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Thesis for the degree of Philosophiae Doctor

Trondheim, February 2015

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Preface

This thesis is submitted as a part of the requirements for the degree of philosophiae doctor (PhD) at the Norwegian University of Science and Technology (NTNU). The work was carried out at the department of Energy and Process Engineering with Prof. Truls Gundersen as the main supervisor. Funding for the research was provided by the BIGCCS International CCS Research Centre.

Abstract

This thesis presents studies on coal based power plants with CO_2 capture. As coal is the single largest fuel in use today to generate electricity, technologies to improve the efficiency and reduce emissions are critical in the future. The oxy-combustion method is one of the three main routes to capture at least 90% of the CO_2 generated by a fossil fuel based power plant. In addition to the standard power plant components such as the boiler and the steam cycle, systems to generate oxygen (ASU) and purify/compress the flue gas (CPU) are required. These additional systems cause an efficiency penalty of around 10% points and also incur additional capital cost.

The objective of this project is to investigate the efficiency improvement potential of the oxy-combustion coal based power plant. Process Integration methodologies such as Pinch and Exergy analyses were used to conduct the investigations. Process Integration methodologies are proven and can be applied to power plants with capture to bring down the efficiency penalty.

Baseline simulations of the overall power plant with capture were established as a part of the study. Recycling the untreated hot flue gas for boiler temperature control provides the best performance. More heat can be recovered from the flue gas before being processed by the CPU by condensing the moisture present in it. The recovered heat can either be used for boiler feedwater preheating or oxygen preheating. Oxygen preheating proved to be a better choice from the efficiency standpoint. Heat can also be recovered from the CPU compressors for feedwater preheating.

All the above mentioned heat integration options boost the system efficiency and reduce the efficiency penalty to less than 7% points. Operating the boiler at a higher pressure enhances flue gas heat recovery. A boiler operating pressure of 16 bars was found to be near-optimal. Additionally, adiabatic compression of the oxygen stream eliminates the need for preheating while keeping the system simple.

Finally, a combined pinch and exergy analysis helps modify the feedwater preheating system of the steam cycle. Pinch analysis helps target the energy (steam mass flows) requirements of the feedwater preheating system while exergy analysis guides the system design. The modified steam cycle has a better performance than the traditional steam cycle while maintaining reasonable network complexity. All the above mentioned process improvements help to attain a capture efficiency penalty of around 6% points.

Acknowledgements

I would like to thank my supervisor Prof. Truls Gundersen for allowing me all the freedom that I needed to carry out the work while always keeping the doors open for a discussion. In addition to that, he was immensely helpful in all the matters related to administrative formalities, my visa processing issues etc... that made my life a whole lot easier than it would have otherwise been!

Big thanks for all the administrative staff at the department who were always available for assistance and with a smile on their face every single time. A special thanks to the EPTraining programme that helped me get active and generally have a good time during my stay at the department as a PhD candidate. Taking part in activities such as St. Olavsloppet will be some of the most memorable events in my life.

Thanks to all the fellow PhD candidates from all over the world for all the "discussion" packed breaks and the customary grøt lunches on Fridays! Those are the times that I always looked forward to and perhaps will remember well into the future.

Special thanks to Chao Fu, Lars Olof Nord and Rahul Anantharaman for all the discussions and guidance whenever I was stuck with my project. These people made me feel that I always had some experts to consult and that gave me a sense of security and confidence in doing the work.

I would like to thank my family members for understanding me and offering help and support in every possible way they could during the course of the PhD programme. Big thanks to Astrid Klungseth and Thomas Eriksen who made me feel welcome in this country and shared both good and bad times with me. Of course a big thanks to all my friends from Tamil Nadu for all the friendly and "not-so-friendly" discussions on everything under the sun that helped me evolve into a well-rounded person! All these people are responsible for my sanity and composure in this country of Norway that is so much distant from where I come from.

Finally, thanks to the picturesque country of Norway that brought it all together and made it all possible. The experience that I have gained and the things that I have learned by living in Norway go well beyond the confines of the classroom and I am certainly grateful for everything that I have gained from this society.

Contents

List of Figures

List of Tables

Nomenclature

$\dot{E}_{ch}$	Chemical exergy of a stream (kW)
$\dot{E}_{mix}$	Mixing exergy of a stream (kW)
$\dot{E}_{ph}$	Physical exergy of a stream (kW)
$\dot{E}_{tot}$	Total exergy of a stream (kW)
$\dot{F}$	Molar flow (mole/s)
$\dot{Q}$	Heat flow (kW)
T_{in}	Inlet temperature
T_{lm}	Log-Mean Temperature difference
T_{out}	Outlet temperature
e_{ch}^{0}	Standard chemical exergy (kJ/mole)
h	Molar enthalpy (kJ/mole)
P	Pressure (bar)
T	Temperature (K or °C)
s	Molar entropy (kJ/mole K)

Sub and Superscripts

0	Reference state
i	Component index

Abbreviations

ASU	Air Separation Unit
ASW	Aspen Simulation Workbook
BFP	Boiler Feed Pump
BFW	Boiler Feed Water
CCS	CO_2 Capture and Storage
CMIP	Coupled Model Intercomparison Project
CPU	Compression and Purification Unit
CW	Cooling Water
D/A	Deaerator
DCA	Drain Cooler Approach
DOE	Department of Energy
DS	De-Superheater
EOR	Enhanced Oil Recovery
EOS	Equation of State
ESM	Earth System Model
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulphurization

FW	Feed Water
FWH	Feed Water Heater
GHG	Green House Gas
GMSL	Global Mean Sea Level
GMST	Global Mean Surface Temperature
GWP	Global Warming Potential
HEX	Heat Exchanger
HHV	Higher Heating Value
HP	High Pressure
HPT	High Pressure Turbine
IEA	International Energy Agency
IP	Intermediate Pressure
IGCC	Integrated Gasification and Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
IPT	Intermediate Pressure Turbine
LCOE	Levelized Cost of Electricity
LHV	Lower Heating Value
LMTD	Log Mean Temperature Difference
LNG	Liquefied Natural Gas
LP	Low Pressure
LPT	Low Pressure Turbine
NCS	Norwegian Continental Shelf
NETL	National Energy Technology Laboratory
NPS	New Policies Scenario
OECD	Organization for Economic Cooperation and Development
PA	Pinch Analysis
PC	Pulverized Coal
PDM	Pinch Design Method
PI	Process Integration
ppm	parts per million
PV	Photo-Voltaic
RCP	Representative Concentration Pathways
RF	Radiative Forcing
RFG	Recycled Flue Gas
SCR	Selective Catalytic Reduction
TTD	Terminal Temperature Difference
USC	Ultra Super Critical
WFGD	Wet Flue Gas Desulphurization
WMGHG	Well-Mixed Green House Gas

Introduction

Carbon dioxide Capture and Storage (CCS) is a technologically mature option that is expected to play a significant role among the portfolio of options suggested for climate change mitigation. Though technologically ready for deployment, large scale commercial adoption of the technology is delayed due to the costs involved. To a large extent, the costs involved are due to the energy penalty associated with the capture part of the CCS chain. The good news is that there is potential for improvement and various methodologies are readily available to exploit the same. One such methodology is called Process Integration (PI). Process Integration is a proven methodology applied to various industries to reduce energy consumption and emissions. Power plants being large units generally in operation for several decades, even incremental improvements yield meaningful savings over their lifetime.

In 2009, The Research Council of Norway established several centres for Environment-friendly Energy Research (FME) with an aim to foster innovation in selected areas related to energy and the environment. These centres focus on a wide range of topics such as renewable energy, energy efficiency and climate policy and are a direct result of the policy agreement achieved in Stortinget (The Norwegian Parliament) in January 2008. BIGCCS International CCS Research Centre is one of those centres established with a focus on Carbon dioxide Capture and Storage. The BIGCCS centre is led by SINTEF Energy Research AS and has both academic and industrial institutions as its partners. The main objective of the BIGCCS centre is to do research and develop solutions that lead to:

- At least 90 percent CO_2 capture
- A 50 percent cost reduction from current levels
- CCS with efficiency loss of less than 6 percentage points
- A basis for assessing and qualifying storage sites for CO_2 and quantifying storage capacity in Norway and Europe

The centre also has a graduate level programme with several doctoral students and post-doctoral fellows. This PhD project is one such program which focuses on the capture side of the CCS chain.

1.1 Motivation

Mitigation of climate change and limiting the warming of the planet to less than two degrees Celsius by the end of this century requires concerted effort from all the major emitters of greenhouse gases. This includes the OECD economies that are responsible for most of the historical emissions as well as emerging economies that are expected to be responsible for most of the future emissions. The technologies that are available today for climate mitigation such as renewables and CCS are expensive. While the OECD economies are facing demographic challenges, the emerging economies need faster economic growth and access to cheaper energy to lift millions of people out of poverty. This makes the burden sharing on emissions reduction ever more difficult in the ongoing negotiations on climate change.

Norway is in a unique position with abundant clean energy (hydroelectric resources) for domestic consumption while also relying on revenue from the export of fossil fuels. Norway is also a pioneer in climate change legislation with ambitious targets to limit the emissions of greenhouse gases and even become carbon neutral by the year 2050. Targeted research on various clean energy technologies including CCS is a part of the above mentioned strategy. Participation in research and development of such technologies also offer a competitive edge and future business potential to exploit the CO_2 geological storage capacity available in the Norwegian Continental Shelf. Although coal is not consumed domestically in Norway, coal still is the single largest fuel for generation of electricity worldwide. Investing in the development of technologies that could address the emissions from the coal usage is therefore essential for climate change mitigation. By the time the world leaders agree on the level and the timing of emissions reduction, availability of mitigation technologies would be critical to actually achieve the targets. Due to the forward looking planning and investment in research, Norway is expected to be in a better position to take advantage of any changes in the future.

1.2 Objectives

The primary objective of this project is to investigate efficiency improvement potential of the oxy-combustion coal based power plant.

As a part of the Process Integration (PI) group at the department of Energy and Process Engineering, the main focus will be to apply established PI methodologies such as Pinch Analysis and Exergy Analysis to oxy-combustion power plants. This would identify the improvement potential and would suggest modifications to exploit the same. The output of this work would then serve as a basis for further investigations such as economic studies, experimental investigations and so on.

The tasks involved can be listed as follows:

- Modelling and simulation of an oxy-combustion coal based power plant both with and without CO_2 capture.
- Study of the influence of various operating parameters on the performance of the power plant. The following questions are to be answered: In the case of pressurized combustion, what is the optimal boiler operating pressure to achieve the best efficiency? Would the energy optimal oxygen purity be different if there was no air leakage into the boiler? What is the optimal level of compression in the CPU before the cryogenic process can begin?
- To 'design' a steam cycle that can exploit the heat integration potential of the oxy-combustion coal based power plant. Established process integration methodologies such as Pinch and Exergy analyses are applied to modify the feedwater preheating network of the steam cycle.

The overall objective of the project revolves around system level analyses to identify process modifications that could yield efficiency improvements. Generally, process modifications to improve efficiency invariably increase cost and complexity of the system. In some cases, the process modifications could also result in reduced operability and reliability of the system. In this project, investigations related to the economics and other issues related to the suggested process modifications are not considered.

1.3 Contributions

The main contributions of the thesis are:

- ❖ The energy saving potential of using pressurized combustion in coal based power plants has been documented and quantified
- ❖ Oxy-combustion efficiency potentials considering various heat integration options such as flue gas hot recycle, flue gas latent heat recovery, oxygen preheating and CPU heat integration have been quantified

- Identification of the near optimal operating parameters (boiler operating pressure, oxygen purity and CPU parameters) for best overall efficiency for an oxy-combustion coal based power plant with heat integration
- The advantage of using adiabatic compression to supply oxygen at high temperature and pressure directly to the boiler as opposed to using multi-stage compression has been demonstrated. This achieves high efficiency by reducing boiler thermodynamic losses while eliminating the need for oxygen preheating and associated additional equipment.
- Pinch based energy targeting of steam cycle feed water preheating to achieve better steam cycle performance has been carried out.
- Using Pinch and Exergy analysis in combination to improve the feedwater preheating network of a steam cycle has been carried out. This results in a network that is a compromise between high efficiency and acceptable complexity.

1.4 Thesis organization

The thesis comprises of seven chapters. Chapter 2 presents a distilled synopsis of a background on climate change and the importance of the CCS technologies for mitigation. The chapter presents notable graphs from reports published by IPCC with explanations. Chapter 2 also calls attention towards the challenges facing large scale deployment of CCS. Chapter 3 covers the technical background related to the oxy-combustion technology for CO_2 capture and various process integration methodologies. Publications from the literature are collected in the form of tables under various topics supported with explanations. Chapter 4 through 6 cover the main work of the PhD project. Chapter 4 explains the baseline process modelling with results from four different cases. The cases cover a range of configurations both with and without capture and also with various degrees of heat integration. This chapter lays the foundation in terms of assumptions used in the simulations throughout the project and in terms of overall process layout.

Chapter 5 deals with the study of the effect of various operating parameters on the performance of the power plant. Parameters studied include the operating pressure, oxygen purity and CPU operating parameters. This chapter provides an idea of the overall efficiency improvement potential with heat integration. Finally, Chapter 6 aims at developing a steam cycle for Oxy-Combustion power plants with heat integration. In this chapter, a combined pinch and exergy analysis method is applied to the feedwater heating section of the steam cycle to arrive at an improved version of the same. Chapter 7 consists of the conclusions and further work recommendations.

1.5 Publications summary

Paper I

Soundararajan, R., Gundersen, T., 2013. Coal based power plant using oxy-combustion for CO_2 capture: Pressurized coal combustion to reduce capture penalty. Applied Thermal Engineering 61(1), 115-122.

The goal of this paper is to design and study a new variation of an oxy-combustion coal based power plant with CO_2 capture. This variation employs a pressurized coal combustor that burns coal in an oxygen rich environment. The concept is compared with an atmospheric pressure oxy-combustion power plant (baseline case). Such analyses would provide us with information regarding potential heat integration and improvement opportunities of oxy-combustion coal based power plants. Also, this study highlights the efficiency improvement potential of the oxy-combustion technology for coal based power plants. The power cycle presented in this paper is a supercritical cycle that has a gross electric power output of 774 MW for the baseline case and 792 MW for the pressurized case. The auxiliary power consumption is reduced from 224 MW in the baseline case to 214 MW in the pressurized case due to the absence of air leakage into the boiler. The recovery of latent heat from the flue gases is increased due to the elevated dew point in the pressurized case. This results in a net LHV and HHV efficiency improvement of 1.7 percentage points each over the baseline case. In both cases, over 90% of the produced CO_2 is captured and compressed to 110 bar after removal of volatiles and other pollutants such as SO_X and NO_X.

Paper II

Soundararajan, R., Gundersen, T., Ditaranto, M., 2014. Oxy-combustion coal based power plants: Study of operating pressure, oxygen purity and downstream purification parameters. Chemical Engineering Transactions 39, 229-234.

The goal of this paper is to investigate the effects of various operating parameters. This is done via a sensitivity study to identify near optimal values of various parameters to achieve best overall performance. Power plants that employ a boiler operating at a pressure higher than ambient pressure avoid air leakage into the boiler and also recover more of the latent heat available in the flue gases. Such power plants require compression of the oxygen stream before the combustor, an entirely new boiler house design and modifications to the downstream flue gas processing systems. Selection of an operating pressure that is energy optimal is the key to design of such systems. Besides the operating pressure, the oxygen purity and the downstream separation parameters have a considerable impact on the overall performance of such power plants. The study indicates that a boiler operating pressure of around 16 bars is required to exploit the heat recovery potential to the maximum. Along with the oxygen purity of 97% and a CPU operating pressure of 24 bars, the net LHV efficiency is improved from 37.9% to 38.9%.

Paper III

Soundararajan, Rengarajan; Anantharaman, Rahul; Gundersen, Truls. Design of Steam Cycles for Oxy-combustion Coal based Power Plants with Emphasis on Heat Integration. Energy Procedia 2014-51, 119-126

In this study, pinch analysis is used as a tool to integrate heat from the CO_2 capture process into the steam cycle of the power plant. This way of heat integration provides an opportunity to make better use of the available low grade heat at the power plant premises by approaching the minimum allowable temperature difference between the hot and the cold streams. This ultimately results in a better overall efficiency by generating additional power for the same fuel input and also by reducing the consumption of cooling required in the capture process. The resulting steam cycle will be a custom design for oxy-combustion coal based power plants and will be tightly integrated with the capture process. As this method brings a lot of changes to the steam cycle configuration, this is best suited for new power plants rather than retrofit of existing plants. Results show that the Pinch method of heat integration achieves better overall thermal efficiency compared to the conventional method of steam cycle design and heat integration.

Paper IV

Soundararajan, R., Gundersen, T., Design of steam cycles for oxy-combustion coal based power plants: Heat integration using pinch analysis. Elsevier Energy. (Submitted, under review).

In this paper, a new steam cycle design is proposed for oxy-combustion coal based power plants. This steam cycle is designed with heat integration in mind. Latent heat available in the flue gas coming out of the boiler and the compression heat from the CPU intercoolers can be integrated into the steam cycle feedwater preheating for additional power generation. Pinch Analysis methodology can be applied to the feedwater preheating network to improve the efficiency. The improvement in efficiency often comes at the expense of additional heat exchangers and increased network complexity. An attempt has been made to construct a heat exchanger network for the pinch based design. Finally, Exergy analysis is applied to identify zones of maximum efficiency improvement potential and to reduce the total number of additional heat exchangers required. The resulting feedwater preheating network has better efficiency than the traditional design but has fewer heat exchangers than that of the pinch design. The baseline power plant designed by traditional methods has a net LHV efficiency of 35.8%. The pinch based design has a net LHV efficiency of 36.2%. The final simplified design achieves a net LHV efficiency of 36.0%.

Other conference publications:

Soundararajan, Rengarajan; Gundersen, Truls. Coal Based Power Plants Using Oxy-Combustion for CO_2 Capture: Pressurized Coal Combustion to Reduce Capture Penalty. PRES 2012, 15th Conference on Process Integration, Modelling and Optimisation for Energy Saving and Pollution Reduction; 2012-08-25 - 2012-08-29

Soundararajan, Rengarajan; Gundersen, Truls. Coal Based Power Plants Using Oxy-Combustion for CO_2 Capture: Pressurized Coal Combustion to Reduce Capture Penalty. Chemical Engineering Transactions 2012; Volume 29. p. 187-192

Soundararajan, Rengarajan; Anantharaman, Rahul; Gundersen, Truls. Design of steam cycles for oxy-combustion coal based power plants with emphasis on heat integration. Trondheim CCS Conference (TCCS-7); 2013-06-04 - 2013-06-06

Soundararajan, Rengarajan; Gundersen, Truls; Ditaranto, Mario. Oxy-combustion coal based power plants: Study of operating pressure, oxygen purity and downstream purification parameters. PRES: Conference Process Integration, Modelling and Optimisation for Energy Saving and Pollution Reduction; 2014-08-23 - 2014-08-27

Presentations:

Soundararajan, Rengarajan; Gundersen, Truls. Utilization of Low-grade Heat and Process Integration in oxy-combustion Coal based Power Plants. 2013 Spring Meeting and 9th Global Congress on Process Safety; 2013-04-28 - 2013-05-01

Soundararajan, Rengarajan; Anantharaman, Rahul; Gundersen, Truls. Design of steam cycles for oxy-combustion coal based power plants with emphasis on heat integration. IEAGHG Oxy Combustion Conference (OCC3); 2013-09-09 - 2013-09-13

Climate change and CCS

Climate change is one of the major threats that we face in this century. The inherent complex nature of the science behind the climate change and the uncertainties associated with the projection of future impacts and costs makes it harder to arrive at a solution on a scale that is required. The complex nature of the science involved makes it difficult for the common man (or woman) to understand and participate in shaping the necessary policies required. In some cases, it is much easier and comforting to deny the science and maintain the status quo rather than to make a change. Although several technologies with various levels of maturity are readily available to tackle the issue, the costs involved are generally high. Fair and sustainable policies are required to bridge the gap and enable the transition. Amidst all the uncertainties, there are some clear directions. No one technology but rather a portfolio of options is going to be the future. Additionally, the long-time that is spent in making the decisions is going to make it more difficult if not impossible to tackle the problem in the future. This chapter aims at simplifying the science and help the reader gain a bigger picture of the broader problem that we face.

2.1 Anthropogenic climate change

Global scale direct physical and biogeochemical measurements combined with remote sensing from ground stations and satellites offer insights into the changes in the climate system. Paleo-climate reconstructions extend our knowledge of the earth's climate into the past hundreds to millions of years. Together, they provide a comprehensive view of the changes in the climate system such as surface and ocean temperature, water cycle, sea level, etc... Some of the notable changes to the climate system include increase in Global Mean Surface Temperature (GMST) since the late 19^{th} century, warming of the upper ocean (above 700m) from 1971 to 2010 and persistent shrinking of glaciers world-wide. Another significant observation is the increase in the rate of sea level rise (from tenths of mm yr^{-1} to mm yr^{-1}). There is a high degree of confidence that ocean thermal expansion and glacier mass loss are the dominant contributors to Global Mean Sea Level (GMSL) rise during the 20^{th} century[1]. Figure 2-1 shows the observed changes in sea level during recent times.

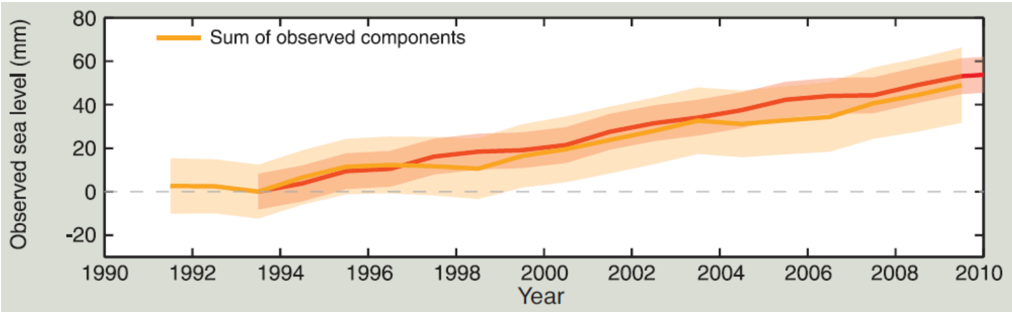


Figure 2-1: A comparison of the observed sea level (orange) with the satellite altimeter data (red)[1]. The shading indicates uncertainty estimates (two standard deviations) (Image source: IPCC).

Well Mixed Green House Gas (WMGHG) concentrations in the atmosphere have seen an increase during the industrial era due to anthropogenic emissions. Past changes in atmospheric greenhouse gas (GHG) concentrations are obtained both from direct measurements and polar ice cores. Atmospheric concentrations of GHGs such as carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) in 2011 exceeded the range of concentrations recorded in the past 800 kyr. The radiative forcing (RF) caused due to the changes in atmospheric concentration of GHGs can be calculated as the radiative properties of GHGs are well known. An increase in the atmospheric concentration of GHGs leads to a positive RF which in turn leads to a warming of the planet. Anthropogenic aerosols on the other hand are responsible for a negative RF. It is also important to mention that natural drivers such as volcanic eruptions and solar activity have a considerable impact on the climate of the planet. Nonetheless, the natural forcing is a small fraction of the WMGHG forcing. Various climate models are used to simulate past climate scenarios as well as to predict future climate variations. Climate models have been refined over the years and the confidence with which the models reproduce annual mean surface temperature changes over the historical period is very high. Many models are also able to reproduce patterns of precipitation and the observed changes in ocean heat content with increasing levels of confidence. Figure 2-2 shows that the observed past changes in land and ocean temperatures and ocean heat content cannot be explained with natural factors alone.

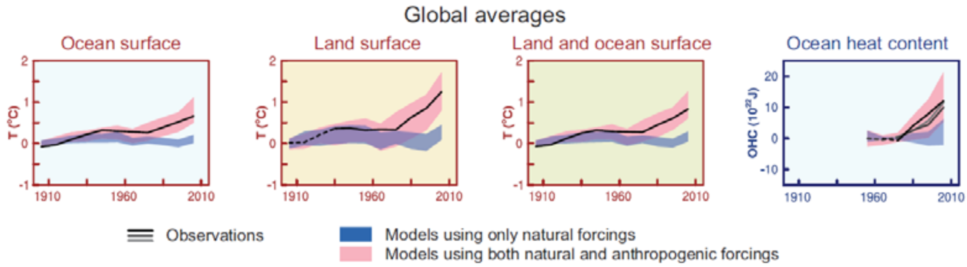


Figure 2-2: A comparison of observed and simulated change in the climate system[1]. The shading shows 5 to 95% range of the simulated response (Image source: IPCC).

