon development and export of the custom membrane model from Aspen Custom Modeler to Aspen Plus, a whole process simulation was conducted to analyze the system's performance. However, dynamic characteristics of membrane module such as membrane fouling, temperature effects, hydrophobicity, etc. is not considered since this is the beyond of the scope of this study.

5.2.3. Amine absorption model development

The development of the end-of-pipe MEA absorption PCC model for the Turakurgan NGCC power plant, both with and without EGR deployment, has been extensively studied in a previously published article [20] and in Chapter 4. The model covers the entire CO_2 capture process, including flue gas pre-treatment, steam extraction for solvent regeneration, MEA absorption, water wash for solvent recovery, CO_2 compression, and

CO_2 transportation. These processes have been optimized using sensitivity analysis to identify the best operational parameters.

The same modelling principles and methodology used for the MEA absorption-related models in this study are applied consistently throughout. Each component—from the pre-treatment of flue gas to the final CO_2 transportation—is carefully modelled and optimized to maximize efficiency and minimize energy penalties associated with CO_2 capture.

5.3. Case studies

In case of decarbonizing NGCC power plant through CCSU integration, there are several studies seeking which PCC CO_2 capture technique is feasible in such a high scale CO_2 emissions and low CO_2 content in the flue gas. However, most literature typically focuses on individual cases using single PCC techniques. To determine whether NGCC power plants can be technically and economically competitive with current and potential future carbon taxes and emission restriction costs, it is essential to conduct comprehensive case studies. These studies should evaluate different process configurations, incorporating both conventionally proven mature absorption methods and emerging promising candidates such as membrane separation, along with their hybrid configurations. In this context, Turkurgan NGCC power plant, amine absorption and membrane separation CO_2 capture plants have been simulated for comparative analysis based on the methodology provided in above subsections. The following is a list of all the cases investigated in this study, accompanied by figures illustrating the overall process flow.

- CO_2 capture without EGR – (1) Amine absorption & (2) Membrane separation (standalone)
- CO_2 capture with EGR – (3) Amine absorption & (4) Membrane separation (standalone)
- CO_2 capture with (5) & without EGR (6) – hybrid amine absorption plus membrane separation
- CO_2 capture with selective EGR – (7) Amine absorption & (8) Membrane separation (standalone)

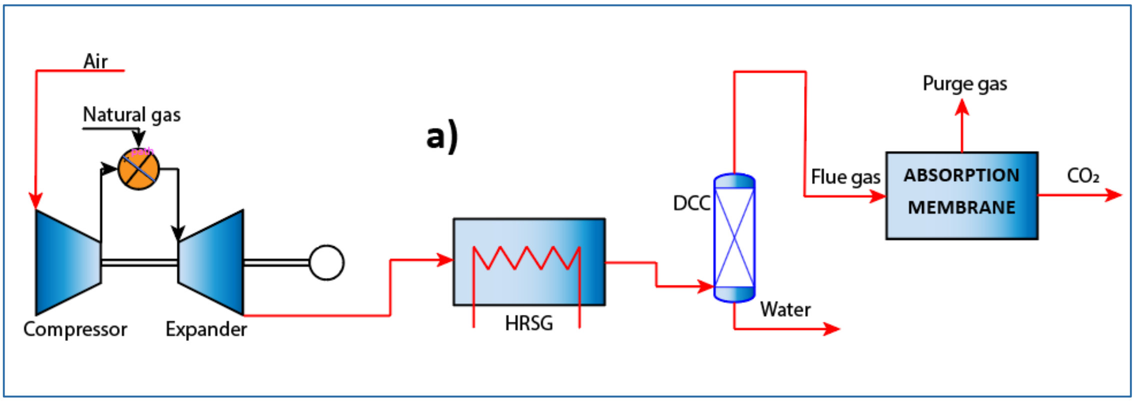

Figure 5.3. CO_2 capture non-EGR/SEGR – (baseline) MEA absorption (case 1) and standalone membrane separation (case 2).

There are 8 different CO_2 capture cases in total represented each two similar cases using one process flowsheet. For instance, in Figure 5.3, the only difference between case 1 and case 2 is the CO_2 capture technology either standalone MEA absorption or standalone membrane separation without any modifications. Although, it is true that the results will not likely to be better in those two cases without EGR/SEGR integration compared to those with plant modifications, those calculations are crucial in order to determine quantitative comparison among all different cases.

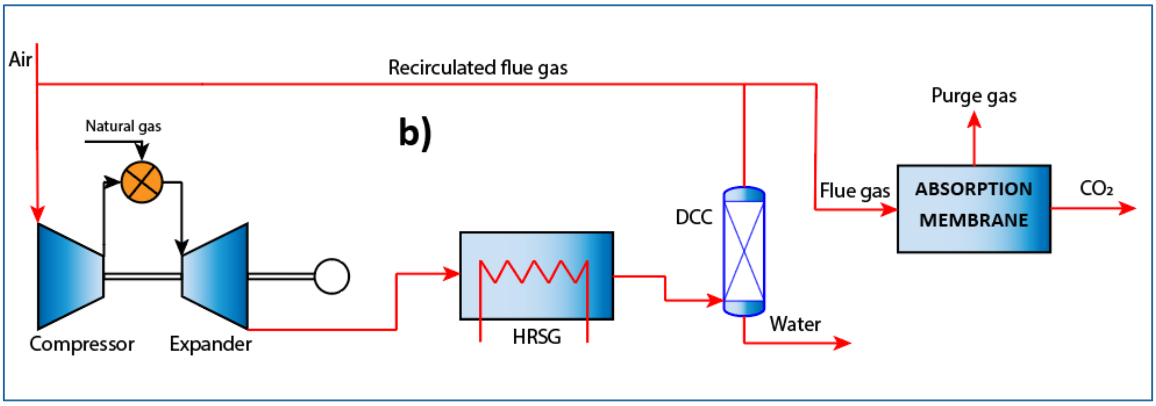

Figure 5.4. CO_2 capture with EGR – MEA absorption (case 3) and membrane separation (case 4).

In terms of case 3, MEA absorption technology is implemented with 45% EGR selected in Chapter 3, while the same EGR is tested with only multistage membrane separation technology in case 4 (Figure 5.4).

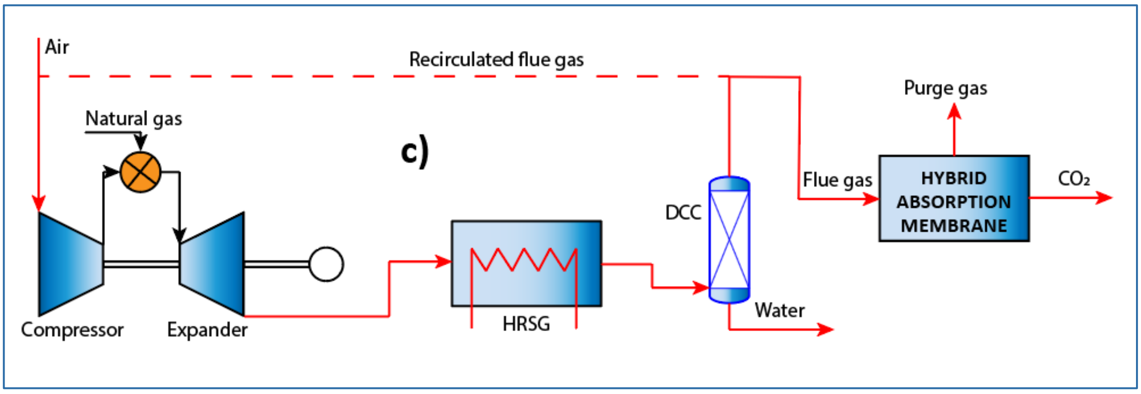

Figure 5.5. CO_2 capture by hybrid MEA absorption & membrane separation with EGR (case 5) and without EGR (case 6).

Hybrid absorption and membrane separation method is also interesting combination to check techno-economic viability. In case 5, hybrid MEA absorption and membrane separation are combined with power plant flue gas without recirculation initially separating CO_2 in one stage membrane module followed by amine absorption for further purification of high concentrated CO_2. The same technique is employed for case 6 with 45% EGR modification (Figure 5.5).

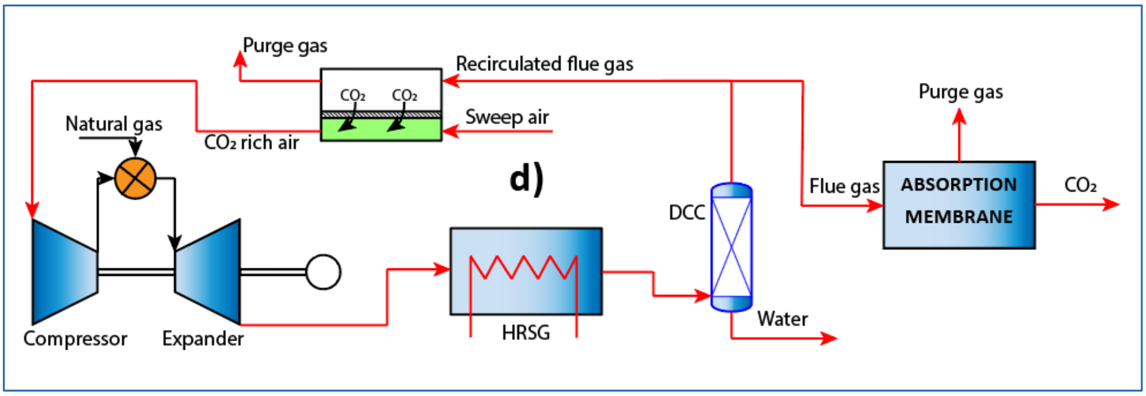

Figure 5.6. CO_2 capture with SEGR – MEA absorption (case 7) and membrane separation (case 8).

Since polymeric membrane is applied with air sweep for the selective EGR integration in the simulation, the process configuration shown in Figure 5.6 can be interpreted as membrane & absorption for case 7 and membrane & membrane for case 8.

5.4. Economic estimation approach

Techno-economic analysis (TEA) is a critical tool for assessing the feasibility and cost-effectiveness of technologies aimed at decarbonizing NGCC power plants through CCSU. This analysis evaluates both the technical performance and economic viability of various CCSU strategies, enabling stakeholders to make informed decisions. By examining factors such as CAPEX and OPEX, energy efficiency/penalty, and potential revenue streams if available, TEA provides a comprehensive understanding of the trade-offs and benefits associated with each technology. In the context of NGCC power plants, TEA is essential for determining whether implementing CCSU can meet current and future regulatory requirements, such as carbon taxes and emission restrictions, while maintaining economic competitiveness. Through detailed case studies and scenario analysis, TEA helps identify the most promising configurations, whether using mature absorption techniques, emerging membrane separation technologies, or hybrid approaches, thus guiding investment and policy decisions in the pursuit of sustainable energy solutions.

In this study, as the main technical indicators for thorough comparison among different cases, energy penalty/plant efficiency, required membrane area, capture rate, and product purity (CO_2 purity) are evaluated, while levelized cost of electricity (LCOE), total annualized cost (TAC), and CO_2 avoidance cost (CAC) are estimated with the following assumptions and considerations provided in Table 5.2. Furthermore, the size and capacity of the all process equipment are either user input with sensitivity analysis or Aspen Plus “Sizing” tool especially when the columns are in equilibrium mode.

Table 5.2. Main assumptions and considerations for techno-economic estimation.

Description	Value	Reference
Economic life of capture plant	25 years	Assumption
Chemical Engineering Plant Cost Index	799.5 (April)	[21]
NGCC plant’s annual capacity factor	0.85	[22]
Annual interest rate	12%	Assumption
Membrane permeance	2500 GPU	[11]
Membrane CO_2/N_2 selectivity	50	[11]

Replacement membrane period	3 years	Assumption
Replacement membrane cost	15 $/m^2$	[10]
Membrane skid cost	50 $/m^2$	[10]
Equipment installation factor	243.51%	[23]
Electricity price ($/kWh)	0.071	[24]
Solvent price MEA ($/metric ton)	1290	[25]
Cooling water price ($/m^3$)	Pumping cost	Assumption

*The CO_2 transport & storage costs are excluded in the estimation.

The one of the economic measures used in this study is the LCOE, which is obtained from the ratio between the total annualized cost, TAC, and net power output, NPO (Equation 8):

$$\mathrm{LCOE} = \frac{\mathrm{TAC}}{\mathrm{NPO}} \tag{5.2}$$

TAC is given by the sum of the annualized capital cost (ACC), fixed operational cost (FOC), and variable operational cost (VOC) (Equation 9):

$$\mathrm{TAC} = \mathrm{ACC} + \mathrm{FOC} + \mathrm{VOC} \tag{5.3}$$

where FOC is assumed to be 3% percent of total capital cost [26], TCC, VOC is estimated using the data in Table 5.2, and ACC is found by the capital recovery factor, CRF, multiplied by TCC (Equation 10):

$$\mathrm{ACC} = \mathrm{CRF} * \mathrm{TCC} \tag{5.4}$$

In the case of CRF, it is determined by the plant's economic life, EL, average annual interest rate, i_{av}, as follows (Equation 11):

$$\mathrm{CRF} = \frac{i_{av} * (1+i_{av})^{EL}}{(1+i_{av})^{EL} - 1} \tag{5.5}$$

TCC includes the fixed capital cost, FCC, which is the sum of direct and indirect capital costs, DC and IC, respectively, and working capital, WC (Equation (12)):

$$\mathrm{TCC} = \mathrm{DC} + \mathrm{IC} + \mathrm{WC} \tag{5.6}$$

The energy penalty can be expressed as the additional energy required due to CCSU integration relative to the baseline energy (Equation 2):

$$\text{Energy penalty} = \frac{E_{total,CCSU} - E_{baseline}}{E_{baseline}} * 100\% \qquad (5.7)$$

Where $E_{total,CCSU}$ and $E_{baseline}$ correspond to total energy consumption with CCSU integration and baseline plant energy consumption without CCSU respectively.

