WandoanPower
a carbon solution

Wandoan Power Project
Pre-feasibility Study Knowledge Sharing Report

June 2011

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Unless otherwise stated, all costs in this report are expressed in Australian dollars.

To assist the reader an abbreviations list has been provided after the Contents page.

Enquiries

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Acknowledgements

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Executive Summary

Purpose of this report

In 2010, Stanwell Corporation Limited (Stanwell) and GE Energy LLC (GE) working as the Wandoan Power Consortium conducted a pre-feasibility study to assess the viability of an integrated gasification combined cycle (IGCC) power station capturing 90% of CO_2 from the fuel stream for transport and storage by CTSCo Pty Ltd (CTSCo).

This report seeks to share the study findings and describe the knowledge gained during this phase of the Wandoan Power Project (Wandoan Power). The knowledge sharing focuses on the Wandoan Power component (the IGCC with carbon capture) of the integrated Wandoan IGCC with CCS Project which was shortlisted for pre-feasibility studies under the Australian Government's CCS Flagships Program.

For knowledge related to carbon transport and storage investigations refer to the CTSCo Knowledge Sharing Report.

The target audience for the report is assumed to have a pre-requisite understanding of carbon capture and storage (CCS), utility power generation and project development. Learnings and issues that would be common to traditional generic power project development activities and processes, or location and jurisdiction specific topics have not been documented.

Key pre-feasibility study findings

The key aspects proposed for Wandoan Power have not fundamentally changed from those originally developed in the preceding concept/scoping study phase. A number of valuable insights have been gained with the following key findings:

- **Viability of technology confirmed.** GE's technology for an IGCC plant with 90% CO_2 capture is technically viable and can be deployed in Queensland at industrial scale as part of an integrated carbon capture and storage (CCS) project generating 341MW sent out at design temperature of 28°C with a CO_2 intensity of approximately 119 kg/MWh sent out. This CO_2 intensity is significantly lower than that of conventional fossil fuel power generation technologies e.g. black coal at 850-950 kg/MWh and gas-fuelled CCGT at approximately 400 kg/MWh.
- **Gasification learnings identified.** In the course of its pre-feasibility engineering work GE Gasification identified a number of key technical learnings which have direct applicability to Wandoan Power and could deliver cost reductions and/or performance benefits.
- **Potential site selected and secured.** A specific site near the town of Wandoan in Queensland has been selected and secured with a purchase option agreement. This site, close to the proposed source of coal feedstock, has been evaluated and found to be suitable for location of the proposed power station from engineering, infrastructure and environmental perspectives.
- **Development approval strategy selected.** Various options have been considered for obtaining the necessary project development approvals and an approvals strategy has been selected which offers a good prospect of success.

- **Integrated stakeholder relations strategy agreed.** The Proponents and Funding Stakeholders have agreed that successful development of a CCS project requires exemplary management of stakeholder relations and this consensus has formed the basis for an agreed stakeholder relations strategy going forward.
- **Schedule for integrated CCS by 2017/18 developed.** If the integrated Wandoan IGCC with CCS Project is developed with CO_2 storage exploration in parallel with power station design, then demonstration of integrated CCS could commence in 2017/18 at the earliest.

  It is expected that CTSCo will need a substantial quantity of CO_2 with defined quality and availability for 'proving-up' geological storage resources through CO_2 injection and plume monitoring. Such a source of CO_2 is currently not available via existing production processes. Wandoan Power will be able to provide this necessary source of CO_2 once it is operational.

  If power station design is only scheduled to commence after a program of CO_2 storage exploration has been undertaken (drilling and core analysis) then it would be very difficult to achieve a large-scale integrated CCS demonstration before 2020.
- **Capable EPC contractors identified and shortlisted.** The project has investigated market interest in development of Wandoan Power through an exercise to procure the services of a major construction firm to undertake front-end engineering and design (FEED) during a feasibility study phase. After considering a long list of ten candidates three firms were shortlisted for further consideration. Any one of these three firms has the capability to complete FEED in conjunction with GE Gasification and then proceed to deliver the project under a lump sum turn-key contract.
- **EPC procurement strategy enables feasibility study budget to be reduced.** This EPC procurement effort has enabled Wandoan Power to firm up its budget for the feasibility phase of the project. The target budget of $75 million over two years is significantly lower than earlier estimates developed during the scoping phase of this project. Finalisation of this budget can be undertaken once the outcome of the CCS Flagships Program is known.
- **Project funding explored.** Wandoan Power has developed a model for funding the project which enables a combination of grant funding and commercial funding. For the commercial funding portion, the opportunity to access US Ex-Im Bank finance has been explored and it appears that there is a good prospect of securing a substantial debt facility provided that normal project finance arrangements are in place. These arrangements would need to address the fact that this demonstration project will require a revenue stream comparable with that required for scalable renewable energy projects such as large-scale solar thermal projects.
- **Alternative CO_2 technologies compared.** Stanwell and GE have surveyed various other industrial-scale coal-fuelled CO_2 capture projects under evaluation, definition or deployment. Globally, only one of the 37 projects (Kemper IGCC) is proceeding to construction. Many of the other proposed projects aim to demonstrate the partial capture of CO_2 by retrofitting post combustion capture equipment to existing power station units. However, there are some issues which need to be better understood when comparing IGCC-based pre-combustion capture projects with post combustion capture projects:
  - **Scale-up risk:** Post combustion capture technologies have not been deployed at any significant scale with the largest deployments in the world to date being two 25MWe scale

