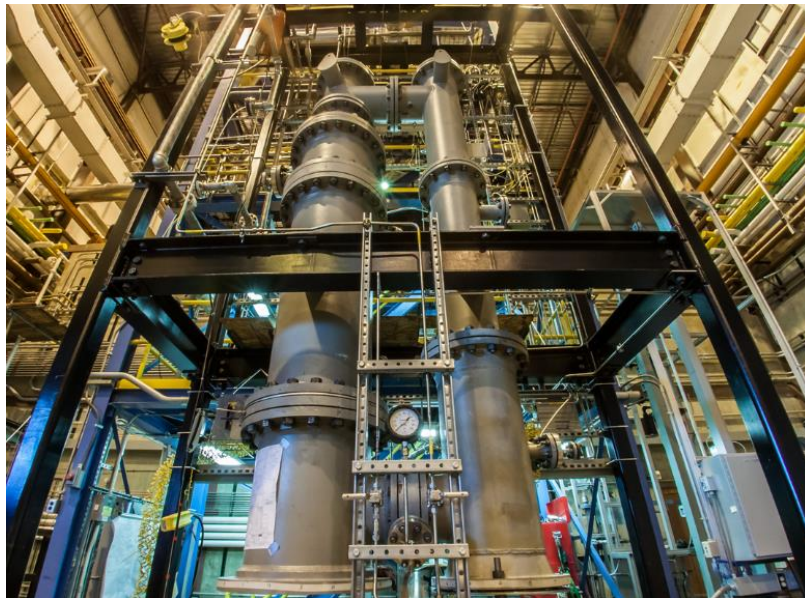




NATIONAL ENERGY TECHNOLOGY LABORATORY



Modular CO₂ Capture Processes for Integration with Modular Scale Gasification Technologies: Literature Review and Gap Analysis for Future R&D

1 October 2020



U.S. DEPARTMENT OF
ENERGY



NATIONAL
ENERGY
TECHNOLOGY
LABORATORY

Office of Fossil Energy

DOE/NETL-2020/2149

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference therein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed therein do not necessarily state or reflect those of the United States Government or any agency thereof.

Cover Illustration: The Chemical Looping Reactor in Morgantown, West Virginia. One demonstration site for NETL's research on Radically Engineered Modular Systems.

Suggested Citation: Smith, K.; Chen, S.; Siefert, N. *Modular CO₂ Capture Processes for Integration with Modular Scale Gasification Technologies: Literature Review and Gap Analysis for Future R&D*; DOE/NETL-2020.2149; NETL Technical Report Series; U.S. Department of Energy, National Energy Technology Laboratory: Pittsburgh, PA, 2020; p 136. DOI: 10.2172/1668758.

Modular CO₂ Capture Processes for Integration with Modular Scale Gasification Technologies: Literature Review and Gap Analysis for Future R&D

Kathryn Smith¹, Scott Chen¹, Nicholas Siefert²

¹ Carbon Capture Scientific, P.O. Box 188 4000 Brownsville Road, South Park, PA 15129

² U.S. Department of Energy, National Energy Technology Laboratory, 626 Cochrans Mill Road, Pittsburgh, PA 15236

DOE/NETL-2020/2149

1 October 2020

NETL Contacts:

Nicholas Siefert, Principal Investigator

David Hopkinson, Technical Portfolio Lead

Randall Gemmen, Associate Director

Bryan Morreale, Executive Director, Research & Innovation Center

This page intentionally left blank.

Table of Contents

EXECUTIVE SUMMARY.....	1
1. GASIFICATION MARKET AND TECHNOLOGY REVIEW.....	4
1.1 GASIFICATION MARKET.....	4
1.2 GASIFICATION TECHNOLOGY.....	12
1.3 CONCLUDING REMARKS ON GASIFICATION	28
2. LITERATURE REVIEW ON PRE-COMBUSTION CARBON CAPTURE TECHNOLOGIES WITH POTENTIAL FOR USE WITH MODULAR GASIFICATION SYSTEMS.....	29
2.1 SOLVENT-BASED PROCESSES FOR PRE-COMBUSTION CO ₂ CAPTURE	32
2.2 SORBENT-BASED PROCESSES FOR PRE-COMBUSTION CO ₂ CAPTURE.....	38
2.3 MEMBRANE-BASED PROCESSES FOR PRE-COMBUSTION CO ₂ CAPTURE	44
2.4 INTEGRATED PROCESSES FOR PRE-COMBUSTION CO ₂ CAPTURE.....	52
2.5 HYBRID PROCESSES FOR PRE-COMBUSTION CO ₂ CAPTURE	58
2.6 CONCLUDING REMARKS ON MODULAR PRE-COMBUSTION CO ₂ CAPTURE.....	65
3. THERMODYNAMIC PERFORMANCE OF SELECTED PRE-COMBUSTION CO₂ CAPTURE TECHNOLOGIES.....	68
3.1 SELECTED CO ₂ CAPTURE TECHNOLOGIES	68
3.2 METHODOLOGIES USED TO ASSESS THERMODYNAMIC PERFORMANCE ..	68
3.3 ENERGY PERFORMANCE OF DIFFERENT CO ₂ CAPTURE TECHNOLOGIES ...	71
3.4 RESULTS AND DISCUSSION	82
4. ECONOMIC ANALYSIS OF MODULAR SCALE PRE-COMBUSTION CARBON CAPTURE TECHNOLOGIES.....	84
4.1 ECONOMIC ANALYSIS OF A SELEXOL-BASED SOLVENT ABSORPTION PROCESS FOR PRE-COMBUSTION CARBON CAPTURE AT FULL SCALE AND MODULAR SCALE.....	84
4.2 REVIEW OF THE NETL COST AND PERFORMANCE BASELINE REPORT CASE B5B (IGCC POWER PLANT WITH PRE-COMBUSTION CO ₂ CAPTURE USING SELEXOL SOLVENT ABSORPTION)	89
4.3 CONCLUDING COMMENTS ON THE ECONOMICS OF MODULAR PRE- COMBUSTION CARBON CAPTURE PROCESSES.....	94
5. CONCLUSIONS.....	95
6. REFERENCES.....	101
APPENDIX A: IGCC PROCESS DESCRIPTION.....	A-1
APPENDIX B: NETL EXTERNAL R&D AWARDS - GASIFICATION RESEARCH PROGRAM.....	B-1
APPENDIX C: NETL EXTERNAL R&D AWARDS - PRE-COMBUSTION CO₂ CAPTURE RESEARCH.....	C-1

List of Figures

Figure 1: Global syngas usage by application (Global Syngas Technologies Council, 2019).	6
Figure 2: Products available from gasification processes (Kerester, 2014).	7
Figure 3: Global syngas capacity and growth including planned, operating, and under construction gasification power plants (Global Syngas Technologies Council, 2019).	8
Figure 4: Global syngas usage by geographic region (Global Syngas Technologies Council, 2019).	8
Figure 5: Products that can be produced from a polygeneration process using coal gasification (NETL, 2019d).	10
Figure 6: Gasification feedstock variation (Global Syngas Technologies Council, 2019).	11
Figure 7: Schematics of the main types of commercial gasifiers (NETL, 2019c).	14
Figure 8: Process flow diagram of IGCC power plant without CO ₂ capture (Wolfersdorf and Meyer, 2017).	20
Figure 9: Process flow diagram of IGCC power plant with CO ₂ capture (Wolfersdorf and Meyer, 2017).	20
Figure 10: Gasification process for coal and other feedstock as well as the wide range of products provided by gasification technology (NETL, 2019a).	24
Figure 11: Block flow diagram of current state of the art IGCC power plant with CO ₂ capture (adapted from Breeze (2015)).	29
Figure 12: Hypothetical power plant costs as a function of power plant scale (plotted from Table 5).	31
Figure 13: Simplified flow diagram of a physical solvent-based CO ₂ capture process (Siefert et al., 2016a).	33
Figure 14: Simplified flow diagram of a two-stage Selexol-based absorption process (NETL, 2019f).	34
Figure 15: Schematic process flow diagram of Rectisol process (NETL, 2019e).	35
Figure 16: A schematic display of a sorbent process for CO ₂ removal from syngas.	39
Figure 17: Explanation of increased sorbent inventory for a fixed bed adsorption process.	40
Figure 18: Simplified flow diagram of a high-temperature adsorption process for CO ₂ separation from syngas (Steen et al., 2014).	41
Figure 19: Schematic diagram of a syngas membrane separation unit (modified image from Green (2015))	45
Figure 20: The relationship between product recovery rate, membrane area, and product purity at different pressure ratios (Ciferno et al., 2010).	46
Figure 21: Possible locations to integrate membrane-based pre-combustion CO ₂ capture in an IGCC process (Marano and Ciferno, 2009).	47
Figure 22: Integration options for H ₂ selective membranes in an IGCC process (Marano and Ciferno, 2009).	47
Figure 23: An IGCC power plant with H ₂ -selective membrane (Franz et al., 2014).	48
Figure 24: An IGCC power plant with CO ₂ selective membrane (Ho and Han, 2019).	49
Figure 25: Schematic diagram of the WGS system equilibrium shift with application of (a) H ₂ - selective membranes and (b) solid CO ₂ sorbent (Gao et al., 2019; Ji et al., 2018).	53
Figure 26: Flowsheet of CaO sorption-enhanced IGCC with CO ₂ capture system (Chen et al., 2012).	54
Figure 27: Process flow diagram of SEWGS by CAESAR Project (Gazzani et al., 2013).	55

List of Figures (cont.)

Figure 28: Schematic display of WGSMR (Smart et al., 2010).	56
Figure 29: Process flow diagram of an IGCC power plant with WGSMR (Maas et al., 2016). ..	57
Figure 30: Process flow diagram of an IGCC power plant with a H ₂ selective WGSMR (Carbo et al., 2006).	57
Figure 31: Process flow diagram of an IGCC power plant using a partially integrated CO ₂ selective WGSMR (Cabo et al., 2006).	58
Figure 32: Process flow diagram of a pre-combustion H ₂ -selective membrane-solvent hybrid power plant with an air-blown gasifier (Scholes et al., 2013a).	60
Figure 33: Process flow diagrams of a physical solvent absorption process with CO ₂ -selective membranes to ensure CO ₂ purity > 95%: a) membrane retrofitted to standard physical solvent process, and b) membrane used to replace second flash stage of standard physical solvent process (adapted from Scholes et al. (2013b)).	61
Figure 34: Simplified block flow diagram of an IGCC power plant.	69
Figure 35: An example of a process flow diagram used in ProTreat simulation for baseline case.	70
Figure 36: Block process flow diagram of PSA-based SEWGS process.	72
Figure 37: Process flow diagram of PSA-based SEWGS process used in ProTreat simulations.	72
Figure 38: Block process flow diagram of H ₂ selective membrane integrated process.	74
Figure 39: Process flow diagram of H ₂ selective membrane in ProTreat simulation.	75
Figure 40: Block process flow diagram of CO ₂ selective membrane-based process.	77
Figure 41: Process flow diagram of CO ₂ selective membrane process used in ProTreat simulations.	77
Figure 42: Block process flow diagram of H ₂ selective MR-based process.	79
Figure 43: Process flow diagram of H ₂ selective MR used in ProTreat simulations.	79
Figure 44: Block process flow diagram of CO ₂ selective MR-based process.	81
Figure 45: Process flow diagram of CO ₂ selective MR for ProTreat simulations.	81
Figure 46: Total capital costs as a function of temperature for Selexol solvent absorption process for 90% CO ₂ removal from 543 MW IGCC power plant (Ashkanani et al., 2020).	86
Figure 47: Operating cost (power requirement) as a function of temperature for Selexol solvent absorption process for 90% CO ₂ removal from 543 MW IGCC power plant (Ashkanani et al., 2020).	86
Figure 48: LCOC for Selexol (Ashkanani et al., 2020). (Note that this value of LCOC does not include all costs associated with carbon capture at an IGCC power plant, only the costs and power consumption directly associated with carbon capture equipment.)	87
Figure 49: Breakdown of (A) capital costs (CAPEX) and (B) operating costs (OPEX) for Selexol (10°C) solvent CO ₂ capture process at 543 MW scale. (Rotating equipment includes compressors, pumps, gas expanders, etc.)	87
Figure 50: Change in LCOC with power plant scale using the Selexol solvent absorption process.	88
Figure 51: Breakdown of (A) capital costs (CAPEX) and (B) operating costs (OPEX) for Selexol (10°C) solvent CO ₂ capture process at modular scale 54 MW. (Rotating equipment includes compressors, pumps, gas expanders, etc.)	89

List of Tables

Table 1: Characteristics of Different Types of Gasifiers, adapted from (Maurstad, 2005; Higman and van der Burgt, 2003; Ratafia-Brown et al., 2002; Phillips, 2006)	13
Table 2: Gasifier Characteristics for IGCC Applications (Gray, 2017).....	15
Table 3: Typical Gasifier Characteristics and Corresponding Raw Syngas Composition, adapted from (Madden, 2017; Gray, 2017; Carpenter, 2008).....	17
Table 4: Optimal Syngas Composition for Different Product Streams (Carpenter, 2008; Meerman et al., 2011; Ciferno and Marano, 2002).....	18
Table 5: Hypothetical LCOE Variation with Power Plant Scale.....	31
Table 6: Advantages and Disadvantages of Adsorption Process Configurations	39
Table 7: Summary of Advantages and Disadvantages of H ₂ -Selective and CO ₂ -Selective Membrane Configurations for CO ₂ Capture from IGCC Processes.....	50
Table 8: Parameters Affecting the Capital and Operating Costs of Stand-Alone Solvent and Membrane Processes for CO ₂ Capture (adapted from Echt (2002))	59
Table 9: Comparison of Solvent and Membrane CO ₂ Removal Systems (adapted from Echt (2002))	63
Table 10: Comparison of Hybrid to Solvent and Membrane CO ₂ Capture Processes (adapted from Echt (2002))	64
Table 11: Hybrid Solvents (Kohl and Nielson, 1997; Bhattacharyya et al., 2017).....	65
Table 12: Summary of Pre-Combustion CO ₂ Capture Technologies	67
Table 13: Baseline Case and Selected CO ₂ Capture Technologies used in Thermodynamic Analysis	68
Table 14: Simulation Results for Baseline Case B5B – IGCC Power Plant with CO ₂ Capture (James et al., 2019; Tumer et al., 2019).....	70
Table 15: Operating Conditions and Process Assumptions for SEWGS Process.....	71
Table 16: Assumptions used in H ₂ Selective Membrane Process Simulation.....	73
Table 17: Assumptions and Conditions used in CO ₂ Selective Membrane Process	76
Table 18: Assumptions used in H ₂ Selective Membrane Reactor Process.....	78
Table 19: Assumptions and Conditions for CO ₂ Selective Membrane Reactor Process.....	80
Table 20: Power Plant Performance Summary for all Assessed CO ₂ Capture Technologies.....	83
Table 21: Parameter Values used to Calculate LCOC.....	85
Table 22: Total Power Plant Cost Estimation Summary for Baseline Case B5B (which uses Selexol solvent absorption for CO ₂ capture). Original data can be found in James et al. (2019).....	90
Table 23: Initial and Annual Operating and Maintenance Costs for Baseline Case B5B (which uses Selexol Solvent Absorption for CO ₂ Capture) (James et al., 2019).....	92
Table 24: LCOE for Selexol Solvent Absorption Process (data from James et al. (2019)).....	93
Table 25: Promising CO ₂ Capture Processes for Different Gasification Processes and End-Use Applications at Modular Scale.....	99

Acronyms, Abbreviations, and Symbols

Term	Description
AGR	Acid gas removal
AMP	2-amino-2-methyl-1-propanol
AR	Adsorptive reactor
ASR	Automotive shredder residue
ASU	Air separation unit
BGL	British Gas Lurgi
BTG	Blue Tower Gasifier
CO ₂	Carbon dioxide
CCDP	Ceramic-carbonate dual-phase
CCS	Carbon capture and storage
CLC	Chemical looping combustion
CLG	Chemical looping gasification
CMR	Catalytic membrane reactor
CMS	Carbon molecular sieve
COE	Cost of electricity
DEA	Diethanolamine
DIPA	Diisopropanolamine
DIPAM	Diisopropylamine
DMA	Dimethyl amine
DOE	U.S. Department of Energy
EERC	Energy and Environmental Research Center
EOS	Equation-of-state
EZ	Equilibrium zone
FEED	Front-end engineering design
FT	Fischer-Tropsch
GTI	Gas Technology Institute
HP	High pressure
HRSG	Heat recovery steam generator
HTFT	High-temperature Fischer-Tropsch
HTGC	High-temperature gas cooling
HTSC	High-temperature shift conversion

Acronyms, Abbreviations, Symbols (cont.)

Term	Description
HTW	High-temperature Winkler
IGCC	Integrated gasification combined cycle
IP	Intermediate pressure
KRW	Kellogg Rust Westinghouse
LANL	Los Alamos National Laboratory
LCO	Low-cost oxygen
LCOC	Levelized cost of capture
LCOE	Levelized cost of electricity
LP	Low pressure
LTFT	Low-temperature Fischer-Tropsch
LTSC	Low-temperature shift conversion
MAG	Modular allothermal gasifier
MDEA	Methyl diethanolamine
MEA	Monoethanolamine
MHPS	Mitsubishi Hitachi Power Systems
MMst	Million short tons
MR	Membrane reactor
MSW	Municipal solid waste
MTR	Membrane Technology and Research, Inc.
MTSC	Medium-temperature shift conversion
MTZ	Mass transfer zone
MW _{el}	Megawatts of electrical power output
MW _{th}	Unit capacity of gasifier in Megawatts
NEM	Nanopore engineering membrane
NMP	N-methylpyrrolidinone
NETL	National Energy Technology Laboratory
OMB	Opposed multi-burner
OTM	Oxygen transport membrane
PBI	Polybenzimidazole
PC	Pulverized coal
PSA	Pressure swing adsorption

Acronyms, Abbreviations, Symbols (cont.)

Term	Description
PTSA	Pressure and temperature swing adsorption
RTI	Research Triangle Institute
SOTA	State-of-the-art
SES	Synthesis Energy System
SEWGS	Sorption enhanced water gas shift
SFG	Siemens fuel gasification technology
SGS	Sour gas shift conversion
SMR	Steam methane reformers
SNG	Synthetic natural gas
SRU	Sulfur recovery unit
SUNY	State University of New York
TEPCO	Tokyo Electric Power Company
TIGAR	Twin IHI gasifier
TOU	Tetraoxaundecane
TRIG	Transport Integrated Gasification
TSA	Temperature swing adsorption
WGS	Water gas shift
WGSMR	WGS membrane reactor

Acknowledgments

This work was completed by Carbon Capture Scientific as part of the National Energy Technology Laboratory's (NETL) research for the U.S. Department of Energy (DOE) under DOE NETL FWP Number: 1022402, Task 14.0: Modular CO₂ Capture Processes for Integration with Modular Scale Gasification Technologies. The authors wish to acknowledge Badie Morsi and Husain Ashkanani (Department of Chemical and Petroleum Engineering, University of Pittsburgh) for completing the economic analysis of the solvent capture process at varying plant scales. Final review of the report was provided by Randall Gemmen, David Hopkinson and Kevin Resnik (U.S. Department of Energy, National Energy Technology Laboratory). Finally, the authors would like to acknowledge the technical leadership provided by Tim Fout, Dan Hancu, Travis Shultz (U.S. Department of Energy, National Energy Technology Laboratory), and Lynn Brickett (U.S. Department of Energy, Office of Fossil Energy).

.

EXECUTIVE SUMMARY

The motivation for this report is the recent focus of the U.S. Department of Energy's (DOE) gasification program to develop modular scale gasification processes for electricity generation and other applications. Mass-produced, modular gasification systems have been proposed to decrease the upfront capital costs and to encourage flexible deployment of advanced gasification technology using a diverse set of feedstocks. To fully realize the benefits of advanced gasification technology for power generation as well as other chemical applications, pre-combustion carbon dioxide (CO₂) capture must be considered. Therefore, the aim of this report is to assess the potential of integrating modular scale carbon capture processes with modular scale coal gasification technologies, and to help guide future research and development efforts in this area.

In order to understand the current status of gasification processes, a broad literature review of the gasification market and technology options was conducted. It was found that despite declining trends over the past decade in the U.S., global demand for coal gasification processes to produce energy is increasing, particularly as more widespread environmental regulations are adopted and due to the potential for fluctuating prices of other fuels such as natural gas. Integrated gasification combined cycle (IGCC) power generation has the ability to provide low-cost, low-emission energy from locally sourced coal with superior carbon capture capabilities, particularly when compared to traditional coal-based energy generation. Increasing energy demands along with stricter environmental regulations will encourage further deployment of coal gasification energy projects in the future, particularly in remote areas and developing countries. Combining the applications of power generation and chemical production will enable a more flexible and diverse path for growth of coal gasification technology. The use of modular gasification technology proposes a range of benefits including the use of standard equipment/components, improved quality, faster assembly and testing at manufacturing site before shipment to operating site, and lower capital and operating costs. In addition, building multiple small spread-out gasifiers, rather than a few centralized large gasifiers, has the potential to increase the types of feedstocks that can be used and the potential to allow co-feeding of low cost, no cost, or negative cost feedstocks which otherwise might be costly to ship long distance to centralized gasifiers.

When assessing the need to integrate carbon capture technology with novel gasification processes, it is important to assess the syngas properties and composition resulting from the newer gasification technology to fully understand the need, suitability, and feasibility of different pre-combustion carbon capture processes for different product streams. This report has assessed the syngas properties resulting from a range of different types of gasifiers using various feedstock (lignite, bituminous coal, etc.) under different operating conditions (e.g., oxygen or air blown gasification). The syngas requirements for different applications (e.g., power, F-T chemicals, hydrogen) were then assessed. Using this information, different carbon capture technologies were considered based on both (a) the type of gasification process in use and (b) the requirements of the downstream application.

A literature review of pre-combustion carbon capture technologies was conducted to evaluate the potential of commercially available and near-commercial processes for pre-combustion carbon capture at modular scale. Analysis showed that, at modular scale, the capital cost of the carbon capture equipment was most important for reducing the levelized cost of electricity (LCOE). A range of commercial and novel physical solvents were found to be suitable for pre-combustion

CO₂ capture for a range of applications (e.g., electricity, hydrogen, and ammonia production), although in traditional equipment (e.g., random packed column), solvents may not offer significant cost reductions at modular scale. Waste heat driven solvent processes could significantly reduce the power and capital cost associated with CO₂ compression. Membrane-based processes, particularly H₂-selective membranes, were considered to have promising potential for reducing the cost of pre-combustion capture at modular scale, in particular when coupled with N₂ sweep and/or as a hybrid process with a downstream waste heat driven solvent process for H₂S and CO₂ separation. High-temperature sorbent-based processes also show promising potential for modular scale pre-combustion CO₂ capture, particularly when integrated with the water gas shift (WGS) process where the WGS catalyst is combined with a high-temperature CO₂ sorbent to provide high CO conversion at low steam to carbon ratios. However, at modular scale, high-temperature sorbent processes may have issues with achieving rapid and large turn-down ratios and will likely require complex process control. Integration of membrane separation processes with the WGS reactor is also likely to provide significant cost reductions at modular scale. The combination of membrane technologies with either waste-heat-driven solvent processes or integrated WGS is expected to create an efficient and size-reduced process which would be ideal for carbon capture from modular scale gasification processes.

A thermodynamic analysis of the most promising pre-combustion carbon capture technologies was conducted to further assess the energy performance of each process. Using Pro Treat software, an IGCC power plant process was simulated using a Selexol-like process for carbon capture, and the results were validated with the U.S. DOE Baseline Case B5B. The same methodology was used to assess the performance of membrane separation (CO₂-selective and H₂-selective), sorption enhanced water gas shift (SEWGS), and membrane reactors (CO₂-selective and H₂-selective). It was found that both the H₂-selective and CO₂-selective membrane reactors showed the best energy performance with net power plant efficiencies of 36.3 % and 36.8 %, respectively (compared to 33.7% for the baseline Selexol process).

Economic analysis of carbon capture technologies is essential for encouraging industrial deployment, particularly at modular scale due to the reported loss of economy of scale. An economic screening analysis of the Selexol-like solvent CO₂ capture process has been completed for a full scale 500 MW IGCC power plant. These results were scaled down to modular scale to assess the change in carbon capture costs with power plant scale. It was found that as the power plant scale was reduced from 500 MW to 50 MW, the levelized cost of capture (LCOC) increased by approximately 40%. Additionally, as the power plant size was reduced to modular scale, the capital costs represented a larger portion of the LCOC when using a standard physical solvent absorption process for CO₂ capture. Further analysis is required to understand how to minimize the increase in LCOC as power plant scale is reduced and to assess the economic performance of other capture technologies.

This report provides a review of the technology options available for integrating modular scale carbon capture technologies with modular scale coal gasification processes. A range of different feedstock and gasification technologies were reviewed to understand the properties of the syngas produced by different gasifiers. The syngas properties required for different applications were then assessed. This information was combined into a matrix (refer to Table 25) to aid selection of effective modular carbon capture technologies for different gasification applications. This report can be used to guide future R&D of pre-combustion carbon capture technologies and ensure they are well aligned with future gasification processes and end use applications.

Summary of Key Findings and Recommendations for Future R&D

- 1. In addition to greenhouse gas reductions, pre-combustion CO₂ capture is required for all polygeneration gasification applications (H₂, fertilizer, chemicals, liquid fuels, etc.).**
- 2. Modular scale capture processes will need to integrate with modular scale gasifiers with high levels of automated controls to vary flow rates to optimize production of electricity vs. polygeneration products.**
- 3. To the extent possible, modular scale gasification should take advantage of the following: (a) brown-field development, (b) advanced manufacturing of compact reactors, (c) testing at the manufacturing site before shipment, (d) shipment of small skids that can be quickly installed and scaled-up at the site, and (e) rely on low-cost local feedstocks.**
- 4. Future R&D for modular scale pre-combustion carbon capture should focus on capital cost reduction and/or operation at water gas shift (WGS) temperatures to reduce heating/cooling requirements of syngas.**
- 5. Processes that integrate multiple, steady-state steps with large-turn-down ratios are highly encouraged, such as combining WGS with H₂ separation. WGS with H₂ separation does not require switching, flushing, and the flux can be varied to adjust for varying inlet syngas flow rates by varying the pressure of the H₂ permeate output.**
- 6. Hybrid processes, such as integrated “H₂ membrane WGS reaction followed by physical solvent separation”, can provide compact operation while simultaneously allowing varying flow to power generation and polygeneration equipment. This is particularly the case for physical solvent systems operating at room temperature, which can vary flowrates quickly and with large turn-down ratios.**
- 7. Local production of fertilizers for agricultural use could provide a sizable revenue stream from modular scale gasification. In the future, processes should be modelled for polygeneration cases in which ammonia sulfate, potassium nitrate, gypsum, and/or other agricultural fertilizers are generated at the modular scale gasifier for local use. Coal, biomass and municipal wastes have the elements needed to produce most fertilizers; however, processes optimized for modular scale require further R&D, first system modelling followed by experimental studies.**
- 8. H₂ separating membranes are best suited for polygeneration cases where pure hydrogen or ammonia are co-products; whereas CO₂ separating membranes/solvents/sorbents are best suited for polygeneration cases where SNG, chemicals or F-T liquids are the co-products. As such, R&D into both types of membrane separation processes is prudent.**
- 9. Air blown gasification processes are unlikely to be suitable at modular scale for non-power applications due to the large amount of N₂ in the syngas which will most likely increase the required equipment sizes and hence capital costs of all steps.**
- 10. Modular-scale capture processes are crucial to the development of modular-scale gasifiers because traditional solvent-based capture processes become cost prohibitive as the scale is reduced down to 50 MW compared with conventional 500 MW designs.**

1. GASIFICATION MARKET AND TECHNOLOGY REVIEW

1.1 GASIFICATION MARKET

Gasification is the process of converting coal, or another carbonaceous feedstock such as biomass or municipal solid waste, into a synthesis gas that can then be used for electric power generation or for production of chemicals, fertilizers, and/or transportation fuels. Since its introduction over two centuries ago, coal gasification has had periods of growth and decline for different applications in response to varying local and international market forces. Electric power generation via coal gasification is known as integrated gasification combined cycle (IGCC). IGCC power generation is generally considered an environmentally superior process when compared to traditional pulverized coal power plants due to reduced emissions of CO₂ and other pollutants (particulates, heavy metals, etc.) and as it is more “carbon-capture-ready.” The market penetration of IGCC in the U.S. has been low, but coal gasification growth is occurring in other parts of the world, such as China for varying applications including coal-to-chemicals. The first section of this report will review the current status of the gasification market and discuss options for future growth of coal gasification processes for power generation as well as production of other products.

1.1.1 Current Status of Coal Gasification Market

In 2018, the United States consumed approximately 687 million short tons (MMst) of coal, which equated to around 13% of U.S. energy consumption (EIA, 2019b). Most of this coal is being used for electric power generation with 28% of electricity generation coming from coal in 2018. However, since 2007 the use of coal in the U.S. has been declining, mainly due to the reduction in the use of coal for electricity generation. The decline in coal usage in the U.S. is predicted to continue through 2035, mainly due to the projected closure of coal-fired generating units and competitive price pressure from natural gas and renewables (EIA, 2019a). Despite this trend, energy diversity and security are important and, as such, coal usage for electric power generation will remain in the electricity mix of the future, with coal generation expected to account for at least 17% of total electricity generation in 2050 (EIA, 2019a). With estimates of U.S. recoverable coal reserves that would last about 325 years, and recoverable reserves at producing mines that would last about 26 years (EIA, 2018), coal is an accessible and abundant resource that has the potential for significant growth with optimum alignment of technological and market conditions.

Coal Gasification for Electricity Generation

The coal gasification market has had a history of periods of high growth and low growth, predominantly driven by factors including the demand for chemicals and energy as well as geopolitical issues. While coal derived syngas has been used to light towns and heat homes since the eighteen century, the first large-scale commercial coal gasification power plant was built in South Africa in 1955 for the production of coal-to-liquids. The energy crisis of the 1970s, which resulted in substantial petroleum shortages and subsequent price increases in the U.S., led to a growth period in the 1980s for commercial scale coal gasification power plants for coal-to-chemicals applications. Coal gasification then transitioned to an alternative energy provider with the first coal-to-natural gas power plant built in North Dakota in 1984 and the first commercial scale IGCC demonstration built at Cool Water, California in 1984 (Fair, 2016). Further increases to energy prices in the 2000s led to accelerated development and plans for more coal gasification

energy projects in the U.S. (including Tampa Electric IGCC (2019), Kemper County IGCC (Madden, 2017) and Duke Energy Edwardsport IGCC project (2019)). However, in the U.S. at least, this trend halted in the past decade due to significant reductions in natural gas prices as a result of the introduction of hydraulic fracking of shale for natural gas extraction. However, in developing countries like China, planning and construction of coal gasification power plants has continued to grow in order to meet demands for energy and chemical production. In the last decade, China has seen significant growth in coal-to-chemicals power plants including for ammonia, methanol, olefins, and other products (Chang et al., 2016).

Since 2010, very few new IGCC power plants have been planned or built in the U.S. for electricity generation. Duke Energy's Edwardsport IGCC power plant in Indiana (net power output of 618 MW_{el}) started operation in 2013 after replacing a traditional 160 MW coal fired power plant at the same site (Duke Energy, 2019). Mississippi Power's Kemper County project was originally designed as a coal-based IGCC process with carbon capture and storage (CCS). However, due to significant cost pressures, the power plant will now operate with natural gas rather than coal gasification. Over the past decade a number of plans for new coal-based IGCC power plants have been cancelled and existing IGCC power plants have closed including Tampa Electric's Polk power station in Florida (Tampa Electric, 2019), Api Energia (Italy), Demkolec or WAC (Netherlands), and Elcogas (Spain). These closures and cancellations were generally due to cost pressures and uncertainty around carbon emission regulations. However, plans to close the 250 MW_{el} Wabash River IGCC power plant in Indiana (U.S.) were reversed in 2019 when it was announced that the gasification power plant would be converted into an anhydrous ammonia production power plant and CCS power plant. Conversion of the gasification power plant and construction of the CCS power plant is expected to begin in 2020 and completion is expected in 2022 at a cost of US \$600m (Jasi, 2019). Globally, there are plans for new large (>500 MW_{el}) coal-based IGCC power plants (Wolfersdorf and Meyer, 2017), particularly in developing countries like China and India; however, many are characterized by delays and cost issues.

The main reason reported for the lack of commercialization of coal-based gasification for power generation is that the capital costs are not competitive with conventional power plants. Therefore, there is a need for research and development (R&D) to focus on cost reductions, including a generic assessment of the design and construction strategies in order to decrease significant cost overruns and lower the overall installed cost of IGCC power plants. Additional R&D effort is required to improve the availability of IGCCs as nearly all coal-based IGCCs have taken 3–5 years to reach a stable level of availability and that level is most commonly less than the target value of 85% (Phillips et al., 2017). To encourage economic decisions for new gasification power plants, technology providers need to develop standard power plant designs, rather than providing a license and equipment. The economies of scale could be improved by building multiple trains or modular IGCCs. Operating and maintenance costs need to be reduced through technology advancement and power plant operation needs to be flexible to accommodate daily fluctuations in power demand. This could be achieved via hydrogen storage or through syngas diversion to making other syngas derived products when power generation is not required.

Coal Gasification for Non-Power Applications

There are around 300 operating gasification power plants worldwide with around 700 gasifiers, and as shown in Figure 1, most of these gasifiers are for non-power generation applications

(Global Syngas Technologies Council, 2019). The latest gasification technologies are a lot more diverse in their feedstocks, operational configuration, and products. However, production of chemicals via gasification is still the predominant coal-based gasification application for the near future. It has been reported that about 25% of the world's ammonia and over 30% of the world's methanol are being produced via gasification, which has more than doubled in the past decade (Higman, 2013).

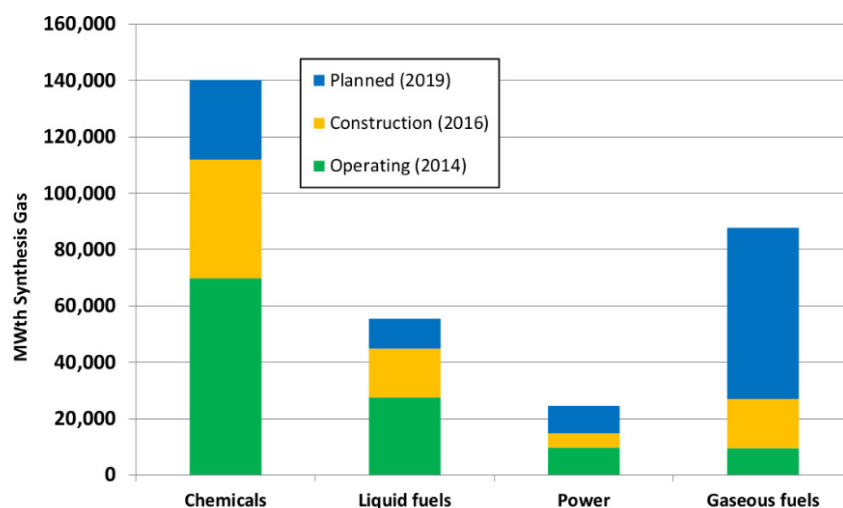


Figure 1: Global syngas usage by application (Global Syngas Technologies Council, 2019).

Coal gasification can be used to produce a range of valuable products (see Figure 2 for examples of products produced from gasification). In developing countries like China, mega-power plants with multiple train gasifiers are being built for production of products including Fischer-Tropsch liquids, synthetic natural gas (SNG), and methanol-to olefins (Higman, 2013). Polygeneration gasification power plants, which produce multiple products including electricity from the same initial stream of syngas, have promising potential for future gasification power plants as the chemical products often realize a higher added value in comparison to pure electricity generation. Large refineries, such as Jamnagar in India and Jazan in Saudi Arabia, are increasing gasification capacity worldwide via electricity generation and production of chemicals and fuels (Wolfersdorf and Meyer, 2017; Higman, 2013; Kerester, 2014).

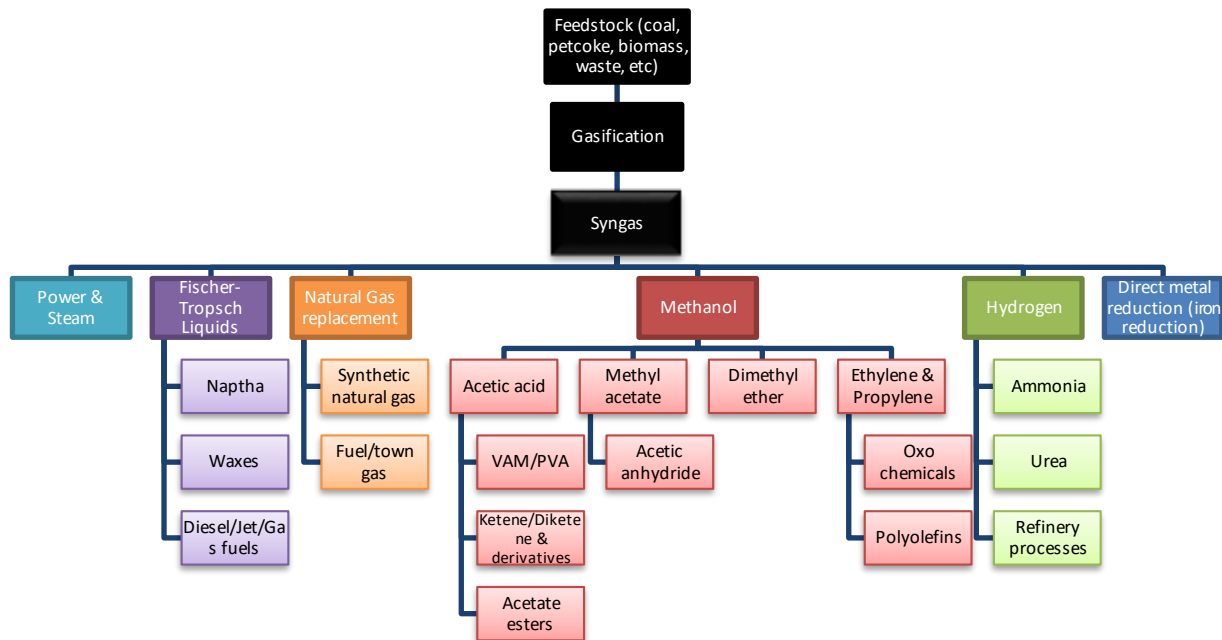


Figure 2: Products available from gasification processes (Kerester, 2014).

1.1.2 Future Market Trends for Gasification Processes

Future Demands for Syngas

Global demand for large, new coal gasification power plants has slowed (particularly for power generation) as a result of shifts in global energy prices (Fair, 2016). Low natural gas prices have been the biggest threat to new coal gasification projects for power generation, particularly in the U.S. where natural gas prices have been low and are predicted to remain relatively low in the upcoming decade (World Bank Group, 2019). Despite these challenges, global demand for gasification processes is projected to rise, as shown in Figure 3, with the majority of this growth occurring in the Asia Pacific region and for the production of chemicals and fuels (refer back to Figure 1). Reducing import dependencies of LNG and crude oil as well as ensuring security of energy supply will help drive further development of coal-based syngas applications, particularly in regions without readily available natural gas.

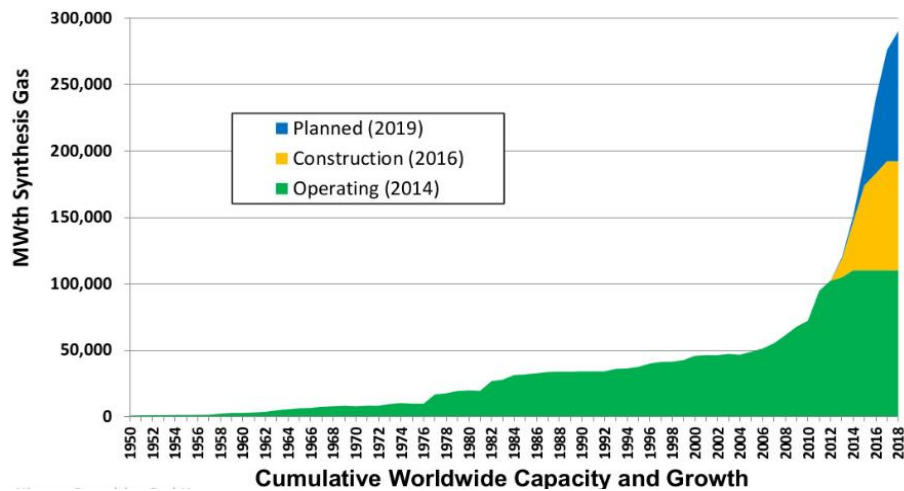


Figure 3: Global syngas capacity and growth including planned, operating, and under construction gasification power plants (Global Syngas Technologies Council, 2019).

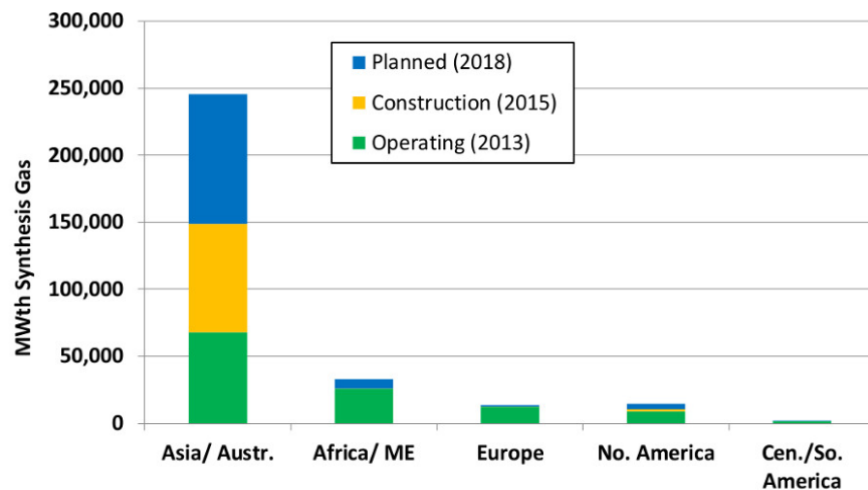


Figure 4: Global syngas usage by geographic region (Global Syngas Technologies Council, 2019).

Global energy consumption is also projected to increase in the coming decades, particularly in non-OECD countries where a significant proportion of new energy will come from coal. Whether this coal-based energy is obtained from traditional pulverized coal (PC) power plants or coal gasification power plants will be influenced by a range of factors including capital costs, time to build, environmental regulations, financing, and the capacity of the power plant (Fair, 2016).

Coal Gasification Power Plants (IGCC) of the Future

Future IGCC power plants will benefit most from being located (a) close to low-cost solid fuel resources, (b) in an area with some degree of environmental regulation, (c) where there is high demand for jobs, (d) where there is high NG prices, (e) where current coal power generation

equipment is not meeting air quality standards, and (f) where water for cooling is scarce (Aiken et al., 2004). Traditional large-scale coal gasification power plants (e.g., greater than 500 MW) may not always be preferred in the power plants of the future due to their high capital costs, lack of centralized load demand, and long-range transmission capability. Therefore, implementing smaller-scale coal gasification power generation (50–300 MW) in targeted locations may be a more successful approach for future development of coal-based IGCC power plants.

Future system and techno-economic analyses are needed and will be crucial for identifying the best options for improving the economics of gasification processes when implementing a modular (unit sizes of approximately 50 to 350 MW) gasification technology approach.

Reducing capital costs of gasification power generation via modular operation and the inclusion of co-production of other high value products, which adds a new revenue stream, are both options for improving the economics of gasification. An early screening study completed by NETL showed that modular or small-scale gasification processes could have economic benefits in a number of rural locations (Lyons, 2018). For example, in the rural Alaska and Appalachia regions, coal and various types of biomass feedstock could be used with gasification processes to produce power, diesel and other chemicals that could ultimately help to reduce the costs of electricity, transport and heating fuels while also creating jobs and reducing greenhouse gas emissions. The University of Alaska-Fairbanks is designing a modular, air-blown fixed bed gasifier to produce clean syngas for an existing diesel engine generator. This will enable Alaska's local coal resources to be used for energy generation at remote sites rather than importing expensive diesel fuel. However, it is important to note that air-blown gasifiers make carbon capture and polygeneration quite difficult due to large amounts of N₂, and as such, will have limited applicability to sites which need carbon capture to meet environmental regulations and/or for polygeneration applications with strict syngas requirements. Despite significant solar resources in rural southwest U.S., small-scale coal gasification could help to lower the cost of power by minimizing the significant cost of transmission lines. Also, U.S. military installations could also benefit from the use of modular scale coal gasification (using biomass or fossil fuels) in order to produce jet fuel and provide power while also meeting greenhouse gas emission requirements (Lyons, 2018). A modular scale gasification power plant, e.g., 50 MW, could be ideal to support industrial facilities where coal is readily available but natural gas is not available and diesel fuel is expensive (e.g. Eastern Kentucky). Locating a polygeneration plant that produces power and products like ammonia for fertilizer production could also be a benefit in agricultural areas. Also, IGCC power generation uses less water compared with traditional PC and other energy sources making it suitable to water-constrained areas. Finally, repowering brownfield PC plants with coal gasification could be an attractive option for encouraging investment in areas that have old facilities with stricter emissions standards (Aiken et al., 2004). Increasing environmental regulations will benefit coal-based gasification power applications because the cost to capture carbon dioxide and other pollutants is typically lower than other coal power plant designs once the power plant has been built (Fair, 2016).