Besides, the efficiency of a power plant, often referred to as thermal efficiency, is a measure of how well the plant converts the energy contained in its fuel into electrical energy, which is calculated as follows (Equation 3):

$$\eta = \frac{E_{netoutput}}{F_{NG} * LHV} * 100\% \qquad (5.8)$$

Where $E_{netoutput}$ is total net power output of the plant and F_{NG} and LHV are mass flowrate of natural gas (kg/s) and lower heating value of the fuel respectively.

As for CAC calculation ($/tonne of CO_2), TAC is divided by annual CO_2 emissions (tonne/year) as follows:

$$CAC = \frac{TAC}{\text{Annual } CO_2 \text{ emissions}} \qquad (5.9)$$

Where annual CO_2 emissions of the Turakurgan NGCC power plant is found using plant's capacity factor (0.85) which is equivalent to 7446 hours.

The detailed cost calculations are carried out through the methodology used in [23], and individual parameters are determined via the methodology of [27–29].

5.5. Results and Discussion

In this section, the results of the techno-economic comparative analysis for the integration of different CCSU technologies into a NGCC power plant are presented and discussed. Eight distinct cases are considered. The analysis examines key performance metrics such as energy consumption, net power efficiency, CO_2 capture rate, CO_2 purity, CAPEX, OPEX, and CO_2 emissions avoided. These metrics provide insight into the operational and economic viability of each CCSU configuration, facilitating a thorough evaluation of the most efficient and cost-effective solutions for decarbonizing NGCC power plants. Detailed simulation results and their comparative analysis are provided in following subsections.

5.5.1. Simulation results

The comparative study highlights the significant differences in performance between membrane-based and absorption-based systems, with EGR and SEGR integration showing considerable potential in reducing energy penalties and costs. By analyzing the overall energy consumption, cost structure, and CO_2 capture efficiency, this section aims to identify the most practical and feasible CCSU technologies for large-scale deployment in NGCC plants, particularly in the context of Uzbekistan's energy sector.

All the simulation results are summarized in Table 5.3. It outlines a techno-economic comparative analysis results of different CCSU integration cases in Turakurgan NGCC power plant in Uzbekistan. The table presents results for eight different configurations, including standalone absorption, membrane separation, hybrid combinations of these technologies, and the use of EGR and SEGR.

Table 5.3. Overall results for techno-economic calculation of CCSU integration to the NGCC plant in eight different cases.

Cases	Unit	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8
Description		ABS	EGR + ABS	MEM	EGR + MEM	MEM + ABS	EGR+MEM + ABS	SEGR + ABS	SEGR +MEM
Total energy consumption	MWh	53.89	50.18	135.45	83.23	144.9	90.67	36.95	44.47
Net power efficiency drop	%	7.15	6.66	17.98	11.05	19.24	12.04	4.91	5.9
CO_2 capture rate & recovery	%	90	90	75	90	80	80	85	80
CO_2 purity in the product	%	98	98	96	95	98	98	98	95
Total CAPEX with installation	M$	248.85	195.02	233.37	178.43	193.35	142.87	97.57	145.52
Annualized CAPEX	M$	31.73	24.87	29.75	22.75	24.65	18.22	12.44	18.56
Fixed OPEX	k$	7466	5850	7001	5353	5800	4286	2927	4366
Variable OPEX	M$	33.29	29.41	73.46	45.31	80.86	51.29	23.39	24.89
CO_2 emissions avoided	Mtpa	1.053	1.053	0.878	1.053	0.936	0.936	0.995	0.936

Note: ABS – Absorption; MEM – Membrane separation; EGR – Exhaust gas recirculation; SEGR – Selective EGR;

Overall, the results in Table 5.3 provide a comprehensive comparison of different carbon capture integration methods for NGCC power plants. The key takeaway from the analysis is the significant advantage of using SEGR combined with absorption (Case 7) in terms of both energy efficiency and cost-effectiveness. This configuration results in the lowest total energy consumption (36.95 MWh), minimal efficiency drop (4.91%), and the sufficient CO_2 emissions avoided (0.995 Mtpa), while maintaining high CO_2 purity (98%) and comparatively low CAPEX and OPEX. These results indicate that SEGR, when paired with absorption, can significantly reduce the operational costs and energy penalties typically associated with conventional carbon capture technologies.

In contrast, membrane-only systems, particularly without EGR or SEGR (Case 2 and Case 4), exhibit the highest energy consumption and largest efficiency penalties, making them less attractive for large-scale application despite their lower environmental footprint. Hybrid configurations (Cases 5 and 6), though more efficient than standalone membrane systems, still present higher costs and energy penalties compared to SEGR-absorption combinations. Overall, the analysis suggests that SEGR-enhanced configurations, especially SEGR with absorption, provide the most balanced and viable solution for NGCC power plants aiming to implement CCSU technologies.

5.5.2. Case study results

Standalone amine absorption is the benchmark for post-combustion CO_2 capture and achieves a robust CO_2 capture rate of 90% with high CO_2 purity at 98% (Figure 5.7). However, the process consumes 53.89 MWh of energy, resulting in a notable efficiency drop of more than 7% as shown in Figure 5.8. The CAPEX for this case is $248.85 million, with fixed and variable operational expenditure OPEX totaling $40.76 million annually. While amine absorption is a well-proven technology, its drawbacks include high energy consumption, primarily due to the heat required for solvent regeneration, which causes significant energy penalties. From an environmental perspective, the relatively large energy demand results in a higher operational carbon footprint, offsetting some of the decarbonization gains. Despite these downsides, absorption remains a reliable choice for CO_2 capture, especially in retrofitting existing NGCC plants, but its high OPEX and energy consumption limit its competitiveness in the long term.

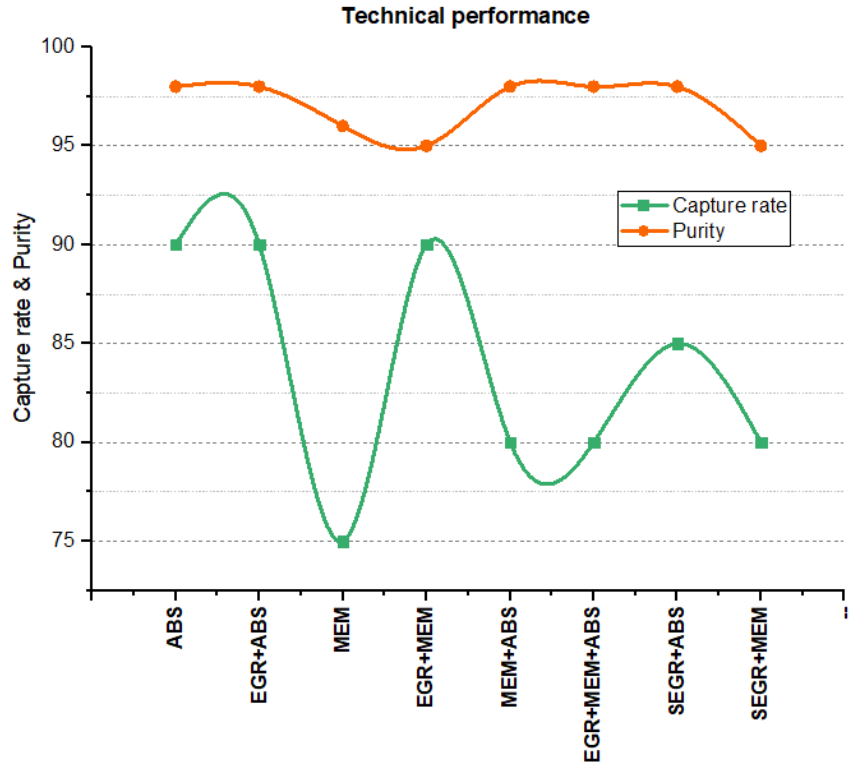

Figure 5.7. The technical performance of various carbon capture technologies, focusing on two key metrics: CO_2 capture rate and CO_2 purity.

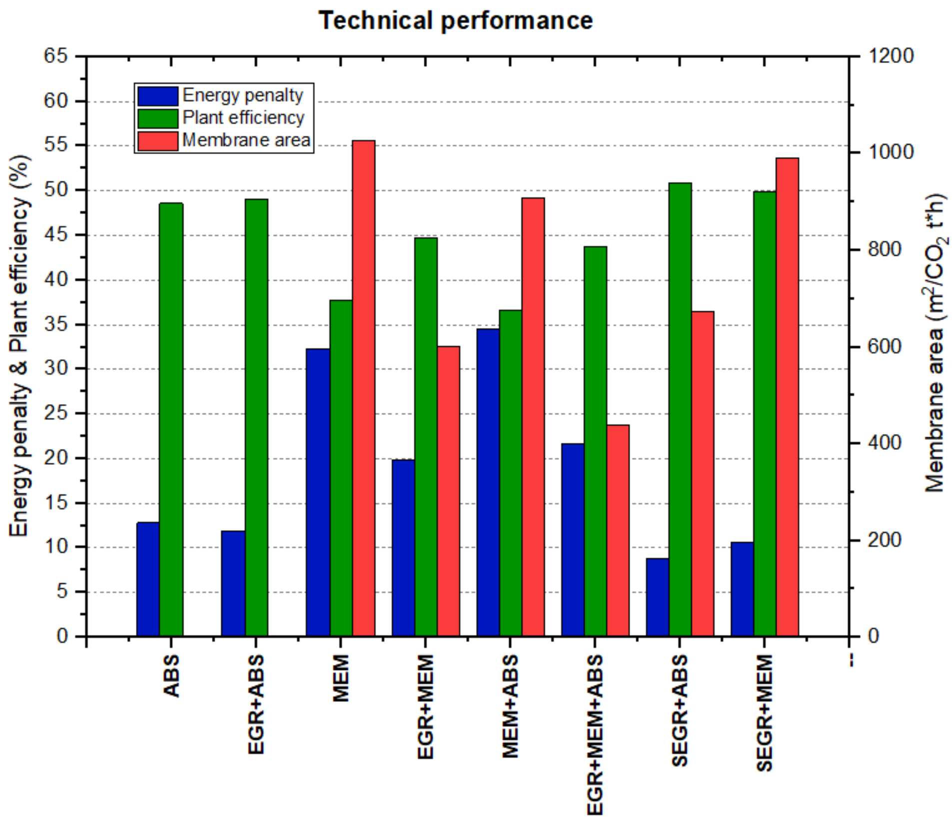

Figure 5.8. Comparison of energy penalty, plant efficiency, and required membrane area for each case.

Integrating EGR into the amine absorption system results in a significant improvement in both energy consumption and economic performance. In this case, energy consumption decreases by around 7%, and the efficiency drop is reduced to 6.66%. Meanwhile, the CO_2 capture rate can easily be remained at 90%, and purity is maintained at 98%. CAPEX is notably lower at $195.02 million that is due to mainly significant reduction in absorber size in response to the flue gas flowrate decrease, and OPEX drops substantially by 16% (Figure 5.9). EGR works by increasing the CO_2 concentration in the flue gas, which reduces the volume of gas that needs to be treated, thus lowering the energy requirement for solvent regeneration. This not only improves the economic feasibility of the capture system but also reduces the environmental burden by lowering the auxiliary power requirements. The reduced energy consumption directly translates to fewer emissions from the plant's overall operations, making this a more sustainable option than standalone absorption.

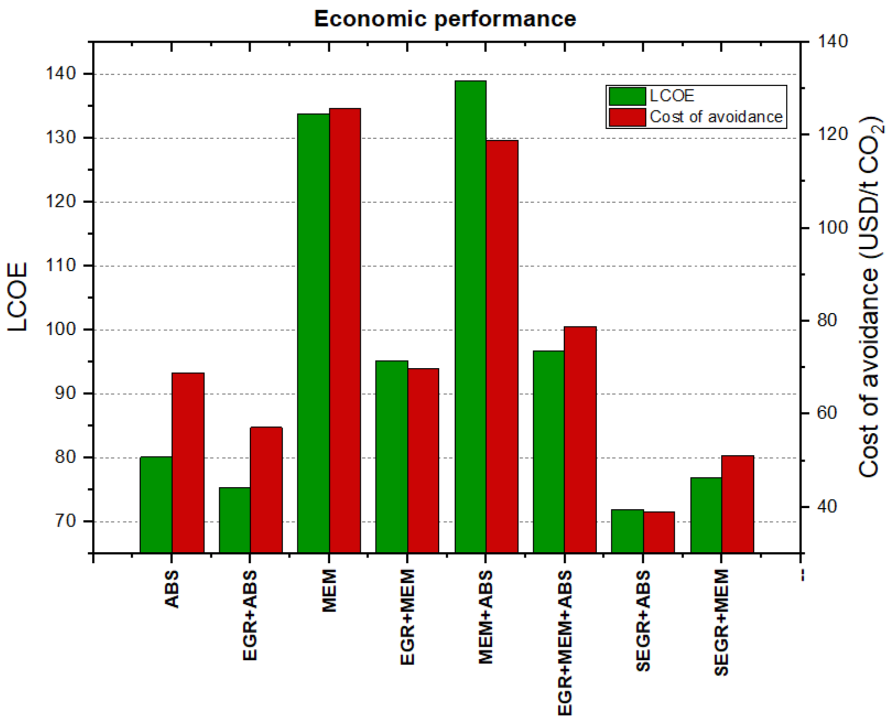

Figure 5.9. The economic performance of different carbon capture technologies by comparing two critical metrics: Levelized Cost of Electricity (LCOE) in green bars and Cost of CO_2 Avoidance.

