



COOPERATIVE RESEARCH CENTRE FOR COAL IN SUSTAINABLE DEVELOPMENT
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Callide Oxyfuel Project

Feasibility Study

PART 1 – Project Background & Summary

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Project History and Acknowledgements

In late 2003, the Australian Government (represented by Tania Constable and John Karas) petitioned the Australian Coal Industry COAL21 members to consider options for projects to demonstrate 'near-zero emission technologies for electricity generation from coal. Over the following months under the leadership of Mark O'Neill a NZETs roadmap was developed and published as part of the COAL21 National Plan of Action in March 2004. The COAL21 Roadmap included the demonstration of oxyfuel technology based on a submission prepared by Chris Spero (CS Energy), Louis Wibberley (BHP Billiton, now with CSIRO), Terry Wall (University Newcastle), Peter Coombes (Delta Electricity), Burt Beasley (Tarong Energy, now with the ACA), Barry Waining (IHI Engineering Australia), Keiji Makino (IHI, Japan), and Takashi Kiga (IHI, Japan; now JCoal).

In April 2004, the CRC for Coal in Sustainable Development (CCSD) convened an Oxyfuel Working Group to undertake a feasibility study program to evaluate the technical and economic merits of oxyfuel technology and to develop a demonstration project at the Callide A power station site. In September 2004, the Callide Oxyfuel Demonstration feasibility study and in particular the collaboration between Australia and Japan, was formerly recognised through the signing of the 'Feasibility Study Memorandum of Understanding'.

The very kind and generous financial, technical and general support provided by the key sponsors and participants to the OFWG, the Feasibility Study MOU, and the preparation of this feasibility study report, as listed below in alphabetical order, are gratefully acknowledged.

Organisation	Participant
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CO2CRC	Dr Peter Cook and Andy Rigg
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JPower	Kiyotaka Muramatsu, and Nohibiro Misawa
Stanwell Corporation	Howard Morrison and Trevor Gleeson
Tarong Energy Ltd	Burt Beasley (now ACA) & Leigh Miller
University of Newcastle	Prof. Terry Wall, Prof. Rajender Gupta and Sameer Khar
Xstrata Coal	Barry Isherwood, Colin Whyte and Peter Coates (CEO)

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Chris Spero
Project Manager

April 2007

Executive Summary

Background

There is a growing recognition worldwide that for many decades into the future, coal will continue to be the main source of primary energy for the production of electricity, but that innovative technology solutions will be required to control greenhouse gas emissions and their potential impact on the environment through global warming.

Ultra supercritical technology is the next advancement in conventional pulverised coal (PC) fired power generation and is now commercial. The scope for CO₂ reductions from ultra-supercritical plant are incremental and proportional to the net thermal efficiency gain (approx. 15%) associated with the higher steam temperatures and pressures in moving from so-called supercritical to ultra-supercritical PC fired power plant. However, there are a number of near-zero emission coal technologies being developed which, when combined with CO₂ capture and storage, have the potential to make significant reductions in emissions from coal-fired power generation, especially CO₂. These technologies include: Integrated Gasification Combined Cycle with Carbon Capture (IGCC-CCS); Pulverised Coal with Carbon Capture (PC-CCS); and Pulverised Coal Oxy-firing with Carbon Capture (PCOF-CCS, more commonly known as oxy-fuel).

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IGCC-CCS technology involves the conversion of coal in a pressurised gasifier to synthesis gas (CO₂, H₂O, H₂ and CO), followed by gas clean-up to remove particulates and oxides of sulfur, conversion of CO by reaction with steam over a catalyst to CO₂ and H₂, separation of the CO₂ for transport and storage, and utilisation of the H₂ as a fuel in a gas turbine or fuel cell. This technology lends itself in particular to the co-production of electricity and chemical feedstock or transport fuels but is complex and high cost. However, the net result is near zero emissions in terms of oxides of sulfur (SO_x), oxides of nitrogen (NO_x) that are formed only in low concentrations, particulates, heavy metals and mercury, and CO₂ when combined with geological storage.

PC-CCS involves processing of the flue gas at the back-end of the boiler to recover the CO₂ only. This is generally achieved in a multi-step procedure involving cooling and filtration of the gas, CO₂ scrubbing from the gas using an absorbent (e.g., amine-based), regeneration of the absorbent using low grade heat usually in the form of low-pressure steam, and finally, compression and refrigeration of the CO₂ stream. The main issues with PC-CCS are:

- (i) The CO₂ concentration in the flue gas stream is low (typically 12 – 15 mole %) and the volumetric flow when compared to e.g., PCOF-CC is very large;
- (ii) Other processes are required to reduce SO_x and NO_x from the process to ~ 10 ppm levels; as they have a poisoning effect on the absorbent.
- (iii) In many cases, PC-CCS may not be suitable for retrofit applications because low-grade heat in the form of low-pressure steam is required and its off-take from an existing steam turbine is usually quite limited.

There are a number of variants for the proposed oxy-firing of pulverised coal boilers, but in simple terms the technology involves replacing air – an O₂/N₂ mixture – by O₂/CO₂ as the

oxidant by additions and modifications to familiar PC technology to include oxygen production, flue gas recycling, and CO₂ compression. The net result of this combustion process is a concentrated stream of CO₂ that enables it to be captured in a more cost effective manner compared to PC-CCS from an air-fired boiler.

Oxy-fuel technology is of potential importance to power and coal companies at an International level for the following reasons:

- The potential for a medium- to long-term, lower cost and lower technology risk option for achieving near zero emissions from coal-based electricity generation.
- The potential to retrofit this technology to standard PF technology (sub-critical as well as super/ultra-super critical PF technology).
- The prospect of applying the technology to new coal-fired plant with significant reductions in the capital and operating cost of flue gas cleaning equipment such as deNO_x and deSO_x plant.

It is recognised that oxy-firing technology has currently only been demonstrated at a pilot scale (< 2 MW Thermal) and that there are a number of technical and commercial issues that need to be addressed before the technology can be applied at a large commercial scale either as a retrofit or as a purpose-designed power plant.

Project Objectives and Scope

The purpose of the Callide Oxyfuel feasibility study was to assess the technical and economic merits of the technology and its application in a demonstration application and in larger scale commercial applications in the future.

The feasibility study was comprised of the following specific tasks:

- (i) Present a state of the art review on the status of the technology with consideration given to the component plant and operations required to operate an oxyfuel boiler;
- (ii) Undertake a fundamental assessment of oxy-firing compared to normal air-firing for pulverised coal combustion;
- (iii) Conduct pilot-scale testing of coals to extend the knowledge base of oxyfuel technology and to validate laboratory test data;
- (iv) Examine the characteristics and capacity for storage of CO₂ in previously identified sedimentary basins in Queensland (Australia);
- (v) Review and assess the broader application of oxyfuel technology to large-scale pulverised coal plant, with an emphasis on plant configurations used in the Asia-Pacific (especially Japan); and
- (vi) Formulate the design concept and costings for a 30 MWe demonstration Project at Callide.

The feasibility study has conducted over a 2 ½ year period from July 2004 to December 2006 and is presented herein in seven parts:

Part 1 – Project Background and Summary

Part 2 – Fundamental Studies

- Part 3 – Techno-Economics of Oxygen-Fired PF Power Generation with CO₂ Capture (Oxygen Production and CO₂ Processing)
- Part 4 – Pilot-scale Studies to Support the Oxyfuel Feasibility Study
- Part 5 – Boiler Retrofit Studies
- Part 6 – Desk-top Study of CO₂ Storage in South East Queensland
- Part 7 – Demonstration Conceptual Design

Summary of Tasks and Findings

Fundamental Studies

The manifest difference between oxy-firing and air-firing of pulverised coal is due to the relative quantities of gases passing through the boiler and the composition of these gases which inherently will have different density, viscosity, specific heat and thermal conductivity as well as different thermal radiation characteristics (as reflected by emissivity) at the higher levels of CO₂ and H₂O in the furnace gases. These differences result in changes to the combustion characteristics of the coal with flow on potential engineering impacts on heat transfer, metal corrosion, and on the flue gas emissions.

The fundamental studies work program was primarily concerned with gathering the latest technical information of oxyfuel technology through a review of the scientific literature, and then augmenting these data with the results of an experimental program designed to measure or determine by process modelling, the differences in the reactivity of the coal, the heat transfer characteristics of the combustion gases, and the characteristics of the remaining ash particles, under oxy-firing versus air-firing conditions.

The literature review identified a number of pilot-scale facilities around the world, typically ranging in size from about 0.3 to 3.0 MW thermal, that have been used to characterise the combustion performance of coals under oxy-firing conditions. A number of demonstration projects ranging in size from 30 MW thermal to 300 MW electrical have been proposed, several during the period of the feasibility study. The key variable involved in the oxy-firing of coal is the recycle flue gas rate (RFG), the optimum level of which is dependent upon the combustion characteristics of the coal, and the heat transfer characteristics of the combustion products (flue gas and particulates).

Coal reactivity measurements conducted in the laboratory were used to determine the volatile yield and combustion kinetics of the test coals (Callide, Acland and Rolleston coals) and provided the necessary rate constants for heat transfer and burnout prediction under a given set of combustion conditions (pulverised coal particle size, excess O₂, and flue gas recycle rate). Heat transfer modelling was then applied to three oxy-fuel plant size scenarios to predict the effects of O₂ concentration and recycled flue gas rate on heat transfer efficiency and adiabatic flame temperature. The furnaces sizes considered were (i) the HRL/ACIRL 150 kg/h Boiler Simulation Furnace located at Ipswich in Queensland – and used for many years to pilot-test the combustion performance of Australian coals in particular; (ii) the Callide A boiler (30 MW electrical) – being evaluated as a demonstration project option; and a large-scale super-critical boiler (nominal 450 MW electrical). Initial experiments conducted prior to the study indicated that the expected effect of oxyfuel combustion on ash formation is to increase the fineness of the ash, and to elevate the decomposition temperatures of carbonate minerals such as calcite and siderite (which can be problematic in PC combustion). The experimental work found that the effect of oxy-firing on ash particle size was coal dependent, but in general the particle size distribution was coarser (generally only slightly) rather than finer as expected. The effect of oxy-firing

on carbonate mineral decomposition and other mineral transformations was not significant for the coals evaluated.

The net result of the fundamental studies work program was to define the key technical parameters such as O₂ concentration and flue gas recycle rate, and combustion rate constants for furnace heat transfer modelling; as inputs to the demonstration plant design concept.

Oxygen Production and CO₂ Processing

The plant capital and energy consumption in the production of oxygen required for oxyfuel combustion has a significant overall cost impact on oxyfuel technology and is an area where significant improvements will be required in the future to make oxyfuel combustion commercially acceptable in the current market. These improvements will involve thermal integration within the process, and O₂ production options with reduced energy penalty.

There are a number of technologies available to separate oxygen from air – including membranes, adsorption processes, and emerging novel techniques such as ion transport membrane based processes, and cryogenic separation. However, cryogenic separation is the only commercially available technology that can be utilised at the scale required for a demonstration project or larger and produce oxygen of sufficient purity (greater than 95%) for an optimal oxyfuel combustion operation.

The technology required for CO₂ capture from oxyfuel combustion is primarily a physical capture process involving flue gas condensation, compression, dehydration and liquefaction. The process is significantly different from PC-CCS where the CO₂ is chemically extracted from the flue gas using adsorption processes.