Polygeneration Plants for the Future

Recent developments in the coal gasification market has shown that a higher value plant can be realized when an IGCC plant is operated to produce electricity as well as synthesize other products (see Figure 5). Two of the most recent IGCC projects (Jamnagar in India and Jazan in Saudi Arabia) are based on multiple gasification trains and will provide power as well as other products including hydrogen, SNG, and chemicals. These plants will benefit from economies of

scale while also allowing continuous operation during the fluctuating demands for electricity. These examples show that polygeneration can be used to reduce the uncertainty in capital costs by acting as a hedging mechanism against price changes (Aiken et al., 2004). The power to chemical product ratio could be varied depending on market prices and plant turndown ratio. Additional benefits include increasing product flexibility and resource utilization for higher efficiencies and better economics. Polygeneration plants are CO₂ capture ready due to gas composition requirements for the synthesis process leading to the requirement of CO₂ removal. A polygeneration plant would also be suitable for integration with intermittent renewable power. As demand for coal-based production of chemicals and fuels is expected to increase (see Figure 4), the potential for polygeneration plants in the future could be considered higher than that for only power generation. One of the main challenges of an IGCC polygeneration plant is that it is significantly more complex compared to traditional power plant facilities. This could be mitigated by the use of modular units which are increased in number as confidence grows i.e., a modular unit will have a lower initial upfront cost (so lower risk) and the process can be increased in size and scale, while part of the plant is running and generating revenue. The modular plant would be as automated as possible and would have known-regular replacement of any consumable parts (e.g., membranes).

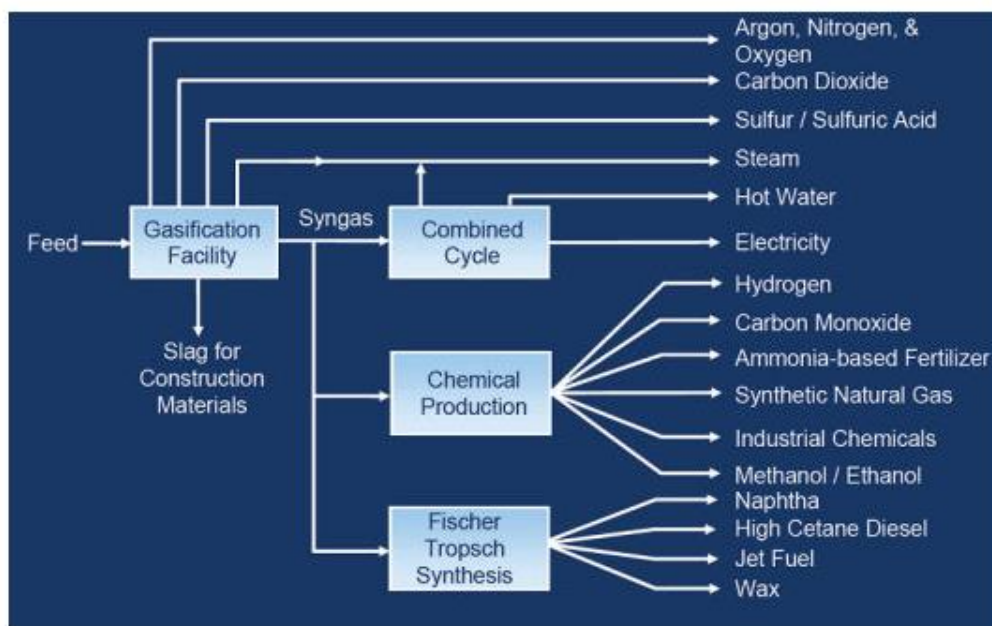


Figure 5: Products that can be produced from a polygeneration process using coal gasification (NETL, 2019d).

Another emerging market for coal gasification is the production of hydrogen. Global demand for hydrogen is increasing due to its potential as a clean fuel for production of energy and transportation via fuel cells. The Hydrogen Council (2017) reported that the hydrogen industry is predicted to become a \$2.5 trillion global industry by 2050. Japan and Australia have taken their first steps to create a new export industry that will convert low-grade brown coal (lignite) from Australia into hydrogen via gasification and ship it in liquefied form to Japan (Treadgold, 2019).

The CO₂ produced in the gasification process will be captured and stored underground, minimizing the overall environmental impact of this process.

In addition to the production of power and chemical products via coal gasification, by-products can also have some value and should be generated to increase the viability of new coal gasification power plants. Although the discharge of solid by-products and waste water in an IGCC power plant is approximately half that produced by other coal-based power plants, the by-products generated (mainly slag, fly ash, coke, tar, sulfur, and ammonia) are environmentally benign and can be sold to other markets (Arroyo Torralvo et al., 2017). Slag (mainly SiO₂ and Al₂O₃) is discharged from the bottom of the gasifier and typically can be used for asphalt and road construction materials. Fly ash is recovered in the particulate removal system and can be used in cement and concrete production. Sulfur is removed from the syngas in the form of H₂S and can be used to form elemental sulfur via the Claus process or for the manufacture of sulfuric acid. Ammonia is used in the manufacture of fertilizers including urea. And crucially for agriculture, ammonia sulfate is a fertilizer that can be produced from the ammonia and the sulfate at a coal gasification facility. For example, the world's largest coal-to-liquids facility coproduces 145,000 tons per year of ammonia sulfate (Zhang, 2017). The Dakota Gasification facility in the U.S. now produces approximately 300,000 tons of urea per year (Dietz, 2020).

Future Feedstock Variation

Coal has been and still is the predominant feedstock for gasification processes (refer to Figure 6). However, as environmental sustainability becomes more important alternate feedstock, such as biomass or other waste materials (Waldheim, 2018), have the potential to become more feasible, either as the sole fuel or mixed with coal.

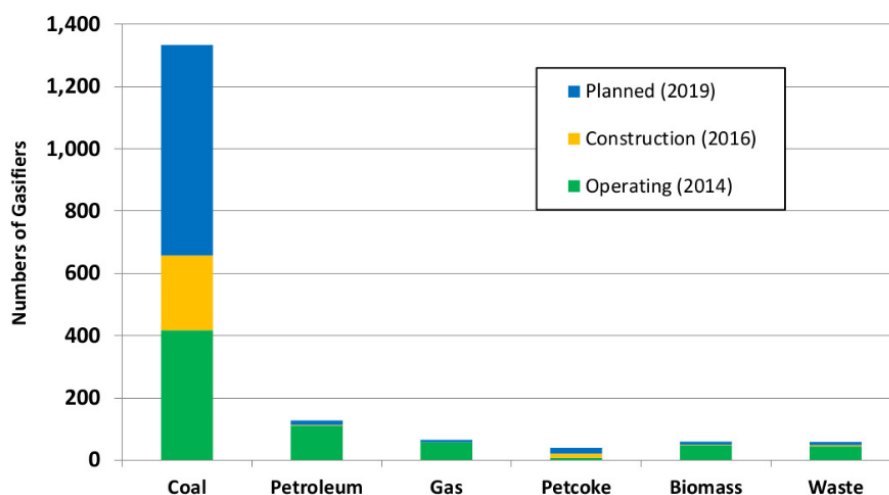


Figure 6: Gasification feedstock variation (Global Syngas Technologies Council, 2019).

According to the World Bank, the world currently generates about 4 billion tons of all types of waste per year, with 75% being disposed in landfill and only 25% recycled. The U.S. alone generates 389 million tons of municipal solid waste (MSW) per year, with approximately 64% being sent to landfill (Gasification Technologies Council, 2011). Due to the environmental

concerns and increasing costs and challenges associated with waste disposal, along with the growing demands for energy, more countries are looking at gasification as an environmentally sustainable way of converting the energy in waste into useful products. Gasification has been in use commercially for more than 15 years for converting highly variable feedstock materials such as MSW, automotive shredder residue (ASR), and hazardous waste into power, steam, and heat. Commercial facilities have been built and are currently operating in Japan, India, and China (Subramanyam and Gorodetsky, 2017). Following China's decision in 2018 to stop taking recycled waste materials from countries around the world, including the U.S., gasification of waste could provide an attractive solution to dealing with waste and generating electricity or other syngas-based fuels.

1.2 GASIFICATION TECHNOLOGY

Commercial scale coal gasification processes have been in operation since the 1970s for a range of applications including electricity generation. The coal gasification equipment used for electricity generation in the earlier IGCC power plants are considered mature and many lessons have been learnt following their construction and operation to enable further improvements to the next generation of IGCC power plants. The following section provides a short summary of the coal gasification technology currently in use for power generation and other applications followed by a discussion on R&D trends for future gasification processes.

1.2.1 Traditional Coal Gasification Technology

Although coal is the primary gasification feedstock (refer to Figure 6), a range of other feedstock can be converted into syngas using gasification technology. In general, the gasification process can be used with any carbon and hydrogen containing feedstock where it is thermo-chemically broken down into a gas containing basic compounds (H₂, CO, CH₄, etc.), which can then be processed into a range of marketable products (ammonia, SNG, electricity, etc.). Gasifiers can be operated with different ranks of coal (lignite, bituminous, etc.) and other fossil fuels, petcoke, and refinery streams, biomass including agricultural waste, and industrial and municipal waste.

Commercial Gasifiers

There are three main types of gasifiers: fixed/moving bed, fluidized bed, and entrained flow. Table 1 shows some of the main characteristics of these gasifiers. The gasifier operating temperature is generally determined by the ash properties of the coal, but in general the operating temperature increases from fixed bed to fluidized bed to entrained flow gasifier (refer to Table 1). The ash can be removed dry at low temperatures (non-slugging gasifiers) or as a low viscosity liquid at high temperatures (slugging gasifier). Entrained flow gasifiers are currently the most favored due their production of syngas without oils or tars, high carbon conversion, low methane production (suitable for synthesis gas products), and high throughput because of high reaction rates at elevated temperature. However, entrained flow gasifiers do require a relatively high oxygen consumption in order to reach the high slugging temperature, which results in a costly air separation unit and some of the coal's chemical energy being converted to sensible heat which can lower the cold gas efficiency. However, some of this sensible energy can be recovered by the syngas coolers (Maurstad, 2005). A good review of the major gasifiers used in IGCC systems is provided by Gray (2017), and a summary of operating experience and improvements for commercial IGCC is provided by Barnes (2013).

Table 1: Characteristics of Different Types of Gasifiers, adapted from (Maurstad, 2005; Higman and van der Burgt, 2003; Ratafia-Brown et al., 2002; Phillips, 2006)

Gasifier Type	Fixed/Moving Bed		Fluidized Bed		Entrained Flow
Ash Conditions	Dry Ash	Slagging	Dry Ash	Agglomerating	Slagging
Size of coal feed	6–50 mm		< 6 mm		< 0.1mm
Preferred feedstock	Lignite, reactive bituminous coal, anthracite, wastes	Bituminous coal, anthracite, petcoke, wastes	Lignite, reactive bituminous coal, anthracite, wastes	Lignite, bituminous coal, anthracite, cokes, biomass, wastes	Lignite, reactive bituminous coal, anthracite, wastes
Ash limitations	No limitations	<25% preferred	No limitations		<25% preferred
Gas outlet temperature	Low (425–600°C)		Moderate (900–1050°C)		High (1250–1600°C)
Gasification pressure	>30 bar		1–30 bar		<50 bar
Oxidant demand	Low		Moderate		High
Steam demand	High	Low	Moderate		Low
Unit capacities	10–350 MW _{th}		100–700 MW _{th}	20–150 MW _{th}	Up to 700 MW _{th}
Key technical issue	Utilization of fines and hydrocarbon liquids		Low carbon conversion		Fouling of syngas cooling heat exchangers and refractory material costs for walls of gasifier
Characteristics	• Small scale • Low oxidant requirements • Relatively high methane in syngas • Production of hydrocarbon liquids (e.g., tars and oils) • High cold gas thermal efficiency when the heating value of the hydrocarbon liquids are included • Limited ability to handle fines • Special requirements for handling caking coal.		• Large scale • Extensive solids recycling • Uniform and moderate temperature • Moderate oxygen and steam requirements.		• High-temperature slagging operation • Entrainment of molten slag in the raw syngas • Relatively large oxidant requirements • Large amount of sensible heat in the raw syngas • Ability to gasify all coal regardless of rank, caking characteristics or amount of fines
Commercial examples	Sasol-Lurgi, British Gas Lurgi (BGL)		KBR transport gasifier (TRIG), High-temperature Winkler (HTW), Kellogg Rust Westinghouse (KRW), SES (U-gas)		GE, Shell, Siemens, E-gas

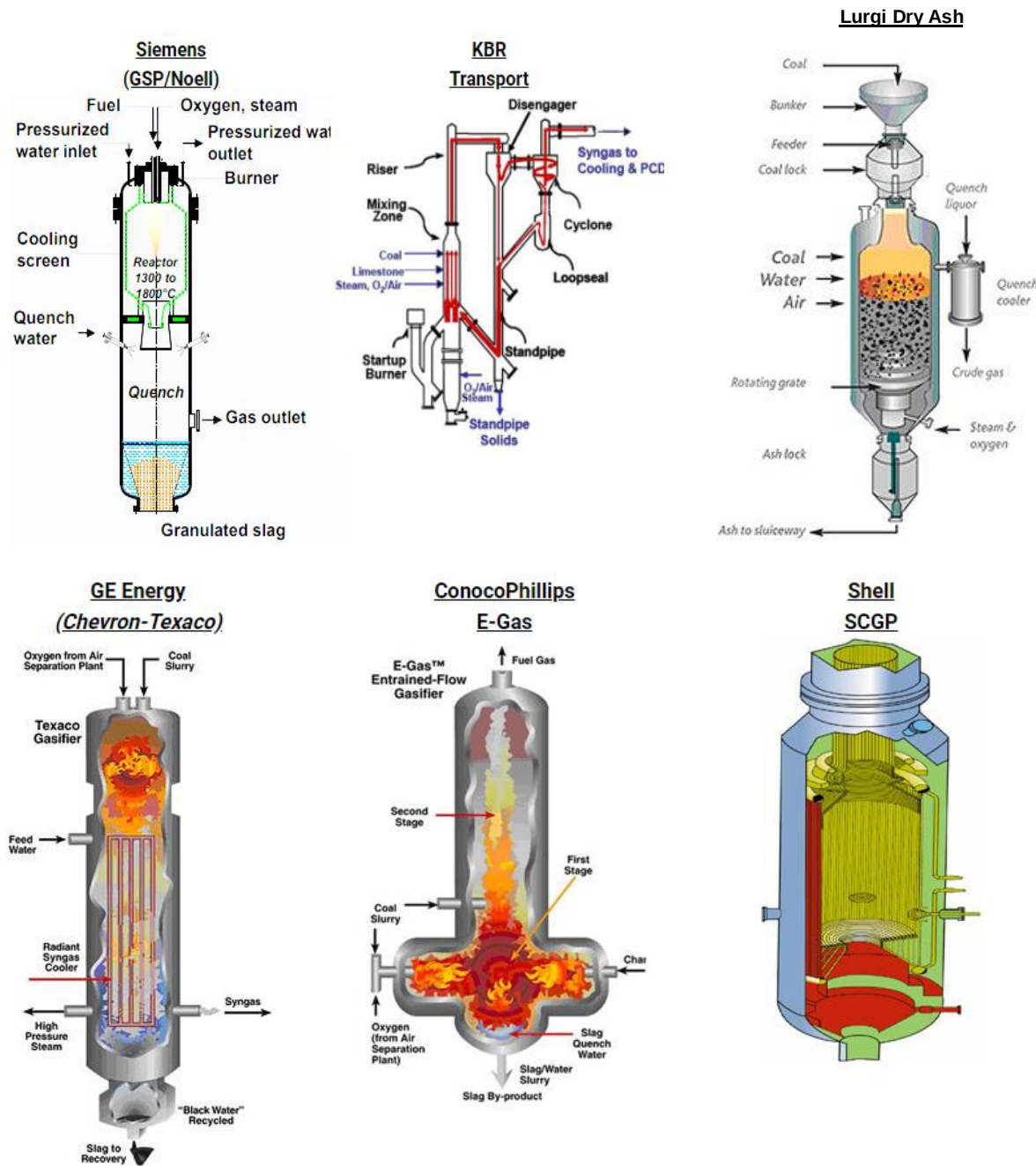


Figure 7: Schematics of the main types of commercial gasifiers (NETL, 2019c).

The most commonly installed commercial gasifier is the Sasol-Lurgi gasifier which is a fixed bed, non-slugging gasifier (developed by Lurgi) which has extensive commercial experience from Sasol's synfuel power plants in South Africa. It is also used in the Great Plains Synfuels Plant in North Dakota, U.S. GE, Shell and E-gas are the next most commonly installed commercial gasifiers (all are entrained flow slagging type) (Maurstad, 2005). Refer to Figure 7 for schematic images of the main commercial gasifiers. For GE gasification-based IGCC, a slurry feed is pumped to the refractory-lined gasifier where the coal is gasified with oxygen to

generate the raw syngas. Heat in the gasifier liquefies the coal ashes and the molten ash is then quenched and crushed at the bottom of the gasifier before being dewatered for disposal. The raw syngas is sent to the downstream high temperature gas cooling (HTGC) section for heat recovery. The E-Gas gasification process is similar to the GE process except for the two-stage slurry feed system. Approximately 75% of the slurry feed and all of the O₂ are sent to the bottom (first stage) of the gasifier where the highly exothermic gasification/oxidation reaction takes place at high temperature. Hot syngas from first stage is mixed with the remaining 25% of the slurry feed in the top (second) stage where the highly endothermic gasification/devolatilization reaction takes place to produce a cooler syngas exit to the HTGC. The Shell gasification process is similar to the GE gasification except that the coal feed is pressured into the gasifier dry. Small amounts of steam are also added to meet minimum system water and H₂ requirements. There are also gasifiers that are based on either hybrid combinations of the three main classifications, such as the KBR transport gasifier which uses a circulating fluidized bed system (Phillips, 2006). Table 2 provides an overview of the main characteristics of some of the commercially available gasifiers for IGCC applications.

Table 2: Gasifier Characteristics for IGCC Applications (Gray, 2017)

Characteristic	GE	Shell	SFG	E-Gas	SES	HTW	TRIG	MHPS
High temperature	✓	✓	✓	✓	✓	✓	✓	✓
High pressure	✓	✓	✓	✓	✓	✓	✓	✓
Large range of coal feed type		✓	✓	✓	✓	✓	✓	✓
High cold gas efficiency (CGE)		✓	✓				✓	✓
Syngas heat recovery	✓	✓	✓	✓	✓	✓	✓	✓
Oxygen blown	✓	✓	✓	✓	✓	✓	✓	
Slagging	✓	✓	✓	✓	✓	✓	✓	✓
Membrane wall		✓	✓					
Low CH ₄ in syngas	✓	✓	✓					✓
Slurry feed	✓							
Dry feed		✓	✓	✓	✓	✓	✓	✓
Air-blown							✓	✓
Entrained flow	✓	✓	✓	✓			✓	✓
Fluidized bed					✓	✓	✓	
Long track record of commercial applications	✓	✓	✓	✓	✓	✓		

Notes: SFG = Siemens Fuel Gasification technology; SES = Synthesis Energy System (formerly U-gas); HTW = High-temperature Winkler; MHPS = Mitsubishi Hitachi Power Systems (air blown E-gas).

Syngas Composition from Coal Gasification

Depending on the type of gasifier and feedstock used, the syngas typically contains a mixture of H₂, CO, CO₂, along with unreacted methane CH₄ and other trace components (including hydrogen sulfide, ammonia, hydrogen chloride, and carbonyl sulfide, as well as various forms of trace metals, including arsenic, mercury, selenium, and cadmium). As can be seen from Table 3, the composition and physical properties of the raw syngas can vary depending on the type of gasifier applied, type of oxidant and feedstock used.

Table 3: Typical Gasifier Characteristics and Corresponding Raw Syngas Composition, adapted from (Madden, 2017; Gray, 2017; Carpenter, 2008)

Gasifier Technology	Shell Coal Gasification Process		Siemens Fuel Gasification Technology (SFG)		E-Gas		GE	HTW (High-Temperature Winkler) (Gray, 2017)		KBR Transport Gasifier (TRIG™) (Madden, 2017)	Transport Gasifier (TRIG™) – Kemper Project	BGL (British Gas Lurgi)		Sasol-Lurgi
Gasifier type	Entrained flow		Entrained flow		Entrained flow		Entrained flow	Fluidized bed		Fluidized bed	Fluidized bed	Fixed/Moving bed		Fixed/Moving bed
Feedstock	Bituminous coal	Lignite	Bituminous coal	Lignite	Bituminous coal	Lignite	Bituminous coal	Lignite	Lignite	Sub-bituminous coal	Lignite	Bituminous coal	Lignite	Bituminous coal
Coal size, mm	<0.1		<0.1		<0.1		<0.1	0.5-5	0.5-5	<2.5–6	0.3-0.5	Lump (5–50 mm)		Lump (5-50 mm)
Oxidant	oxygen		oxygen		oxygen		oxygen	Oxygen + steam	air	oxygen	Air	oxygen		oxygen
Pressure, MPa	2–4.5		2.5–4		2–4.1		3–8	2.5–3	2.5–3	1.5	<3.6	2.5–7		3.1
Exit gas temperature, °C	900 (after internal gas quench)		170–230 (after internal quench)		1040		760 (after syngas cooler) 200-300 (after quenching)	800–900	800–900	930	950	260–700 (typically <540)		200-650
Proven products / Applications	Power, chemicals		Power, chemicals		Power		Power, chemicals	Chemicals	Chemicals	Power	Power, CO ₂ for EOR, chemicals (H ₂ SO ₄ , NH ₃)	Power (small scale), chemicals		Power, chemicals & liquid fuels
Feedstock→ Syngas composition (dry basis) vol% ↓	Bituminous coal	Lignite	Bituminous coal	Lignite	Bituminous coal	Lignite	Bituminous coal	Low ash lignite (Oxygen + steam blown)	High ash lignite (Air blown)	Sub-bituminous coal	Lignite	Bituminous coal	Lignite	Bituminous coal
H ₂	27.25	28.45	26.60	31.04	37.50	37.44	36.27	35.78	16.28	36.19	12.15	31.61	28.25	55.16
CO	64.40	62.47	63.05	55.08	50.00	33.18	47.40	35.66	21.70	41.29	19.41	54.83	56.51	31.17
CO ₂	1.53	2.89	2.96	8.01	8.85	26.18	12.93	22.80	8.79	17.69	9.37	3.47	2.83	5.92
CH ₄	0.03	<0.10	<0.10	<0.10	0.66	0.15	0.12	4.85	1.84	3.10	2.95	4.55	6.05	4.65
N ₂ + Ar	5.31	5.46	5.42	4.31	1.55	1.98	1.92	0.61	50.46	1.30	55.38	3.95	6.05	1.58
H ₂ S	1.33	0.31	0.45	0.20	1.00	0.46	1.20	0.12	0.11	0.11	0.36	1.20	0.30	0.95
COS	0.10	<0.10	0.04	0.02	0.11	0.15	0.02	0.00	0.00	0.00	0.02	0.12	0.00	0.04
NH ₃ + HCN	0.02	<0.10	1.38	1.24	0.22	0.30	0.12	0.18	0.81	0.32	0.36	0.24	0.00	0.53
HCl	0.03	<0.10	-	-	0.11	0.15	0.02	-	-	-	-	0.04	0.00	0.00
C _n H _m	-	-	-	-	-	-	-	-	-	-	-	0.24	0.61	0.32

Processing Syngas for Downstream Applications

The syngas that exits from these gasification processes will require further processing depending on the chosen downstream application. Table 4 provides an overview of the desirable syngas properties for different syngas applications. In general, higher purity syngas (with less inerts like N₂) is required for fuels and chemical synthesis applications resulting in the need for high purity oxygen (via an air separation unit, ASU) in the gasification process and more gas scrubbing/clean-up processes. For most applications, the H₂/CO ratio in the syngas will need to be adjusted via a water gas shift (WGS) reactor. In most chemical synthesis applications, a catalyst is used which introduces strict limitations on the allowable concentration of minor components in the syngas. A range of gas processing or separation processes will be required to adjust the condition or composition of the syngas depending on the desired end product.

Table 4: Optimal Syngas Composition for Different Product Streams (Carpenter, 2008; Meerman et al., 2011; Ciferno and Marano, 2002)

Product/Application	Variable	Optimum Value
Electricity/IGCC (gas turbine)	H ₂ /CO	Depends on amount of CO ₂ capture required
	H ₂ S + COS + CS ₂	< 20 ppmv
	Particulates	< 2 ppmw
	Hydrogen Halides (HCl + HF)	< 1–2 ppmv
	Alkalis (Na + K)	0.03–0.2 ppmv
	CO ₂	Depends on amount of CO ₂ capture required
	Hydrocarbons	High
	N ₂	Note ^a
	H ₂ O	Note ^b
	Heating Value	High ^c
	Pressure	~400 bar
	Temperature	500–600°C
Fischer-Tropsch (F-T) Synthesis of Chemicals/fuels	H ₂ /CO	0.6–2 ^d
	CO ₂	Low (1–2%)
	Hydrocarbons	Low ^g
	NH ₃ + HCN	<1 ppm
	H ₂ O	High ^h
	Sulfur (H ₂ S + COS + CS ₂)	<1 ppm
	Particulates	Low
	Heating value	Unimportant ⁱ
	Pressure	~20–30 bar
	Temperature	200–300°C ^j or 300–400°C
Hydrogen	H ₂ /CO	High (∞)
	CO ₂	Not important ^e
	Hydrocarbons	Low ^g
	N ₂	Low
	H ₂ O	High ^h
	Sulfur	< 1ppm
	Particulates	Low
	Heating value	Unimportant ⁱ
	Pressure	~28 bar
	Temperature	100–200°C

Table 4: Optimal Syngas Composition for Different Product Streams (cont.)

Product/Application	Variable	Optimum Value
Synthetic Natural Gas (SNG)	H ₂ /CO H ₂ CO ₂ (H ₂ /(3CO+4CO ₂))	3:1 10% max Low 0.98–1.03
Methanol	H ₂ /CO CO ₂ Hydrocarbons N ₂ H ₂ O Sulfur Particulates Heating value Pressure Temperature	~2.0 Low ^f Low ^g Low Low <1 ppm Low Unimportant ⁱ ~50 bar (liquid) ~140 bar (gas phase) 100–200°C
Ammonia	H ₂ /N ₂ CO + CO ₂ + H ₂ O Sulfur Inerts (including methane)	3 <30 ppm <1 ppm <2% minimum
Urea	NH ₃ /CO ₂ CO ₂ stream	2.95 >98.5 mol% CO ₂ <2 mg/Nm ³ <0.15 mol% H ₂ <10 ppmv methanol
Fuel Gas (boiler)	H ₂ /CO ratio CO ₂ Hydrocarbons N ₂ H ₂ O Contaminants Heating Value Pressure, bar Temperature	Unimportant Not Critical High Note ^a Low Note ^k High ^c Low 250°C

- (a) N₂ lowers the heating value, but level is unimportant as long as syngas can be burned with a stable flame.
(b) Can tolerate relatively high water levels; steam sometimes added to control NO_x
(c) Efficiency improves as heating value increases.
(d) Depends on catalyst type and temperature. For iron catalyst, value shown is satisfactory; for cobalt catalyst, ~2.0 should be used.
(e) Water gas shift will have to be used to convert CO to H₂; CO₂ in syngas can be removed at same time as CO₂ generated by the water gas shift reaction.
(f) Some CO₂ can be tolerated if the H₂/CO ratio is above 2.0 (as can occur with steam reforming of natural gas); if excess H₂ is available, the CO₂ will be converted to methanol.
(g) Methane and heavier hydrocarbons need to be recycled for conversion to syngas and represent system inefficiency.
(h) Water is required for the water gas shift reaction.
(i) As long as H₂/CO and impurities levels are met, heating value is not critical.
(j) Depends on catalyst type; iron catalysts typically operate at higher temperatures than cobalt catalysts
(k) Small amounts of contaminants can be tolerated

Electricity Generation from Coal Gasification (IGCC)

The key components of a coal-based IGCC power plant are coal preparation, coal gasification and subsequent syngas cooling, ASU, gas clean up, and the combined cycle power block. Basic process flow diagrams of an IGCC power plant without CO₂ capture and one with CO₂ capture can be found in Figure 8 and Figure 9, respectively, followed by a brief description of each process (Wolfersdorf and Meyer, 2017). Good reviews of gasification technologies for IGCC power plants can be found in the literature (Gray, 2017; Carpenter, 2008; Mishra et al., 2018; Pisupati and Krishnamoorthy, 2017) and more information on the main IGCC process steps shown in the figures below can be found in Appendix A.

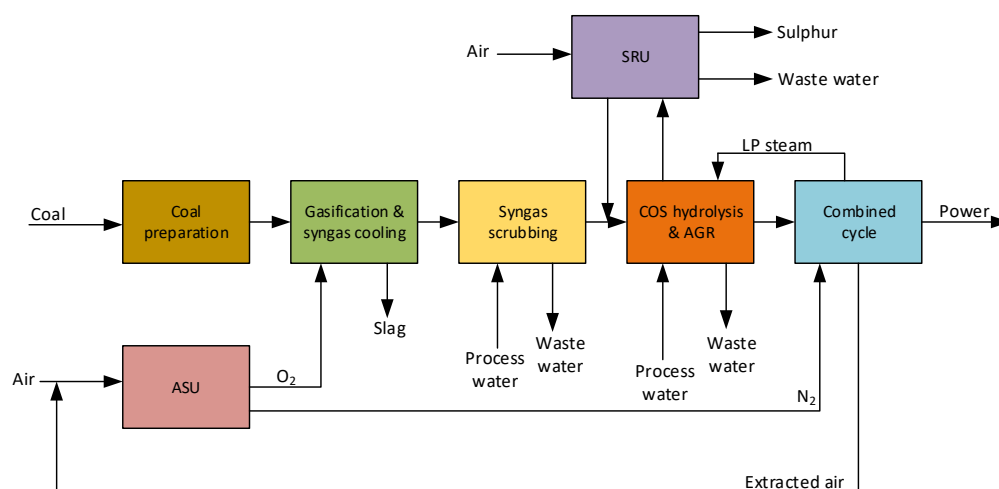


Figure 8: Process flow diagram of IGCC power plant without CO₂ capture (Wolfersdorf and Meyer, 2017).

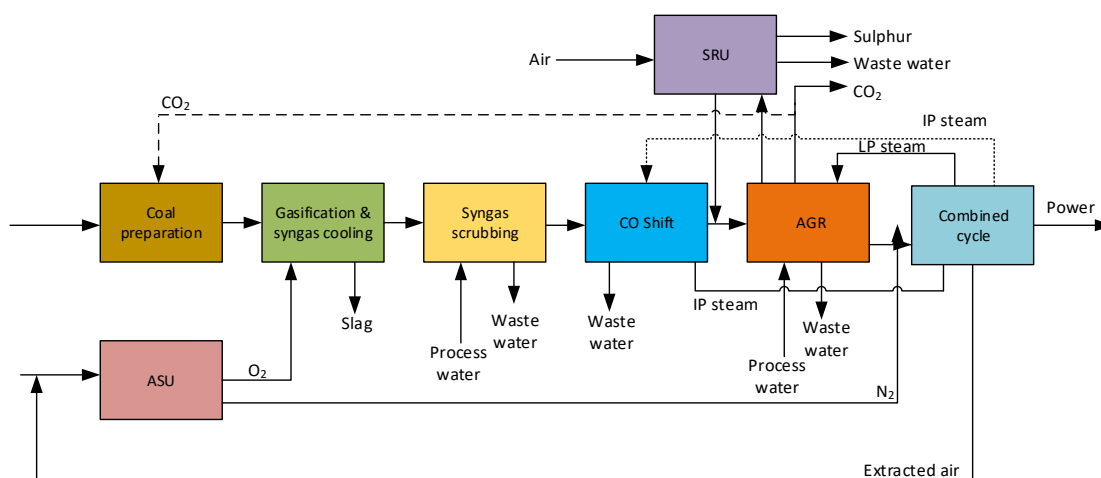


Figure 9: Process flow diagram of IGCC power plant with CO₂ capture (Wolfersdorf and Meyer, 2017).

Compared to traditional PC power plants, IGCC power plants provide a number of advantages including:

- **Higher efficiencies** - With efficiencies currently approaching 50%, IGCC power plants use less coal and produce lower CO₂ emissions compared to conventional coal fired power plants. With further developments in gas turbine concepts and increased process temperatures, efficiencies of more than 60% should be feasible.
- **Lower emissions** - IGCC power plants have advanced pollution controls that lower SO₂ and NO_x emissions to levels comparable with NG power plants. Mercury is easier to capture at an IGCC power plant than at a PC power plant because the mercury is in a higher-pressure stream with less N₂ diluent (Granite et al., 2006). CO₂ can be captured in a more concentrated stream (from syngas with a high CO₂ partial pressure) using technology that is more mature and cheaper to operate. IGCC power plants that incorporate partial CO₂ removal could still retrofit for more extensive capture later as regulations demand.
- **Product flexibility** - Coal gasification in IGCC enables the production of electricity as well as a range of other chemicals, by-products for industrial use, and transport fuels. Additionally, it can produce CO₂ at conditions required for enhanced oil recovery (EOR) and can produce H₂.

Despite these advantages, there are challenges to IGCC power generation that are limiting further commercialization. Some of the main issues that need to be addressed include:

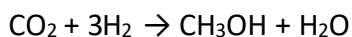
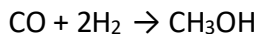
- **Need for pure oxygen** - Traditional gasification configurations are auto-thermal and utilize oxygen for the combustion of the feedstock, which leads to the requirement of an air separation unit which adds considerable cost and complexity to the process.
- **Need for constant feedstock** - In conventional gasifiers, the gasification process takes place in the same reacting volume. The only way to control the product is to vary the input concentration of feedstock (i.e., solid such as coal, water, and oxidant), reactor volume, pressure, or temperature. If a process is optimized for one type of feedstock (e.g., coal) problems can occur, primarily with reaction kinetics, when a different feedstock (e.g., varying coal qualities or biomass) is considered.

Other Syngas Applications

Gasification of coal is well known for its use in power production. Other opportunities for coal gasification include by-product reuse, easier capture of CO₂, production of liquid fuels and other chemicals through new market opportunities, particularly with a modular approach. A new and emerging market for coal gasification is the use of low-cost coal to generate clean syngas that can be used directly as a fuel for the production of materials such as ceramics, glass or aluminum (Fair, 2016). Syngas can also be used in the steel industry to replace natural gas in the production of direct reduced iron. Apart from electricity generation which was described previously, the other main applications that can be used with coal gasification are introduced below.

Methanol

Methanol (CH₃OH) synthesis takes place over a copper catalyst by the reaction of hydrogen (H₂) with carbon oxides according to the following reactions:



For methanol synthesis, the theoretical optimum H₂:CO ratio in the syngas is 2. Approximately 2.5–3.5% CO₂ is required to optimize the reaction, while CO concentration is limited to ~16 vol% to avoid excessive bed heating that could damage the catalyst. Methanol can then be converted to a range of other chemicals including acetic acid, dimethyl ether, ethylene, propylene, methyl acetate, and acetic anhydride. It has been reported that switching between chemical and power production when using the same feedstock is possible for methanol and urea production (Meerman et al., 2011). However, there is a trade-off between flexibility and overall efficiency.

Fischer-Tropsch Liquids

Fischer-Tropsch (FT) processes use an iron or cobalt catalyst to convert H₂ and CO into a mixture of straight chain hydrocarbons, from gaseous methane to high MW waxes, which can then be upgraded into liquid fuels and chemicals. Low-temperature Fischer-Tropsch (LTFT) at 180–250°C, 1–4.5 MPa and high-temperature Fischer-Tropsch (HTFT) at 300–350°C, 2–4 MPa processes are possible, but good heat transfer is required for all options due to the exothermic chemical reactions. For all options, the syngas must have low levels of phenols and tars as well as low sulfur content to prevent catalyst poisoning. Water and CO₂ slow the rate of FT synthesis for iron-based catalysts while the opposite occurs with cobalt-based catalysis. The H₂:CO ratio is also important and varies depending if HTFT or LTFT conditions are used (refer to Table 4). More details on the requirements for FT synthesis can be found in the report by Couch (2008).

Hydrogen

Hydrogen (H₂) has a range of uses in different industries including the refining industry to upgrade fuels and reduce their sulfur content, in ammonia power plants (see below), production of synthetic natural gas, liquid fuels, and chemicals as well as electricity production (via turbines or fuel cells). H₂ and electricity can be co-produced from coal gasification via a number of processing steps. Firstly, coal is gasified with oxygen (air blown operation is not suitable due to difficulty in separating H₂/N₂) and the resulting syngas is cooled, cleaned of particulate matter, and shifted (to primarily H₂ and CO₂) in sour water gas shift reactors. After further cooling, H₂S and then CO₂ is removed from the syngas, typically using physical solvents like Selexol. The CO₂ can be dried and compressed for pipeline transport and underground storage. High purity H₂ (99.999%) is extracted from the H₂-rich syngas via a pressure swing adsorption (PSA) unit and delivered at 60 bar. The PSA purge gas can then be compressed and burned in a conventional gas turbine combined cycle, generating co-product electricity. The H₂/electricity ratio can be varied by lowering the steam-to-carbon ratio in the syngas or by letting part of the de-carbonized syngas bypass the PSA unit (Chiesa et al., 2005). H₂ can also be produced from the de-sulfurized syngas using an iron-based (magnetite, Fe₃O₄) chemical looping system to produce H₂ simultaneously with CO₂ from the syngas (Cormos, 2012).

Ammonia

Ammonia is primarily used for manufacture of fertilizers including urea, ammonium nitrate, sulfate, and phosphate (Higman, 2008). It is also used in production of explosives, plastics, fibers, dyes, and pharmaceuticals. Ammonia synthesis occurs by reacting N₂ with H₂ at high pressure (6–18 MPa), usually over an iron catalyst, although one process uses ruthenium. High

purity H₂ is required (see Table 4). Urea production normally occurs in conjunction with ammonia production with the CO₂ from the ammonia power plant being reacted directly with NH₃ to produce urea (NH₂CONH₂).

Synthetic Natural Gas (SNG)

Demand for natural gas is increasing; however, not all locations have access to conventional or even unconventional (e.g., shale) natural gas. Therefore, there has been recent growth in production of synthetic natural gas (SNG) via coal gasification. SNG has almost the same properties as natural gas and can therefore be used in the same way as natural gas for power generation, as a chemical feedstock or for heating applications. Most commercial coal gasification SNG power plants are in China with the only U.S. commercial power plant being the Great Plains Synfuels power plant in North Dakota which produces SNG, fertilizer (via ammonia), CO₂ (for EOR), and other chemicals.

SNG typically has a composition of 94–96 vol% CH₄, 0.5–1 vol% CO₂, 0.5–1 vol% H₂ with the remaining 2–3 vol% N₂+Ar (Carpenter, 2008). SNG is produced by shifting the coal-based syngas to a CO:H₂ molar ratio of 1:3 and partially removing the CO₂. The shifted, cleaned syngas is then passed over a catalyst (typically nickel) which causes the CO and CO₂ to react with H₂ to form CH₄. If SNG is the main product, then a coal gasification process that produces high CH₄ content would be preferred, such as a fixed/moving bed type, as the volume of gas to be treated is reduced.

1.2.2 Gasification Technology Research & Development

Research and development of gasification technologies is occurring in a range of areas, with some developers focused on integration and efficiency while others focused on smaller, modular scale gasification systems. Generally, all R&D aims to reduce the overall cost of IGCC power generation from coal gasification. Increasingly R&D is considering more diverse gasification processes that maximize multiple benefits such as producing power as well as other value-added products or through the use of diverse feedstock including different ranks of coal, biomass, or waste materials. These diversified gasification processes are depicted in Figure 10.

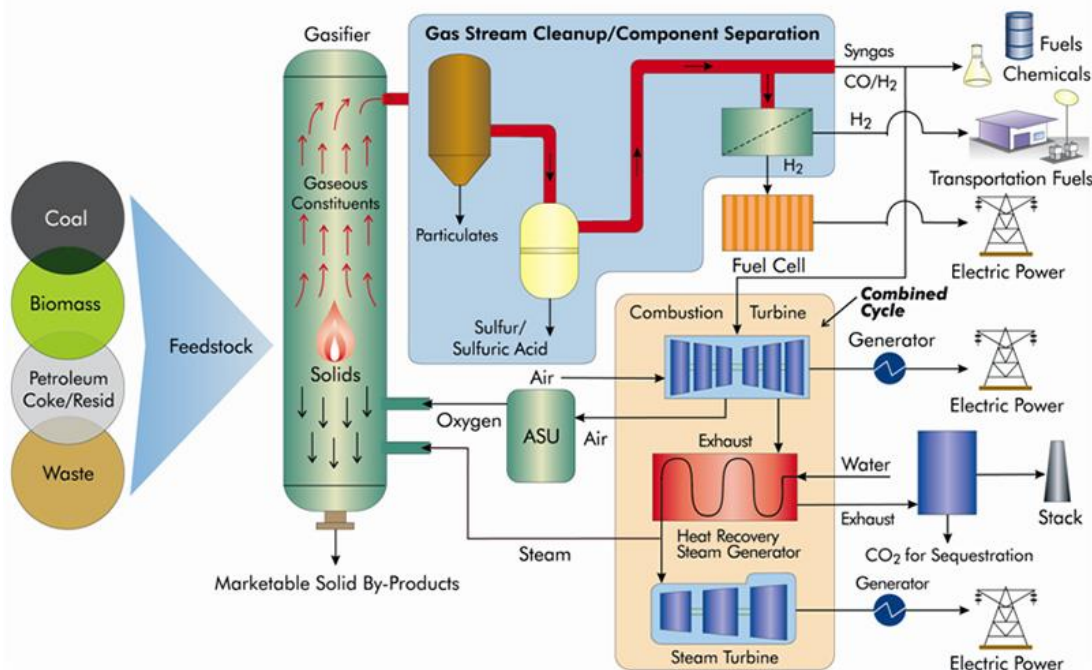


Figure 10: Gasification process for coal and other feedstock as well as the wide range of products provided by gasification technology (NETL, 2019a).

Although considerable attention is given to reducing the capital costs of gasification projects (see next section on modular gasification), researchers and industry are also working to find ways to reduce operating costs, often through efficiency improvements. For example, the ability to remove contaminants from hot or warm syngas instead of first cooling the gas (for use with today's commercially available AGR processes) has the potential to yield significant energy savings. RTI International has made progress in this area by developing a sorbent-based warm syngas cleanup process for H₂S and CO₂ removal that operates at 250–650°C (RTI International, 2019). Another research program is developing a sulfur-tolerant WGS catalyst, which would allow the sulfur in the syngas to be removed more cost effectively at a later stage in the process (Sasaki et al., 2017; de la Osa et al., 2011). Operating and maintenance costs of the gasifier can be reduced through development of higher firing temperature gas turbines to decrease fuel costs as well as automation improvements through development of devices for online measurement of important process parameters (e.g., gas temperature, process pipe thickness, etc.). Other projects have looked at the use of microwave assisted gasification processes to rapidly reach desired temperature (minimize start-up time), and achieve selective activation/heating of coal and other reacting species (reduces size of reactor, reduces catalyst deactivation and improves product distribution and selectivity) (Smith, 2019).

Modular Scale Gasification Systems for Power Generation

Traditionally, IGCC coal-based gasification processes have been designed as large processes (>500 MW) with corresponding high capital costs. Generally, with economies of scale, these large processes are expected to become cheaper as more are built. However, in many cases the significant upfront capital costs of these large power plants have been prohibitive which has limited widespread commercialization of IGCC technologies, and thus prevented the anticipated

cost reductions. Another option for reducing upfront capital cost is to consider installing smaller gasification facilities (unit sizes of approximately 50 to 350 MW) that can produce power to a mini-grid with the potential of also producing other valuable products. An example is SES's fluidized bed gasifier (U-Gas technology developed by Gas Technology Institute, GTI) that can operate efficiently at small-medium scale operations with a range of feedstock including low-rank, low-cost, high-ash, high-moisture coals, coal waste and biomass co-gasification (blends with less than 40% biomass) without changing the gasifier design (Synthesis Energy Systems, Inc., 2019; Lalou, 2014). It has been suggested that if traditional gasification power plants were to be operated in this way, with more than one product stream (e.g., electricity and FT-liquids), then they could encounter operational problems when complete substitution of the chemical process over the electricity process occurs due to low load on the gas turbine. This problem could be mitigated by having multiple, smaller (i.e., modular) gas turbines which is another benefit of a modular gasification approach (Meerman et al., 2011). With a modular design, a power plant can add extra units to scale up its capacity as the process is proven and cost allows. Modular operation could also improve power plant availability since it is possible to still operate the other gasifiers whilst carrying out maintenance or repairs on an individual gasifier. Current commercial large-scale designs often incorporate a spare gasifier in order to achieve acceptable overall power plant availability which entails a significantly higher capital cost. A modular approach, therefore, has the potential to improve the availability and economics of coal gasification processes. The use of multiple modular gasifiers will also allow optimized performance for different feedstock in order to use a mix of resources.