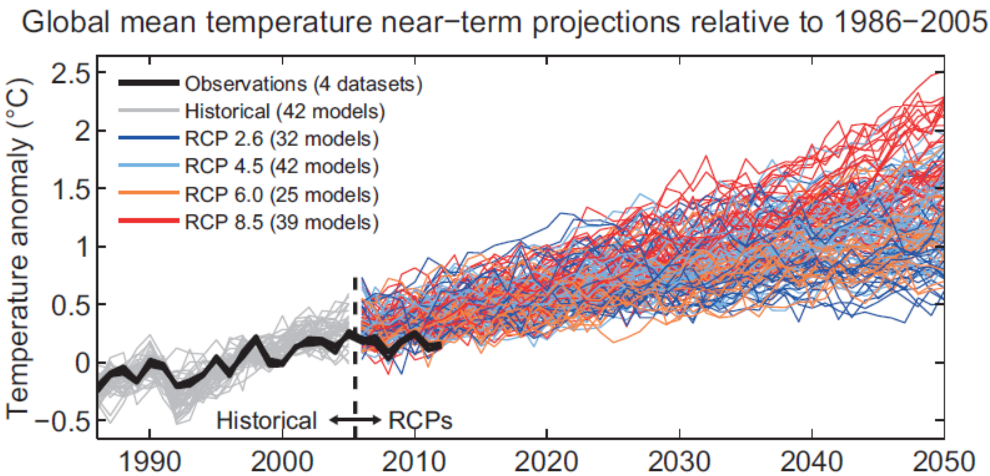


Figure 2-3: Synthesis of near term projections of Global Mean Surface-air Temperature (GMST) under various scenarios (Image source: IPCC)[1].

Projections in climate change are made using models having varying degrees of complexity. These climate models can range from very simple to comprehensive Earth System Models. A set of future forcing and scenarios are used to project the changes in the climate system that represent a range of future economic activity and evolution of technology and policy. The Coupled Model Intercomparison Project Phase 5 (CMIP5) is a multi-model experiment of the World Climate Research Programme that uses a new set of climate scenarios called the Representative Concentration Pathways (RCP). RCP 2.6 and 8.5 form the two extreme climate scenarios. RCP 2.6 assumes that the global annual GHG emissions peak between 2010 and 2020 and then decline substantially thereafter. In RCP 8.5, emissions continue to rise throughout the 21st century. The other two scenarios RCP 4.5 and RCP 6 fall in between the two extremes in which the emissions peak at around 2040 and 2080 respectively. Along with the temperature projections, the climate models predict changes in ocean, atmospheric circulation, ice cover, etc... Global temperatures are projected to increase throughout the 21st century under all scenarios. In the first half of the 21st century, the warming is mainly due to climate feedback and inertia and found to be less dependent on the scenario. From around the mid-21st century, the rate of warming begins to be more dependent on the scenario. Projections of temperature and sea level are shown in Figures 2-3, 2-4 and 2-5.

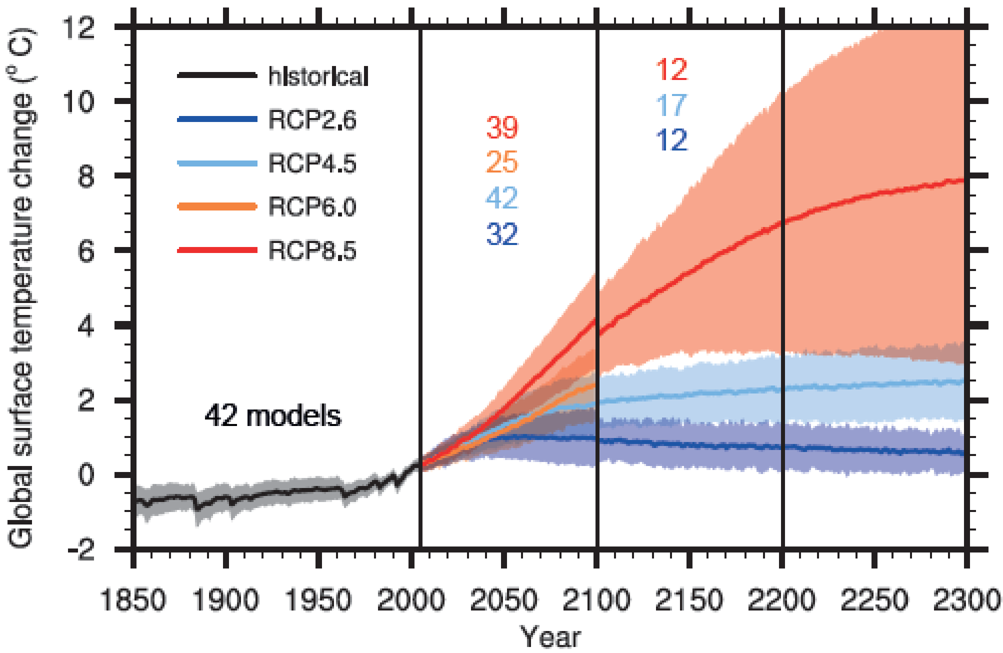


Figure 2-4: Long term temperature projections under various climate scenarios from CMIP5[1]. Solid lines represent multi-model mean while the shading represent 1.64 standard deviations across the distribution of individual models.

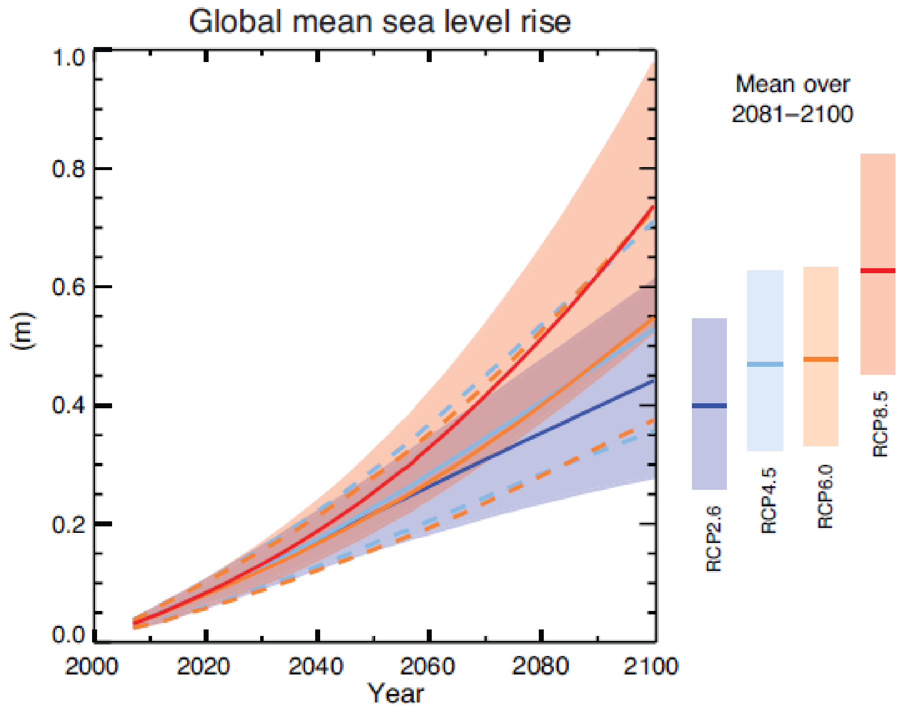


Figure 2-5: Projections of Global Mean Sea Level rise for the four RCP scenarios[1]. The solid lines show median projections where the dashed (RCP 4.5 and RCP 6) and shading (RCP 2.6 and RCP 8.5) show the likely ranges. The time means for 2081 – 2100 are shown as vertical bars to the right (Image source: IPCC).

2.2 Potential impacts of climate change

Climate change is causing glaciers to shrink and permafrost to warm and thaw. Climate change is also altering the geographic ranges, seasonal activities, abundances and migration patterns of various species. Negative effects have been observed on crop yields due to climate change. Combined, the changes and negative effects of the ongoing climate change are expected to be felt disproportionately by people living in various regions of the world. People who are marginalized and economically disadvantaged are especially vulnerable to climate change and to some adaptation and mitigation responses. Around the world, governments, private sector institutions and the general public are increasingly embedding adaptation strategies into their future planning processes. For instance, in North America, proactive adaptation is occurring to protect longer-term investments in energy and public infrastructure. The prevailing uncertainty among governments and other decision makers regarding the timing and magnitude of climate change impacts affects the adaptation and mitigation process. The choices made in the near term are expected to have long term impacts over the risk and future options available for adaptation and mitigation[2]. Key regional risks of climate change include wild fires and urban floods in North America, increased drought related water and food shortages in Asia to name a few. The severity of the risk and potential for adaptation varies with geography and timeframe. The effects of climate change on various sectors of the economy such as energy supply systems, water supply systems, and insurance are difficult to estimate and are expected to be varied[2]. The estimates of global economic impacts of climate change vary based on the underlying assumptions.

2.3 Climate mitigation options

Total anthropogenic GHG emissions have risen more rapidly from 2000 to 2010 than in the previous three decades. From 2000 to 2010, GHG emissions grew on an average of 2.2% per year compared to 1.3% per year over the period from 1970 to 2000. The global economic crisis of 2007/2008 has temporarily reduced global emissions but has not changed the longer-term trend. CO_2 remains the major anthropogenic GHG with 76% of total contributions to the GWP_{100} in 2010. The energy supply sector dominates the global emissions ($GtCO_2eq$) by contributing 35% in 2010, followed by Agriculture Forestry and Other Land-Use sector (AFOLU). Industry, transportation and buildings contribute to the rest of the emissions.

Growth in economic output and population are the main drivers for the increasing GHG emissions worldwide. Over the last decade, the share of emissions growth due to economic growth as a driver has gained importance. The energy and carbon intensity of the economic output have changed worldwide over the years due to changes in economic structure, energy mix of countries and changes in inputs such as capital and labour. Even though the energy intensity of economic growth has fallen throughout the world due to investments in energy efficiency, the coupling between economic growth and increasing GHG emissions still remains valid across the world. Figures 2-6 and 2-7 show the emissions of GHGs attributed to various economic sectors and geographical regions respectively.

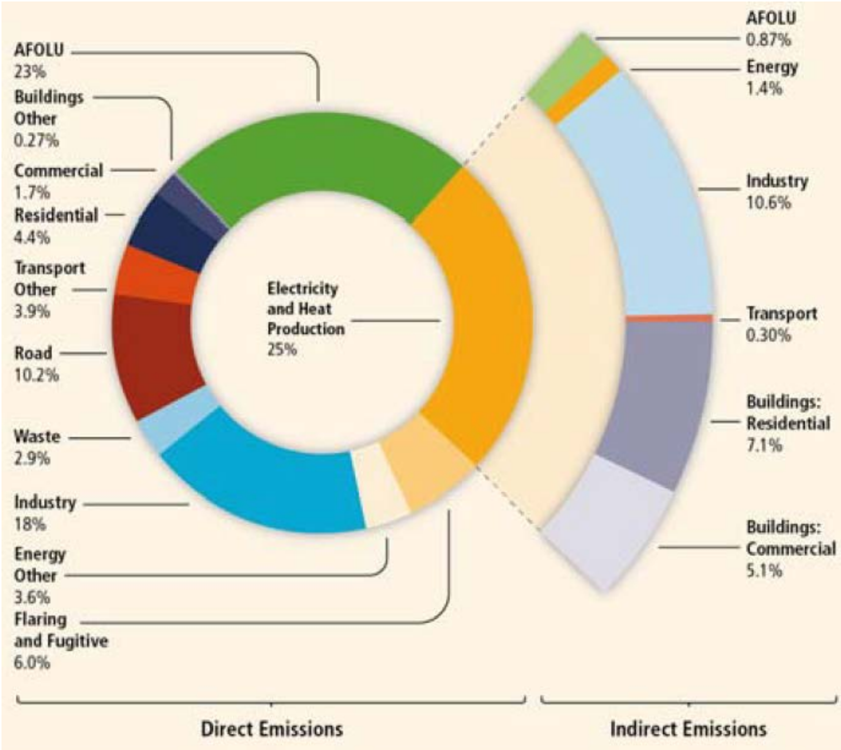


Figure 2-6: Share of direct GHG emissions in 2010 across the sectors[3]. Indirect CO_2 emission shares from electricity and heat production are attributed to sectors of final energy use (Image source: IPCC).

In order to avoid the negative effects of climate change, there is a need to stabilize the global temperature rise over the course of this century to no more than 2 degrees over the pre-industrial levels. This temperature target provides us with the atmospheric GHG concentration target to be achieved in 2100. An atmospheric GHG concentration of 450 ppm CO_2eq at the end of this century is likely to achieve the desired temperature targets. An emissions reduction of at least 41% by 2050 and at least 78% by 2100 compared to 2010 levels is required to achieve this stabilization target. If the global emissions continue to rise as they do today, substantial negative emissions are required in the second half of the century to achieve the temperature targets. Reaching the atmospheric concentration targets require large scale changes to global and national energy systems over the coming decades. Any delay in mitigation measures through 2030 will increase the challenges, could substantially increase the mitigation costs, and reduce the options for bringing the atmospheric concentration levels to 530 ppm CO_2eq by the end of this century. On the other hand, stringent climate mitigation could provide additional benefits such as improvement in air quality and ecosystem benefits.

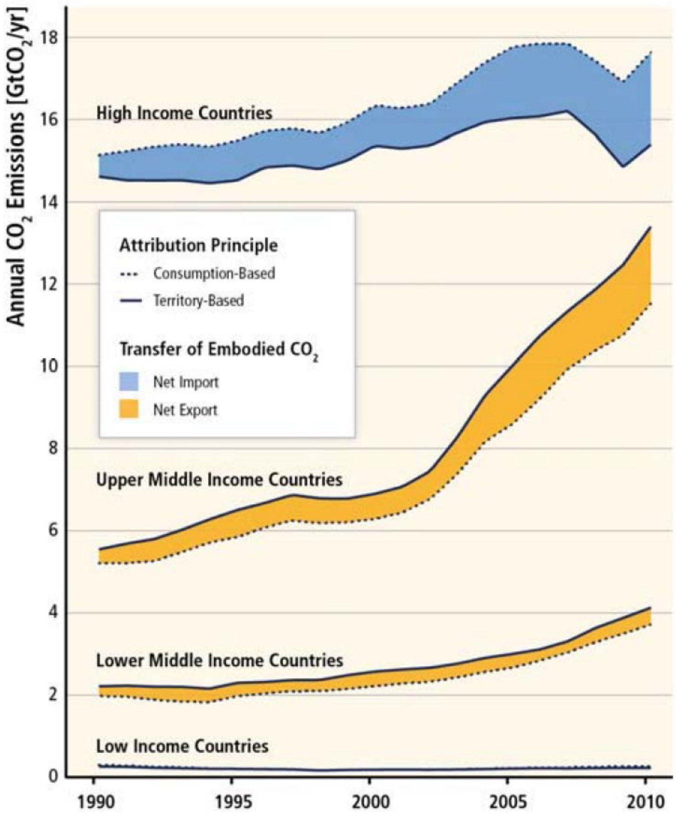


Figure 2-7: Total annual CO_2 emissions ($GtCO_2$/yr.) from fossil fuel combustion for country income groups attributed on the basis of territory (solid line) and final consumption (dotted line) (Image source: IPCC)[3].

The energy supply sector comprising of energy extraction, conversion, storage, transmission and distribution is the largest contributor to the global GHG emissions. The GHG emissions from the energy sector grew more rapidly from 2001 to 2010 than in the previous decade owing to a complex array of reasons including increased coal usage, increased economic activity and growing demand for energy. There are a multitude of options to tackle the emissions from the energy sector. Options include renewable energy, energy efficiency and CCS among others. Improving the efficiency of fossil fuel based power plants and switching to natural gas from coal alone is not enough to achieve the desired climate stabilization targets. It is noteworthy to mention that renewable energy technologies such as solar and wind have become technologically more mature and economically more competitive over the last decade. Over half of the new electricity generating capacity added globally in 2012 is from renewable sources. Nuclear energy is another significant technology that is both low-emission and mature. The share of nuclear energy in the global electricity mix continues to decline owing to concerns such as operational safety following the Fukushima disaster, proliferation risks and other issues related to waste management.

2.4 Significance of the electricity sector

Global demand for electricity is set to increase by around two-thirds in the period from 2012-2035 at 2.2% per year average growth rate[4]. Most of the growth in demand is expected to come from non-OECD countries due to a combination of factors such as increasing population, economic growth and rising living standards. Significant investments in new electricity generation are also required in OECD countries owing to the retirement of a large ageing fleet of power plants. About 64.8% of the current electricity generation fleet is powered by fossil fuels. Replacement for ageing power plants and new capacity additions are expected to be made up of a mix of both renewables and fossil fuels. Investment in renewable sources of power such as solar PV and wind is picking up around the world and the trend is expected to continue in the future. In the period from 2014-2035, it is projected that about half of the gross capacity addition is going to come from fossil fuel based power plants. It is also projected that in the year 2035, 53.7% of the installed capacity and 56.8% of the electricity generation is going to be fossil fuel based. Despite the projected fall in the share of fossil fuel based electricity, the installed capacity is projected to increase by a net amount of 1390 GW[4]. With the growing popularity of electric vehicles, the electricity sector presents another opportunity of cleaning up the transport sector emissions. This signifies the importance of the power sector and the need to address the environmental impacts of fossil fuel based power plants. The World Energy Investment Outlook projects an average investment requirement of $85 billion/year in coal fired power plants with CCS to achieve the 450 Scenario. Figure 2-8 shows the significance of the power sector and summarises the discussions of this section.

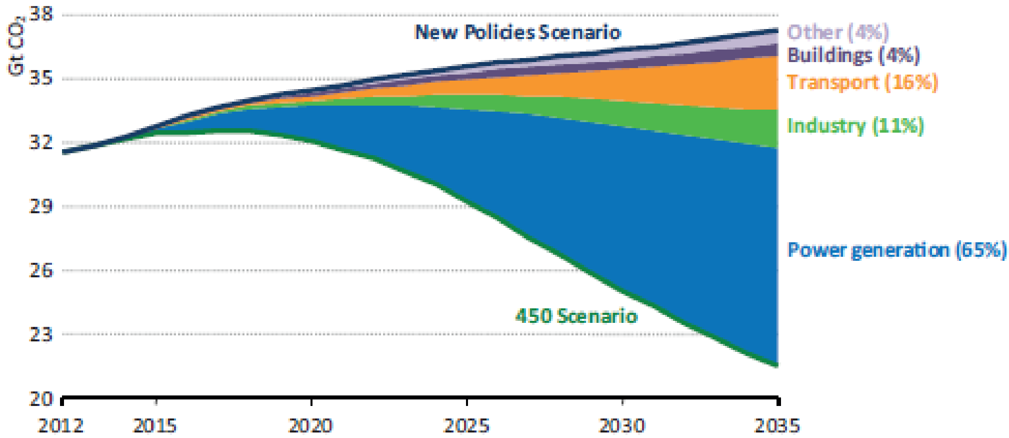


Figure 2-8: World energy-related CO_2 emissions. Current agreed upon emission reduction targets represented by New Policies Scenario and a scenario that aims to stabilize warming by 2C represented by the 450 Scenario (Image source: IEA)[4].

2.5 Significance of coal as fuel

Coal supplies 30% of the world's primary energy needs and 41% of the electricity generation[5]. Almost half of the world's additional energy demand in the past ten years was met by coal. Coal is one of the most abundant and affordable fuels widely available around the world. The technologies used to convert coal into electricity are well developed and widely deployed. As a result, coal fired power plants have a very high availability and provide base load 24/7 electricity supply. Owing to the affordability of coal, it is relied on by large emerging economies such as China and India to lift the living standards of hundreds of millions of people. As the global electricity demand is set to increase significantly over the coming decades, coal as a source of energy is expected to play an increasingly important role. State of the art coal based power plants can attain a net electricity efficiency of about 45% and research is currently under progress to develop new materials to further improve power plant efficiency. Coal burning power plants are here to stay and that is precisely why technologies such as CCS are required to address the environmental issues related to the combustion of coal.

2.6 Role of CO_2 capture and storage

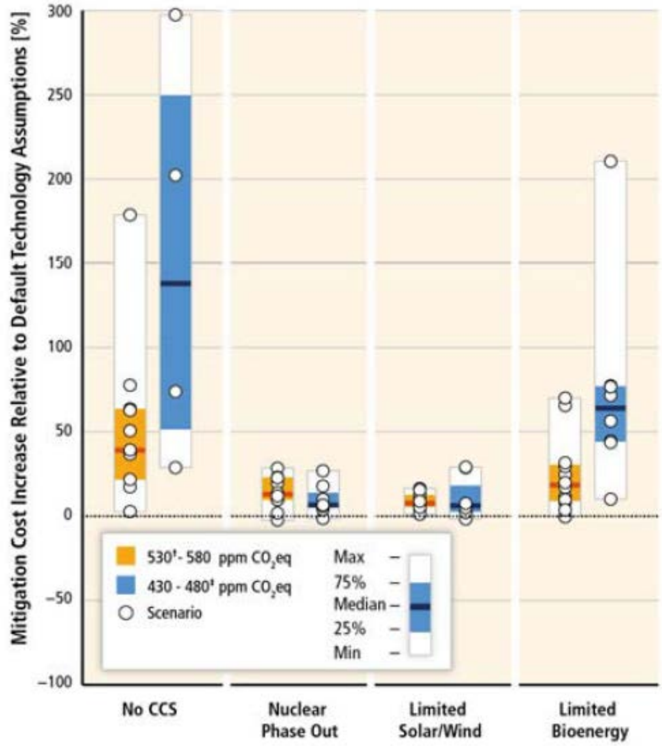


Figure 2-9: Relative increase in net present value mitigation costs (2015-2100, discounted at 5% per year) from technology portfolio variations relative to a scenario with default technology assumptions (Image source: IPCC)[3].

Carbon dioxide Capture and Storage (CCS) is a complete end to end system that is designed to capture CO_2 from large point sources such as power plants and industries, transport the captured CO_2 using pipelines or other means of transport to the storage sites and inject the CO_2 into deep geological structures and finally apply monitoring methods to ensure safe long-term storage. CCS is a resource intensive but necessary technology to achieve the level of mitigation required to stabilize global warming within acceptable levels. The cost of capturing and storing CO_2 from power plants is estimated to be in the range of $60-65 per metric ton[6]. Adding CCS to a power plant also increases the final cost of electricity significantly. This necessitates a global political will and economic incentive to commercialize CCS. Other significant challenges include the risks associated with pipeline transport[7] and geological storage of CO_2[8]. At the same time, there is a great deal of understanding and scientific knowledge regarding pipeline transport[9], injection and geological storage of CO2 because of which it is fair to conclude that CCS is a solution that is technically feasible on a scale required to mitigate anthropogenic climate change[10].

CCS technologies could reduce the specific CO_2eq lifecycle emissions of fossil fuel power plants. Several pilot scale power plants using CCS are already under operation around the world and several demonstration scale power plants are planned and are in various stages of construction[11]. All the individual components of an integrated CCS chain are in use in various parts of the fossil energy chain. Inclusion of CCS in the portfolio of mitigation options is found to bring down the overall cost of mitigation in the longer term (see Figure 2-9). With the gaining popularity of electric vehicles around the world, CCS could help address emissions from the transportation sector along with the energy supply sector. Combining CCS with bio fuels could ultimately result in negative emission which provides an attractive option to accelerate the reduction in global emissions.

2.7 Challenges facing commercial CCS deployment

Barriers exist to large scale commercial deployment of power plants with CCS. These barriers include concerns about the operational safety, risks related to transport of CO_2 and long-term integrity of storage.