The membrane separation technology without EGR shows significantly higher energy consumption at 135.45 MWh, with a steep efficiency drop of 17.98%. However, its high energy consumption is largely due to the low CO_2 concentration in the flue gas, which makes the separation process more energy-intensive. This also creates a larger environmental impact through increased fuel consumption to compensate for efficiency losses. As for the membrane separation paired with EGR, this case shows a marked improvement over the standalone membrane case. Energy consumption is reduced to 83.23 MWh, and the efficiency drop improves to 11.05%, while the CO_2 capture rate increases from 75% to 90% and the purity remains at 95%. CAPEX is lower than the standalone membrane by almost 25%, and OPEX decreases to $50.66 million annually. The introduction of EGR enhances membrane performance by concentrating CO_2 in the flue gas, which alleviates some of the energy burden associated with separation. However, membrane-based systems still show higher energy consumption and lower efficiency compared to MEA absorption with EGR, primarily due to the challenges of maintaining selectivity and permeance under high recirculation rates. From an environmental standpoint, while the energy savings are significant, the process is still less efficient than EGR-enhanced absorption, which limits its attractiveness for large-scale carbon capture deployment.

In the hybrid configuration without EGR, membrane separation is initially used for CO_2 capture, followed by amine absorption for further purification. While this approach takes advantage of both technologies, it suffers from high energy consumption, operational complexity, and inefficiencies that arise from combining two distinct processes. The result is higher overall costs and environmental impacts, primarily due to increased energy demands, making it less suitable for NGCC plant decarbonization. Additionally, the CO_2 capture rate, while reasonable, limits its appeal as a fully effective solution.

Introducing EGR into the hybrid system improves efficiency by concentrating CO_2, reducing energy demand, and lowering operational costs. This makes both membrane and absorption processes more effective. However, despite these gains, the hybrid system still faces challenges, such as higher energy penalties and the complexity of integrating multiple technologies. The environmental benefits, while notable, are less pronounced compared to simpler EGR-based solutions, and the long-term sustainability of such a complex system remains questionable.

The absorption with SEGR case (Case 7) emerges as the most efficient configuration, with the lowest total energy consumption of 36.95 MWh and the smallest efficiency drop of 4.91%. The CO_2 capture rate is 85%, and the purity is maintained at 98%. CAPEX is the lowest of all configurations at $97.57 million, and OPEX is also the lowest at $26.32 million annually. SEGR increases the CO_2 concentration in the flue gas to around 19%, which significantly reduces the amount of gas that needs to be treated in the absorber, thereby lowering energy consumption and operational costs. The reduced energy demand makes this configuration not only the most economically feasible but also the most environmentally friendly, as it minimizes the auxiliary power required for CCSU operations. The higher CO_2 concentration also makes the capture process more efficient, allowing for better utilization of energy resources, which directly translates into lower emissions.

Finally, membrane separation with SEGR shows improved results compared to standalone membrane or membrane with EGR. Energy consumption is 44.47 MWh, and the efficiency drop is 5.9%, with a CO_2 capture rate of 80% and a CO_2 purity of 95%. CAPEX is $145.52 million, and OPEX totals $29.26 million annually. SEGR enhances the membrane system's efficiency by increasing CO_2 concentration, but this configuration still lags behind MEA absorption with SEGR in terms of both economic performances. While SEGR mitigates some of the disadvantages of membrane technology, it cannot fully overcome the higher energy requirements associated with membrane separation under these conditions.

The comparative analysis of all cases shows that SEGR combined with absorption (Case 7) provides the most efficient and cost-effective solution for CCSU in NGCC plants. It achieves the lowest energy consumption, smallest efficiency penalty, and the lowest CAPEX and OPEX, making it the most attractive option. However, from environmental aspect, the use of SEGR with membrane system has better performance as the membrane-based CO_2 capture has lower carbon footprint.

Standalone membrane systems, even with EGR, exhibit higher energy consumption and costs, making them less competitive compared to ABS-based systems. Hybrid configurations, although interesting from a technological standpoint, suffer from high energy penalties and operational complexity, limiting their practical application.

In conclusion, SEGR-based configurations, particularly when combined with absorption, offer the most promising path forward for integrating CCSU into NGCC power plants. Future work should focus on further optimizing SEGR technology and improving membrane performance to make MEM-based systems more viable for large-scale deployment. From an environmental perspective, minimizing energy consumption is key to reducing the overall carbon footprint of CCSU operations, and SEGR-enhanced systems excel in this regard.

5.6. Conclusion

This study conducted a comprehensive techno-economic analysis of eight different CCSU integration cases in an NGCC power plant, comparing amine absorption, membrane separation, hybrid configurations, and EGR/SEGR enhancements. The analysis focused on key performance metrics such as energy consumption, efficiency penalties, CO_2 capture rates, CAPEX, OPEX, and CO_2 emissions avoided.

The results indicate that SEGR combined with MEA absorption (Case 7) offers the most promising balance between efficiency and cost-effectiveness, with the lowest energy consumption (36.95 MWh), minimal efficiency loss (4.91%), and high CO_2 capture (98% purity). This configuration emerges as the most viable option for large-scale CCSU deployment. Standalone membrane systems (Cases 2 and 4) exhibit high energy consumption and efficiency penalties, making them less favorable for NGCC integration. Hybrid configurations, while showing some improvement, are still outperformed by SEGR-absorption or SEGR-membrane setups. One of the limitations of the study include the reliance on currently available commercial membrane technologies, which may limit performance potential. In this perspective, prioritizing SEGR-absorption configurations for near-term implementation in NGCC power plants and investing in the development of membrane technologies to make membrane-based systems more competitive in the future.

5.7. References

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Chapter VI - 6. Potential Carbon Sinks for the power sector in Uzbekistan

This chapter is based on the following article (The paper is currently in pre-print version and under review status in the journal of *Greenhouse Gases: Science and Technology, Wiley*):

Kamolov, A.; Turakulov, Z.; Norkobilov, A.; Variny, M.; Fallanza, M. Regional Resource Evaluation and Distribution for Onshore Carbon Dioxide Storage and Utilization in Uzbekistan. Research Square 2024, https://doi.org/10.21203/rs.3.rs-4557437/v1.

Abstract

This chapter presents a comprehensive assessment of Uzbekistan's potential for carbon capture, storage, and utilization (CCSU), highlighting its importance as a key component of the country's efforts to achieve net-zero emissions. Given Uzbekistan's commitment to reducing greenhouse gas emissions under the Paris Agreement, this study focuses on evaluating the feasibility of CCSU technologies, which are currently absent from the country's Green Economy strategies. The chapter outlines a methodology for efficiently matching CO_2 sources to suitable storage or utilization sinks, based on resource evaluation and spatial analysis.

The assessment covers major CO_2-emitting power sector by mapping the geographical distribution of CO_2 sources and identifying potential sinks, including saline aquifers, enhanced oil recovery (EOR), enhanced natural gas recovery (ENGR), as well as urea, methanol, and algae-based biofixation pathways. The results reveal that Uzbekistan has an estimated annual CSU capacity of 1,171 million tonnes of CO_2, far exceeding its current CO_2 emission levels. Saline aquifers offer the largest storage potential, followed by ENGR and EOR. However, there are challenges in sink distribution, as most CO_2 sources are concentrated around the capital city, where available sink capacities are limited, while the majority of CSU resources are located in the eastern, western, and southern regions of the country.

The analysis shows that although Uzbekistan has significant CO_2 storage capacity for large-scale CCSU deployment, the potential for chemical utilization of CO_2 remains limited. This chapter emphasizes the need for further studies to refine resource evaluations, explore additional CO_2 utilization technologies, and integrate CCSU into Uzbekistan's sustainable development plans.

6.1. Importance of potential CO_2 sinks estimation in Uzbekistan

Uzbekistan holds substantial reserves of oil, natural gas, coal, and uranium, positioning it as a key player in the global energy landscape. It ranks as the 11th largest producer of natural gas globally and the second largest in Central Asia, while also being the 14th largest in terms of proven reserves. With approximately 600 million barrels of proven oil reserves and 1,500 Mt of coal reserves [1], Uzbekistan's rich fossil fuel resources present significant opportunities for both regional and international energy markets. In particular, its vast natural gas reserves provide an ideal foundation for exploring the country's potential for CO_2 storage.

The most suitable geological formations for CO_2 storage in Uzbekistan include depleted oil and gas reservoirs, saline aquifers, and unmineable coal seams, distributed across various regions of the country. The feasibility of utilizing these formations for CO_2 storage is becoming increasingly relevant as Uzbekistan seeks to balance its growing energy demand with the need for sustainable development.

In addition to its energy resources, Uzbekistan is the most populous country in Central Asia, with a population exceeding 37 million [2], more than half of which is made up of youth. With a demographic growth rate of 1.5% annually, Uzbekistan is rapidly emerging as the region's largest industrial hub. This rapid population and industrial growth underscores the importance of efficient resource management. To ensure sustainable development, a transition towards a circular economy is essential. In this context, the adoption of CO_2 utilization technologies [3] presents a valuable opportunity for Uzbekistan to achieve carbon-neutral economic growth.

This chapter aims to address these challenges by, for the first time, identifying the country's major CO_2-emitting point sources and conducting a spatial analysis to match these sources with potential CO_2 sinks. Additionally, the study evaluates potential pathways for CO_2 storage and utilization, considering the capacities for CO_2 injection, long-term storage, and conversion. These efforts contribute to Uzbekistan's short- and mid-term goals for CO_2 reduction, paving the way for a more sustainable future.

6.2. Methodological framework

The research methodology is divided into three main stages: data collection, selection of CO_2 storage and utilization (CSU) pathways, establishing assumptions, and conducting spatial analysis, as illustrated in Figure 6.1. These steps form the foundation of the methodological framework, guiding the research process through a structured sequence of tasks designed to assess the impact of CSU technologies in these key industries.

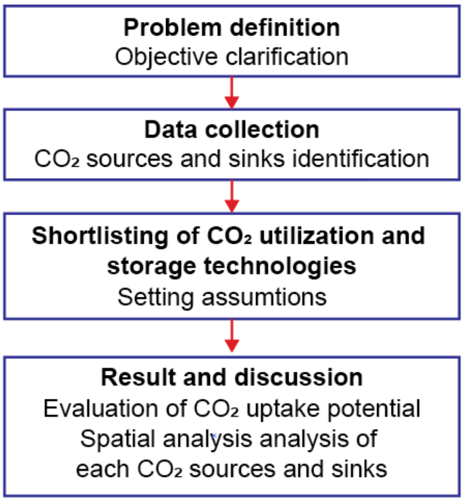

Figure 6.1. Research methodology framework [4].

In assessing CSU methods for Uzbekistan, the first step involved a quantitative analysis of CO_2 emissions from anthropogenic sources. This was done using statistical data, official local sources, and geo-information databases.

Identifying CO_2 sources in the power sector requires a detailed analysis of operational data from power plants including fuel types, production capacities, and practices affecting emission levels. Industry reports and publications further aided in understanding emission trends and sector-specific challenges. These efforts provide a clear map of major emission sources, helping to prioritize CO_2 utilization efforts.

For CO_2 sinks, the study examines various technological and geographical options, including mineral carbonation, geological storage, and conversion to chemical feedstock. Spatial analysis helps identify suitable sites based on proximity to CO_2 sources, land availability, and accessibility, ensuring selected sinks are both technically viable and logistically practical. This approach maximizes the efficiency of CO_2 reduction strategies.

Various CSU technologies are available for fossil fuel-based plants, but selecting the appropriate ones requires careful consideration of factors like geolocation, market size, and technological readiness. Initially, technologies are categorized based on maturity and scalability. The selection process must ensure that the chosen technologies not only operate efficiently but also align with economic and environmental objectives.

Several key questions guide this evaluation:

- What are the technological capabilities in Uzbekistan?
- Is the market size sufficient to support the technology?
- Can the method be economically justified?