Small-scale modular gasification systems are expected to encourage accelerated technology development, reduce investment and operating costs, improve availability, reduce environmental impacts, and allow flexibility to meet site-specific needs. However, most commercially available coal fed gasifiers used in IGCC power generation are single large-scale units. Small-scale wood/biomass gasifiers are commercially available and many small-scale commercial units have been installed, but these gasifiers are typically operated as air blown with a downdraft fixed/moving bed type gasifier at sub-atmospheric pressure and most are used for producing heat with very few successful power applications (40kWe or less). An NETL-funded project with Southern Research Institute aims to develop a fuel flexible and modular oxygen-blown small-scale coal gasifier to produce syngas with very low tar and ammonia (Gangwal, 2019). The modular scale gasifier will be combined with a 1–5 MW combined heat and power system that can be scaled up by modular expansion and deployment at remote sites. Another NETL funded project conducted by The University of Kentucky will test a scaled-down version of a commercial gasification technology with a staged-OMB (opposed multi-burners) gasifier that utilizes coal slurry as a feed for high-temperature gasification (Placido, 2019). This project will enable investigation of small-scale, modular advanced gasification processes with standardized burners. The use of modular and standard equipment, rather than licensed commercial processes, has the potential for significant cost reduction through the use of cheaper units that can be made via advanced manufacturing techniques, pre-assembled and tested before shipment to the site of operation. Modular gasification technology could also be implemented at older PC power plant facilities (that may be near or at their closure) to maintain power generation using an environmentally superior process in areas with abundant coal reserves. For example, a 45 MW_{el} modular coal gasification combined cycle power plant has been demonstrated in South Africa where the mining industry had a need for power using readily available and abundant coal (van

der Linden et al., 2010). A used and refurbished industrial gas turbine was modified for use with syngas produced from a modular gasifier.

Most coal gasifiers require almost pure O₂, which requires an ASU which is generally not considered cost competitive at small scale. Conventional cryogenic air separation processes have both high capital and operating costs, which will be even more significant at modular scale. Therefore, a significant amount of research is being conducted to develop novel air separation technologies with reduced oxygen production costs that can be integrated at modular scale. The U.S. DOE has a research program focused on the development of modular air separation with reduced capital cost, low production costs, and high levels of operational efficiency. The main air separation technologies being investigated include (NETL, 2019b):

- **Membranes** - Intermediate-temperature ceramic hollow fiber membrane modules (Xue, 2019), carbon molecular sieve hollow fiber membrane units (Singh, 2019), ion transport membranes and mixed matrix membranes (Stewart, 2019) are all being developed for efficient oxygen separation from air at modular scale.
- **Sorbents** – High-temperature perovskite sorbents using vacuum swing adsorption (Sethi, 2019a,b) as well as advanced tailored oxygen sorbents that operate without vacuum desorption (Li, 2019) are being developed for air separation. Other studies are investigating the use of oxygen binding adsorbents (Zhou, 2019) and ferrites (Lekse, 2019) to produce oxygen.
- **Novel Cryogenics** – Improvements to the traditional cryogenics-based air separation process include development of novel fluid expanders (Pantula, 2019) and the use of magnetocaloric liquefaction technology (Holladay, 2019).

Gasification Feedstock Variation

Gasification processes can be designed to operate with a variety of feedstock including coal, petroleum, petroleum coke, natural gas, biomass, wastes, and blends of these feedstocks. This feedstock diversity is the fundamental reason why power generation from gasification can be used to address energy security concerns. Coal is the most common source of the carbon feedstock for gasification today and is likely to remain into the future as countries look for options to utilize their vast coal reserves, as demonstrated by China who is now leading the way in building new coal gasification projects.

Despite coal being the dominant gasification feedstock, other materials are increasingly being considered, which can have implications on the choice of gasification technology. Different fuels have different chemical, physical and morphological properties, creating different demands on the gasification process, and therefore the need for different reactor designs or technologies. To enable reliable and stable gasifier operation, the most important feedstock properties to consider include energy content, moisture content, volatile matter composition, ash content and composition, reactivity, particle size and size distribution, bulk density, and charring properties (FAO, 1986). Ideally, a universal gasifier would be developed that can handle all or most fuel types to enable process flexibility into the future.

Recent research has reported on the development of gasifiers that are suitable for a variety of feedstocks using the same equipment configuration. An example is the modular allothermal gasifier (MAG), which uses separate chambers for heat generation and combustion (Dooher et al., 2019). The MAG uses an external catalytic combustion chamber to provide energy for the

endothermic gasification and reforming reactions and can operate over a range of pressures up to 3 MPa (30 bar), which allows for process control for different end-use needs or feedstock rates. Minimal emissions are produced due to the catalytic combustion operations and the system can be used with small gasification systems without increases in heat loss that typically occur with conventional small-scale gasifiers. The system is modular and compact allowing easy transportation to sites, including those that are remote or have space limitations. The MAG gasifier is reported to be suitable for coal as well as biomass applications, with the latter having the benefit of producing a syngas at high-efficiency that can be further upgraded to methane (or hydrogen) and be free of tars, oils, particulates, ash, and alkalis (Nisamaneenate et al., 2015).

Twin IHI Gasifier (or TIGAR) is a fluidized bed type of gasifier suitable for low rank feedstock like lignite and biomass that has been developed by IHI Corporation. It is currently under development and uses steam as the gasifying agent to produce a H₂ rich syngas (Hiroyuki, 2017).

Another relatively new type of gasifier, known as the Blue Tower Gasifier (BTG), incorporates an innovative design that also provides flexibility in feedstock type and equipment scalability (Herdem et al., 2019). Within the BTG system, heat is supplied to the pyrolysis and reforming zones via the use of preheated heat carrier materials instead of direct incineration resulting in a self-sustaining system (following start-up) that can be powered by its own products. Additionally, the thermolysis and reforming processes take place in separate reactors, allowing more control of the reforming stage. Plasma gasification research has also grown recently as fuel flexibility requirements increase; however, low gasification efficiency and high electrical energy requirements are issues that need attention (Janajreh et al., 2013).

Polygeneration Processes

Polygeneration power plants, that produce electricity as well as other products from coal gasification, offer a range of benefits including enhanced energy security, low emissions and potential for carbon capture, cleaner products, feedstock flexibility, market flexibility, increased efficiency, better equipment utilization, and lower costs. Being able to tailor the syngas to a desired composition (regardless of feedstock composition) is important for production of chemicals from syngas. Generally, variations in flow can be accommodated, but a consistent syngas composition is generally desired for further chemical processing. It is well known that the capital costs of electricity generation from coal gasification via IGCC is capital intensive. Similarly, coal gasification that produces syngas for production of gas-to-liquids power plants are also capital intensive, with the syngas production representing greater than half of the capital cost of the power plant (Spath and Dayton, 2003). Future polygeneration gasification power plants will therefore benefit from cost reductions and flexible operating conditions including (Wolfersdorf and Meyer, 2017):

- Gas clean-up that can be operated with varying syngas compositions depending on if the power plant requires optimum syngas composition (via addition of WGS) or without WGS, resulting in lower CAPEX.
- Operation of the synthesis or chemical production section of a polygeneration power plant under partial recycling of unreacted gas which allows for maximum conversion or once-through synthesis option to reduce costs. An example of this arrangement is the Air Products methanol synthesis process (Air Products, 2019).

- Maximum flexibility which can be achieved via load-following designs, whereby electricity generation is increased during peak hours while synthesis production is increased during other times (Meerman et al., 2011, 2012).

Through DOE/NETL funding, The University of Kentucky is developing a local heat and power polygeneration process via modular coal gasification and optional Fischer-Tropsch synthesis resulting in three useful products: power, heat, and liquid hydrocarbons (Nikolic, 2019). A commercially available air separation unit is to be used to produce oxygen and the burner size was fixed to the O₂ available with inside chamber tubes suitable for different kinds of coal. The 5 MW_{el} gasification process will use waste coal fines and biomass (sawdust from lumber industry) with excess syngas being sent to the F-T unit. H₂S and CO₂ are removed to meet EPA requirements and minimize the acid gas removal unit size.

1.3 CONCLUDING REMARKS ON GASIFICATION

Despite the declining trends of the past decade in the U.S., global demand for coal gasification processes to produce energy is increasing, particularly as more widespread and stringent environmental regulations are adopted and due to the potential for fluctuating prices of other fuels such as natural gas. IGCC power generation has the ability to provide low-cost, low-emission energy from locally sourced coal with superior carbon capture capabilities, particularly when compared to traditional coal-based energy generation. Increasing energy demands along with stricter environmental regulations will encourage further deployment of coal gasification energy projects, particularly in remote areas and developing countries. Combining the applications of power generation and chemical production will enable a more flexible and diverse path for growth of coal gasification technology.

The following technical issues need to be considered in order to encourage further deployment of coal gasification technology for power generation:

1. Capital cost reduction particularly at small scale, potentially through adoption of modular technology and brown-field development
2. Increased operational availability of the power plant to at least 85% (Higman and Phillips, 2007)
3. Increased efficiency of carbon capture (and potential for CO₂ utilization)
4. Adopt lessons learned from past IGCC power plants
5. Use of flexible feedstock technology and consideration of polygeneration processes

Polygeneration power plants provide the option for diversified products, but the capital costs still need to be reduced, particularly for the syngas production part of the power plant. The thermal efficiency could also be improved via heat integration, which could be achieved by combining the chemical synthesis power plant with the power generation plant to take advantage of the availability of low-pressure steam. Understanding the impact of coal characteristics and their performance in different gasification technology is important for the design and operation of future gasification applications.

A summary of NETL-funded R&D projects for the Gasification Systems research program can be found in Appendix B.

2. LITERATURE REVIEW ON PRE-COMBUSTION CARBON CAPTURE TECHNOLOGIES WITH POTENTIAL FOR USE WITH MODULAR GASIFICATION SYSTEMS

Pre-combustion carbon capture is defined as when carbon (usually in the form of carbon dioxide, CO₂) is captured from a fuel gas before it is combusted in a gas turbine to produce electricity or is used as a feedstock in another application. Pre-combustion capture is applicable to all fuel gases including natural gas and syngas. Also, dependent on the type of gasifier, pre-combustion capture may or may not be required from chemical looping gasification (CLG) processes. Chemical looping combustion (CLC) and CLG processes have been reviewed by others (Mantripragada and Rubin, 2017; Zhu et al., 2015). Traditional gasification processes produce syngas (mainly hydrogen and carbon monoxide) from a solid fuel (coal, biomass, or solid waste) by applying heat under pressure and in the presence of steam (or carbon dioxide) and oxygen or air. For carbon capture from natural gas, the gas stream (containing mostly methane) is first converted to syngas, through partial oxidation or steam reforming, and then decarbonized via carbon capture processes. Figure 11 is a block flow diagram of the current state-of-the-art (SOTA) coal-based IGCC power plant with pre-combustion CO₂ capture.

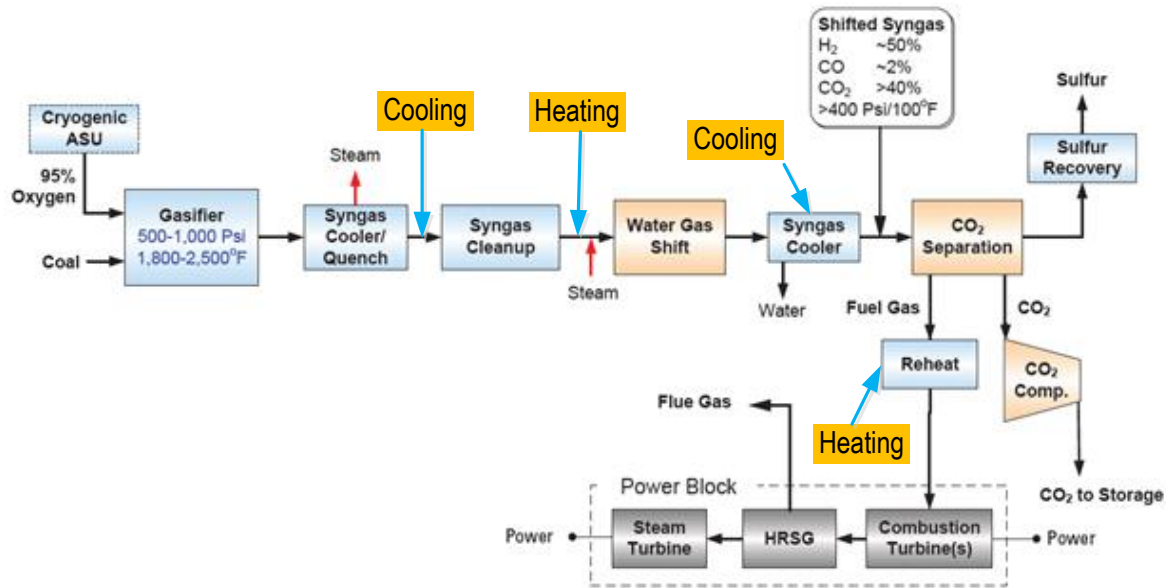
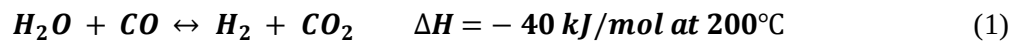


Figure 11: Block flow diagram of current state of the art IGCC power plant with CO₂ capture (adapted from Breeze (2015)).

In this IGCC power plant, syngas from the gasifier is cooled before it is cleaned up by removing particulates and sulfur. After syngas cleanup, the gas is heated to WGS reaction temperature to convert all CO to CO₂ according to the following reaction:



CO₂ now can be removed from the syngas to generate a carbon-free, hydrogen-rich fuel gas. This fuel gas is finally heated to the temperature required for combustion before being used to fuel the combined cycle to produce electricity (including a gas turbine generator and steam turbine generator).

Compared to post-combustion CO₂ capture, which removes dilute CO₂ (~5–15% CO₂ concentration) from low-pressure flue gas (0.05 to 0.15 bar of CO₂ partial pressure), the shifted syngas is rich in CO₂ (~40% concentration) and at much higher partial pressure (~20 bar). Due to the much higher partial pressure of CO₂ in the shifted syngas, pre-combustion CO₂ capture is usually much more efficient when compared to post-combustion CO₂ capture. However, due to the large capital costs associated with the base gasification system, IGCC power plants are often much more expensive than traditional pulverized coal (PC) power plants. It is, therefore, imperative to reduce the capital cost of the IGCC power plant, with or without carbon capture, to encourage success of IGCC power plant technology. Capital cost reduction will be even more critical when it comes to smaller scale modular gasification power plants.

By reviewing Figure 11, it can be seen that the syngas cleanup unit, WGS unit and CO₂ separation unit are the central blocks to pre-combustion CO₂ capture. When pre-combustion CO₂ capture is required, a WGS reaction step is necessary to convert CO to CO₂. Due to the temperature difference between the CO₂ capture unit and the WGS reactor, heating/cooling is required before and after the WGS unit. The cooling and heating associated with the syngas cleanup unit and CO₂ separation unit adversely impact the thermal efficiency of the IGCC power plant. Therefore, innovative gas cleanup or CO₂ separation technologies that can be incorporated into the gasification process with minimal heating or cooling of syngas will improve the overall thermal efficiency of the IGCC power plant. It is desirable to develop process integration concepts that exploit the interactions between the different units in order to improve efficiency and minimize costs. Integration between syngas cleanup, WGS reaction, and CO₂ separation will not only eliminate the heating and cooling between these units, and thus improve the thermal efficiency of the IGCC power plant, but will also eliminate the need for separate equipment items, which will reduce the footprint and capital cost of the power plant. This concept is particularly attractive for modular gasification technology development.

Two factors that are important for the success of modular gasification systems are its compact design (small footprint) and low capital cost. It is well recognized that IGCC is capital intensive compared to PC power plants. When a power plant is downsized, capacity is reduced linearly whereas the capital cost increases according to a power law with an exponent of ~0.65 (Adams et al., 2017). Table 5 and Figure 12 show how the hypothetical total levelized cost of electricity (LCOE) changes with the power plant scale. The full-scale case (556 MW_{el}) and associated costs are from the Baseline Case B5B which is an IGCC process with 90% CO₂ removal (James et al., 2019). In the calculations, the fixed and variable operating costs were kept constant as scale is changed, which is likely not realistic. More likely, these costs will increase as well on a \$/MWh basis. The point of creating Table 5 and Figure 12 is simply to highlight that capital costs must be reduced significantly at modular scale, through advanced manufacturing, mass-production and brownfield development, in order to prevent the problem of economics at small scale.

Table 5: Hypothetical LCOE Variation with Power Plant Scale

Power Plant Scale (MW _{el})	Capital Cost (\$/MWh) * (James et al., 2019)	Fixed Costs (\$/MWh) (James et al., 2019)	Variable Costs (\$/MWh) (James et al., 2019)	Fuel Costs (\$/MWh) (James et al., 2019)	Total LCOE (\$/MWh)
556	75	27	19	23	144
150	115	27	19	23	184
50	168	27	19	23	237
15	257	27	19	23	326
5	377	27	19	23	446

*power law of $C_2 = C_1 (S_1/S_2)^{0.35}$ was used to scale capital cost of the full power plant to modular scale (Adams et al., 2017)

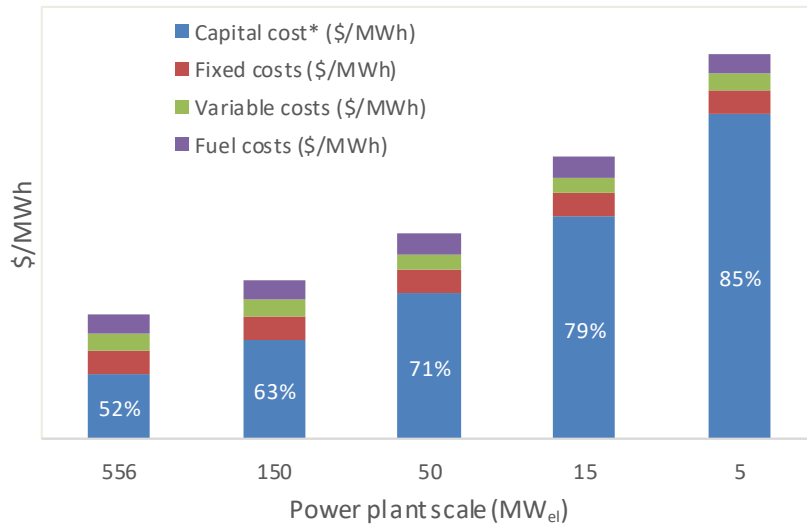


Figure 12: Hypothetical power plant costs as a function of power plant scale (plotted from Table 5).

According to the results in Table 5 and Figure 12, when the scale or size of a power plant is reduced by 100 times (from ~500 MW_{el} to 5 MW_{el}), the total LCOE will increase by about three times. Additionally, in the smallest size power plant, the capital cost will now represent approximately 85% of the LCOE, a significant increase from 52% at the full-scale power plant size. For that reason, reducing capital cost via mass-production and advanced manufacturing becomes increasingly important for modular gasification technologies. Therefore, the analysis conducted in this report will focus on reviewing innovative CO₂ capture technologies that will simplify the IGCC power plant and/or reduce capital costs of the power plant including the integration of WGS reaction and CO₂ capture. Other technologies that do not show promise for radically reduced capital cost (or only incrementally reduced capital or operating costs), such as solvent/sorbent/membrane material improvement, will not be reviewed in detail for this study.

In order to understand the innovative processes presented for pre-combustion CO₂ capture, there are two characteristics of the WGS reaction that need to be understood. The first is that the WGS reaction, see Equation (1), is equilibrium controlled (i.e., a reversible reaction with limited CO conversion) and the second is that the WGS reaction is slightly exothermic with a heat of reaction $\Delta H = -40 \text{ kJ/mol}$ at 200°C. Since the WGS reaction is equilibrium controlled, either a higher concentration of H₂O or a lower concentration of the products (either H₂ or CO₂) will favor the WGS reaction moving forward to provide a higher conversion of CO to CO₂. However, using larger amounts of H₂O (higher H₂O/CO ratio) will adversely impact the thermal efficiency of the power plant; therefore, reducing the product concentration will be the more desirable option for increasing the WGS reaction efficiency. The exothermic nature of the WGS reaction implies that a lower reaction temperature will favor the forward reaction, or conversion of CO to CO₂. This is why conventional WGS reactors are staged with the consecutive stage having a lower temperature. However, a lower reaction temperature will reduce the WGS reaction rate, which will increase the reactor volume (catalyst amount) or capital cost. These two characteristics are therefore the theoretical foundation for integration of WGS reaction and CO₂ separation and overall process optimization.

Researchers have been proposing novel pre-combustion CO₂ capture ideas for reducing the cost of capture (Figuerola et al., 2008). Depending on the different CO₂ capture configurations, these novel ideas can be divided into the following five types of processes: (1) solvent-based absorption processes; (2) sorbent-based adsorption process; (3) membrane-based processes; (4) integrated processes where WGS reaction and CO₂ separation are integrated into one unit operation; and (5) hybrid or other processes. This report will provide an overview of all of these CO₂ capture technologies for suitability with modular scale gasification processes including their advantages and disadvantages.

2.1 SOLVENT-BASED PROCESSES FOR PRE-COMBUSTION CO₂ CAPTURE

A solvent-based CO₂ capture process is an absorption process that is widely used for gas separation and purification. Absorption processes can be used in both pre- and post-combustion power plant applications for CO₂ capture. There are two types of solvents: chemical and physical. As the name implies a chemical solvent relies on the chemical reaction between CO₂ and the solvent to enhance absorption, whereas a physical solvent absorbs molecular CO₂ via van der Waals interactions. Chemical absorption involves the formation of chemical bonds between CO₂ and solvent molecules, and thus can be highly selective and exhibits saturation at a certain level. Whereas, a physical solvent relies on the van der Waals forces and will not show saturation. At lower CO₂ partial pressure, chemical solvents have a higher absorption capacity due to the stronger, selective interaction, which makes them more attractive for use in post-combustion flue gas conditions. At higher CO₂ partial pressures, however, the capacity of chemical solvents levels off due to the saturation of the stronger, but selective interaction. For physical solvents, on the other hand, CO₂ capacity increases linearly with the increase of CO₂ partial pressure (Henry's Law). Thus, above a certain CO₂ partial pressure, physical solvents are preferred. Due to the lower regeneration energy, Selexol and other similar physical solvents outperform chemical solvents such as amines, when the CO₂ partial pressure is above about 10 bar. As mentioned, CO₂ partial pressure in shifted syngas is typically above 20 bar, more than 100 times higher than in post-combustion flue gas; therefore, a physical solvent is usually preferred over a chemical solvent for pre-combustion capture.

Solvent-based CO₂ capture using physical solvents is currently the SOTA pre-combustion CO₂ capture process. A physical solvent absorption process typically consists of an absorber column and solvent regeneration process. Figure 13 is a schematic process flow diagram of a solvent-based CO₂ capture process. Note that the figure below does not show the equipment used to separate H₂S and COS from the syngas.

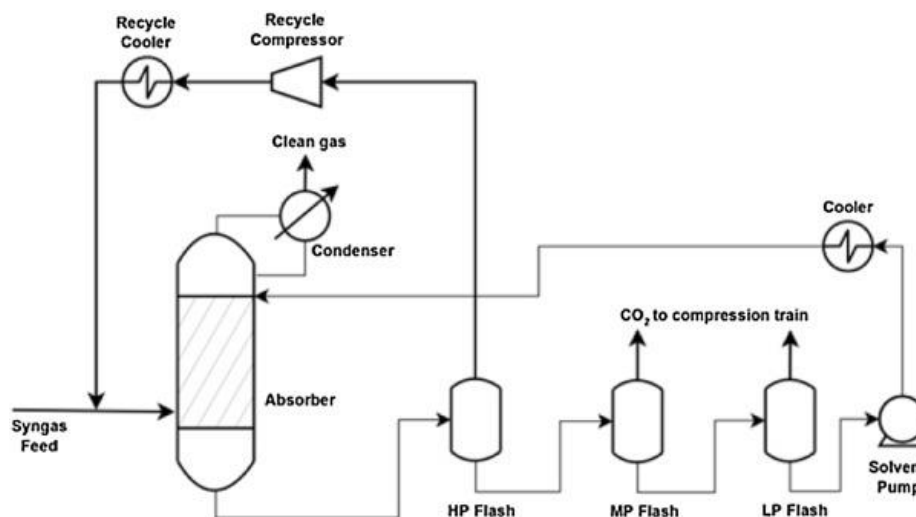


Figure 13: Simplified flow diagram of a physical solvent-based CO₂ capture process (Siefert et al., 2016a).

In this process, untreated raw syngas (feed gas) enters the absorber from the bottom to contact with the lean solvent which flows from top to the bottom of the absorber. CO₂ is favorably dissolved into the solvent as it passes through the column. The cleaned syngas (or treated gas) exits the top of the absorber and the CO₂-rich solvent goes to the regeneration process where the absorbed CO₂ is released via pressure drop (Pressure Swing Absorption) or in some cases temperature increase (Temperature Swing Absorption). Since loss of hydrogen will reduce power plant efficiency, a high-pressure flash drum is usually added before the CO₂ flash drums to recover the dissolved hydrogen from the solvent and recycle it back to the absorber. If a temperature swing (via reboiler) is used to release the dissolved CO₂ from the solvent, then a cross heat exchanger (L/R Exchanger) is usually employed to recover the sensible heat. If pressure swing is used to release the CO₂ from the solvent, then one/or more flash drums (with compressors and coolers) will be used to release the CO₂ before the lean solvent is recycled back to the absorption column, via a solvent cooler if required (as shown in Figure 13).

A number of variations to the basic CO₂ capture process presented in Figure 13 are available depending on the types of solvent used, the solvent regeneration method selected (temperature or pressure swing), and/or if H₂S needs to be removed separately or in the same process. Two of the most popular commercially available solvent-based syngas CO₂ removal processes are the Selexol process and Rectisol process (Kohl and Nielson, 1997). Both processes can remove H₂S and CO₂ using the same solvent. Figure 14 shows the two-stage Selexol process used in DOE's baseline study (James et al., 2019; Zoelle et al., 2015). Syngas enters the bottom of the H₂S absorber and flows upward where it contacts solvent, loaded with CO₂, entering at the top of the column, which preferentially removes H₂S from the gas phase. The gas from the H₂S absorber

flows upward through the second absorber where CO₂ is removed, first by semi-lean, flash-regenerated solvent entering near the middle of the tower, followed by chilled, lean solvent entering at the top of the tower. The treated H₂ rich gas then goes to the combustion turbine. The CO₂ loaded solvent exits the CO₂ absorber where a portion is sent to the H₂S absorber to remove H₂S and the remainder is sent to a series of flash drums for regeneration. The first flash drum operates at 2.0 MPa (289.7 psia) where H₂, CH₄, CO₂, and other dissolved gases are removed, compressed, and returned to the CO₂ absorber which minimizes product losses to the CO₂ stream. The following two sequential CO₂ flash drums operate at 0.55 MPa (80 psia) and 0.1 MPa (16.7 psia), respectively, to remove gaseous CO₂ from the solvent, which is then sent to the CO₂ compressors and the semi-lean solvent is pumped back to the CO₂ absorber.

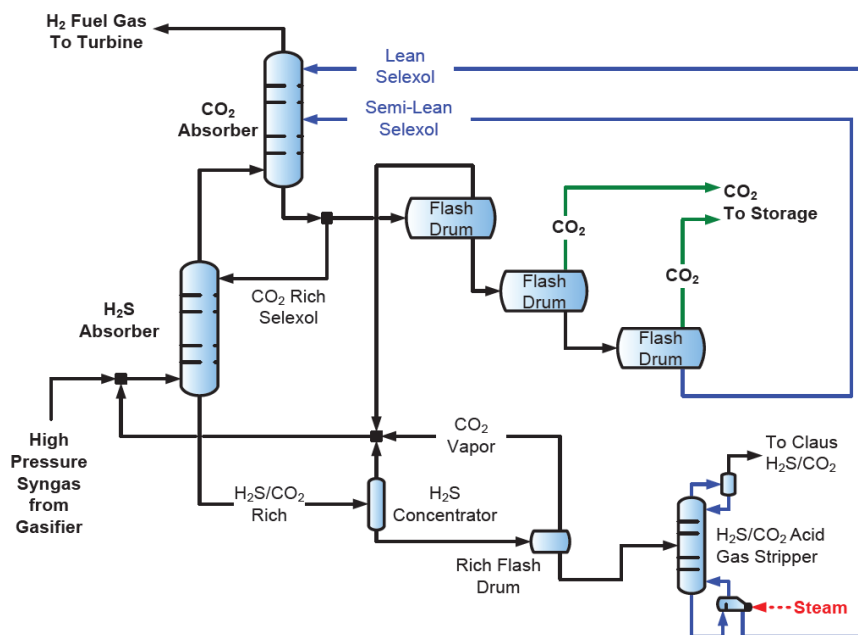


Figure 14: Simplified flow diagram of a two-stage Selexol-based absorption process (NETL, 2019f).

Figure 15 is a simplified schematic process flow diagram of the Rectisol process which uses methanol as its solvent. The absorption temperature in the absorber is extremely low ($\sim -50^{\circ}\text{C}$), especially at the top of the column. Since a refrigeration system is required in this process it is more capital intensive compared to the Selexol process. The main advantage of the Rectisol process is that it can remove all undesirable components including H₂S, COS, and CO₂ in the same process, and in particular it can remove H₂S to <10ppm.

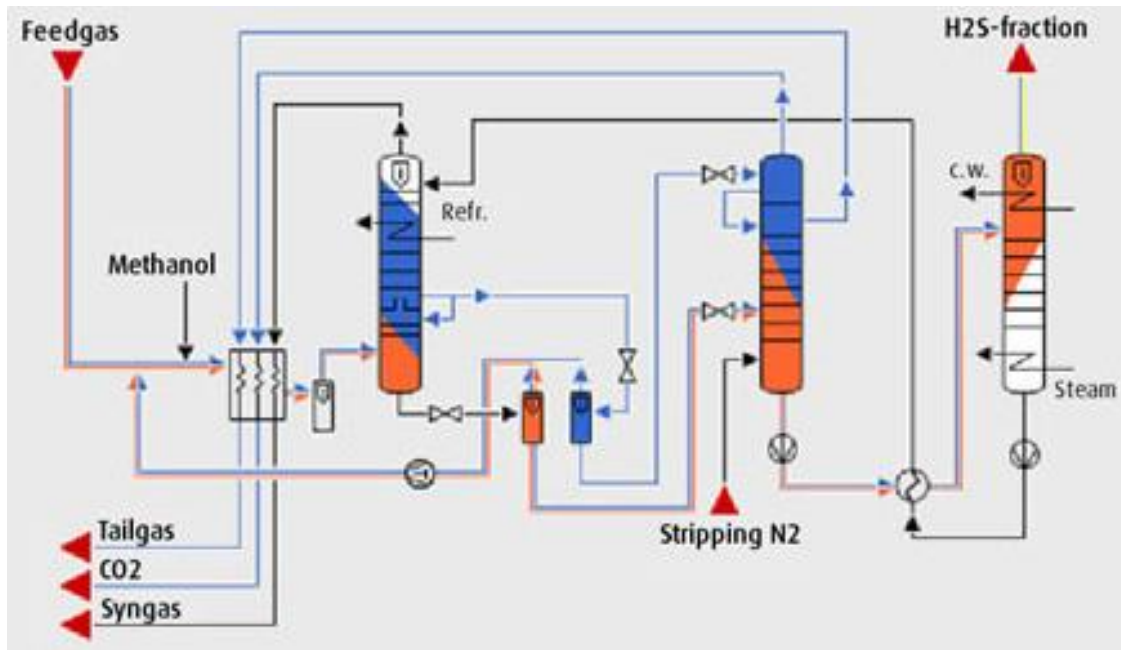


Figure 15: Schematic process flow diagram of Rectisol process (NETL, 2019e).

Although Selexol and Rectisol are the most commonly used physical solvent absorption processes for CO₂ removal from syngas, there are other commercial absorption-based processes available, for example propylene carbonate (Fluor process) and N-Methyl-2-Pyrrolidone or NMP (Purisol process). In addition, a range of other novel solvents such as ionic liquids (which have much higher capital costs) and hydrophobic physical solvents are under development for pre-combustion CO₂ capture (Siefert et al., 2016a; Basha et al., 2013). Promising technical performance has been shown during laboratory-based studies with these novel solvents. However, the overall improvements in efficiency and hence costs between the different solvents in traditional solvent columns are considered incremental and not considered significant enough for reducing the capital cost of carbon capture at modular scale.

2.1.1 Advantages and Disadvantages of Absorption Based Processes for Pre-Combustion CO₂ Capture

The **advantages** of using solvent absorption processes for pre-combustion CO₂ capture are listed below:

- Absorption processes are a mature technology and are commercially available

Solvent processes have been used in gas separation and purification applications in the chemical industry for many decades and are the current SOTA technology for pre-combustion CO₂ capture for IGCC power plants.

- Smooth continuous operation of the process

Solvent-based processes are continuous and operate under steady state conditions. This makes the process operation and control easier. This is especially important when the process scale is large due to longer transition time.

- Allows combined CO₂/H₂S removal

Both physical and weak chemical solvents have the ability to remove H₂S and CO₂ in the same process. When these two gases can be co-sequestered the entire process may be simplified to a single absorption process and the capital cost can be significantly reduced.

- The process may not require heat for solvent regeneration

Due to high partial pressure of CO₂ in syngas, physical solvents or weak chemical solvents (such as MDEA) can be used to absorb CO₂ and the regeneration of these solvents can be achieved through pressure swing. Pressure swing regeneration eliminates capital and energy intensive heat exchangers including the cross heat exchanger.

- Flexibility to use temperature swing for solvent regeneration

Temperature swing regeneration offers the possibility of regenerating the solvent and producing CO₂ product at higher pressure by using heat. This could be advantageous when a cheap heat source is available. Besides, higher regeneration pressure will reduce the pressure difference between absorber and stripper (or flasher), which in turn will reduce the power consumption in a circulating solvent process and in the CO₂ compression. For solvent-based processes, sensible heat can be easily recovered using a cross heat exchanger. However, temperature swing solvent regeneration is more complex than pressure swing regeneration because it often requires sensible heat recovery.

- Easy solvent reclamation

It is unavoidable that some solvent may be degraded after contacting industrial syngas streams with a range of minor components. Solvent reclamation is very common and the degraded solvent can be easily removed through a slip stream of a reclamation process.

- Some solvents can be synthesized onsite using syngas

Some solvents, particularly methanol for the Rectisol process, can be synthesized on-site from the syngas.

The **disadvantages** of using solvent absorption processes for pre-combustion CO₂ capture are listed below:

- Traditional absorption process operates at relatively low temperature

Solvent-based absorption processes operate at relatively low temperature, particularly when compared to the high temperature of the syngas. If operated at high temperature, the solvent may not be chemically stable or its vapor pressure may be so high that solvent loss will be significant.

- High capital cost, particularly at small scale

Absorption involves mass transfer in the gas phase, gas liquid interface and in the liquid phase. Mass transfer in the gas phase is relatively fast. But mass transfer in the liquid phase can be slow. Another factor that affects the overall mass transfer rate is the interfacial area between the gas phase and the liquid phase. The interfacial area per unit

volume in either packed or tray columns is usually low compared with adsorption beds and membrane modules. The low interfacial area and slow liquid phase mass transfer often results in taller columns making the absorption processes capital intensive.

- Need for multiple pieces of equipment

Most solvents dissolve small amounts of hydrogen. The high-pressure flash vessel and a H₂ compressor are used to minimize the loss of hydrogen. At modular scale, the costs for these equipment items become expensive. H₂ uptake into void space of solid sorbent and H₂ diffusion through membrane can also complicate the design of other capture processes. It is important to note that at modular scale, it is crucial to minimize the number of pieces of equipment to avoid equipment whose costs are weak functions of the scale of the equipment, such as pressure vessels.

2.1.2 **R&D Focus for Absorption Processes**

Future improvements for solvent-based pre-combustion CO₂ capture processes will include:

- Increase the working capacity of the solvent

Increasing the working capacity of the solvent will improve both the capital cost and operating cost of the process. Higher working capacity will reduce the circulating volume of the solvent, which will reduce the column size and pumping power requirements. For temperature swing regeneration processes, it will also reduce the sensible heat required for the cross heat exchanger.

- Improve stability of the solvent toward thermal, oxidative, and resistance to any contaminants in the syngas

Improvement in solvent stability will reduce the consumption of the solvent, which will reduce solvent loss and operating costs of the process.

- Process intensification

Absorption processes rely on interaction between the gas and liquid phases. Absorption equipment which can generate high gas/liquid interfacial area (e.g., via a membrane contactor) and high liquid side mass transfer rates will be able to reduce the footprint of the process and capital cost.

- Improve CO₂/H₂ selectivity

Increasing the CO₂/H₂ selectivity will reduce the hydrogen loss in the solvent and increase the productivity. Ultimately, the flash drum used to recover hydrogen could be eliminated, which will reduce the capital cost of the process and also increase the CO₂ product regeneration pressure and thus reduce operating costs.

- Reduce solvent corrosivity

Reducing the solvent corrosivity could enable use of a less expensive metal for construction of the columns, which will reduce capital cost.

- Reduce solvent volatility

Reducing solvent volatility will reduce solvent lost from the CO₂ product, which in turn reduces the operating cost.

It should be noted that these potential improvements for pre-combustion solvent absorption processes will reduce either the capital or the operating cost of the process but will not significantly change the process configuration as shown in Figure 13. All potential improvements, except the process intensification option, are expected to provide only incremental improvements, rather than transformational impacts, on the LCOE of the IGCC power plant with carbon capture. As the capital cost is expected to be more important at modular scale, novel solvent processes will likely need to be coupled with H₂-selective membranes and take advantage of waste heat in order to provide significant cost benefits at modular scale.

2.2 SORBENT-BASED PROCESSES FOR PRE-COMBUSTION CO₂ CAPTURE

Sorbent-based processes are a widely used unit operation (called adsorption) in the chemical industry for fluid (gas, vapor, or liquid) separation. Adsorption refers to the phenomenon of a fluid component being concentrated at the surface, or in the pores, of a solid. The solid is called the sorbent or adsorbent, and the fluid is called the sorbate or adsorbate. Although adsorption takes place only on the surface of a sorbent, this surface can be quite large when the sorbent is porous. Indeed, sorbents in industrial applications are almost always micro-porous to maximize surface area so as to increase the sorbent capacity.

Sorbent-based processes can be used for both pre- and post-combustion CO₂ capture. Figure 16 is a schematic display of an adsorption process. Here M refers to fresh sorbent and N represents saturated sorbent. In this process, desorption (or sorbent regeneration) is achieved by raising the temperature of the saturated adsorbent to drive the adsorbate (in this case CO₂) out. In Figure 16, the solid sorbent is assumed to be in countercurrent contact with the gas phase and the sorbent moves from the top to the bottom of the adsorption and desorption columns. Such a process configuration is similar to Figure 13 except that one utilizes a liquid solvent and the current process utilizes a solid sorbent. However, as the adsorption process involves a solid sorbent, continuous operation (i.e., at steady state conditions) becomes much more difficult to accomplish compared to a gas/liquid absorption process. This issue could be critical when the process scale is very large, such as the scale of a large power plant.

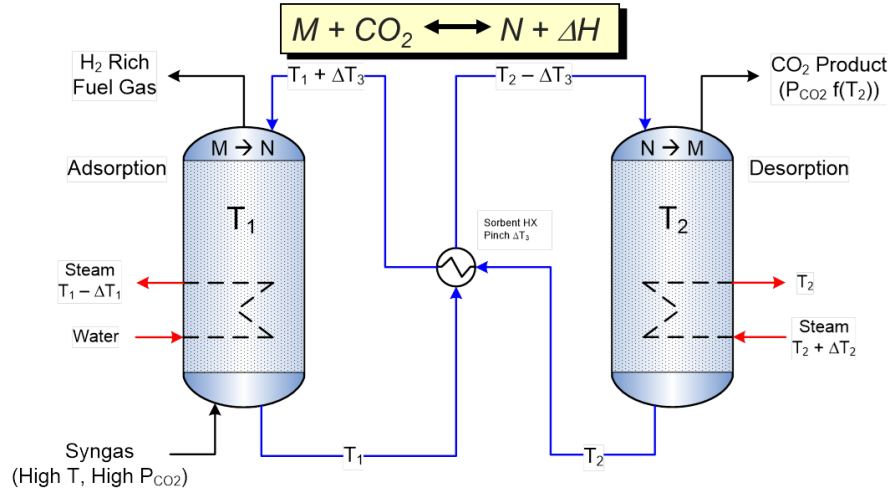


Figure 16: A schematic display of a sorbent process for CO₂ removal from syngas.

There are three basic process configurations available for an adsorption process: fixed bed, moving bed, and fluidized bed. A fixed bed configuration is the most commonly used option, especially when the gas component to be separated is only present in trace amounts. In this case temperature swing adsorption (TSA) is usually used for sorbent regeneration. When the gas component to be separated has a high concentration in the feed stream (e.g., 10% or more), a fixed bed adsorption process using TSA will no longer be suitable and a PSA process is normally used. In a PSA process, multiple beds are often used to improve process efficiency. In a fluidized bed, the solid is often treated like a liquid so that continuous operation can be assumed but it has some drawbacks as shown in Table 6. A fluidized bed is usually selected only when intensive heat transfer is required. A moving bed is the least commonly used configuration because of its equipment requirements and complex process control. Table 6 lists some advantages and disadvantages of the three process configurations available for adsorption processes.

Table 6: Advantages and Disadvantages of Adsorption Process Configurations

Process	Advantages	Disadvantages
Fixed Bed	• Least attrition • Easy operation	• Unsteady-state operation • Cyclical operation mode • Large sorbent inventory • Lowest process efficiency
Moving Bed	• Low sorbent inventory • Countercurrent flow • Steady state operation • Highest process efficiency (similar to countercurrent solvent processes)	• Complex equipment and process control • Attrition issue
Fluidized Bed	• Continuous operation • High mass and heat transfer rates	• Back mixing will reduce driving force • Serious attrition issue • Difficult to scale up (without high-quality computational simulations)

One of the disadvantages of the fixed bed configuration is the need for a large sorbent inventory due to the successive adsorption and desorption steps. This results in a time-cycle and the adsorption/desorption steps are in a transient-state instead of steady-state. Multiple packed-beds are often used in shifted time-cycles to achieve continuous production. Such transient operation leads to high sorbent inventory and many locations requiring automated switching of valves. Figure 17 displays a sorbent bed during different times of the adsorption process. At any moment, the pink shaded zone (called Mass Transfer Zone or MTZ) is where adsorption is occurring. The other sections of the adsorption bed, either the equilibrium zone (EZ), where the sorbent is saturated with adsorbate (CO₂) or the fresh zone where adsorption has not yet taken place, is not being used. Clearly, the MTZ is only a fraction of the entire fixed bed and as such the majority of the sorbent is not being used. This may not be critical, particularly when the adsorbate in the gas phase is only present in trace amounts, because a small bed could be used for a long time. But when the adsorbate concentration in the feed stream is higher, say more than ~5% (such separation is called bulk separation), the adsorbate will quickly saturate large amounts of sorbent, and the unused bed will become critical. When comparing an adsorption process with an absorption process the entire absorption column is the MTZ.

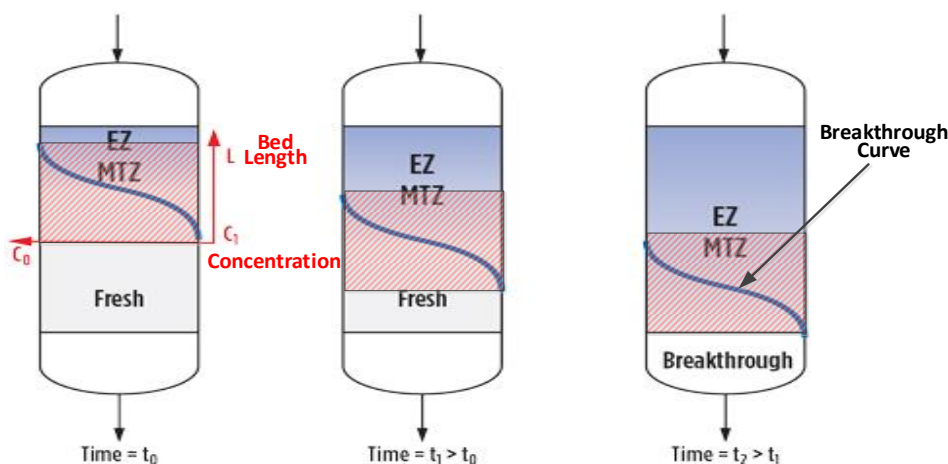


Figure 17: Explanation of increased sorbent inventory for a fixed bed adsorption process.

Despite the disadvantages of adsorption processes, compared with solvent absorption processes, one advantage is that adsorption can occur at elevated temperature, which will minimize cooling and heating of the syngas, and as a result, improve the thermal efficiency of the IGCC process. One such example is the use of CaO as an adsorbent to adsorb CO₂ at WGS reaction temperature (Ramkumar and Fan, 2010; Rout et al., 2019). Figure 18 displays such a process where shifted syngas enters the adsorption column and CO₂ is selectively adsorbed by CaO and the syngas is cleaned (Steen et al., 2014). The saturated adsorbent (now CaCO₃) is then regenerated in the desorption column and the regenerated sorbent is reused for the next cycle. This type of sorbent-based CO₂ capture technology can be integrated with the WGS reaction if the sorbent can be tolerated with a WGS catalyst. Indeed, the idea of combining adsorption and WGS is widely explored in pre-combustion CO₂ capture and the process is called Sorption Enhanced WGS (SEWGS) (Gazzani et al., 2013; Manzolini et al., 2013b). TDA Research Inc. has also developed a novel high-temperature PSA process based on an advanced physical adsorbent with a

mesoporous carbon grafted with surface functional groups that selectively removes CO₂ from syngas at temperatures above the dew point of the syngas (Alptekin, 2019).