pilot projects. This means that the development of larger scale post combustion capture projects is subject to considerable schedule, cost and performance risk.

- **Integration:** To date, most post combustion capture projects are proposed as add-on retrofits processing a small slipstream from existing pulverised coal power plants. This means that significant engineering development is still required to attain the high level of process integration required for existing or new plants if they are to achieve high levels of CO_2 capture with acceptable levels of energy efficiency.
- **CO_2 specification uncertainty:** Uncertainty and potential volatility surround CO_2 specification as post combustion capture processes have not yet been fully engineered for deployment at large scale with high levels of integration with power plants.

At this point in time an IGCC project with 90% pre-combustion capture of CO_2 is the most prospective technology for achieving successful demonstration of CCS through reliable production of CO_2 at a consistent specification.

Project cost estimates and economic analysis

Key aspects of the pre-feasibility cost estimation and analysis are summarised below:

- **Project capital cost estimated to -20% to +25% level of accuracy.** Wandoan Power's pre-feasibility study estimate is that the Total Installed Cost of the IGCC power station with CO_2 capture plant will be $3,773 million based on current costs and exchange rates. The estimate is generally to -20% to +25% accuracy. This means that the final capital cost is expected to be within a range from $3,020 million to $4,720 million.

  WorleyParsons and GE have provided most of the information used to develop the estimated capital cost. Their work has been performed to a prescribed standard (AACE[1]Class 4) and is based on the assumption that the project would be built using a high level of onsite fabrication.

  A major driver of the project's estimated capital cost is the high cost of doing work in a relatively remote Australian location. Preliminary engineering analysis by Worley Parsons and GE has identified some specific cost reduction opportunities including increased fabrication offsite, site layout adjustments and design enhancements. These cost reduction opportunities, worth in total approximately $200 million, have been taken into account by Wandoan Power in estimating the Total Installed Cost.

  Further cost reduction may be achieved through some targeted cost reduction activities including value engineering of the design and construction approach (aiming for more modularisation) together with some trade-off analysis of potential alternative project locations and optimisation of scope versus performance requirements.
- **Comparative analysis:** To assist various stakeholders to understand the Wandoan Power estimated cost in a way that supports comparative analysis across technologies and globally

[1] Association for the Advancement of Cost Engineering. For more information refer www.aacei.org.

this report also presents a normalised cost estimate based on generic assumptions and publicly available information from a US based IGCC project. This 'cost walk' exercise makes a number of stepped cost and performance adjustments to the publicly available project costs associated with the above-mentioned project, which were reported at the time of the analysis, to arrive at an estimated cost for single train 50 Hz project with 90% carbon capture located at Wandoan. Using a USD/AUD exchange rate of 1.00 results in an estimated Total Installed Cost of USD 3,067 million or USD 8,993 / kW for Wandoan Power. This figure is within the accuracy of Wandoan Power's pre-feasibility capital cost estimating range.

This 'cost walk' analysis indicates that a Wandoan sized 50Hz IGCC plant with 90% CO_2 capture normalised to ISO conditions and located in the US gulf coast region would cost USD 4,798 / kW. The incremental site specific cost of building the plant in Australia at Wandoan adds USD 4,195 / kW. The difference reflects a variety of factors including site ambient conditions (significantly warmer), local logistical requirements and local construction costs.

- **Levellised cost of electricity:** Wandoan Power's pre-feasibility study financial modelling indicates that if the project is developed with a grant funding contribution of $1,800 million applied to the construction phase then the project's levellised cost of electricity is $192/MWh in current dollars. This figure provides an indication of the average revenue that the plant owners would have to achieve to break even as it includes the cost of procuring a CO_2 offtake service from CTSCo and an assumed cost of capital.

  This cost is higher than current electricity prices in Australia which are based on fossil fuel technologies with high carbon emissions. However, the estimated levellised cost is competitive with costs for other scalable low emission technologies such as solar thermal.