A preliminary assessment of CO_2 utilization and uptake potential has been conducted for each evaluated pathway. These metrics are essential for evaluating the effectiveness of CSU technologies in reducing CO_2 emissions and mitigating climate change. CO_2 utilization potential refers to the market share of products that can be produced using captured CO_2, while uptake potential measures the capacity of a technology to reduce atmospheric CO_2. Both play a critical role in determining the overall impact of these technologies on emission reduction, as outlined in Equation 6.1.

$$\begin{cases} \mathrm{CO_2\ uptake\ potential} = \mathrm{Specific\ mass}\left[\frac{t_{CO_2}}{t_{product}}\right] \cdot \mathrm{Market\ size}\ [\frac{t_{product}}{year}] \\ \mathrm{CO_2\ utilization\ potential} = \frac{\mathrm{Annual\ CO_2\ emission}\ [\frac{t_{CO_2}}{year}]}{\mathrm{CO_2\ uptake\ potential}\ [\frac{t_{CO_2}}{year}]} \end{cases} \tag{6.1}$$

Together, these metrics provide a holistic understanding of the role CO_2 utilization technologies can play in achieving sustainability goals and contributing to global GHG emission reductions.

Based on data availability, market demand, and CO_2 removal potential, the following five major CO_2 sinks have been identified as the most promising for Uzbekistan:

- CO_2-based methanol synthesis
- CO_2-based urea production
- CO_2 biofixation
- CO_2-enhanced oil and natural gas recovery

- CO_2 sequestration in saline aquifers and mineral rocks

The following subsections provide an overview of each pathway, detailing its applications and potential benefits specific to Uzbekistan.

6.3. Data collection and calculation of CO_2 sinks in Uzbekistan

6.3.1. CO_2 to Methanol production

Uzbekistan currently operates methanol production facilities with an overall capacity of around 300,000 tonnes [5]. Additionally, Uzbekistan’s Gas Chemical Complex has partnered with Air Products to build a methanol-to-olefins (MTO) facility by the end of 2025. This new plant will be located in the Karakul Free Economic Zone in the Bukhara region and is expected to produce up to 1.34 million tonnes of methanol annually [6]. Globally, there are 90 methanol production facilities with a combined capacity of 110 million tonnes, averaging 1.2 million tonnes per plant [7], Based on this, Uzbekistan’s total methanol production capacity, assumed at 1.64 million tonnes once the new facility is operational, should meet the country’s near- to mid-term needs. The carbon reduction potential of this methanol production is assessed hypothetically, assuming Uzbekistan achieves such a high production rate using renewable hydrogen. This pathway could significantly reduce CO_2 emissions while supporting the country’s growing methanol demand.

6.3.2. CO_2 to Urea

Uzbekistan’s agricultural sector plays a vital role in the nation’s economy, with land management and efficient agricultural production being key factors for sustainable development. Recognizing its reliance on agriculture, Uzbekistan has increased its focus on fertilizer production over the past decade to meet domestic needs and boost exports. According to publicly available data, Uzbekistan’s urea production is concentrated in three major chemical plants, with a combined annual capacity of approximately 1.25 million tonnes. The largest producer, Navoiyazot JSC in Navoiy, has a capacity of 577,500 tonnes. Fargonaazot OJSC in the Fergana Valley and Maxam-Chirchik JSS in the Tashkent Region also contribute significantly, with capacities of 577,500 and 270,000 tonnes per year, respectively [8–10]. While large-scale green ammonia production is still in its early stages, a switch to CCSU-based CO_2 supply could potentially meet the CO_2

demand for urea production at these plants, replacing conventional CO_2 sources. In the near to mid-term, a shift to green or blue hydrogen in the conventional ammonia production process is also anticipated. Although global urea demand is projected to grow by about 1% annually [11], we assume that Uzbekistan's fertilizer production will follow a similar trend. For the purpose of estimating the CO_2 capture potential in urea production, however, we will maintain a constant production scale, assuming that existing plants transition to more sustainable production methods as described above.

6.3.3. CO_2 to biofixation

CO_2 biofixation through algae cultivation offers a promising solution for reducing emissions in Uzbekistan. Algae farming requires land, nutrients, trace metals, water, CO_2, and sunlight [12], and several potential sites across the country could meet these needs. Uzbekistan's climate, with 320 sunny days and 2900-3100 hours of sunlight per year, is highly favorable for large-scale algal cultivation [13]. Despite its reliance on transboundary water (90%) and limited fresh water resources [14], the use of wastewater in algae farming presents a dual advantage. Many microalgae species thrive in wastewater, including industrial, agricultural, and domestic streams, as well as saline and brackish water. The oil and gas sectors, which produce significant amounts of wastewater, can also provide a potential resource. For example, up to 75% of the total liquids produced from oil wells is water, which requires disposal [15]. Natural gas-fired thermal power plants in Uzbekistan, particularly its 11 plants (including NGCC and hybrid conventional), could serve as key CO_2 sources for algae cultivation. These plants emit relatively clean flue gas, containing low CO_2 levels (3-9%), making them good candidates for this approach despite the high costs of capturing CO_2 for other uses [16].

Two potential locations have been identified for algae biofixation: the Turakurgan TPP in the east and Tashkent TPP in the capital, both offering access to flue gas, wastewater, and saline groundwater [17]. While estimating the CO_2 abatement potential is complex, due to factors like algae strain growth, nutrient availability, and site conditions, this method holds significant promise for reducing emissions and addressing wastewater challenges simultaneously. Detailed information on the technical and economic part of this route as in the case of Turakurgan TPP located in the eastern part of Uzbekistan can be found from our previously published paper [18].

6.3.4. Enhanced hydrocarbon recovery

Enhanced hydrocarbon recovery, also known as tertiary recovery, is a technique used to extract additional oil or natural gas from fields where conventional methods are no longer effective. While primary and secondary recovery rely on pressure differences to extract hydrocarbons, enhanced recovery techniques alter the chemical properties of the oil or gas to improve extraction. For instance, EOR can extract 30% to 60% or more of a reservoir's oil, compared to 20% to 40% using traditional methods [19]. This process often involves injecting CO_2 into underground formations, which helps release trapped oil and gas, increasing overall production. Locating CO_2 capture facilities near oil and gas fields can help reduce transportation costs. However, one major drawback of this method is the potential environmental impact, as it may accelerate hydrocarbon extraction and its associated risks [20].

6.3.5. Geological CO_2 storage

Uzbekistan has six sedimentary basins that contain hydrocarbon reserves and saline aquifers, making them ideal for both geological CO_2 storage and enhanced hydrocarbon recovery. The largest of these is the Amudarya basin, which contains the majority of the country's gas reserves and spans Uzbekistan, Turkmenistan, Iran, and Afghanistan [21]. The portion of this basin within Uzbekistan covers more than 90,000 km^2. Notably, the South Hissar and Bukhara-Khiva regions in this basin produce around 50 billion cubic meters of natural gas annually. These regions also contain deep saline aquifers, located 700 to 1000 meters underground, which offer potential for CO_2 storage. General overview of potential sites of CO_2 storage and hydrocarbon reserves are drawn in Figure 6.2.

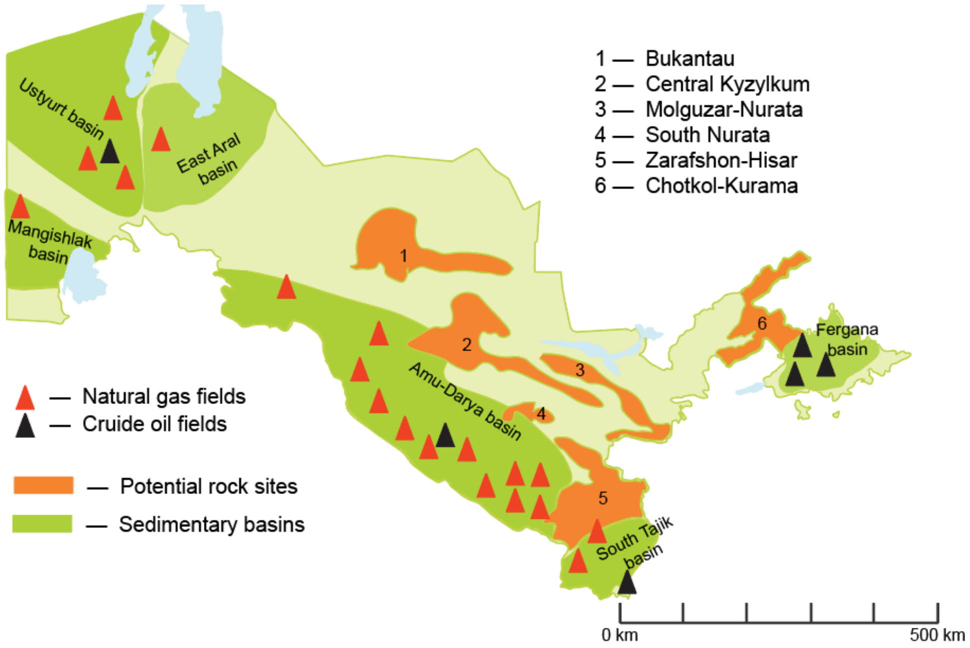

Figure 6.2. Potential sites for CO_2 sequestration and enhanced hydrocarbon recovery.

The Mangyshlak basin, part of the Middle Caspian basin, extends across Kazakhstan, Turkmenistan, and western Uzbekistan. In Uzbekistan, the Shakpakhty hydrocarbon reserve is located within this basin and includes a single gas field. Its geological structure, composed of Middle Jurassic rocks, has low oil and gas potential [22]. The Ustyurt basin, triangular in shape, lies between the Caspian and Aral Seas and spans both Kazakhstan and Uzbekistan, with over 25% of the basin located on the Ustyurt plateau in Uzbekistan. It is geologically connected to the East Aral basin through basement rocks that have undergone similar deformation and metamorphism [23]. Jurassic and younger formations continue seamlessly between these basins. In both the Ustyurt and East Aral basins, hydrocarbons are predominantly gas, with only minor oil reservoirs. The most significant potential for resource utilization within Uzbekistan lies in the saline aquifers, particularly in the Amudarya delta and the Aral Sea region.

The Surkhandarya basin, also referred to as the South Tajik basin, forms part of the larger Afghan-Tajik basin and is notable for its oil and gas hydrocarbon discoveries. Three types of petroleum traps are identified here: structural, structural-stratigraphic, and purely stratigraphic [24]. The primary oil reservoirs are associated with marine carbonate rocks and Eocene sandstones, while the main gas reservoirs are found in offshore carbonate formations. The Fergana basin, spanning Uzbekistan, Kyrgyzstan, and Tajikistan, is another critical geological feature. It holds around 70% of Uzbekistan's oil reserves, making it a key source of the country's oil production [25].

In Uzbekistan, six promising sites have been identified for in-situ CO_2 mineralization, a process that converts CO_2 into solid minerals underground, ensuring its long-term stability. These sites are geologically suitable for reactions between CO_2 and specific rock types, forming stable carbonate minerals (see Figure 6.2). The evaluation of CO_2 storage capacity in the hydrocarbon basins follows the methodology set by the Carbon Sequestration Leadership Forum (CSLF) [26], ensuring a standardized and comparable assessment across different regions. The effective CO_2 storage capacity in these reserves is determined using Equation 6.2.

$$\begin{cases} M_{CO2_{oil}} = k \cdot \rho_{CO_2} \cdot \left[\frac{RF \cdot OOIP}{VF}\right] \\ M_{CO2_{gas}} = k \cdot \rho_{CO_2} \cdot RF \cdot OGIP \cdot \left[\frac{P_s \cdot T_r \cdot Z_r}{P_r \cdot T_s \cdot Z_s}\right] \end{cases} \tag{6.2}$$

Here, M_{CO2} – the effective CO_2 storage capacity, k – the efficiency factor, ρ_{CO2} – the density of CO_2 in the reservoir, RF – the recovery factor, OOIP – the original oil in place, OGIP – the original gas in place, VF – volume factor, P – pressure, T – temperature, and Z – compressibility factor in the reservoir and surface.

The effective CO_2 storage capacity of saline aquifers is calculated following the United States Department of Energy's methodology [27]. This approach assumes that saline aquifers are part of regional flow systems, where CO_2 is predominantly contained within hydrodynamic traps. Table 6.1 provides a summary of the initial data and assumptions used in these calculations, with the effective CO_2 storage capacity determined by Equation 3.

$$M_{CO2_{aquifers}} = \alpha \cdot A \cdot \delta \cdot \varphi \cdot \rho_{CO_2} \tag{6.3}$$

where δ is the efficiency factor, A is the total area of the sedimentary basin, δ is the thickness of formation, and φ is porosity.

Uzbekistan's extensive mafic and ultramafic rock formations offer significant potential for in-situ CO_2 mineralization. However, due to incomplete studies on the country's CO_2 storage capacity in these mineral formations, this aspect was not included in the evaluations presented in this work.

Table 6.1. Initial data and assumptions for estimation of CO_2 storage capacity [4].