The efficacy of separation of CO₂ by liquefaction is dependent on the composition of the raw gas and the selection of the specific upstream flue gas treatment processes used. Low oxygen purity or high rates of air ingress into the boiler can result in unacceptable levels of inerts (or non-condensable gases) such as N₂, NO, O₂ and Ar in the raw flue gas with negative impacts on the amount of power required to compress and liquefy the gas, the composition of the final CO₂ product, and the overall CO₂ recovery rate.

Whilst the CO₂ recovery processes that have been proposed for demonstration and commercial plants are well established, the nature of the raw flue gas feed is different in composition from the types of gases to which these processes are normally applied in the oil and gas industry and chemical industry. As a consequence, there is considerable uncertainty about the composition of final CO₂ product, the fate of certain inert gases such as NO, the power consumption involved in process and the overall recovery rate of CO₂ from the feed gas. The findings of the work undertaken in this feasibility study on oxygen production and CO₂ processing, have been used in the conceptual design of the Callide Oxyfuel demonstration project to make choices about the type of oxygen system that should be used and the purity of O₂ feed to the boiler, and as a reference against which various CO₂ processing options could be compared and checked. Developments in CO₂ recovery processes continue to be published and will be reviewed as the demonstration occurs.

Pilot-Scale Testing

A pilot test program was undertaken in the IHI 150 kg/h Combustion Test facility located in Aioi, Japan, utilising ten (10) tonnes each of Callide, Acland and Rolleston coals. The main objectives of the pilot scale testing were to provide a comparison of air and oxy-fuel combustion of the coals considered for retrofit on a practical scale, and to validate the laboratory and heat transfer modeling results from the fundamental studies work program.

During the pilot-scale tests, observations and measurements relating to coal burnout, heat transfer, ash deposition and flue gas emission characteristics were made. At the conclusion of each test, the combustor was allowed to cool and samples of ash from different parts of the test furnace were collected for subsequent characterisation. In addition to the measurement program, further detailed analysis and interpretation of the results was carried out subsequent to the pilot-scale work.

The main findings from the pilot-test program were as follows:

- (i) Turn-down tests confirmed the stable ignition and flame stability in air- and oxy-firing modes for the three test coals, and as expected the flame temperature under oxy-firing conditions was lower than for air-firing.
- (ii) Under oxy-firing conditions, the concentration of NO_x, SO₂ and SO₃ in the flue gases, expressed in *ppmv* is higher than for air-firing due to the reduced flue gas volume. However, the mass emission rate expressed as *mg emission/MJ fuel* burned is lower under oxy-firing conditions. In particular, the mass emission rate for NO_x was 1/3 of that for air-firing; the reduction in mass emission rate for the SO₂ & SO₃ was slightly reduced because more sulphur was adsorbed by the fly ash under oxy-firing conditions.
- (iii) The level of unburned carbon in the fly ash was lower under oxy-firing conditions than in air-firing.
- (iv) No significant differences were generally observed in ash deposition rates, heat transfer rates, or the character of the ash deposits or fly ash (in terms of composition and size distribution), when comparing air- and oxy-firing for the Callide and Rolleston coals. Some minor differences in ash characteristics were observed that are coal specific, e.g., the Acland coal showed a relative increase in the iron level in the fly ash and produced a coarser bottom ash under oxy-firing conditions.
- (v) In general and practical terms, the differences observed in the concentration of trace elements in the flue gas, fly ash and fly ash leachate when comparing air- and oxy-firing were not significant. For some trace elements in some coals the levels slightly increased in oxy-firing, but for others the levels decreased.

Computational Fluid Dynamics (CFD) modelling was applied to the pilot-test furnace to compare measured and predicted heat transfer and flame characteristics. The measured overall heat transfer during oxy-firing was around 1.5 % greater than the heat transfer produced during air-firing, compared to a prediction of around 5% increase. In addition, the flame temperature and furnace exit gas temperature were predicted to lower during oxy-firing, which was consistent with observations. The other modelling consistency observed related to the flame characteristic. The oxy-fuel ignition and therefore the onset

of the flame is at a greater distance from the burner than in air-firing, however peak flame temperatures are similar.

The pilot-scale test results have been used primarily to validate the laboratory data from the fundamental studies work, and as inputs to the Callide demonstration conceptual design, development of control and operating philosophies for the plant, to establish environmental performance impacts due to the recycle gas and data for the required environmental impact statement.

Boiler Retrofit Studies

The boiler retrofit tasks were undertaken in two parts:

Part I (Year 1) – System design, including flow sheets, computational fluid dynamics (CFD) modelling, layout, ancillary plant design, process/piping and instrument diagrams (P&IDs), integrated control and monitoring systems (ICMS), and preliminary costing.

Part II (Year 2) – Plant simulation studies, which specifically examined boiler dynamics including startup, shutdown, effect on steam temperatures, operability and maintainability; and applications to large-scale boilers.

The engineering detail developed in the retrofit studies, together with the results of supporting work programs including pilot-scale testing, has verified the technical feasibility of oxyfuel combustion and its application to the Callide Oxyfuel demonstration project. These inputs have been used to develop the demonstration design concept and operating philosophy and as an input to the initial costing of the retrofit.

CO₂ Storage Options

A desktop study was undertaken to provide an initial assessment of potential CO₂ storage options for the Callide Oxyfuel Project, targeting capacities of up to 75,000 t CO₂ pa.

The scope of work relating specifically to the Callide demonstration and Queensland more generally included the following:

- (i) General review of earlier GEODISC Research findings on the CO₂ storage potential of coals in the Bowen, Cooper, Clarence-Moreton and Galilee Basins.
- (ii) Description of a risking scheme for CO₂ storage in coal seams.
- (iii) Review of CO₂ injection and storage potential of the Denison Trough and related studies, including an assessment of reserves versus production to date and a geomechanical stability simulation for injection into the Springton gas natural gas field in the northern Denison Trough.
- (iv) Review of CO₂ injection and storage potential of the Southern Surat Basin (Wunger Ridge and Roma Shelf), including an assessment of regional hydrology and the potential impact of CO₂ injection on the Great Artesian Basin, and oil and gas production versus reserves.

Based on a storage quantity of 25,000 – 30,000 t/yr for 3 to 4 years for the Callide Oxyfuel Project, the following specific 'risked storage capacity' options have been identified:

- Near depleted natural gas fields in the Denison Trough formation, 250 – 300 km by road from the Callide site (~ 15 Mt CO₂)
- Enhanced coal bed methane recovery from the Dawson River coalfields south of the township of Moura, 100 – 150 km by road from the Callide site (~ 5 Mt CO₂)
- Enhanced coal bed methane recovery from the Fairview/Durham Ranch CBM fields, 300 km by road from the Callide site (~ 60 Mt CO₂)

The results of the geosequestration desktop studies will be applied in the decision making process concerning specific site selection for a CO₂ injection and storage demonstration, and in the definition of a characterisation and testing program as part of the front-end engineering design of the demonstrated facility.

Callide Oxyfuel Conceptual Design

Part 7 of the Feasibility Study report presents a detailed description of the conceptual design for the Callide Oxyfuel Project and covers the scope and objectives of the demonstration, together with details of the plant, project management and approvals, and technology commercialisation. The conceptual design is based on the detailed technical work presented in Parts 2 – 6 of the Feasibility Study and on additional information provided to CS Energy by a number of suppliers on a confidential basis for the purposes of the feasibility study.

The purpose of the conceptual design study is to provide the project parameters for the Front End Engineering Design (FEED) and Financial Investment Decision (FID) for the proposed oxyfuel technology demonstration.

It is intended that the demonstration project will be conducted in 3 overlapping stages.

Stage 1 involves refurbishment of the existing Callide A Unit No. 4 near Biloela in central Queensland, installation of a cryogenic oxygen plant – air separation unit (ASU) of 660 t/day nominal capacity, modifications to the unit as required for oxy-firing, and installation of a nominal 100 t/day CO₂ capture and purification plant (CPU). The plant will be operated for 4 to 5 years to prove oxyfuel combustion at the 30 MWe size and to obtain the necessary technical and cost data for subsequent application to commercial large-scale plant (> 250 MWe).

Geological storage of up to 100 t/day of CO₂ will be demonstrated in Stage 2 of the Project over a nominal 3 year period. The principal area to be evaluated during project FEED is the Denison Trough formation that extends some 200 km north-south and lies 200 – 250 km west of Callide. The Denison Trough formation consists of series of Permian sandstones capped with mudstone and igneous conglomerates that occur as a series of anticlines and synclines with some outcropping on its western margin. At the present time, natural gas is recovered from a number of locations along the ridge of the formation at depths ranging from 1000 – 1500 m in both the Northern and Southern Denison and this gas is piped to a central gas processing facility near Rolleston and then east to Gladstone.

Stage 3 represents the project wrap up in terms of defining any future activity with the Callide Oxyfuel Project, development and implementation of a commercialisation strategy involving application to larger plants in Australia and overseas and realising benefits from

the intellectual property, rehabilitation of geosequestration site, and implementation of the final ongoing monitoring program as may be required.

The overall project cost based on the concept design study results is AUD 188 million, less revenue from the sale of electricity over the operating period expected to be around AUD 10 million. Estimates of the cost of generation in the future have been made using published data and information provided by plant suppliers, and this indicates that oxyfuel technology should be cost competitive with (if not lower cost than) other near zero emission coal technologies such as Integrated Gasification Combined Cycle (IGCC) and Post Combustion Capture (PCC) involving pulverised coal firing with back-end chemical absorption (scrubbing) of CO₂ from the flue gas. In addition, the cost forecast indicates that oxyfuel technology could compete with standard pulverised coal technology (no capture) and natural gas combined cycle technologies in the Australian context, if their was a value on Carbon in the range of AUD 25 – 35/t CO₂.

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1. Introduction

Continued population growth and economic development are projected to drive increases in the demand for energy over the next half century, particularly in developing nations. It is clear that fossil fuels will continue to be a major energy source worldwide due to their abundance, low cost and suitability for use in base-load power stations. For example, China's energy demand is expected to grow at 5% per year through the year 2020, with its demand for coal to fuel power generation increase by 20 million short tons annually over the next 5 years. In Queensland, coal-fired generation accounts for 88% of electricity demand, which demand has grown by 53% in the last 10 years.

While debate continues on the full impact of emissions from these fuels, attention is increasingly being focussed on reducing the energy sector's emissions signature while maintaining competitiveness. Data from the International Energy Agency (IEA) shows that worldwide, coal used for power generation produces around 30% of the total carbon dioxide (CO₂) emissions, and its projections to 2030 show no significant decrease in these levels. While oil and gas supplies are likely to be significantly depleted from 2050 on, it is projected that there are approximately 200 years of coal reserves remaining worldwide.

To enable developed and developing nations to continue to use coal as a cost-effective source of energy without harming the climate, the capture and storage of CO₂ seems the only reasonable answer. The need to gather hard data from commercial-scale demonstration projects across a diverse range of reliable and affordable clean coal pathways is becoming broadly accepted.