Two main challenges can be identified as main barriers to the commercial deployment of CCS:

- Lack of policy and economic incentives on a global scale to stabilize GHG emissions[12]
- Lack of public understanding of the CCS technology, potential risks and benefits[13]

Oxy-combustion current state of the art

The oxy-combustion technology is one of the three main routes along with post and pre-combustion technologies to capture CO_2 from large point sources such as power plants. Post-combustion method captures CO_2 from the flue gas by using amine solvents whereas the pre-combustion method strips CO_2 directly from the fuel to produce hydrogen. Integrated Gasification Combined Cycle (IGCC) is a pre-combustion method that is studied around the world for its high efficiency and the ability to produce hydrogen. Hydrogen has the potential to decarbonize the transport sector in the future and hence gains particular interest from that perspective. Even though attractive from the potential benefits standpoint, IGCC technology faces issues such as system availability, development of gas turbines that could burn hydrogen and high cost. Other methods such as Chemical Looping Combustion (CLC) are also actively researched for CO_2 capture purposes. Direct combustion of fuel in oxygen is the method of focus in this thesis. Originally developed for high temperature applications such as the production of glass, metal and cement during the 1970s, the technology gained interest as a greenhouse gas mitigation option in the early 1980s[14]. Since then, the technology has been applied to both natural gas and coal based power plants with an aim of developing a system that is capable of capturing the CO_2 generated at a reasonable cost. The basic premise of the technology is that by burning the fuel in oxygen instead of air, the dilution of flue gas by atmospheric nitrogen can be avoided. As a result, the flue gas will mainly contain carbon dioxide and water vapour. This would enable the capturing of pure CO_2 after condensing the water fraction. While in practice it is much more complicated and challenging, the technology today is well tested and all but commercial. This method of CO_2 capture is attractive from the cost as well as the life cycle environmental standpoint and hence is expected to play a major role in the future. Additionally, this method can be applied to both new and existing coal based power plants in the near term. This chapter aims to collect some of the published literature related to the oxy-combustion technology applied to coal based power plants.

3.1 Oxygen production

The oxygen supply system lies at the heart of the oxy-combustion coal based power plant. Although several other technologies including membrane separation and adsorption exist to produce oxygen at commercial quantities, cryogenic distillation is widely accepted as the technology of choice for coal based power plants. This is due to the purity, volume and other requirements. Cryogenic distillation of air is a well-established technology and several industrial gas companies such as Air Liquide, Linde and Air Products have developed their own variations of the technology. The industrial gas companies are ready to supply Air Separation Units (ASU) that produce oxygen for commercial scale oxy-combustion power plants. ASUs are fairly large units that consume a substantial amount of power to produce oxygen. Several improvements including heat integration, Brayton cycle expansion of nitrogen are proposed to reduce this energy consumption.

For instance, the air needs to be compressed before it can be cooled for separation in the ASU. The compression process generates a large amount of heat that can be used to preheat the boiler feedwater of the steam cycle. This generates additional electricity that can bring down the net energy consumption of the ASU. The specific energy consumption of a typical three column cycle varies between 175 and 195 kWh/t. For a double column cycle with dual reboiler, the specific energy consumption ranges from 167 and 197 kWh/t. The actual energy consumption depends on the supply pressure of oxygen and level of heat integration among other factors. In this thesis, the ASU itself is not simulated in detail, but the energy consumption to produce oxygen at 1.6 bars and 95% purity is assumed to be 198 kWh/t. The ASU is assumed to be a standalone unit without heat integration and hence a higher specific energy consumption value is used. It is noteworthy to mention that producing oxygen at purity lower than 95% doesn't affect the specific energy consumption substantially. At the same time, reaching purity higher than 97% will cause a significant jump in the specific energy consumption due to the need to separate argon from oxygen. Due to this phenomenon, it is widely accepted that an oxygen purity of 95% is energy optimal for oxy-combustion applications for CO_2 capture. Table 3-1 presents a collection of relevant publications on oxygen supply systems from the literature.

Table 3-1: Published literature on oxygen supply

Oxygen supply	References
Cryogenic distillation	[15],[16],[17],[18],[19],[20]
Other methods	[15],[21],[22],[23],[24],[25]
Process integration on ASU	[19],[26],[27],[28]
Other significant works	[21],[29],[30]

3.2 Oxy-combustion boilers and steam cycle

In terms of technological readiness, the oxy-combustion boiler is considered to be mature, demonstrated and ready for commercialization. Combustion of coal in oxygen rich environment has been studied in detail over the past few decades and several manufacturers are now ready to supply boiler components for oxy-combustion power plants. Flue gas recycle is an important element of the oxy-combustion power plant and is required to maintain the boiler temperatures within acceptable levels. Typically around 70 wt. % of the total furnace gas flow is recycled and the rest is taken for further processing downstream. A recirculation fan is required to overcome the pressure drop in the gas side of the boiler and this will result in an increased auxiliary consumption. The boiler also consumes additional auxiliary power for coal feeding, ash removal, etc. By controlling the amount of recycle and oxygen concentration (28-35%) in the gas going to the burners, it is possible to control the combustion and achieve air like heat transfer. This feature makes oxy-combustion technology suitable for retrofitting old power plants with minimal modifications.

Unlike the air fired coal based power plants, oxy-combustion power plants use part of the recycle feed (instead of air) to transport coal into the boiler. The recycle feed going to the coal mills must contain very low moisture and acid content compared to the secondary recycle feed used to control boiler temperature. This is required to prevent corrosion of the fuel supply units. The secondary recycle feed need not be de-sulfurized depending on the initial sulphur content of the coal used. Recycling the secondary recycle feed at higher temperatures results in better overall performance of the power plant. In a conventional air-fired power plant, the incoming air is preheated by using the outgoing flue gases to improve the overall efficiency. In case of the oxy-combustion power plant, the oxygen feed can be preheated for better combustion efficiency. Recovering heat from flue gases to generate additional power in the steam cycle is proposed to improve the efficiency of coal based power plants. This feature is particularly attractive for plants capturing CO_2, since the flue gas needs to be cooled before processing and any additional power generation will result in reduced capture penalty. However, the economic viability of such heat recovery options depend on the additional investment required. This is further intensified by the need to use corrosion resistant materials for heat exchanger construction. In this thesis, such flue gas heat recovery systems are investigated from the efficiency point of view. Economic analyses are out of scope for this PhD thesis.

The steam cycle and electricity generation systems are some of the most matured units in an oxy-combustion coal based power plants. They have very high reliability owing to their decades of technological improvement and operational experience. Advanced steam generators using Nickel based alloy materials are currently under development to enable the usage of higher pressure and temperature steam to further improve the power plant efficiency. When available, these Ultra Super Critical (USC) steam cycles will help bring down the cost of electricity from power plants with CCS. However, those material based advancements are several years if not decades away and hence there is a need to investigate other incremental improvements using process integration. Regenerative feedwater preheating and reheating are employed in modern steam power plants to achieve high efficiency. The feedwater preheating system offers some options for heat integration and potential improvement. Table 3-2 presents some of the published work on oxy-combustion, boiler systems and steam cycle.

Table 3-2: Published literature on the boiler system and the steam cycle

Boiler and steam cycle	References
Combustion	[31],[32],[33],[34],[35],[36]
Heat transfer	[37],[38],[39]
Boiler design	[11],[37],[40],[41],[42],[43],[44],[45]
Steam cycle	[46],[47],[48],[49],[50],[51]
Process integration	[52],[53]

3.3 Downstream purification and compression

Control and removal of various pollutants such as NO_X, SO_X and particulate matter are required for oxy-combustion power plants just as they are for air fired coal based power plants. However, the systems employed may be different in case of oxy-combustion power plants. Particulate removal is carried out using bag filters or Electrostatic Precipitators (ESP). Generally, particulates are removed from the recycled flue gas to avoid corrosion caused by increased concentration in the recycle loop. In a conventional air-fired power plant, Selective Catalytic Reduction (SCR) is the best available control technology for

NO_X control whereas Wet Flue gas Desulphurization (WFGD) is the technology of choice for sulphur removal. In case of an oxy-combustion power plant, primary measures for NO_X control includes a combination of low NO_X burners and staged combustion. Secondary measures such as SCR can also be applied in conjunction if required. Studies indicate that production of NO_X in oxy-combustion boilers per unit heat supplied is generally low due to lack of nitrogen in the combustion zone. Experiments also indicate that part of the NO_X produced during combustion is re-burned due to flue gas recycle. As a result, dedicated NO_X control measures are usually not required for oxy-combustion boilers. Novel methods such as sour-compression to remove NO_X emissions as acids during the CO_2 compression stage are under development. For sulphur removal, WFGD can be utilised with some modifications such as using oxygen from the ASU instead of air to avoid flue gas contamination. The placement of an FGD unit depends on the sulphur content of coal. Care must be taken to prevent corrosion of the flue gas path and recirculation fan due to increased acid gas concentration due to recirculation. The placement of FGD outside of the recycle loop enables hot recirculation of the flue gases thereby avoiding the thermodynamic losses involved in preheating of the flue gases. Alternate methods for sulphur control include co-capture of acid gases along with CO_2 and removal as acids during the compression stage (Sour-compression).

Although the goal of oxy-combustion is to carry out the combustion of fuel in oxygen rich environment to enable easier capture of CO_2, additional purification steps are required to achieve final product specifications. This is due to the fact that the oxygen used for combustion is only 95% pure, coal has its own impurities and leakage of atmospheric air into the boiler introduces volatile components such as nitrogen. Removal of volatiles is done using cryogenic processes and hence moisture needs to be removed to avoid formation of ice crystals. The moisture removal is accomplished by a combination of cooling and compression along with a drying stage to reach ppm levels before the cryogenic process can begin. Although the moisture treatment systems are commercially mature, the systems need to be adapted and modified to treat flue gases of large volume and acidity to be able to function well in an oxy-combustion coal based power plant. Partial condensation of the flue gas and separation is the widely accepted method for volatile removal although distillation can be used. The former method is energy efficient while the latter achieves very high product purity. A product purity of at least 95% and a recovery rate of at least 90% are generally aimed at when designing the downstream processing units. Finally, the CO_2 stream must be compressed for pipeline transport and storage. Based on the application (Enhanced Oil Recovery vs. deep underground storage), the pressure and purity requirements may vary. A pipeline pressure of 110 bars is assumed in this thesis. Some of this compression work can be recovered to generate additional electricity in the steam cycle. Table 3-3 presents a selection of published literature on various topics related to emission control and downstream processing.

Table 3-3: Published literature on emission control systems

Emission control	References
SO_X, NO_X and particulates	[54],[55],[56],[57]
Volatile components	[30],[58],[59]
Compression	[58],[60],[61]
Process Integration	[60],[61]
Other aspects	[62],[63],[64],[65]

3.4 Economic and policy aspects

Various studies have been performed on the economic and environmental performance of oxy-combustion coal based power plants. Studies conducted by the U.S. department of energy (DOE) conclude that oxy-combustion is competitive in terms of Levelized Cost of Electricity (LCOE) generated vis-à-vis a power plant employing post combustion technology for CO_2 capture (11.30 vs 11.44 ¢/kWh). Many other studies also confirm the economic competitiveness of oxy-combustion power plants. There have also been studies that looked into the environmental performance of oxy-combustion power plants from an overall lifecycle perspective. One of the studies conducted in the Industrial Ecology group in the department of energy and process engineering, NTNU, finds that oxy-combustion power plants have minimal impact on the environment under several impact categories such as human toxicity. Although the technology is ready for commercial deployment and competitive in terms of both environmental and economic performance indicators, the outlook for large scale deployment of the technology still remains bleak. This is mainly due to the lack of globally coordinated and binding emission reductions target to stabilize atmospheric greenhouse gas levels. The outlook for CCS in general is also hampered by the negative public perception of technology. Nonetheless, it is shown that the inclusion of CCS in the portfolio of control measures would ultimately result in lower cost of greenhouse gas mitigation. Table 3-4 presents some of the publications found in literature related to the aspects discussed in this section.

Table 3-4: Published literature on economic and policy issues related to CCS

Economics, policy, etc...	References
Economic analyses	[66],[67],[68],[69],[6],[70],[71]
Environmental assessment	[72],[68],[73]
Policy issues	[13],[74],[4],[75]
Other studies	[11],[76],[77],[78],[75]

3.5 Process integration in oxy-combustion power plants

Process Integration (PI) has been proposed as one of the ways to improve the overall performance of the oxy-combustion power plant. Various methods such as Pinch Analysis (PA), Exergy Analysis and mathematical optimization come under the ambit of process integration. PI methods have been applied to industrial units such as oil refineries to improve the performance. Over the years, these methodologies have been proven to be effective in achieving meaningful reduction in energy consumption and resulting in a net cost advantage. An oxy-combustion power plant has additional systems such as ASU and the CPU apart from the power plant and hence there are synergies in terms of heat surplus and deficit that can be exploited. Such heat integration will require additional capital investments and add complexity to the power plant. However, such heat integration will also result in an improved performance and hence are essential in bringing down the energy penalty associated with capture. In this thesis, a combined Pinch and Exergy analysis methodology is used to improve the efficiency of the oxy-combustion power plant while keeping the added complexity to a minimum. Though economic evaluations will add value to the thermodynamic results obtained, rigorous cost studies are out of scope of the PhD work.

Table 3-5: Published literature on Process Integration related topics

PI methodology	References
Pinch method	[79],[80],[81],[82],[83],[84],[85]
Exergy method	[82],[83],[86],[87],[88]
Mathematical	[89],[90],[91],[92],[93]
Other aspects	[94],[95],[96]
Applications	[60],[97],[98],[99],[100],[101]

Modelling of oxy-combustion coal based power plants

Oxy-combustion technology, also known as oxy-fuel technology involves combustion of fossil fuels in an oxygen enriched environment instead of atmospheric air. This increases the concentration of CO_2 in the flue gas and reduces the concentration of other gases such as nitrogen and ultimately enables the capture of CO_2 resulting from fossil fuel combustion. However, the oxygen required for combustion has to come from the atmospheric air. This requires oxygen production systems to be installed in addition to the power generating equipment. In addition to the oxygen production systems, downstream purification systems and modifications to the boiler are necessary to complete the oxy-combustion power plant. This chapter discusses in detail, the modelling process of such power plants with results from various simulation cases.

4.1 Oxygen production

Cryogenic Air Separation is the technology of choice for production of oxygen for coal based oxy-combustion power plants[102]. Cryogenic distillation satisfies the requirements such as the production volume, purity, pressure and other operational requirements[17]. It is the technology assumed in this thesis for calculation purposes. The ASU itself is a standalone unit and has not been simulated, instead the energy required to operate the ASU is derived from the literature[18]. Although heat integration can be used to recover the compression heat from the ASU[26], such options are not investigated. An oxygen purity of 95% and a specific energy consumption of 0.198 kWh/kgO_2 for the ASU are assumed in this thesis.

4.2 Boiler Island

An oxy-combustion boiler is very similar to its air fired counterpart in terms of the main operating principles[103]. However, there are some technological issues and challenges. Some of the technical considerations involved in the design of oxy-combustion boilers are listed as follows:

1) Achievement of similar adiabatic flame temperature as that of air combustion by adjusting oxygen concentration is necessary for flame stabilization[104].
2) Changes in gas composition will result in changes in radiative and convective heat transfer. While radiative heat transfer is linked to the adiabatic flame temperature, convective heat transfer is linked to the recycle fraction[104].
3) Excess oxygen in case of oxy-combustion is critical to the overall efficiency of the power plant as ASU consumes large amounts of power to produce oxygen[104].
4) Emission control methodologies may have to be modified to conform to existing SO_X and NO_X emission regulations[104].
5) A small amount of recycle feed going to the coal mills must be dried and removed of acid gases to avoid corrosion in the coal mills[11].

Recycled Flue Gas (RFG) is used to control the adiabatic flame temperature and achieve stable combustion in the oxy-combustion boiler. Introducing the oxygen stream into the burner complicates the design while offering one more degree of freedom for flame stabilization and control[11]. The oxygen stream must be preheated before it is mixed with the flue gas to avoid condensation and acid formation. The degree of preheat also has an impact on the overall efficiency of the system. In a conventional air fired coal based power plant, coal is transported using primary air supply through the coal mills. In case of oxy-combustion, the primary gas supply for coal transport must also come from the flue gas. As the coal mills are operated at a relatively low temperature compared to the flue gas temperature, the flue gas must be cooled, dried and stripped of acid forming gases to avoid corrosion[11]. The secondary recycle that controls the flame temperature can be circulated without acid gas removal and cooling based on the fuel properties. Conventional coal boilers can withstand fuel sulphur content of upto 3.5% and recycling of the flue gas increases the boiler sulphur concentration by about three times. This enables the recycling of flue gas without desulphurization (FGD) for coals having less than 1% sulphur content ultimately resulting in a much smaller FGD unit placed outside the flue gas recycle loop[105]. Similarly, moisture from the recycle feed can be removed prior to recycle. Removing moisture requires cooling the flue gas stream and then preheating the same back which is not very efficient from the thermodynamic perspective. In this thesis, the flue gas is assumed to be recycled at high temperature without any treatment except for ash removal. This enables to achieve a simpler overall configuration and a higher net efficiency. The ash from the flue gas must be removed prior to recycle to avoid corrosion of the boiler tubes.

Air leakage is a common phenomenon in coal based power plants. Atmospheric air leaks into the boiler due to the difference in pressure between the surroundings and the combustion chamber. The boiler is usually operated at a pressure slightly below the ambient for various safety reasons. The amount of air that leaks into the boiler is dependent on a multitude of factors such as size of the power plant, age and construction[45]. Air leaks at various points such as the combustion zone, air preheaters and along the flue gas flow path. Air leaking into the combustion zone affects the heat transfer and mass flow through the boiler. Moreover, as the air leaks from the periphery of the boiler, it does not aid in combustion of the fuel. In an air fired power plant, air leakage results in loss of efficiency and unit capacity, but is still considered a minor operational issue[45]. This is in contrast to an oxy-combustion power plant, where air leakage will result in increased downstream purification requirements in addition to all of the above mentioned issues. Hence, minimizing air leakage is vital to efficient operation of oxy-combustion power plants. Operating the boiler at higher than atmospheric pressure will eliminate air leakage and improve the efficiency[42].

4.3 Steam cycle

A schematic of a steam cycle model is shown in Figure 4-1. Modern coal based power plants utilize supercritical steam conditions and reheat to achieve a high average temperature of heat supply. Average temperature of heat rejected depends on the ambient conditions and cooling available at the site. In addition to reheat, modern steam power plants use regenerative feedwater preheating to increase the overall efficiency[106]. Regenerative feedwater preheating is done by extracting steam from the turbines at multiple stages (E1 to E8) and using it to preheat the feedwater before the boiler (W9). The final feedwater temperature combined with the total number of preheaters play a role in the overall efficiency of the power plant. Total number of feedwater preheaters is generally restricted by network complexity and plant economics as additional units yield diminishing improvements in efficiency.

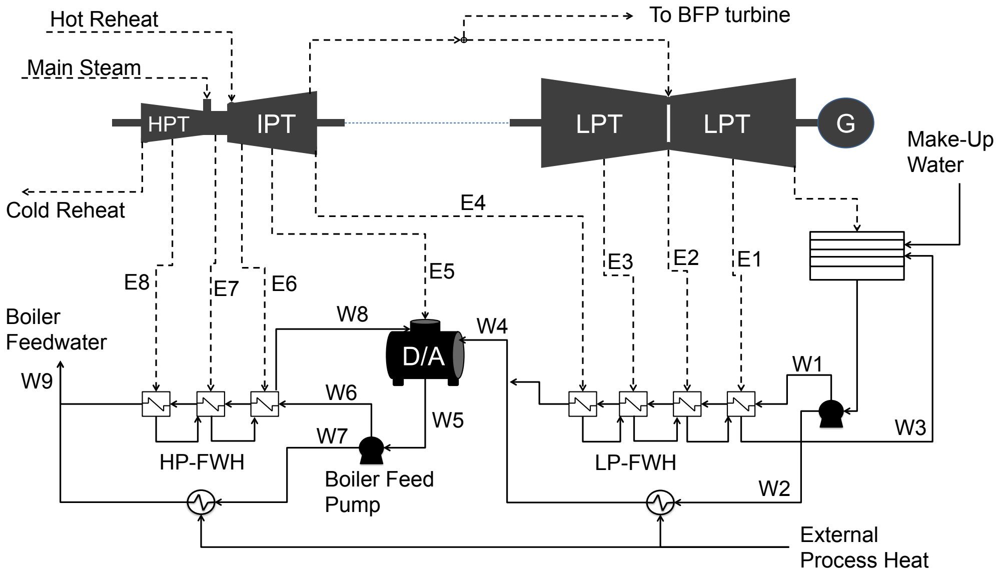


Figure 4-1: Schematic of the steam cycle with external heat integration

4.4 Heat integration

Process integration offers a significant potential for reducing the penalty of CO_2 capture by increasing the overall efficiency of the power plant. The air separation is a sub-ambient process and involves compression of large quantities of air. As the air needs to be cooled before separation, the recovered heat can be utilised to produce more power in the steam cycle[26]. This would also reduce the cooling water requirements and associated pump work. Similarly, the downstream purification is a sub-ambient process and uses compression. The compressors have intercoolers to reduce power consumption. Heat can be recovered from the CPU compressor intercoolers to generate additional power. Steam cycle feedwater preheating is using steam extractions that can be substituted with heat recovered from the ASU/CPU to generate additional power[26].

As opposed to the conventional coal based power plant without CO_2 capture, the flue gas from a power plant with capture has to be cooled for processing and compression in the CPU. This cooling provides an opportunity for significant heat recovery as the flue gas contains large amount of moisture from combustion. However, care must be taken to avoid corrosion of the heat exchanger components due to acid formation. Special heat exchangers with inert materials may be required for such applications raising the cost of heat recovery[53].

Hence, thorough economic analyses are required to support the economic feasibility of such heat recovery options[53]. Operating the boiler at a higher pressure will increase the amount of heat recoverable from the flue gas by raising the dew point of the flue gas. A higher operating pressure also results in elimination of air leakage into the boiler and hence further reduces CPU power consumption. Higher operating pressure of the boiler will require thicker wall construction and air tight enclosure which will increase the capital expenditure. In addition to using the recovered heat to substitute some of the steam extracted for feedwater preheating, the process heat can also be used for oxygen preheating. Preheating the oxygen stream will reduce the thermodynamic losses in the combustion chamber and thereby has an impact on the boiler efficiency. In this thesis, flue gas heat recovery is applied to all the simulation cases as a standard feature. Heat recovery from ASU compressors are not considered as the ASU itself was not simulated in detail. CPU heat recovery and oxygen preheating are applied to selected cases and will be explained in detail in following sections.

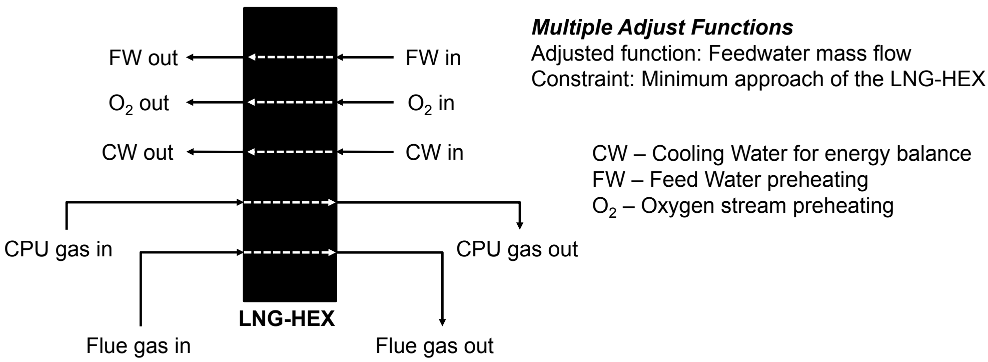


Figure 4-2: Heat integration calculation methodology using Aspen HYSYS

Aspen HYSYS was used to carry out the heat integration calculations. A schematic of the heat integration method is shown in the Figure 4-2. An LNG Heat exchanger unit available in Aspen HYSYS along with adjust functions are used to estimate the amount of feedwater preheating that can be achieved. The feedwater to be preheated by process streams can be extracted from either the low or high pressure side of the feedwater preheating system depending on the temperature levels of the process streams. The feedwater after the heat transfer can be introduced back into the feedwater preheating train at appropriate locations. The feedwater streams, flue gas stream from the boiler and various CPU gas streams are transferred to Aspen HYSYS for heat recovery calculations.

The inlet and outlet temperature of the flue gas stream and the CPU gases are determined by process conditions. Fixing the temperature levels of feedwater streams allows one to adjust the mass flows to achieve maximum heat recovery. Any remaining heat needs to be discarded to the cooling water system. The resulting mass flows of feedwater are then transferred back to Aspen PLUS simulations to complete the simulation and calculate the overall performance of the power plant.