	Amu-Darya	Fergana	Surkhandarya	East Aral	Ustyurt	Mangyshlak
ρ_{CO2r}, kg/m^3	600	750	600	690	690	570
k	0.250	0.250	0.250	0.250	0.250	0.250
RF	0.250	0.300	0.300	0.300	0.300	0.250
VF	1.5	1.5	1.5	1.5	1.5	1.5
CF	0.005	0.005	0.0041	0.0059	0.0059	0.0041
Age	[a]	Mesozoic and Cenozoic	Paleogene	Middle Jurassic	Middle Jurassic	Triassic
φ	0.255	0.094	0.255	0.255	0.110	0.118
α, m	500	94	500	500	500	200
δ	0.0051	0.0051	0.0051	0.0051	0.0051	0.0052

[a] - Jurassic (Southwestern Hisar), Cretaceous, Mesozoic (oil and gas in Bukhara-Khiva region)

6.4. Spatial analysis procedure

A key factor influencing the cost of storing or converting captured CO_2 into value-added products is the geographical location. Positioning CO_2 sources near CO_2 sinks helps address challenges like transportation and potential leaks more effectively. Therefore, conducting a spatial analysis is crucial when planning the "CO_2 source-to-CO_2 sink" framework [28,29].

Spatial data analysis is vital for resolving issues related to the placement and distribution of objects within a geographic region. In Uzbekistan, CO_2 sources have been categorized based on their locations into various economic regions, including Fergana, Tashkent, Mirzachul, Zarafshan, Kashkadarya, Surkhandarya, and Karakalpakistan (see Figure 6.3). This regional categorization is important for optimizing CO_2 management strategies.

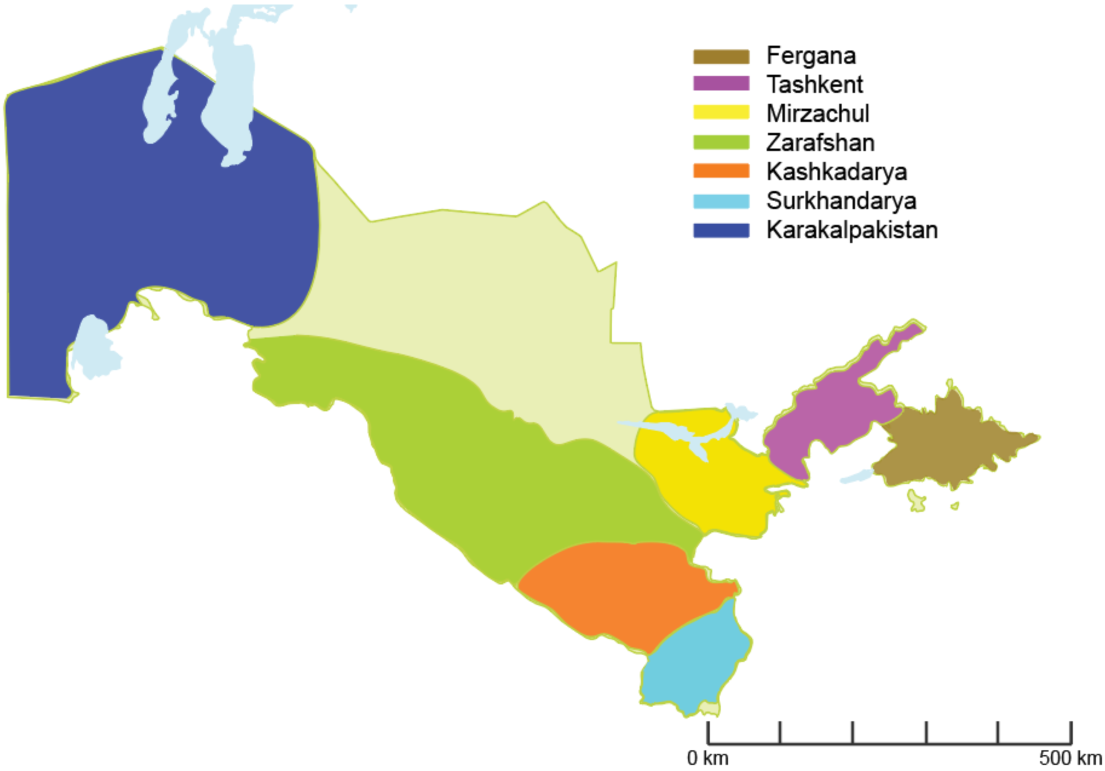

Figure 6.3. Location of economic regions in Uzbekistan [4].

Likewise, the potential for CO_2 uptake and storage in these locations has been assessed in order to identify possible CO_2 sinks. This method aids in optimising logistics and infrastructure development for effective carbon management.

6.5. Results and Discussion

6.5.1. Results and discussion of potential CO_2 sinks

In evaluating Uzbekistan's potential for CO_2 utilization and storage, several key options emerge, each with distinct capacities and challenges. A primary avenue for CO_2 utilization is through its integration into urea and methanol production. Leading facilities such as "NavoiyAzot" LLC, "Maxam Chirchik" LLC, and "Farg'onaAzot" LLC collectively utilize around 0.91 million tons (Mt) of CO_2 annually in urea production. In methanol production, "NavoiyAzot" LLC and the "Methanol Island (MTO)" facility together process approximately 2.4 Mt of CO_2 per year. Both methods are based on mature, commercially proven technologies (Technology Readiness Level 9), well-established within the country's chemical industry.

Another promising utilization pathway is biofixation, particularly relevant in the Tashkent and Fergana economic regions, with an annual capacity to absorb about 1.85 Mt of CO_2. However, biofixation poses unique challenges, including the requirement for lower CO_2 concentrations in flue gas and specific site conditions that must be carefully managed.

Geological storage offers substantial CO_2 sequestration potential, particularly through EOR, enhanced natural gas recovery (ENGR), and mineral trapping in deep saline aquifers. For instance, the Amu-Darya basin, Uzbekistan’s largest sedimentary basin, has an EOR capacity of around 13 Mt and an ENGR capacity exceeding 245 Mt. The Fergana basin, which holds the highest potential for EOR, can store around 54.16 Mt of CO_2, although its ENGR potential is less than 1 Mt. In the Surkhandarya basin, EOR capacity exceeds 5 Mt, while ENGR capacity is estimated at 19 Mt. Despite the expansive areas of the East Aral, Mangyshlak, and Ustyurt basins, their smaller oil reservoirs limit their EOR potential. However, these basins are more suited for ENGR, with a combined capacity exceeding 106.72 Mt.

The most promising long-term storage option lies in mineralization within saline aquifers. For example, the Amu-Darya basin alone has the capacity to sequester around 7.67 gigatons (Gt) of CO_2 in its saline formations. Additionally, the Fergana and Surkhandarya basins offer significant storage potential, with capacities of approximately 675 Mt and 671 Mt, respectively. Notably, the East Aral, Mangyshlak, and Ustyurt basins collectively provide the largest saline aquifer storage capacity, exceeding 25 Gt, offering stable, long-term CO_2 storage solutions for the region.

Table 6.2. Total storage capacity of the sedimentary basins [4].

<table>
<tr><th>CO_2 sinks</th><th>Amu-Darya</th><th>Fergana</th><th>Surkhan-darya</th><th>East Aral</th><th>Ustyurt</th><th>Mangyshlak</th><th>Total</th></tr>
<tr><td>EOR (Mt)</td><td>12.998</td><td>54.16</td><td>5.055</td><td>-</td><td>-</td><td>-</td><td>72.215</td></tr>
<tr><td>ENGR (Mt)</td><td>245.697</td><td>0.844</td><td>18.89</td><td colspan="3">106.72</td><td>372.151</td></tr>
<tr><td>Saline aquifers (Mt)</td><td>7670.4</td><td>675.954</td><td>671.16</td><td>9588</td><td>14025</td><td>1963.52</td><td>34594.034</td></tr>
<tr><td>Total</td><td>7929.095</td><td>730.958</td><td>695.105</td><td colspan="3">25683.24</td><td>35,038.4</td></tr>
</table>

When comparing the various CO_2 sinks available in Uzbekistan, the most mature and readily deployable options are urea and methanol production, as well as EOR, all of which have achieved a high Technology Readiness Level (TRL). While urea and methanol production are reliable and well-established methods for CO_2 utilization, their impact is somewhat limited by the relatively small size of their markets. On the other hand, CO_2 utilization potential is significantly higher in saline aquifers and ENGR, although these are less mature technologies. Additionally, geological CO_2 storage methods, including EOR and ENGR, face challenges such as potential CO_2 leakage, especially in earthquake-prone regions.

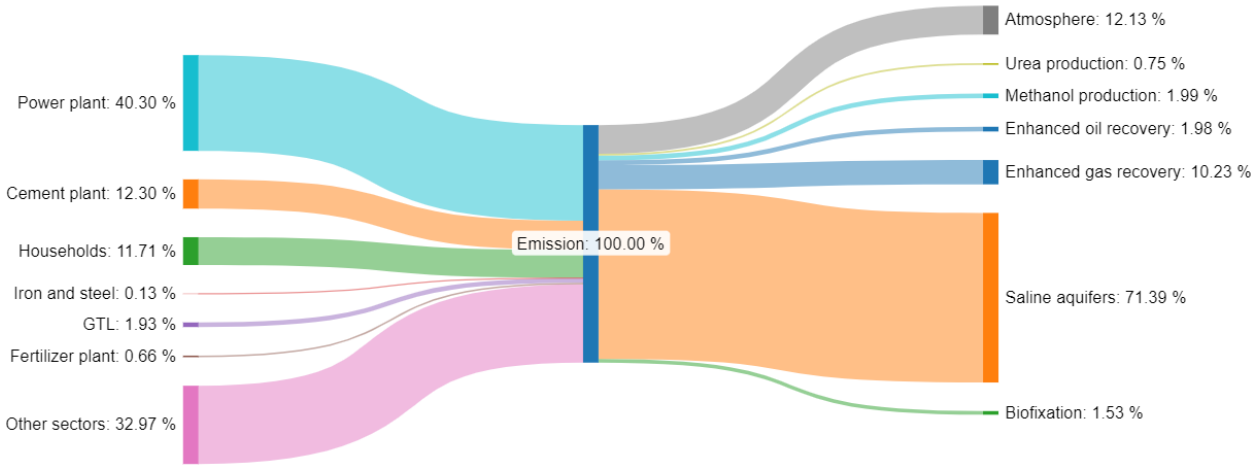

Figure 6.4. Representation of the breakdown of CO_2 emissions across various sectors in Uzbekistan, such as power plants, cement production, households, iron and steel industries, GTL plants, and fertilizer production [4].

The figure highlights how these emissions can be routed into different pathways for either utilization or storage. The key pathways include urea and methanol production, EOR, ENGR, mineralization in saline aquifers, and biofixation.

Biofixation offers environmental benefits but also requires specific conditions for successful implementation, further complicating its widespread use. Each of these methods comes with distinct advantages and challenges, underscoring the importance of adopting a diversified strategy for managing CO_2 emissions in Uzbekistan.

The next subsection will focus on analyzing the challenges of aligning CO_2 sources with sinks, considering both their geographic locations and capacities. Table 6.3 provides a preliminary assessment of each carbon sink route, considering its feasibility, potential, and technological readiness.

Table 6.3. Evaluation of CSU potential of the economic regions [4].

Region	Potential	Opportunities	Challenges
Fergana		Mature CSUs have a high potential	Transporting CO_2 from another region
Tashkent		Many sources of CO_2 are located in one line	There is no potential (or very low potential) for CSU
Mirzachul			
Zarafshan		Mature CSUs have a high potential	CO_2 leakage (low possibility)
Kashkadarya		Mature CSUs have a high potential	CO_2 leakage (very low possibility)
Surhandarya		CO_2 sources are located in the sinks	Transporting CO_2 from another region
Karakalpakistan		There are 3 hydrocarbon-rich basins	Far from CO_2 sources, CO_2 leakage
Zero	Low	Medium	Higher	High	Very high

6.5.2. Results and discussion of spatial analysis

When assessing the feasibility of CCSU for a specific region or country, a critical factor is the spatial relationship between CO_2 emission sources and potential storage or utilization sites. A preliminary spatial analysis can provide valuable insights into this relationship by visually mapping out both the major CO_2-emitting facilities and the potential storage or utilization locations, and then analyzing their proximity to one another.

This can be achieved by overlaying emission sources—such as power plants—on a map that highlights available CO_2 storage locations, including geological formations like saline aquifers or sites suited for enhanced oil or gas recovery (EOR/ENGR). By doing so, a visual understanding can emerge, offering an initial assessment of how feasible and cost-effective it would be to develop CCSU projects based on how closely the emission sources are located to the storage or utilization points.

Table 6.4 provides a comprehensive breakdown of annual CO_2 emissions from power plants across different regions in Uzbekistan. It also includes the estimated CO_2 uptake capacities through various methods such as urea and methanol production, EOR, ENGR, mineral storage in saline aquifers, and biofixation. This detailed information allows for a more accurate evaluation of each region's CCSU potential and helps identify where the greatest opportunities for emissions reduction and carbon management lie.

Table 6.4. CO_2 sources by power sector and CO_2 uptake potential of the economic regions [4].