Against this background, the CRC for Coal in Sustainable Development (CCSD) in cooperation with the Australian Coal Industry (COAL21 program), Electricity Generators and researchers have been evaluating the techno-economics of a range of near-zero emission coal technologies for electricity production from coal. In particular a partnership, referred to as the Oxy-Fuel Working Group (OFWG), was established in April 2004 and formalised under a Memorandum of Understanding (MOU) in September 2004 to conduct a detailed feasibility study on an emerging technology known as oxy-fuel or oxy-coal combustion. The main purpose of the feasibility study was to determine the technical merits and costs of developing a demonstration project in Queensland based on a 30 MWe Unit at Callide A Power Station, now formally known as the Callide Oxyfuel Project.

The OFWG comprised the following organisations (listed alphabetically):

- Australian Coal Association Research Program (ACARP)
- Cooperative Research Centre for Coal in Sustainable Development (CCSD)
- Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)
- CS Energy
- IHI Engineering Australia (IEA)
- Ishikawajima-Harima Heavy Industries (IHI)
- JCoal (formerly known as Center for Coal Utilization, Japan (CCUJ))
- JPower (not a signatory to the MOU but joined the OFWG in late 2005)
- Stanwell Corporation
- Tarong Energy
- University of Newcastle
- Xstrata Coal

There are a number of variants for the proposed method of oxy-firing of PF boilers, but in simple terms the technology involves modification to familiar PF technology to include oxygen separation; flue gas recycling; and CO₂ compression, transport, and storage (Figure 1). Relatively pure oxygen is mixed with a proportion of either wet or dry flue gas taken down stream of the particulate cleaning plant (typically 70% of the total gas flow) and blown into the wind box of the boiler. Primary air to sweep the pulverising mills is substituted with dry flue gas. The net result of this combustion process is a concentrated stream of CO₂, that enables the CO₂ to be captured in a more cost effective manner compared to post combustion capture of CO₂ from an air-fired boiler.

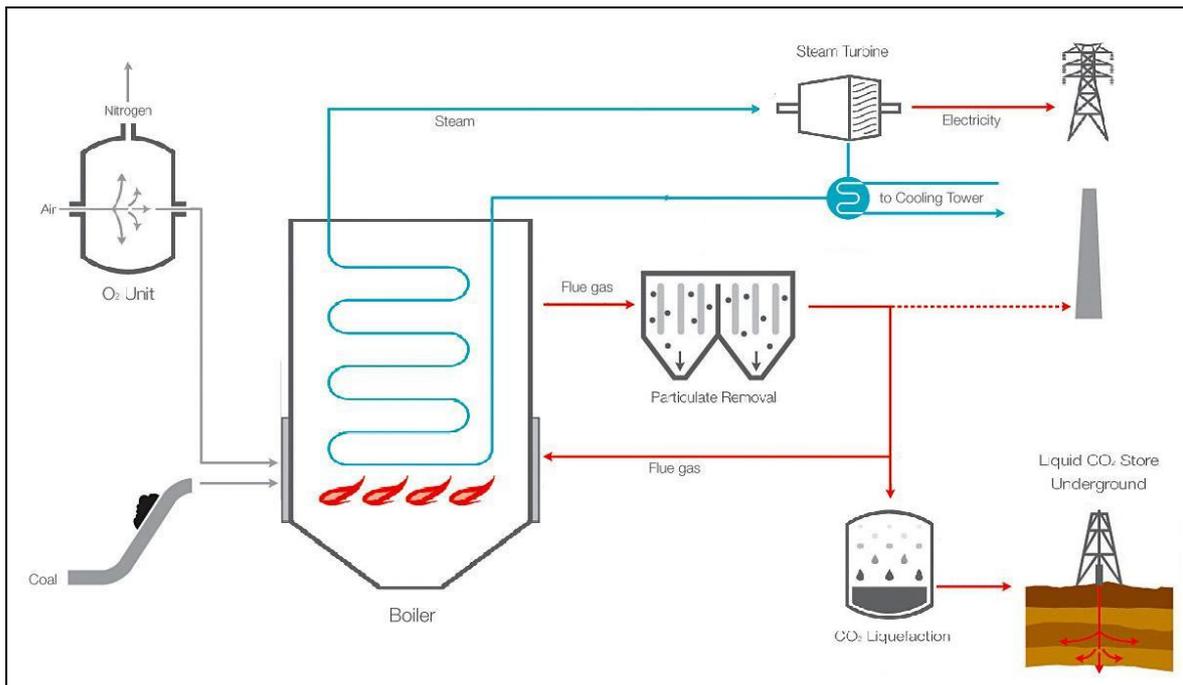


Figure 1 - Schematic of an oxyfuel boiler. The add-on components are the O₂ unit, flue gas recirculation route, and the CO₂ liquefaction process.

To achieve the overall purpose of the oxyfuel feasibility the OFWG was tasked to:

- (vii) Present a state of the art review on the status of the technology with consideration given to the component plant and operations required to operate an oxyfuel boiler;
- (viii) Undertake a fundamental assessment of oxy-firing compared to normal air-firing for pulverised coal combustion;
- (ix) Conduct pilot-scale testing of coals to extend the knowledge base of oxyfuel technology and to validate laboratory test data;
- (x) Examine the characteristics and capacity for storage of CO₂ in previously identified sedimentary basins in Queensland (Australia);
- (xi) Review and assess the broader application of oxyfuel technology to large-scale pulverised coal plant, with an emphasis on plant configurations used in the Asia-Pacific (especially Japan); and
- (xii) Formulate the design concept and costings for a 30 MWe demonstration Project at Callide.

CS Energy’s No. 4 (30 MWe) Unit at Callide A Power Station located near Biloela in Central Queensland (Australia), Figure 2, was selected as the basis of the study for the following specific reasons:

- (i) There are four existing units which are currently stored and therefore potentially available for development into an oxy-fuel demonstration project;
- (ii) The 30 MWe size is well suited to the scale of CO₂ production required to demonstrate CO₂ sequestration; and
- (iii) Callide A is well positioned relative to the eastern boundary of the Bowen Basin and the northern boundary of the Surat Coal basins which overlay a series of Permian sandstones which potentially could be used for geological storage of CO₂.

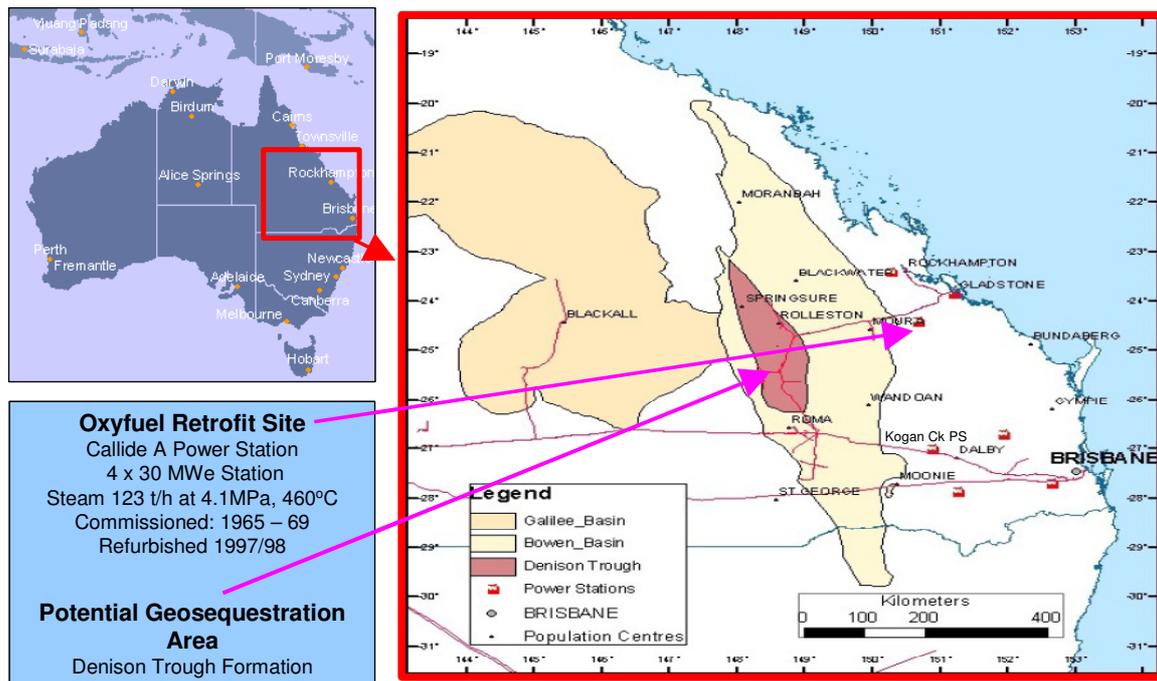


Figure 2 - Region map of South-East and Central Queensland indicating the location of Callide A and regional geology

In undertaking the detailed work of feasibility study, it was recognised that in the longer term the overarching goals were to establish a facility that would provide a basis for large-scale oxyfuel plant design and implementation (for both retrofit and new plant applications), and to develop the necessary engineering capability in Australia and overseas to build and operate oxyfuel plants on a commercial basis as a technology for near-zero emissions electricity generation from pulverised coal.

2. Report Structure & Outline

This feasibility study report is presented in seven (7) parts to reflect the scope of the study and the tasks undertaken by various agencies, and each part has been prepared so that it may be read on a standalone basis. A general description of the content of each Part follows.

Part 1 – Project Overview

This 1st part of the feasibility study report has been included to provide a general description of the context, purpose and methodology of the feasibility study, and to present a technology overview as a lead in to the more detailed and more technical presentations in Parts 2 – 7 of the study.

Part 2 – Fundamental Studies

The essential difference between oxy-firing and air-firing of pulverised coal is due to the relative quantities of gases passing through the boiler and the composition of these gases which inherently will have different density, viscosity, specific heat and thermal conductivity. These differences manifest themselves as changes to the ignition characteristics, devolatilisation and char combustion characteristics of the pulverised coal particles, the physical properties of the ash itself, the emissivity of the ash particles in the gas stream and on boiler surfaces, and on the melting and sintering characteristics of the ash particles. In engineering terms, these changes impact on heat transfer, and metal corrosion, and on the flue gas emissions.

Part 2, presents a review of oxyfuel technology state-of-the-art, together with a detailed description of the experimental and modelling studies that were undertaken to understand and to compare and contrast the effects of oxy-firing with air-firing of pulverised coal in terms of radiative and convective heat transfer, reactivity of coals, and ash impacts.

The fundamental studies examined 4 coals:

Coal 1: Callide coal (19.7 MJ/kg) – Callide Basin

Coal 2: Callide low-calorific value coal (14 MJ/kg) – Callide Basin

Coal 3: Acland domestic/export thermal coal (Moreton basin – Walloon coal measures)

Coal 4: Rolleston export thermal coal (South-west Bowen Basin)

Coal 1 was used as the design coal for this study.

The experimental and modelling work applied to these coals included the following:

- (i) Measurement of the reactivity of the test coals in a drop tube furnace to compare the volatile matter yield and char combustion behaviour of the coal in the normal O₂/N₂ gas regime with the O₂/CO₂ (oxy-firing) gas regime, and to determine the reaction kinetics of the coal chars. Relevant kinetic data for the design coal was input to the IHI Combustion/Heat Transfer model used to determine combustion performance and optimum conditions for oxy-firing in the Callide A boiler.
- (ii) Measurement of the ash melting characteristics and prediction of the effects of O₂/N₂ versus O₂/CO₂ gas regimes on these characteristics using techniques such as Thermo-mechanical analysis, QEM-SCAN, viscosity calculations, and

theoretical deposition rate calculations based on stickiness calculations and particle aerodynamics using the CCSD Ash Effect Predictor model.