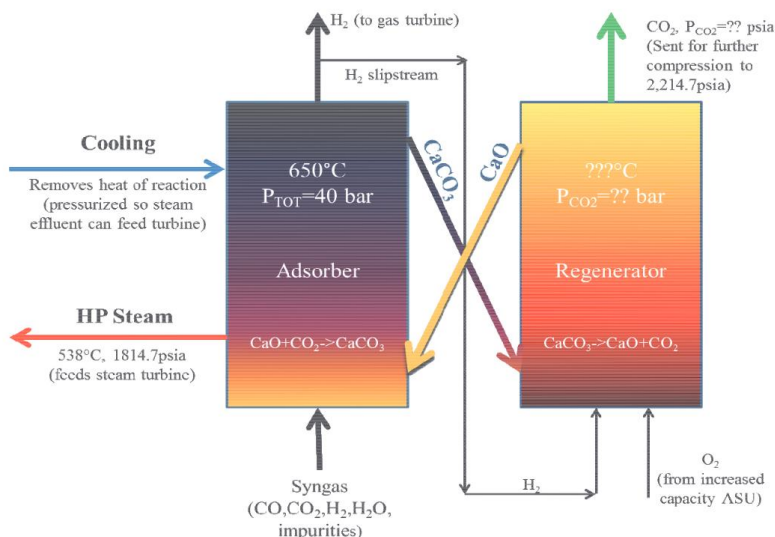


Figure 18: Simplified flow diagram of a high-temperature adsorption process for CO₂ separation from syngas (Steen et al., 2014).

There are no commercially-operating adsorption processes for pre-combustion (IGCC) CO₂ capture. However, Air Products and Chemicals have used vacuum swing adsorption at the Valero Refinery in Port Arthur, U.S, to capture CO₂ from two steam methane reformers (SMR) in order to produce a high purity hydrogen stream for production of cleaner burning transportation fuels (Air Products, 2011). The closest commercial application of an adsorption process for CO₂ separation is the PSA process for H₂ purification from syngas. However, H₂ purification has different requirements compared to a CO₂ removal process. In H₂ purification, the purity of H₂ is the key performance parameter, whereas the recovery rate of the H₂ and CO₂ purity is not as critical. For an IGCC power plant with CO₂ capture, the H₂ recovery rate and CO₂ purity are both important, but the H₂ purity (above 93%) and CO₂ recovery rate (above 90%) can be compromised. As a result, a H₂ purification process designed to produce highly pure H₂ would require modifications to facilitate the new requirements of CO₂ capture for sequestration.

A hybrid pressure and temperature swing adsorption (PTSA) process has been studied by Tokyo Electric Power Company (TEPCO) and Mitsubishi Heavy Industries using a high capacity/selectivity sorbent, zeolite Ca-X(β), which showed 11% reduction in the power consumption as compared with the conventional PSA process (Zaman et al., 2013). An adsorption-cryogenic hybrid CO₂ capture process has also been studied using a vacuum swing adsorption process followed by further purification using a low-temperature unit to produce liquid CO₂ with an overall energy consumption of 1.4 GJ/t CO₂ (Song et al., 2018).

2.2.1 Advantages and Disadvantages for Sorbent Based Processes for Pre-Combustion CO₂ Capture

The **advantages** of adsorption or sorption-based gas separation processes for pre-combustion CO₂ capture are listed below:

- Mature technology that is commercially available in the chemical industry

Sorbent-based processes have been used in industrial gas separation and purification applications for many years. Sorbent-based PSA is the technology of choice for producing very high purity H₂ in the chemical industry.

- Can produce high purity H₂

PSA can be used to produce high purity H₂, which may be necessary for fuel cells or other applications. An IGCC equipped with a sorbent-based PSA for H₂ production offers flexibility for polygeneration.

- Allows for combined CO₂/H₂S removal

Depending on the needs, sorbent-based processes have the flexibility to remove H₂S and CO₂ together and these two gases can then be sequestered together.

- Sorbent regeneration may not need heat

When sorbent-based processes are used for bulk gas separation (concentration of the targeted gas component is >10%), a pressure swing regeneration mechanism is preferred. The advantage of PSA is that the process cycle will be much faster because no heating/cooling is required, and the productivity of the process equipment is increased.

- Potential use at high temperature

Sorbents that can be operated at high temperature are commercially available but have not been used commercially for CO₂ removal. High temperature operation is important for pre-combustion CO₂ capture as a high temperature option will offer the possibility of eliminating heating and cooling of syngas and it may be possible to integrate with the WGS reaction.

- Faster mass transfer between gas phase and porous solid

Unlike liquids, porous solid particles can maintain a high interfacial area between the gas and solid sorbent which is important for efficient mass transfer and reducing the size (and cost) of equipment.

The **disadvantages** of adsorption process for pre-combustion CO₂ capture are listed below:

- Not steady state operation, more difficult to scale-up

Since most adsorption processes involve solid sorbents in a fixed bed configuration, either TSA or PSA, smooth steady state operation is difficult to achieve. The cyclical

nature of the process makes achieving both high recovery rate and high product purity difficult. The unsteady state operation mode of the adsorption process also makes scale up more difficult. Pumping/pressuring solids is more complicated than pumping liquids.

- Fixed bed TSA process is not practical

Due to the cyclical nature of the fixed bed adsorption process, the balance of adsorption time and desorption time including heating/cooling of the sorbent bed will be important. As the bed size increases, the heating and cooling of the bed will take longer to reach design temperature. The longer heating/cooling times of the bed will increase the sorbent inventory to an unacceptable level.

- PSA process uses pressure as driving force and is energy intensive

In a PSA process, both total pressure of feedstock and partial pressure of targeted component are the driving forces for separation. Energy consumption for regeneration could be intensive especially when only a few beds are used.

- CO₂ pressure and H₂ loss during flash recovery

As with absorption processes, when PSA is used, the partial pressure of the product CO₂ gas stream will be lower than the partial pressure in the feed stream and will likely require further compression. Additionally, some H₂ may be lost with the CO₂ stream.

- Sorbent-based processes are often capital intensive

Adsorption processes and absorption processes are similar in terms of capital cost. At modular scale, both will become capital intensive, meaning the majority of the LCOE will be the capital cost.

- Sorbent is more sensitive to contaminants and moisture in syngas

In an absorption process, when some solvent is degraded and capacity is lost, the degraded solvent can be removed through a reclamation process and most of the solvent can still be reused. However, this is not the case when some capacity of the sorbent is lost. When sorbent capacity loss reaches a certain level, the entire sorbent has to be replaced (you cannot separate the bad surface from the good surface). As a result, sorbent lifespan is reduced and costs increase. Depending on the type of sorbent used, the presence of water vapor may negatively affect the capacity of the sorbent and reduce the availability of the active surface area.

2.2.2 R&D Focus for Adsorption Based Processes

Some of the **improvements** required for future implementation of sorbent-/adsorption-based pre-combustion CO₂ capture processes will include:

- New process design or new sorbents that can avoid cyclic operation

As mentioned in previous sections, the incorporation of solid sorbents in the process makes steady state operation difficult. Novel processes or new sorbent materials that can achieve steady state operation will help the advancement of adsorption process. This

includes combined solvent/sorbent designs to allow the sorbent to flow and to achieve steady-state, countercurrent, continuously-looping operation.

- Sorbent materials better able to keep H₂, N₂, and CO out of the void space

Development of better sorbent materials with higher working capacity and higher selectivity for CO₂ is important for reducing costs and encouraging commercial application. H₂, N₂, and CO can reside in the void spaces between the solid sorbents, which causes lower selectivity, lower CO₂ regeneration pressures, and/or increased recycle rates. Stability of the sorbent and resistance to water and other contaminants is also important.

A significant advantage of some sorbents (depending on their reaction chemistry) for IGCC applications at any scale is that they can be operated at temperatures higher than traditional solvent processes. A sorbent-based hot/warm CO₂ capture process that can operate at a temperature above the required combustion turbine temperature will improve the IGCC cycle efficiency and potentially result in a decrease in power production costs. An adsorption process that can be combined with the WGS reaction to shift the chemical equilibrium while separating CO₂ from the syngas is also advantageous. In addition to improving the thermal efficiency, this type of process could provide additional benefits to the IGCC CO₂ capture power plant by accelerating the WGS reaction rate and reducing the excess steam required for the traditional WGS reaction.

2.3 MEMBRANE-BASED PROCESSES FOR PRE-COMBUSTION CO₂ CAPTURE

Membranes are a commercially-available technology used in the chemical industry for both CO₂ separation and H₂ separation/purification (Scholes et al., 2010). MTR Polaris™ CO₂ selective membranes have been used commercially with syngas for CO₂ separation from H₂ (Lin et al., 2014). There is, however, no commercial operation of membrane processes for CO₂ capture from syngas in IGCC applications.

Figure 19 is a schematic of a H₂ selective membrane. In this case, the membrane is designed/chosen so that H₂ molecules more easily permeate through the membrane. A partial pressure differential of H₂ across the membrane serves as the driving force for a portion of the H₂ to selectively diffuse through the membrane, creating a H₂-rich permeate stream. However, membrane separation is not limited to such molecular sieve effects. Diffusivity difference and/or solubility difference can also be used to drive separation. Any property, that causes one component to be more permeable than the other components, could be used to drive separation through the membrane. MTR has developed a H₂-selective, multilayer composite polymer membrane called Proteus™ for high-temperature CO₂ capture (Kniep, 2019).

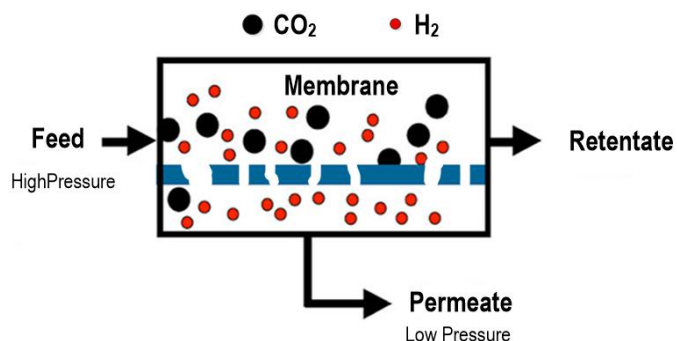


Figure 19: Schematic diagram of a syngas membrane separation unit (modified image from Green (2015))

Gas separation membranes, in comparison to solvent and sorbent separation techniques, function as “unit operations” as opposed to a “process” approach, which simplifies the gas separation system, providing increased IGCC power plant integration flexibility and smaller equipment footprint. In addition, gas separation membranes can be designed to produce CO₂ at pressure and, if desired, to co-capture CO₂ and H₂S.

In membrane separation processes, the gas stream that passes through the membrane is called the permeate and the retained stream is called the retentate. The ratio of retentate pressure to permeate pressure is called the pressure ratio. The two most important properties for a membrane process are permeability and selectivity. Permeability is an indication of how fast a gas molecule can pass through a membrane and determines the required membrane surface area, and therefore, the footprint or capital cost of a membrane system. A related parameter, which is more closely related to membrane productivity, is known as permeance, and equals the permeability divided by the thickness of the membrane. For membranes with the same permeability, the thinner membrane will have a higher permeance. Therefore, a thinner membrane is beneficial to provide high permeance and increase productivity. Selectivity measures the ability of a membrane to separate two gases and is defined as the ratio of the individual gas permeabilities. Increasing selectivity has minimal effect on reducing membrane surface area but can increase the product purity in the permeate stream. Generally, there is a trade-off between membrane permeability and selectivity. A membrane that has a high selectivity tends to have a low permeability and vice versa. However, it is desirable that a membrane have both high permeability and high selectivity. Permeability, selectivity, chemical/thermal/mechanical stability, and packing density will all influence the performance of a membrane system.

An important phenomenon related to membrane unit design is the trade-off between a product purity and product recovery rate. The driving force for separation in a membrane is the partial pressure difference across the membrane. When the required recovery rate is high, the remaining partial pressure of the product gas (on the retentate side) will be low and the driving force for the product component will be low. In contrast, the partial pressure of the other gas components in the retentate will be high. As a result, the product purity at higher recovery rates will be low. Figure 20 shows the relationship between membrane surface area, CO₂ removal, and CO₂ purity at different pressure ratios in a single stage membrane process. In order to increase the CO₂ removal rate, the required membrane surface area will increase and the CO₂ purity will decrease. This trend is especially profound when the recovery rate is 90% and higher. However, for pre-

combustion CO₂ capture, these trends may not be as pronounced as they are for post-combustion carbon capture. The trade-off will still have to be considered when selecting a CO₂ capture process. Membrane separation processes that can achieve, either high H₂ recovery rate and high H₂ purity, or high CO₂ recovery rate and high CO₂ purity are desirable.

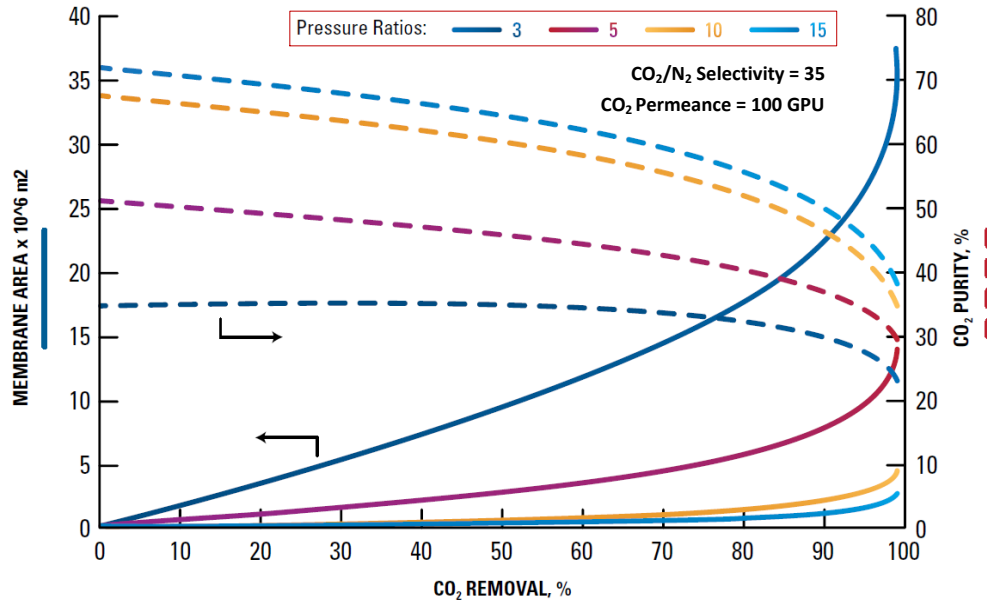


Figure 20: The relationship between product recovery rate, membrane area, and product purity at different pressure ratios (Ciferno et al., 2010).

Membrane-based pre-combustion CO₂ capture technologies can be integrated into an IGCC power plant in many ways. For example, Marano and Ciferno (2009) have comprehensively analyzed the integration of a membrane-based CO₂ capture process within an IGCC power plant. Based on their process analyses, the use of H₂ selective membranes was recommended over CO₂ selective membranes and four locations in the IGCC process were identified to locate the H₂ selective membranes as shown in Figure 21. Further detail on the four integrations are shown in Figure 22a to Figure 22d. The main reason for recommending a H₂ selective membrane configuration was due to its ability to produce a high-pressure CO₂ rich stream which minimizes subsequent CO₂ compression to 150 bar which is required for sequestration.

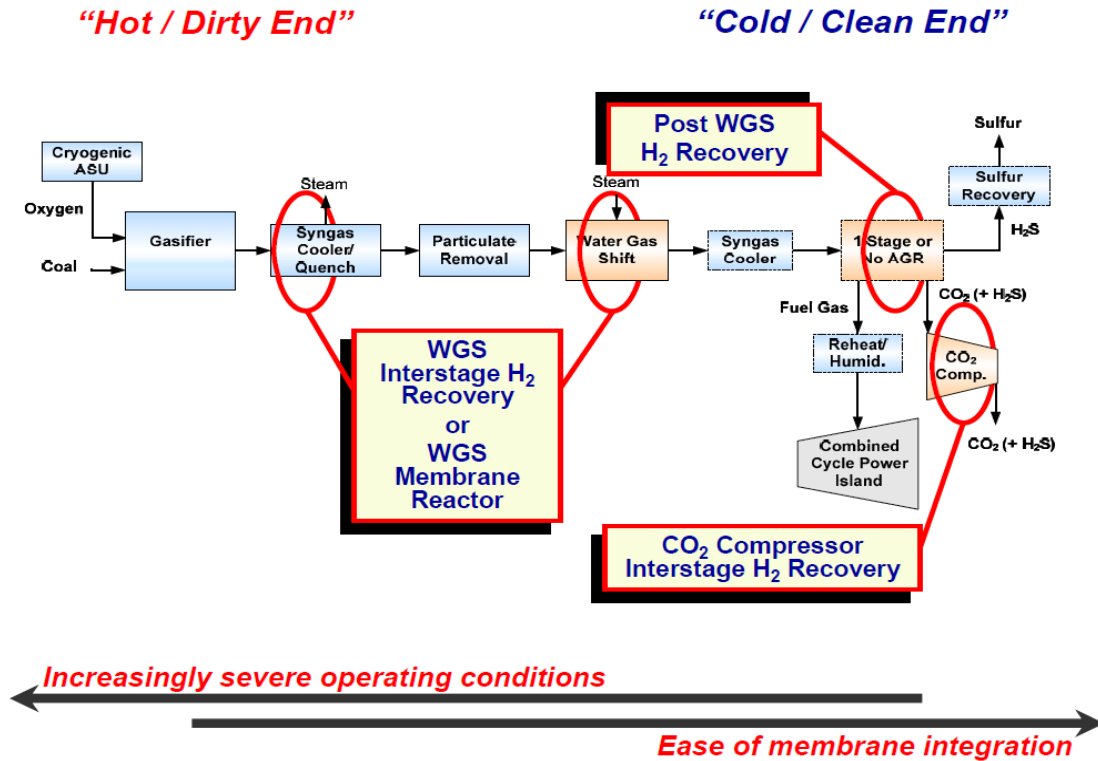


Figure 21: Possible locations to integrate membrane-based pre-combustion CO₂ capture in an IGCC process (Marano and Ciferno, 2009).

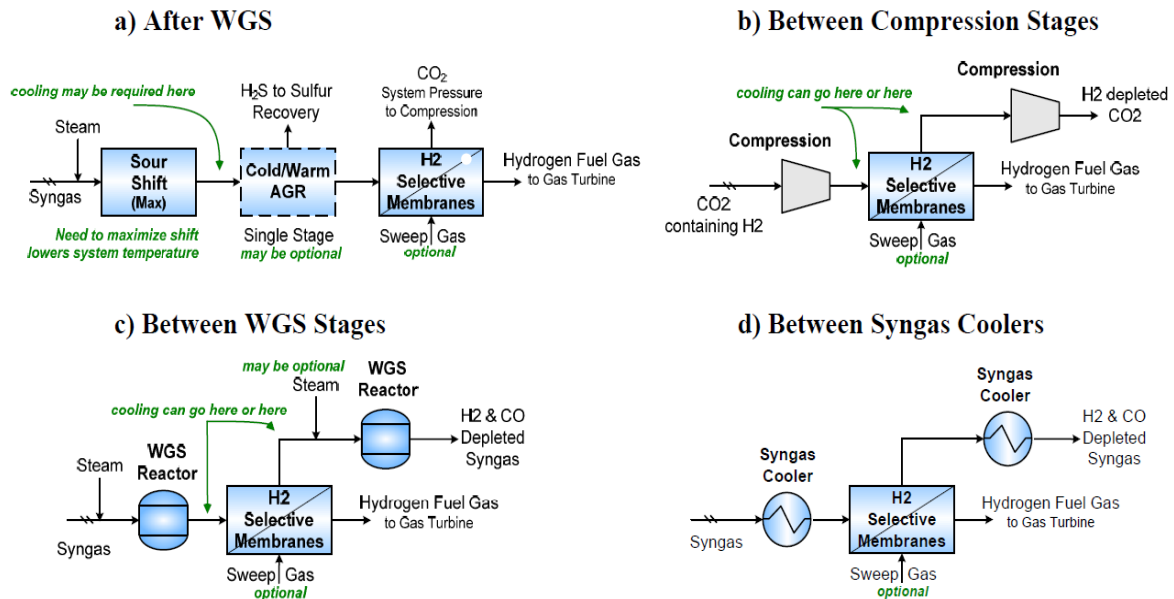


Figure 22: Integration options for H₂ selective membranes in an IGCC process (Marano and Ciferno, 2009).

An example of a H₂ selective membrane-based pre-combustion CO₂ capture process is shown in Figure 23 (Franz et al., 2014). In this process, raw syngas is quenched, and particulates are removed before the syngas passes through a series of WGS reactors to convert all CO to CO₂. The shifted syngas is further cooled and sulfur is removed. The sweet syngas is then heated before passing through a H₂ selective membrane unit to recover H₂. In this configuration, H₂ recovery rate is important. However, as mentioned earlier (see Figure 20), when H₂ recovery rate is high, its purity will decrease unless the membrane's selectivity is extremely high or a sweeping mechanism is used. Fortunately, H₂ selective membranes including those made from ceramic, metallic or zeolite, can all achieve extremely high selectivity (>1000). Therefore, H₂ purity may not be an issue even at high recovery rates. However, without a sweeping gas, the partial pressure of H₂ will decrease as the recovery rate increases. Therefore, the H₂ gas stream will have to be compressed to the pressure of the gas turbine. A more favorable design would be to use nitrogen from the ASU as a sweeping gas. This configuration will keep the permeate side containing H₂ at high pressure and help to improve process efficiency. One disadvantage of using the H₂ selective membrane configuration is that the CO₂ rich retentate stream may still contain some H₂ and other impurities such as Ar, N₂, CH₄, and CO. Therefore, this CO₂ rich stream may require further purification to achieve >95% quality. This is the reason why in the process shown in Figure 13, a post-combustion unit is added to burn all the combustible impurities. This configuration also uses cold H₂S removal before the membrane unit, because it assumes that the H₂ selective membranes are metallic, ceramic, or zeolite type membranes which are not tolerant to H₂S. For an optimal modular gasification system, a sour WGS reaction and a high-temperature H₂S removal process is desired so that the fuel gas (containing H₂) does not have to be cooled and reheated. A more desirable configuration would be a H₂S tolerant, high-temperature membrane so that H₂S and CO₂ can be co-captured in the same process.

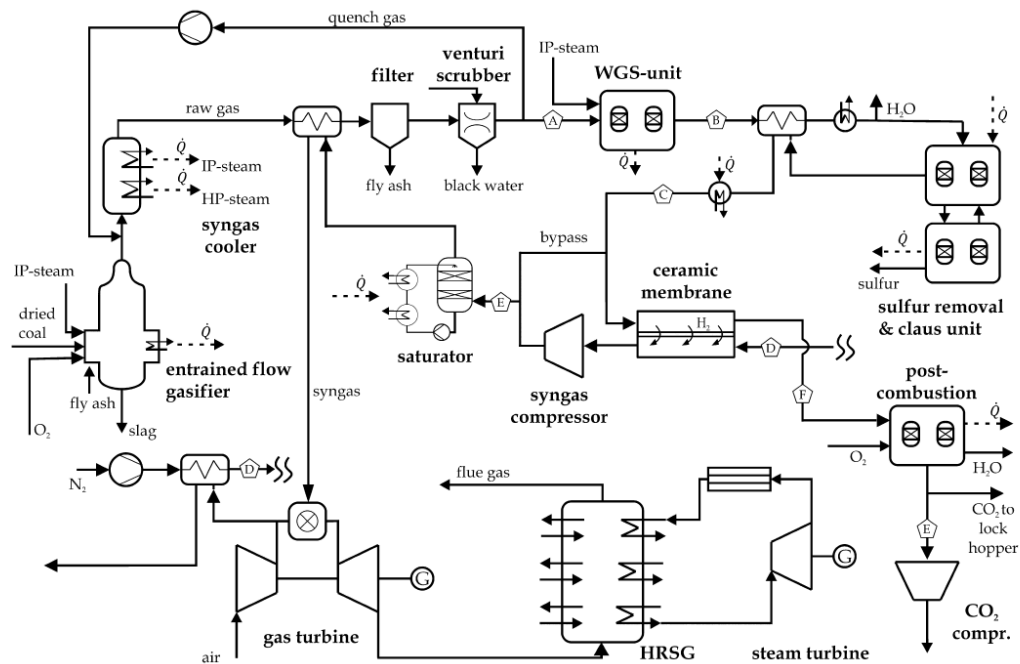


Figure 23: An IGCC power plant with H₂-selective membrane (Franz et al., 2014).

There are fewer examples of CO₂ selective membranes for pre-combustion CO₂ capture applications. Figure 24 is one example where the CO₂ selective membrane is H₂S tolerant and selective to both CO₂ and H₂S, but can only be used at low temperature. After the sour WGS reaction, the shifted syngas has to be cooled before entering the membrane unit. As with H₂ selective membranes, it will not be possible to completely remove CO₂ from the shifted syngas, and some CO₂ as well as other contaminants in the syngas will remain in the retentate. These impurities along with hydrogen fuel can be burned in the combustion turbine. One of the disadvantages of this configuration is that the pressure of product CO₂ will be lost which will increase the subsequent CO₂ compression power. This example requires the syngas to be cooled to approximately 107°C, which is not necessary if the membrane selected can tolerate a higher temperature. For modular gasification systems, a higher temperature membrane will be more favorable since it can eliminate the heating and cooling of the syngas. CO₂-selective mixed matrix membranes capable of facilitated transport have been reported for CO₂/H₂ separation at high pressures of at least 1.52 MPa and high temperatures above 100°C (Zhao et al., 2014).

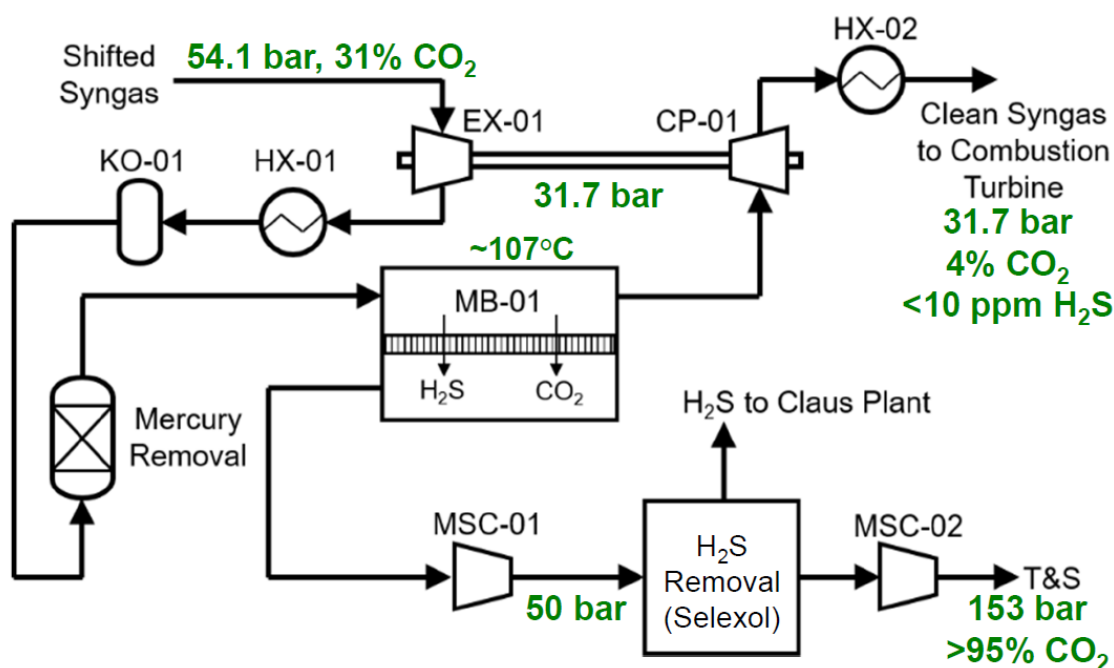


Figure 24: An IGCC power plant with CO₂ selective membrane (Ho and Han, 2019).

Both a H₂ selective membrane and a CO₂ selective membrane have potential for CO₂/H₂ separation for gasification applications. Both configurations have advantages and disadvantages which have been summarized in Table 7. It should be noted that because of the flexible nature and modular design of membrane processes, both H₂ and CO₂ selective membrane processes have the potential to reduce the footprint of the IGCC power plant and are more suitable for modular gasification systems. The choice between a H₂ selective membrane and a CO₂ selective membrane would likely be determined by the polygeneration application. H₂ selective membrane would be best for the hydrogen and ammonia synthesis polygeneration cases, whereas CO₂

selective membrane would be best for the Chemicals, F-T Liquid, and SNG polygeneration cases.

Table 7: Summary of Advantages and Disadvantages of H₂-Selective and CO₂-Selective Membrane Configurations for CO₂ Capture from IGCC Processes

Membrane and Configuration	Advantages	Disadvantages
H₂ selective membrane configurations	• CO₂ rich stream at the retentate side will have high pressure and the CO₂ compression work could be minimized. • Fuel gas H₂ can be diluted to some degree without impacting gas turbine performance, thus, N₂ produced from the ASU can be used as sweep gas to improve H₂ recovery rates yet maintain relatively high permeate side stream pressure. • Can produce high purity hydrogen which may be used for other applications, e.g., as a fuel for fuel cell or for making ammonia. This makes the process flexible for the H₂ and NH₃ polygeneration cases.	• The retentate stream, the CO₂ rich stream, may not be able to achieve 95% purity and will therefore require further purification before it can be transported by pipeline. • Currently, metallic-based H₂ selective membranes are not able to tolerate H₂S in syngas at desired levels.
CO₂ selective membrane configurations	• H₂ rich retentate stream will have high pressure and no further compression will be needed before going to the gas turbine. • Possibility of developing both H₂S and CO₂ selective membranes, and thus H₂S and CO₂ can be co-captured. • Ideal for the SNG, Chemicals, and F-T Liquids polygeneration cases.	• Permeate side CO₂ stream will lose its pressure, so CO₂ compression work is high.

2.3.1 Advantages and Disadvantages of Membrane Processes

The **advantages** of a membrane-based process for pre-combustion CO₂ capture are numerous as can be seen by the following discussion:

- Simple operation

As membrane modules do not have any moving parts, its operation is simplified. This will reduce maintenance costs.

- No chemical agents are required

Unlike solvent-/sorbent-based processes, a membrane process does not use chemical agents and will not cause any secondary environmental problems. When a chemical agent is needed, the demand for such chemical will be extremely large considering the scale of CO₂ emissions. Worldwide CO₂ emissions is over 20 Billion tons/annually. A technology that uses chemical agents at a rate of 1 kg/ton CO₂, the total consumption will be 20 Million tons/annually. It will become one of the largest chemical users in the chemical industry.

- No phase changes are involved

Membrane-based processes do not involve phase change of any component in the process and therefore no heat effects will be generated. This also makes membrane process control simpler and more efficient.

- Membrane units typically have smaller footprints

Membrane-based gas separation modules have high membrane packing density (surface area per volume). Mass transfer per unit volume in a membrane unit could be much higher than an absorption column. Therefore, membrane units are usually more compact and more suitable for modular gasification process.

- Higher temperature operation is possible

There are many types of membrane materials available. Inorganic membranes including ceramic, zeolite, and metallic membranes can be used at high temperatures. Some organic polymeric membranes such as Polybenzimidazole (PBI) can also be used at higher temperatures (Lin, 2019). Higher temperature operation offers desirable options for integration of membrane with WGS reactions.

- Easy to scale up

Due to its modular nature, membrane units are easy to scale up. For modular gasification systems, this advantage is important.

The **disadvantages** of a membrane-based processes for pre-combustion CO₂ capture are discussed below:

- Membranes will not be able to achieve high recovery and high purity at the same time

In most cases, it is difficult for membrane processes to achieve a high recovery rate and high purity for a product gas at the same time. However, this disadvantage may be partially overcome when a sweep gas is available or when the selectivity of a membrane is extremely high. The latter, however, will produce a very low pressure permeate stream and require further compression.

- Membrane fouling

Membrane materials are delicate and sensitive to contaminants such as dust and chemicals. Sometimes careful pretreatment may be needed to minimize fouling.

- Inorganic membranes may have low packing density

Unlike polymeric membranes, which are soft and can be shaped to different modules, inorganic membranes will be more difficult to handle, often have less packing density, and are more likely to fail due to fracture due to changing applied pressures.

2.3.2 **R&D Focus for Membrane Processes**

Some of the improvements required for future implementation of membrane-based pre-combustion CO₂ capture processes will include:

- **Permeability improvement**

Permeability directly correlates to the membrane surface area required for separation. A membrane with higher permeability is always desirable as it will result in a lower capital cost membrane.

- **Selectivity improvement**

Selectivity impacts the purity of the product. Higher selectivity is desirable when a high recovery rate is required.

- **Contaminant tolerance**

A membrane separation unit is a good candidate to be integrated with the WGS reactor. As the WGS reaction is equilibrium controlled, selective removal of the product component will significantly increase the CO to CO₂ conversion and will reduce steam usage and thus increase the overall process efficiency. It would be ideal for the membrane to be sulfur tolerant to enable integration with a sour WGS reaction.

- **Stability of the membrane**

Thermal stability, chemical stability, as well as mechanical strength are all important to the performance of the membrane unit.

- **Integration with WGS reactor**

The membrane unit shows promising potential to be integrated with the WGS reactor. As mentioned previously, the WGS reaction is exothermic and equilibrium controlled. Integrating the WGS reaction with H₂/CO₂ separation to constantly remove the product will significantly improve the CO to CO₂ conversion and improve power plant thermal efficiency.

- **Hybrid H₂ Membrane with Physical Solvents**

Separating H₂ with a membrane and the CO₂ using a physical solvent (regenerated using waste heat) can improve power plant efficiency while simultaneously being flexible and generating co-products for any of the polygeneration cases.

2.4 **INTEGRATED PROCESSES FOR PRE-COMBUSTION CO₂ CAPTURE**

The previous sections reviewed solvent-based, sorbent-based and membrane-based pre-combustion CO₂ capture technologies from the syngas of an IGCC power plant. This section will review process options where these CO₂ separation technologies can be integrated with the WGS reactions that occur as part of an IGCC process with CO₂ capture.

As previously mentioned, the WGS reaction is exothermic and equilibrium controlled. High temperature favors reaction kinetics and reduces reactor volume (less catalyst required). Low

temperature favors CO to CO₂ conversion and improves power plant thermal efficiency. Currently, the WGS reaction is achieved using multiple reactors, with reaction temperatures varied from high to low (from 500°C to 200°C). This arrangement encourages both high CO conversion and smaller reactor volumes. If a separation process can be integrated into the WGS reaction process, the reaction product (H₂ or CO₂) can be constantly removed and chemical equilibrium will not be limiting CO to CO₂ conversion, and higher conversions may be reached.

In order to achieve such integration, a CO₂ capture technology that can operate at WGS reaction temperature (200–500°C) is highly desirable. Integration of a solvent absorption-based process to the WGS reaction is unlikely as solvent-based processes can rarely be used at such high temperatures. Even if operation at such temperature is possible, the selectivity of the solvent might be difficult to maintain because the uptake of hydrogen into solvent typically increases with temperature. Sorbent-based processes have the advantage of being able to operate at elevated temperatures. However, sorbent-based processes will also have the low selectivity due to hydrogen residing within the pores of the solid and/or the space in between particles.

A simpler option would be to integrate a membrane separation process with the WGS reaction (Chen and Chen, 2020). A membrane reactor can seamlessly integrate WGS reaction and membrane separation. Membranes, including metallic, ceramic, and zeolite membranes, are all possible choices for operation at the high temperatures seen in the WGS reactors. Even a polymeric membrane, e.g., PBI (Berchtold et al., 2012), may be able to meet the requirements of this integrated process. Both H₂ selective and CO₂ selective membranes are applicable.

Figure 25 shows a schematic diagram of a WGS process with H₂ selective membranes and a sorbent-based WGS process (SEWGS). The corresponding equilibrium shifts that are possible under these configurations is also shown.

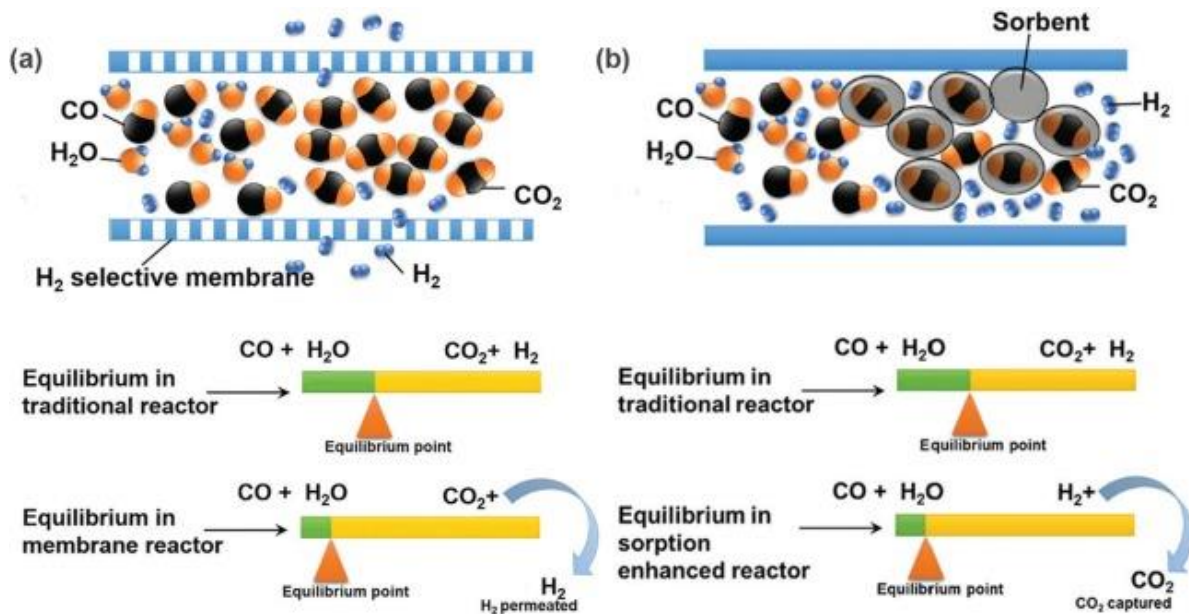


Figure 25: Schematic diagram of the WGS system equilibrium shift with application of (a) H₂-selective membranes and (b) solid CO₂ sorbent (Gao et al., 2019; Ji et al., 2018).

Considering the importance of capital cost for modular gasification systems, this report will focus on the technologies that can eliminate separate H₂S removal and/or eliminate cooling/heating steps for H₂S removal.

2.4.1 Adsorption and WGS Integrated Process

Currently, the most widely studied integrated WGS reaction technology is sorption enhanced water gas shift (SEWGS) reaction. Figure 26 is an example of SEWGS process, as presented by Chen et al. (2012).

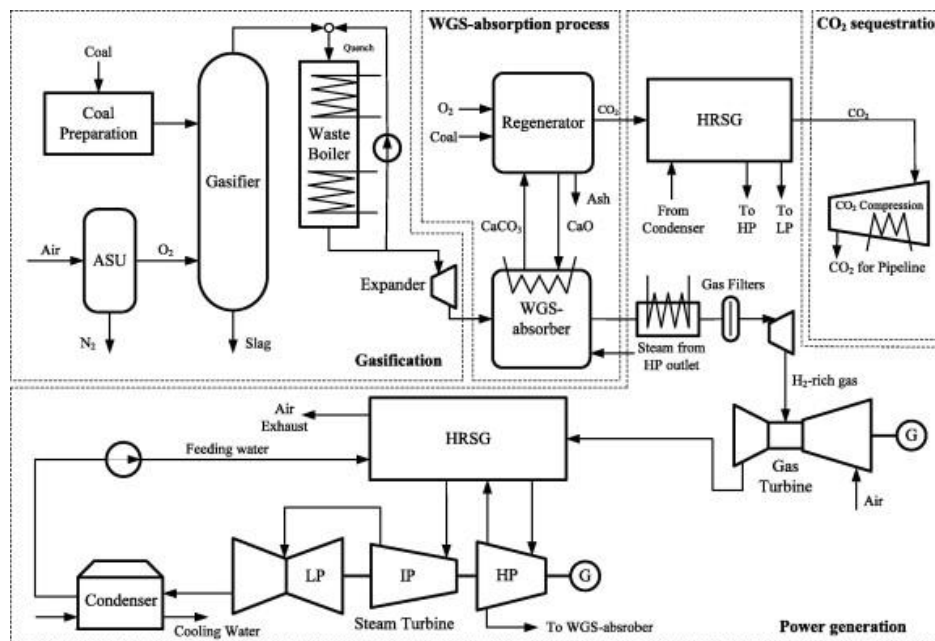


Figure 26: Flowsheet of CaO sorption-enhanced IGCC with CO₂ capture system (Chen et al., 2012).

Different process configurations for SEWGS are possible. In the example presented in Figure 26, the WGS catalyst is mixed with the high-temperature sorbent CaO. The process is cyclical and uses TSA for sorbent regeneration. During the adsorption cycle, raw syngas passes through the reactor and undergoes the WGS reaction with the resulting CO₂ being captured by CaO in situ and the H₂ remains in the gas stream as product. During the regeneration step, coal, and oxygen are combusted to provide the heat needed for CaO regeneration which releases CO₂. The H₂S in the gas reacts with CaO to produce CaS which is further oxidized in the regenerator to CaSO₄, which is periodically removed with the ashes and deactivated sorbents before reuse in the cement industry. The hot CO₂ is cooled down through the HRSG (heat recovery steam generator) process.

The issue with the presented example, a TSA-based SEWGS, is the heat requirements. The WGS reaction is an exothermic reaction and the heat of adsorption will also add heat to the process. As mentioned, high-temperature adsorption requires a high heat of adsorption and the process will have a high heat effect. For a modular gasification system, such a configuration may not be favorable. In the meantime, high heat requirements will reduce power plant thermal performance. A PSA type process may be more realistic and efficient, although heat

management will still need to be considered due to the exothermic nature of both the WGS and adsorption processes.

A PSA-based SEWGS process has been extensively studied by the CAESAR project in Europe (Najmi et al., 2016; Gazzani et al., 2011). The process flow diagram of SEWGS integrated within an IGCC power plant from this project is shown in Figure 27 (Gazzani et al., 2013). In the process simulation study, a 6 train (9 beds per train) PSA system was used. Considering the importance of the capital cost for modular gasification, a PSA-based SEWGS may not be attractive for pre-combustion CO₂ capture due to the complex equipment requirements of the process.

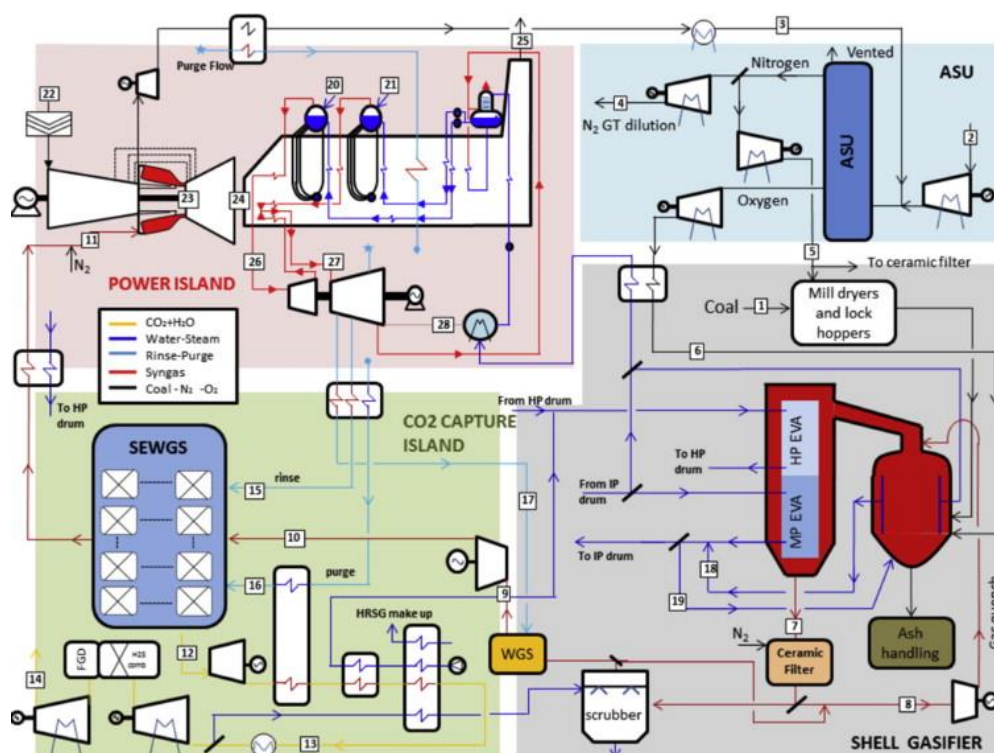


Figure 27: Process flow diagram of SE WGS by CAESAR Project (Gazzani et al., 2013).

2.4.2 Membrane and WGS Integrated Process

Due to steady-state temperature and pressure, membrane separation processes are relatively easier to integrate into the WGS reaction when compared to sorption processes. The integrated unit is called a WGS membrane reactor (WGSMR) and a schematic display is shown in Figure 28 (Smart et al., 2010).