Region	CO_2 emission power sector, Mtpa	Annual CO_2 uptake potential, Mta						
		Urea	Methanol	EOR	ENGR	Saline aquifers	Biofixaton	Total
Fergana	3.03	0.292	0	1.8	0.028	22.532	0.74	25.39
Tashkent	19.09	0.197	0	0	0	0	1.11	1.307
Mirzachul	12.21	0	0	0	0	0	0	0
Zarafshan	5.84	0.42	2.41	0.217	4.1	191.76	0	198.9
Kashkadarya	5.00	0	0	0.217	4.1	63.92	0	61.67
Surkhandarya	0	0	0	0.168	0.61	22.37	0	23.15
Karakalpakstan	2.77	0	0	0	3.56	852.55	0	856.1

6.5.3. CO_2 storage and utilization for power sector

In the context of Uzbekistan's power sector, there are 12 significant CO_2-emitting point sources, connected to six different CO_2 storage and utilization pathways. These pathways include crude oil, natural gas, and saline aquifer reservoirs, as well as urea, methanol, and algae production using CO_2. Figure 6.2 indicates that most large-scale CO_2 storage sites are concentrated in the southern regions, where oil and natural gas reserves are readily available. A visual proximity analysis can be performed to better understand the spatial relationship between CO_2 sources and sinks across Uzbekistan's seven economic zones—Fergana, Tashkent, Mirzachul, Zarafshan, Kashkadarya, Surkhandarya, and Karakalpakstan—as depicted in Figure 6.5.

In the eastern Fergana region, also known as the Fergana Valley, the geographical landscape, favorable climate, and water availability make hydropower a significant energy source. As a result, fossil fuel-based power stations in this densely populated region are relatively small [2]. The two main CO_2-emitting facilities, Turakurgan TPP and Fergana TPC, rely on natural gas, emitting over 3 Mtpa of CO_2 annually. Nearby potential CO_2 sinks, including EOR and sedimentary basins, are within a 100 km radius, making them viable targets for CO_2 storage. However, CO_2 demand from urea and algae production in the region has a minimal impact on overall sink capacity, primarily serving as supplementary options to EOR and saline aquifer storage.

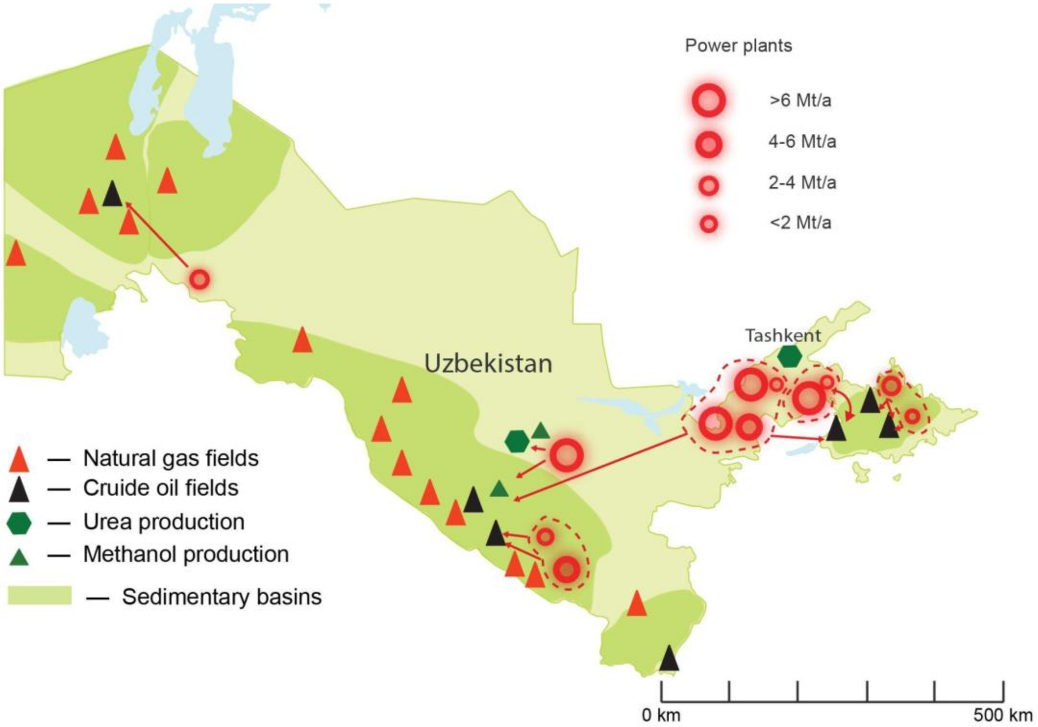

Figure 6.5. Distribution of CO_2 emission sources by power sector and potential CO_2 sinks.

In Tashkent and Mirzachul, the regions are central to Uzbekistan's power supply, responsible for nearly two-thirds of total CO_2 emissions. Four natural gas-fired TPPs/TPCs and two coal-fired TPPs dominate the emissions landscape, with more than 30 Mtpa of CO_2 emitted. However, these zones lack substantial CO_2 sinks, with urea and algae plants only accounting for a modest 1.3 Mtpa of CO_2 demand. To address this, two key mitigation strategies could be employed: (1) increasing renewable energy installations, and (2) constructing long-distance pipelines to transport CO_2 to nearby sinks in the Kashkadarya, Zarafshan, and Fergana regions. The coal-fired Angren and New Angren power plants could potentially use the eastern sedimentary basin for storage, while emissions from the Syrdarya plants might be directed toward the southwestern basins.

Moving to Zarafshan and Kashkadarya, these regions are rich in natural resources, particularly gold and natural gas. CO_2 emissions from Navoi TPP, Talimarjan TPP, and Muborak TPC are significant, with combined storage potential through ENGR exceeding 8 Mtpa. While methanol and urea production account for about 2.4 Mtpa and 0.42 Mtpa of CO_2 demand, the dominant storage option remains saline aquifers, with a storage capacity of 192 Mt in Zarafshan alone. Kashkadarya follows a similar trend, with 93% of its CO_2 sink capacity in saline aquifers and 6% in ENGR.

In the southern and western regions of Uzbekistan, Surkhandarya and Karakalpakstan stand out as the most remote areas with the lowest levels of power generation compared to other parts of the country. In Karakalpakstan, there is only one major fossil fuel-based power source, the Takhiatash natural gas-fired power plant, with a capacity of 980 MW. Despite being the largest region in Uzbekistan, most of Karakalpakstan consists of desert or semi-desert landscapes. This region also faces significant climate vulnerabilities, exacerbated by two major issues: persistent water shortages and the continued shrinking of the Aral Sea, which has become a pressing global environmental concern [30–32]. In terms of CCSU potential, Karakalpakstan holds both natural gas and oil reserves, providing substantial CO_2 storage capacity. However, one of the primary challenges lies in the significant distance between the Takhiatash power plant, a major CO_2 source, and the natural gas and oil reservoirs that could serve as sites for EOR and ENGR. Although these reservoirs are situated within the same region, the large distances involved complicate the practical implementation of EOR and ENGR techniques. Given these challenges, a viable solution for decarbonizing the region could involve either shutting down the Takhiatash plant or operating it at reduced capacity while simultaneously investing in the development of renewable energy sources, such as solar and wind, which have significant potential in the area. Regarding Surkhandarya, located in the south, this region does not have any TPP or TPC. As a result, it relies primarily on electricity supplied by the Talimarjan TPP and from transboundary power resources imported from neighboring Tajikistan [33]. This dependency highlights the region’s unique energy dynamics compared to other parts of Uzbekistan, as well as the importance of regional power interconnections for maintaining its electricity supply. Overall, in both cases, these regions' remoteness, combined with their specific environmental and energy profiles, underscores the need for carefully considered, region-specific strategies for reducing CO_2 emissions and improving energy sustainability.

6.6. Conclusion

This chapter marks the first comprehensive assessment of Uzbekistan's CSU potential, taking into account the country's resource availability and site-specific conditions. The total CO_2 storage capacities of key options—EOR, ENGR, and saline aquifers—are calculated, alongside the potential for CO_2 utilization through three primary routes: methanol and urea production, and photosynthetic biofixation. A spatial analysis has also been conducted, focusing on the proximity of CO_2 emission sources to potential storage sites, with particular emphasis on the power sector.

Uzbekistan has an impressive CSU capacity, amounting to 1,171 million tonnes of CO_2 annually, which significantly surpasses the country's yearly CO_2 emissions. Within this framework, the Tashkent and Mirzachul economic zones are the major contributors to emissions from the power sector, accounting for nearly two-thirds of these emissions. Among the available storage options, saline aquifers offer the largest CO_2 sequestration potential with a capacity of 35,000 million tonnes, followed by ENGR with 372 million tonnes and EOR with 72 million tonnes.

In the near term, CO_2-to-enhanced hydrocarbon recovery could serve as a practical approach in specific regions like Fergana, Zarafshan, Kashkadarya, and Karakalpakstan. Meanwhile, primary CO_2 emission sites, such as Tashkent and Mirzachul, can prioritize CO_2 conversion and emission reduction pathways, including renewable energy integration and other sustainable options.

Future research should focus on more detailed evaluations of resources, assessments of individual CO_2 storage and utilization technologies, and explore offshore CSU potential within Central Asia.

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Chapter VII – 7. Conclusions and Future work

7.1. Summary of conclusions

This doctoral thesis has presented a comprehensive investigation into the decarbonization pathways and carbon capture, storage, and utilization (CCSU) technologies applicable to Uzbekistan's energy sector, with a particular focus on natural gas combined cycle (NGCC) power plants. Specifically, this thesis has focused on different CCSU integration scenarios with end-of-pipe techno-economic evaluation in the case of the Turakurgan NGCC power plant located in Namangan region in the eastern part of Uzbekistan. The research has provided valuable insights into the potential of CCSU for achieving Uzbekistan's sustainability targets, while identifying key challenges and opportunities for future developments. This chapter consolidates the conclusions drawn from the corresponding objectives and results, with a brief outline of future research directions to enhance the feasibility of CCSU in Uzbekistan.

Carbon Emissions estimation in Uzbekistan and its reduction prospects

Chapter 2 of this thesis presents the first detailed evaluation of Uzbekistan's CO_2 emissions, and discusses the potential pathways for its reduction. The findings underscore the pressing need for decarbonization efforts in these sectors, particularly given their disproportionate contribution to Uzbekistan's greenhouse gas emissions.

A notable gap identified in this chapter is the lack of research and publications on Uzbekistan's decarbonization policies, highlighting a clear deficiency in the international scientific literature. This absence of research constrains the ability of both policymakers and researchers outside the region to engage with Uzbekistan's climate challenges and contributes to the country's limited visibility in global decarbonization efforts.

Uzbekistan's reliance on fossil fuels for energy generation remains a core issue, particularly given the growing demand that could exacerbate the challenges in the country's energy sector. However, the chapter identifies significant potential in transitioning to renewable energy sources, especially solar power, as an alternative to conventional fossil fuel-based industries. Despite these opportunities, current economic structures—including low electricity prices and the lack of a financial incentive for businesses and households to adopt renewable energy—pose major obstacles to progress. This lack of motivation, compounded by a broader absence of social concern for sustainability, delays meaningful action towards reducing CO_2 emissions.

The chapter also makes a compelling case for economic reform as a driver of decarbonization. Specifically, in the case of current high cost of CO_2 reduction by CCSU (average capture and storage cost of around 80-100 USD per tonne of CO_2), the introduction of a carbon tax and the liberalization of the energy market are identified as crucial steps toward fostering a more sustainable energy system. These measures would not only create financial incentives for businesses and consumers to shift towards renewable energy combined with CCSU integration but also provide the economic framework necessary to support the transition in the case of low CO_2 market.

In summary, Uzbekistan has multiple pathways toward decarbonization, but the current lack of robust sustainability policies and international financial support slows the country’s progress.

Modelling of Turakurgan NGCC Power Plant and EGR integration

Chapter 3 presents a comprehensive modelling of the Turakurgan NGCC power plant, employing Aspen Plus® software to simulate key operational parameters and evaluate the integration of Exhaust Gas Recirculation (EGR) as a precursor to CCSU.

The introduction of EGR into the NGCC power plant’s operations resulted in notable improvements in the plant’s ability to concentrate CO_2 within the flue gas, from an initial 3.96 mol% to 7.32 mol%. This higher concentration of CO_2 is particularly advantageous for capture technologies, thereby improving the cost-effectiveness of the capture system. Simultaneously, EGR reduced the mass flow of the flue gas by 45%, which further contributes to more efficient CO_2 capture by lessening the strain on downstream equipment and systems designed for gas handling and separation.

However, this operational improvement did come with a slight trade-off. The incorporation of EGR into the system reduced the output of the gas turbine, one of the power plant’s primary energy-generating components. Despite this decrease in gas turbine efficiency, the overall performance of the plant was not compromised, as the increased output from the steam cycle compensated for the shortfall. The enhanced steam cycle, driven by the heat generated through EGR, allowed the plant to maintain stable energy production levels, ensuring that the benefits of CO_2 capture were realized without significant losses in total plant efficiency. This underscores the viability of integrating

EGR into NGCC plants without severely impacting their economic or operational sustainability.

A key outcome of the analysis was the identification of an optimal EGR ratio. After simulating various scenarios, the study concluded that an EGR ratio of 0.45 strikes the best balance between maximizing CO_2 concentration in the flue gas and minimizing the negative impact on turbine output. This finding is particularly important as it provides a clear operational guideline for future implementation of EGR in similar power plants, ensuring that both environmental and economic objectives can be met.

End-of-Pipe CCSU by MEA Absorption

Chapter 4 investigates the integration of Monoethanolamine (MEA)-based carbon capture technology in a Turakurgan NGCC power plant, focusing on an end-of-pipe approach to capture CO_2 emissions, compression, transportation, and subsequent storage. This study highlights both the potential benefits and challenges of employing such technology within Uzbekistan's energy sector.