- (iii) Determination/prediction of radiative and convective heat transfer characteristics and design parameters such as:
- Emissivity of particles and gas as a function of beam length and O₂ partial pressure for air-firing versus oxy-firing;
 - Adiabatic flame temperature as a function of the O₂ fraction at the burner inlet; and
- Relative heat absorbed by the furnace (heat transfer efficiency).

The measured and calculated parameters given above were used to determine the optimum combustion conditions for the oxyfuel boiler with respect to O₂ firing rate, flue gas recirculation rate, and flue gas moisture content to match air-firing and oxy-firing performance.

Part 2 of the feasibility study consists of the following sub-parts:

Part No.	Title
2.1	Literature review – Oxyfuel combustion technology for coal-fired power generation
2.2	Analysis of coals used in experiments for Callide oxyfuel retrofit study
2.3	Radiative heat transfer inputs for VEGA CFD modelling of the Callide A retrofit by IHI; Use of the wide band model (WBM) to estimate constants in the weighted sum of grey gas model (WSGGM)
2.4	Convective heat transfer impacts when retrofitting Callide A to oxy-fuel
2.5	Experimental determination of the reactivity of coals in O ₂ /N ₂ and O ₂ /CO ₂ environments as pf
2.6	Ash impacts in oxy-fuel combustion inferred from the products of the combustion experiments

Part 3 – Techno-economics of Oxygen-Fired PF Power Generation with CO₂ Capture (Oxygen Production and CO₂ Processing)

Two essential plant components of an oxyfuel boiler are the supply of oxygen (by separation from nitrogen in air) and the processing and treatment of the flue gases at the exit of the boiler to recover CO₂ either in a liquid state or as a supercritical fluid for subsequent transport, and injection into an appropriate geological formation. Part 3 of this feasibility study has included the following tasks:

- State-of-the-art reviews of technologies for oxygen production and CO₂ capture, including a review of patents.
- Technology selection for the feasibility study
- Detailed technical and economic assessment of the oxygen production and CO₂ capture technology as part of a complete process
- Development of detailed flow sheets

- Process optimisation
- Detailed comparison of oxy-firing versus the air-fired PF with post combustion capture case
- Determination of CO₂ handling and road transport requirements and costs.

The results of this part of the feasibility study were used to make decisions about oxygen purity, oxygen plant configuration, and the design of flue gas processing plant for CO₂ capture.

Part 4 – Pilot-scale Studies to Support the Oxyfuel Feasibility Study

The pilot-scale test program, which was undertaken as an additional activity to the original project scope, was designed by the University of Newcastle, CS Energy and IHI, and funded by ACARP, CCSD, IHI and Xstrata coal. The specific objectives of the pilot scale studies were to:

- Provide a comparison of air and oxyfuel combustion of the coals considered for retrofit on a practical scale, including flame stability, as an input to the reference design of the Callide Oxyfuel demonstration project.
- Establish the environmental performance of oxyfuel combustion (for the future Environmental Impact Assessment of the Callide retrofit demonstration).
- Validate current laboratory combustion experiments.
- Provide data for combustion and heat transfer for scaling to power station furnaces.
- Provide data for validation of IHI 'VEGA' boiler CFD code.

The pilot test program involved sampling and transportation of 10 tonnes (each) of the following three coals: Callide (design), Acland, and Rolleston coals. Testing was conducted initially on the Callide and Acland coals in September 2005 and subsequently on the Rolleston coal in December 2005. The general sequence of testing involved testing each coal under air-firing conditions at various loads, followed by testing under oxy-firing conditions at various loads. In each case, tests were generally conducted over a two-day period.

During the pilot-scale tests, observations and measurements relating to coal burnout, heat transfer, ash deposition and flue gas emission characteristics were made. At the conclusion of each test, the combustor was allowed to cool and samples of ash from different parts of the test furnace were collected for subsequent characterisation.

The pilot-scale test results have been used primarily to validate the laboratory data from the fundamental studies work, and as inputs to the Callide demonstration conceptual design and development of control and operating philosophies for the plant.

The pilot-scale work is presented in two sub-parts:

Part No.	Title
4.1	Final Report
4.2	Advanced analyses, mathematical modelling and interpretation of results

Part 5 – Boiler Retrofit Studies

The boiler retrofit tasks were undertaken in two parts:

Part I (Year 1) – System design, including flow sheets, computational fluid dynamics (CFD) modelling, layout, ancillary plant design, process/piping and instrument diagrams (P&IDs), integrated control and monitoring systems (ICMS), and preliminary costing.

Part II (Year 2) – Plant simulation studies, which specifically examined boiler dynamics including startup, shutdown, effect on steam temperatures, operability and maintainability. In addition, an evaluation is presented on the broader potential for CO₂ abatement through the application of oxyfuel technology on a commercial scale to an existing 1000 MWe ultra super-critical boiler in Japan.

The retrofit design activities were led by IHI/JCoal in Japan and largely funded by the New Energy and Industrial Technology Development Organization (NEDO) in Japan.

The engineering detail presented in the retrofit studies, are major inputs to the conceptual design of the Callide Oxyfuel demonstration project presented in Part 7 of the feasibility study.

Part 6 – Desk-top Study of CO₂ Storage in South East Queensland

Earlier work conducted under the GEODISC research program as part of the Australian Petroleum CRC (APCRC) identified a number of sedimentary basins in South East Queensland with potential for CO₂ storage, including the Bowen and Surat basins within deep sandstone formations and in overlying coal seams. The present study, led by the CRC for Greenhouse Gas Technologies (CO₂CRC) has focussed on the Denison Trough formation some 250 – 300 km west of Callide (see Figure 2), which has been producing natural gas for many years. This work was augmented by a broader study conducted by the CO₂CRC for the Australian Coal Association to consider all the eastern sedimentary basins in Australia known to have CO₂ geological storage potential. In the context of South East Queensland, the following relevant work was undertaken:

- (v) General review of GEODISC Research findings on the CO₂ storage potential of coals in the Bowen, Cooper, Clarence-Moreton and Galilee Basins
- (vi) Description of a risking scheme for CO₂ storage in coal seams
- (vii) Review of CO₂ injection and storage potential of the Denison Trough and related studies, including an assessment of reserves versus production to date and a geomechanical stability simulation for injection into the Springton gas natural gas field in the northern Denison Trough
- (viii) Review of CO₂ injection and storage potential of the Southern Surat Basin (Wunger Ridge and Roma Shelf), including an assessment of regional hydrology and the potential impact of CO₂ injection on the Great Artesian Basin, and oil and gas production versus reserves.

It is intended that the results of the geosequestration desktop studies will assist in the decision making process concerning specific site selection for a CO₂ injection and storage demonstration, and in the definition of a characterisation and testing program as part of

the front-end engineering design of the demonstrated facility. Based on a target storage quantity of 25,000 – 30,000 t/yr for 3 to 4 years for the Callide Oxyfuel Project, the following specific 'risked storage capacity' options have been identified:

- Near depleted natural gas fields in the Denison Trough formation, 300 – 350 km by road from the Callide site (~ 15 Mt CO₂)
- Enhanced coal bed methane recovery from the Dawson River coalfields south of the township of Moura, 100 – 150 km by road from the Callide site (~ 5 Mt CO₂)
- Enhanced coal bed methane recovery from the Fairview/Durham Ranch CBM fields, 350 km by road from the Callide site (~ 60 Mt CO₂)

Part 7 – Demonstration Conceptual Design

The final part of the Feasibility Study report presents a detailed description of the conceptual design for the Callide Oxyfuel Project and covers the scope and objectives of the demonstration, together with details of the plant, project management and approvals, and technology commercialisation. The conceptual design is based on the detailed technical work presented in Parts 2 – 6 of the Feasibility Study and on additional information provided to CS Energy by a number of suppliers on a confidential basis for the purposes of the feasibility study.

3. Technology Overview

3.1. Electricity Sector Greenhouse Emissions

According to the Australian Greenhouse Office (National Greenhouse Gas Inventory, 2004), current emissions of carbon dioxide from Australian electricity grid-connected electricity generation are approximately 190 Mt pa with an average emission intensity of approximately 0.9 t/MWh (sent-out). These emissions represent about 30% of the total greenhouse gas emissions (expressed as tonnes of CO₂ equivalent, tCO₂-e), and are increasing at a rate of around 2.5 – 3.0% pa (Figure 3). On current projections, Australia will meet or fall just short of the notional Kyoto target of 108% of 1990 levels in 2010.

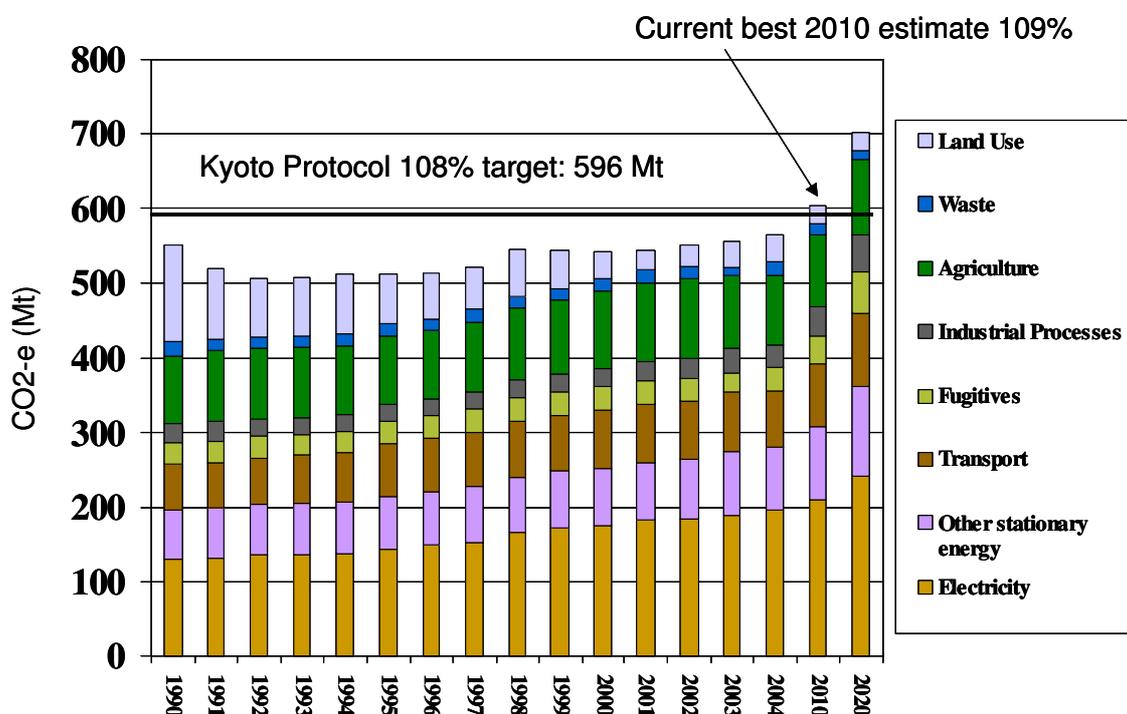


Figure 3 - Australia's historical and projected greenhouse gas emissions by sector (CRAI, 2006)

Data for GHG emissions published by the IPCC (2005) shows similar trends in most other developed and developing countries.