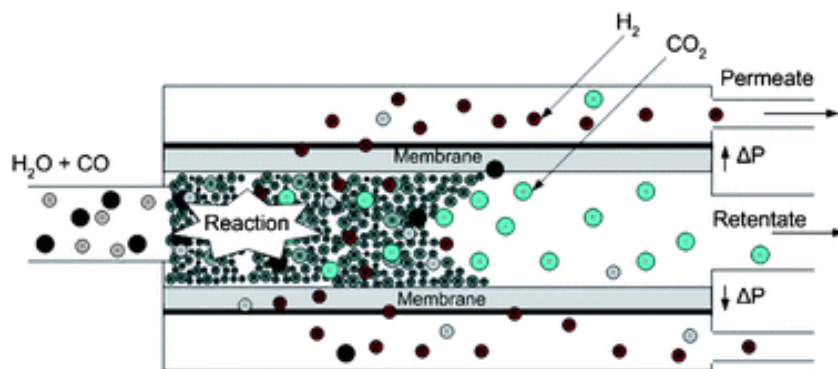


Figure 28: Schematic display of WGS MR (Smart et al., 2010).

A membrane reactor integrated with the WGS reactor is the most promising option for combined CO₂ capture and WGS reaction. The WGS reaction is an exothermic reaction that is equilibrium controlled with multi-stages (reactors) operating at temperatures from 200 to 500°C. When a membrane reactor is used, the product gas, either H₂ or CO₂ can be constantly removed from the reactor and the reaction equilibrium will be shifted towards completion. The use of a WGS MR in an IGCC power plant will reduce the capital cost, because of process integration and higher WGS reaction temperature (uses less catalyst), and also increase CO to CO₂ conversion and thus improve power plant efficiency.

A variety of process configurations have been proposed for WGS MR depending on the different membrane materials being developed (Ovalle-Encinia, 2019; Tang, 2019; Meng, 2019). From a process point of view, these different membrane reactors can be classified as either H₂ selective or CO₂ selective membrane reactors. Figure 29 is an example of an IGCC power plant integrated with a H₂-selective membrane reactor (Maas et al., 2016). In this example, a sour WGS catalyst was used and sulfur was removed after the WGS reaction. N₂ from the ASU is used as a sweep gas at the permeate side of the WGS MR. The process also used a compressor to compress the H₂ rich permeate stream to turbine entrance pressure. Similar to the membrane process in Figure 23, the retentate stream is CO₂ rich, but also contains some contaminants such as Ar, N₂, CO, H₂ and CH₄ which have to be removed before entering the pipeline for transportation. In the process shown in Figure 29, this is achieved by a post-combustion unit (the same as in Figure 23) to burn all the combustibles.

Comparing Figure 13 and Figure 29, it is clear that the difference between these two processes is that the H₂ separation membrane unit and the WGS reactor are integrated into one unit in Figure 29, whereas in Figure 30, these two units are separate. The integration of these two units requires the processes to operate at the same temperature. However, the beginning of the WGS reaction is not equilibrium controlled and a high reaction temperature can be used to reduce catalyst usage. After the bulk of CO is converted to CO₂, the WGS reaction will approach equilibrium and the partially converted syngas can go to the membrane reactor. Therefore, it might be optimal to use a regular WGS reactor to convert bulk CO to CO₂ at high temperature, before it enters the membrane reactor. Such a configuration can reduce total catalyst use and maximize the separation function of the membrane reactor. Figure 30 is an example of partial integration of the MR and WGS reactor with a H₂ selective membrane reactor in use.

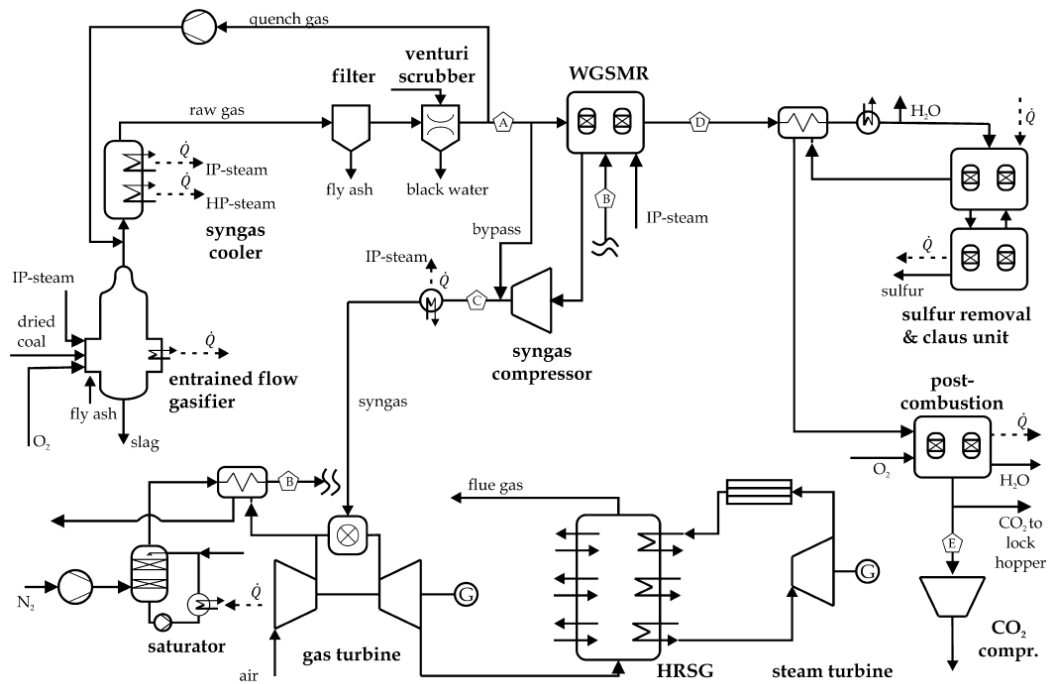


Figure 29: Process flow diagram of an IGCC power plant with WGSMT (Maas et al., 2016).

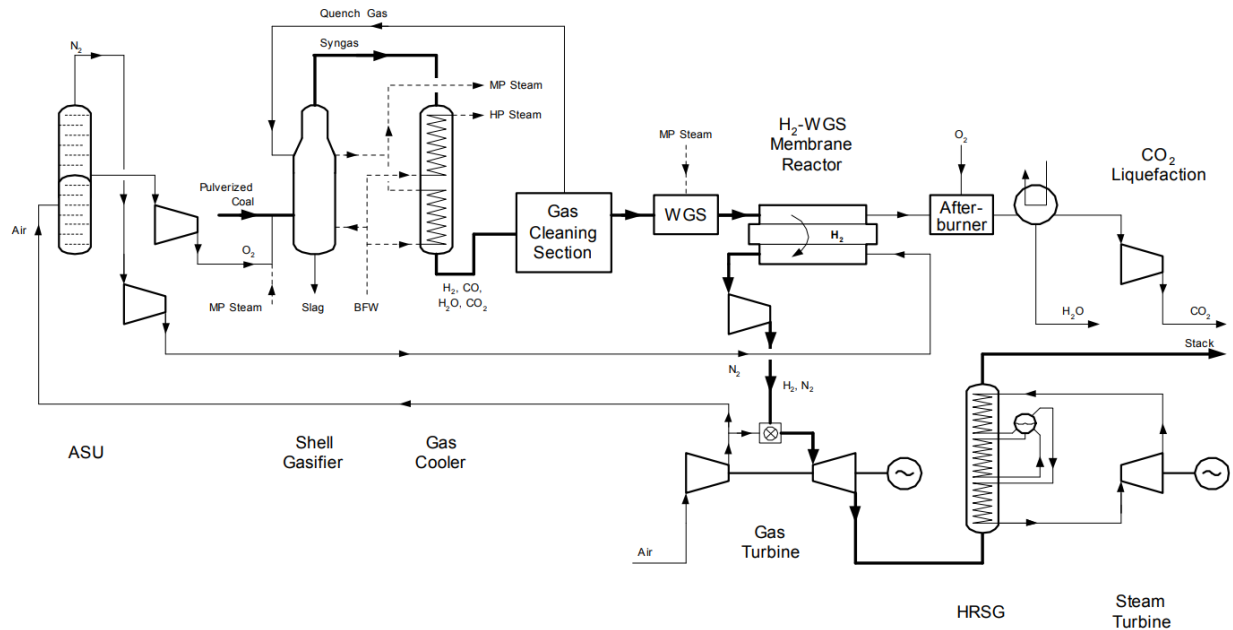


Figure 30: Process flow diagram of an IGCC power plant with a H₂ selective WGSMT (Carbo et al., 2006).

A WGSMR could also be operated with a CO₂ selective membrane, which will be slightly different from the H₂ selective process. Figure 31 provides a process flow diagram of an IGCC power plant using a CO₂ selective WGSMR. In this example, a partially integrated configuration is shown. When a CO₂ selective WGSMR is used, the permeate side is CO₂ and H₂S if a sour WGS reaction is used. This stream could be pure enough if the membrane selectivity is high. However, the pressure of the permeate stream is usually low because no sweep gas can be used, which will increase the subsequent compression power required to compress CO₂ to 150 bar required for pipeline sequestration.

The advantages and disadvantages of H₂ selective WGSMR and CO₂ selective WGSMR are the same as for the H₂ selective membrane and CO₂ selective membrane processes.

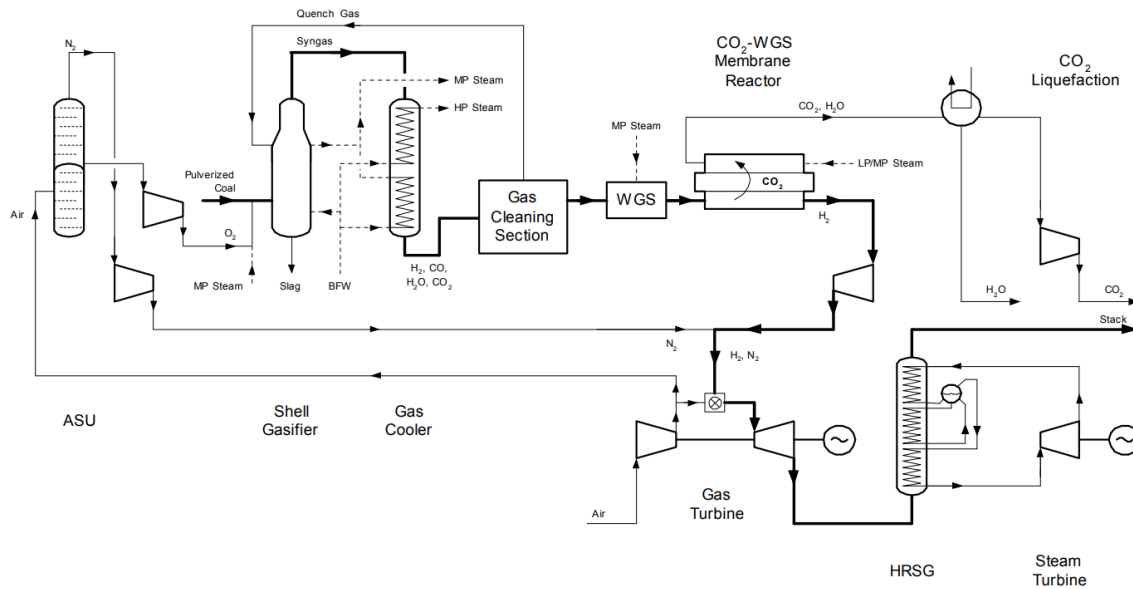


Figure 31: Process flow diagram of an IGCC power plant using a partially integrated CO₂ selective WGSMR (Cabo et al., 2006).

2.5 HYBRID PROCESSES FOR PRE-COMBUSTION CO₂ CAPTURE

Hybrid CO₂ removal systems are defined as the combination of multiple CO₂ removal unit operations either in one unit or in series. In hybrid processes, the presence of one unit can mitigate the shortcomings of the other resulting in a hybrid system that potentially has lower capital and operating costs as well as being more flexible in handling changes in operating conditions. Under flexible, small-scale conditions, there is the potential for efficient partial carbon capture at one of the hybrid module's capacity, which could then be increased as needed with the addition of more modules which have demonstrated successful operation. Also, if one process module has a higher CO₂ capture energy demand, it could be sized to match available waste heat, with the remaining capture being achieved with the less energy demanding unit resulting in improved overall process efficiency. There are many different combinations and configurations available for hybrid CO₂ capture processes and some have particular promise for

improved performance at modular scale. Some of the most common and promising hybrid options are discussed below.

2.5.1 Hybrid Solvent/Membrane Processes for Pre-Combustion CO₂ Capture

The use of hybrid capture processes, such as a membrane system upstream or downstream of a solvent absorption column, is considered a promising option for improving the overall CO₂ capture performance at modular scale. Economic studies have highlighted cost benefits of such hybrid systems for removing CO₂ from large volumes of gas (Echt, 2002). In addition to the volume of gas to be treated, the critical parameters affecting the capital and operating costs of the stand-alone solvent and membrane processes for CO₂ capture are shown in Table 8. By strategically combining these processes, overall costs can be minimized. For example, if an upstream membrane unit can remove some CO₂ from the syngas (low capital cost single-stage unit likely applicable), then the downstream solvent absorption unit would be smaller, with reduced capital cost. If instead a stand-alone membrane process only was used, this would likely require a two-stage system which would have substantially higher capital and operating costs due to the need for gas compression.

Table 8: Parameters Affecting the Capital and Operating Costs of Stand-Alone Solvent and Membrane Processes for CO₂ Capture (adapted from Echt (2002))

Parameter	Operating Costs	Capital Costs
	Solvent Absorption	
Circulation Rate	Pump power, solvent losses	Pump cost, solvent inventory
Reboiler Duty (chemical solvent)	Energy requirement	Affects stripper column size
Column Diameters	-	Most expensive equipment
Solvent Cost	Solvent makeup	Solvent initial fill
	Membrane	
Pre-treatment	Energy use, consumables	Standard vs. advanced pre-treatment requirements
CO ₂ Removal Per Stage	Hydrocarbon losses	Single-stage vs. two-stage
Number of Stages	Compressor fuel	Compression
Membrane Elements	Replacement elements	Initial fill of elements

The potential for reduced unit costs with a hybrid system needs to be balanced against the increased costs of the additional processing unit, which has been investigated in a number of economic studies (Song et al., 2018). Some reports have found that the capital and operating costs of a solvent-membrane hybrid system are lower than a stand-alone solvent system as the membrane is more efficient at processing higher partial pressures of CO₂ (Echt, 2002). Due to practical/physical limitations on the column diameter of a solvent tower, some absorption processes will require a 2-train configuration (for both the absorption and regeneration columns). However, if a hybrid solvent-membrane configuration is adopted, a single stage membrane

followed by a single train solvent column setup could be used. This is an important consideration for modular processes which are typically built off-site and transported to the operation site by truck. Other reported advantages of this configuration include flexibility in handling varying CO₂ content (by varying membrane area) and reduction in solvent foaming/degradation as the membrane pre-treatment will remove contaminants before the gas contacts the solvent.

A comprehensive simulation-based study on the use of a hybrid CO₂ capture process, containing a H₂-selective membrane and a MEA (monoethanolamine) solvent process, for pre-combustion CO₂ capture has been reported (Scholes et al., 2013a). The study considered both air-blown and oxygen-blown IGCC processes, with a H₂-selective membrane downstream of the gasifier followed by a chemical (MEA) solvent absorption process (refer to Figure 32). H₂ is recovered in the membrane permeate stream and the CO₂ concentrated retentate stream is fed to the solvent column, which is operated at gasifier pressure. For the oxygen blown gasifier with WGS, the membrane can achieve CO₂ concentrations of up to 85% in the retentate, which makes the solvent separation process ideally suited to a physical solvent like Selexol or Purisol (or an adsorption or cryogenic process). Results from this study for the oxygen fed gasifier showed that for a membrane H₂/CO₂ selectivity of 100, the diameter of the MEA solvent column is reduced by 15% and the column height is reduced by over 30% resulting in significant capital cost reductions (Scholes et al., 2013a). In this arrangement, the exiting absorber gas containing H₂ and CO is returned to the membrane permeate stream before combustion. Additionally, the permeate stream is recompressed to gasification pressure to enable comparison with the solvent only process. The operating costs or energy demand (mainly from recompression of the membrane permeate) of this process increased by less than 3% compared to the solvent only case, which could be reduced if the downstream turbine could operate at 2000 kPaa. The promising CAPEX reductions reported in this study using the chemical solvent MEA are expected to be similarly beneficial for physical solvents as the driving force for absorption is increased with the higher CO₂ concentration in the feed gas.

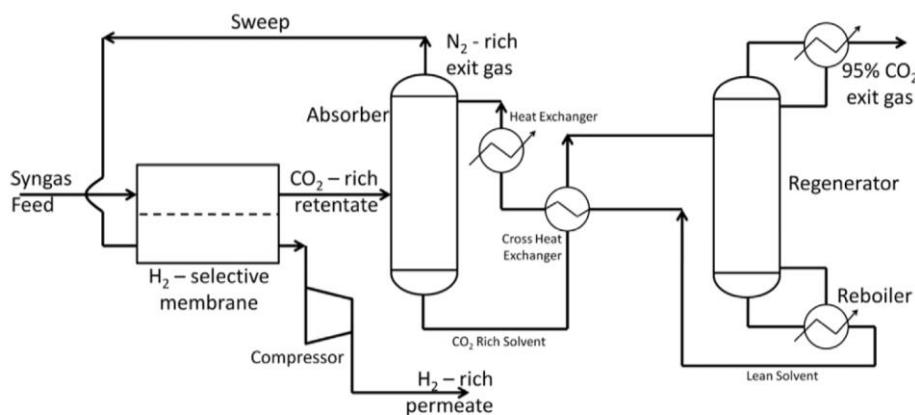


Figure 32: Process flow diagram of a pre-combustion H₂-selective membrane-solvent hybrid power plant with an air-blown gasifier (Scholes et al., 2013a).

In a similar simulation-based study, a hybrid physical solvent absorption process with a CO₂-selective membrane was studied for pre-combustion CO₂ capture (Scholes et al., 2013b). The motivation for this study resulted from the inability of traditional physical solvent processes to achieve the CO₂ purity required for pipeline/storage due to the focus on recovery and recycling of combustible syngas components like H₂. One configuration that was investigated involved adding a CO₂-selective membrane to an existing physical solvent absorption process (refer to Figure 33a). The CO₂/H₂ selectivity of 4 required by the membrane is readily achieved with existing polymeric membranes like PDMS (Scholes et al., 2010). With PDMS a membrane area of 7000 m² was required which would provide a compact footprint. However, the process required an increased energy demand of up to 18% due to operation of the vacuum on the permeate, which provides the membrane driving force. The vacuum pump energy costs could be mitigated by at least 45% through recycling the retentate waste gas, which contains H₂, to the combined cycle or back to the absorber. An alternate hybrid solvent membrane configuration was investigated which involved operating the physical solvent absorption process with only one flash stage and then using a CO₂-selective membrane to produce a high purity CO₂ product in the membrane permeate (refer to Figure 33b). The retentate is recycled back to the absorber. Operating under this arrangement, with partially reduced flash stage pressure, results in the solvent not being fully regenerated which reduces the performance of the absorber. In turn, this requires a larger solvent flow rate which increases the diameter and hence capital cost of the absorber. Additionally, the required membrane area was reported to be in the order of 1 km², due to low CO₂/H₂ selectivity, which is significantly larger than the previous configuration making this configuration less desirable.

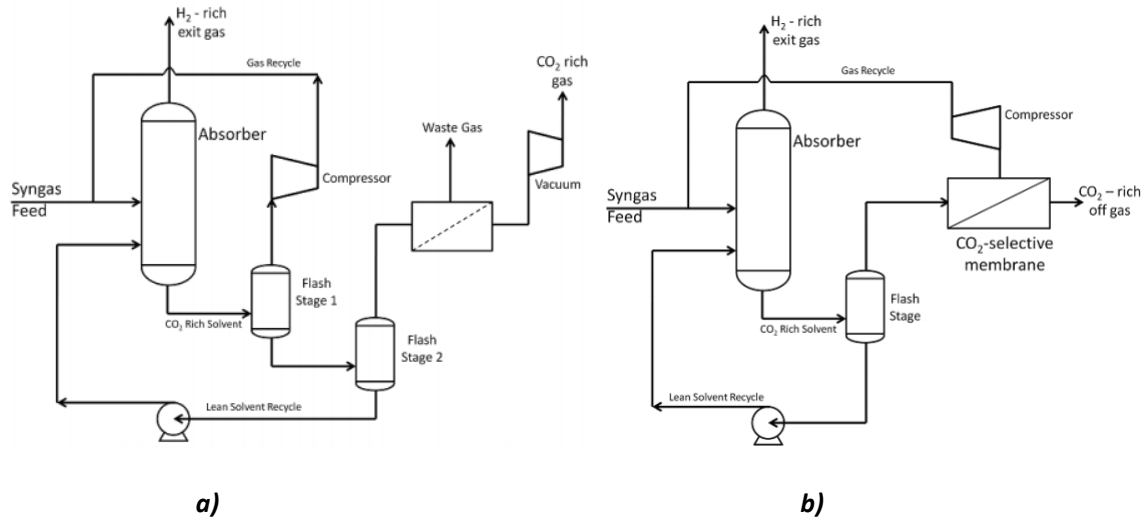


Figure 33: Process flow diagrams of a physical solvent absorption process with CO₂-selective membranes to ensure CO₂ purity > 95%: a) membrane retrofitted to standard physical solvent process, and b) membrane used to replace second flash stage of standard physical solvent process (adapted from Scholes et al. (2013b)).

Another commonly proposed hybrid process involves the use of a solvent and a membrane in a single unit known as a solvent membrane contactor (Scholes et al., 2012). In this supported liquid membrane process, CO₂ transfer occurs through the liquid in the pores of the membrane, therefore, achieving higher diffusivities in the liquid phase as compared to in the solid/membrane phase. In this configuration both selectivity and flux can be increased because the porous membrane allows large fluxes and the solvent in the pores offer high selectivity. Membrane contactors provide high surface-area-to-volume ratio, resulting in a compact system suited to modular design. Generally, the membranes are not participating in the separation process, but a barrier with higher surface area between the liquid and gaseous phases (Zaman and Lee, 2013). Pilot power plant trials for pre-combustion membrane contactors have been reported and while many membrane materials can handle the high temperatures of up to 300°C, it is difficult to find the adhesive at this temperature range which is required to construct the modules (Scholes et al., 2012; Kentish, 2019). Additionally, membrane wetting and fouling are issues to be addressed (Song et al., 2018).

Advantages and Disadvantages of Hybrid Solvent and Membrane Processes

When deciding what type of technology to use for a CO₂ separation process, a number of issues need to be considered, many of which are site and process specific. For example, if very low levels of H₂S are required, normally a solvent unit is required after the membrane unit. Therefore, when choosing a hybrid system it is important to understand the advantages and disadvantages (or limitations) of both units in order to capitalize on the benefits provided from their combined performance. Table 9 provides a useful comparison for considering the parameters that impact the operating and capital costs of a hybrid solvent and membrane process for CO₂ capture.

Table 9: Comparison of Solvent and Membrane CO₂ Removal Systems (adapted from Echt (2002))

Operating Issues		
	Solvents	Membranes
User Comfort Level/ Technology Maturity	Very familiar, mature technology	Still considered new technology
Hydrocarbon Losses	Very low	Losses depend upon conditions
Meets Low CO ₂ Spec.	Yes (ppm levels)	No (<2% economics are challenging)
Meets Low H ₂ S Spec.	Yes (<4 ppm)	Sometimes
Energy Consumption	Moderate - high (for chemical solvents)	Low, unless compression is needed
Operating Cost	Moderate	Low to moderate
Maintenance Cost	Low to moderate	Low, unless compression is needed
Ease of Operation	Relatively complex	Relatively simple
Environmental Impact	Moderate	Low
Dehydration	Product gas saturated (particularly for chemical solvent)	Product gas dehydrated
Capital Cost Issues		
	Solvents	Membranes
Delivery Time	Long for large systems	Modular construction is faster
On-Site Installation Time	Long for traditional design	Short for skid-mounted / modular equipment
Pre-treatment Costs	Low	Low to moderate
Recycle Compression	Not used	Use depends upon conditions

Hybrid systems, such as using a membrane unit upstream of a solvent unit, can have overall positive impacts if the weakness of one unit can be offset by the strength of the other unit. This can create a low cost and flexible process that can adapt to changing conditions, which are important features at modular scale. Generally, the overall performance of a process is dependent on a range of variables such as syngas composition, operating conditions, economic variables, site specific conditions and the technical performance of the chosen unit operation. An effective hybrid process is one where the disadvantages of one unit operation are complemented by the advantages of the other. For example, a membrane process can effectively concentrate the CO₂ but has trouble reaching high purity, whereas a solvent process can achieve the required purity but has a large equipment footprint with dilute CO₂ gas streams (Scholes et al. 2013a). Table 10 lists some of the potential benefits provided by a hybrid solvent and membrane process compared to the stand-alone units.

Table 10: Comparison of Hybrid to Solvent and Membrane CO₂ Capture Processes (adapted from Echt (2002))

Operating Issues	Hybrid vs. Solvent Only	Hybrid vs. Membrane Only
Hydrocarbon Losses	Increased losses, unless there is a use for the permeate	Slight increase in losses, but typically no compression
Meets Low CO ₂ Spec	Same	Yes, much better
Meets Low H ₂ S Spec	Same	Yes, much better
Energy Consumption	Lower	Higher
Operating Cost	Lower	Higher
Maintenance Cost	Slightly higher	Higher
Ease of Operation	Slightly more complex	More complex
Dehydration	Product still saturated	Re-saturates product gas
Corrosion Potential	Lower (lower loadings)	Not a concern
Amine Foaming	Virtually eliminated	Not a concern
Capital Cost Issues	Hybrid vs. Solvent Only	Hybrid vs. Membrane Only
Recycle Compression	Not a concern	Eliminates need for compression
Total Installed Cost	Same to lower	Higher
Very Large Gas Flow	Significant savings	Higher

It is clear that there are numerous process configurations with solvents and membranes that can be used as hybrid capture systems to potentially reduce the cost of pre-combustion CO₂ capture. When considering a modular scale design, hybrid processes offer unique opportunities to reduce costs and maximize flexible operation at capacities that are beneficial to each modular unit.

2.5.2 Other Hybrid Processes for Pre-Combustion CO₂ Capture

Other novel hybrid pre-combustion capture processes have been proposed including the use of hybrid solvents (Bhattacharyya et al., 2017). Hybrid solvents take advantages of the benefits of both physical (bulk removal of CO₂) and chemical solvents (deep removal of acid gases such as H₂S) by balancing characteristics including solvent regeneration energy requirements, vapor pressure, corrosivity, thermal stability, degradation, foaming, and selectivity towards CO₂ and H₂S in comparison to H₂ and hydrocarbons (Bhattacharyya et al., 2017). A hybrid solvent is reported to be particularly advantageous to treating gas at high pressure due to the reduction in energy penalty for CO₂ compression. This will also reduce thermal regeneration requirements of the solvent leading to higher energy efficiency. The most well-known commercial hybrid solvents and other reported mixtures from the literature are shown in Table 11.

Table 11: Hybrid Solvents (Kohl and Nielson, 1997; Bhattacharyya et al., 2017)

Commercial Name / Reference	Physical Solvent	Chemical Solvent	Uses/Comments
Sulfinol	Sulfolane	Diisopropanolamine (DIPA) or methyl diethanolamine (MDEA)	DIPA is used when almost complete removal of both H ₂ S and CO ₂ is required, while MDEA is used for selective removal of H ₂ S over CO ₂
Amisol	Methanol	Secondary alkylamine (e.g., diisopropylamine (DIPAM) or diethylamine (DEA))	Amisol can remove more H ₂ S than DEA and MDEA for partial pressure >~1 bar. Water wash is required due to high vapor pressure
Selefining	Methanol	Secondary or tertiary amine	Selective removal of H ₂ S and the extent of CO ₂ capture can be controlled by adjusting the water content of the solvent mixture
Yogish (1990)	N-methylpyrrolidinone (NMP), sulfolane, and methanol	40% aqueous dimethyl amine (DMA)	CO ₂ uptake increased by 2-3 times in comparison to that of the pure physical solvents
Gervasi et al. (2014)	Tetraoxaundecane (TOU)	Monoethanolamine (MEA), Diethylamine (DEA), and 2-amino-2-methyl-1-propanol (AMP)	Physical solvent addition improves the absorption and regeneration efficiencies

Another novel reactor configuration for coal gasification consists of a membrane reactor (MR) followed by one or more adsorptive reactors (ARs) in parallel, operating alternately, for the production of high purity H₂ with simultaneous CO₂ capture during the WGS reaction (Chen et al., 2018; Tsotsis, 2019). A commercial sour-shift WGS catalyst (Co/Mo/Al₂O₃) was used in both the MR and the AR, while a carbon molecular sieve (CMS) membrane was used in the MR, and a hydrotalcite adsorbent was used in the AR. The hybrid MR–AR process configuration was shown to intensify the efficiency of the WGS reaction, as well as function as a high-efficiency, ultra-compact process.

2.6 CONCLUDING REMARKS ON MODULAR PRE-COMBUSTION CO₂ CAPTURE

In completing this review, it has been shown that for a small-scale modular gasification power plant, the capital cost will represent the biggest portion of the LCOE. With this in mind, different pre-combustion CO₂ capture technologies were reviewed with the aim of minimizing the increase in LCOE with CO₂ capture at modular scale. The review was focused on technologies that have significant potential to simplify the IGCC power plant with pre-combustion CO₂ capture, either through temperature match to minimize or eliminate cooling/heating processes, or through pressure match so that compression/expansion processes can be avoided. Five types of CO₂ capture technologies have been reviewed: solvents, sorbents, membranes, integrated, and

hybrid processes. These processes have been assessed with the advantages and disadvantages of each summarized in Table 12.

The two most important characteristics of a modular system are: (1) its compactness (small footprint), and (2) its capital cost. As shown in Table 5, variable operating cost per unit volume of product is relatively constant when the power plant scale is reduced. Modularization can reduce capital cost and fixed operating costs, but on a per volume of product basis, modular scale could still have cost disadvantages compared to large scale. It is expected that capital cost will be critical when the power plant scale is reduced by two orders of magnitude. As scale is reduced, capital cost will represent a larger share of the LCOE. It is therefore important that the capture technology will have excellent capital cost advantages when the scale is small.

Based on the analysis completed in this review, membrane-based technologies show the greatest potential for CO₂ capture from modular gasification power plants. In particular, H₂ selective membrane reactors should be a focus for long-term R&D. Considering the demand and difficulties related to obtaining a high-quality H₂ stream at low cost, a membrane-based process would be most appropriate and at lower temperatures, polymeric membranes may also be used. Polymeric membranes offer very low cost, compact design, high packing density, and in the short term they may be the best choice for carbon capture from modular gasification systems when coupled with traditional solvent processes. From the summary in Table 12, it is also clear that the WGSMR process configurations, either H₂ selective or CO₂ selective, have many advantages which also make them attractive to pre-combustion CO₂ capture at modular scale: equipment is modular in nature, small footprint, low capital cost, especially for H₂ selective membrane reactors, which also offer flexibility for a polygeneration power plant. Finally, there are numerous process configurations with both solvents and membranes that can be used as a hybrid capture system to reduce the cost of pre-combustion CO₂ capture. When considering a modular scale design, hybrid processes offer unique opportunities to reduce cost and maximize flexible operation at capacities that are beneficial to each modular unit.

Another area to consider when downsizing the IGCC power plant with membrane technology, but not discussed in detail in this report, is the ASU. Cryogenic-based ASU not only consumes a significant amount of electricity, but it is also capital intensive and has a large footprint. Cryogenic air separation is the typical process in use, but its economy of scale favors a very large unit. For modular gasification systems, a membrane-based air separation unit will be much more desirable. An oxygen transport membrane or ion transport membrane will be much more viable to provide oxygen for the modular gasification unit. Further, an oxygen separation process, which can be operated using the heat generated from the WGS and/or WGS-temperature CO₂ adsorption, would likely lead to improved power plant efficiency.

A summary of NETL-funded R&D projects for the Pre-Combustion Carbon Capture research program can be found in Appendix C.

Table 12: Summary of Pre-Combustion CO₂ Capture Technologies

Process	Advantages	Disadvantages
Physical Solvent-Based process	• Commercially available at scale • Favorable economy of scale • Scale up is well understood • High purity CO₂ • Selective H₂S removal	• Low temperature • High affinity for heavy hydrocarbons • High capital cost for small scale • Involves chemicals • Cannot be integrated with WGS
Chemical Solvent-Based process (e.g., MDEA)	• Commercially available at scale • Favorable economy of scale • Scale up is well understood • Improved selectivity for CO₂ over other syngas components • High purity CO₂	• Energy consumption for solvent regeneration • Corrosion and solvent degradation issues • High capital cost for small scale • Involves chemicals • Cannot be integrated with WGS
Sorbent-Based Processes	• Potential to use at high temperature • Favorable economy of scale	• Process complexity • High capital cost for small scale • Involves chemicals • More sensitive to contaminants
SEWGS PSA	• Same as sorbent-based process + • High purity H₂ • Integrated with WGS reactor	• Same as sorbent-based process + • Capital intensive
SEWGS TSA	• Same as sorbent-based process + • High purity CO₂ • Integrated with WGS reactor	• Same as sorbent-based process + • High heat effect • Difficult integrate heat transfer
H₂ Selective Membrane	• Easy operation and modular in nature • No chemicals • High pressure CO₂ stream • Use of N₂ as sweeping gas • High purity H₂ product • Flexible for H₂ and NH₃ polygeneration	• Low pressure H₂ without sweep gas • CO₂ needs to be further purified • Not compatible with SNG, Chemicals, and F-T Liquids polygeneration cases
CO₂ Selective Membrane	• Easy operation and modular in nature • No chemicals • High pressure H₂ and high CO₂ purity • H₂S capture and co-sequestration • Flexible for SNG, Chemicals, and F-T Liquids polygeneration cases	• Cannot produce high purity H₂ • Not compatible with H₂ and NH₃ polygeneration cases • CO₂ needs to be compressed
H₂ Selective Membrane Reactor	• Same as H₂ Selective membranes • Compact and less capital intensive	• The same as H₂ selective membrane
CO₂ Selective Membrane Reactor	• Same as CO₂ selective membrane + • Compact & less capital intensive	• The same as CO₂ selective membrane
Hybrid e.g., H₂-selective membrane with solvent	• Meet CO₂ and H₂S specifications • Low energy requirement • Low hydrocarbon losses • Use of waste heat for solvent regeneration	• Additional capital cost needs to be balanced • Operating cost may increase due to additional unit operation • Optimization of configuration required

3. THERMODYNAMIC PERFORMANCE OF SELECTED PRE-COMBUSTION CO₂ CAPTURE TECHNOLOGIES

3.1 SELECTED CO₂ CAPTURE TECHNOLOGIES

The previous section reviewed different pre-combustion CO₂ capture technologies and discussed the advantages and disadvantages of integrating them with modular gasification systems. Among the carbon capture technologies that were reviewed, adsorption-based technologies were found to be unfavorable for modular scale pre-combustion CO₂ capture, except if operation could occur at high temperatures and at steady-state. Today's commercially-available adsorption-based processes are more complicated in terms of process control and layout compared with traditional solvent-based processes. This section will assess the thermodynamic performance of the five most promising technologies reviewed in the previous section. The solid sorbent-based technologies with TSA are excluded, including low-temperature and high-temperature processes. The low-temperature adsorption process is excluded because it does not use high-temperature syngas cleanup, and as a result, its thermodynamic performance will not be competitive. The high-temperature TSA SEWGS (temperature swing adsorption-sorption enhanced water gas shift) process is also excluded because the technology is more complicated and capital intensive. The high-temperature SEWGS process is more like a calcium looping process rather than a gasification-based process so it was not considered in this analysis. The remaining categories of pre-combustion carbon capture technologies that have been assessed for thermodynamic performance (including the baseline case) are listed in Table 13.

Table 13: Baseline Case and Selected CO₂ Capture Technologies used in Thermodynamic Analysis

Selected Technologies					
Baseline case – Selexol solvent (James et al., 2019; Turner et al., 2019)	SEWGS PSA	H ₂ Selective Membrane	CO ₂ Selective Membrane	H ₂ Selective Membrane Reactor	CO ₂ Selective Membrane Reactor

3.2 METHODOLOGIES USED TO ASSESS THERMODYNAMIC PERFORMANCE

To compare the thermodynamic performance of the different technologies, a common IGCC power plant process flow diagram was established as shown in Figure 34. In this standard process, the WGS reactor is considered to be part of the CO₂ capture process and is not shown separately. The two shaded areas were not simulated in this study and only the energy and mass exchanges between the different sections are considered. For example, the gasification section was not simulated but data from the DOE baseline report was adopted (James et al., 2019; Turner et al., 2019). Therefore, for all capture technologies the syngas composition and condition are from the quenched clean syngas stream (i.e., stream number 11 for Baseline Case B5B (James et al., 2019; Turner et al., 2019)). The energy exchange between the gasifier and the heat recovery steam generator (HRSG) sections was calculated based on the DOE Baseline report (James et al., 2019; Turner et al., 2019).

As mentioned in the previous section, it is preferred that H₂S be separated together with the CO₂ in a combined capture process. For the capture technologies considered in this analysis, all offer this arrangement, or at least researchers and developers are making progress in this direction (e.g., H₂ selective membranes (Kamakoti et al., 2005; Melendez et al., 2017)). As such, H₂S removal and the Claus power plant are not simulated in this analysis. However, in the energy performance estimation, H₂S removal and the Claus power plant are considered. Even though the H₂S and CO₂ separation processes are not simulated in detail, the compression of CO₂ was considered for all the capture technologies because of its high energy intensity. The CO₂ compression work was simulated based on the total amount of CO₂ product stream. Dehydration and other processing steps are not simulated. Based on the process shown in Figure 34, the energy performance of each CO₂ capture technology including the WGS were evaluated using ProTreat computer simulation software package. An example of a process flow diagram (for the Baseline Case B5B) used in the ProTreat simulation is shown in Figure 35.

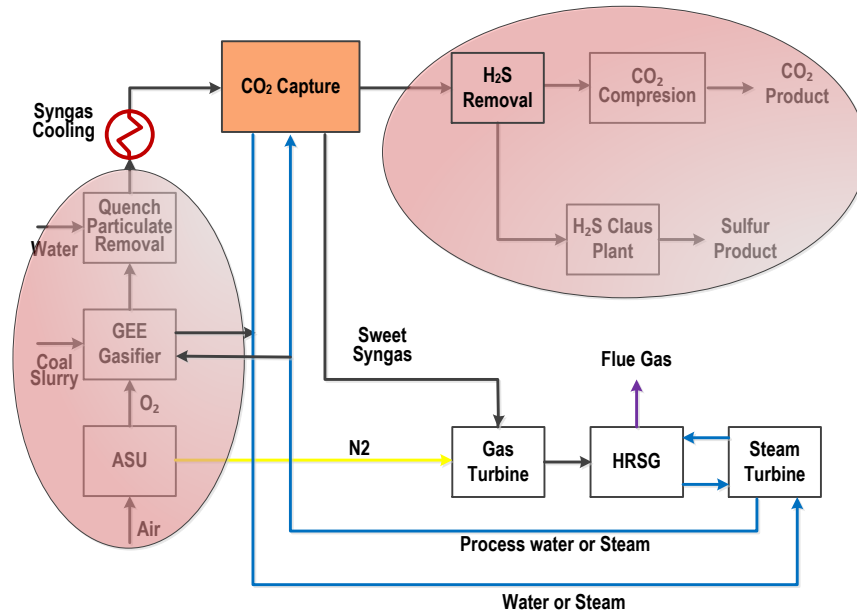


Figure 34: Simplified block flow diagram of an IGCC power plant.

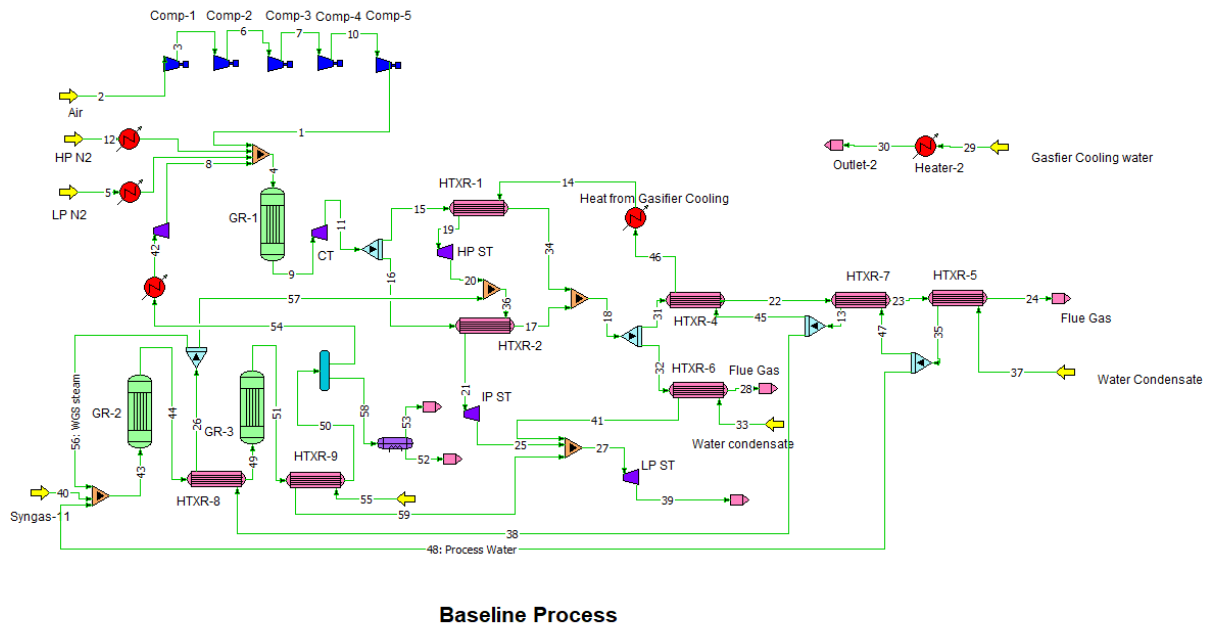


Figure 35: An example of a process flow diagram used in ProTreat simulation for baseline case.

The results published from Baseline Case B5B (IGCC power plant with Selexol CO₂ capture) were used to validate the simulation developed with ProTreat. Using the operating conditions and specifications given in the Baseline report, the power island was simulated and the results are listed in Table 14. By matching the total power generation of Baseline Case B5B, the energy efficiency of the turbines is calculated and these results are also listed in Table 14. After this validation step, all equipment/process efficiencies are kept constant.

Table 14: Simulation Results for Baseline Case B5B– IGCC Power Plant with CO₂ Capture (James et al., 2019; Turner et al., 2019)

Item	Gas Combustion Turbine	Sweet Gas Expander	Steam Turbine				Total Power
			High Pressure (HP)	Intermediate Pressure (IP)	Low Pressure (LP)	Total	
Isentropic Efficiency, %	88.5	83.5	91	90	89	N/A	N/A
Power Produced, MW	464	3	54	86	133	274	741

Using the validated simulation, specifications and assumptions, six pre-combustion CO₂ capture technologies including the DOE Baseline were evaluated for their energy performance. The assumptions and simplifications used for each specific CO₂ capture technology are described below.

3.3 ENERGY PERFORMANCE OF DIFFERENT CO₂ CAPTURE TECHNOLOGIES

Using the methodology outlined above, five different CO₂ capture technologies were evaluated for their energy performance and compared to the Baseline Case B5B (IGCC power plant with H₂S and CO₂ capture using Selexol solvent) from the DOE Baseline report (James et al., 2019; Turner et al., 2019).

3.3.1 SEWGS PSA Process

The PSA-based SEWGS process layout is shown in the block process flow diagram in Figure 36. A PSA-based SEWGS CO₂ capture process was used. The process flow diagram of the SEWGS process used in the ProTreat simulation is shown in Figure 37. The operating conditions including operating temperature and pressure for the process are shown in Table 15. These numbers are adopted from Gazzani et al. (2013) except the operating pressure, which the authors chose as 3.17 MPa, whereas 5.5 MPa was chosen in this report to be consistent with other processes in the current study.

Table 15: Operating Conditions and Process Assumptions for SEWGS Process

Operating Temperature (°C)	Operating Pressure (MPa)	Steam to Carbon Ratio	Rinse Steam (23.8 bar) Usage	Purge Steam (1.1 bar) Usage	CO ₂ Product Pressure (MPa)
350	5.5	1.5	H ₂ O/CO ₂ =0.33	H ₂ O/CO ₂ =0.44	0.1

In the SEWGS process, process steam is extracted from two locations of the steam turbine. In the reference, the authors used approximately 0.33 mole of steam for each mole of CO₂ in the rinse step and 0.44 mole of steam for the purge step. The steam pressures for the rinse step and the purge step are different. For the rinse, IP steam has to be used, whereas for the purge step, overheated LP steam can be used. The pressure of CO₂ product from the purge step, which is mixed with water vapor, is atmospheric pressure.