4.5 Emission control and CPU

Flue gas from oxy-combustion of coal is composed of CO_2, water vapour, nitrogen, oxygen, argon and other pollutants such as oxides of sulphur and nitrogen. Removal of water vapour is carried out in multiple stages throughout the downstream purification process. Conventional power plants use Wet Flue Gas Desulphurization (WFGD) for sulphur removal and a combination of NO_X removal steps such as low NO_X burners and Selective Catalytic Reduction (SCR)[71]. Low NO_X burners are also employed in case of oxy-combustion for NO_X reduction while the flue gas recycle helps in the reduction of overall NO_X formation due to various mechanisms involved[32]. Hence, SCR may not necessarily be needed for oxy-combustion applications. Novel acid gas removal methods such as sour compression that remove oxides of sulphur and nitrogen during the compression process are suggested for oxy-combustion systems[55]. In this thesis, sour compression and removal of acid gases during the compression process is assumed. The sour compression schematic is shown in Figure 4-3. In the sour compression method, SO_2 and NO_X are removed as H_2SO_4 and HNO_3 respectively by water contact in absorption towers. The system is capable of removing 99% of SO_2 and 90% of NO_x. The removal efficiency is dependent on factors such as temperature, pressure, residence time and presence of liquid water[55].

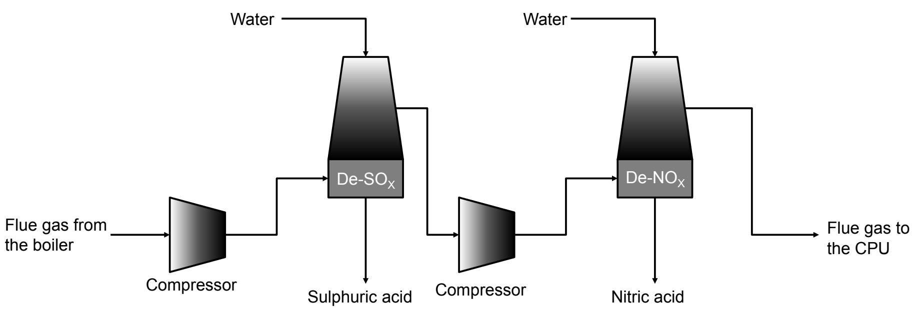


Figure 4-3: Sour compression system for removal of SO_X and NO_X

An oxygen purity of 95-97% is considered energy optimal for oxy-combustion applications as removal of Argon from Oxygen is extremely energy intensive due to close boiling points. This introduces a minor quantity of impurities such as nitrogen and argon into the combustion process. In addition to that, the air leakage and fuel impurities result in the presence of additional volatile components in the flue gas. A CO_2 purity of at least 95% is required for geological storage applications and this necessitates the removal of volatile components. The volatile components are removed by means of cryogenic processing such as flashing or distillation. While flashing is simple and saves energy, distillation results in very high product purity (99.9% CO_2 in the final product)[58]. In this thesis, a two stage flash based volatiles removal system is assumed as it is shown to be the most economic option[70]. The performance of the flash based CPU in terms of CO_2 recovery and specific energy consumption depends on the choice of various operating parameters such as the pressure of flue gas before cooling begins and the temperature and pressure of the flash stages. Parameters were taken from optimization results available in the literature[59]. Finally, the Peng-Robinson equation of state was used in Aspen Plus to carry out the simulation process[63].

4.6 Process description

The overall process flow diagram of the power plant with capture is shown in Figure 4-4. All units of the power plant including the steam cycle, the boiler island, and the CPU are shown in the figure along with the heat integration between various units. The ASU, the coal preparation and handling system and the ash handling system are not shown in the figure. The Oxygen from the ASU (S1) goes through a compression and heat exchanger train (C1 & HEX1) before entering the boiler (S2). The pressure and temperature of stream S2 depend on the compression mode of the compressor train C1 and the heat recovery/addition assumed which in turn depend on the simulation case. For instance, to operate the boiler at atmospheric pressure, the compression (C1) can be skipped. A major portion of the flue gas S3 is used as a recycle (S4) to control the furnace temperature. A fan is also required to overcome the pressure drop in the gas circulation path. Atmospheric air is assumed to leak into the boiler in cases with negative gage pressure. The flue gas stream S5 is then taken to the downstream CPU for purification and compression to pipeline conditions. Stream S5 needs to be cooled before any compression can take place and this represents a heat recovery opportunity (Q2).

As the oxy-combustion flue gas contains a lot of moisture, flue gas latent heat recovery is carried out in heat exchanger unit HEX2. Moisture is removed via a drier unit D1. The dry flue gas is compressed (C2) to a pressure of 30 bar and any heat recovery opportunities arising from the compression are fully exploited (Q3). Isothermal compression is employed in compressor train C2. The flue gas is then cooled to 15 ^{o}C, the remaining moisture is removed using the drier D2, and then the flue gas is fed into the first multi stream heat exchanger (m-HEX1). Stream S7 undergoes partial condensation in the heat exchanger and enters the flash drum F1 for vapour liquid separation. The liquid portion is rich in CO_2 and is expanded in valve V1 to satisfy the cooling needs of the incoming stream S7. The vapour stream is lean in CO_2 and hence undergoes one more stage of partial condensation (m-HEX2) and separation (F2) to improve the recovery rate of CO_2. The vapour stream S10 is then emitted to the atmosphere after utilising the stream for cooling purposes. The streams S13 and S14 undergo final compression in the compressor trains C3 and C4 respectively. Isothermal compression is used and heat recovery (Q4 & Q5) is carried out. The final product is achieved by pumping the liquid (dense phase) CO_2 to pipeline pressure. Stream S14 satisfies both the pipeline purity requirement and pressure level. Tables 4-1 to 4-4 present various assumptions used in the process simulations throughout the thesis.

Table 4-1: Ambient air composition

Component	Volume fraction dry	Volume fraction at 60% R.H
Nitrogen	78.09	77.30
CO_2	0.03	0.03
H_2O		1.01
Argon	0.93	0.92
Oxygen	20.95	20.74
Gas constant (J/(kg K))	287.06	288.16
Molecular weight	28.96	28.85

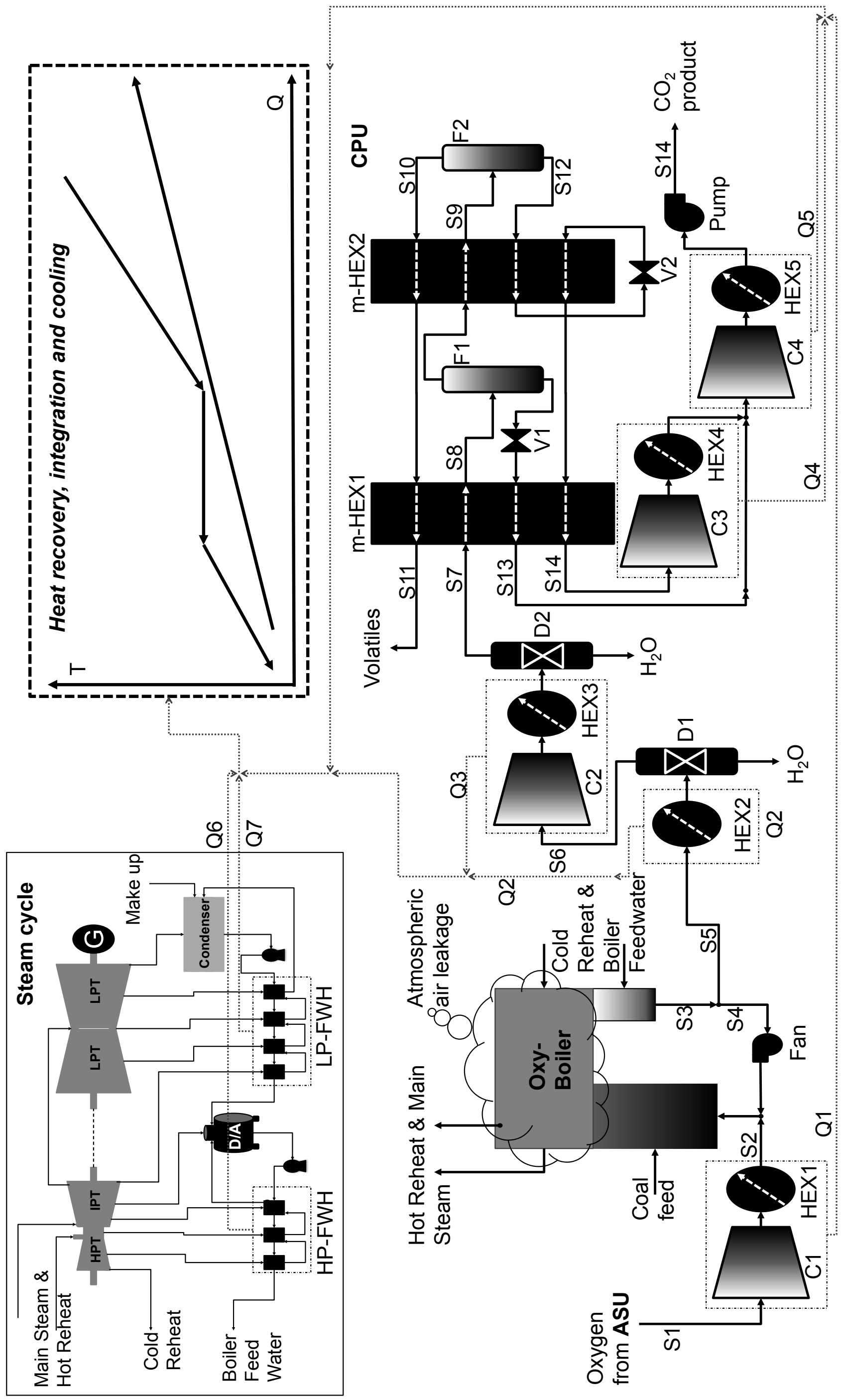


Figure 4-4: Overall schematic of the power plant with heat integration

Table 4-2: Coal composition and heating value

Bituminous Douglas Premium coal characteristics			
Proximate analysis wt.%		Ultimate analysis wt.%	
Moisture	8.000	Carbon	66.520
Ash	14.150	Nitrogen	1.560
Volatiles	22.950	Hydrogen	3.780
Fixed carbon	54.900	Total sulphur	0.520
Total sulphur	0.520	Ash	14.150
		Chlorine	0.010
		Moisture	8.000
		Oxygen	5.460
HHV (MJ/kg)	26.230		
LHV (MJ/kg)	25.170		

Table 4-3: Selected simulation parameters for the cycle

Parameter	Value	Units
Steam Cycle		
Main steam pressure	280	bar
Main steam temperature	600	^{o}C
Reheat temperature	610	^{o}C
Condenser pressure	0.048	bar
Feedwater final temperature	310	^{o}C
Deaerator pressure	18	bar
Turbine efficiency (HP/IP/LP)	92/94/88	%
Turbine-Generator mech. loss	1.89	%
Boiler island		
Boiler operating pressure	1.0124	bar
Excess oxygen@ combustor outlet	3	% (dry)
Combustor exit temperature	1850	^{o}C
Boiler minimum design pinch	20	^{o}C
Fan pressure ratio	1.04	No unit
Recycle ratio	71	Mass %
Fuel flow	6000	TPD
Air leakage	1	%

A model of the steam cycle used in the simulation is also shown in Figure 4-4. The steam cycle receives the main steam and the hot recycle from the boiler, and these are expanded in the turbines to generate power. The exhaust from the low pressure turbines are condensed in a condenser and the condensate is then pumped to higher pressures. The condensate, referred to as Boiler Feed Water (BFW) is heated through a series of heat exchangers by extracting steam from the steam turbines. This regenerative feedwater preheating results in a higher steam cycle efficiency. The BFW and the cold reheat are then fed to the boiler for heat transfer. This feedwater preheating train represents opportunities for heat integration (Q6 & Q7). Low grade heat recovered from other units of the power plant, such as the oxygen/flue gas compressor trains and the flue gas latent heat, can be used to supply a part of this preheating requirement. Heat integration reduces the steam extraction from the turbines, thereby increasing the electricity generated.

Table 4-4: CO_2 specifications and CPU operating parameters

Parameter	Value	Units
CO_2 specifications		
CO_2 purity	>95	%
State	Liquid	-
Volatiles (N_2/O_2/Ar)	<4	%
Pressure	110	bar
Temperature	<49	^oC
CPU operating parameters		
Pre-compression pressure	33	bar
First flash (P/T)	32/-30	bar/ ^oC
Second flash (P/T)	31/-54	bar/ ^oC
Compressor efficiency	85	%
Recovery rate	>90	%

4.7 Simulation cases and results

Based on the above process design and parameters, various cases were simulated in Aspen Plus with and without CO_2 capture to form as a baseline for further evaluations. The cases are explained in detail as below:

1) Air fired case with no CO_2 capture.
2) Oxy-combustion case with atmospheric pressure boiler.
3) Oxygen preheating added to case 2.
4) CPU heat integration added to case 3.

Case 1:

A schematic of the air fired Supercritical Pulverized Coal (PC) boiler is shown in Figure 4-5. In the air fired case, ambient air is used for combustion of coal at atmospheric pressure. A forced draft fan is used to overcome the pressure drop on the air side. Primary air supply, which is a part of the combustion air, is also used to transport coal through the coal mills and to the burners. Remaining air is called secondary air is then added in stages to the combustion chamber to control the temperature and for heat transfer. The total amount of air flow to the boiler is set based on the target excess oxygen at the boiler exit. Ash resulting from the combustion of coal is collected at two places. Bottom ash is collected at the furnace bottom while fly ash takes part in the convective heat transfer along with the flue gas and is collected at the furnace exit. Electrostatic Precipitators are used to collect the fly ash. The flue gas also exchanges heat with the incoming air through an air preheater unit. Typically, large power plants use regenerative air preheaters where the flue gas transfers heat with a large rotating disc which then transfers the heat to the primary and secondary air supply. The disc rotates in a sealed set-up isolating the flue gas and the air flow paths while minimizing the leakage and cross flow between the two. Regenerative air preheaters are essential in modern power plants to achieve high efficiency. The boiler system also typically includes a Flue Gas Desulphurization unit and NO_X control system based on local environmental regulations. In this simulation, traditional de-SO_X and de-NO_X systems are not considered for simplicity reasons. The steam cycle of case 1 is assumed to be a standalone steam cycle with no heat integration. Heat input to the steam cycle occurs only through the main steam and reheated steam from the boiler.

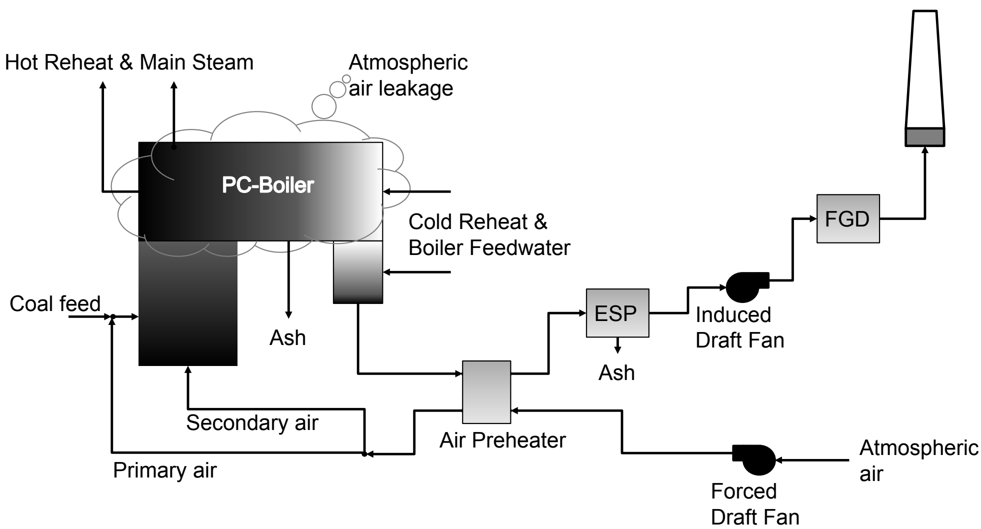


Figure 4-5: Schematic of the air fired pulverized coal boiler

Case 2:

The oxy-combustion coal based power plant in case 2 can be derived from the overall schematic presented in Figure 4-4. The ASU and the CPU are present in this case consuming a significant portion of the generated power. The compressor C1 and the heat exchanger HEX1 in Figure 4-4 are bypassed. The oxygen stream from the ASU is fed to the boiler at atmospheric pressure without any compression or preheating. Heat transfer from the CPU (Q3-Q5) is also bypassed in this case. Instead, cooling water is used to cool the CPU compressor intercoolers. Heat from the flue gas (Q2) is however recovered using HEX2 and integrated with the feedwater preheating of the steam cycle. This enables the recovery of latent heat from the flue gas and hence increases the overall system efficiency.

Case 3:

Case 3 is similar to case 2, but has oxygen preheating. The heat exchanger HEX1 is used to preheat the oxygen to 300 ^{o}C. The heat required to preheat oxygen is taken from the flue gas coolers (HEX2). Additional heat from the flue gas coolers are utilized in the feedwater preheating section of the steam cycle. Cooling water is used for the CPU intercoolers. As the fuel flow to the boiler is kept the same for various simulation cases, oxygen preheating results in changes in the recycle flow and heat output of the boiler. This results in more power being produced at the steam turbines and higher overall efficiency. Oxygen preheating does not affect the mass flow of the gas being processed by the CPU and hence has no effect on the CPU power consumption.

Case 4:

CPU heat recovery is added to case 3 to obtain case 4. Heat from the CPU intercoolers (HEX3 - HEX5) is utilized along with heat from the flue gas to perform oxygen preheating and part of the feedwater preheating. This results in increased power generation by the steam turbines along with reduced cooling water consumption for CPU cooling needs.

Table 4-5 presents various performance parameters for the four cases. Despite the significant increase in gross power production in case 2, the net power produced is less than that of case 1 due to ASU and CPU auxiliary power consumption. This results in a net efficiency penalty of 7.7%. As the fuel flows to all cases are same, the same amount of CO_2 is produced in all four cases. Cases 2 to 4 capture 95.8% of the CO_2 generated which is well above the target of 90%. Oxygen preheating in case 3 increases the power produced at the turbines compared to case 2 but does not increase the auxiliary power consumption. This results in a net LHV efficiency increase of 0.6 percentage points. This also results in lower specific energy consumption on a CO_2 avoided basis compared to the case without capture (Case 1). Finally, case 4 includes CPU heat integration in addition to oxygen preheating that result in improved overall performance and a final capture penalty of 6.8%. System net efficiencies are calculated on LHV/HHV basis from the fuel heating values (Table 4-2) and the fuel flow (Table 4-3). Efficiency penalty and the CO_2 avoided values are calculated for all the cases with Case 1 as the baseline.

Table 4-5: Performance of baseline cases with and without capture

	Unit	Case 1	Case 2	Case 3	Case 4
Steam cycle					
Boiler heat input	MW_{th}	1648.1	1685.5	1726.8	1726.8
External feedwater preheating	MW_{th}	-	67.0	29.0	69.6
Condenser duty	MW_{th}	823.8	889.6	883.1	919.2
Shaft power	MW	825.9	864.5	874.3	878.7
Gross power output	MW_{el}	810.2	848.1	857.7	862.1
Gross efficiency	%	46.4	48.5	49.1	49.3
Boiler island					
Oxygen flow (pure oxygen)	kg/s	-	142.9	142.8	142.8
Oxygen production power	MW_{el}	-	107.2	107.1	107.1
Auxiliaries	MW_{el}	22.0	15.2	14.5	14.5
Oxygen preheating	MWth	-	-	40.4	40.4
Flue gas heat recovery	MW_{th}	-	67.0	69.3	69.2
CPU					
Compression and pumping work	MW	-	67.8	67.8	67.7
Total CPU power requirement	MW_{el}	-	71.3	71.3	71.3
CPU heat recovery	MW_{th}	-	-	-	40.7
Net electricity output	MW_{el}	781.6	647.3	657.7	661.8
Net LHV eff.	%	44.7	37.0	37.6	37.9
Net HHV eff.	%	42.9	35.5	36.1	36.3
Efficiency penalty	%	-	7.7	7.1	6.8
CO_2 capture performance					
CO_2 produced	kg/s	169.2	169.2	169.2	169.2
CO_2 captured	kg/s	-	162.1	162.1	162.1
CO_2 production intensity	kg/kWh	0.78	0.94	0.93	0.92
CO_2 capture intensity	kg/kWh	-	0.90	0.89	0.88
CO_2 avoided	kg/kWh	-	0.74	0.74	0.74
Spec. energy CO_2 avoided	kWh/kg	-	0.28	0.25	0.24

The effects of boiler pressure, oxygen purity and CPU parameters

As discussed in the previous chapter, adding CO_2 capture to a coal based power plant leads to efficiency penalty. One of the ways of reducing the capture penalty is to go for a pressurized coal combustion system[42, 43]. Operating the boiler at a higher pressure by compressing the oxygen stream enables increased heat recovery from the boiler flue gas. Additionally, a higher boiler pressure results in reduced downstream processing due to elimination of air leakage into the boiler. Oxygen can be compressed either adiabatically or isothermally and can also be combined with preheating for enhanced boiler efficiency[87]. More heat can be recovered from the flue gas at higher pressure. At the same time, the overall compression work increases with the boiler operating pressure. It is therefore necessary to arrive at an optimal operating pressure for the boiler considering all the above mentioned effects of compressing oxygen. Finally, it is also essential to evaluate the energy optimal oxygen purity at higher boiler operating pressures. This has to be done in conjunction with the CPU operating parameters. This chapter deals with parametric analysis of the oxy-combustion coal based power plant with capture under various, operating pressures, oxygen purity and downstream CPU operating parameters.

A conventional (negative gage pressure) air-combustion coal based power plant without CO_2 capture is modelled initially to serve as a baseline (Case 1 from Chapter 4) to estimate capture penalty and emissions avoided by the capture plants. A conventional oxy-combustion counterpart is also simulated as a baseline power plant with capture (Case 2 from Chapter 4). Power plants with pressurized boiler (HP-OXY) are derived from the latter by adding a compressor to the oxygen stream before the combustor and making necessary changes to the pressure drop in the gas path and the downstream CPU compressor stages. The commercial simulation package Aspen Plus® was used for all the simulations. The Aspen HYSYS® simulation tool was used to estimate the amount of heat recovery between the hot and cold streams. Necessary care was taken to ensure that heat recovery takes place at appropriate temperatures.

Minimum temperature differences for various hot and cold stream combinations were assumed and maintained. This was achieved by using multi-stream heat exchangers (LNG) and solving multiple adjust operations simultaneously in Aspen HYSYS® to modify the mass flows of the cold streams. The above method was used to simulate complete power plants with boilers at various pressure levels to find the optimal operating pressure.

The boiler island and the CPU of the high pressure power plant with capture are linked to Aspen Simulation Workbook (ASW) for the sensitivity cases (16 bars only). Multiple scenarios with various oxygen purities and CPU operating parameters are then fed into the simulation via the ASW to obtain the impact on the overall performance. For all the sensitivity cases, only the flue gas latent heat recovery is considered and not the CPU heat recovery for simplicity purposes. The steam cycle is not simulated in detail for the sensitivity cases and instead, the shaft power produced is estimated using the conversion efficiencies obtained from the base cases. The results from the sensitivity cases are then used to calculate various performance parameters such as the CO_2 recovery rate, net efficiency and the specific energy required to avoid one kg of CO_2 emitted.

5.1 Effect of boiler operating pressure on performance

In this section, a high pressure oxy-combustion coal based power plant is derived from Case 4 of Chapter 4. The whole power plant is simulated for the boiler operating pressures of 2, 4, 8, 16 and 32 bars. In each of the high pressure cases, an isothermal oxygen compression scheme with (Isothermal300) and without oxygen preheating (Isothermal) and an adiabatic oxygen compression scheme are investigated. Even though isothermal compression results in lower energy consumption, adiabatic oxygen compression results in higher boiler efficiency by producing compressed oxygen at higher temperature. During isothermal compression of oxygen, the heat from the intercoolers are recovered and utilized in the steam cycle feedwater preheating. Oxygen preheating can be added to the isothermal compression scheme to achieve low compression work as well as high boiler efficiency. Adiabatic oxygen compression results in a simpler system design with minimal number of stages and no heat transfer units.