In March 2004, the Australian Coal Association through COAL21 released a National Plan of Action that presented a roadmap for the development and commercialisation of near zero-emission clean coal technology options (ACA, 2005). Then in June 2004, the Australian Government launched a white paper – Securing Australia's Energy Future (Commonwealth Government, 2004) that was underpinned by 3 themes – Energy economics, energy security, and environmental sustainability. These national policy initiatives provided the broader context and need for the conception and feasibility study on oxyfuel technology; and in particular, endorsed the need for development of clean coal technologies with carbon capture and sequestration.

3.2. Technology Options

There are a number of near-zero emission coal technologies being developed which, when combined with CO₂ capture and storage, have the potential to make significant reductions in emissions from coal-fired power generation, especially CO₂, namely: Integrated Gasification Combined Cycle with Carbon Capture (IGCC-CCS); Pulverised Coal with Carbon Capture (PC-CCS); and Pulverised Coal Oxy-firing with Carbon Capture (PCOF-CCS, more commonly known as oxy-fuel). These technologies are often categorised as pre- and post-combustion technologies (Figure 3).

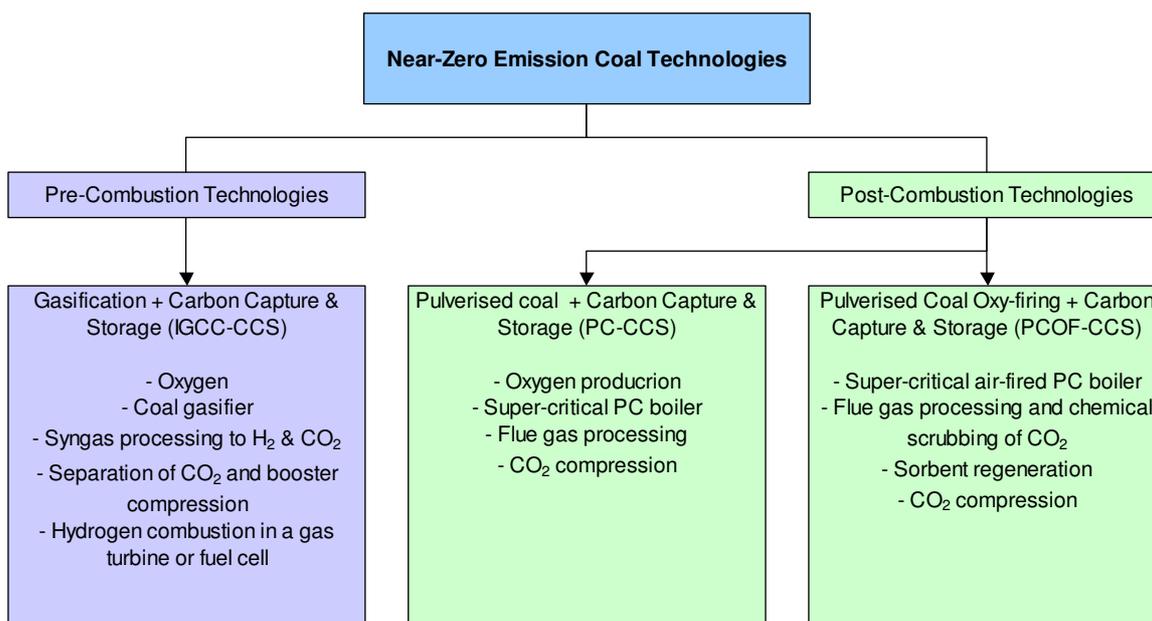


Figure 4 - Outline of the main near-zero emission clean coal technologies generally under development

IGCC-CCS technology involves the conversion of coal in a pressurised gasifier to synthesis gas (CO₂, H₂O, H₂ and CO), followed by gas clean-up to remove particulates and oxides of sulfur, conversion of CO by reaction with steam over a catalyst to CO₂ and H₂, separation of the CO₂ for transport and storage, and utilisation of the H₂ as a fuel in a gas turbine or fuel cell. This technology lends itself in particular to the co-production of electricity and chemical feedstock or transport fuels but is complex and high cost. However, the net result is near zero emissions in terms of oxides of sulfur (SO_x), oxides of nitrogen (NO_x) that are formed only in low concentrations, particulates, heavy metals and mercury, and CO₂ when combined with geological storage.

PC-CCS involves processing of the flue gas at the back-end of the boiler to recover the CO₂ only. This is generally achieved in a multi-step procedure involving cooling and filtration of the gas, CO₂ scrubbing from the gas using an absorbent (e.g., amine-based), regeneration of the absorbent using low grade heat usually in the form of low-pressure steam, and finally, compression and refrigeration of the CO₂ stream. The main issues with PC-CCS are:

- (iv) The CO₂ concentration in the flue gas stream is low (typically 12 – 15 mole %) and the volumetric flow when compared to eg PCOF-CC is very large;
- (v) Other processes are required to reduce SO_x and NO_x from the process; and

- (vi) SO_x generally have a poisoning effect on commercially the absorbent. In many cases, PC-CCS may not be suitable for retrofit applications because low-grade heat in the form of low-pressure steam is required and its off-take from an existing steam turbine is usually quite limited.

There are a number of variants for the proposed oxy-firing of pulverised coal boilers, but in simple terms the technology involves additions and modifications to familiar PC technology to include oxygen production, flue gas recycling, and CO₂ compression. The net result of this combustion process is a concentrated stream of CO₂ that enables it to be captured in a more cost effective manner compared to PC-CCS from an air-fired boiler.

A general schematic of the process is shown in Figure 1, showing oxygen and coal being fed to an existing or new boiler, flue gas recirculation to control combustion conditions, and down stream CO₂ recovery from the flue gas, prior to its transport and geological storage. Pulverised coal oxy-firing is a relatively simple process that should be retrofitable to existing boilers and provides a means of substantially reducing SO_x, NO_x, and particulates as well as CO₂.

An important parameter in the practical operation of an oxyfuel boiler is the flue gas recycle ratio (R), defined as:

$$R = \frac{m_{RFG}}{m_{RFG} + m_{PFG}} \quad \text{Eqn 1.1}$$

where

m_{RFG} = mass flow of recycle flue gas

m_{PFG} = mass flow of product flue gas which exits the system for subsequent treatment and CO₂ recovery

As noted by Tan et al, 2005, in the case of a plant retrofit, the flue gas recycle ratio is selected so that the oxidising mixture (which reacts with the coal) yields combustion and heat transfer characteristics similar to those in the equivalent air-fired system (see Section 3.4, below).

The specific reasons for considering oxy-fuel as an option for clean coal technology development are as follows:

- (i) The existing capacity of pulverised coal plant worldwide (old and new) is very substantial, and there are plans for a significant number of new pulverised fuel plants to be installed around the world.
- (ii) A number of techno-economic studies have indicated that the CO₂ capture cost from oxy-fuel is potentially competitive with those for IGCC-CC and PC-CC.
- (iii) The technical risks associated with oxy-fuel are potentially less than other clean coal technologies because the technology is less complex.
- (iv) In particular countries, the potential for lower capital and operating costs of gas cleaning in oxy-fired pulverised coal boilers (deNO_x and deSO_x) could lead to early commercial applications of the technology.
- (v) It is generally recognised that market conditions in Australia are significantly different from those of Japan, USA and Europe in terms of fuel costs and electricity pricing. In addition, for the near to medium term, the supply balance and

economics for the production of low cost electricity versus other coal-based applications such as gas to liquids, strongly favours the former.

A general technical comparison of the three technologies describe above, compared to a conventional air-fired supercritical pulverised coal boiler, are presented in Table 1.

Table 1 - Indicative technical comparison of coal technologies for power generation

Case	Units	Case 1	Case 2	Case 3	Case 4
Net Power (MWe)	MWe	500	500	500	500
Gross Power (MWe)	MWe	524	633	633	588
Net Thermal Efficiency	%, higher heating value basis	41.0	34.0	34.0	35.7
Coal feed rate	kg/s	49	59	59	56
O ₂ required	kg/s	110	130	130	40
CO ₂ flow to be treated	kg/s	500	610	180	130
Emission rates					
CO ₂	kg/MWh net	780	100	100	95
SO _x	kg/MWh net	3.0	3.7	0.02	0.01
NO _x	kg/MWh net	1.9	2.3	0.9	0.1
Particulates	kg/MWh net	0.1	< 0.01	< 0.01	< 0.01
Total ash	kg/MWh net	75	90	90	85

Input assumptions:

1. Case 1 – Conventional pulverised coal air-fired, ultra super-critical boiler, with no CO₂ capture (i.e., USC PC)
2. Case 2 - Conventional pulverised coal air-fired, ultra super-critical boiler, with 90% CO₂ capture. Assumes this can be done with normal SO_x and NO_x in the flue gas (which is not presently the case), (i.e., USC PC-CC)
3. Case 3 – Pulverised coal, ultra super-critical boiler with oxy-firing and 90% CO₂ capture (i.e., USC PC-OF-CC).
4. Case 4 – Integrated gasification combined cycle with 90% CO₂ capture (i.e., IGCC-CC)
5. Black coal - 21% ash (as-received) and 25 MJ/kg (as-received, higher heating value)
6. The efficiency and emission rate data presented are proposed for hypothetical mature technology in each case.
7. Data presented for Cases 2 – 4 include CO₂ capture but exclude transport and geosequestration.

A broad study on the pathways for achieving deep cuts in Greenhouse Gas Emissions from the Electricity Supply Industry in Australia was commissioned jointly by the National Generators Forum (NGF) and the Electricity Supply Association of Australia (ESAA) and was reported by CRAI in September 2006. The report is of particular relevance to the present study because it presents a broad outline of Greenhouse problem, proposes a notional National Greenhouse Gas abatement target of 50% of 2010 emission levels from the electricity sector by 2050 (i.e., a 96 Mt CO₂-e), and evaluates the efficacy of a range of technology solutions including the application of oxyfuel technology to achieve these targets.

The role that plant retrofits for carbon capture and storage can play in delivering such a target is illustrated in Figure 5. The scenario depicted 4 shows the generation profile from a range of technologies that might be applied to achieve the 96 Mt target (constrained

generation, with and without retrofits) compared to a business as usual (or unconstrained) generation. The main benefit of introducing retrofits into the generation mix, as indicated by the scenario analysis, is economic in that new high efficiency coal-fired plant such as ultra-super-critical without CCS can continue to be built for some time into the future in lieu of new-built coal-fired plants with CCS, and still achieve the 96 MTCO₂-e target. Such an outcome reduces the prospect of stranding existing pulverised coal fired boilers, and allows more time for more complex and higher cost technologies such as IGCC-CCS to be optimised and introduced into the electricity market.