Key planning decisions

Key planning decisions that helped guide the pre-feasibility study included the:

- **AACE framework.** The AACE cost estimation framework enabled Wandoan Power and the Funding Stakeholders to have a better, ongoing dialogue about objectives, outcomes and project maturity.
- **Monthly Steering Committee.** The Steering Committee, comprising both the integrated Project and funder representatives, provided an extremely valuable forum to report progress, receive guidance and ensure common understanding on issues that arose.

Lessons learned

In addition to the key findings discussed earlier, a number of key lessons were identified during the pre-feasibility study about management and delivery of this type of project:

- **Early alignment between all funding stakeholders is needed on objectives, timelines and funding.** Executing the pre-feasibility study work and complying with the various funders' requirements required significant administration and coordination efforts and presumed an alignment of strategy and intent which was not always apparent. A faster and more effective execution of CCS demonstration projects could be achieved with a pooled funding approach where a single agency with the appropriate administrative capacity and technical expertise coordinated and distributed funds. Such an approach would require early alignment of objectives, timelines and funding principles on the part of all interested funding stakeholders.

- **Project funding discontinuity creates challenges.** Establishing a better coordinated process for delivery of funding for CCS would assist project proponents in developing and retaining project team expertise and strategic relationships with contractors and other key counterparties.
- **Close coordination is required between the integrated Project Proponents.** The integrated project structure comprising separate proponents for the power station and CO_2 storage projects enabled each proponent to focus on its strengths. However, a good flow of information between the projects and a coordinated approach to common activities such as risk, schedule and stakeholder engagement was needed for this arrangement to work effectively.
- **CCS requires a number of timely legislative, regulatory and policy decisions to be made.** Regulatory activities need to feature clearly in the scheduling of project activities and all parties need to have clear visibility of the project impact if decisions or timing does not align with project schedule expectations.
- **Targeted site selection enables detailed study and facilitates earlier permitting discussions.** Given Australia's non-prescriptive environmental permitting approach and regulators who are unfamiliar with this new technology, commencing detailed permitting early draws out potential issues affecting project decision making and facilitates discussion with regulators.
- **Traditional power station site selection assumptions do not necessarily translate to this kind of project.** The site selection criteria may be different for projects demonstrating new technologies to those for well established technologies.
- **Private sector incentivisation requires further thinking.** This could entail clarification of assumptions about what activity is reasonable to expect private sector firms to invest in as research and development and what work is of a nature that requires public sector support. At present there are no obvious high-level principles or shared assumptions that form a framework for ongoing decision making. Furthermore, given the innovative nature and large size of CCS demonstration projects there appears to be scope for simplifying and clarifying the taxation incentives that apply to private sector investments in demonstration projects.

Recommendations summary and value proposition

The Wandoan Power Project, executed in parallel with the integrated CO_2 transport and storage work program proposed by CTSCo, offers a unique value proposition that would enable Australia to achieve demonstration of coal-fuelled CCS power generation at industrial scale before 2020.

The next step in a carefully managed project development process is to undertake more detailed project investigations and engineering which would deliver:

- Evaluation and confirmation of opportunities for significant capital cost reduction.
- A final plant design based on a specific location with detailed plant layout and plot plan.
- Completion of the major project development and environmental approvals and permit processes.

- Firm contractual arrangements for plant procurement involving an experienced global EPC contractor.
- Capital and operating costs estimated to AACE Class 2 with -10% +15% level of accuracy.
- A financing plan including detailed arrangements for equity, debt and grant funding contributions.
- A comprehensive report presenting a business case for making a Financial Investment Decision about construction of the power station with carbon capture.

The Proponents are in the process of preparing a detailed proposal for undertaking further work which would include a significant amount of engineering work performed by GE Gasification and an EPC firm in accordance with a carefully integrated work plan. Wandoan Power is targeting an estimated cost of $75 million over two years for this phase which could be approximately one third of the overall cost for the integrated CCS Project, with the remaining two thirds of expenditure being required for ‘proving up’ of carbon storage opportunities.

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Abbreviations and glossary

Abbreviation	Description
AACE	Association for the Advancement of Cost Engineering
AEMO	Australian Energy Market Operator
AUD	Australian dollar
ACA	Australian Coal Association
ACALET	Australian Coal Association Low Emissions Technologies Ltd
AGR	Acid Gas Removal
AHD	Australian height datum
APFS	Accelerated Pre-feasibility Study
ASU	Air separation unit
ad	Air-dried
ar	As received
BoP	Balance of plant
^{o}C	Degree Celsius
CCGT	Closed cycle gas turbine
CCS	Carbon capture and storage
CHP	Coal handling plan
CO	Carbon Monoxide
CO_2	Carbon dioxide
CO2CRC	Cooperative Research Centre for Greenhouse Gas Technologies
COD	Commercial Operation Date
CSA	Coal Supply Agreement
CSG	Coal seam gas
CTA	Carbon transport agreement
CTG	Combustion turbine generator
CTS	Carbon transport and storage
CTSCO	Carbon Transport and Storage Company Pty Ltd
Daf	Dry ash free
DERM	Department of Environment and Resource Management
DFS	Definitive Feasibility Study
DOR	Division of Responsibility