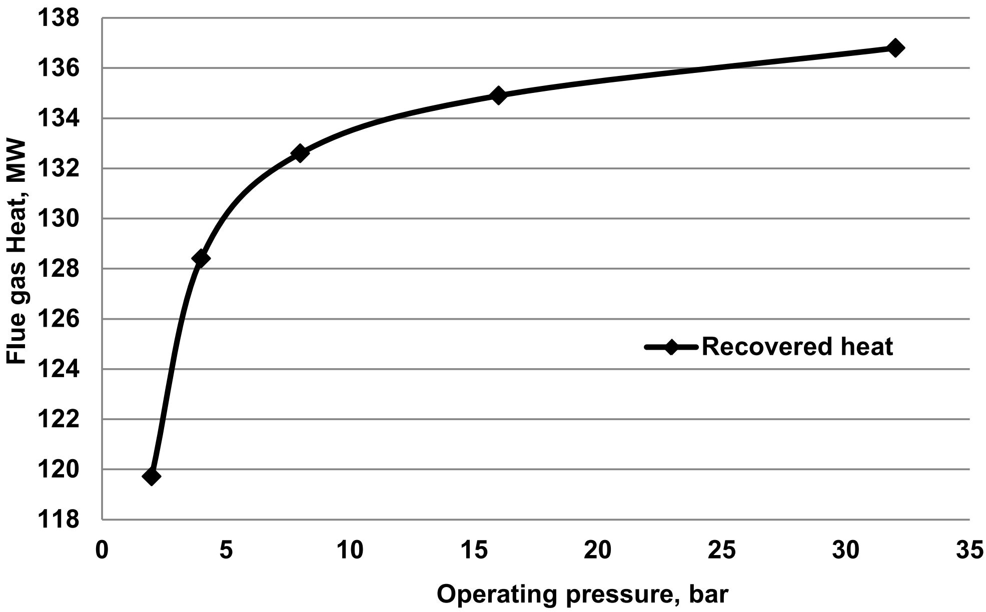


Figure 5-1: Flue gas heat recovery at various boiler operating pressures

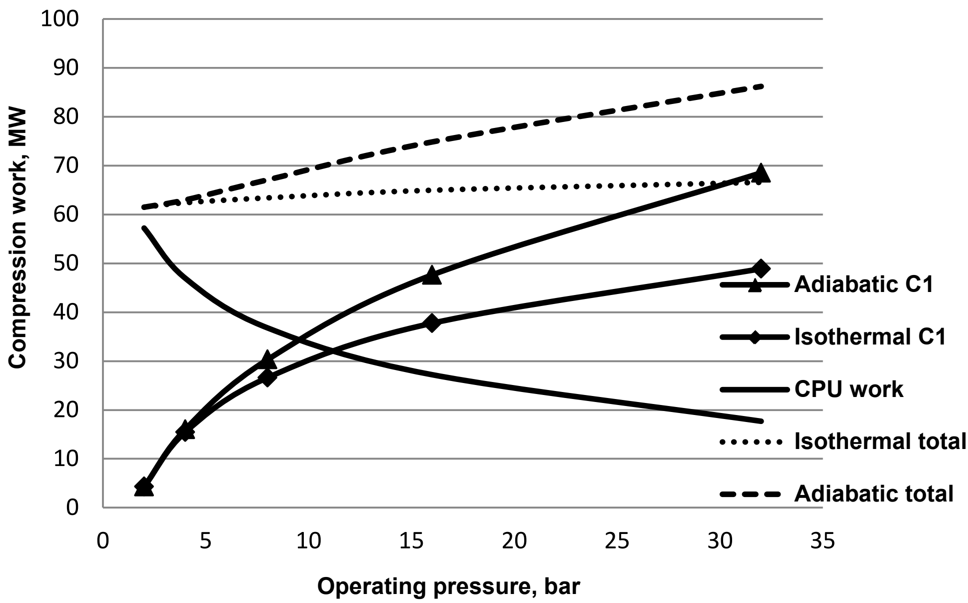


Figure 5-2: Variation of compression work with boiler operating pressure

Figure 5-1 shows the amount of heat recovered from the flue gas at various pressure levels. Most of the heat available in the flue gas can be recovered at a pressure of about 10 bars. Any pressure increase after 10 bars produces only marginal increment in the heat recovery from flue gas. Figure 5-2 shows the effect of operating pressure on the compression work involved. The compression work required downstream the boiler drops with the boiler operating pressure. This is in line with the expectation that any compression upstream the boiler would result in a corresponding drop in the compression work downstream as the pipeline pressure is kept the same. The work required to compress oxygen isothermally is smaller compared to the adiabatic compression of oxygen. Finally, the total compression work stays roughly the same for isothermal compression and increases with pressure in case of adiabatic compression. It is noteworthy to mention here that, adiabatic compression results in a higher boiler thermal output. In case of isothermal compression, the boiler thermal output stays the same and additional compression work at higher pressures is discharged to the cooling water system through the intercoolers. Figure 5-3 shows the gross electric power generated by the steam turbines for various compression schemes. As expected, in the cases with adiabatic compression of oxygen, the gross power output rises with the operating pressure. This is due to the reduction in boiler thermodynamic losses achieved because of the higher oxygen temperature going into the boiler[87]. In isothermal compression cases, the gross power increase is mainly due to the flue gas heat recovery. The heat recovered from the intercoolers of the oxygen compressors have very low quality and hence much lower conversion efficiencies.

Figure 5-4 shows the net effect of boiler operating pressure and the choice of oxygen compression mode. Simple isothermal compression without oxygen preheating results in the lowest performance among all the compression modes throughout the chosen pressure range. For boiler operating pressures below 8 bars, isothermal compression combined with oxygen preheating to 300°C results in a better performance. For pressure above 8 bars, adiabatic compression is just as good as isothermal compression with oxygen preheating. Moreover, adiabatic compression results in a simpler overall system. At pressures above 16 bars, simple isothermal compression without preheating falls behind the other two compression modes. Hence a boiler operating pressure of 16 bars and adiabatic oxygen compression is chosen as the overall best method owing to the net plant efficiency and downstream purification requirements.

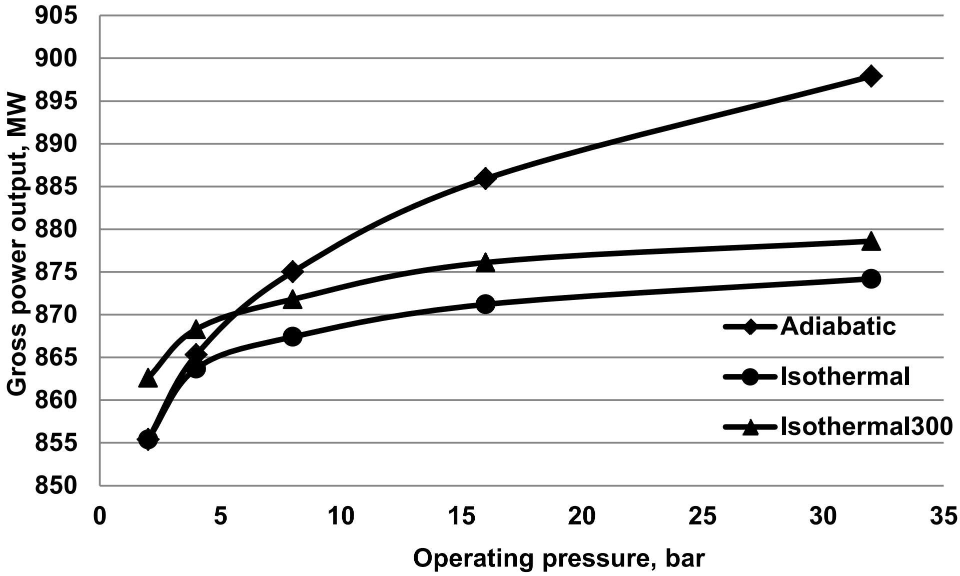


Figure 5-3: Gross power production vs the boiler operating pressure

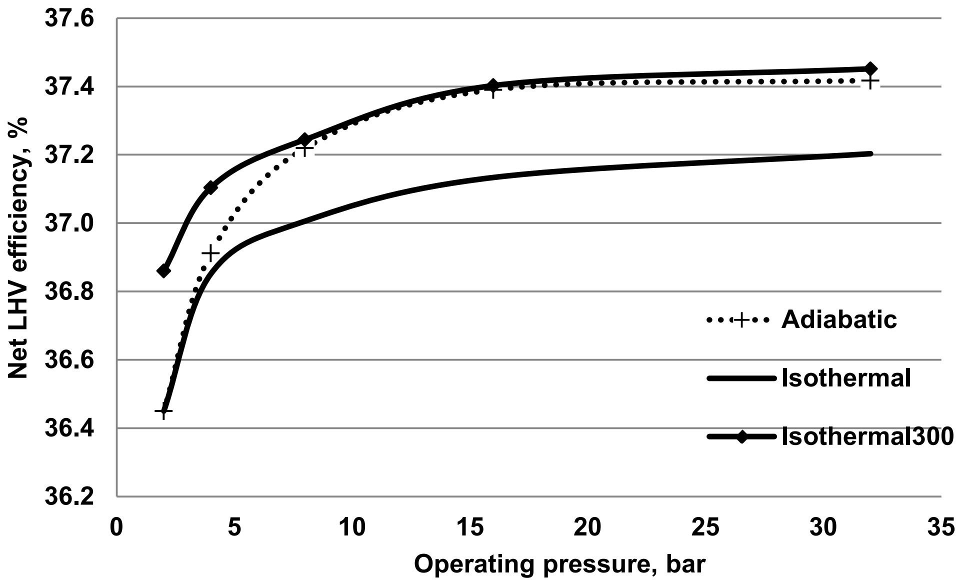


Figure 5-4: Overall effect of boiler operating pressure on net plant efficiency

Table 5-1 shows various parameters comparing the performance of the atmospheric case with the best performing pressurized case (16 bars, adiabatic). More CO_2 is captured in the pressurized case leading to lower specific energy consumption on a CO_2 avoided basis. Increasing the boiler operating pressure to 16 bars by compressing the oxygen stream from the ASU results in the elimination of air leakage as expected. This leads to a marginal increase in oxygen consumption from the ASU while reducing the overall mass flow through the CPU. The increase in oxygen demand from the ASU is due to the excess oxygen requirements and the absence of air leakage. Power necessary to compress the oxygen stream increases the auxiliary power requirement. At the same time, the CPU power requirement is reduced due to less compression work. The pressurization of the boiler also results in a slight increase in the auxiliary consumption both in the boiler island and in the steam cycle. Total auxiliary consumption in the pressurized case is therefore higher than that of the atmospheric counterpart (Figure 5-5). Despite the increase in auxiliary power consumption, the pressurization of the boiler results in a better overall performance due to enhanced heat recovery and improved oxygen preheating due to adiabatic compression. All the work spent in compressing the oxygen is converted into heat and is transferred to the steam cycle through the boiler. This is indicated by the increase in boiler heat supply to the steam cycle. More of the moisture available in the flue gas is condensed and the thermal energy is recovered for feedwater preheating in the pressurized coal combustion. The pressurized case has a net efficiency penalty of 6.0% compared to 6.8% for the atmospheric case.

The contribution of various factors to this improvement is shown in Figure 5-6. Enhanced heat recovery is responsible for an increase in 18.4 MW of gross power while the adiabatic oxygen compression increases the gross power produced by 5.5 MW. Adiabatic compression of oxygen raises the temperature of the supplied oxygen and hence substitutes preheating. This reduces the boiler thermodynamic losses and increases the gross power at the turbines. Pressurization of the boiler also causes an increased auxiliary consumption of 9.2 MW resulting in a net benefit of 14.7 MW of electricity. This corresponds to an improvement of 0.8% points in net efficiency.

5.2 Performance of the pressurized coal based power plant

Table 5-1: Performance of the pressurized (16 bar, adiabatic oxygen compression) coal based power plant compared with the atmospheric counterpart

	Atmospheric	Pressurized	Unit
Steam cycle			
Boiler heat input	1726.8	1737.7	MW_{th}
External feedwater preheating	69.6	146.92	MW_{th}
Condenser duty	919.2	983.2	MW_{th}
Shaft power	878.7	903.0	MW
Gross power output	862.1	885.9	MW_{el}
Gross efficiency	49.3	50.7	%
Boiler island			
Oxygen flow (pure oxygen)	142.8	144.6	kg/s
Oxygen production power	107.1	108.5	MW_{el}
Auxiliaries	14.5	18.3	MW_{el}
Oxygen preheating	40.4	-	MWth
Flue gas heat recovery	69.2	135.0	MW_{th}
CPU			
Compression and pumping work	67.7	25.9	MW
Total CPU power requirement	71.3	27.2	MW_{el}
CPU heat recovery	40.7	14.2	MW_{th}
Net electricity output	661.8	676.5	MW_{el}
Net LHV eff.	37.9	38.7	%
Net HHV eff.	36.3	37.1	%
Capture efficiency penalty	6.8	6.0	%
CO_2 capture performance			
CO_2 produced	169.2	169.2	kg/s
CO_2 captured	162.1	165.4	kg/s
CO_2 production intensity	0.92	0.90	kg/kWh
CO_2 capture intensity	0.88	0.88	kg/kWh
CO_2 avoided	0.74	0.76	kg/kWh
Spec. energy CO_2 avoided	0.24	0.21	kWh/kg

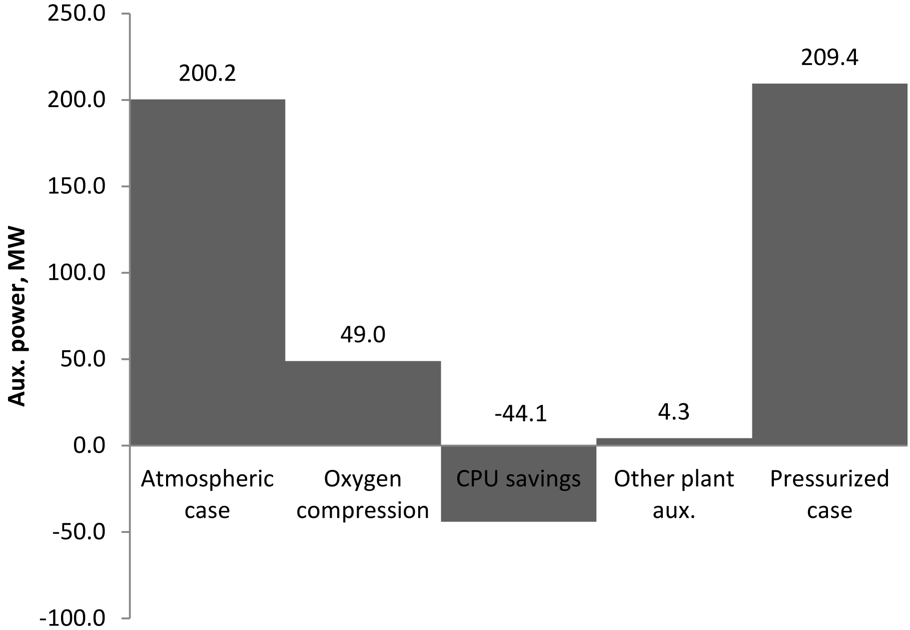


Figure 5-5: Changes in auxilliary power consumption due to pressurization of the boiler

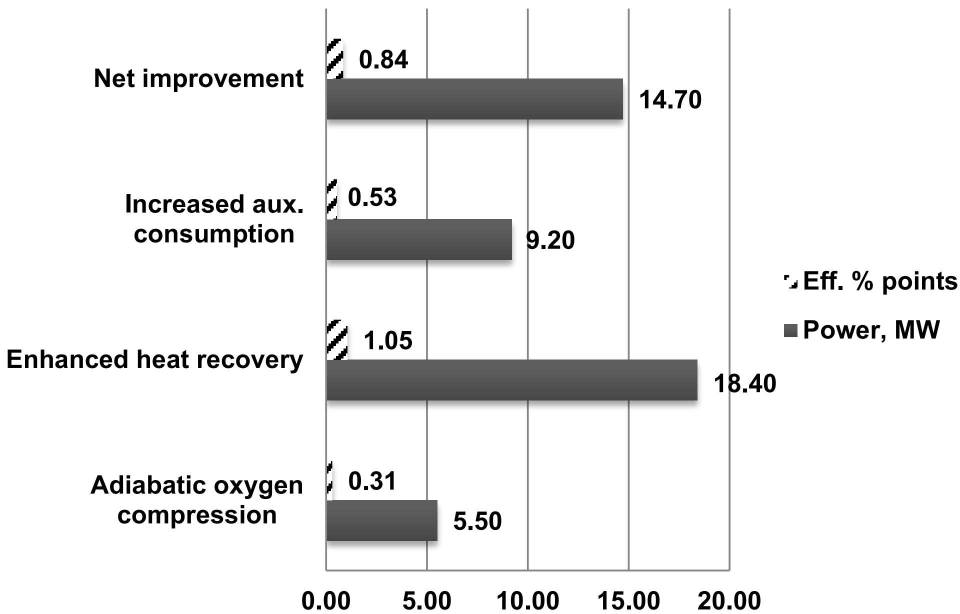
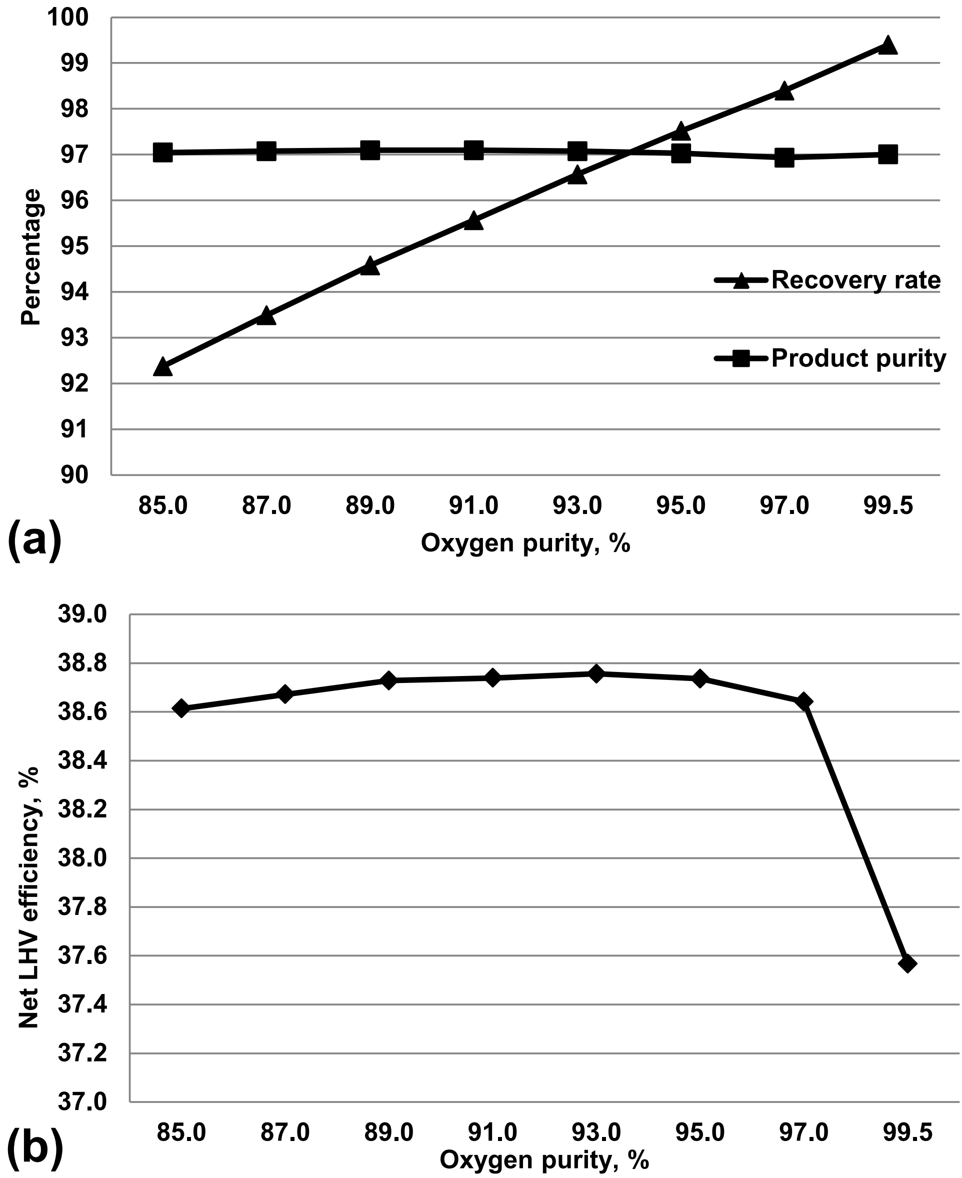


Figure 5-6: Contribution of various factors to the overall efficiency improvement

5.3 Optimal oxygen purity and CPU operating parameters



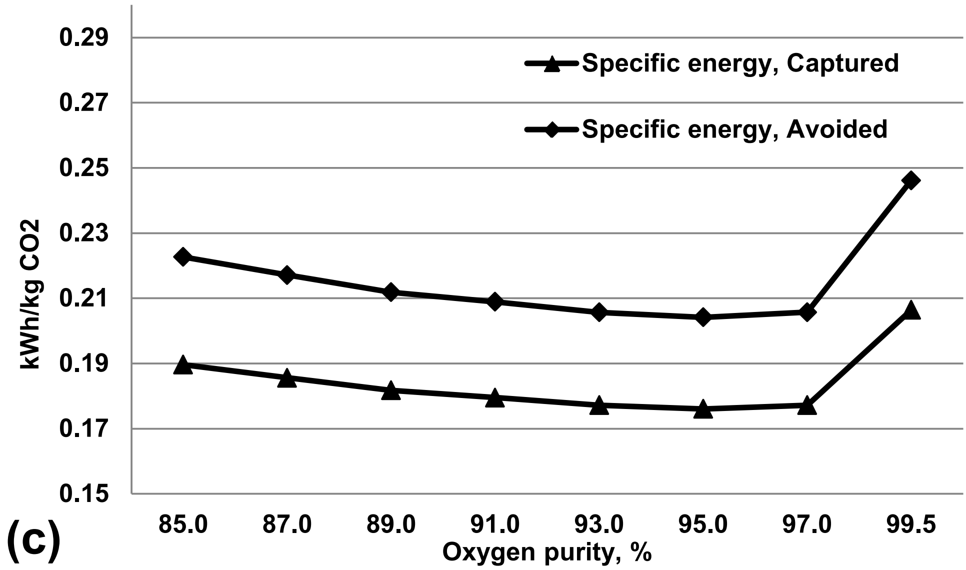
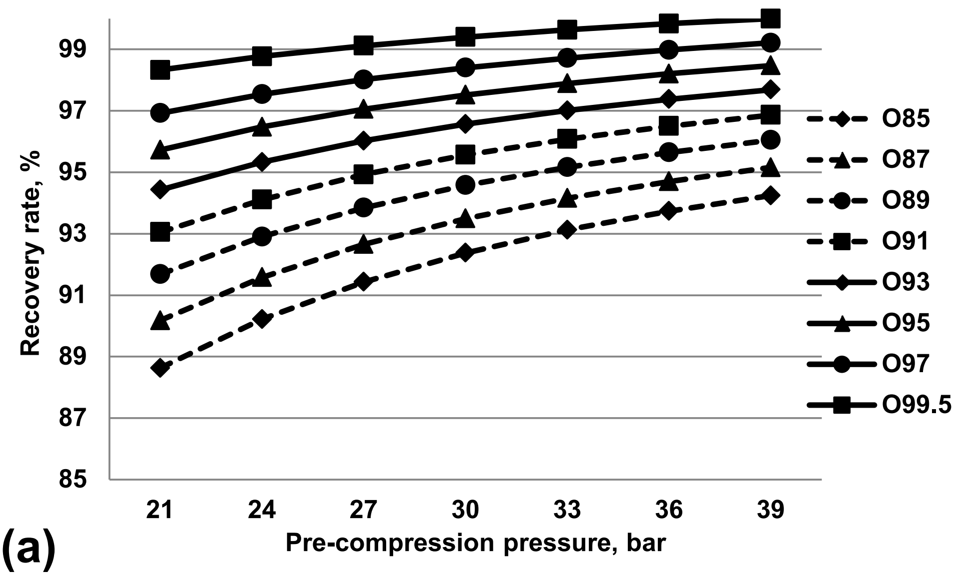


Figure 5-7: Effect of oxygen purity on the performance of the power plant.