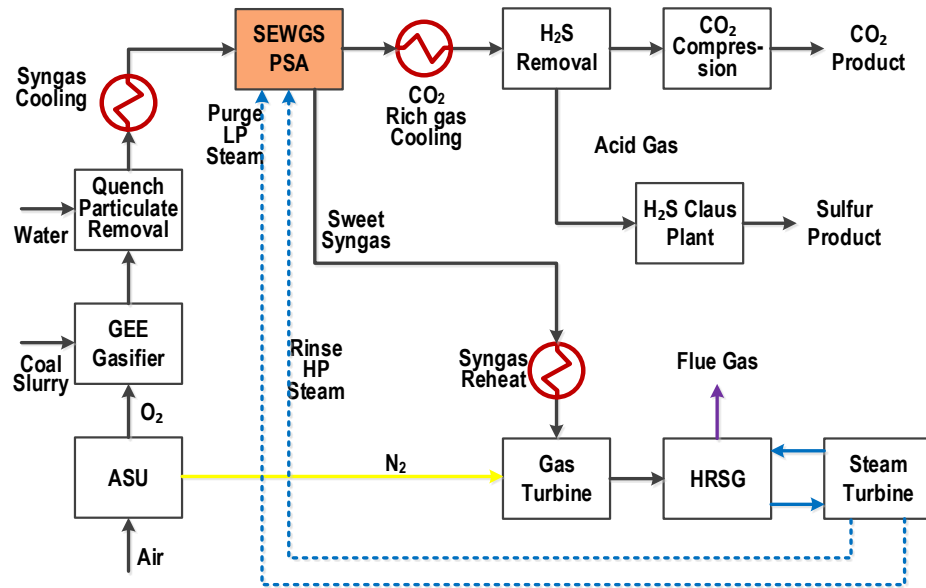


Figure 36: Block process flow diagram of PSA-based SEWGS process.

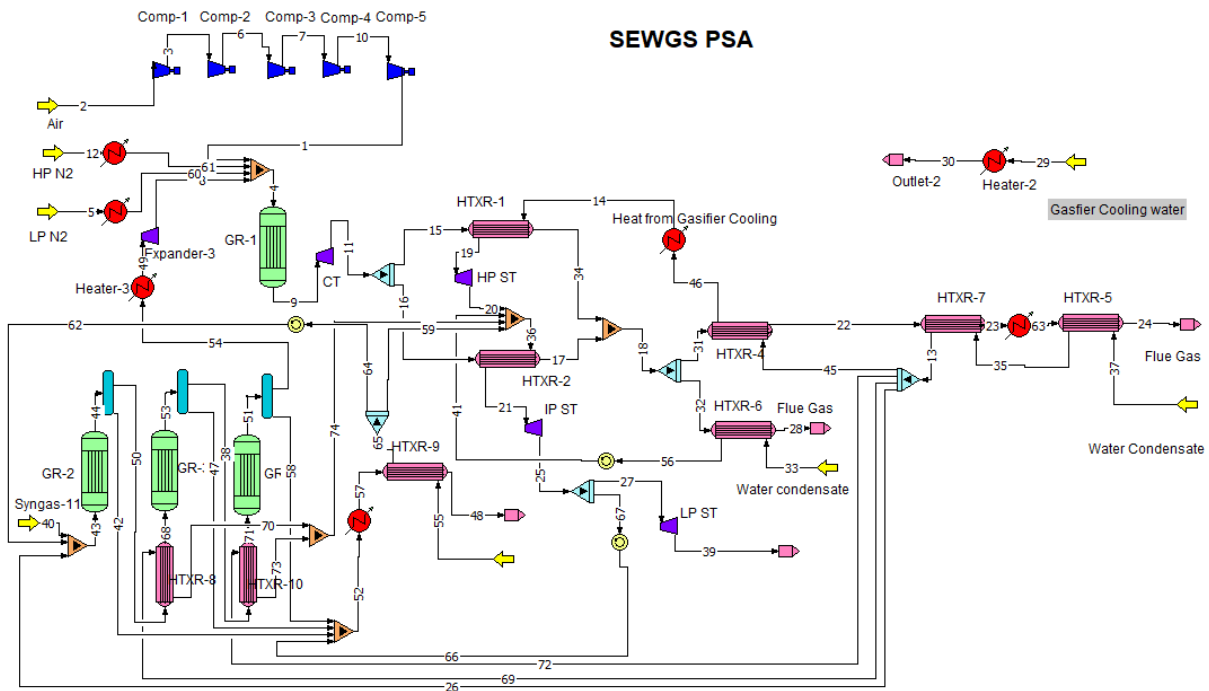


Figure 37: Process flow diagram of PSA-based SEWGS process used in ProTreat simulations.

In Gazzani et al. (2013), the authors claim that the CO₂ and steam mixture from the purge step should be expanded from atmospheric pressure to vacuum so that some power can be recovered. However, in this analysis, this expansion step is eliminated as it is likely not cost effective to add a vacuum step to a modular gasification system. As a result, the energy performance of SEWGS PSA process conducted here is not as attractive as that presented in (Gazzani et al., 2013).

In the ProTreat simulation conducted in this study, the detailed PSA process was not simulated, but the conditions of the two product streams along with steam usages were included in the simulations. Due to the application of high temperature for the WGS reaction, all the water vapor in the shifted syngas will enter the gas turbine along with all combustibles, which will increase the combustion turbine power output. The SEWGS process was found to produce about 485 MW_{el} from the combustion turbine and 268 MW_{el} from the steam turbine. Compared to the reference case, a higher combustion turbine output was obtained due to the rinse steam which follows the H₂ product. Similarly, the lower steam turbine power generation is due to the rinse and purge steam use in the capture process.

Overall, the PSA-based SEWGS process showed slightly better energy performance when compared to the base case process (refer to Table 20 for full comparison).

3.3.2 H₂ Selective Membrane Process

The block process flow diagram of the H₂ selective membrane-based process used for pre-combustion carbon capture is shown in Figure 38. Operating conditions and assumptions made for the H₂ selective membrane process are listed in Table 16. The process simulation flow diagram used for the ProTreat simulation is shown in Figure 39.

Table 16: Assumptions used in H₂ Selective Membrane Process Simulation

Operating Temperature (°C)	Steam to Carbon Ratio	H ₂ Recovery Rate (%)	H ₂ Selectivity	Permeate Side Pressure (MPa)	Retentate Side Pressure (MPa)
215	1.8	99	Infinity	3.2	5.1

In this process, syngas from stream number 11 (gasifier exit) in the Baseline Case B5B (James et al., 2019; Turner et al., 2019) is subjected to three WGS reactors at different temperatures. The syngas temperature at the outlet of the last WGS reactor is controlled at 215°C and all heat generated during the WGS reaction is integrated with the steam cycle. Based on the heat quality, integration was completed with either IP or LP, but no heat was considered to be integrated with the HP section. The hydrogen selectivity (over all other components) of the H₂ selective membrane was assumed to be infinity, which is realistic for hydrogen selective metallic membranes. The recovery rate of H₂ is assumed to be 99%. In the ProTreat simulation, the H₂ selective membrane unit performance was not simulated in detail, but a component splitter was used to mimic the membrane separation at conditions listed in Table 16. Also, the permeate side pressure is arbitrarily chosen if there is no sweeping gas. As mentioned previously the WGS reaction is equilibrium controlled. To achieve high CO conversion, a relatively low temperature is required. In this simulation a WGS reactor outlet temperature of 215°C is used to match the DOE Baseline report stream 17 (outlet of WGS) conditions. An even lower operating

temperature is possible which will increase the number of applicable membrane materials. However, even at a temperature of 215°C some polymeric membranes (e.g., PBI) could be considered. Polymeric membranes may not have as high H₂ selectivity as metallic membranes, but their advantage is in their low cost and more compact nature. Low capital cost and compactness could make them more economically competitive under modular gasification system conditions. However, the highly selective metallic membranes are better suited for polygeneration for pure H₂ or NH₃ cases. So, it is important to highlight that both types of H₂ selective membranes may have value, depending on the downstream applications.

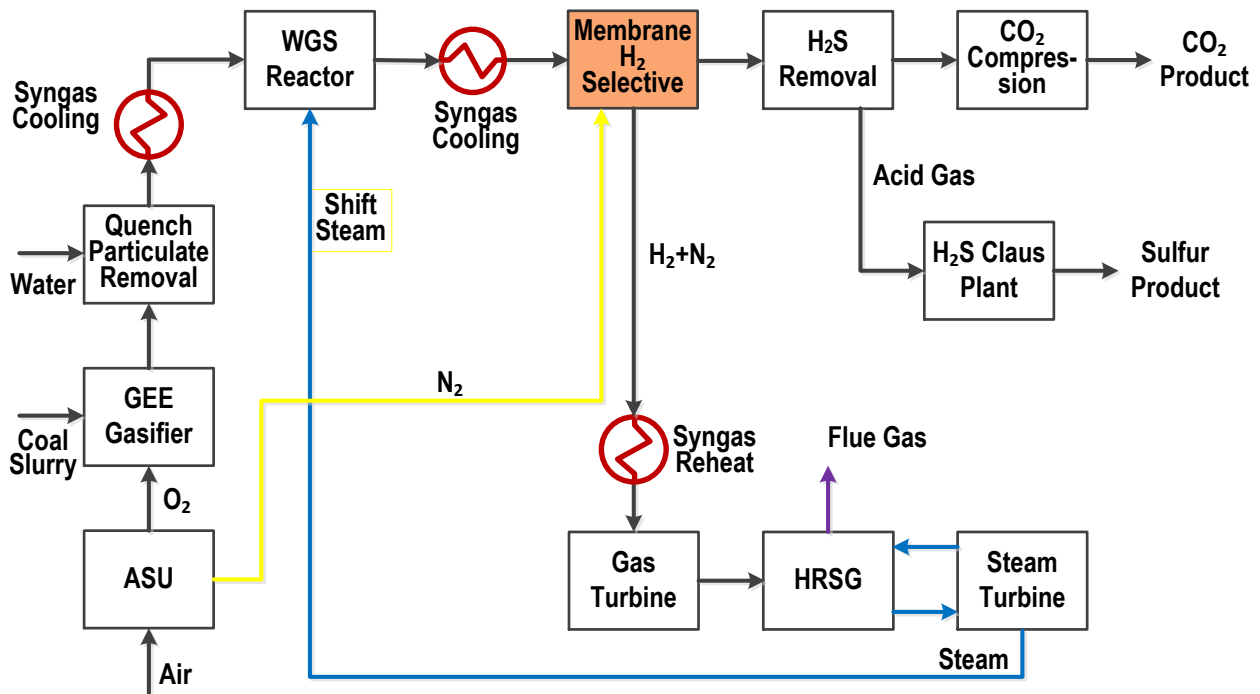


Figure 38: Block process flow diagram of H₂ selective membrane integrated process.

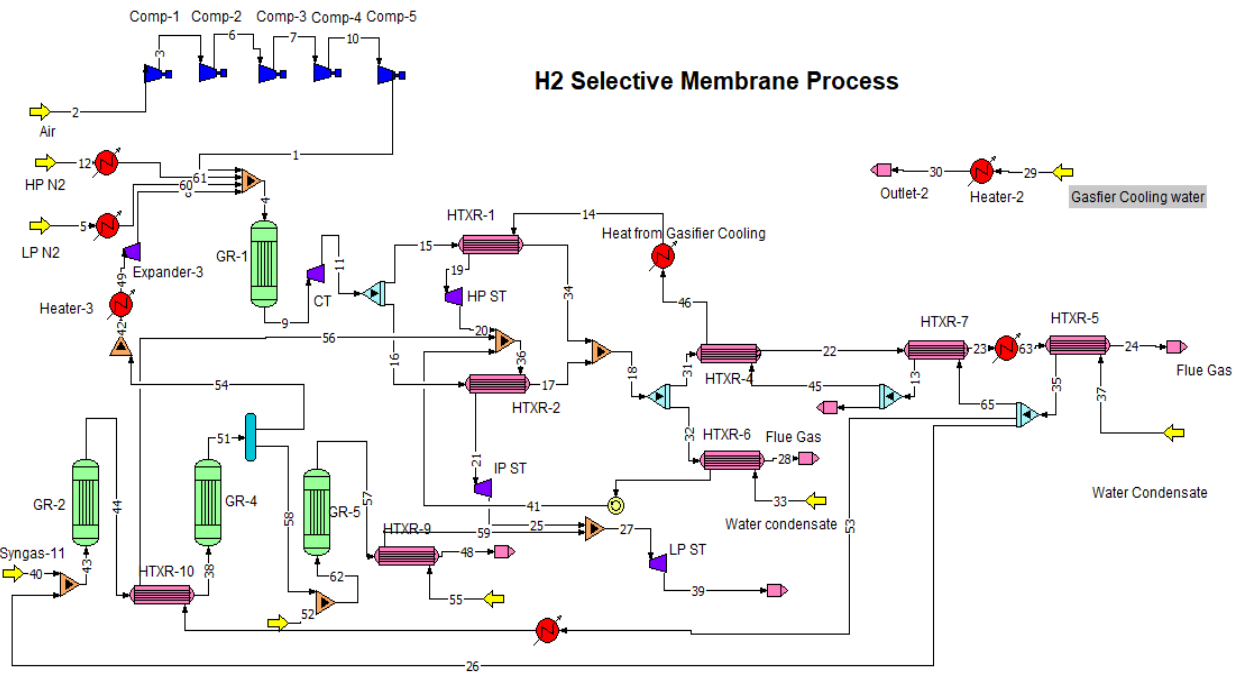


Figure 39: Process flow diagram of H₂ selective membrane in ProTreat simulation.

One of the advantages of using a H₂ selective membrane (for the IGCC and the NH₃ polygeneration case) is that nitrogen can be used as a sweeping gas, which can maintain the high pressure of the hydrogen stream and enhance its recovery. Depending on the membrane permeability and pressure ratio used, the permeate side pressure can vary. A low permeability membrane may need a higher driving force (i.e., a higher pressure ratio) and will result in low permeate side pressure. This analysis assumed that nitrogen from the ASU unit is available to sweep hydrogen to achieve 99% H₂ recovery and still have high enough pressure to enter the combustion turbine without further compression.

One disadvantage of this process is that the CO₂ rich stream has to be further treated before it can enter the CO₂ pipeline. To mitigate this issue, some authors propose using oxy-combustion and some propose using an OTM (oxygen transport membrane) unit to produce oxygen in situ to burn off the left-over combustibles including CO, CH₄, and H₂ (Manzolini et al., 2013b; Kelly, 2017). For a modular gasification system, compactness and simplicity of the process is important. If an ASU is available on site, then oxy-combustion may be an easier option and has a lower cost. In this simulation, all of the combustibles are simply burnt using pure oxygen. Since relatively complete conversion of CO is assumed, any power usage incurred by this extra oxygen requirement is neglected.

Another consideration for a H₂ selective membrane process is that the water vapor will be present in the retentate stream with the CO₂ and therefore will not go through to the combustion turbine, which will reduce the combustion turbine power generation. However, lower water vapor in the combustion turbine will reduce material/turbine lifetime issues that arise when higher water vapor is present (caused by increased heat transfer effects of the flame resulting in

increased metal temperature) (Maurstad, 2005). Using the H₂ selective membrane process, the combustion turbine generates a similar amount of power as the baseline case. A H₂O and H₂ selective membrane would be desirable to maximize power generated from the combustion turbine, but at this time that is difficult to achieve (and could lead to other material issues as discussed above – an economic analysis would be useful to understand the impacts of each option).

The H₂ selective membrane equipped IGCC power plant produced 455 MW_{el} from the combustion turbine and 286 MW_{el} from the steam turbine. The combustion turbine power production is lower than the baseline process because only H₂ from the raw syngas enters the combustion gas turbine which significantly reduces the mass flow rate of the gas turbine. Besides, relatively lower temperature for the WGS reaction downgraded the heat quality generated through the WGS reaction, which increased the output of the steam cycle. On the other hand, all other syngas components stay on the retentate side of the membrane and flow with the CO₂ stream and as a result, more power is produced from the steam turbine.

Due to the high pressure of the CO₂ product stream, the H₂ selective membrane process can save significant compression power and improves the overall energy performance compared to the base case (refer to Table 20 for full comparison).

3.3.3 CO₂ Selective Membrane Process

The block process flow diagram for the CO₂ selective membrane-based process is shown in Figure 40, and the assumptions and operating conditions of the process are listed in Table 17. The process flow diagram used in the ProTreat simulation is shown in Figure 41.

Table 17: Assumptions and Conditions used in CO₂ Selective Membrane Process

Operating Temperature (°C)	Steam to Carbon Ratio	CO ₂ Recovery Rate	CO ₂ and H ₂ S Selectivity	Permeate Side Pressure (MPa)	Retentate Side Pressure (MPa)
225	1.8	95%	Infinity	0.5	4.7

In this analysis, it is assumed that the CO₂ and H₂S selectivity over the other syngas components are infinity. This may not be realistic for most of the currently available membranes, but a facilitated CO₂ (and H₂S) selective membrane may be able to achieve extremely high selectivity (Zhao et al., 2014). Besides, lower selectivity may reduce both the H₂ and CO₂ recovery rates, but the impact on the energy performance should be minimal. Considering the scope of this study includes novel technologies still under development, assuming an ideal performance is acceptable and simplifies the analysis process.

As with the H₂ selective membrane case, a component splitter is used to mimic the membrane separation unit. CO₂ and H₂ recovery rates are assumed to be 95% and 100%, respectively. The advantage of using a CO₂ selective membrane is the high CO₂ purity of the CO₂ product stream, which will not require further treatment (after H₂S removal) before entering the pipeline. However, the CO₂ product stream pressure will be relatively low, especially when the membrane permeability is low resulting in the need for some compression.

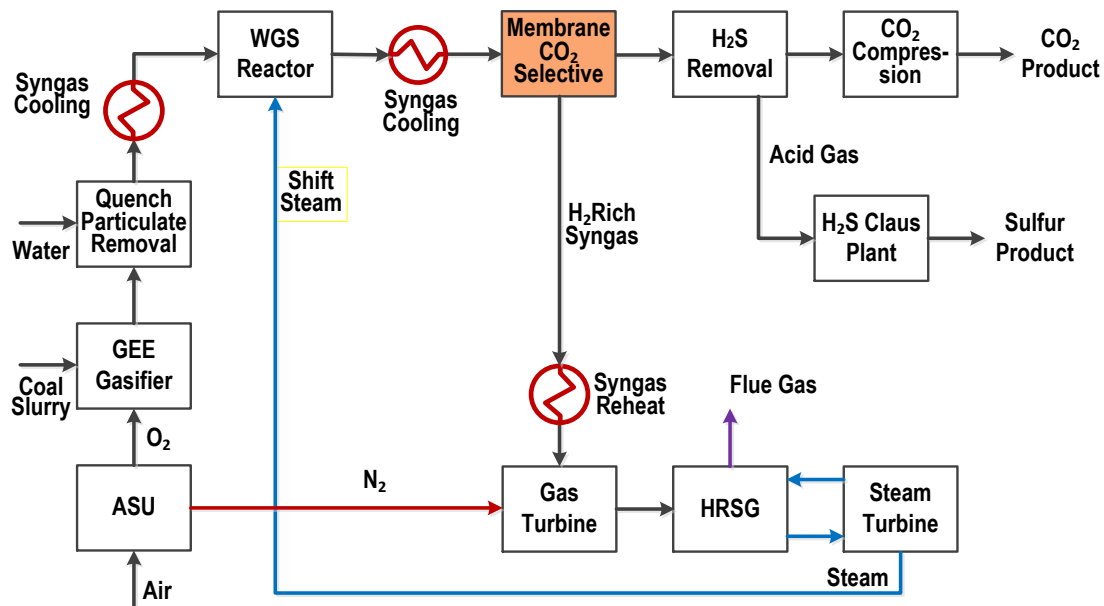


Figure 40: Block process flow diagram of CO₂ selective membrane-based process.

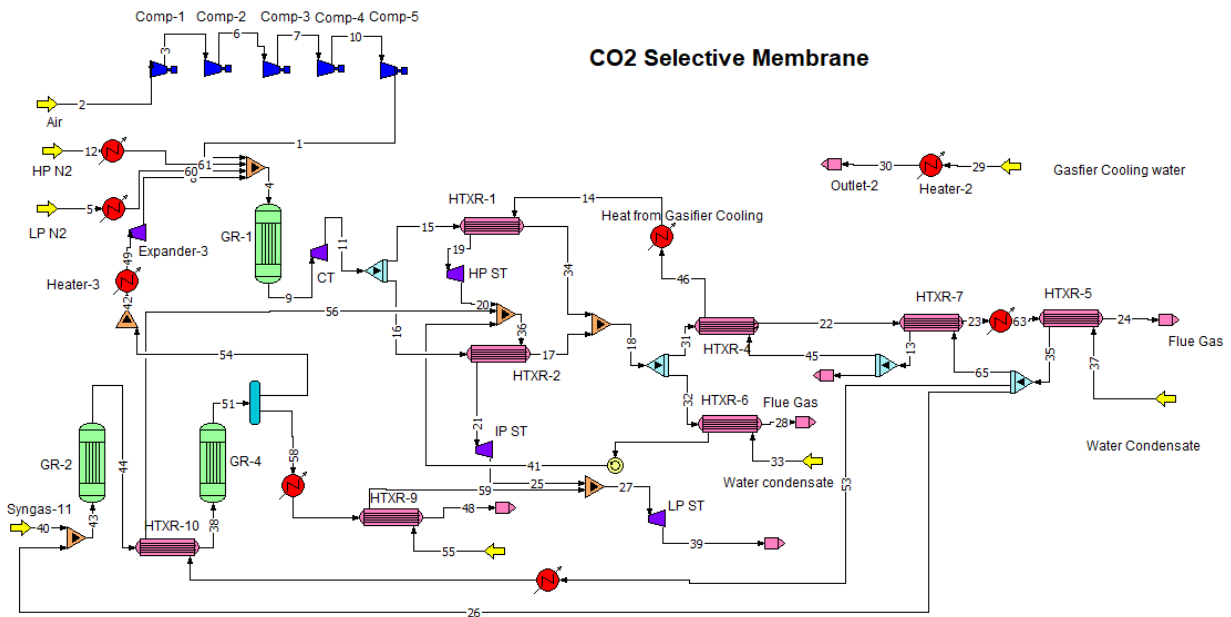


Figure 41: Process flow diagram of CO₂ selective membrane process used in ProTreat simulations.

In contrast to the H₂ selective membrane process, the CO₂ selective membrane process will keep all combustible components and water vapor in the fuel stream, and thus increase the power generation of the combustion turbine. This process produces 477 MW_{el} from the combustion turbine compared with the Baseline value of 464 MW_{el}. This process also produces 267 MW_{el} from the steam turbine which is similar to the Baseline case. The relatively low operating temperature used in the analyses reduces the net energy output for the CO₂ selective membrane process. If high-temperature membranes are available, then the energy performance will improve.

The disadvantage of the CO₂ selective membrane, particularly when compared to the H₂ selective membrane process, is that the CO₂ product stream will be at a lower pressure and intensive compression will be required.

3.3.4 H₂ Selective Membrane Reactor

The block process flow diagram for the H₂ selective MR-based process is shown in Figure 42 and the assumptions and operating conditions used in the process simulation are listed in Table 18. The process flow diagram used in the ProTreat simulation is shown in Figure 43.

As discussed, the WGS reaction is equilibrium controlled at higher temperatures. To enhance the conversion of CO to CO₂, more than the stoichiometric amount of steam is used. In this analysis, steam/carbon ratio of 1.8 is used for the WGS reaction when no product removal is enabled. For the MR a steam/carbon ratio of 1.5 is used to account for the in-situ product removal of the MR configuration. The steam/carbon ratio that was used for the SEWGS process is also used in this process.

Table 18: Assumptions used in H₂ Selective Membrane Reactor Process

Operating Temperature (°C)	Steam to Carbon Ratio	H ₂ Recovery Rate	H ₂ Selectivity	Permeate Pressure (MPa)	Retentate Pressure (MPa)
Adiabatic	1.5	99%	Infinity	3.21	5.1

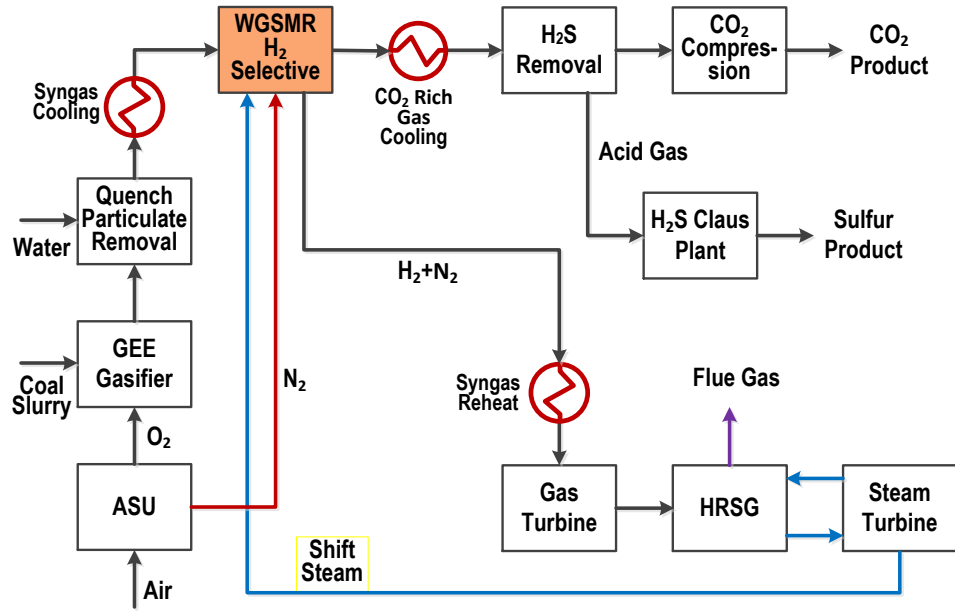


Figure 42: Block process flow diagram of H₂ selective MR-based process.

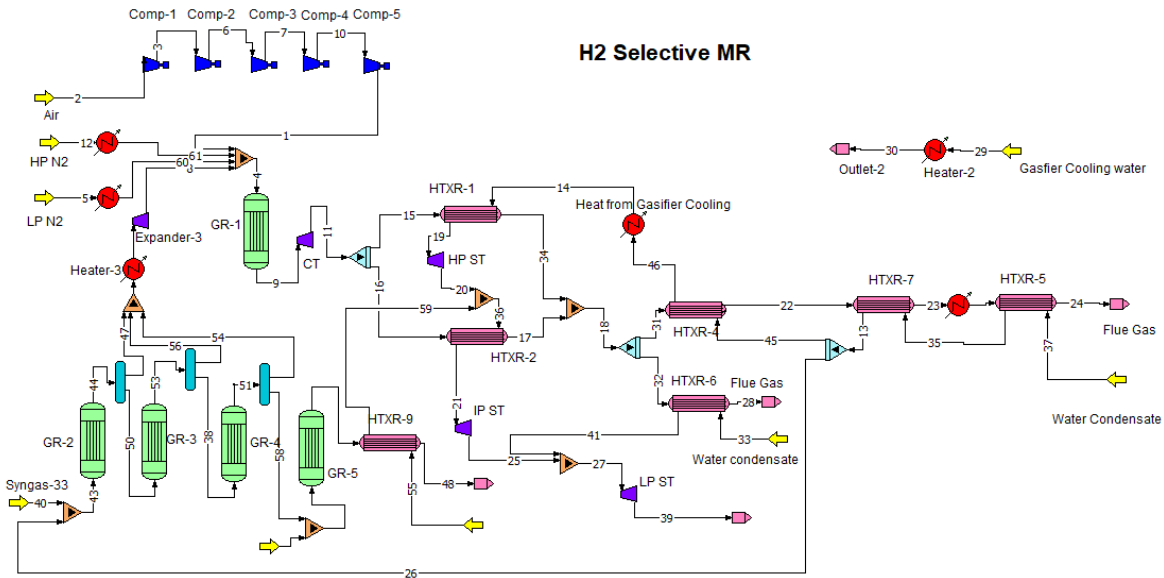


Figure 43: Process flow diagram of H₂ selective MR used in ProTreat simulations.

The MR integrates the WGS reactor with the membrane separation unit and, in an ideal situation, the WGS reactor can be eliminated. However, at the beginning, the syngas is at a condition which is far from equilibrium, i.e., WGS reaction is not equilibrium controlled. It is therefore possible to have at least some of the CO being converted in a separate WGS reactor, where the

product concentration is relatively low and then this stream enters the MR to remove the products (CO₂ or H₂) and further encourage CO conversion.

The operating temperature of the MR, either CO₂ selective or H₂ selective, in this simulation is adiabatic. The product H₂ is constantly removed. Three stages of MRs are used until the CO conversion reaches above 99%. However, depending on the membrane material and catalyst material, MR operating temperature could be higher or lower. A higher operating temperature will allow the WGS reaction to proceed faster and reduces the capital cost. Meanwhile, the equilibrium product concentration will be lower which will increase the membrane area required. Optimization of these parameters via economic analysis would be beneficial.

As with the H₂ selective membrane-based process, the permeate side of the MR uses N₂ to sweep and the retentate stream may need further treatment to remove the combustibles in the CO₂ rich steam.

Due to the higher operating temperature (it changes from 287 to 559°C), the MR equipped IGCC power plant produces more power compared with the same membrane (either CO₂ or H₂ selective) equipped process. The H₂ selective MR process produced 461 MW_{el} from the combustion turbine and 295 MW_{el} from the steam turbine. The output from steam turbine under this configuration is the highest among all the technologies assessed (refer to Table 20 for full comparison).

3.3.5 CO₂ Selective Membrane Reactor

The block process flow diagram of the CO₂ selective MR is shown in Figure 44 and its assumptions and operating conditions are listed in Table 19. The process flow diagram for the ProTreat simulation is shown in Figure 45.

Table 19: Assumptions and Conditions for CO₂ Selective Membrane Reactor Process

Operating Temperature (°C)	Steam to Carbon Ratio	CO ₂ Recovery Rate	CO ₂ and H ₂ S Selectivity	Permeate Side Pressure (MPa)	Retentate Side Pressure (MPa)
500	1.5	95%	Infinity	0.5	4.7

The process flow diagram of the CO₂ selective MR process is very similar to the H₂ selective MR process except that the former requires an additional combustor to remove all the combustibles from the CO₂ rich stream. The CO₂ selective MR has similar advantages and disadvantages to the CO₂ selective membrane process except that the MR integrate the WGS reactor with membrane separation unit. Due to the integration, the WGS MR will be able to achieve higher CO conversion without reducing the temperature.

Higher operating temperature of the CO₂ selective MR process along with the retention of the all combustible components with the H₂ rich syngas enable this process to produce the most power from the combustion turbine (496 MW_{el}). This process also produces 274 MW_{el} from the steam turbine making it the highest power producing option of all the options considered in this study (refer to Table 20 for full comparison).

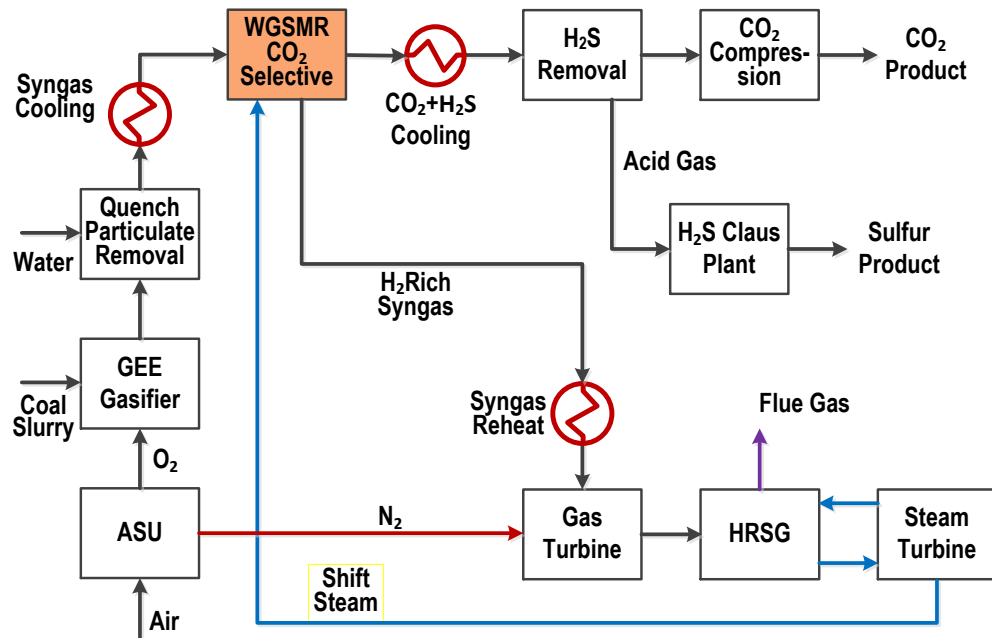


Figure 44: Block process flow diagram of CO₂ selective MR-based process.

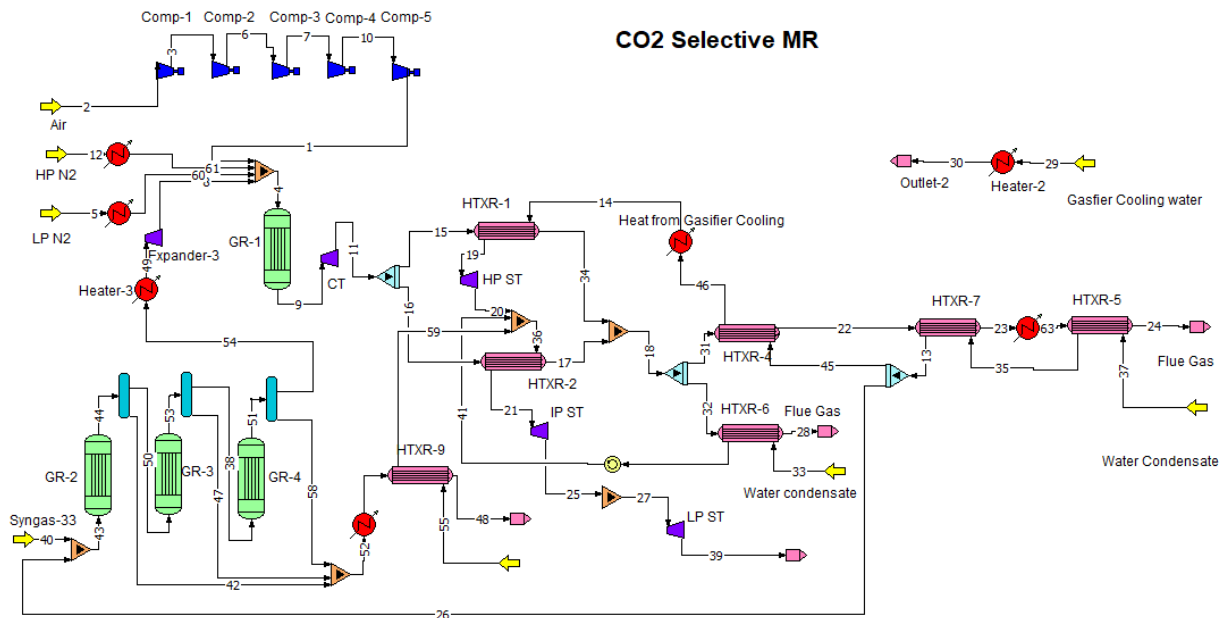


Figure 45: Process flow diagram of CO₂ selective MR for ProTreat simulations.

3.4 RESULTS AND DISCUSSION

The energy performance of an IGCC power plant with different carbon capture technologies were evaluated using ProTreat computer simulation software package. The results are summarized in Table 20. The main objective of the simulation was to determine the net power performance of each process, taking into account the differing gas turbine and steam turbine power, syngas expander and CO₂ compression sections. The power consumption of other sections (including ASU compressors, N₂ compressors, AGR, and balance of power plant) were adopted from the Baseline report (James et al., 2019; Turner et al., 2019).

Results show that all selected technologies exhibit better energy performance when compared to the Baseline Case B5B, which uses the standard Selexol solvent process for CO₂ capture. Both of the WGSMR processes demonstrated the best energy performance among the analyzed technologies. The sour, high-temperature WGSMR processes with CO₂ and H₂ selective membranes showed similar thermal efficiencies of 36.81% and 36.28%, respectively. For comparison the base case thermal efficiency is 33.7%. The results from this study also agree well with those reported by Siefert et al. (2016b), who conducted a comprehensive exergy analysis of IGCC power plant configurations with CO₂ capture. For example, the net power outputs for the reference case using Selexol solvent and the H₂-selective membrane process was 556 MW_{el} and 581 MW_{el}, respectively, in the current study which compares well with 564 MW_{el} and 581 MW_{el}, respectively, for Selexol and H₂-membrane from the Siefert et al. study.

Both MR technologies have overall advantages and disadvantages. The CO₂ selective MR is preferable if power production is the only product since high purity H₂ will not be needed and the high purity CO₂ product can go straight to pipeline (after H₂S removal) without further treatment. It also offers co-sequestration with H₂S if its removal is not needed. The H₂ selective MR process is the most widely studied process in the literature. It provides the flexibility of producing high purity H₂, which could be necessary for fuel cell applications or for other chemical production applications. The disadvantage of the H₂ selective MR process is that the CO₂ rich stream will have to be further treated to remove impurities before CO₂ can be transferred to a pipeline. This may not be an issue for large-scale power plants, but for a modular scale facility any extra process requirements will increase the footprint and capital cost.

As expected, operating with a higher temperature WGS reaction gives better thermal performance of all selected processes. However, high temperature will limit the availability of suitable and cheaper membrane materials. Currently, a lower cost membrane, which can work at more moderate temperatures may offer the best opportunity for commercialization.

The previous section showed that capital cost may play an increasingly significant role in the economics of a modular scale gasification system. Although this analysis was conducted for a full scale IGCC power plant, the thermodynamic performance of the processes at different scales should remain the same. The economic analyses for small scale IGCC power plants equipped with different pre-combustion carbon capture technology may be more critical to the overall picture of the LCOE for the modular gasification system.

Table 20: Power Plant Performance Summary for all Assessed CO₂ Capture Technologies

Performance Summary	Reference – Selexol Solvent (Turner et al., 2019)	SEWGS PSA	Membrane - H ₂ selective	Membrane - CO ₂ selective	WGSMT - H ₂ selective	WGSMT - CO ₂ selective
Combustion turbine power, MW _{el}	464	485	455	477	462	496
Sweet gas expander power, MW _{el}	3	12	0	11	0	15
HP	54	47	52	58	54	56
IP	86	115	101	93	109	104
LP	133	106	134	117	132	113
Total steam turbine power, MW _{el}	274	268	287	267	295	274
Total Gross Power, MW_{el}	741	765	742	755	756	785
CO ₂ compression, MW _{el}	31.7	43.1	8.0	19.7	8.0	27.5
Air separation unit main air compressor, MW _{el}	71.3	71.3	71.3	71.3	71.3	71.3
Air separation unit booster compressor, MW _{el}	5.6	5.6	5.6	5.6	5.6	5.6
N ₂ compressors, MW _{el}	36.6	36.6	36.6	36.6	36.6	36.6
Acid gas removal, MW _{el}	11.6	11.6	11.6	11.6	11.6	11.6
Balance of power plant, MW _{el}	28.1	28.1	28.1	28.1	28.1	28.1
Total auxiliaries, MW_{el}	185	196	161	173	161	181
Net power, MW_{el}	556	569	581	582	595	604
HHV net power plant efficiency	33.9%	34.6%	35.3%	35.4%	36.1%	36.6%
HHV net power plant heat rate, kJ/kWh	10675	10446	10229	10201	9976	9832

4. ECONOMIC ANALYSIS OF MODULAR SCALE PRE-COMBUSTION CARBON CAPTURE TECHNOLOGIES

Modular power plant design is an increasingly popular approach for providing a more flexible and efficient power plant with reduced design and construction expenses. However, the main disadvantage of a modular approach is the loss of economy of scale (Sievers et al., 2017). Therefore, it is important to understand how different parameters impact the economic performance of a process at different power plant scales.

The economic and technical performance of full scale coal fired power plants, with and without CO₂ capture, have been evaluated by many including the U.S. DOE's NETL in their baseline reports of which the latest is entitled "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 4" (James et al., 2019). This report uses an IGCC power plant base case consisting of a GE IGCC power plant with 90% CO₂ capture using the Selexol solvent absorption process. Other researchers have conducted economic analyses of novel carbon capture technologies including solvents, membranes, sorbents and integrated processes. This section will assess the economic performance of pre-combustion carbon capture processes and provide insights into how the economic performance could change as the process is reduced to modular scale.

4.1 ECONOMIC ANALYSIS OF A SELEXOL-BASED SOLVENT ABSORPTION PROCESS FOR PRE-COMBUSTION CARBON CAPTURE AT FULL SCALE AND MODULAR SCALE

Solvent absorption is considered the standard industrial process for acid gas removal from syngas. The economic performance of the Selexol solvent absorption process for CO₂ capture from a full scale IGCC power plant has been assessed in this section. The results are subsequently scaled down to assess changes in economic performance at modular scale. The analysis and cost estimates presented in this section are focused on the CO₂ capture power plant only.

4.1.1 Economic Performance of Full Scale IGCC Power Plant (543 MW) with Selexol-Based CO₂ Capture

An economic screening analysis has been completed for the Selexol solvent absorption process for CO₂ capture from an IGCC power plant by researchers at The University of Pittsburgh (Ashkanani et al., 2020). Aspen Plus v8.8 was used to simulate the CO₂ capture process from a typical syngas stream in a 543 MW pre-combustion IGCC power plant using different physical solvents including Selexol. The process included a counter current packed-bed absorber operating under high pressure over a wide range of temperatures and three pressure-swing flash drums for solvent regeneration. Simulations were conducted for both random IMTP50 packing and structured Mellapak 250 Y packing in the absorber. The syngas flow rate was 155 kg/s and the solvent flow rate was varied to achieve minimum 90% CO₂ capture efficiency. The absorber inside diameter ranged from 6 to 8 m and the packing height from 36 to 48 m. The absorber pressure was maintained at about 51 bar and the operating temperatures for Selexol ranged from 0 to 50°C. The physicochemical properties of the solvent were obtained from the literature and the equilibrium solubilities of the fuel gas components in each solvent were modelled using the PC-SAFT equation-of-state (EOS). The operational constraints imposed on the process included no flooding in the absorber, less than 600 ppm water concentration in CO₂ rich gas stream, and

less than 0.5 mol% of fuel gases (H₂, CO, CH₄) in the CO₂ rich gas stream (which would be sent to sequestration site).

The total capital costs, operating costs and the levelized cost of capture (LCOC) for the capture power plant were calculated to understand the economic performance of the pre-combustion CO₂ capture process. It should be noted that the LCOC calculated in this study accounted only for the CO₂ capture and CO₂ compression processes, not the entire cost to convert an IGCC power plant into an IGCC-CCS power plant, i.e., the LCOC reported here does not include the costs of the WGS equipment and any changes in the power cycle output due to sending H₂ rather than CO to the gas turbine. As the aim of the original research study (conducted by University of Pittsburgh researchers in collaboration with NETL) was to compare the economic performance of different solvents; it was concluded that these extra costs were outside the scope of the original analysis. As such, the values for LCOC presented here should be carefully compared with values of LCOC in the literature due to different boundaries assigned to different economic analyses.

The LCOC calculation used in this study is dependent on the capital and operating costs, power plant lifetime (N), the annual discount rate (i), capacity factor (f_c), operating and maintenance cost factor ($f_{O\&M}$), and the capital recovery factor (f_{CR}). Table 21 shows the capital recovery factor and LCOC calculated using the equations below with the assumed values of the parameters, which were based on the work presented by Siefert et al. (2016a). Further details on the equations and parameters used to determine the capital costs, operating costs, and CO₂ capture rate can be found in (Ashkanani et al., 2020).

$$f_{CR} = \frac{i(1+i)^N}{(1+i)^N - 1}$$

$$LCOC = \frac{(f_{CR} + f_{O\&M}) \sum (Capital\ cost)_{2019}}{f_c \times (tons\ of\ CO_2\ captured/year)} + \frac{\sum (Operating\ cost)_{2019}}{(tons\ of\ CO_2\ captured/year)}$$

Table 21: Parameter Values used to Calculate LCOC

Parameter	Value
i , %/year	10
N , years	30
$f_{O\&M}$, %/year	4
f_c	0.8

In general, the total capital costs incurred using Mellapak 250Y structured packing in the absorber are lower than those using random packing IMTP50 as shown in Figure 46. This is likely due to the increased mass transfer area provided with the structured packing resulting in lower flow rates, smaller flash drums, and lower pumping cost. This highlights the ability of high efficiency equipment with high gas/liquid interfacial area to reduce capital and operating costs as well as provide a smaller equipment footprint, which is important at modular scale. The lowest capital cost for Selexol solvent capture was found at an absorption operating temperature of 25°C

using Mellapak 250Y structured packing, while the highest capital cost was found at 0°C using IMTP50 random packing (due to increased heat exchange equipment demands). Figure 47 shows the operating costs required when using IMTP50 are higher than those when using Mellapak 250Y, which is due to the need for higher solvent flow rate when using IMTP50 than that when using Mellapak 250Y. Also, the highest operating costs were incurred at 0°C due to the need for more cooling at this low temperature.

This analysis indicates that the lowest LCOC can be obtained when the CO₂ capture process is carried out at low temperatures (due to the increased solubility of CO₂ in the solvents), leading to smaller absorber diameter and lower solvent circulation rates, which offsets the increased cooling requirements (refer to Figure 48). The lowest LCOC using Selexol for this 543 MW IGCC power plant arrangement was \$7.46 at operating temperatures of 5 and 10°C. (Note that this value of LCOC does not include all costs associated with carbon capture at an IGCC power plant.)

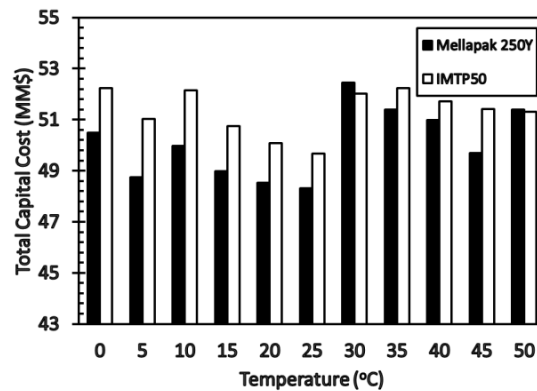


Figure 46: Total capital costs as a function of temperature for Selexol solvent absorption process for 90 % CO₂ removal from 543 MW IGCC power plant (Ashkanani et al., 2020).