A key outcome is the significant CO_2 reduction achievable through a 90% capture rate, equating to approximately 1.05 million tonnes of CO_2 annually. This represents a substantial step toward reducing Uzbekistan's carbon emissions. Notably, the study identifies a 40% MEA solvent concentration as the most energy-efficient, surpassing the performance of lower concentrations. This higher concentration enhances absorption, leading to a reduced energy input for solvent regeneration, which is critical for improving economic viability.

Moreover, the research underscores the importance of optimizing CO_2 compression and dehydration processes, integration water wash section and CO_2 stream dehydration to meet the current standards for MEA emissions crucial for transport and storage. By utilizing an efficient compression strategy, the system can save notable energy input, improving overall energy efficiency. Despite these gains, the study finds that the energy demand for CO_2 regeneration remains substantial, even with an optimized case reboiler duty of 3.97 GJ per tonne of CO_2. This high energy consumption poses a challenge to the cost-effective implementation of carbon capture, especially given the low market price of CO_2 in Uzbekistan.

Techno-Economic Comparative Analysis of CCSU Configurations

Chapter 5 presents a detailed techno-economic comparative analysis of eight different CCSU configurations for the Turakurgan NGCC power plant, evaluating the performance of MEA absorption, membrane separation, and hybrid systems.

Among the configurations analyzed, SEGR (Selective Exhaust Gas Recirculation) combined with MEA absorption emerged as the most promising option. This setup achieved the optimal balance between energy consumption and capture efficiency, making it the most viable for large-scale deployment. It offered the lowest energy penalty (4.91%) and minimal levelized cost of electricity (LCOE) at a slight over 70 USD/t CO_2, proving to be the most cost-effective solution for reducing CO_2 emissions while maintaining operational stability. In contrast, membrane-only systems were less favorable, primarily due to their high energy requirements and efficiency drop (11.05% and 17.98% with and without EGR integration). These systems, while technologically advanced, are not yet practical for NGCC plants due to their significant energy penalties and cost implications.

The analysis also explored hybrid configurations that combine membrane technologies with MEA absorption with and without EGR. Although these configurations showed some improvements, they still lagged behind the SEGR-absorption or SEGR membrane system in terms of overall efficiency (12-19%) and cost-effectiveness with almost double LCOE without EGR compared to SEGR absorption.

Overall, SEGR integration into both absorption and membrane systems shows much better performance than standalone/hybrid cases or benchmark MEA absorption. With the currect maturity of commercial polymeric membranes such as Polaris™ used in this study, SEGR with amine absorption can be the first option to further investigation of its implementation at larger scale in Uzbekistan.

Potential Carbon Sinks in Uzbekistan

For the first time, this research provided a detailed assessment of Uzbekistan's carbon storage potential, estimating a total capacity of 1171 million tonnes of CO_2 annually. Saline aquifers were identified as the most significant potential sinks, followed by Enhanced Gas Recovery (EGR) and Enhanced Oil Recovery (EOR). Furthermore, CO_2-

based methanol production and biofixation using algae were identified as promising utilization routes, with capacities of 2.4 Mt and 1.85 Mt of CO_2 per year, respectively.

The spatial analysis highlighted logistical challenges in transporting CO_2 from major emission sources to storage sites, particularly given the geographical distribution of storage capacities. Despite these challenges, the integration of CCSU remains a crucial component of Uzbekistan's decarbonization strategy, particularly in the context of its continued reliance on fossil fuels for power generation.

7.2 Future Work

Based on the findings of this thesis, several areas for future research and development have been identified:

Optimization of Carbon Capture Technologies

Although this research demonstrated the feasibility of integrating CCSU into Uzbekistan's NGCC power plants, the energy demand of current carbon capture technologies remains a critical barrier to widespread adoption. Future work should prioritize the development of more energy-efficient capture processes, including the use of advanced solvents, sorbents, and membrane technologies. Investigating novel CO_2 utilization routes, such as biofixation or mineralization, could also provide additional pathways for reducing the environmental and economic costs of CCSU.

CO_2 Storage and Utilization in Central Asia

While this research provided a preliminary assessment of Uzbekistan's CO_2 storage potential, more detailed studies are required to assess the long-term viability of these sites, particularly saline aquifers and EOR/EGR fields. Future studies should also explore offshore CO_2 storage options in the Caspian Sea, as well as collaborative storage initiatives with neighboring countries in Central Asia. Additionally, further work is needed to improve the efficiency of CO_2-based product manufacturing, such as methanol and urea production, as part of a circular economy approach.

Economic and Policy Frameworks

One of the significant challenges identified in this research is the lack of a supportive regulatory and economic framework for CCSU in Uzbekistan. Future work should focus on developing policy recommendations that incentivize CCSU adoption, such as carbon pricing mechanisms, subsidies for renewable energy, and investment in CCSU infrastructure. Collaborating with international partners and leveraging Uzbekistan's strategic location for cross-border energy trade could provide additional economic benefits and accelerate decarbonization efforts.

Integration of Renewable Energy Sources

As RES becomes more cost-competitive, future research should explore the integration of solar and wind power with CCSU systems to further reduce the carbon footprint of Uzbekistan's power sector. Hybrid systems combining RES with CCSU technologies could provide a flexible solution for balancing energy demand while reducing emissions.

Public Awareness and Education

A critical obstacle to decarbonization in Uzbekistan is the current lack of social awareness and political will. Future efforts should focus on raising public awareness about the benefits of CCSU and the importance of transitioning to a low-carbon economy. Engaging stakeholders from the public and private sectors will be essential for building the social and political support necessary for large-scale CCSU deployment.

In conclusion, this thesis has laid the groundwork for the integration of CCSU in Uzbekistan's power sector, but significant work remains to achieve the country's decarbonization goals. By addressing the technical, economic, and social challenges identified in this research, Uzbekistan can pave the way for a more sustainable and resilient energy future.

Capítulo VII – 7. Conclusiones y trabajo futuro

7.1. Resumen de conclusiones

Esta tesis doctoral ha presentado una investigación exhaustiva sobre las vías de descarbonización y las tecnologías de captura, almacenamiento y utilización de carbono (CCSU) aplicables al sector energético de Uzbekistán, con un enfoque particular en las plantas de ciclo combinado de gas natural (NGCC). Específicamente, esta tesis se ha centrado en diferentes escenarios de integración de CCSU con una evaluación tecno-económica al final del proceso en el caso de la planta de ciclo combinado de gas natural de Turakurgan, ubicada en la región de Namangan, en el este de Uzbekistán. La investigación ha proporcionado valiosas perspectivas sobre el potencial de CCSU para alcanzar los objetivos de sostenibilidad de Uzbekistán, al tiempo que identifica los principales desafíos y oportunidades para futuros desarrollos. Este capítulo consolida las conclusiones derivadas de los objetivos y resultados correspondientes, con un breve resumen de las futuras direcciones de investigación para mejorar la viabilidad de CCSU en Uzbekistán.

Estimación de emisiones de carbono en Uzbekistán y perspectivas de reducción

El capítulo 2 de esta tesis presenta la primera evaluación detallada de las emisiones de CO_2 en Uzbekistán y discute las posibles vías para su reducción. Los hallazgos subrayan la urgente necesidad de esfuerzos de descarbonización en estos sectores, dado su desproporcionada contribución a las emisiones de gases de efecto invernadero de Uzbekistán.

Un vacío notable identificado en este capítulo es la falta de investigaciones y publicaciones sobre las políticas de descarbonización en Uzbekistán, destacando una clara deficiencia en la literatura científica internacional. Esta ausencia de investigación limita la capacidad tanto de los responsables de las políticas como de los investigadores fuera de la región para involucrarse con los desafíos climáticos de Uzbekistán y contribuye a la limitada visibilidad del país en los esfuerzos globales de descarbonización.

La dependencia de Uzbekistán de los combustibles fósiles para la generación de energía sigue siendo un problema central, especialmente dado el creciente aumento de la demanda, lo que podría agravar los desafíos en el sector energético del país. Sin embargo, el capítulo identifica un potencial significativo en la transición hacia fuentes de energía renovable, especialmente la solar, como una alternativa a las industrias convencionales basadas en combustibles fósiles. A pesar de estas oportunidades, las estructuras económicas actuales, incluidos los bajos precios de la electricidad y la falta de incentivos financieros para que las empresas y los hogares adopten energía renovable, representan importantes obstáculos para el progreso. Esta falta de motivación, sumada a la ausencia general de preocupación social por la sostenibilidad, retrasa la acción significativa hacia la reducción de las emisiones de CO_2.

El capítulo también presenta un argumento convincente para la reforma económica como motor de la descarbonización. Específicamente, en el caso del alto costo actual de la reducción de CO_2 mediante CCSU (con un costo promedio de captura y almacenamiento de entre 80 y 100 USD por tonelada de CO_2), la introducción de un impuesto al carbono y la liberalización del mercado energético se identifican como pasos cruciales hacia la creación de un sistema energético más sostenible. Estas medidas no solo crearían incentivos financieros para que las empresas y los consumidores cambien hacia la energía renovable combinada con la integración de CCSU, sino que también proporcionarían el marco económico necesario para apoyar la transición en el caso de un mercado de CO_2 bajo.

En resumen, Uzbekistán tiene múltiples vías hacia la descarbonización, pero la actual falta de políticas de sostenibilidad sólidas y apoyo financiero internacional ralentiza el progreso del país.

Modelado de la planta de ciclo combinado de gas natural (NGCC) de Turakurgan e integración de EGR

El capítulo 3 presenta un modelado exhaustivo de la planta NGCC de Turakurgan, empleando el software Aspen Plus® para simular los parámetros operativos clave y evaluar la integración de la Recirculación de Gases de Escape (EGR) como un precursor para CCSU.

La introducción de EGR en las operaciones de la planta NGCC resultó en mejoras notables en la capacidad de la planta para concentrar el CO_2 dentro de los gases de escape, de un 3,96 mol% inicial a un 7,32 mol%. Esta mayor concentración de CO_2 es particularmente ventajosa para las tecnologías de captura, mejorando así la rentabilidad del sistema de captura. Al mismo tiempo, la EGR redujo el flujo másico de los gases de escape en un 45%, lo que contribuye aún más a una captura más eficiente de CO_2 al reducir la carga sobre el equipo y los sistemas aguas abajo diseñados para el manejo y la separación de gases.

Sin embargo, esta mejora operativa conllevó un ligero compromiso. La incorporación de EGR en el sistema redujo la producción de la turbina de gas, uno de los componentes principales generadores de energía de la planta. A pesar de esta disminución en la eficiencia de la turbina de gas, el rendimiento general de la planta no se vio comprometido, ya que el aumento en la salida del ciclo de vapor compensó la reducción. El ciclo de vapor mejorado, impulsado por el calor generado a través de la EGR, permitió que la planta mantuviera niveles estables de producción de energía, asegurando que los beneficios de la captura de CO_2 se lograran sin pérdidas significativas en la eficiencia total de la planta. Esto subraya la viabilidad de integrar EGR en plantas NGCC sin afectar gravemente su sostenibilidad económica u operativa.

Un resultado clave del análisis fue la identificación de una relación óptima de EGR. Tras simular varios escenarios, el estudio concluyó que una relación EGR de 0,45 proporciona el mejor equilibrio entre maximizar la concentración de CO_2 en los gases de escape y minimizar el impacto negativo en la producción de la turbina. Este hallazgo es particularmente importante, ya que proporciona una clara directriz operativa para la futura implementación de EGR en plantas similares, asegurando que tanto los objetivos ambientales como los económicos puedan cumplirse.

Captura de CO_2 mediante absorción con MEA

El capítulo 4 investiga la integración de la tecnología de captura de carbono basada en Monoetanolamina (MEA) en la planta NGCC de Turakurgan, centrándose en un enfoque de "final de tubería" para capturar las emisiones de CO_2, su compresión, transporte y posterior almacenamiento. Este estudio resalta tanto los beneficios potenciales como los desafíos de emplear dicha tecnología dentro del sector energético de Uzbekistán.

Un resultado clave es la reducción significativa de CO_2 que se puede lograr a través de una tasa de captura del 90%, lo que equivale a aproximadamente 1,05 millones de toneladas de CO_2 anualmente. Esto representa un paso importante hacia la reducción de las emisiones de carbono en Uzbekistán. Específicamente, el estudio identifica una concentración de solvente de MEA al 40% como la más eficiente en términos energéticos, superando el rendimiento de concentraciones más bajas. Esta mayor concentración mejora la absorción, lo que lleva a una reducción en la entrada de energía necesaria para la regeneración del solvente, algo crucial para mejorar la viabilidad económica.

Además, la investigación subraya la importancia de optimizar los procesos de compresión y deshidratación de CO_2, integrando una sección de lavado de agua y la deshidratación del flujo de CO_2 para cumplir con los estándares actuales. Al utilizar una estrategia de compresión eficiente, el sistema puede ahorrar una cantidad notable de energía, mejorando la eficiencia energética general. A pesar de estos avances, el estudio concluye que la demanda de energía para la regeneración de CO_2 sigue siendo considerable, incluso con un caso optimizado la energía requerida del rehervidor es de 3,97 GJ por tonelada de CO_2. Este alto consumo de energía supone un desafío para la implementación rentable de la captura de carbono, especialmente dado el bajo precio de mercado del CO_2 en Uzbekistán.