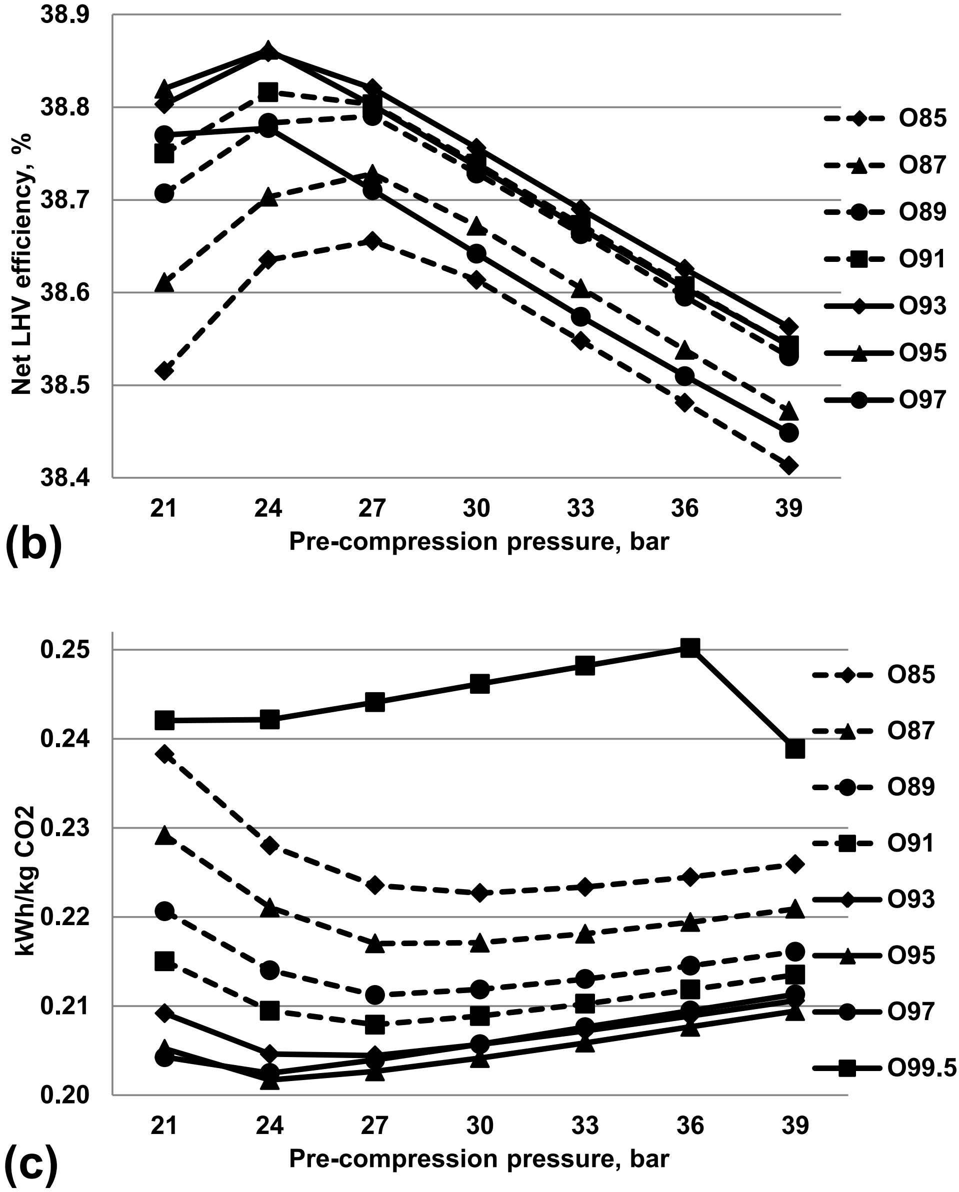
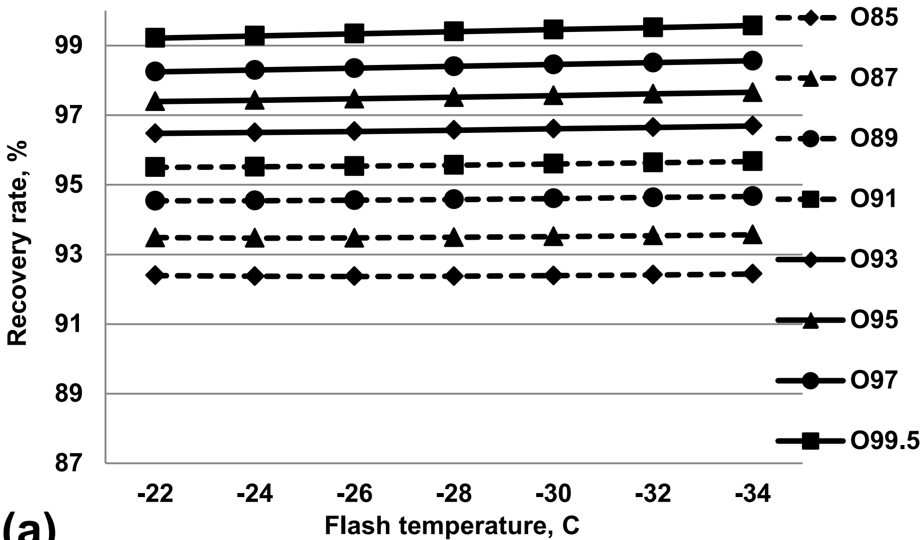


Figure 5-8: Effect of downstream compression (C2 in Figure 4-4) on the performance of the power plant

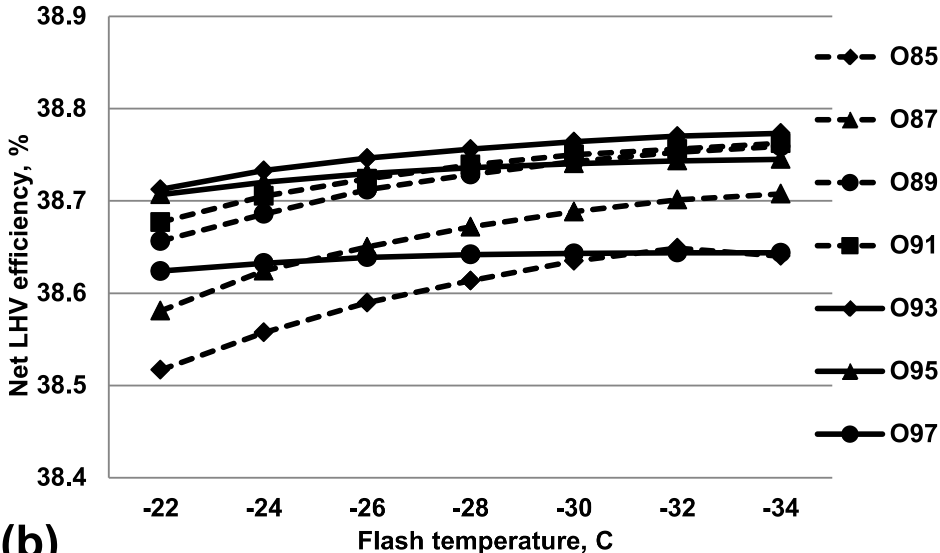
Figure 5-7 shows the effect of oxygen purity on the final CO_2 product purity, recovery rate, overall LHV efficiency of the power plant, and the specific energy consumption related to the capture of CO_2. Downstream parameters are kept the same as in the baseline case to find the impact of oxygen purity. The energy consumption in the ASU for various oxygen purity levels are provided by Fu[107]. The energy required to produce oxygen from air increases with the oxygen product purity. The energy requirement increases substantially beyond the purity level of 97 %, as argon needs to be separated from oxygen[16]. Increase in the oxygen purity results in increased CO_2 recovery but has no effect on the purity. Removal of argon from air results in a substantial drop in the overall system efficiency as shown in Figure 5-7. Optimal oxygen purity for pressurized coal combustion systems is in the vicinity of 95%.

The impurities present in coal and the air leakage bring volatile components such as nitrogen into the boiler. In a high pressure boiler, even though the air leakage is avoided, impurities are introduced via coal and the oxygen stream. Hence, there is always a need for a purification unit downstream. Two stage flash type CPU has been shown to be an economical choice that also meets the pipeline purity requirement[70]. The energy consumption of the CPU however, depends on the CPU operating parameters such as the pre-compression pressure (outlet of C2) and the temperature of stream S8 (Figure 4-4). A sensitivity study of the oxygen purity and the CPU operating parameters is therefore required to find the energy optimal combination to achieve the desired product purity while capturing at least 90 % of the CO_2 produced. The sensitivity analyses are carried out by running the simulation for various combinations of oxygen purity ranging from 85% to 99.5% and the CPU parameters. The range for temperature in stream S8 was -22°C to -34°C, while the range for pre-compression pressure was 21 to 39 bars. The baseline values stand at 95% oxygen purity, 33 bar pre-compression pressure and -30°C CPU flash temperature. The results were then compared to the baseline air fired power plant without capture to arrive at the energy required to avoid one kg of CO_2 emitted.

Figure 5-9 shows that the CPU flash temperature has no effect on the CO_2 recovery rate. It is also clear that the CPU flash temperature has very little effect on the overall plant efficiency and hence the specific power required to avoid CO_2. The pre-compression pressure however has a profound impact on the recovery rate and hence the overall performance of the system. Figure 5-8 shows the effect of the pre-compression pressure on the recovery rate, net plant efficiency and the specific power consumption. Recovery rate can be increased by increasing the pre-compression pressure, whereas the net plant efficiency peaks at a pressure of 24 bars. A combination of higher oxygen purity (95-97%) and a lower outlet pressure from C2 ensures a high recovery rate combined with high overall plant efficiency. This results in low specific energy consumption for capture as shown in Figure 5-8. At very low pre-compression pressure (21 bars for 95 % oxygen purity), there will be little or no condensation in heat exchanger m-HEX1 and hence the dual flash CPU essentially functions as a single flash CPU.



(a)



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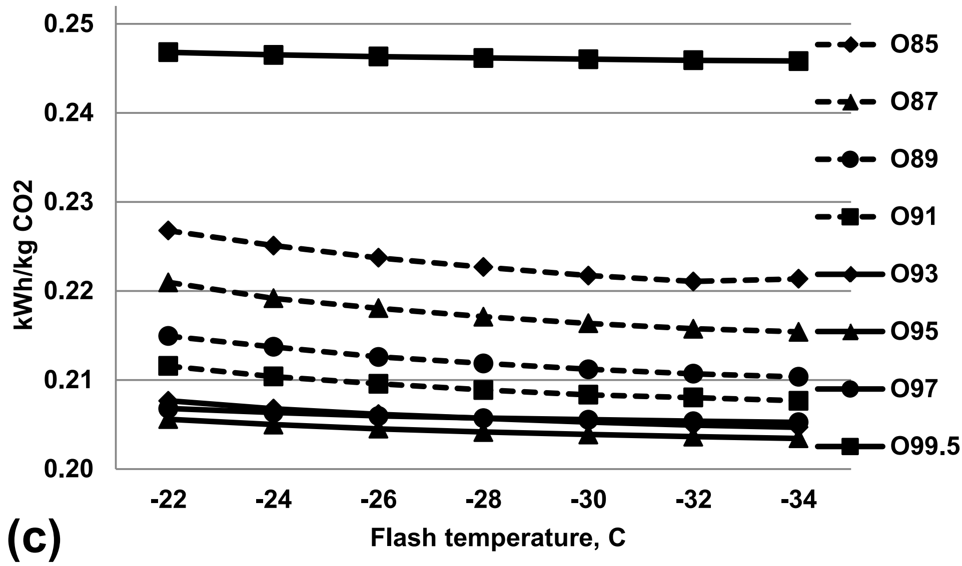

Figure 5-9: Effect of CPU flash temperature (at S8 in Figure 4-4) on the performance of the power plant

The baseline power plant without capture has a net LHV efficiency of 44.7 % and the baseline oxy-combustion power plant with capture has a net LHV efficiency of 37.9 %. The high efficiency of the capture plant is due to flue gas heat recovery and CPU heat integration. Increasing the boiler operating pressure to 16 bars recovers the flue gas latent heat and the compression heat thereby resulting in a net LHV efficiency of 38.7 %. A study of the impact of oxygen purity and CPU operating parameters provides a near optimal combination of these parameters (~97 % oxygen purity and 24 bars pre-compression pressure) resulting in a final net LHV efficiency of 38.9 %.

Design of steam cycles with heat integration using Pinch Analysis

Regenerative feedwater preheating is employed in all modern steam power plants to increase the overall efficiency[106, 108]. Steam is extracted at various pressures from the steam turbines and used to preheat the feedwater before it enters the boiler. While it is better to have more steam extractions for better efficiency, the number is generally limited by the economics of the power plant. Pinch analysis can be used to adjust the mass flows of the steam extractions and increase the efficiency for the same number of extractions[97, 100]. Pinch Analysis involves lumping of the hot and cold streams together in appropriate temperature intervals into hot and cold composite curve[85, 109]. The composite curves are then brought closer together while separated by a chosen minimum temperature difference. This enables heat from the steam extractions to be better utilized and hence ultimately results in improved power plant efficiency.

While the Pinch method of steam cycle design results in better performance compared to the traditional steam cycle design, it also results in a cycle that is much more complicated and requires large investment in terms of number of heat exchangers and additional heat transfer area. The economic optimization of the steam cycle with respect to return on investment is out of scope for this work. On the other hand, an attempt has been made to design a steam cycle that is a compromise between the traditional design and the pinch based approach. This results in a power plant that has better efficiency than the traditional design and fewer heat exchangers compared to the pinch based design. This is achieved with the help of exergy analysis. Exergy analysis helps pinpoint the zones with maximum efficiency gains and hence guides in the investment of additional heat exchange units[87, 100]. This ultimately results in a balance between added network complexity and thermal efficiency gains.

6.1 Methodology

The base case for this chapter is derived from case 4 of Chapter 4 with a few minor modifications. The CPU compressors in the base case use single stage adiabatic compression instead of a multi-stage isothermal compression scheme.

As a result, the power consumed by the CPU and the total auxiliary consumption of the base case is higher. This results in slightly lower net plant efficiency. While it is better to use multistage compression with intercoolers from the efficiency standpoint, single stage adiabatic compression results in a much simpler system. A simpler system is easier to integrate and thus helpful in further evaluations done in this chapter. The steam cycle in the base case is designed using a set of rules that in the remaining of the chapter will be referred to as the ‘established design/method’. The established method of steam cycle design will be explained in detail in the following sub sections. The base case has heat integration between the boiler flue gas, the CPU intercoolers and the steam cycle. Pinch analysis is then applied to the base case steam cycle to modify the feedwater preheating section. Other units of the power plant such as the boiler and the CPU remain unaltered. This method, which will be henceforth referred to as the ‘Pinch design/method’, is also explained in detail. The pinch method of steam cycle design results in a system that has better performance compared to that of the baseline case as expected. The performance boost is accompanied by substantial increase in the steam cycle complexity by means of number of additional heat exchange units required. It is also known that the total capital expenditure is tied to the total number of heat exchangers and hence it is essential to keep the number down.

A new steam cycle is designed using the pinch method but with fewer number of steam extractions compared to the baseline case. This helps reducing the network complexity and hence the cost. As expected, the efficiency improvement is also reduced. A heat exchanger network is developed for the feedwater preheating system along with the heat integration for the new pinch case. This heat exchanger network offers insights into the physical considerations of the pinch design method. The network also provides an idea of the complexity involved and the improvement potential. This leads to the application of Exergy analysis in order to reduce the network complexity. Exergy analysis is applied to both the baseline case and the original pinch case and offers insights into the contribution of various heat exchangers to the overall performance improvement. By investing in additional heat exchangers only in the zones of maximum potential, a balance can be achieved between network complexity and performance improvement. The evolution of such a steam cycle which is a hybrid design between the established and the pinch method of design will be explained in detail in the following sections.

6.1.1 Base case system design using the established method

The base case system design starts with the design of the oxy-combustion boiler. Aspen Plus was used to model the boiler unit. The boiler consists of a combustion chamber modelled using a combination of yield and Gibbs reactors. The heat transfer sections of the boiler are modelled using standard coolers. A fan is required to overcome the pressure drop along the gas flow path. Figure 4-4 shows the schematic of the boiler island along with the CPU. With the boiler island and the CPU design fixed, the steam cycle is designed for the heat output of the boiler. Modelling the steam cycle at the end enables the integration of the flue gas and CPU surplus heat into the feedwater heating network. Figure 4-1 shows the schematic of the steam cycle used in the base case. The steam cycle has high, intermediate and low pressure turbine sections mechanically coupled together and driving the same generator unit. The main condenser is supplied with cooling water from the cooling towers that are not shown in the figure. There are two pumps in operation, one after the condenser and one after the deaerator providing the necessary boost in water pressure. The deaerator which also serves as one of the feedwater preheating units (contact type) is modelled as a tank in Aspen Plus. The feedwater preheating system consists of two sections, low and high pressure, separated by the deaerator.

In this study, it is assumed that eight steam extractions will be used in the baseline case. The steam extractions are represented by E1 to E8 in Figure 4-2. The heaters are assumed to be counter-current shell and tube type exchangers with internal zones for de-superheating, condensation and sub-cooling. Each steam extraction, after delivering its energy in a heat exchanger, is throttled to the next lower extraction pressure and mixed with the sub-cooling section of the lower pressure heater. The sub-cooled water is mixed with the main feedwater in the deaerator and in the main condenser and hence results in a difference in the mass flow of feedwater before and after the deaerator.

Figure 6-1 shows the heat transfer inside the individual heat exchangers. TTD stands for Terminal Temperature Difference and is the difference between the feedwater exit temperature and the saturation temperature of the steam extraction. DCA stands for Drain Cooler Approach temperature and represents the temperature difference at the feedwater preheater inlet. TTD along with the pipe pressure loss determines the extraction pressure and DCA determines the mass flow of the steam extraction. In Aspen Plus, this is implemented using multiple design specifications solving for the steam extraction mass flows.

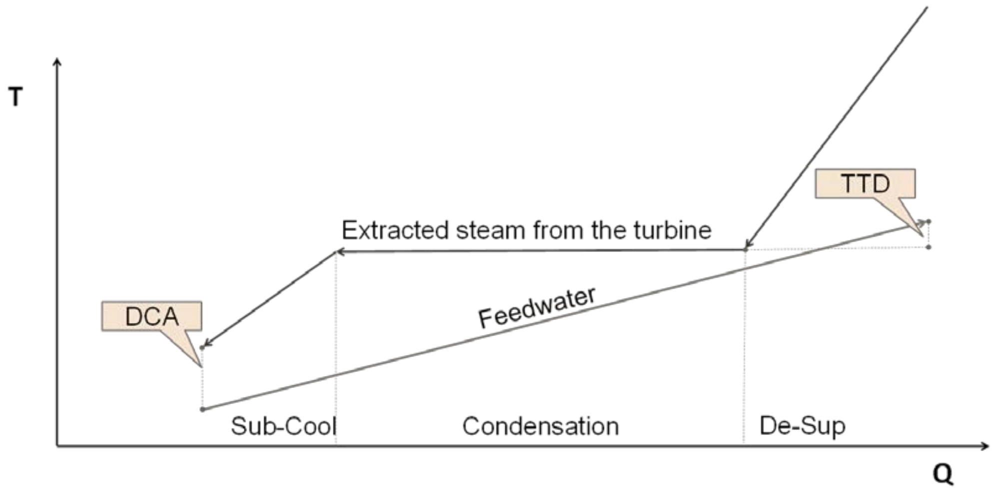

Figure 6-1: Heat transfer zones inside a feedwater preheater

The following steps are involved in the established method of feedwater preheating system design:

- Determination of final feedwater temperature
- Determination of total number of feedwater preheaters
- Type and arrangement of the heaters
- Allocation of the heating load to individual heaters (equal enthalpy/temperature rise)
- Calculation of extraction pressures based on TTD and the pipe pressure loss
- Calculation of extraction mass flows based on DCA

Heat integration is the last step in the modelling process. Feedwater can be extracted from the outlet of the pumps (W1 and W7 in Figure 4-1) and heated in parallel with the feedwater heaters using surplus heat from the CPU or the boiler flue gas. The heated feedwater can then be mixed back into the main feedwater stream. A similar approach can be found in the literature[98]. In the baseline case, one feedwater extraction is made from the boiler feed pump following the deaerator for each of the process streams. The extracted water is heated to the exit temperatures of the various HP feedwater heaters as allowed by the process streams. The mass flows are limited by the assumed minimum temperature differences. It is assumed that a minimum temperature difference of 10°C for CPU gases and 20°C for the boiler flue gas would be sufficient. A similar method is also used in the low pressure side of the feedwater preheating network. Water extractions are made for each of the process streams and the heated water is mixed either to the inlet of a feedwater heater or to the deaerator based on the temperature level of the process streams.

6.1.2 Pinch Analysis and the pinch method of steam cycle design

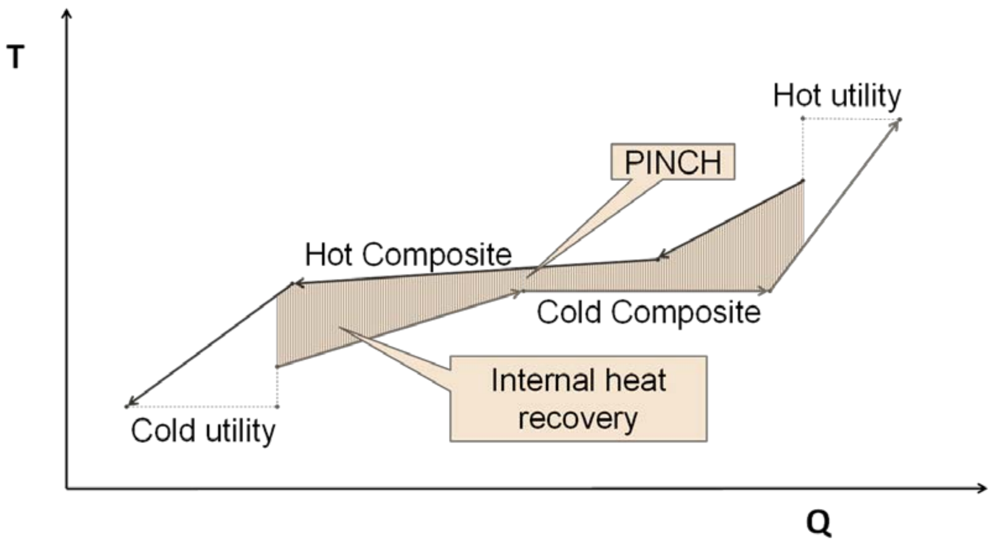

Figure 6-2: Pinch analysis and heat recovery

The core of the pinch analysis method relies on energy targeting based on composite curves and the heat recovery pinch. All the hot streams that need to be cooled are combined in appropriate temperature intervals to give a hot composite curve. This composite curve is the equivalent stream that represents all the individual hot streams in temperature and enthalpy. A similar method is applied to cold streams to obtain the cold composite curve. The composite curves are then graphically moved closer to each other until they are vertically separated by the chosen minimum temperature difference[85]. At this point, the overlapping sections recover heat between the streams and the non-overlapping sections require external utilities to satisfy the heating and/or cooling requirements. This method maximizes the internal heat recovery thereby minimizing the external utility consumption. The overall cost minimization depends on the trade-off between the investment required in terms of heat exchanger area and the cost of utilities. This trade-off is represented by the chosen minimum temperature difference that also fixes the heat recovery pinch.

The techniques of pinch analysis are applied to the feedwater heating network of the steam cycle. In the feedwater heating network, steam extractions act as both utilities and hot streams and are only used to heat the feedwater. Because of that nature of the steam cycle, the hot and cold streams are always in energy balance and no external utilities are required. Hence, when pinch analysis is applied to the steam cycle, the objective is to reduce the overall steam consumption and increase the power generation. In addition, the feedwater heating network has multiple pinches caused by the onset of condensation of each steam extraction. The application of pinch analysis would provide the new steam extraction mass flows, and a new heat exchanger network will be required in order to realize the energy targets. This is in contrast to the established design method where the heat exchanger network arrangement is fixed which in turn dictates the steam extraction mass flows.

The Aspen HYSYS simulation tool was used to perform the energy targeting. Simulation parameters such as final feedwater temperature, steam extraction pressures and minimum allowable temperature differences between various stream combinations were all kept the same as that of the baseline case. Only the pressure of extraction E8 was altered in order to maintain the final feedwater temperature. All the stream data such as steam extraction pressures and temperatures, flue gas and CPU gas parameters are submitted to HYSYS. A multi-stream (LNG) heat exchange unit available in HYSYS combined with the built-in optimizer module was used to adjust the mass flows and bring the composite curves closer. It is to be noted that a global minimum temperature difference of 3°C has been used for the optimization. The objective for optimization was to minimize the overall LMTD of the LNG exchanger while satisfying the constraint on minimum approach temperature. As the process streams have a higher minimum pinch requirement, their temperatures were shifted appropriately so as to achieve the global 3°C. For instance, the flue gas has a ΔT of 20°C with the feedwater in the baseline case. Hence, the temperature of the flue gas was shifted 17°C below the actual value. The optimization was applied individually to the LP and HP side of the feedwater preheating network. Care must be taken while constructing the heat exchanger network to ensure that the allowable minimum temperature differences for various stream combinations are not violated.