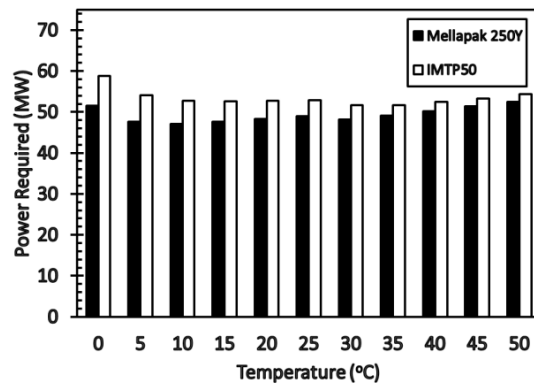


Figure 47: Operating cost (power requirement) as a function of temperature for Selexol solvent absorption process for 90% CO₂ removal from 543 MW IGCC power plant (Ashkanani et al., 2020).

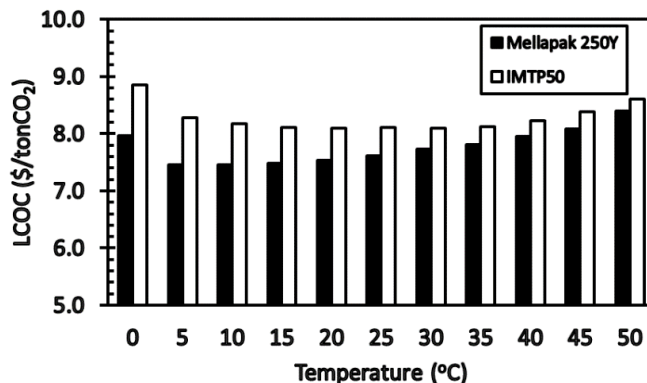


Figure 48: LCOC for Selexol (Ashkanani et al., 2020). (Note that this value of LCOC does not include all costs associated with carbon capture at an IGCC power plant, only the costs and power consumption directly associated with carbon capture equipment.)

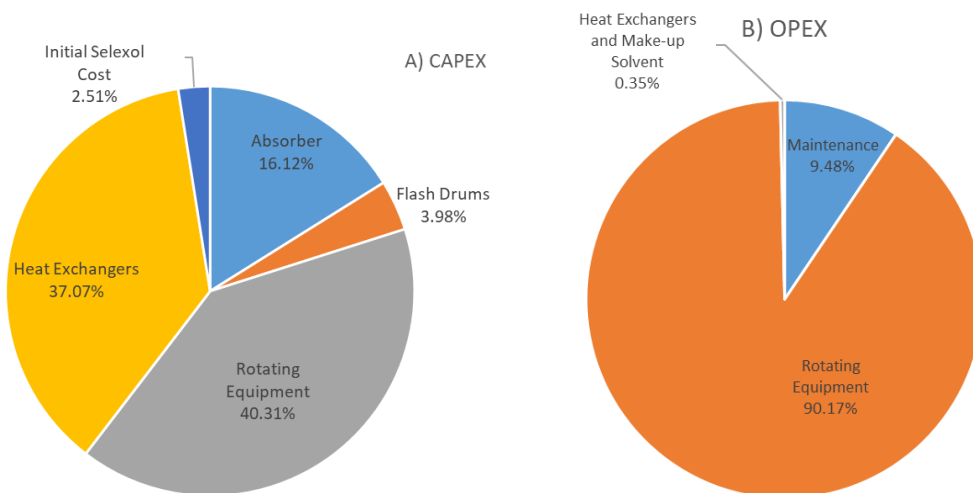


Figure 49: Breakdown of (A) capital costs (CAPEX) and (B) operating costs (OPEX) for Selexol (10°C) solvent CO₂ capture process at 543 MW scale. (Rotating equipment includes compressors, pumps, gas expanders, etc.)

Figure 49 shows the breakdown of capital and operating costs for a full scale 543 MW IGCC Selexol solvent CO₂ capture power plant. At this scale the capital costs are dominated almost equally (~40% each) by the heat exchangers and rotating equipment (which includes compressors, pumps, gas expanders, etc.), with the absorber being the next highest contributor to total CAPEX at 16%. The operating costs are largely dominated by the rotating equipment (90%) followed by maintenance costs.

4.1.2 Economic Performance of Small Scale IGCC Power Plant (54 MW) with Selexol-Based CO₂ Capture

The same economic analysis methods used for the full scale IGCC CO₂ capture power plant were applied to smaller, modular scale CO₂ capture power plants. This analysis showed that as the power plant scale is reduced from 543 MW to 54 MW the LCOC for a Selexol solvent absorption process increased by approximately 40% (refer to Figure 50).

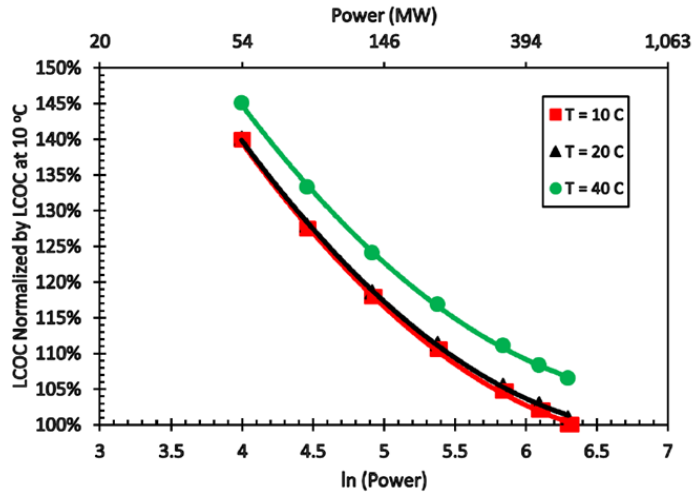


Figure 50: Change in LCOC with power plant scale using the Selexol solvent absorption process.

To further assess the change in economic performance with scale, the contributions to capital and operating costs for the Selexol process at 10°C have been presented in Figure 51 for a 54 MW scale power plant. At this smaller scale the rotating equipment (which includes compressors, pumps, gas expanders, etc.) contributes slightly more to the capital costs but slightly less to the operating costs, compared to the full-scale case. At modular scale, the operating costs are still largely dominated by the rotating equipment.

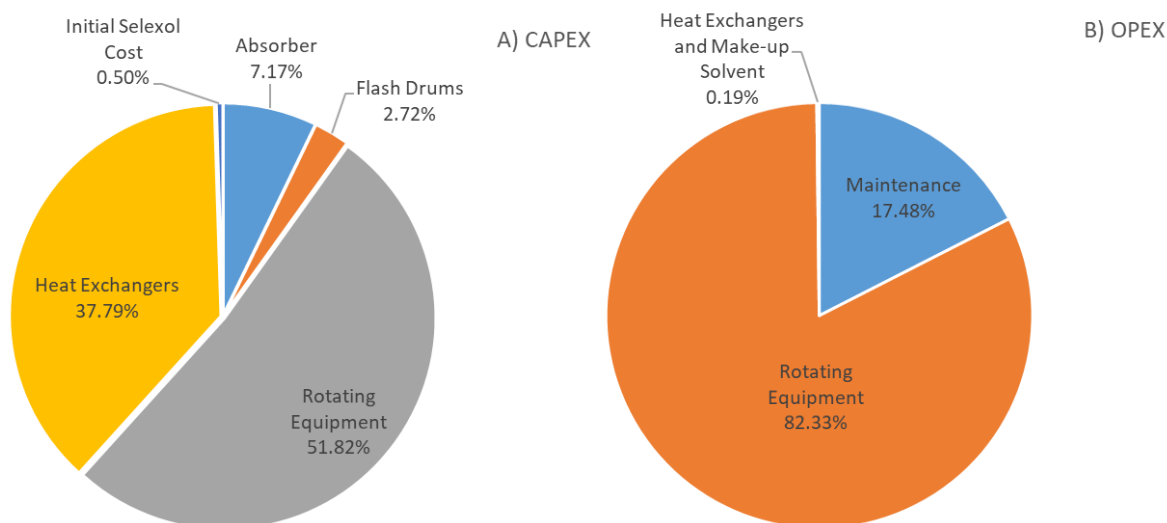


Figure 51: Breakdown of (A) capital costs (CAPEX) and (B) operating costs (OPEX) for Selexol (10°C) solvent CO₂ capture process at modular scale 54 MW. (Rotating equipment includes compressors, pumps, gas expanders, etc.)

From this analysis, it can be seen that as the size of a power plant is reduced from 500 MW to 50 MW, the capital costs have an increasingly important impact on the levelized cost of capture when using a standard physical solvent absorption process for CO₂ capture. These observations are important for guiding future development of pre-combustion carbon capture processes for integration with modular scale IGCC power plants. For example, it will be important for a novel solvent to reduce the capital costs of the process through improved absorption capacity, which can then reduce solvent circulation rates and pumping requirements.

4.2 REVIEW OF THE NETL COST AND PERFORMANCE BASELINE REPORT CASE B5B (IGCC POWER PLANT WITH PRE-COMBUSTION CO₂ CAPTURE USING SELEXOL SOLVENT ABSORPTION)

Sections 2 and 3 presented a literature review and thermodynamic analyses of promising pre-combustion CO₂ capture technologies, with a focus on modular scale processes for electricity generation from coal gasification. This section briefly reviews the data provided in Baseline Case B5B from the 2019 NETL Baseline report (James et al., 2019), which would be relevant for future analyses with other carbon capture technologies that use Baseline Case B5B as a baseline. The capital cost data for Baseline Case B5B is reproduced in Table 22 and the operating and maintenance costs are reproduced in Table 23. The power plant sections relevant to the CO₂ capture process (in this case Selexol solvent absorption) are highlighted in yellow.

Table 22: Total Power Plant Cost Estimation Summary for Baseline Case B5B (which uses Selexol solvent absorption for CO₂ capture). Original data can be found in James et al. (2019)

Case:		B5B	GEP Radiant IGCC w/ CO ₂				Estimate Type:			Conceptual	
Power Plant Size (MW, net):		556					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Power Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
1. Coal Handling											
Subtotal		\$39,916	\$87	\$10,420	\$0	\$50,422	\$7,563	\$0	\$11,597	\$69,583	\$125
2. Coal Preparation & Feed											
Subtotal		\$17,729	\$4,219	\$7,724	\$0	\$29,671	\$4,451	\$0	\$6,824	\$40,946	\$74
3. Feedwater & Miscellaneous BOP Systems											
Subtotal		\$66,577	\$9,896	\$44,322	\$0	\$120,795	\$18,119	\$0	\$39,692	\$178,606	\$321
4. Gasifier, ASU, & Accessories											
Subtotal		\$622,791	\$407	\$325,078	\$0	\$948,277	\$142,242	\$111,510	\$183,964	\$1,385,992	\$2,491
5. Syngas Cleanup											
5.1	Double Stage Selexol	\$126,860	\$0	\$51,816	\$0	\$178,677	\$26,802	\$35,735	\$48,243	\$289,456	\$520
5.2	Sulfur Removal	w/5.1	w/5.1	w/5.1	\$0	\$0	\$0	\$0	\$0	\$0	\$0
5.3	Elemental Sulfur Plant	\$48,681	\$9,489	\$62,377	\$0	\$120,546	\$18,082	\$0	\$27,726	\$166,354	\$299
5.4	Carbon Dioxide (CO ₂) Compression & Drying	\$32,248	\$4,838	\$13,969	\$0	\$51,054	\$7,658	\$0	\$11,743	\$70,455	\$127
5.5	(CO ₂) Compressor Aftercooler	\$481	\$76	\$206	\$0	\$764	\$115	\$0	\$176	\$1,054	\$2
5.6	Mercury Removal (Carbon Bed)	\$283	\$0	\$214	\$0	\$497	\$75	\$25	\$119	\$715	\$1
5.7	Water Gas Shift (WGS) Reactors	\$88,465	\$0	\$35,368	\$0	\$123,833	\$18,575	\$0	\$28,482	\$170,889	\$307
5.10	Blowback Gas Systems	\$675	\$379	\$212	\$0	\$1,267	\$190	\$0	\$218	\$1,675	\$3
5.11	Fuel Gas Piping	\$0	\$958	\$627	\$0	\$1,585	\$238	\$0	\$365	\$2,188	\$4
5.12	Gas Cleanup Foundations	\$0	\$227	\$153	\$0	\$380	\$57	\$0	\$131	\$568	\$1
Subtotal		\$297,693	\$15,968	\$164,941	\$0	\$478,603	\$71,790	\$35,760	\$117,202	\$703,355	\$1,264
6. Combustion Turbine & Accessories											
Subtotal		\$81,377	\$726	\$6,465	\$0	\$88,567	\$13,285	\$8,198	\$16,636	\$126,687	\$228

Case:		B5B	GEP Radiant IGCC w/ CO ₂				Estimate Type:		Conceptual		
Power Plant Size (MW, net):		556					Cost Base:		Dec 2018		
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Power Plant Cost	
				Direct	Indirect			Process	Project	\$/1,000	\$/kW
7. HRSG, Ductwork, & Stack											
Subtotal		\$55,354	\$1,322	\$13,379	\$0	\$70,055	\$10,508	\$0	\$12,271	\$92,834	\$167
8. Steam Turbine & Accessories											
Subtotal		\$52,821	\$281	\$17,362	\$0	\$70,465	\$10,570	\$0	\$13,397	\$94,431	\$170
9. Cooling Water System											
Subtotal		\$25,220	\$6,799	\$12,735	\$0	\$44,753	\$6,713	\$0	\$8,748	\$60,214	\$108
10. Slag Recovery & Handling											
Subtotal		\$5,513	\$547	\$3,880	\$0	\$9,941	\$1,491	\$0	\$1,900	\$13,332	\$24
11. Accessory Electric Plant											
Subtotal		\$40,070	\$1,741	\$11,893	\$0	\$53,704	\$8,056	\$0	\$9,858	\$71,618	\$129
12. Instrumentation & Control											
Subtotal		\$15,995	\$397	\$4,012	\$0	\$20,404	\$3,061	\$848	\$3,972	\$28,285	\$51
13. Improvements to Site											
Subtotal		\$2,988	\$2,337	\$15,693	\$0	\$21,017	\$3,153	\$0	\$7,251	\$31,421	\$56
14. Buildings & Structures											
Subtotal		\$0	\$6,399	\$7,460	\$0	\$13,859	\$2,079	\$0	\$2,391	\$18,329	\$33
Total		\$1,324,044	\$51,125	\$645,364	\$0	\$2,020,533	\$303,080	\$156,316	\$435,703	\$2,915,632	\$5,240

Note: Highlighted data will vary depending on chosen capture technology.

Table 23: Initial and Annual Operating and Maintenance Costs for Baseline Case B5B (which uses Selexol Solvent Absorption for CO₂ Capture) (James et al., 2019)

Case:	B5B	GEP Radiant IGCC w/ CO ₂		Cost Base:	Dec 2018
Power Plant Size (MW, net):	556	Heat Rate-net (Btu/kWh):	10,118	Capacity Factor (%):	80
Operating & Maintenance Labor					
Operating Labor			Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	\$/hour	Skilled Operator:	2.0
Operating Labor Burden:		30.00	% of base	Operator:	11.0
Labor O-H Charge Rate:		25.00	% of labor	Foreman:	1.0
				Lab Techs, etc.:	3.0
				Total:	17.0
Fixed Operating Costs					
Annual Cost					(\$) (\$/kW-net)
Annual Operating Labor:					\$7,453,446 \$13.395
Maintenance Labor:					\$30,614,140 \$55.019
Administrative & Support Labor:					\$9,516,897 \$17.103
Property Taxes and Insurance:					\$58,312,648 \$104.798
Total:					\$105,897,131 \$190.315
Variable Operating Costs					
					(\$) (\$/MWh-net)
Maintenance Material:					\$56,854,832 \$14.58018
Consumables					
	Initial Fill	Per Day	Per Unit	Initial Fill	
Water (gal/1000):	0	3,969	\$1.90	\$0	\$2,201,757 \$0.56463
Makeup and Waste Water Treatment Chemicals (ton):	0	11.8	\$550.00	\$0	\$1,898,578 \$0.48688
Sulfur-Impregnated Activated Carbon (ton):	78	0.107	\$12,000.00	\$939,432	\$375,773 \$0.09637
Water Gas Shift (WGS) Catalyst (ft ³):	15,607	10.7	\$480.00	\$7,491,563	\$1,498,313 \$0.38424
Selexol Solution (gal):	551,323	54.7	\$38.00	\$20,950,275	\$606,622 \$0.15557
Sodium Hydroxide (50 wt%, ton):	0.00	20.0	\$600.00	\$0	\$3,498,833 \$0.89726
Sulfuric Acid (98 wt%, ton):	0.00	0.353	\$210.00	\$0	\$21,643 \$0.00555
Claus Catalyst (ft ³):	w/equip	2.00	\$48.00	\$0	\$28,053 \$0.00719
Triethylene Glycol (gal):	w/equip	452	\$6.80	\$0	\$896,534 \$0.22991
Subtotal:				\$29,381,269	\$11,026,105 \$2.82760

Table 23: Initial and Annual Operating and Maintenance Costs for Baseline Case B5B (cont.)

Case:	B5B	GEP Radiant IGCC w/ CO ₂			Cost Base:	Dec 2018
Power Plant Size (MW, net):	556	Heat Rate-net (Btu/kWh):	10,118		Capacity Factor (%):	80
Waste Disposal						
Sulfur-Impregnated Activated Carbon (ton):	0	0.107	\$80.00	\$0	\$2,505	\$0.00064
WGS Catalyst (ft3):	0	10.7	\$2.50	\$0	\$7,804	\$0.00200
Selexol Solution (gal):	0	54.7	\$0.35	\$0	\$5,587	\$0.00143
Claus Catalyst (ft3):	0	2.00	\$2.50	\$0	\$1,461	\$0.00037
Crystallizer Solids (ton):	0	37.6	\$38.00	\$0	\$416,756	\$0.10688
Slag (ton):	0	635	\$38.00	\$0	\$7,050,036	\$1.80795
Triethylene Glycol (gal):	0	452	\$0.35	\$0	\$46,145	\$0.01183
Subtotal:				\$0	\$7,530,294	\$1.93111
By-Products						
Sulfur (tons):	0	145	\$0.00	\$0	\$0	\$0.00000
Subtotal:				\$0	\$0	\$0.00000
Variable Operating Costs Total:				\$29,381,269	\$75,411,231	\$19.33888
Fuel Cost						
Illinois Number 6 (ton):	0	5,791	\$51.96	\$0	\$87,859,022	\$22.53107
Total:				\$0	\$87,859,022	\$22.53107

For the 556 MW_e IGCC power plant with a Selexol solvent absorption process for CO₂ capture, the levelized cost of electricity is presented in Ashkanani et al. (2020). These results will be used as a baseline to compare the economic performance of other novel capture technologies in future analysis.

Table 24: LCOE for Selexol Solvent Absorption Process (data from James et al. (2019))

Component	Value, \$/MWh	Percentage
Capital	75.2	49%
Fixed	27.2	28%
Variable	19.3	13%
Fuel	22.5	15%
Total LCOE (Excluding T&S)	144.2	95%
CO ₂ T&S	8.1	5%
Total LCOE (Including T&S)	152.3	100%

4.3 CONCLUDING COMMENTS ON THE ECONOMICS OF MODULAR PRE-COMBUSTION CARBON CAPTURE PROCESSES

Generally, the fixed capital investment for a modular power plant design is expected to be higher than a conventionally designed power plant. This is due to the loss of economy of scale, which could ideally be compensated for through modular construction and engineering. However, some studies have shown that investment costs for modular scale may not be that much higher than conventionally designed power plants (Sievers et al., 2017). Additionally, other advantages of modular design should be taken into account when considering its investment, including the opportunity for faster reaction to changes in market conditions due to shorter lead times, (Bramsiepe et al., 2014) and stepwise capacity increase (Bramsiepe et al., 2012). The ability to increase capacity by multiplying functional processing units can also decrease the investment risk by avoiding scale-up issues (Buchholz, 2010). Additionally, the investment risk can be reduced because an early investment can be used to start production at low volumes, providing extra time to gain market insight (Sievers et al., 2017). In case of poor market performance, the production could be stopped without losing a large investment (Bramsiepe et al., 2012).

The literature contains a wide variety of processes and technologies for pre-combustion carbon capture and it can be difficult to determine which technologies are most promising in terms of economic and/or technical performance. Although most techno economic analyses of CO₂ capture processes reference a base case to enable comparison of metrics such as LCOE or CO₂ emissions avoided, nearly all studies use different assumptions including fuel costs, cost methods and base cases, which makes comparisons between studies difficult. Additionally, LCOE or LCOC definitions may vary from study to study, such as in using different assumed capacity factors, power plant lifetimes, discount interest rates and other economic assumptions. Additional analysis is required to fully assess economic potential of novel CO₂ capture processes, particularly at modular scale.

5. CONCLUSIONS

This report has assessed the potential of integrating modular scale carbon capture processes with modular scale coal gasification technologies and can be used to help guide future research and development efforts in this area.

A literature review of the gasification market showed that global demand for coal gasification processes is increasing and IGCC power generation has the ability to provide low-cost, low-emission energy from locally sourced coal with superior carbon capture capabilities. A flexible and diverse path for further growth of coal gasification technology is through polygeneration, i.e., applications for power generation and production of other products including chemicals. All of these applications will require syngas processing including CO₂ capture. Modular scale gasification and carbon capture could enable the use of mass manufacturing techniques, standard equipment (rather than licensed equipment), improved quality, testing at site of manufacture, transportation and quick assembly at site, and overall lower costs. Deployment of multiple small-scale gasifiers, rather than a few centralized large gasifiers, can increase the types of gasifier feedstock and potentially allow co-feeding of low cost or no cost feedstocks from local resources.

The syngas properties resulting from a range of different types of gasifiers using various feedstock under different operating conditions were assessed. The optimal syngas requirements for different syngas applications were then evaluated. Following a literature review, thermodynamic analysis and economic analysis, different pre-combustion carbon capture technologies were recommended for the different applications. At modular scale, the capital cost of the carbon capture equipment was highlighted as most important for reducing the LCOE.

Overall, membrane-based processes, particularly membranes that operate at the temperature of the syngas exiting the WGS, were found to have the most potential for reducing the cost of pre-combustion capture at modular scale. A H₂-selective membrane coupled with N₂ sweep and/or as a hybrid process with a downstream waste heat driven solvent process for H₂S and CO₂ separation were found to be promising options. Waste heat driven solvent processes can significantly reduce the power and capital cost associated with CO₂ compression. Integration of membrane separation or sorption processes with the water gas shift reactor is also likely to provide significant cost reductions at modular scale. The combination of membrane technologies with either waste-heat-driven solvent processes or integrated WGS is expected to create an efficient and size-reduced process which would be ideal for carbon capture from modular scale gasification processes. These findings were also in agreement with the thermodynamic analysis conducted in this study, which showed that the H₂-selective and CO₂-selective membrane reactors showed the best energy performance with net power plant efficiencies of 36.3 % and 36.8 %, respectively (compared to 33.7% for the baseline Selexol process).

Economic analysis of the Selexol solvent CO₂ capture process showed that as the power plant size was reduced from full scale (500 MW) to modular scale (50 MW), the LCOC increased by approximately 40% and the capital costs represented a larger portion of the LCOC at modular scale when using a standard physical solvent absorption process for CO₂ capture. Further detailed analysis is required to understand how to minimize the increase in LCOC as power plant scale is reduced.

Although electricity generation from coal-based IGCC with carbon capture was the main focus of this report, other gasification processes and applications have also been reviewed. The applicable carbon capture processes for the main gasification applications considered in this report have been discussed below followed by a summary in Table 25. Three different gasification scenarios have been considered for each application: (1) oxygen blown entrained flow gasifier using high-quality coal; (2) air blown transport gasifier with lignite; and (3) oxygen blown fixed/moving bed gasification with a mixed feedstock (e.g., coal and biomass).

Electricity Generation

For power generation using modular scale IGCC technology, the syngas should be free of contaminants such as particulates and trace metals (to avoid damage to the gas turbine) but the ratio of H₂:CO is not as important as in other syngas applications. However, if at least 90% carbon capture is required a water gas shift reactor (or combined reactor/separator) will be necessary.

For an oxygen fired entrained flow gasifier using high-quality feedstock like coal/pet coke, a membrane-based process is likely to be the most promising option for removing CO₂ from the syngas at modular scale. The use of a modular membrane reactor that combines the shift reaction and CO₂ removal would be ideal. Alternatively, a membrane separation process could be used following the water gas shift reaction process. For both processes, either a H₂ selective or CO₂ selective membrane would provide syngas suitable for power generation with reduced CO₂ emissions. However, a combined H₂ and H₂O selective membrane would be ideal due to its ability to send both the H₂ and H₂O to the gas turbine for maximum power output while also producing a dry CO₂ stream at the high pressure required for pipeline/sequestration. Hybrid membrane/solvent processes should also be considered for this application at modular scale.

For an air blown transport gasifier fired with feedstock like lignite, higher concentrations of N₂ will be present in the syngas. This will challenge membrane-based processes due to the lower partial pressure of H₂ and CO₂ in the syngas. Therefore, either a modular SEWGS, traditional physical solvent absorption process (like Selexol) or hybrid solvent/membrane process would be best suited for electricity generation with CO₂ capture from an air-blown gasification process.

An oxygen blown fixed/moving bed type of gasification process with a mixed feedstock (e.g., coal and biomass) is likely to result in a syngas containing higher amounts of methane and higher hydrocarbons as well as unwanted components like tar. Under these syngas conditions, a chemical solvent such as MDEA (which can flash off non-polar hydrocarbons while holding onto the CO₂ and H₂S chemically) or a modular SEWGS process would be the most promising options for removing CO₂ and producing electricity, although 90% capture of CO₂ would be difficult with high concentrations of methane and other hydrocarbons. A facilitated transport CO₂ selective membrane process, that avoids transfer of hydrocarbons, could also be considered. Although the presence of methane results in a higher cold gas efficiency and lower O₂ usage, which is advantageous to power generation, methane also limits carbon capture during syngas cleanup and combustion of methane will add to greenhouse gas emissions. If there is a high requirement for carbon capture, then low methane content is preferred in the syngas to avoid added costs of cleaning the syngas via methane reforming or post-combustion CO₂ removal (Carpenter, 2008).

Hydrogen Refinery

Hydrogen is used in the refining industry for upgrading fuels and reducing their sulfur content, in the production of ammonia, SNG, liquid fuels and other chemicals, in hydrogen powered vehicles, and for electricity generation via IGCC or fuel cells. Applications that require nearly pure H₂ (up to 99.95% H₂) include ammonia synthesis and PEM fuel cells (Carpenter, 2008). Less rigorous standards apply to hydrogen produced for petroleum hydrogenation and power production via IGCC power plants. Methanol, substitute/SNG and Fischer-Tropsch synthesis all require a H₂/CO blend.

The most promising modular scale gasification process for producing hydrogen is via an entrained flow oxygen fired gasifier with high-quality coal feedstock with CO₂ removal from the syngas using H₂ selective membranes, either as part of a membrane reactor or following the standard sour shift reactor process as a membrane separation module. SEWGS, solvent, and pressure swing adsorption (PSA) hybrid processes could also be considered.

For the air blown gasification case, nitrogen in the syngas will make CO₂ separation difficult and increase the size and capital cost of the whole power plant; and therefore, is not recommended for this application at modular scale.

For a mixed feedstock application, a H₂-selective membrane process is unlikely to provide the required H₂ purity due to the increased hydrocarbon content in the syngas. Hybrid processes may be considered in this situation.

Ammonia/Urea

Ammonia is produced according to the reaction $3\text{H}_2 + \text{N}_2 \rightarrow 2\text{NH}_3$ with the N₂ sourced from the ASU and high purity H₂ obtained from the purified syngas (with CO + CO₂ content <30 ppmv, sulphur <1 ppmv, and inerts (including methane) <2% (Higman and van der Burgt, 2003; Carpenter, 2008)). Most ammonia power plants are built in conjunction with urea power plants as the CO₂ from the ammonia power plant can be used directly for urea production.

For an entrained flow gasifier using high-quality coal, the stringent syngas requirements for ammonia production make CO₂ separation using a H₂ selective membrane with a N₂ sweep a promising option for ammonia production. Alternatively, a solvent absorption process, like the Rectisol process, could also be used to provide a high purity H₂ stream.

For the air blown gasification process, the large amounts of nitrogen in the syngas are likely to limit economic feasibility of this application at modular scale.

For the mixed feedstock case, a H₂ selective membrane with N₂ sweep could be considered; however, the retentate is likely to retain gases that contain high energy density, making further purification necessary for the CO₂ rich stream.

F-T Chemicals

The Fischer-Tropsch chemical process uses a Fe/Co catalyst to convert syngas containing H₂ and CO to a mixture of straight chain hydrocarbons. The syngas has strict limitations of the amount of sulphur, tars, and phenols to avoid processing issues including catalyst poisoning. The H₂:CO ratio varies depending on which catalyst is used (refer to Table 4), but water gas shift reactions will be required.

For this reason, this application is unlikely to be suitable at modular scale using a fixed/moving bed gasifier with mixed feedstock due to the high concentrations of sulfur, tars, etc.; although SEWGS with further upstream processing for contaminant removal or a chemical solvent absorption process could be considered.

Similarly, for the air blown gasification process, the large amount of nitrogen in the syngas is likely to increase the costs of processing equipment limiting its application at modular scale.

The use of an oxygen blown entrained flow gasifier with high-quality coal feedstock is likely to produce a syngas at modular scale that can be treated to the required F-T specifications with either a H₂ or CO selective membrane process, SEWGS sorbents or a physical solvent process.

Methanol

Methanol is produced from syngas by reacting CO and CO₂ with H₂ over a metallic catalyst in either a gas phase or liquid phase process. Optimal syngas composition includes a H₂:CO ratio of 2:1. The syngas can contain ~ 3 vol% CO₂ in gas phase reactors as it will react with any excess H₂ to form more methanol. CO content is limited to ~16 vol% to limit excessive heating in the reactor.

With these specifications, the air blown gasification process is unlikely to be suitable at modular scale due to the large amounts of nitrogen in the syngas which will increase the costs of processing equipment at modular scale.

However, similar to F-T chemicals, the use of an oxygen blown entrained flow gasifier with high-quality coal feedstock is likely to produce a syngas that can be treated at modular scale to the required specifications with either a H₂ or CO selective membrane process, SEWGS, sorbents or a physical solvent process.

SEWGS with upstream H₂S/NH₃/HCN removal and tar cracking could be considered for the mixed feedstock.

SNG (Synthetic Natural Gas)

The U.S. currently has a relatively cheap and abundant supply of natural gas. However, globally natural gas is in demand and conventional natural gas is becoming more expensive which makes production of SNG from coal gasification an attractive option. SNG consists of ~95% methane and is produced by passing cleaned syngas over a metal catalyst to react H₂ with CO₂ and CO to form CH₄. The syngas requires a CO:H₂ ratio of ~1:3 which requires CO₂ removal, likely by a physical solvent for a syngas produced from an entrained flow gasifier with high-quality feedstock.

The syngas produced by a fixed/moving bed gasifier with mixed feedstock will have a higher than average methane content which is advantageous to SNG production from syngas.

However, for the air blown gasification process, the large amounts of nitrogen in the syngas are likely to limit economic feasibility of this application at modular scale.

Table 25 provides a summary of the applicable capture processes for these different syngas applications.

Table 25: Promising CO₂ Capture Processes for Different Gasification Processes and End-Use Applications at Modular Scale

Gasifier Type and Feedstock	Syngas Application		
	Electricity generation only	H ₂ -Refinery / Ammonia	F-T Chemicals / Methanol / SNG
Oxygen-Blown Entrained Flow Gasifier (Coal / Pet Coke)	- Membrane/MH₂ (H₂-selective and CO₂-selective) - SEWGS (PSA and high temp TSA) - Sorbent - Solvent - Hybrid options (e.g., H₂-selective membrane/solvent)	- Membrane H₂R (H₂-selective) - Hybrid options with H₂-selective membrane - Solvent - Sorbent (PSA) - SEWGS (PSA, relatively low recovery)	- Membrane/MR (CO₂-selective) - Solvent (H₂S/CO₂/NH₃/HCN) - SEWGS - Sorbent (PSA) (CO₂/H₂S selective)
Air-blown Transport Gasifier (Lignite)	- SEWGS (PSA) - Solvent (CO₂ & H₂S selective) - Membrane (high CO₂ selectivity)	<i>Large amounts of N₂ will complicate the process and increase the equipment size and hence capital cost of all steps (gasification, WGS reaction, gas clean up, CO₂ removal). For some chemical processes like F-T and methanol, N₂ may adversely impact conversion if not removed before synthesis.</i>	
Oxygen-Blown Fixed/Moving Bed Gasifier (Mixed Feedstock) (High C1, C2, C3 Case)	- Solvent (high selectivity for CO₂ over hydrocarbons) - SEWGS (90% CO₂ capture is difficult with >10% C1+) - Membrane (CO₂ selective facilitated transport membrane)	- Hybrid options with H₂-selective membrane and: - Solvent (e.g., MDEA) - SEWGS	- SEWGS with upstream H₂S/NH₃/HCN removal and tar cracking - Solvent (high selectivity for CO₂ over hydrocarbons)

Notes: MR = Membrane Reactor; SEWGS = Sorption Enhanced Water Gas Shift; PSA = pressure swing adsorption; TSA = Temperature Swing Adsorption.

This page intentionally left blank.

6. REFERENCES

- Adams, II, T.A.; Hoseinzade, L.; Madabhushi, P. B.; Okeke, I. J. Comparison of CO₂ Capture Approaches for Fossil-Based Power Generation: Review and Meta-Study. *Processes* **2017**, *5*, 44.
- Aiken, R.; Ditzel, K. H.; Morra, F.; Wilson, D. S. *Coal-Based Integrated Gasification Combined Cycle: Market Penetration Strategies and Recommendations*; U.S. Department of Energy, National Energy Technology Laboratory, 2004.
- Air Products. Air Products Signs Two Agreements to Move Texas Carbon Capture and Sequestration Project Forward. May 26, 2011.
<http://www.airproducts.com/company/news-center/2011/05/0526-air-products-signs-two-agreements-for-texas-carbon-capture-and-sequestration-project.aspx>.
- Air Products. Biofuels LPMEOH™ Liquefaction.
<http://www.airproducts.com/Company/technology-partnerships/technology-licensing/energy/biofuels-lpmeoh-liquefaction.aspx> (accessed Oct 3, 2019).
- Alptekin, G. Pilot Testing of a Highly Effective Pre-Combustion Sorbent-Based Carbon Capture System. In *2019 NETL Carbon Capture, Utilization, Storage, and Oil and Gas Technologies Integrated Review Meeting*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Arroyo Torralvo, F.; Fernández Pereira, C.; Font Piqueras, O. 14 - By-products from the integrated gas combined cycle in IGCC systems. In *Integrated Gasification Combined Cycle (IGCC) Technologies*; Wang, T., Stiegel, G., Eds.; Woodhead Publishing, 2017; pp. 465–494.
- Ashkanani, H.E.; Wang, R.; Shi, W.; Sierfert, N. S.; Thompson, R. L.; Smith, K.; Steckel, J. A.; Gamwo, I. K.; Hopkinson, D.; Resnik, K.; Morsi, B. I. Levelized Cost of CO₂ Captured Using Five Physical Solvents in Pre-combustion Applications. *International Journal of Greenhouse Gas Control* **2020**, *101*, 103135.
- Barnes, I., Ed. *Recent operating experience and improvement of commercial IGCC*; CCC/222; I.C.C. Centre, London, UK, 2013.
- Basha, O. M.; Keller, M. J.; Luebke, D. R.; Resnik, K. P.; Morsi, B. I. Development of a conceptual process for selective CO₂ capture from fuel gas streams using [hmim][Tf₂N] ionic liquid as a physical solvent. *Energy and Fuels* **2013**, *27*, 3905–3917.
- Berchtold, K. A.; Singh, R. P.; Young, J. S.; Dudeck, K. W. Polybenzimidazole composite membranes for high temperature synthesis gas separations. *Journal of Membrane Science* **2012**, *415–416*, 265–270.
- Bhattacharyya, D.; Turton, R.; Zitney, S. E. 11 - Acid gas removal from syngas in IGCC plants. In *Integrated Gasification Combined Cycle (IGCC) Technologies*; T. Wang, T., Stiegel, G., Eds.; Woodhead Publishing, 2017; pp. 385–418.
- Bramsiepe, C.; Sievers, S.; Seifert, T.; Stefanidis, G. D.; Vlachos, D. G.; Schnitzer, H.; Muster, B.; Brunner, C.; Sanders, J. P. M.; Bruins, M. E.; Schembecker, G. Low-cost small scale processing technologies for production applications in various environments—Mass

- produced factories. *Chemical Engineering and Processing: Process Intensification* **2012**, 51, 32–52.
- Bramsiepe, C.; Krasberg, N.; Fleischer, C.; Hohmann, L.; Kockmann, N.; Schembecker, G. Information Technologies for Innovative Process and Plant Design. *Chemie Ingenieur Technik* **2014**, 86, 966–981.
- Breeze, P. *Carbon Capture and Storage Coal-Fired Generation*; Academic Press, 2015; pp. 73–86.
- Buchholz, S., Future manufacturing approaches in the chemical and pharmaceutical industry. *Chemical Engineering and Processing: Process Intensification* **2010**, 49, 993–995.
- Carbo, M. C.; Jansen, D.; Haije, W. G.; Verkooijen, A. H. M. Advanced membrane reactors for fuel decarbonisation in IGCC: H₂ or CO₂ separation? In *Fifth Annual Conference on Carbon Capture and Sequestration*, Alexandria, VA, 2006.
- Carpenter, A. M., Ed. *Polygeneration from coal*; CCC/139; I.C.C. Centre, 2008.
- Chang, S.; Zhuo, J.; Meng, S.; Qin, S.; Yao, Q. Clean Coal Technologies in China: Current Status and Future Perspectives. *Engineering* **2016**, 2, 447–459.
- Chen, H.; Cao, M.; Zhao, L.; Ciora, R. J. Experimental Study of an Intensified Water-Gas Shift Reaction Process Using a Membrane Reactor/Adsorptive Reactor Sequence. *Industrial and Engineering Chemistry Research* **2018**, 57, 13650–13660.
- Chen, S.; Xiang, W.; Wang, D.; Xue, Z. Incorporating IGCC and CaO sorption-enhanced process for power generation with CO₂ capture. *Applied Energy* **2012**, 95, 285–294.
- Chen, W.-H.; Chen, C.-Y. Water gas shift reaction for hydrogen production and carbon dioxide capture: A review. *Applied Energy* **2020**, 258, 114078.
- Chiesa, P.; Consonni, S.; Kreutz, T.; Williams, R. Co-production of hydrogen, electricity and CO₂ from coal with commercially ready technology. Part A: Performance and emissions. *International Journal of Hydrogen Energy* **2005**, 30, 747–767.
- Ciferno, J. P.; Marano, J.J. *Benchmarking Biomass Gasification Technologies for Fuels, Chemicals and Hydrogen Production*; U.S. Department of Energy, National Energy Technology Laboratory, 2002.
- Ciferno, J.; Plasynski, S.; Brickett, L.; Jones, A.; Vaux, G.; Chen, S.; Munson, R.; Murphy, J.; Marano, J.; Strock, J. *DOE/NETL Advanced carbon dioxide capture R&D program: Technology Update*; U.S. Department of Energy, National Energy Technology, 2010.
- Cormos, C.-C., Evaluation of syngas-based chemical looping applications for hydrogen and power co-generation with CCS. *International Journal of Hydrogen Energy* **2012**, 37, 13371–13386.
- Couch, G. *Coal to liquids*; CCC/132; IEA Clean Coal Center, 2008.
- de la Osa, A. R.; De Lucas, A.; Valverde, J. L.; Romero, A.; Monteagudo, I.; Sanchez, P. Performance of a sulfur-resistant commercial WGS catalyst employing industrial coal-derived syngas feed. *International Journal of Hydrogen Energy* **2011**, 36, 44–51.

- Dietz, J. Lessons learned from one year of urea production, 2020.
<https://www.dakotagas.com/news-center/publications/basin-today/lessons-learned-one-year-urea-production>
- Dooher, J. P.; Castaldi, M. J.; Modroukas, D. P. Advanced concepts in modular coal and biomass gasifiers. *Journal of Energy Resources Technology, Transactions of the ASME*, **2019**, 141.
- Duke Energy. Edwardsport IGCC. <https://www.duke-energy.com/our-company/about-us/power-plants/edwardsport> (accessed Oct 1, 2019).
- Echt, W. Hybrid Systems: Combining Technologies Leads to More Efficient Gas Conditioning. In *52nd Annual Laurance Reid Gas Conditioning Conference*, UOP LLC: Norman, Oklahoma, 2002.
- EIA. U.S. Energy Information Administration, Annual Energy Outlook 2019 with projections to 2050, January 2019a.
- EIA. U.S. Energy Information Administration, Monthly Energy Review, Table 6.2, May 2019b.
- EIA. U.S. Energy Information Administration, U.S. Coal Reserves, Table 15, November 2018.
- Fair, D., Ed. The Future of Gasification. *Cornerstone Magazine, I. Synthesis Energy Systems*; 2016.
- FAO. *Wood gas as engine fuel*; Food and Agriculture Organization of the United Nations: Rome, Italy, 1986,
- Figuerola, J. D.; Fout, T.; Plasynski, S.; McIlvried, H.; Srivastava, R. D. Advances in CO₂ capture technology-The U.S. Department of Energy's Carbon Sequestration Program. *International Journal of Greenhouse Gas Control* **2008**, 2, 9–20.
- Franz, J.; Maas, P.; Scherer, V. Economic evaluation of pre-combustion CO₂-capture in IGCC power plants by porous ceramic membranes. *Applied Energy* **2014**, 130, 532–542.
- Gangwal, S. Small-Scale Engineered High Flexibility Gasifier. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Gao, W.; Zhou, T.; Gao, Y.; Wang, Q. Enhanced water gas shift processes for carbon dioxide capture and hydrogen production. *Applied Energy* **2019**, 254, 113700.
- Gasification Technologies Council. *Gasification: the Waste-to-Energy Solution*; Gasification Technologies Council, 2011.
- Gazzani, M.; Macchi, E.; Manzolini, G. CAESAR: SEWGS integration into an IGCC plant. *Energy Procedia* **2011**, 4, 1096–1103.
- Gazzani, M.; Macchi, E.; Manzolini, G. CO₂ capture in integrated gasification combined cycle with SEWGS – Part A: Thermodynamic performances. *Fuel* **2013**, 105, 206–219.
- Gervasi, J.; Dubois, L.; Thomas, D. Screening tests of new hybrid solvents for the post-combustion CO₂ capture process by chemical absorption. *Energy Procedia* **2014**, 63, 1854–1862.

- Global Syngas Technologies Council. The Gasification Industry.
<https://www.globalsyngas.org/resources/the-gasification-industry/> (accessed Oct 1, 2019).
- Granite, E. J.; Myers, C. R.; King, W. P.; Stanko, D. C.; Pennline, H. W. Sorbents for Mercury Capture from Fuel Gas with Application to Gasification Systems. *Industrial & Engineering Chemistry Research* **2006**, *45*, 4844–4848.
- Gray, D. D. 8 - Major gasifiers for IGCC systems. In *Integrated Gasification Combined Cycle (IGCC) Technologies*; T. Wang, T., Stiegel, G., Eds. Woodhead Publishing, 2017; pp. 305–355.
- Green, J. Thin film technology innovation drives advances in gas treatment: part one. In *Hydrocarbon Engineering*, 2015.
- Herdem, M. S.; Lorena, G.; Wen, J. Z. Simulation and Performance Investigation of a Biomass Gasification System for Combined Power and Heat Generation. *Journal of Energy Resources Technology, Transactions of the ASME* **2019**, *141*.
- Higman, C. State of the Gasification Industry – the Updated Worldwide Gasification Database. 2013 International Pittsburgh Coal Conference, Beijing, China, 2013.
- Higman, C.; Phillips, J. Integrated Gasification Combined Cycle (IGCC) Design Considerations for High Availability—Volume 1: Lessons from Existing Operations, E.P.R. Institute, Ed.; Electric Power Research Institute, 2007.
- Higman, C.; van der Burgt, M. Chapter 5 - Gasification Processes. In *Gasification*; Higman, C, M. van der Burgt, M., Eds.; Gulf Professional Publishing: Burlington, 2003; pp. 85–170.
- Higman, C.; van der Burgt, M. *Gasification*; Gulf Professional Publishing, 2008.
- Hiroyuki, O. State-of-the-art technologies for reliable/ sustainable coal fired power plants, 2017.
<http://www.jcoal.or.jp/event/upload/18.%20State-of-the-Art%20Technologies%20for%20Reliable%20Sustainable%20Coal%20Fired%20Power%20Plants%20%28Mr.%20Otani%29.pdf>. (accessed Sept 6, 2017).
- Ho, W.; Han, Y. Transformational Membranes for Pre-combustion Carbon Capture. In *2019 NETL Carbon Capture, Utilization, Storage, and Oil and Gas Technologies Integrated Review Meeting*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Holladay, J. Magnetocaloric cryogenic system for high efficiency air separations. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Hydrogen Council. Hydrogen scaling up A sustainable pathway for the global energy transition. Hydrogen Council, Roadmap, 2017.
- James, R.; Kearins, D.; Turner, M.; Woods, M.; Kuehn, N.; Zoelle, A. *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*; U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.