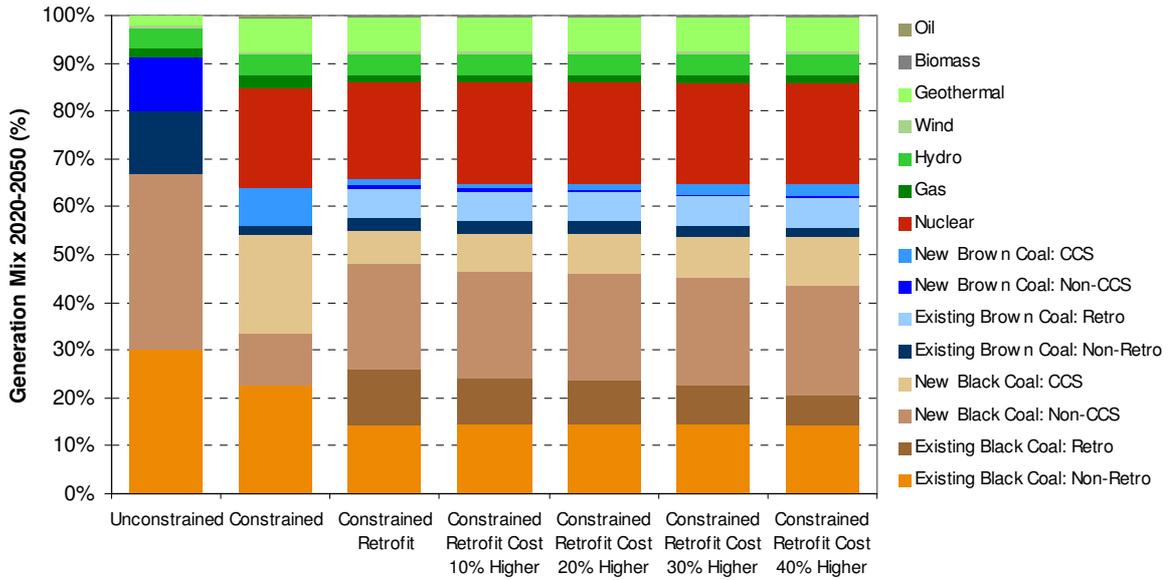


Figure 5 - Electricity production profiles for fossil, nuclear, hydro and renewable technologies to reduce GHG emissions from this sector to 50% of 2010 levels by 2050 (i.e., 96 Mt CO₂-e); with the application of retrofit technologies such as oxyfuel (CRAI, 2006).

The technology cost profiles published by the NGF/ESAA are indicative of other studies and support the view that oxy-fuel technology with CCS is potentially one of the lower cost options for achieving near zero emissions from coal-fired power plant (Figure 6).

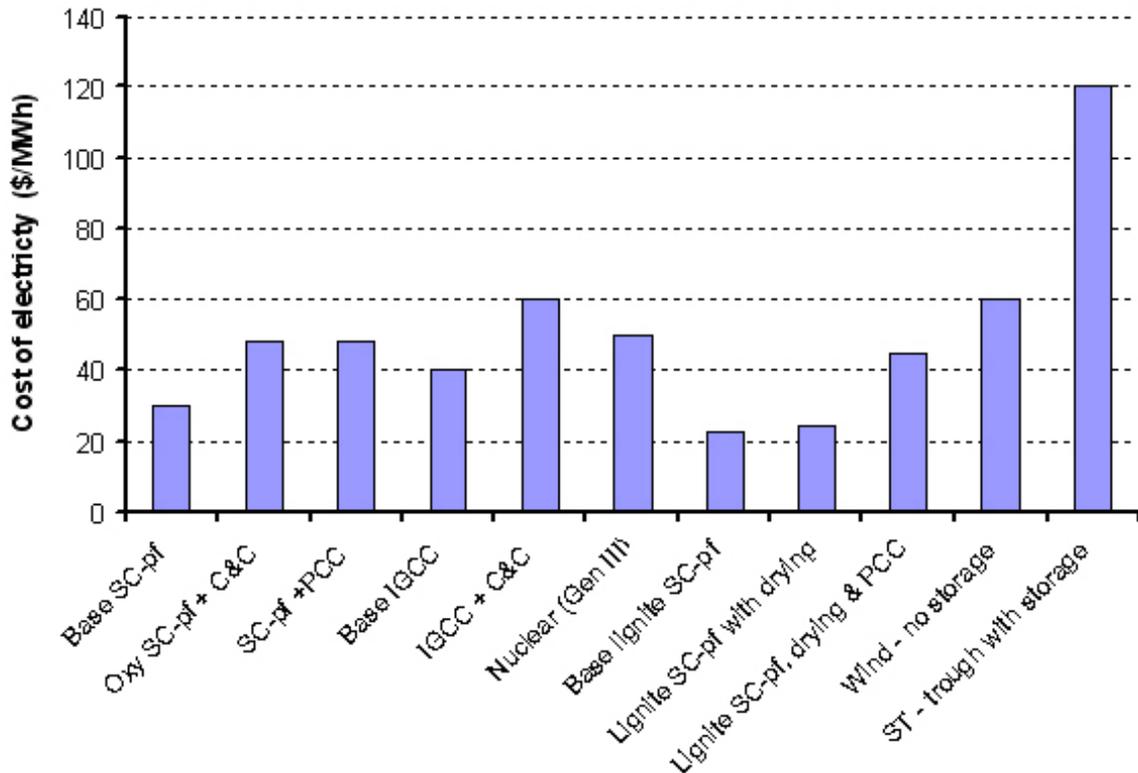


Figure 6 - Technology cost comparison for fossil energy, nuclear, hydro and renewable electricity generation in an Australian context (Wibberley et al, 2006)

3.3. Oxy-fuel Status

As noted by Wall (2007), Tan et al (2005) and Buhre et al (2005), oxy-fuel combustion techniques can be adapted to a furnace in a number of ways:

- (i) Full oxy-fuel combustion with 100% oxygen
- (ii) Oxygen enhanced combustion involving enrichment of air with oxygen
- (iii) Oxy-fuel combustion with recycled flue gas (using 95 – 98% O₂ diluted by recycled flue gas)

Full oxy-fuel combustion and oxygen enhanced combustion techniques have been used in a number of industrial applications such as glass and cement manufacture and in blast furnaces for iron making. The benefit of oxy-fuel in these cases includes efficiency improvement and NO_x reduction.

Oxy-fuel combustion with recycled flue gas has not generally been applied industrially however, laboratory and theoretical work has provided an initial understanding of design parameters and operational issues. In addition there have been a number of investigations using pilot-scale facilities in the US, Europe, Japan, and Canada (Table 2). Studies have also assessed the feasibility and economics of retrofits and new power plant.

The operation of coal-fired boilers with flue gas recycling (but no oxy-firing) is widely used in a number of applications, including:

- Lignite fired boilers – where a 10 – 30% proportion of the gases are extracted from the top of the radiant section of the boiler and reinjected via the primary gas stream through the coal pulverisers to evaporate the large proportion of moisture that comes with the coal to ensure good ignition and flame stability and improved boiler efficiency
- Coal-fired supercritical boilers – where a 5 – 15% proportion of the flue gases are extracted at the back-end of the process after particulate removal and reinjected at the front end of the boiler, under the burner zone, to control gas temperature and steam temperatures at the top of the radiant section of the boiler
- Coal-fired boilers, generally – in a process known as reburning, to control/reduce NO_x emissions.

Some of the conclusions that can be drawn from the research findings to date are as follows:

- (i) Pilot-scale studies have demonstrated that there are no significant technical barriers to oxy-firing of pulverised coal.
- (ii) Typically, the optimum O₂ concentration from the oxygen plant for oxy-fuel applications is around 97 - 98%; and the optimum recirculation rate is generally around 70% which yields about 30% O₂ (mole %, wet) in the windbox of the boiler, and about 3 - 3.5% O₂ (mole %, wet) at the furnace exit. At these conditions, flame condition and heat transfer characteristics reasonably approximate those for air-fired pulverised coal boilers.
- (iii) Oxy-firing yields significant reductions in NO_x, typically around 50% lower than for the air-fired case.
- (iv) Preliminary cost evaluations indicate CO₂ capture costs (\$/tCO₂ avoided) and electricity costs (\$/MWh) are competitive with and possibly lower than from IGCC systems and conventional pulverised fuel with amine-based post-combustion capture of CO₂.
- (v) Technical issues to be considered or addressed include flame stability, heat transfer, level of flue gas clean up necessary and acceptable level of nitrogen and other contaminants for CO₂ compression, and corrosion due to elevated concentrations of SO₂/SO₃ and H₂O in the flue gas.

Table 2 - List of oxy-fuel pilot-scale facilities and related studies (adapted from Wall et al, 2004 and Tan et al, 2005)

Organisation	Furnace Used	Scope & Objectives
EERC and ANL (UK)	10 Million BTU/h (~ 3.0 MWt) tower furnace with internal square cross section of 1 x 1 m and 6 m length- using a single swirl burner.	<ul style="list-style-type: none"> • Demonstration of the technical feasibility of the CO₂ recycle boiler. • Determination of ratio of recycle gas to O₂ for achieving similar performance to an air-fired system. • Quantification of observable operational changes in flame stability, burnout and emissions. • Providing a basis for scaling experimental results to commercial scale applications.
IFRF (The Netherlands)	IFRF Furnace #1: 2.5 MWt horizontal furnace with internal square cross section of 2 x 2 m and 6.25 m length – using an air-staged swirl burner.	<ul style="list-style-type: none"> • Optimisation of O₂-RFG firing conditions to yield similar heat transfer performance to an air fired system. • Evaluation of the impact of O₂-RFG process on furnace performance, including flame ignition and stability, heat transfer, combustion efficiency and pollutant emissions as compared to an air-fired system.
IHI (Japan)	IHI's 1.2 MWt combustion test furnace: a horizontal cylinder furnace with 1.3 m inner diameter and 7.5 m length – using a swirl burner.	<ul style="list-style-type: none"> • Determination of combustion characteristics of pulverised coal in O₂/CO₂ mixtures. • Evaluation of the effects of wet and dry recycled flue gases on oxy-firing combustion processes.
Air Liquide and B&W (USA)	1.5 MWt pilot-scale boiler with staged air combustion system.	<ul style="list-style-type: none"> • Demonstration of the technical feasibility of conversion from air-firing to O₂-RFG firing for a large-scale boiler. • Highlighting the impact of the O₂-RFG conditions on boiler efficiency and emissions.
CANMET (Canada)	Vertical Combustor Research Facility (0.3 MWt): A cylindrical down-fired and adiabatic vertical combustor with an inner diameter of 0.6 m and length of 6.7 m 0 using a swirl burner.	<ul style="list-style-type: none"> • Pulverised coal combustion behaviour in various O₂-RFG mixtures compared with air-fired systems. • Evaluation of the technical factors on combustion performance

The key technological knowledge gaps identified in the literature were as follows:

- Alternative technologies to reduce the costs of oxygen production.
- Heat transfer performance of large units
- The effect of dilution and contaminants on system design of the carbon dioxide compression train and CO₂ recovery.

- Effect of recycled gas on the system, especially corrosion of materials due to high SO₂, SO₃, carbon dioxide and moisture levels.
- Verification of burner design and performance.
- Understanding the differences in coal and ash behaviour from a scientific perspective in oxygen/nitrogen compared with oxygen/carbon dioxide, and the reasons for these differences.
- Design and cost comparison of a purpose built oxy-fuel boiler when compared with retrofit.

Work on the development of oxy-fuel technologies applicable to coal combustion is being pursued on at least two fronts: for retrofit applications where the technology fix can be added onto existing coal-fired units, and as new build applications where significant economic benefits in terms of reduced boiler size may be realisable (Table 3).