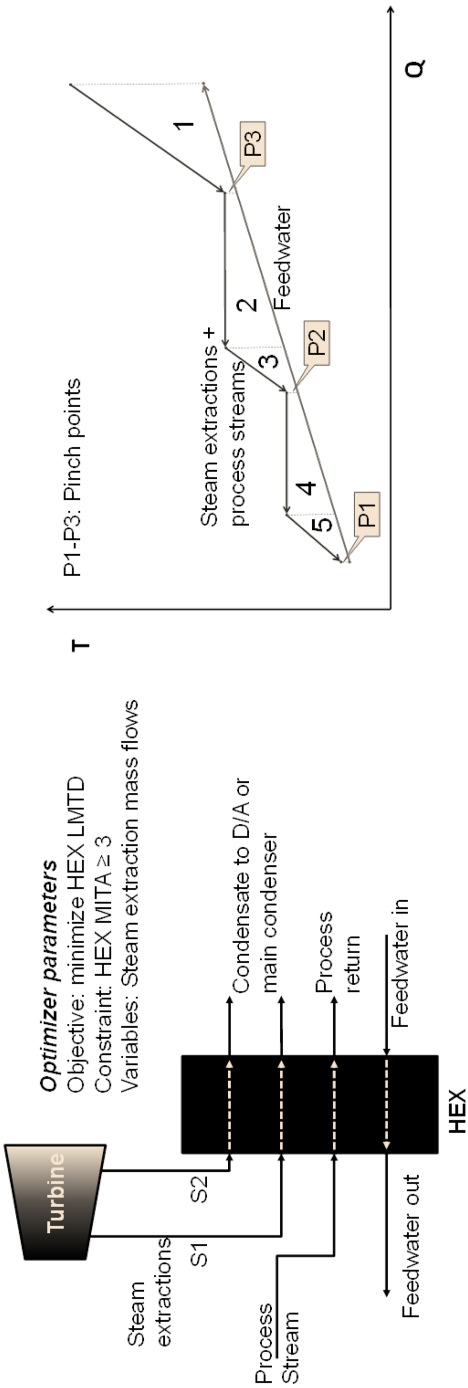

Figure 6-3: Closing the pinches caused by steam extractions

The Pinch Design Method[79] for heat exchanger networks can be summarized using the following heuristics:

- Start at the Pinch, where the network is most constrained and move away
- Above pinch, $CP_H \leq CP_C$ and below pinch, $CP_H \geq CP_C$ for individual matches
- It is essential to match every cold stream below pinch with a hot stream and every hot stream above pinch with a cold stream to avoid cross pinch heat transfer
- Once a match is found, make the heat exchanger as large as possible to minimize the total number of units

Stream splitting may sometimes be required to satisfy the above requirements for network design.

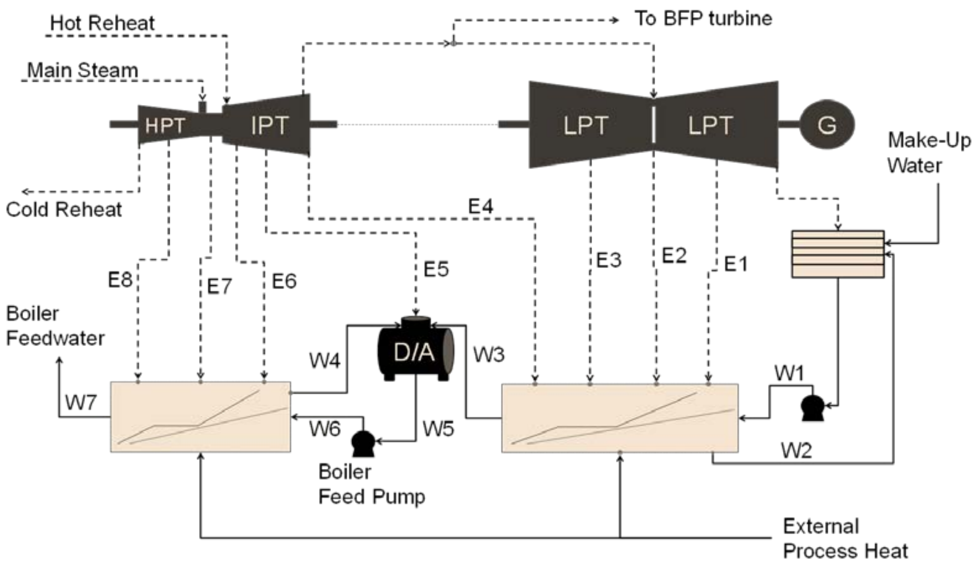

Figure 6-4: Steam cycle designed by using the pinch method

Figure 6-3 shows the composite curves of the feedwater heating network with two steam extractions and a process stream. Together, they heat a single feedwater stream. The pinches are caused by the onset of condensation of the two steam extractions (P2 & P3) and also at the inlet of the feedwater due to sub-cooling of the extracted steam. Generally, a major portion of the heating load is shared by the latent heat of the extracted steam (P1). The heat transfer can be divided into 5 zones. In zone 1, the extracted steams are de-superheated while in zone 5, the steam extractions are sub-cooled. The process stream supplies heat in all the zones except where condensation takes place (2 & 4) based on the temperature levels. This is based on the assumption that process streams are not cooled below their dew point. This insight into the composite curves of the feedwater heating network helps the design process along with the heuristics provided by the pinch design method. For instance, in zone 1, the feedwater has to be split into three streams in order to bring both the steam extraction and the process stream to the pinch point P3. In zone 2, no stream splitting is required as there is only one hot stream that can be matched with the feedwater. This approach also provides the count of the number of heat exchangers required for the network. For this example, a total of 11 units are required. This compares to just three units required with the established method. After construction of the network, simplifications can be made to combine smaller units with larger units without violating the minimum allowable temperature differences. Figure 6-5 shows an arrangement of heaters that can be used to realize the heat transfer represented by the composite curves in Figure 6-3.

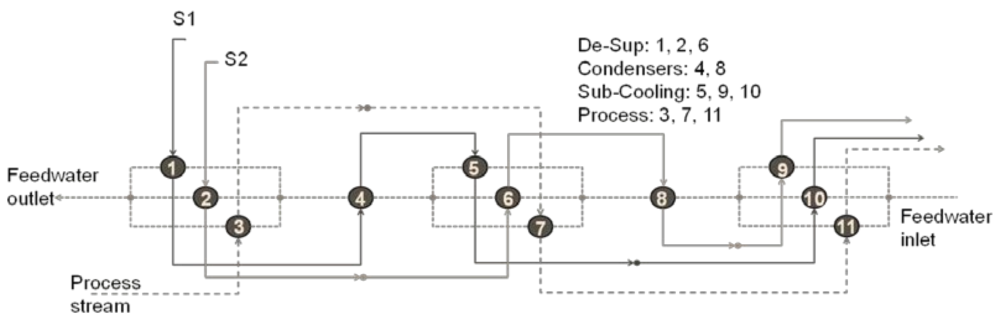

Figure 6-5: Heat exchanger network by pinch design method

6.1.3 Exergy Analysis of feedwater preheating systems

The pinch method of targeting and design results in a feedwater preheating network that is significantly more complicated than the network designed using the established method. The pinch method achieves performance improvements by utilizing the steam extractions better than the established method by closing the temperature gap between the hot and cold streams to the allowable minimum values. At this point, exergy analysis could throw more light at the thermodynamic aspects of the pinch based design.

Table 6-1: Environmental conditions for exergy calculations

Parameter	Value	Units
Temperature (T_0)	288.15	K
Pressure (p_0)	101.325	kPa
Relative humidity	0.6	%
Air composition	Wet/Dry	vol.%
Nitrogen	77.3/78.09	
Oxygen	20.74/20.95	
Argon	0.92/0.93	
Carbon dioxide	0.03/0.03	
Water vapour	1.01/0	
Gas constant	288.16/287.06	J/kg K
Molecular weight	28.854/28.964	-

Exergy is defined as the quality of energy. Unlike energy, exergy is not conserved and can be destroyed due to several mechanisms. All practical engineering systems destroy exergy to a larger or lesser degree during their normal operation under design conditions. Exergy can be destroyed in irreversible processes such as mixing of two streams of different chemical composition, throttling of streams to lower pressure levels using valves or by transferring heat at a finite temperature difference[88]. Although it is impossible to operate practical systems reversibly, exergy loss can be minimized. For instance, exergy loss due to heat transfer can be minimized by investing in additional heat exchange area and using smaller driving forces for the same amount of heat transfer[19]. In the case of the feedwater preheating network, the main source of irreversibility is the heat transfer. Exergy analysis locates and quantifies the exergy loss in the feedwater preheating network. By comparing the exergy flows and losses of the established design with that of the pinch design, zones of maximum improvement can be identified. This information can be used to critically select heat exchangers thereby resulting in a much simpler network. Environmental conditions must be fixed in order to calculate the exergy of a particular stream. The environmental conditions assumed in this study are shown in Table 6-1.

The total exergy value associated with a stream is given by the sum of its exergy components namely physical, chemical and mixing exergy values as given by Equation (6-1).

$$\dot{E}_{tot} = \dot{E}_{ph} + \dot{E}_{ch} + \dot{E}_{mix} \tag{6-1}$$

The physical (thermo-mechanical) exergy is the maximum amount of work that can be derived by reversibly changing the unmixed components of a stream from its process state to the reference conditions, as shown in Equation (6-2).

$$\dot{E}_{ph} = \left[\sum_i (\dot{F}_i h_i) - \sum_i (\dot{F}_{0,i} h_{0,i})\right] - T_0 \left[\sum_i (\dot{F}_i s_i) - \sum_i (\dot{F}_{0,i} s_{0,i})\right] \quad (6\text{-}2)$$

The total chemical exergy flow of a stream is given by the summation of standard chemical exergy values of individual components making up the stream as shown by Equation (6-3).

$$\dot{E}_{ch} = \sum_i (\dot{F}_i e^0_{ch,i}) \quad (6\text{-}3)$$

Finally, the mixing exergy of a stream can be defined as the work required to separate a mixture into its components at the process conditions and is expressed by Equation (6-4).

$$\dot{E}_{mix} = \left[\dot{F}h - \sum_i (\dot{F}_i h_i)\right] - T_0 \left[\dot{F}s - \sum_i (\dot{F}_i s_i)\right] \quad (6\text{-}4)$$

Term	Description
$\dot{F}_i, \dot{F}$	Molar flow of component i and the mixture (mole/s)
$h_i, h_{0,i}$	Molar enthalpy of component i in process and reference conditions (kJ/mole)
$s_i, s_{0,i}$	Molar entropy of component i in process and reference conditions (kJ/mole K)
h, s	Molar enthalpy and entropy of the mixture under process conditions
$e^0_{ch,i}$	Standard chemical exergy for component i, kJ/mole

Several control volumes are established within the steam cycle such as the boiler system, steam turbines, condenser, feedwater preheating system and the rest of the plant. The boiler is the main source of exergy input into the steam cycle in the form of heat. Exergy also enters the steam cycle via process streams integrated into the feedwater preheating system. Work output from the turbines form the main exergy output of the steam cycle. Exergy is also lost to the surroundings through the condensers. Exergy is destroyed due to irreversibility in steam turbines, pipe pressure loss and in the feedwater preheaters. By comparing the exergy loss profile of the established and the pinch based steam cycles, zones of maximum scope for improvement can be identified. The pinch method of steam cycle design mainly affects the feedwater heating system and hence the improvements are expected to be concentrated in the feedwater heating train.

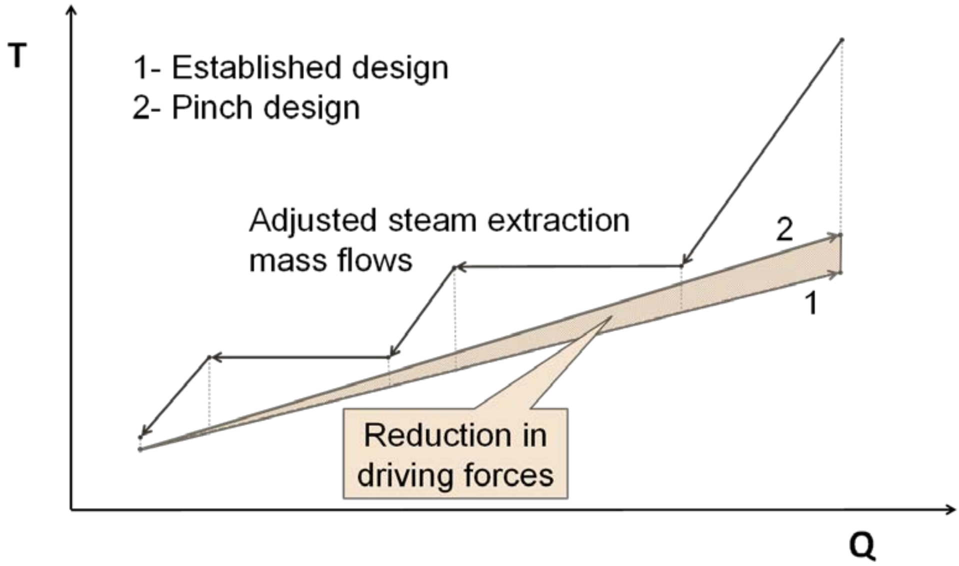

Figure 6-6: Closing the pinches reduces the driving force between the hot and cold streams

It is assumed that the pressure loss inside the feedwater heaters is negligible and the irreversibility is caused only by heat transfer over a finite temperature difference. The change in exergy of any stream under those conditions would only be due to the thermal components of exergy as given by Equation (6-5).

$$\dot{E}_q = \dot{Q}\left[1 - \frac{T_0}{T_{lm}}\right] \tag{6-5}$$

Where,

$$T_{lm} = \frac{T_{in} - T_{out}}{ln\left(\frac{T_{in}}{T_{out}}\right)} \tag{6-6}$$

$\dot{E}_q$ is the exergy flow associated with the heat transferred $\dot{Q}$, and T_{lm} defined by Equation (6-6) gives the logarithmic mean temperature of the heat transfer. When applied to the hot composite curve in any interval, Equation (6-5) provides the exergy transferred by all the hot streams in that particular interval. Similarly, when applied to the cold composite curve, the equation provides the exergy received by the feedwater. The difference between the exergy transferred and the exergy received gives the exergy lost in the heat transfer process.

6.1.4 Evolution of the hybrid design method

The established method of steam cycle design produces a network that is simple and robust. The pinch method produces a feedwater preheating network that is more efficient but is significantly more complicated. The established method achieves its simplicity by desuperheating, condensing and then subcooling the steam extractions inside the same heat exchanger which results in the least number of units. The pinch based design uses individual units and stream splits to make feedwater heating closely follow the cooling of the heat sources. One way to combine the benefits of both systems is to use additional heat exchangers in places where it could provide the maximum efficiency improvement. In other parts of the network, the streams can be throttled and combined just like the established method. This can be referred to as the compromise/hybrid design which has a higher efficiency than the established method for the same design parameters while having fewer number of units compared to the complete pinch based design. The total number of units can be further reduced by having the process exchangers in parallel with the main feedwater preheating network. An example of such a system is shown in Figure 6-7.

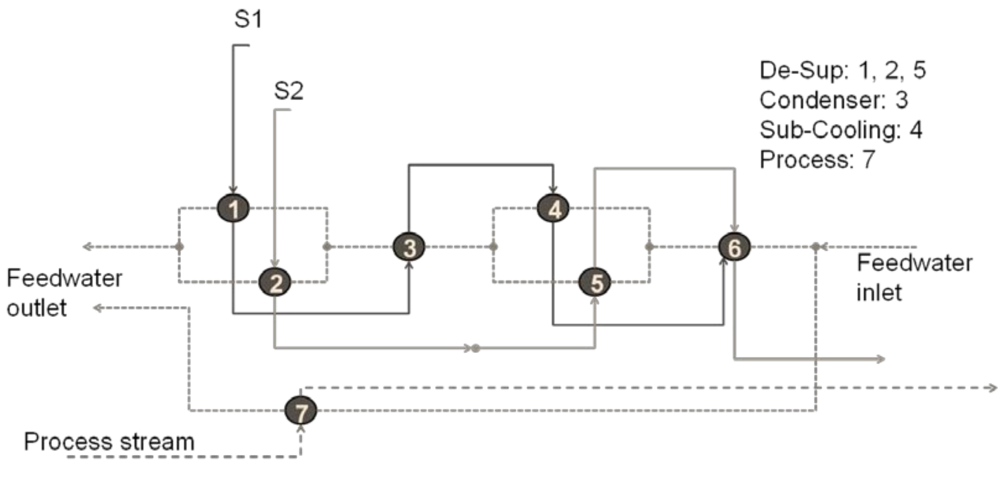

Figure 6-7: Hybrid network representation

The de-superheating sections have stream splits utilizing dedicated units just like the pinch based design. As the network proceeds towards the lower temperature part of the system, steam extractions are throttled to the next lower pressure and combined in one exchanger with multiple internal heat transfer zones. In essence, the design principle moves from pinch based at the high temperature side to established arrangements at the lower temperature side. This is based on the assumption that the majority of the savings in exergy occurs in the high temperature part of the network.

6.2 Results and discussion

6.2.1 Performance results

Table 6-2 presents various performance parameters of the simulation cases considered in the study. The baseline case is designed using the established method. Pinch case 1 is a modified version of the baseline case where the steam cycle feedwater heating network is designed using the pinch method. Pinch case 2 is derived from Pinch case 1 by removing two of the steam extractions to arrive at a simpler feedwater preheating system. The hybrid case is the result of the insights gained from exergy analysis of the baseline and the pinch cases. All the cases have the same level of fuel input and total auxiliary power consumption. The pinch cases recover slightly more heat from the boiler flue gas. The improvement in the output is due to increased power production by the steam turbines.

Table 6-2: Performance summary of the simulation cases

Parameter	Baseline case	Pinch case 1	Pinch case 2	Hybrid case	Unit
Fuel energy input			1610.9		MW
Boiler heat input			1553.0		
Process heat recovered	136.5	154.0	154.0	149.0	
Condenser duty	879.2	888.5	895.1	887.8	
Steam turbine shaft power	811.9	818.6	813.0	815.6	
Gross electric power	796.5	803.1	797.6	800.2	
Steam cycle aux.			7.0		
CPU power req.			78.1		
ASU power req.			98.2		
Boiler island aux.			15.5		
Total aux.			219.5		
Net electric power	597.6	604.3	598.8	601.4	
Net plant eff. LHV/HHV	37.1/35.6	37.5/36.0	37.2/35.7	37.3/35.8	%

Figure 6-8 shows the hot and cold composite curves along with the temperature difference. The figures represent the low pressure side of the feedwater preheating network for the baseline case and that of Pinch case 1. As seen in the figure, the temperature difference between the hot and cold composite curves gradually increases towards the higher temperature side of the network. The overall gap between the curves is closer in the pinch design.

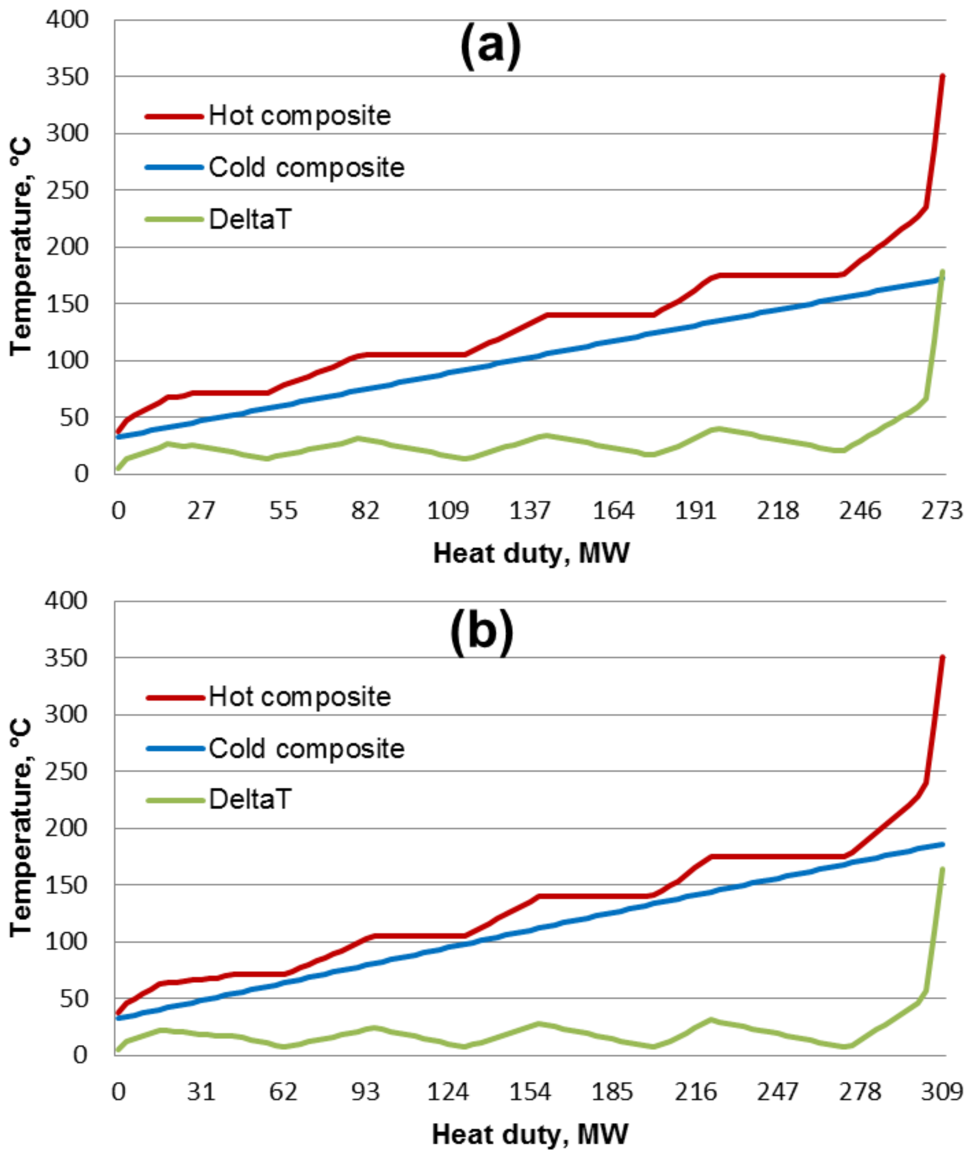

Figure 6-8: Composite curves of the LP Feedwater preheating system, (a) established design and (b) pinch design

6.2.2 Exergy results

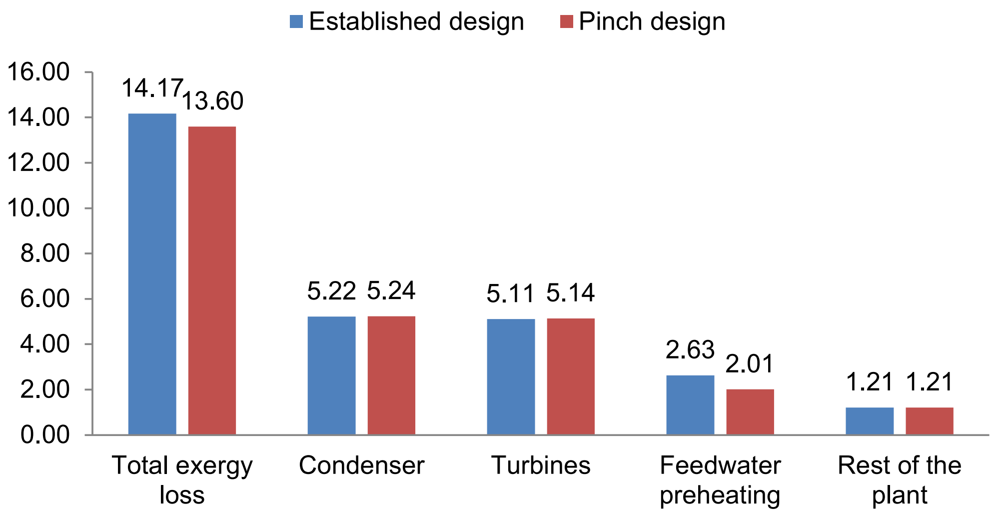

Figure 6-9: Exergy loss in the steam cycle

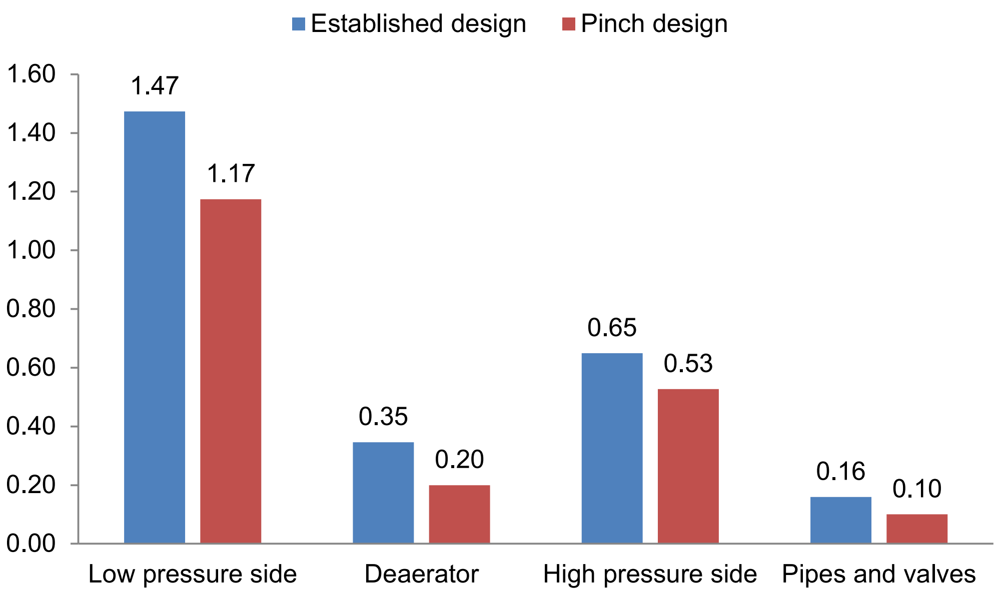

Figure 6-10: Exergy loss in the feedwater preheating system

Figure 6-9 shows the exergy losses in various control volumes of the steam cycle as a percentage of the total exergy input. The total exergy loss in the steam cycle is reduced from 14.2% to 13.6% of the exergy input. The exergy losses in the condenser and the turbines each are just above 5% of the total exergy input and they represent the major sources of exergy destruction. As the condenser design is limited by the ambient conditions and the turbine efficiencies are assumed fixed, their contributions to the exergy losses do not deviate much between the established and the pinch design. Basically, all the reduction in exergy loss is due to improvements in the feedwater preheating section of the steam cycle. As a result, the total work generated by the steam cycle rises from 85.8% to 86.4% of the exergy input.