- Janajreh, I.; Raza, S. S.; Valmundsson, A. S. Plasma gasification process: Modeling, simulation and comparison with conventional air gasification. *Energy Conversion and Management* **2013**, *65*, 801–809.
- Jasi, A. Wabash Valley Resources closes investment for CCS project. *The Chemical Engineer* 2019.
- Jayaweera, I.; Perea, E. Development and Testing of a High Temperature PBI Hollow-Fiber Membrane Technology for Pre-Combustion CO₂ Capture. In *2019 NETL Carbon Capture, Utilization, Storage, and Oil and Gas Technologies Integrated Review Meeting*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Ji, G.; Yao, J. G.; Clough, P. T.; Diniz da Costa, J.; Anthony, E. J.; Fennell, P. S.; Wang, W.; Zhao, M. Enhanced hydrogen production from thermochemical processes. *Energy & Environmental Science* **2018**, *11*, 2647–2672.
- Kamakoti, P.; Morreale, B.; Ciocco, M. V.; Howard, B. H.; Killmeyer, R. P.; Cugini, A. V.; Sholl, D. S. Prediction of Hydrogen Flux Through Sulfur-Tolerant Binary Alloy Membranes. *Science* **2005**, *307*, 569–573.
- Kelly, S.M. OTM Technology: Process intensification and modularization. In *Modular Gasification-Based Energy Systems Workshop*, Pittsburgh, PA, 2017.
- Kentish, S. E. 110th Anniversary: Process Developments in Carbon Dioxide Capture Using Membrane Technology. *Industrial & Engineering Chemistry Research* **2019**, *58*, 12868–12875.
- Kerester, A. Gasification Can Help Meet the World's Growing Demand for Cleaner Energy and Products. *Cornerstone: The Official Journal of the World Coal Industry* **2014**, *2*.
- Kniep, J. Bench-Scale Development of a Transformative Membrane Process for Pre-Combustion CO₂ Capture, In *2019 NETL Carbon Capture, Utilization, Storage, and Oil and Gas Technologies Integrated Review Meeting*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Kohl, A. L.; Nielsen, R. B. Chapter 14 - Physical Solvents for Acid Gas Removal, In *Gas Purification*, Fifth Edition; A.L. Kohl, A. L., Nielsen, R. B., Eds.; Gulf Professional Publishing: Houston, 1997; pp. 1187–1237.
- Lalou, C. Distributed power with advanced clean coal gasification technology. *Cornerstone* **2014**, Autumn, 55–60.
- Lekse, J. Development of oxygen carriers for coal conversion to syngas. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Li, F. Radically engineered modular air separation system using tailored oxygen sorbents. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Lin, H. Development of Carbon Molecular Sieves Hollow Fiber Membranes Based on Polybenzimidazole Doped with Polyprotic Acids with Superior H₂/CO₂ Separation

- Properties. In *2019 NETL Carbon Capture, Utilization, Storage, and Oil and Gas Technologies Integrated Review Meeting*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Lin, H. Sorption Enhanced Mixed Matrix Membranes for Hydrogen Purification and Carbon Dioxide Capture. In *2019 NETL Carbon Capture, Utilization, Storage, and Oil and Gas Technologies Integrated Review Meeting*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Lin, H.; He, Z.; Sun, Z.; Vu, J.; Ng, A.; Mohammed, M.; Kniep, J.; Merkel, T. C.; Wu, T.; Lambrecht, R. C. CO₂-selective membranes for hydrogen production and CO₂ capture - Part I: Membrane development. *Journal of Membrane Science* **2014**, *457*, 149–161.
- Lyons, D. Modular Gasification - New Markets for Coal Use. In *NARUC Winter Policy Summit*, 2018.
- Lyons, D. NETL Gasification Program Overview. In *2019 NETL Gasification Systems Project Review Meeting*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Maas, P.; Modigell, M.; Hake, J.-F.; Stolten, D.; Scherer, V.; Markewitz, P.; Zhao, L.; Nauels, N. Energetic and economic evaluation of membrane-based carbon capture routes for power plant processes. *International Journal of Greenhouse Gas Control* **2016**, *44*, 124–139.
- Madden, D. R. 23 - Case study: Kemper County IGCC project, USA. In *Integrated Gasification Combined Cycle (IGCC) Technologies*; Wang, T., Stiegel, G., Eds.; Woodhead Publishing, 2017; pp. 817–832.
- Mantripragada, H. C.; Rubin, E. S. Chemical Looping for Pre-combustion and Post-combustion CO₂ Capture. *Energy Procedia* **2017**, *114*, 6403–6410.
- Manzolini, G.; Gazzani, M.; Turi, D. M.; Macchi, E. Application of Hydrogen Selective Membranes to IGCC. *Energy Procedia* **2013b**, *37*, 2274–2283.
- Manzolini, G.; Macchi, E.; Gazzani, M. CO₂ capture in Integrated Gasification Combined Cycle with SEWGS – Part B: Economic assessment. *Fuel* **2013b**, *105*, 220–227.
- Marano, J. J.; Ciferno, J. P. Integration of Gas Separation Membranes with IGCC Identifying the right membrane for the right job. *Energy Procedia* **2009**.
- Maurstad, O. *An Overview of Coal based Integrated Gasification Combined Cycle (IGCC) Technology*; MIT: Cambridge, MA, 2005.
- Meerman, J. C.; Ramirez, A.; Turkenburg, W. C.; Faaij, A. P. C. Performance of simulated flexible integrated gasification polygeneration facilities. Part A: A technical-energetic assessment. *Renewable and Sustainable Energy Reviews* **2011**, *15*, 2563–2587.
- Meerman, J. C.; Ramirez, A.; Turkenburg, W. C.; Faaij, A. P. C. Performance of simulated flexible integrated gasification polygeneration facilities, Part B: Economic evaluation. *Renewable and Sustainable Energy Reviews* **2012**, *16*, 6083–6102.
- Melendez, J.; de Nooijer, N.; Coenen, K.; Fernandez, E.; Viviente, J. L.; van Sint Annaland, M.; Arias, P. L.; Pacheco Tanaka, D. A.; Gallucci, F. Effect of Au addition on hydrogen

- permeation and the resistance to H₂S on Pd-Ag alloy membranes. *Journal of Membrane Science* **2017**, 542, 329–341.
- Meng, L. Zeolite Membrane Reactor for Pre-Combustion Carbon Dioxide Capture. In *2019 NETL Carbon Capture, Utilization, Storage, and Oil and Gas Technologies Integrated Review Meeting*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Mishra, A.; Gautam, S.; Sharma, T. Effect of operating parameters on coal gasification. *International Journal of Coal Science & Technology* **2018**, 5, 113–125.
- Najmi, B.; Bolland, O.; Colombo, K. E. A systematic approach to the modeling and simulation of a Sorption Enhanced Water Gas Shift (SEWGS) process for CO₂ capture. *Separation and Purification Technology* **2016**, 157, 80–92.
- NETL. 5.1. Gasification Introduction. National Energy Technology Laboratory. <https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/intro-to-gasification> (accessed Nov 6, 2019a).
- NETL. Air Separation. https://www.netl.doe.gov/coal/gasification/air_separation (accessed Nov 20, 2019b).
- NETL. Commercial Gasifiers. <https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/types-gasifiers> (accessed Oct 23, 2019c).
- NETL. Gasification-based cogeneration/coproduction. <https://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/co-generation> (accessed Oct 3, 2019d).
- NETL. Rectisol. <https://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/rectisol> (accessed Dec 9, 2019e).
- NETL. Selexol. <https://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/selexol> (accessed Dec 9, 2019f).
- NETL. *Wabash River Coal Gasification Repowering Project: A DOE Assessment*; U.S. Department of Energy, National Energy Technology, 2002. doi:10.2172/790376.,
- Nikolic, H. Gasification Combined Heat and Power from Coal Fines. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Nisamaneenate, J.; Sornkade, P.; Atong, D.; Sricharoenchaikul, V. Advanced reforming of agro-waste by modular gasifier for fuel generation. *Chemical Engineering Journal* **2015**, 282, 170–178.
- Ovalle-Encinia, O. High Temperature Ceramic-Carbonate Dual-Phase Membrane Reactor for Pre-Combustion Carbon Dioxide Capture. In *2019 NETL Carbon Capture, Utilization, Storage, and Oil and Gas Technologies Integrated Review Meeting*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Pantula, R. Development of a two-phase dense fluid expander for advanced cryogenic air separation and low-grade heat recovery. In *2019 NETL Annual Project Review Meeting*

- for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Phillips, J. N.; Booras, G. S.; Marasigan, J. The History of Integrated Gasification Combined-Cycle Power Plants. In *ASME Turbo Expo 2017: Turbomachinery Technical Conference and Exposition*, 2017.
- Phillips, J., Different Types of Gasifiers and Their Integration with Gas Turbines. In *The Gas Turbine Handbook*. EPRI/Advanced Coal Generation; U.S. Department of Energy: Washington, DC, 2006.
- Pisupati, S. V.; Krishnamoorthy, V. 2 - Utilization of coal in IGCC systems. In *Integrated Gasification Combined Cycle (IGCC) Technologies*; Wang, T., Stiegel, G., Eds.; Woodhead Publishing, 2017; pp. 83–120.
- Placido, A. Staged Opposed Multi Burner (OMB) for Modular Gasifier/Burner. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Ramkumar, S.; Fan, L.-S. Calcium Looping Process (CLP) for Enhanced Nuncatalytic Hydrogen Production with Integrated Carbon Dioxide Capture. *Energy & Fuels* **2010**, *24*, 4408–4418.
- Ratafia-Brown, J.; Manfredo, L.; Hoffmann, J.; Ramezan, M. *Major Environmental Aspects of Gasification-based Power Generation Technologies*; U.S. Department of Energy, National Energy Technology Laboratory, 2002.
- Roh, K.; Lee, J. H. Control Structure Selection for the Elevated-Pressure Air Separation Unit in an IGCC Power Plant: Self-Optimizing Control Structure for Economical Operation. *Industrial & Engineering Chemistry Research* **2014**, *53*, 7479–7488.
- Rout, K. R.; Gil, M. V.; Chen, D. Highly selective CO removal by sorption enhanced Boudouard reaction for hydrogen production. *Catalysis Science & Technology* **2019**, *9*, 4100–4107.
- RTI International. Business update: RTI and eastman partner on syngas clean-up technology. <https://www.rti.org/brochures/rti-and-eastman-chemical-demonstrate-warm-temperature-syngas-cleanup-technology> (accessed Dec 6, 2019).
- Sasaki, T.; Suzuki, T.; Takaoka, M.; Akasaka, Y. Performance of a low temperature reactive sulfur-tolerant WGS catalyst using industrial coal gasification gas feed. *International Journal of Hydrogen Energy* **2017**, *42*, 2008–2017.
- Scholes, C. A.; Simioni, M.; Qadar, A.; Stevens, G. Membrane gas–solvent contactor trials of CO₂ absorption from syngas. *Chemical Engineering Journal* **2012**, *195–196*, 188–197.
- Scholes, C. A.; Smith, K. H.; Stevens, G. CO₂ capture from pre-combustion processes - Strategies for membrane gas separation. *International Journal of Greenhouse Gas Control* **2010**, *4*, 739–755.
- Scholes, C.A.; Anderson, C. J.; Cuthbertson, R.; Stevens, G. W.; Kentish, S. E. Simulations of Membrane Gas Separation: Chemical Solvent Absorption Hybrid Plants for Pre- and

- Post-Combustion Carbon Capture. *Separation Science and Technology* **2013a**, 48, 1954–1962.
- Scholes, C.A.; Anderson, C. J.; Stevens, G. W.; Kentish, S. E. Membrane gas separation physical solvent absorption combined plant simulations for pre-combustion capture. *Energy Procedia* **2013b**, 37, 1039–1049.
- Sethi, V. Advanced sorbents for modular oxygen production for radically engineered modular systems (REMS) gasifiers. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019a.
- Sethi, V. Low-cost oxygen for small scale modular gasification systems. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*. U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019b.
- Siefert, N. S.; Agarwal, S.; Shi, F.; Shi, W.; Roth, E. A.; Hopkinson, D.; Kusuma, V. A.; Thompson, R. L.; Luebke, D. R.; Nulwala, H. B. Hydrophobic physical solvents for pre-combustion CO₂ capture: Experiments, computational simulations, and techno-economic analysis. *International Journal of Greenhouse Gas Control* **2016a**, 49, 364–371.
- Siefert, N.S.; Narburgh, S.; Chen, Y. Comprehensive Exergy Analysis of Three IGCC Power Plant Configurations with CO₂ Capture. *Energies* **2016b**, 9, 669.
- Sievers, S.; Seifert, T.; Franzen, M.; Schembecker, G. Fixed capital investment estimation for modular production plants. *Chemical Engineering Science* **2017**, 158, 395–410.
- Singh, R. High selectivity and high throughput carbon molecular sieve hollow fiber membrane based modular air separation unit for producing high purity O₂. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Smart, S.; Lin, C. X. C.; Ding, L.; Thambimuthu, K.; Diniz da Costa, J. C. Ceramic membranes for gas processing in coal gasification. *Energy & Environmental Science* **2010**, 3, 268–278.
- Smith, M. W. Microwave-Enhanced Coal Gasification. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Song, C.; Liu, Q.; Ji, N.; Deng, S.; Zhao, J.; Li, Y.; Song, Y.; Li, H. Alternative pathways for efficient CO₂ capture by hybrid processes—A review. *Renewable and Sustainable Energy Reviews* **2018**, 82, 215–231.
- Spath, P. L.; Dayton, D. C. *Preliminary Screening — Technical and Economic Assessment of Synthesis Gas to Fuels and Chemicals with Emphasis on the Potential for Biomass-Derived Syngas*; U.S. Department of Energy, National Renewable Energy Laboratory, 2003.

- Steen, W.; Richardson, C.; Lu, Y.; Lu, H.; Rostam-Abadi, M. Sorbent Enhanced Water Gas Shift-rethinking Carbon Capture in IGCC. *Energy Procedia* **2014**, 63, 1686–1702.
- Stewart, F. Advanced oxygen separation from air using a novel mixed matrix membrane. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Subramanyam, V.; Gorodetsky, A. 5 - Municipal wastes and other potential fuels for use in IGCC systems. In *Integrated Gasification Combined Cycle (IGCC) Technologies*; Wang, T., Stiegel, G., Eds.; Woodhead Publishing, 2017; pp. 181–219.
- Synthesis Energy Systems, Inc. SES Gasification Technology.
<http://www.synthesisenergy.com/technology#how-it-works> (accessed Nov 6, 2019).
- Tampa Electric. Polk Power Station.
<https://www.tampaelectric.com/company/ourpowersystem/powergeneration/polk/> (accessed Oct 1, 2019).
- Tang, Z. Integrated Multichannel WGS Catalytic Membrane Reactor for Pre-Combustion Carbon Capture. In *2019 NETL Carbon Capture, Utilization, Storage, and Oil and Gas Technologies Integrated Review Meeting*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Treadgold, T. Japan And Australia Launch An Experimental Coal To Hydrogen Export Industry, 2019. <https://www.forbes.com/sites/timtreadgold/2019/07/24/japan-and-australia-launch-an-experimental-coal-to-hydrogen-export-industry/#1b94b4057332> (accessed Oct 3, 2019).
- Tsotsis, T. A High Efficiency, Ultra-Compact Process for Pre-Combustion CO₂ Capture. In *2019 NETL Carbon Capture, Utilization, Storage, and Oil and Gas Technologies Integrated Review Meeting*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Turner, M.; Iyengar, A.; Woods, M. *Cost and Performance Baseline for Fossil Energy Plants Supplement: Sensitivity to CO₂ Capture Rate in Coal-Fired Power Plants*; U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- van der Linden, S.; Wiley, M.; Williams, G.; Swart, R. Syngas fuel hybrid 45 Mw GTCC/ORC power plant using modular 500 TPD coal/biomass modular pyrolytic gasification. In *Proceedings of the ASME Turbo Expo.*, 2010.
- Waldheim, L. *Gasification of waste for energy carriers: A review*; IEA Bioenergy, 2018.
- Wolfersdorf, C.; Meyer, B. 25 - The current status and future prospects for IGCC systems. In *Integrated Gasification Combined Cycle (IGCC) Technologies*; Wang, T., Stiegel, G., Eds.; Woodhead Publishing, 2017; p. 847–889.
- World Bank Group. *Commodity Markets Outlook*, A.W.B. License: Creative Commons Attribution CC BY 3.0 IGO, Washington, DC, 2019.
- Xue, X. Modularization of ceramic hollow fiber membrane technology for air separation. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements*,

- Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Yogish, K. Absorption of CO₂ in some hybrid solvents. *The Canadian Journal of Chemical Engineering* **1990**, 68, 511–512.
- Zaman, M.; Lee, J. H. Carbon capture from stationary power generation sources: A review of the current status of the technologies. *Korean Journal of Chemical Engineering* **2013**, 30, 1497–1526.
- Zhang, X. Visiting the world's biggest sing coal-to-liquid project in Yinchuan, China. EA Clean Coal Center, 2017.
- Zhao, Y.; Jung, B. T.; Ansaloni, L.; Ho, W.S.W. Multiwalled carbon nanotube mixed matrix membranes containing amines for high pressure CO₂/H₂ separation. *Journal of Membrane Science* **2014**, 459, 233–243.
- Zhou, S. Pilot testing of a modular oxygen production system using oxygen binding adsorbents. In *2019 NETL Annual Project Review Meeting for Crosscutting, Rare Earth Elements, Gasification and Transformative Power Generation*, U.S. Department of Energy, National Energy Technology: Pittsburgh, PA, 2019.
- Zhu, L.; Jiang, P.; Fan, J. Comparison of carbon capture IGCC with chemical-looping combustion and with calcium-looping process driven by coal for power generation. *Chemical Engineering Research and Design* **2015**, 104, 110–124.
- Zoelle, A.; Keairns, D.; Turner, M. J.; Woods, M.; Kuehn, N.; Shah, V.; Chou, V.; Pinkerton, L. L.; Fout, T. *Cost and Performance Baseline for Fossil Energy Plants Volume 1b: Bituminous Coal (IGCC) to Electricity Revision 2b – Year Dollar Update*; U.S. Department of Energy, National Energy Technology, 2015.

This page intentionally left blank.

APPENDIX A: IGCC PROCESS DESCRIPTION

The information below provides further information on the IGCC process flow diagrams shown in Figure 8 and Figure 9.

- **Coal Preparation** – Coal milling and drying (if required).
- **Air separation unit (ASU)** – Most gasifiers require almost pure air (95–99% O₂) to gasify the feedstock (although some do operate with air). The ASU, which is typically based on cryogenic distillation, is a significant capital and operating cost element due to the costly compressors and associated power consumption. More than 80% of the internally consumed electricity within an IGCC power plant is consumed by the ASU system. This represents more than 10% of the gross power output in a typically sized IGCC power plant (Roh and Lee, 2014). The O₂ purity required is determined by the syngas application and while some IGCC applications are operated with air, most gasification processes including power generation require oxygen to reduce the inert gas composition in the syngas.
- **Coal gasification** – Conducted in fixed/moving bed (counter-current or co-current), fluidized-bed (stationary or circulating), entrained-flow, or plasma gasifiers. The choice of gasifier can depend on the feedstock and final application. For example, if a higher gasification pressure of up to 80 bar is required for a synthesis application (as opposed to 30–40 bar for power application), a slurry feed is preferred which means an entrained flow gasifier should be used. Most recently built power plants and project designs use entrained flow gasifiers (GE, E-Gas, Shell, others). The use of advanced gasification processes (e.g., plasma gasification) is expected to grow in the future as fuel flexibility requirements increase.
- **Syngas cooling (and heat recovery)** – Several options are available including full water quench (Siemens), partial quench by water (GE) or cold raw gas (Shell), radiant and convective syngas cooling (GE, Siemens), or combinations of each. Another option, E-Gas, utilizes the cooling effect **from endothermic gasification reactions after the injection of secondary carbonaceous fuel**.
- **Syngas scrubbing** – The cooled syngas, at approx. 200–250°C, can be sent to filters for particulate (fly ash and char) removal or it can be sent to a water scrubber. Halides and alkalis, which can poison downstream catalysts, are also removed by wet scrubbing. Mercury also needs to be removed from the syngas, which is typically done via adsorption using an activated carbon type of sorbent.
- **COS hydrolysis (if required)** – If very low sulfur (< 10 ppmv) syngas is required, converting COS to H₂S before sulfur removal may be necessary (most commercial acid gas removal (AGR) processes do not efficiently remove sulfur in the form of COS). Syngas passes through a catalytic hydrolysis reactor where over 99% of the COS is converted to H₂S.
- **Water gas shift reactor (or CO shift reactor)** – In applications where the scrubbed syngas H₂/CO ratio must be increased/adjusted to meet downstream process requirements, the syngas is passed through a multi-stage, fixed-bed reactor containing shift catalysts to convert CO and water into additional H₂ and carbon dioxide (CO₂).

There are four common types of water gas shift reactors, which are chosen based on required syngas composition, including high-temperature shift conversion (HTSC), medium-temperature shift conversion (MTSC), low-temperature shift conversion (LTSC), and sour gas shift conversion (SGS).

- **Acid Gas Removal (AGR)** - Sulfur containing contaminants (H₂S and/or COS) and CO₂ are removed from the syngas to levels compatible with downstream catalyst systems and to comply with power plant environmental regulations. Also, in some processes selectively removing CO₂ is required to provide a pure stream of another syngas constituent (such as H₂) or when the CO₂ is the desired product stream for use in other processes such as enhanced oil recovery, chemical production, and refrigeration applications. Normally a solvent absorption process is used, for example the chemical solvent MDEA or physical solvents Selexol or Rectisol.
- **Combined cycle** – The clean syngas is burned in high efficiency, low emission gas turbines to generate electricity. Hot exhaust from the gas turbine is cooled through a heat recovery steam generator (HRSG) to generate high pressure superheated steam to make additional power in the steam turbine. Gas turbines for syngas operation are commercially available.
- **Sulfur Recovery Unit (SRU)** - One-third of the H₂S is burned with oxygen from the ASU to form SO₂ which is then combined with the remaining H₂S before being catalytically converted into sulfur via the Claus process.

APPENDIX B: NETL EXTERNAL R&D AWARDS - GASIFICATION RESEARCH PROGRAM

The NETL Gasification Systems research program aims to increase availability, efficiency, and reliability of fossil energy power systems while maintaining environmental standards through early stage R&D. A major focus has been to improve modular systems that convert coal to energy and other high value products through gasification. A number of projects have been supported to assist the development of modular/small scale coal gasification with advanced technologies to achieve cost reductions through mass production (instead of economies of scale). The program is focused on the following key technology areas (Lyons, 2019):

- **Process Intensification for Syngas** – program focuses on development of modular gasification processes including gasification of coal into syngas, syngas cleanup, and syngas conversion to value added products including electricity.
- **Air Separation** – program aims to reduce oxygen production costs, accomplish process intensification and integration technology into modular design. The current technologies focus on membranes, advanced sorbents, ceramic membranes (ion transport), novel cryogenics including modularization and other innovative concepts (e.g., magnetic field-based air separation).
- **Coal-Biomass to Liquids** – program aims to advance technology for modular gasification-based systems that enable efficient and cost-effective conversion of coal (and biomass coal co-feed) into liquid fuels like gasoline, diesel, and jet fuel. The program aims to develop products using coal, waste coal, coal fines, and biomass resources from local sites.
- **Negative Greenhouse Gas Emissions** - focuses on designs and strategies for modular gasification-based systems enabling negative lifecycle emissions of greenhouse gases. The main focus in biomass-coal co-firing and advanced CO₂ capture technologies.

As of 2019/2020 NETL Gasification Systems Program funds the following projects (note projects 7, 8 and 9 also relate to pre-combustion capture):

1. Project Title: [Low-cost Oxygen \(LCO\) for Small-scale Modular Gasification Systems](#)

Prime Performer: Thermosolv LLC, Laramie, Wyoming

Project Duration: 10/01/2016 – 03/31/2019

Agreement Number: FE0028002

Key Technology: Air Separation

Summary: This project aims to develop and demonstrate an advanced oxygen production technology for use in coal-fed gasification plants. The specific technical objectives are to scale-up the low-cost oxygen production based on vacuum pressure swing with high-temperature perovskite sorbent, evaluate performance as a function of operational parameters, and perform cyclic adsorption/rinse/desorption experiments to demonstrate oxygen production rate and purity.

2. Project Title: [Advanced Sorbents for Modular Oxygen Production for REMS Gasifiers](#)

Prime Performer: Thermosolv LLC, Laramie, Wyoming

Project Duration: 12/01/2017 – 11/30/2019

Agreement Number: FE0031528

Key Technology: Air Separation Technology

Summary: This project will develop advanced oxygen sorbents using high O₂ storage capacity of perovskites. The composite sorbent will be fabricated at increased scale and the capacity and rate of O₂ production will be measured.

3. **Project Title:** [Radically Engineered Modular Air Separation System using Tailored Oxygen Sorbents](#)

Prime Performer: North Carolina State University

Project Duration: 01/02/2018 – 01/01/2021

Agreement Number: FE0031521

Key Technology: Air Separation Technology

Summary: This project will develop modular coal gasifiers with reduced capital cost and energy consumption. A pilot scale modular air separation unit (ASU) will be demonstrated to test advanced O₂ sorbent capacity and O₂ generation without vacuum desorption.

4. **Project Title:** [Oxygen Binding Materials and Highly Efficient Modular System for Oxygen Production](#)

Prime Performer: Research Triangle Institute (RTI), North Carolina

Project Duration: 10/01/2016 – 06/30/2019

Agreement Number: FE-0027995

Key Technology: Air Separation Technology

Summary: This project aims to develop a process for efficient O₂ separation from air using adsorbents or membranes with oxygen carriers to produce high purity oxygen. The process should be scaled up in modular form while still being competitive with current state-of-the-art processes. The process will target a sorbent bed-factor of less than 600 lb-sorbent/TPD O₂ (tons/day O₂) and an O₂/N₂ separation factor greater than 20 for membranes.

5. **Project Title:** [Pilot Testing of a Modular Oxygen Production System Using O₂ Binding Adsorbants](#)

Prime Performer: Research Triangle Institute (RTI), North Carolina

Project Duration: 12/01/2017 – 11/30/2020

Agreement Number: FE0031527

Key Technology: Air Separation Technology

Summary: This project will design, fabricate and test a modular (10–20kg/day) O₂ production system to obtain O₂ purity of >95% at equal or less cost than the current systems. The O₂ binding adsorbant and pressure swing adsorption processes will be optimized and scaled-up using simulations. Production costs will be determined.

6. **Project Title:** [Modularization of Ceramic Hollow Fiber Membrane Technology for Air Separation](#)

Prime Performer: University of South Carolina, Columbia, South Carolina

Project Duration: 01/01/2018 – 12/31/2020

Agreement Number: FE0031473

Key Technology: Air Separation Technology

Summary: This project will develop a membrane module for air separation and O₂ production using ceramic hollow fiber membranes. The high efficiency membranes will be characterized, assembled in stacks, modelled to optimize design and tested for permeation performance.

7. **Project Title:** [Integrated Water-Gas-Shift Pre-Combustion Carbon Capture Process](#)

Prime Performer: TDA Research, Wheat Ridge, Colorado

Project Duration: 10/01/2014 – 09/30/2020

Agreement Number: FE0023684

Key Technology: Negative Greenhouse Gas Emissions

Summary: This project aims to demonstrate the techno-economic viability of an integrated WGS catalyst/CO₂ removal system to IGCC power plants and CTL power plants. A high-temperature PSA adsorbent (mesoporous carbon with surface functional groups) is used to remove CO₂ via strong physical adsorption above the dew point of the syngas and a commercial low-temperature catalyst is used for the water gas shift. A heat management system will also be developed.

8. **Project Title:** [Advance Syngas Cleanup for Radically Engineered Modular Systems \(REMS\)](#)

Prime Performer: Research Triangle Institute (RTI), North Carolina

Project Duration: 12/01/2017 – 06/30/2020

Agreement Number: FE0031522

Key Technology: Reactor Engineering Design

Summary: This project aims to develop modular sorbent-based warm syngas cleanup to be competitive with state-of-the-art-plants. The project will expand the experimental database for sorbent desulfurization of low-sulfur syngas and determine lowest cost design for a fixed bed sorbent formulation.

9. **Project Title:** [Warm Gas Multi-Contaminant Removal System](#)

Prime Performer: TDA Research, Wheat Ridge, Colorado

Project Duration: 06/28/2012 – 07/31/2020

Agreement Number: SC0008243

Key Technology: Negative Greenhouse Gas Emissions

Summary: This project aims to demonstrate techno-economic viability of a syngas purification system to eliminate potential catalyst poisons and environmental pollutants from coal-derived syngas. A high-temperature sorbent is operated above the dew point of the syngas in a regenerable manner for NH₃ and Hg. All other contaminants (trace metals, HCN, etc.) are removed irreversibly.

10. Project Title: [Poison Resistant Water-Gas-Shift Catalysts for Biomass and Coal Gasification](#)

Prime Performer: TDA Research, Wheat Ridge, Colorado

Project Duration: 06/19/2010 – 08/11/2020

Agreement Number: SC0004378

Summary: This project aims to develop a sour shift catalyst that has higher CO conversion than current commercial catalysts due to its ability to operate at lower temperatures where the WGS equilibrium is more favourable. The catalyst also needs to be resistant to poisons in biomass/coal-derived syngas.

11. Project Title: [Development of Two-Phase Dense Fluid Expander for Advanced Cryogenic Air Separation and Low-Grade Heat Recovery](#)

Prime Performer: Air Products and Chemicals, Inc, Allentown, PA

Project Duration: 10/01/2015 – 03/31/2020

Agreement Number: FE0026186

Key Technology: Air Separation Technology

Summary: This project aims to understand the limitations associated with two-phase dense fluid expansion within an ASU and use this knowledge to construct two prototype devices (centrifugal and axial impulse) for cryogenic air separation.

12. Project Title: [Gasification Combined Heat and Power from Coal Fines](#)

Prime Performer: University of Kentucky, Lexington, Kentucky

Project Duration: 12/06/2017 – 09/30/2019

Agreement Number: FE0031520

Key Technology: Reactor Engineering Design

Summary: This project will complete a front-end engineering design (FEED) study for a 5 MW_{el} polygeneration plant using waste coal fines and biomass with the objective of identifying the main equipment items and operating conditions. A preliminary polygeneration process design will be completed followed by an assessment of the economic viability.

13. Project Title: [Making Coal Relevant for Small Scale Applications: Modular Gasification for Syngas/Engine CHP Applications in Challenging Environments](#)

Prime Performer: University of Alaska Fairbanks, Alaska

Project Duration: 04/01/2018 – 05/31/2021

Agreement Number: FE0031601

Key Technology: Reactor Engineering Design

Summary: This project will complete a front-end engineering and design (FEED) study for modular/small scale gasification units for non-baseload applications. The work will include design of the gasifier, cleanup train and plant components. Demonstration of a small-scale coal gasification to fuel reciprocating engine generator will be completed.

14. Project Title: [Small Scale Engineered High Flexibility Gasifier](#)

Prime Performer: Southern Research Institute, Birmingham, Alabama

Project Duration: 12/01/2017 – 11/30/2020

Agreement Number: FE0031531

Key Technology: Reactor Engineering Design

Summary: This project aims to develop a modular pressurized oxygen-blown gasifier that is simple to operate and minimizes tar production. It is expected to reduce coal conversion costs (via modular system) and provide flexibility for site specific needs (e.g., syngas composition dependent on flexible feed options). An experimental program will be implemented to optimize the performance and validate the model for a 1–5 MW power generation simulation.

15. Project Title: [Staged OMB \(Opposed Multi-Burner\) Gasifier/Burner](#)

Prime Performer: University of Kentucky, Lexington, Kentucky

Project Duration: 12/01/2017 – 11/30/2020

Agreement Number: FE0031506

Key Technology: Reactor Engineering Design

Summary: This project will test a staged opposed multi-burner (OMB) gasifier at modular scale for high-temperature gasification. Expected benefits include loading flexibility, improved gasification efficiency, prolong refractory/burner life and a standardized burner design.

16. Project Title: [Application of Chemical Looping with Spouting Fluidized Bed for Hydrogen-Rich Syngas Production from Catalytic Coal Gasification](#)

Prime Performer: University of Kentucky, Lexington, Kentucky

Project Duration: 10/01/2014 – 05/31/2019

Agreement Number: FE0024000

Key Technology: Air Separation Technology

Summary: This project will develop a low capital cost catalytic gasification process via the synergistic utilization of chemical looping to provide oxygen to the gasification process, thereby foregoing the necessity of having an air separation unit (ASU). The chemical looping particles will be comprised mainly of iron oxides that should catalyze the gasification process as well as enhance the water-gas shift (WGS) process required to

achieve a high-hydrogen syngas. A spouted bed reactor configuration will also be investigated.

17. Project Title: [Low Cost Air Separation Process for Gasification Applications](#)

Prime Performer: TDA Research, Wheat Ridge, Colorado

Project Duration: 10/01/2015 – 05/31/2019

Agreement Number: FE0026142

Key Technology: Air Separation Technology

Summary: This project will develop a new chemical sorbent for an air separation system that can operate at high temperature, eliminating the thermodynamic inefficiencies inherent in conventional cryogenic air separation units. Unlike the sorbents used in commercial PSA systems, this sorbent selectively removes oxygen (not nitrogen), which enables effective utilization of the large amounts of energy in the high-pressure oxygen-depleted stream.

APPENDIX C: NETL EXTERNAL R&D AWARDS - PRE-COMBUSTION CO₂ CAPTURE RESEARCH

A number of projects have been supported by NETL to assist the development of pre-combustion carbon capture technologies. As of March 2020, the NETL pre-combustion capture key technology area funds the following external projects:

1. Project Title: [Pilot Testing of a Highly Effective Pre-Combustion Sorbent-Based Carbon Capture System](#) (Alptekin, 2019)

Prime Performer: TDA Research, Inc., Wheat Ridge, Colorado

Project Duration: 10/01/2013 – 03/31/2021

Agreement Number: FE0013105

Key Technology: Sorbents

Summary: The process developed in this project will use TDA's novel high-temperature PSA process which is based on an advanced physical adsorbent with a mesoporous carbon grafted with surface functional groups that selectively removes CO₂ from syngas at temperatures above the dew point of the gas. This project will demonstrate techno-economic viability of the new sorbent-based technology by evaluating technical feasibility (via 0.1 MW_{el} slipstream tests) and carry out process design and engineering analysis. The project is led by TDA Research, Inc. in cooperation with CDM Smith, Inc, Gas Technology Institute, the University of Alberta, the University of California Irvine, and Sinopec. Research will include pilot scale production of the sorbent, CFD analysis to optimize cycle sequence and reactor design, long term sorbent life evaluation testing and design and fabrication of a 0.1 MW_{el} pilot scale testing unit. Pilot-scale testing will be conducted at NCCC followed by testing at Sinopec's IGCC power plant in China. These facilities use different types of gasifiers (air-blown transport gasifier vs. oxygen-blown gasifier) and feedstocks (low-rank coals vs. petcoke), which will allow researchers to assess process efficacy in very different gas streams. Finally, a techno-economic evaluation will be completed to calculate the impact of the CO₂ capture system on power plant efficiency and the cost of electricity (COE).

2. Project Title: [A High Efficiency, Ultra-Compact Process for Pre-Combustion CO₂ Capture](#) (Tsotsis, 2019)

Prime Performer: University of Southern California

Project Duration: 10/01/2015 – 03/31/2019

Agreement Number: FE0026423

Key Technology: Novel concepts

Summary: This project will assess the performance of a high-efficiency, low-temperature reactor process for the water gas shift (WGS) reaction in an IGCC process and enable simultaneous removal of H₂ and CO₂. The project is led by the University of Southern California in collaboration with Media and Process Technology Inc. and the University of California, Los Angeles. A unique hybrid syngas separation process has been developed that uses a membrane- and adsorption-enhanced WGS reactor system previously developed for H₂ production via methane steam reforming that allows for in-situ preferential H₂ permeation

and simultaneous CO₂ adsorption. A membrane reactor (MR) and an adsorptive reactor (AR) in tandem produce an ultra-pure H₂ product continuously until the adsorbent (in the AR unit) is saturated, which is then regenerated via a temperature swing adsorption (TSA) operation. The project will test a previously developed carbon molecular-sieve-based membrane and a range of promising adsorbents including a hydrotalcite-based adsorbent while a mathematical model will analyze the resulting data, further optimize the system, develop preliminary technical designs, and conduct a techno-economic analysis.

3. **Project Title:** [Zeolite Membrane Reactor for Pre-Combustion Carbon Dioxide Capture](#) (Meng, 2019)

Prime Performer: Arizona State University

Project Duration: 10/01/2015 – 03/31/2020

Agreement Number: FE0026435

Key Technology: Membranes

Summary: This project will develop a bench-scale zeolite membrane reactor for water-gas shift (WGS) reaction with CO₂ capture. A stable, H₂ semi-permeable MFI-type zeolite membrane reactor will be scaled up and tested at bench scale followed by process design and techno economic analysis of the process for IGCC applications. The membrane reactor will also be tested with raw syngas from a coal gasifier (2 kWth IGCC power plant). The project will be led by Arizona State University, in collaboration with Media and Processes Technology Inc., the University of Cincinnati, Nexant Inc., and the University of Kentucky.

4. **Project Title:** [Sorption Enhanced Mixed Matrix Membranes for Hydrogen Purification and Carbon Dioxide Capture](#) (Lin, 2019)

Prime Performer: State University of New York (SUNY)-Buffalo

Project Duration: 10/01/2015 – 12/31/2019

Agreement Number: FE0026463

Key Technology: Membranes

Summary: This project aims to develop high-temperature H₂-selective membranes with the high selectivity properties of metallic membranes, but with the high permeability of and ease of manufacturing of polymeric membranes. The project team will fabricate and optimize thin film composite membranes, perform parametric testing using simulated syngas in the laboratory, and conduct field testing of the membrane stamps at the University of Kentucky Center for Applied Energy Research with actual syngas. A process design and a techno-economic analysis will be completed based on the newly developed membranes. This analysis will clarify the potential of membrane technology for CO₂ capture from coal-derived syngas, providing the criteria of membrane performance that must be met to achieve the DOE program goals.

5. **Project Title:** [Integrated Multichannel Water Gas Shift Catalytic Membrane Reactor for Pre-Combustion Carbon Capture](#) (Tang, 2019)

Prime Performer: Bettergy Corporation, Peekskill, NY

Project Duration: 07/02/2018 – 08/18/2021

Agreement Number: SC0018853

Key Technology: Membranes

Summary: This project aims to develop an integrated catalytic membrane reactor (CMR) system that combines a high-temperature water-gas-shift (WGS) reaction with a H₂ separation membrane to produce H₂ while simultaneously delivering CO₂ at high pressure, in a one stage process (WGS-CMR). Bettergy's patented nanopore engineering membrane (NEM) platform technology will be used to develop this modularized membrane supported on catalytic substrates. Phase I tests a lab scale unit for high WGS conversion and high purity H₂ production and CO₂ in retentate stream. Phase II will optimize the process and develop a multi-channel prototype system for testing and finally a plan to commercialize the technology will be developed.

6. **Project Title:** [High-Temperature Ceramic-Carbonate Dual-Phase Membrane Reactor for Pre-Combustion Carbon Dioxide Capture](#) (Ovalle-Encinia, 2019)

Prime Performer: Arizona State University, Tempe, AZ

Project Duration: 10/01/2018 – 09/30/2021

Agreement Number: FE0031634

Key Technology: Membranes

Summary: This project will develop a high-temperature, high-pressure ceramic-carbonate dual-phase (CCDP) membrane reactor (MR) for the water-gas-shift (WGS) reaction to produce a high concentration H₂ stream with CO₂ capture. Previous work has successfully fabricated the membranes and tested CO₂ permeation of CCDP membranes. This project will design and fabricate membranes with improved CO₂ permeance and mechanical strength that can be tested in a lab scale reactor with simulated coal-derived syngas. A model will be developed and optimized for high purity CO₂ and H₂ streams. Process design and a techno economic analysis of the CCDP membrane reactor will be completed for a full scale IGCC plant.

7. **Project Title:** [Transformational Membranes for Pre-Combustion Carbon Capture](#) (Ho and Han, 2019)

Prime Performer: Ohio State University, Columbus, OH

Project Duration: 10/01/2018 – 09/30/2021

Agreement Number: FE0031635

Key Technology: Membranes

Summary: This project will develop a novel amine-containing facilitated transport membrane for CO₂ capture from coal derived syngas. The membrane process aims to have high CO₂/H₂ selectivity and CO₂ permeance by placing a CO₂ selective layer on a nano-porous polymer support to provide chemical stability to H₂S. CO₂ transfer through the membrane is enhanced via reaction with amino groups, while H₂ is rejected as it does not react with the membrane. H₂S can permeate through the membrane significantly faster than CO₂ and can be removed in the front section of the membrane module. The modules will be

fabricated as spiral-wound membranes and will be tested with simulated syngas at 20–32 bar and 100–120°C. A high level techno economic analysis will be completed.

8. **Project Title:** [Bench-Scale Development of a Transformative Membrane Process For Pre-Combustion CO₂ Capture](#) (Knierp, 2019)

Prime Performer: Membrane Technology and Research, Inc, Newark, CA

Project Duration: 10/01/2018 – 09/30/2021

Agreement Number: FE0031632

Key Technology: Membranes

Summary: This project will further develop a novel H₂-selective, multilayer composite polymer membrane called Proteus™ by scaling-up the second-generation Proteus membrane (known as Gen-2 Proteus membrane). Membrane Technology and Research, Inc. (MTR) will work with its partners Susteon and the Energy and Environmental Research Center (EERC) in the development of this novel membrane process. The membranes operate at higher temperatures (than Selexol), which will reduce energy requirements due to less syngas cooling and lower the capital cost for converting captured CO₂ to liquid. Specifically, this project will enable fabrication of high-temperature prototype modules using the Gen-2 Proteus membranes followed by validation of module performance in laboratory tests. The modules will be tested with coal derived syngas at EERC which will enable parametric and lifetime testing of the modules. The process will be optimized, and a techno-economic analysis will be updated based upon the results of testing at EERC.

9. **Project Title:** [Development and Testing of a High Temperature PBI Hollow-Fiber Membrane Technology for Pre-Combustion CO₂ Capture](#) (Jayaweera and Perea, 2019)

Prime Performer: SRI International, Menlo Park, CA

Project Duration: 10/01/2018 – 09/30/2021

Agreement Number: FE0031633

Key Technology: Membranes

Summary: SRI International will be testing novel polybenzimidazole (PBI) polymer hollow-fiber membrane modules for high flux and selectivity of hydrogen over other syngas components. The membranes can operate at temperature at or above WGS temperatures. SRI's existing bench-scale test skid will be upgraded to accommodate large fiber modules (four and six inches) for field testing.

10. **Project Title:** [Development of Carbon Molecular Sieves Hollow Fiber Membranes Based on Polybenzimidazole Doped with Polyprotic Acids with Superior H₂/CO₂ Separation Properties](#) (Lin, 2019)

Prime Performer: State University of New York (SUNY), Amherst, NY

Project Duration: 10/01/2018 – 09/30/2021

Agreement Number: FE0031636

Key Technology: Membranes

Summary: This project aims to develop a highly efficient membrane-based process using carbon molecular sieve (CMS) hollow fiber membranes to capture CO₂ from coal-derived syngas. The CMS membranes will be made from polybenzimidazole (PBI) doped with polyprotic acids and are expected to be chemically stable, can operate at temperatures of 200–300°C, are easily scalable, and have high H₂ permeance (1,000 GPU) and H₂/CO₂ selectivity of 40. Membranes assembled into pencil modules will undergo parametric testing at lab scale using simulated syngas containing H₂S, CO, and H₂O vapor. H₂-selective membranes will also be designed for use as a membrane reactor for the low-temperature water-gas shift (WGS) reaction and will be tested for efficiency. Using test data, a techno-economic analysis based on the newly developed membranes will be completed. The project will be led by The State University of New York, Buffalo, along with its partners Los Alamos National Laboratory (LANL) and Trimeric Corporation.

11. Project Title: [Bench Scale Testing of a High Efficiency, Ultra-Compact Process for Pre-Combustion CO₂ Capture](#) (Tsotsis, 2019)

Prime Performer: University of Southern California, Los Angeles, CA

Project Duration: 06/01/2019 – 05/31/2022

Agreement Number: FE0031737

Key Technology: Novel Concepts

Summary: USC in collaboration with UCLA and M&PT are developing novel integrated processes for combining WGS with either H₂-selective membranes or CO₂ absorbents. The project aims to end at TRL 5, via scaling-up of the prototype system and its testing on actual syngas at the University of Kentucky (UK). As shown previously in this report, these integrated processes have the potential to achieve high efficiency at IGCC power plants, and can be designed for different polygeneration cases, depending on whether using H₂-selective membranes or CO₂ absorbents.

This page intentionally left blank.



Brian Anderson, Ph.D.

Director
National Energy Technology Laboratory
U.S. Department of Energy

Dan Hancu

Technology Manager, Carbon Capture
Technology
Science & Technology Strategic Plans
& Programs
National Energy Technology Laboratory
U.S. Department of Energy

Lynn Brickett

Office of Clean Coal & Carbon
Management (FE-20)
U.S. Department of Energy

Bryan Morreale

Executive Director
Research & Innovation Center
National Energy Technology Laboratory
U.S. Department of Energy