Análisis tecnoeconómico comparativo de configuraciones CCSU

El capítulo 5 presenta un análisis tecnoeconómico comparativo detallado de ocho configuraciones diferentes de CCSU para la planta NGCC de Turakurgan, evaluando el rendimiento de la absorción de MEA, la separación por membrana y los sistemas híbridos.

Entre las configuraciones analizadas, la Recirculación Selectiva de Gases de Escape (SEGR) combinada con absorción de MEA resultó ser la opción más prometedora. Esta configuración alcanzó el equilibrio óptimo entre consumo de energía y eficiencia de captura, lo que la convierte en la más viable para su implementación a gran escala. Ofreció la penalización energética más baja (4.91%) y el menor costo nivelado de electricidad (LCOE) con un poco más de 70 USD/t de CO_2, lo que la convierte en la solución más rentable para reducir las emisiones de CO_2 mientras se mantiene la estabilidad operativa. En contraste, los sistemas basados únicamente en membranas fueron menos favorables, principalmente debido a sus altos requisitos energéticos y la caída de eficiencia (11,05% y 17,98% con y sin integración de EGR). Estos sistemas, aunque tecnológicamente avanzados, aún no son prácticos para plantas NGCC debido a sus significativas penalizaciones energéticas e implicaciones de costos.

El análisis también exploró configuraciones híbridas que combinan tecnologías de membrana con absorción de MEA, con y sin EGR. Aunque estas configuraciones mostraron algunas mejoras, todavía estaban por detrás del sistema SEGR-absorción o del sistema SEGR-membrana en términos de eficiencia general (12-19%) y rentabilidad, con casi el doble de LCOE sin EGR en comparación con la absorción SEGR.

En general, la integración de SEGR en ambos sistemas, de absorción y membrana, muestra un mejor rendimiento que los casos autónomos/híbridos o la absorción de MEA estándar. Con la madurez actual de las membranas poliméricas comerciales, como Polaris™ utilizada en este estudio, SEGR con absorción de aminas puede ser la primera opción para una investigación más profunda sobre su implementación a mayor escala en Uzbekistán.

Potenciales sumideros de carbono en Uzbekistán

Por primera vez, esta investigación proporcionó una evaluación detallada del potencial de almacenamiento de carbono en Uzbekistán, estimando una capacidad total de 1171 millones de toneladas de CO_2 anuales. Los acuíferos salinos se identificaron como los sumideros más significativos, seguidos por la Recuperación Mejorada de Gas (EGR) y la Recuperación Mejorada de Petróleo (EOR). Además, se identificaron como rutas prometedoras de utilización la producción de metanol basada en CO_2 y la biofijación utilizando algas, con capacidades de 2,4 millones de toneladas y 1,85 millones de toneladas de CO_2 por año, respectivamente.

El análisis espacial destacó desafíos logísticos en el transporte de CO_2 desde las principales fuentes de emisión hacia los sitios de almacenamiento, particularmente dada la distribución geográfica de las capacidades de almacenamiento. A pesar de estos desafíos, la integración de CCSU sigue siendo un componente crucial de la estrategia de descarbonización de Uzbekistán, especialmente en el contexto de su continua dependencia de los combustibles fósiles para la generación de energía.

7.2. Trabajo futuro

Basado en los hallazgos de esta tesis, se han identificado varias áreas para la investigación y el desarrollo futuros:

Optimización de tecnologías de captura de carbono

Aunque esta investigación demostró la viabilidad de integrar CCSU en las plantas NGCC de Uzbekistán, la demanda de energía de las tecnologías actuales de captura de carbono sigue siendo una barrera crítica para su adopción generalizada. El trabajo futuro debería priorizar el desarrollo de procesos de captura más eficientes en términos de energía, incluyendo el uso de solventes avanzados, adsorbentes y tecnologías de membranas. Investigar nuevas rutas de utilización de CO_2, como la biofijación o la mineralización, también podría proporcionar vías adicionales para reducir los costos ambientales y económicos de CCSU.

Almacenamiento y utilización de CO_2 en Asia Central

Si bien esta investigación proporcionó una evaluación preliminar del potencial de almacenamiento de CO_2 en Uzbekistán, se requieren estudios más detallados para evaluar la viabilidad a largo plazo de estos sitios, particularmente los acuíferos salinos y los campos de EOR/EGR. Los estudios futuros también deberían explorar opciones de almacenamiento de CO_2 en alta mar en el Mar Caspio, así como iniciativas de almacenamiento colaborativo con los países vecinos de Asia Central. Además, es necesario realizar más trabajos para mejorar la eficiencia de la fabricación de productos basados en CO_2, como la producción de metanol y urea, como parte de un enfoque de economía circular.

Marcos económicos y de políticas

Uno de los desafíos significativos identificados en esta investigación es la falta de un marco regulatorio y económico que apoye CCSU en Uzbekistán. El trabajo futuro debería centrarse en desarrollar recomendaciones políticas que incentiven la adopción de CCSU, como mecanismos de precios del carbono, subsidios para energías renovables e inversión en infraestructura de CCSU. Colaborar con socios internacionales y aprovechar la ubicación estratégica de Uzbekistán para el comercio de energía transfronterizo podría proporcionar beneficios económicos adicionales y acelerar los esfuerzos de descarbonización.

Integración de fuentes de energía renovable (RES)

A medida que las fuentes de energía renovable (RES) se vuelven más competitivas en términos de costos, la investigación futura debería explorar la integración de la energía solar y eólica con los sistemas CCSU para reducir aún más la huella de carbono del sector energético de Uzbekistán. Los sistemas híbridos que combinan RES con tecnologías CCSU podrían proporcionar una solución flexible para equilibrar la demanda energética mientras se reducen las emisiones.

Conciencia pública y educación

Un obstáculo crítico para la descarbonización en Uzbekistán es la falta actual de conciencia social y voluntad política. Los esfuerzos futuros deberían centrarse en aumentar la conciencia pública sobre los beneficios de CCSU y la importancia de la transición hacia una economía baja en carbono. Involucrar a los actores de los sectores público y privado será esencial para construir el apoyo social y político necesario para la implementación a gran escala de CCSU.

En conclusión, esta tesis ha sentado las bases para la integración de CCSU en el sector energético de Uzbekistán, pero aún queda mucho trabajo por hacer para alcanzar los objetivos de descarbonización del país. Al abordar los desafíos técnicos, económicos y sociales identificados en esta investigación, Uzbekistán puede allanar el camino hacia un futuro energético más sostenible y resiliente.

This doctoral thesis consists of a compilation of six articles, where I am the first or co-first author, published in international scientific journals that complies with the guidelines established by the Department of Chemical and Biomolecular Engineering at the University of Cantabria.

The articles published in peer reviewer journals:

1. **Kamolov, A**.; Turakulov, Z.; Rejabov, S.; Díaz-Sainz, G.; Gómez-Coma, L.; Norkobilov, A.; Fallanza, M.; Irabien, A. Decarbonization of Power and Industrial Sectors: The Role of Membrane Processes. *Membranes* **2023**, *13*, 130, doi:10.3390/membranes13020130 (Published under co-first authorship).

2. Turakulov, Z.; **Kamolov, A**.; Norkobilov, A.; Variny, M.; Díaz-Sainz, G.; Gómez-Coma, L.; Fallanza, M. Assessing Various CO_2 Utilization Technologies: A Brief Comparative Review. *J. Chem. Technol. Biotechnol.* **2024**, *99*, 1291–1307, doi:10.1002/jctb.7606 (Published under co-first authorship).

3. Turakulov, Z.; **Kamolov, A**.; Norkobilov, A.; Variny, M.; Fallanza, M. Assessment of CO_2 Emission and Decarbonization Measures in Uzbekistan. *Int. J. Environ. Res.* **2024**, *18*, 28, doi:10.1007/s41742-024-00578-6 (Published under co-first authorship).

4. **Kamolov, A**.; Turakulov, Z.; Furda, P.; Variny, M.; Norkobilov, A.; Fallanza, M. Techno-Economic Feasibility Analysis of Post-Combustion Carbon Capture in an NGCC Power Plant in Uzbekistan. *Clean Technol.* **2024**, *6*, 1357–1388, doi:10.3390/cleantechnol6040065.

5. Turakulov, Z.; **Kamolov, A**.; Norkobilov, A.; Variny, M.; Fallanza, M. Techno-Economic and Environmental Analysis of Decarbonization Pathways for Cement Plants in Uzbekistan. *Chem. Eng. Res. Des.* **2024**, *210*, 625–637, doi:10.1016/j.cherd.2024.09.003.

The articles in submitted and under review status:

1. "Techno-Economic Comparative Analysis of Absorption, Membrane, and Hybrid Carbon Capture Technologies in NGCC Power Plant" – a research paper manuscript completed to submit to the *Journal of Chemical Technology and Biotechnology*, MDPI.

Authors: **Azizbek Kamolov**, Zafar Turakulov, Adham Norkobilov, Miroslav Variny, Marcos Fallanza.

2. "Regional Resource Evaluation and Distribution for Onshore Carbon Dioxide Storage and Utilization in Uzbekistan" – a research paper submitted to the journal of *Greenhouse Gases: Science and Technology*, Wiley (written under co-first authorship). (Status – under review)

Authors: **Azizbek Kamolov**, Zafar Turakulov, Adham Norkobilov, Miroslav Variny, Marcos Fallanza. (Pre-print: doi:10.21203/rs.3.rs-4557437/v1)

The conference proceedings published in peer reviewed journals:

1. **Kamolov, A**.; Turakulov, Z.; Avezov, T.; Norkobilov, A.; Variny, M.; Fallanza, M. Carbon Capture and Utilization through Biofixation: A Techno-Economic Analysis of a Natural Gas-Fired Power Plant. *Eng. Proc*. **2024**, 67, 55. doi:10.3390/engproc2024067055

2. **Kamolov, A**.; Turakulov, Z.; Norkobilov, A.; Variny, M.; Fallanza, M. Evaluation of Potential Carbon Dioxide Utilization Pathways in Uzbekistan. *Eng. Proc.* **2023**, *56*, 194, doi:10.3390/ASEC2023-15503.

3. **Kamolov, A**.; Turakulov, Z.; Norkobilov, A.; Variny, M.; Fallanza, M. Decarbonization Challenges and Opportunities of Power Sector in Uzbekistan: A Simulation of Turakurgan Natural Gas-Fired Combined Cycle Power Plant with Exhaust Gas Recirculation. *Eng. Proc.* **2023**, *37*, 24, doi:10.3390/ECP2023-14648.

4. Turakulov, Z.; **Kamolov, A**.; Norkobilov, A.; Variny, M.; Fallanza, M. Enhancing Sustainability and Energy Savings in Cement Production via Waste Heat Recovery. *Eng. Proc*. **2024**, 67, 11. doi:10.3390/engproc2024067011

5. Turakulov, Z.; **Kamolov, A.**; Eshbobaev, J.; Turakulov, A.; Norkobilov, A.; Boboyorov, R. Modeling and Simulation of Chemical Absorption Methods for CO_2 Separation from Cement Plant Flue Gases. *Eng. Proc*. **2023**, 56, 142. doi:10.3390/ASEC2023-15352

6. Turakulov, Z.; **Kamolov, A**.; Turakulov, A.; Norkobilov, A.; Fallanza, M. Assessment of the Decarbonization Pathways of the Cement Industry in Uzbekistan. *Eng. Proc.* **2023**, *37*, 2, doi:10.3390/ECP2023-14639.

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Participation in national and international conferences, symposiums and seminars:

1. “International conference on Actual problems of innovative technologies in the development of chemical, petroleum-gas, and the food processing industry in 2021” devoted to the 30-year anniversary of the Tashkent Institute of Chemical Technology;

2. “6th International Symposium On Green and Smart Technologies for A Sustainable Society” (December, 2021, University of Cantabria).

3. International scientific and practical conference of “Modern problems of ecology, environmental protection, and biotechnology” – held in Tashkent Institute of Chemical Technology in June 15-16, 2021, Tashkent, Uzbekistan.

4. “The 2nd International Electronic Conference on Processes - Process Engineering” (May, 2023, MDPI Processes). Title: “Decarbonization challenges and opportunities of power sector in Uzbekistan: A simulation of Turakurgan natural gas-fired combined cycle power plant with exhaust gas recirculation (English)”;

5. “The 4th International Electronic Conference on Applied Sciences” (October, 2023, MDPI Applied Science). Title: “Evaluation of potential carbon dioxide utilization pathways in Uzbekistan”;

6. “The 3rd International Electronic Conference on Processes —Green and Sustainable Process Engineering and Process Systems Engineering (ECP 2024)” (May, 2024, MDPI, Processes). Title: “Carbon Capture and Utilization through Biofixation: ATechno-Economic Analysis of a Natural Gas-Fired Power Plant” (Poster);

7. “49th International conference of Slovak Society of Chemical Engineering – SSCHE 2023” (May, 2023, Slovak Society of Chemical Engineering and European Federation of Chemical Engineering). Title: “Simulation and analysis of absorption with MEA process for CO_2 capture in the case of Turakurgan NGCC power station” (Lecturer).