Figure 6-10 reveals that the reduction in exergy losses is biased towards the low pressure side of the feedwater preheating system. The deaerator and the high pressure side contribute equally to the improvements. The deaerator is fed with steam extraction at a very high temperature due to reheat. The degree of superheat available in the steam extractions are better utilized in the pinch method of design. At the low pressure side, better utilization of the steam extractions results in a higher feedwater temperature going into the deaerator. At the high pressure side, the final feedwater temperature is kept the same by reducing the pressure of one of the steam extractions.

At the high pressure side of the feedwater preheating network, the final feedwater temperature was maintained between various cases. Most of the savings in exergy comes from the higher temperature side of the feedwater heating network both at the HP and LP side (Figures 6-13a and 6-13b). This suggests that the superheat available in steam extractions is not properly utilized in the established design method. In addition, the deaerator is also responsible for some savings in exergy. This leads to the development of the hybrid network design. It is essential to make better use of the superheat available in the steam extractions. This can be achieved by splitting the feedwater stream and installing dedicated desuperheaters. The total number of units can be reduced by employing the established design principles at the lower temperature side of the network where the improvement brought by the pinch design is not significant.

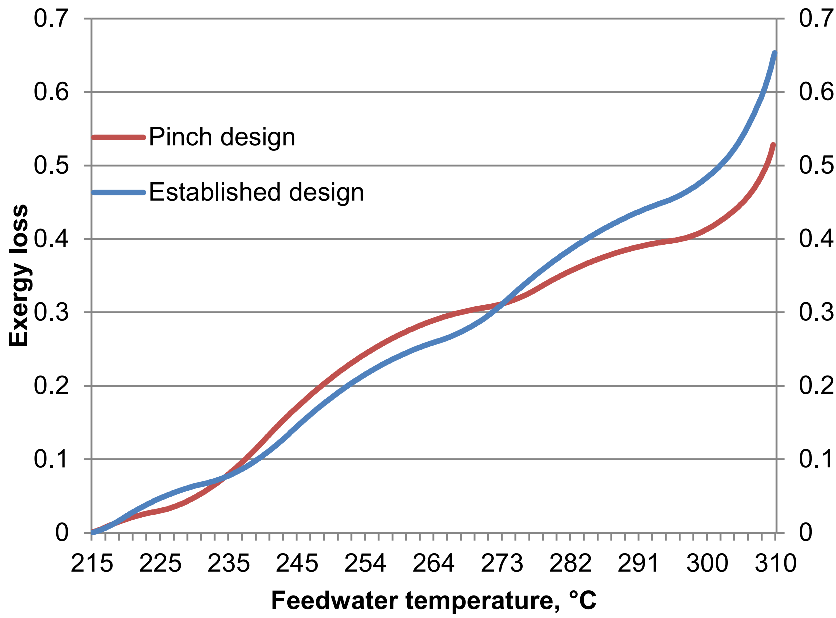

Figure 6-11a: Accumulated exergy loss profile of the HP feedwater preheating network

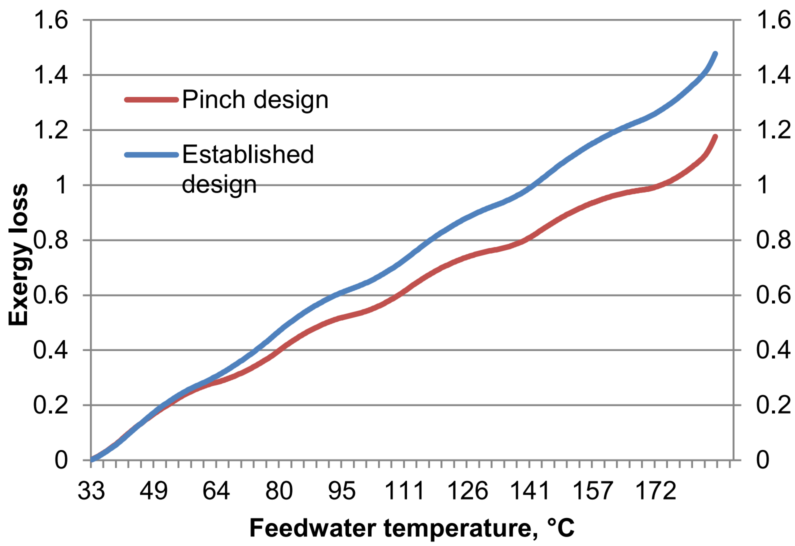

Figure 6-11b: Accumulated exergy loss profile of the LP feedwater preheating network

Figures 6-11a and 6-11b show the exergy loss profile of the feedwater preheating network. The accumulation of exergy losses as a percentage of exergy input is plotted against the feedwater temperature. The overall exergy losses are lower in the pinch design compared to that of the established design. This results in better efficiency. As the feedwater is heated from 33°C to the target temperature at the low pressure side of the feedwater preheating network, the exergy loss gradually increases as steam extractions with higher degree of superheat are used. In the pinch design, the degree of superheat available in the steam extractions is better utilized to achieve a higher target temperature of 184°C compared to 172°C for the established design.

6.2.3 Network results

Figures 6-14 (HP section) and 6-15 (LP section) show the feedwater preheating networks for the steam cycle designed using the pinch method (Pinch case 2). The steam cycle presented has 5 steam extractions and 4 process streams. The low and the high pressure side of the network are separated by a deaerator which is also fed by a steam extraction (not shown in the figure). Each steam extraction has dedicated desuperheaters, condensers and sub-coolers. At the high pressure side, the steam extractions (S41 and S51) are combined in the last sub-cooler (Unit 9) for simplicity. A similar simplification has been done at the low pressure side (Unit 23). Steam extraction S11 has no superheat available at the extracted pressure and hence a dedicated desuperheater is not assigned. The flue gas stream (G41) is split into a non-condensing (Unit 20) and a condensing unit (Unit 25). The condensing unit needs special materials to deal with the acid formation. It is to be noted that the steam cycle with two extractions removed is still significantly more complex than the established design while achieving only marginal efficiency improvements. The system has 25 heat exchange units and a deaerator. The steam cycle designed using the established method has a total of 16 units and a deaerator.

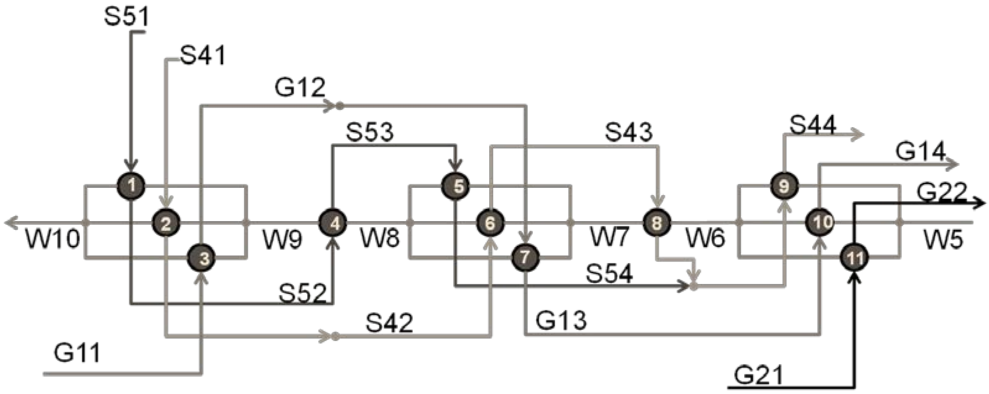

Figure 6-12: High Pressure feedwater preheating system for Pinch case 2

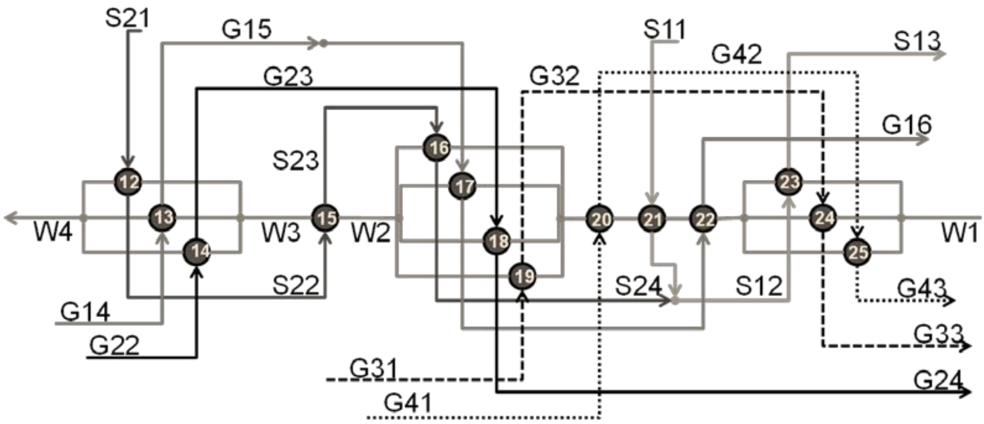

Figure 6-13: Low Pressure feedwater preheating system for Pinch case 2

Table 6-3 shows the temperature, pressure and mass flows of various streams in Figures 6-12 and 6-13. Figure 6-14 shows the arrangement of heat exchangers of the final hybrid design. DS1 to DS5 in Figure 6-14 are dedicated desuperheaters making use of the superheat available in the steam extractions. H1 to H7 are heat exchangers with internal zones to utilize the rest of the heat available in the steam extractions. Feedwater is extracted or added to the network at several locations for process heat recovery. P1 to P7 represent process heat exchangers recovering heat from the flue gas and the CPU gas streams. Table 6-4 provides the stream details for reference.

Table 6-3: Stream table for the pinch case (Figures 12 and 13)

Stream ID	Description	Temperature, °C	Pressure, bar	Mass flow, kg/s
W1	LP feedwater	32.4	22.0	452.3
W2	LP feedwater	96.2	22.0	452.3
W3	LP feedwater	136.7	22.0	452.3
W4	LP feedwater	158.0	22.0	452.3
W5	HP feedwater	215.0	325.0	592.0
W6	HP feedwater	235.5	325.0	592.0
W7	HP feedwater	272.9	325.0	592.0
W8	HP feedwater	279.1	325.0	592.0
W9	HP feedwater	297.6	325.0	592.0
W10	HP feedwater	308.0	325.0	592.0
S11	LP steam 1	71.1	0.3	9.5
S21	LP steam 2	246.0	3.6	35.7
S22	LP steam 2	140.0	3.6	35.7
S23	LP steam 2	139.9	3.6	35.7
S24	LP steam 2	71.0	3.6	35.7
S13	LP drain	37.5	0.3	45.2
G14	Flue gas	235.5	1.0	204.6
G16	Flue gas	63.0	1.0	204.6
G22	CPU gas 1	225.5	15.0	180.0
G24	CPU gas 1	78.0	15.0	180.0
G31	CPU gas 2	152.3	80.0	152.3
G33	CPU gas 2	45.0	80.0	152.3
G41	CPU gas 3	96.2	33.0	177.1
G43	CPU gas 3	45.0	33.0	177.1
S41	HP steam 1	354.0	60.4	66.7
S51	HP steam 2	406.4	87.0	37.0
S44	HP drain	220.5	60.4	103.0
G11	Flue gas	341.0	1.0	204.6
G14	Flue gas	235.5	1.0	204.6
G21	CPU gas 1	293.0	15.0	180.0
G22	CPU gas 1	225.5	15.0	180.0

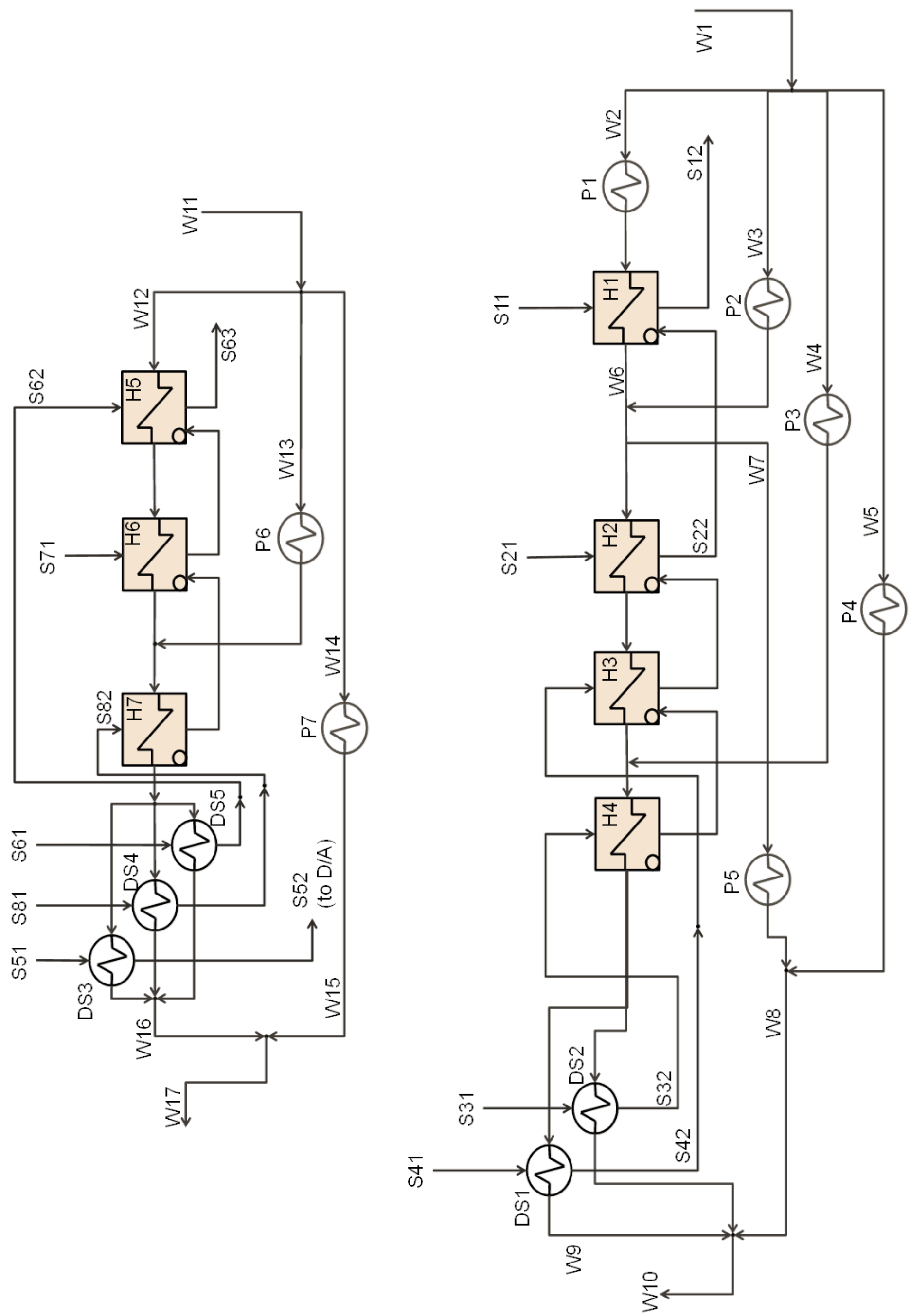

Figure 6-14: High and Low Pressure feedwater preheating systems for the hybrid case

Table 6-4: Stream table for the hybrid case (Figure 6-14)

Stream ID	Description	Temperature, °C	Pressure, bar	Mass flow, kg/s
W1	LP feedwater	32.4	22.0	468.4
W2	LP feedwater	32.4	22.0	311.4
W3	LP feedwater	32.4	22.0	67.0
W4	LP feedwater	32.4	22.0	48.0
W5	LP feedwater	32.4	22.0	42.0
W6	LP feedwater	67.0	22.0	311.4
W7	LP feedwater	67.0	22.0	67.0
W8	LP feedwater	182.0	22.0	109.0
W9	LP feedwater	182.0	22.0	215.7
W10	LP feedwater	180.2	22.0	468.4
W11	HP feedwater	215.7	325.2	586.6
W12	HP feedwater	215.7	325.2	486.1
W13	HP feedwater	215.7	325.2	45.0
W14	HP feedwater	215.7	325.2	55.5
W15	HP feedwater	310.0	325.2	55.5
W16	HP feedwater	309.9	325.2	531.1
W17	HP feedwater	309.9	325.2	586.6
S11	LP steam 1	71.1	0.3	8.1
S12	LP drain	54.1	0.3	67.0
S21	LP steam 2	140.9	1.2	16.1
S31	LP steam 3	246.4	3.8	18.0
S32	LP steam 3	174.5	3.6	18.0
S41	LP steam 4	350.9	9.4	24.9
S42	LP steam 4	178.7	8.9	24.9
S51	HP steam 1	448.0	18.5	23.3
S52	HP steam 1	299.3	18.0	23.3
S61	HP steam 2	554.2	36.1	23.7
S62	HP steam 2	301.7	35.0	23.7
S81	HP steam 1	406.5	88.6	34.4
S82	HP steam 1	301.2	86.0	34.4
S63	HP drain	220.8	35.0	94.9

Pinch design of steam cycles

It is shown that pinch analysis and design can be used to design highly efficient steam cycles with heat integration. For a given set of design parameters such as the main steam, reheat conditions, final feedwater temperature, and the total number of steam extractions, the pinch method of design results in a thermodynamically efficient steam cycle. The driving forces and hence the exergy losses associated with heat transfer are reduced in the feedwater preheating network. This ultimately results in the steam cycle converting more of the input exergy into electricity as proven by the exergy analysis. The exergy analysis also indicates that the improvements are concentrated in the zones where the feedwater temperature is higher. The pinch method requires stream splits, additional units and heat exchange area to realize the promised efficiency improvements. A hybrid network is developed by combining the design principles of the established method and the pinch method based on the insights achieved from the exergy analysis. The steam cycle with hybrid feedwater preheating network achieves a better efficiency compared to the established design while using less number of units compared to the pinch design. However, a rigorous economic analysis is required to add value to the thermodynamic results achieved in this study.

Conclusions and Future work

7.1 Conclusions

As the oxy-combustion technology for coal based power plant matures, novel process modifications and heat integration are required to reduce the capture penalty. This would allow the development of the 'next-generation' coal based power plants with low emissions and high efficiency. Simulation results from this project show the improvement potential of various heat integration opportunities. Flue gas heat recovery is shown to be an important design element to achieve lower capture penalties. Recovered heat from the flue gas is used to preheat the boiler feedwater in the steam cycle. However, oxygen preheating is found to be a better recipient of the flue gas heat to improve the overall efficiency. This is due to the reduction of combustion related exergy loses which are otherwise large. Finally, the heat from the CPU intercoolers can also be recovered to achieve a very high net efficiency. Due to the combination of the above process integration measures, the power plant with capture achieves an efficiency penalty of around 6% points. This compares to the efficiency penalty of over 10% points reported in the literature.

Increasing the boiler operating pressure has a significant impact on the overall performance of the oxy-combustion coal based power plant. Firstly, it helps eliminate the air leakage into the boiler and the associated inefficiencies. Secondly, it reduces the need to preheat the oxygen if adiabatic compression mode is used. Finally, a higher boiler operating pressure means better flue gas heat recovery due to elevated dew point. The downstream compression requirements are also reduced accordingly. All the above mentioned factors help achieve a better overall plant efficiency. Studying the impact of the boiler operating pressure in conjunction with the CPU heat integration helps uncover the true potential of the system. It is shown that a boiler operating pressure of 16 bars gives the best efficiency while enabling proper operation of the downstream purification systems. Adiabatic compression of the oxygen stream keeps the system simple and at the same time results in a better performance. A sensitivity study of these operating parameters helps identify the near-optimal combination of the parameters. Results indicate that the elimination of air leakage into the boiler is not sufficient to use additional energy in the ASU to remove argon from oxygen.

Heat recovery and integration in an oxy-combustion coal based power plant takes advantage of the steam cycle that is available onsite to generate additional power. Design of the steam cycle follows an established methodology that is aimed at simplifying the overall system. Applying the Pinch Design Method improves the steam cycle performance by reducing the losses in the feedwater preheating system. However, the resulting steam cycle is significantly more complex and has many additional heat exchangers. Exergy analysis helps identify the zones with the most significant improvements and thereby helps assign additional heat exchangers accordingly. This ultimately results in a steam cycle that is efficient and at the same time needs only a few additional heat exchangers. This study shows that the proven Process Integration methodologies of Pinch and Exergy analyses can be combined to achieve meaningful results. The efficiency improvement achieved is in the order of 0.4% points. The Pinch Design Method ultimately guides the evolution of a hybrid feedwater preheating network that features dedicated heat exchangers for the desuperheating section and fewer steam extractions. These features enable the system to achieve a better efficiency while also keeping the network complexity to the minimum.

Advancements in material technology are expected to boost the efficiency of steam cycles by enabling the usage of higher temperature and pressure steam. However, such advancements generally require years of research and experimentation before commercialization. In the meantime, incremental improvements offered by established PI methodologies can be applied to both new and old power plants to improve the performance.

7.2 Future work

Pinch Integration methods achieve better performance at the expense of increased complexity and probably reduced operability. Flue gas heat recovery requires heat exchangers made of corrosion resistant materials to function properly. Such materials are generally more expensive than the traditional materials that heat exchangers are constructed with today. Adding heat recovery exchangers to the compressor train may affect their operability. The economic feasibility of such additional complexity could only be justified by conducting a thorough economic analysis. Hence, such system level economic assessments to evaluate heat integration options are required in the future. A detailed study of the operability and reliability of heat integration options in the power plant are also required before such options are implemented. This project mainly focuses on the steady state performance of power plants with heat integration. Dynamic simulation of such complex systems to understand the impact of load changes, system behaviour under start-up, shut down and other scenarios are required to gain a better understanding.

Optimization of the whole system for key operating variables is another recommended future work in this area. In this project, operating the boiler at 16 bars is shown to be efficient. Operating the boiler at such a high pressure offers unique challenges related to fuel delivery and ash removal. Experimental investigations of such systems are therefore required to prove the technology. Several pilot/demonstration scale power plants with pressurized boiler system and heat integration are required in the near future to gain a better understanding of the practical issues related to such boiler systems. Full scale demonstration plants while providing key insight into the technicalities of CCS enabled power plants, can also provide an estimate of the cost of doing CCS and hence would ultimately lead to the commercialization of the technology.

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