Table 3 - Proposed oxyfuel demonstration projects (IEA 2nd Oxy-fuel Combustion Network January 2007)

Demonstration project	Description
Total - Lacq (France)	<ul style="list-style-type: none"> • 30 MW new build gas-fired oxy-fuel boiler producing 150,000 tpa super-critical CO₂ to be piped for storage in a depleted oil and gas reservoir. • Project now under construction with practical completion scheduled for No. 2008
SaskPower – Shand River (Canada)	<ul style="list-style-type: none"> • 300 MWe NZET lignite-fired oxyfuel boiler to be located at Shand River near the Wybern oil fields. Super-critical CO₂ to be piped for enhanced oil recovery. • B&W boiler supply, Air Liquide O₂ and CO₂ plant supply • Feasibility study to be completed mid 2007 • Target commercial load in 2011
Vattenfall – Cottbus (Germany)	<ul style="list-style-type: none"> • 30 MWt lignite fired new build plant • 100 TPD 'product grade' liquid CO₂ recovery • Alstom boiler supply, Linde O₂ and CO₂ plant supply • Site works commenced Jun. 2006, and practical completion scheduled for Jul. 2008 • Integration with steam cycle of Swartze Pumpe 1000 MWe power plant • Cost is 70 million € capital + 23 € operating over 3½ years
CS Energy (Australia/Japan Consortium) – Callide (Australia)	<ul style="list-style-type: none"> • 30 MWe black coal-fired PC, retrofit to Callide A Unit No. 4 • IHI boiler supply • 660 tpd O₂ and 100 tpd liquid CO₂ recovery • Road transport of CO₂ to depleted gas fields • Front-end engineering design to be completed Jun. 2007, construction from Sep. 2007 and commercial operation for 5 years from Nov. 2009 • Net cost is nominally AUD 165 million (CAPEX + OPEX including CO₂ transport and storage)
Jupiter Oxygen Corporation – Orrville (USA)	<ul style="list-style-type: none"> • 25 MWe black coal fired PC, retrofit of Orrville pressurised boiler • Doosan Babcock boiler supply • Currently at feasibility assessment stage

3.4. Combustion Impacts

3.4.1 Flame Stability, Coal Reactivity and Heat Transfer

The design differences between an oxyfuel boiler and a normal air-fired boiler relate to differences in the configuration of the system (where the former requires a supply of oxygen, and the necessary equipment to recirculate a large proportion of the flue gases), together with differences in the net gas flows through the boiler and differences in gas composition through the boiler.

A relative comparison of the differences in flue gases through the boiler (Table 3) indicates that the effect of oxy-firing is to reduce adiabatic flame temperature (i.e., the maximum theoretical temperature of the products of combustion assuming no heat loss to the surroundings) if the O₂ volume proportion of the O₂/CO₂ is the same as air, of 21%, and the volumetric flow of the boiler gases through the system. In a typical pulverised coal fired boiler, the impact of these changes can manifest in the following ways:

- (i) Delayed coal particle ignition, reduced flame temperature, flame instability
- (ii) Reduced heat transfer in the radiative (or furnace) section of the boiler and therefore a requirement to pick-up additional heat in the convective section (or rear pass) of the boiler.

Table 4 - Properties of gases at 1400 K, 101.325 kPa (absolute)

Property	Unit	H ₂ O	O ₂	N ₂	CO ₂	SO ₂
Density (ρ)	kg/m ³	0.157	0.278	0.244	0.383	0.56
Thermal conductivity (k)	W/mK	1.3631 e-01	8.721 e-02	8.1839 e-02	9.7193 e-02	5.6252 e-02
Specific heat capacity @ const. pressure (c_p)	kJ/kgK	2.55	1.18	1.27	1.33	0.81
Dynamic viscosity (μ)	kg/ms	5.0184 e-05	5.9231 e-05	4.9076 e-05	4.9163 e-05	5.0197 e-05
Kinematic Viscosity (ν)	m ² /s	3.20 e-04	2.09 e-04	2.00 e-04	1.31 e-04	9.11 e-05

A key aspect in the design of an oxyfuel system, therefore, is to introduce sufficient oxygen into the pulverised coal flame to ensure satisfactory ignition and flame stability, and to correctly balance the amount of flue gas that is recycled around the boiler to establish the gas temperature at the exit of the radiative section of the boiler (otherwise referred to as the furnace exit gas temperature) for a satisfactory balance of furnace and convective pass heat transfer.

An additional factor influenced by the local gas environment and temperature in oxy-firing is the reactivity of coal in terms of devolatilisation and char burnout. The effect of reduced flame temperature on particle ignition and the need to ensure adequate oxygen supply to the pulverised coal as it exits the coal burner has already been noted. Additional measures that are being evaluated by plant suppliers is the use of a oxygen lance through the centre of the burner or modifications to the burner geometry itself to ensure good oxygen migration and mixing with the coal particles to achieve good ignition and flame stability characteristics. In some cases, it is considered that some reduction in oxygen levels in the secondary gas (i.e., oxygen + recycled flue gas introduced to the boiler via the windbox) may be necessary to ensure that the overall product gas composition does not contain additional oxygen with consequent downstream impacts in the flue gas processing/CO₂ recovery process at the boiler exit.

Likewise, the effect of the changed gas environment on char reactivity also needs to be considered. Studies reported in Part 2 of this feasibility study have indicated that the chemical effects of what is effectively an O₂/CO₂ gas environment, as opposed to the O₂/N₂ environment associated with normal air-firing, has a secondary and beneficial effect on char reactivity because of the activation effect of CO₂ on carbon. In addition, the reduced volumetric flow of gases in the boiler under oxy-firing conditions result in lower gas velocities and therefore increased residence time of coal particles in the boiler. The net effect is that no significant difference in burnout, as supported by the results of pilot-scale testing, is observed.

3.4.2 Ash Deposition

The effect of oxy-firing on the ash depositional characteristics under oxy-firing conditions has not been extensively studied to date. The main variables that will effect ash deposition in the radiation zone of the boiler will be particle trajectory and ash viscosity, which will depend on: (i) particle aerodynamics at the burner exit and through the boiler; and (ii) on the particle size, composition and temperature of the burning coal particle/resultant ash particle(s) and on the local gas composition (particularly the partial pressure of oxygen and SO₂), respectively.

Again, there are counterbalancing factors within the boiler, which based on modelling and pilot-scale studies to date, tend to indicate no significant effect of oxy-firing. Specifically, as will be discussed later, the concentration of SO₂ in the flue gases is expected to be around 3 times higher than that under normal air-firing conditions, which intuitively will have a negative impact on ash slagging propensity. However, reduced flame temperature and consequent increased emissivity of the gas and particles, combined with reduced particle velocities, would be expected to result in reduced slagging propensity.

The accumulation of weakly bonded/sintered ash deposits in the convection pass of a coal-fired boiler, generally referred to as fouling, is mainly influenced by the concentration of submicron particles in the gas steam and elevated levels of alkali metals such as Sodium. As in the case of boiler slagging, fouling under oxy-firing conditions is a relatively new area of investigation. However, modelling studies and pilot-scale tests to date, have indicated no significant impact arising from oxy-firing conditions.

3.4.3 Flue Gas Emissions

One of the principal drivers for oxyfuel technology is near zero emissions in terms of CO₂, oxides of nitrogen (NO_x), Oxides of Sulfur (SO_x), and Particulates.

Depending on the configuration of the flue gas processing and CO₂ capture equipment employed in a oxyfuel scheme, CO₂ recovery rates in excess of 80% and typically around 90% have been targeted (refer to Part 3 of the feasibility study report).

The production of NO_x during coal combustion is a complex phenomenon in part dependent on the chemical characteristics of the coal, but more particularly, on the firing conditions within the boiler. The NO_x produced in combustion results from oxidation of Nitrogen (N₂) in the air, referred to as thermal-NO_x; and the oxidation of Nitrogen in the coal (as organically bound N) referred to as fuel-NO_x. The most important factors in coal firing that influence [NO_x] are the flame conditions associated with the burners; principally Oxygen concentration and flame temperature. Approximately 95% of the total NO_x consists of Nitric Oxide (NO), the remainder consisting of Nitrogen Dioxide (NO₂), with small amounts of Nitrous Oxide (N₂O).

One of the singular outcomes of oxy-firing that has been observed in pilot-scale tests is the substantial reduction in NO_x emissions, typically in the range of 50 – 75% as a result of the changed combustion conditions. The evidence indicates that there are two factors that are driving the reduced NO_x outcome. The first is the absence to a large degree of nitrogen (as N₂) in the combustion zone of the boiler; and the second and more dominant factor is the apparent rapid reduction of the NO_x in the recycled flue gas into N₂ in the flame by reactions with evolved volatile matter.

Emissions of Oxides of Sulfur (SO_x) are primarily a function of the Sulfur content of the coal. In oxy-firing, the effect of recycling the flue gas is to increase the concentration of SO₂ and SO₃ within the boiler by a factor of about 3 depending on the recycle ratio. This has potential impacts on high temperature in the hot sections of the boiler and dew point corrosion in the cold sections of the boiler exposed to flue gas. Options for dealing with the elevated SO_x levels in the boiler involve careful material selection, operation of the boiler at a higher backend temperature, and removal of water vapour and some SO₂ from the recycled flue gas prior to boiler re-entry.

Regarding SO_x emissions to the atmosphere, all the SO_x is removed in the flue gas treatment/CO₂ capture plant.

Very little has been documented on the fate of trace elements in the coal during oxy-firing, and no meaningful conclusions were gleaned from the literature examined as part of the feasibility study. This issue has been addressed in the pilot-scale work reported in Part 4 of this feasibility study report.

3.5. Oxyfuel CO₂ Capture Processes

There are a few variants to the general flowsheet proposed for CO₂ capture from an oxyfuel application, but the main part of the process is the compression of the flue gas to the point where the CO₂ can be physically separated from the other gas components present.

Pure CO₂ exists in gas phase at standard pressure/temperature conditions (0 °C and 101.325 kPa or 1 bar) with a gas density of 1.976 kg/m. At a temperature or pressure above the critical point (7,390 kPa/74 bar and 31.1 °C), CO₂ exists in supercritical state (Figure 7).

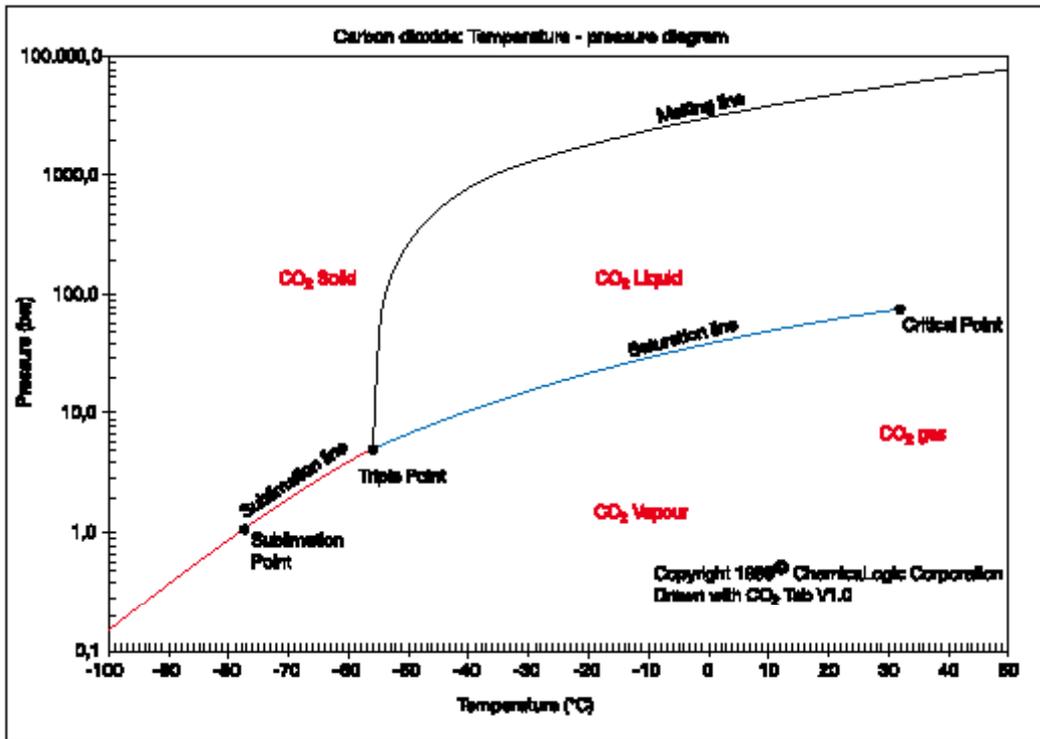


Figure 7 - Phase diagram for CO₂

For road transport applications, the CO₂ product is recovered from a pressurised gas stream by refrigeration to yield a liquid product at around minus 20 °C and 20 bar (2000 kPa). For pipeline transport, the product CO₂ is generally in a supercritical state (at pressures exceeding 75 bar) so that it behaves as a gas but with the density of a liquid (Figure 8).

The key features of the liquefaction process as it relates to CO₂ recovery from a binary CO₂-N₂ gas mixture (taken to represent a flue gas feed stream) are that:

- The temperature and pressure of the mixture determine the composition of the vapour and liquid at equilibrium.
- The initial composition of the mixture will determine the relative amounts of liquid and vapour under these conditions.
- Increasing the pressure or reducing the temperature of the mixture will result in more liquid, but with a corresponding higher amount of N₂ in the liquid.
- For the above temperature and pressure, increasing the amount of N₂ present decreases the amount of liquid formed, although the composition of the vapour and liquid will not be altered.

The last 2 points highlight the trade-off between liquefaction and purity, which is very significant for oxy-pf, especially if retro-fitting older stations which will have higher levels of N₂ in the flue gases from ingress air.

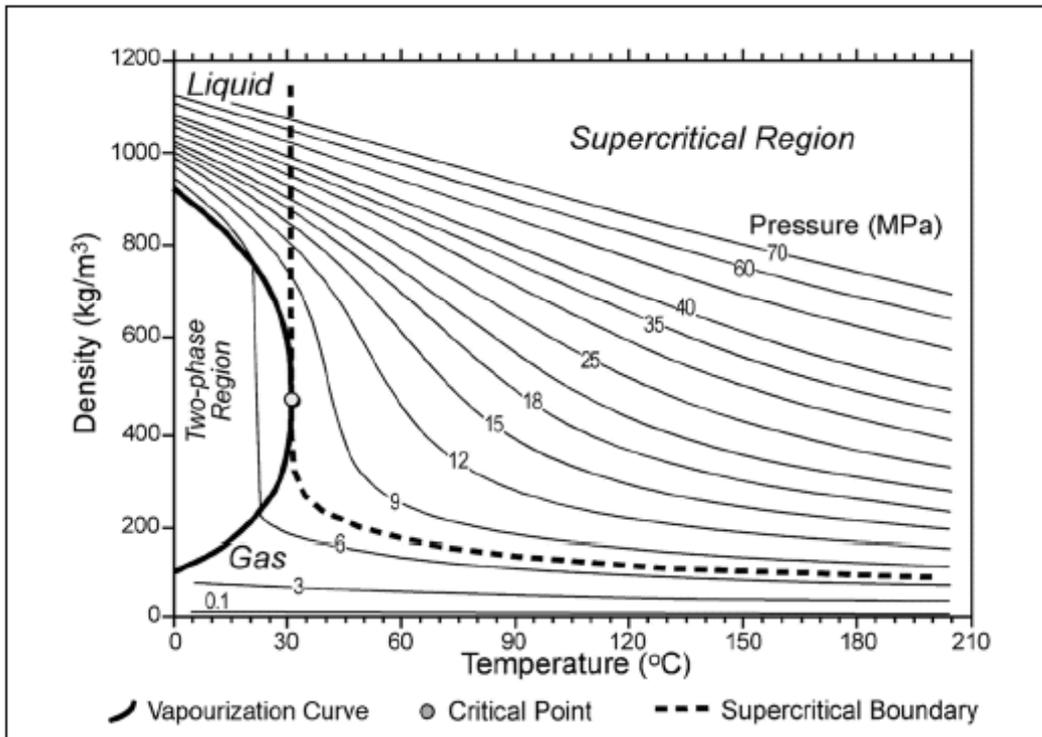


Figure 8 - Variation in CO₂ density with temperature and pressure

It should also be noted that whilst the phase diagram for pure CO₂ is well established, the effect of impurities, which generally is known to effect the phase transitions, is still an area where fundamental measurements are being made. However, it is recognised that the presence of inert components such as oxygen, nitrogen and argon, will shift the sublimation and saturation lines towards higher pressures which from a practical perspective means increased power consumption in compression, lower quality CO₂ product in the case of a super-critical fluid, and reduced CO₂ recovery from the raw/feed gas. These aspects are explored in detail in Part 4 of the feasibility study report.

An indicative scheme for CO₂ recovery from flue gas (Figure 9), will typically involve the following steps:

Step 1 – Flue gas condensation and neutralization

This step involves reducing the temperature of the flue gas from the power plant from typically 130 – 150 °C to 25 – 35 °C and neutralization of acid gases (primarily SO_x), by injection of water and an alkali such as soda ash or sodium hydroxide. This process removes any remaining particulates, most of the SO_x and most of the water vapour down to the saturation level at condenser outlet temperature.

The internal components of the condenser are typically manufactured from stainless steel.

Step 2 – Flue gas compression

In this process, the pressure of the flue gas is increased from atmospheric pressure (say 1 bar) to a pressure of around 20 - 30 bar, with some further reduction in moisture content as condensate.

As noted by Birkestad (2002), the flue gas compressor is the most expensive component cost in the flue gas processing stream and consumes the most power.

Typically, a centrifugal compressor is used for large-scale CO₂ compression applications because their associated operating and maintenance costs, and power consumption are lower than other types (such as reciprocating compressors or screw compressors). Their main disadvantage is that they cannot achieve a high pressure-ratio without multiple stages.

Step 3 – Gas/Liquid drying

Further dehydration of the liquid/gas CO₂ mixture is required to minimise (eliminate) down stream corrosion particularly in the CO₂ transport medium (be it tanker or pipeline). This is normally achieved using either a molecular sieve or a hygroscopic fluid such as triethylene glycol (TEG).

A molecular sieve is a material containing tiny pores of a precise and uniform size that is commonly used as an absorbent for gases and liquids. Molecules small enough to enter the pores are absorbed while larger molecules pass around the porous medium. In this way, water is effectively removed (separated) from the CO₂ and N₂ in the compressed flue gas stream.

Ethylene glycols are commonly used in natural gas operations to remove water and impurities. TEG has excellent hygroscopicity and low volatility and acts to remove water from a gas stream through a process of weak H-bonding between the water molecule and the TEG molecule.

TEG is usually selected for large plant (such as natural gas processing applications) because the operating cost is generally lower than for a molecular sieve; but the latter is a more effective desiccant.

The TEG and molecular sieve media are regenerated by heating.

Stage 4 – CO₂ liquefaction and inert separation

Inerts or non-condensable gases such as N₂, NO, O₂ and Ar are separated from the CO₂ (and SO₂) using an integrated process of cooling, distillation and reflux condensing. Cooling is obtained using either an external refrigeration process such as an ammonia cycle, or an internal refrigeration process involving additional compression and cooling, to produce liquid CO₂ at say - 40°C (and 20 – 30 bar as in *Step 2* above). A fraction of the liquid CO₂ (from the base of the distillation/reflux vessel) is then extracted and sprayed counter current fashion over the warmer CO₂/Inerts stream to establish a distillation/reflux process where the CO₂ is preferentially liquefied and the inerts are vented.

For pipeline applications where the CO₂ is transported in super-critical state (> 31°C and > 75 bar), the pressure of the liquid CO₂ is increased to 85 - 110 bar in a high pressure pump; and as it warms up downstream in the pipe transforms from a liquid to a supercritical fluid (see Figure 7) when the temperature exceeds 31 °C.

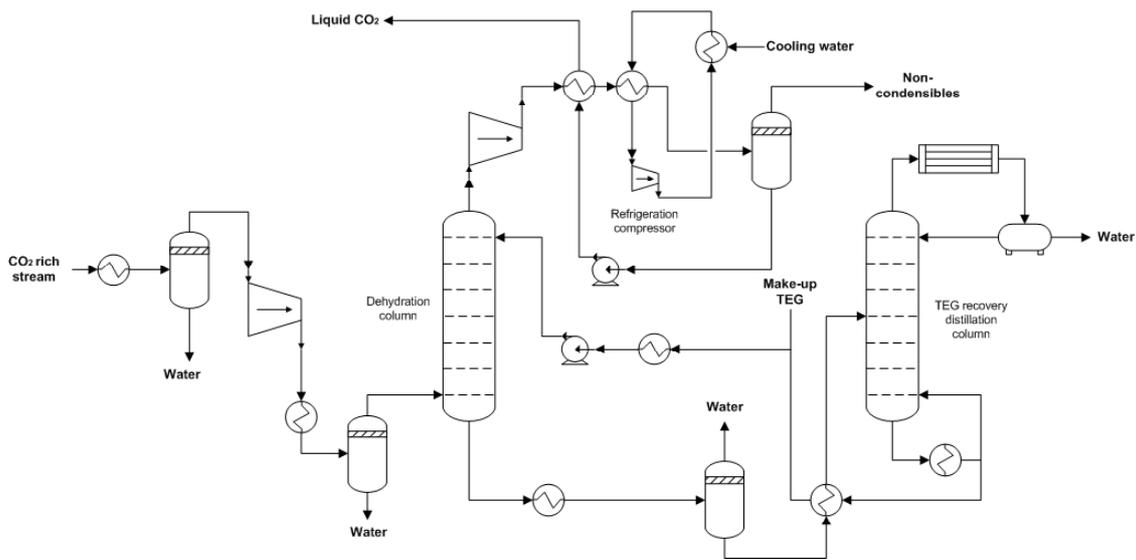


Figure 9 - Indicative process flowsheet arrangement for CO₂ compression and liquefaction from an oxy-fuel plant (see Feasibility Study Report Part 3)

Whilst the CO₂ recovery process uses unit operations that are well established, the nature of the raw flue gas feed is different in composition from the types of gases to which these processes are normally applied in the oil and gas industry and chemical industry. As a consequence, there is considerable uncertainty about the composition of final CO₂ product, the fate of certain inert gases such as NO, the power consumption involved in process and the overall recovery rate of CO₂ from the feed gas. Part 3 of this feasibility study examines these issues in considerable detail, and presents a simulation of a specific CO₂ recovery scenario for the Callide Oxyfuel case.

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