Abbreviation	Description
DRET	Department of Resources, Energy and Tourism
EEP	Engineered equipment package
ESOO	Electricity Statement of Opportunity
e.g.	For example
EHV	Extra high voltage
EIS	Environmental impact study
EPA	Environmental Protection Agency
EPBC	Environment Protection and Biodiversity Conservation
EPC	Engineer procure and construct
EPRI	Electric Power Research Institute
EUR	Euros
Ex-Im	Export-Import Bank of the United States
FEED	Front-end engineering design
FID	Financial Investment Decision
FX	Foreign Exchange
G8	Group of Eight countries (US, Japan, Germany, France, Britain, Italy, Canada, and Russia).
GCCSI	Global Carbon Capture and Storage Institute
GE	GE Energy
GEG	GE Gasification
GHG	Greenhouse gas
GJ	Gigajoule
GST	Goods and Services Tax
GT	Gas Turbine
HAZAN	Hazard analysis
HAZOP	Hazard and operability study
HHV	High heating value
HRSG	Heat recovery steam generator
HV	High voltage
Hz	Hertz
i.e.	That is
IGCC	Integrated gasification combined cycle
IP	Intellectual property
ISO	International Standards Organisation

Abbreviation	Description
k	Thousand
kJ	Kilojoule
kg/hr	Kilograms per hour
kg/MWh	Kilogram per megawatt hour
KPa	Kilo Pascals absolute
kt/a	Kilotonne per annum
kV	Kilovolt
kWh	Kilowatt hour
kW	Kilo watt
L	Litre
l/MWh	Litres per megawatt hour
LLC	Limited Liability Company
LNG	Liquefied natural gas
LP	Low pressure
LSTK	Lump Sum Turn-Key
LV	Low voltage
m	Million
mg/Nm3	Milligrams per normal cubic metre
Ml/a	Mega litres per annum
Ml	Mega litre
MLF	Marginal loss factor
mm	millimetres
MOU	Memorandum of understanding
MP	Medium pressure (steam)
MPag	Mega pascals gauge
Mt	Million tonnes
Mtpa	Million tonnes per annum
MV	Medium voltage
MW	Megawatt
MW^e	MW equivalent
MWh	Megawatt hour
N_2	Nitrogen

Abbreviation	Description
NEM	National Electricity Market
NG	Natural gas
NOC	Normal Operating Case
NOx	Oxide of nitrogen
NPV	Net present value
NTP	Notice to Proceed
O&M	Operation and maintenance
O_2	Oxygen
OE	Owners engineer
OEM	Original equipment manufacturer
OHS	Occupational health and safety
P90	90% probability that the value is exceeded
P10	10% probability that the value is exceeded
PC	Pulverised Coal
PCC	Post Combustion Capture
PFA	Project Funding Agreement
PPA	Power Purchase Agreement
PM	Particulate matter
PM10	Particulate matter with an aerodynamic diameter of up to 10 µm, i.e. the fine and coarse particle fractions combined.
PMBOK	Project Management Body of Knowledge
POE	Probability of event
PPM	Parts per million
ppmvd	Parts per million volume dried
ppmvw	Parts per million volume wet
PPP	Public Private Partnership
R&D	Research and development
RFP	Request for Proposal
RH	Relative humidity
RSC	Radiant syngas cooler
SO_2	Sulphur dioxide
SOx	Oxide of sulphur
SRU	Sulphur recovery unit

Abbreviation	Description
Stanwell	Stanwell Corporation Limited
STG	Steam turbine generator
T	Tonne
t/a	Tonnes per annum
t/d	Tonnes per day
t/MWh	Tonnes per mega watt hour
The Consortium	Stanwell and GE
The Project	Wandoan IGCC with CCS Project
TIC	Totalled installed cost
ToR	Terms of Reference
Tpa	Tonnes per annum
UCG	Underground coal gasification
UJV	Unincorporated joint venture
µm	micron
USC	Ultra supercritical
USD	United States dollar
USGC	US Gulf Coast
Wandoan Power	Wandoan Power Project
WBS	Work Breakdown Structure
wt%	Weight percentage
XCQ	Xstrata Coal Queensland
ZPWD	Zero-process water discharge
3D	Three dimensional

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Appendix list

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2	CO_2 Capture Technology Selection and its Role in Moving CCS Forward
3	IGCC with CO_2 Capture Process Summary
4	Wandoan Power General Site Plot Plan
5	Wandoan Power Project: Non-confidential Report

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1. Introduction

1.1 Background

The Wandoan IGCC with CCS Project (the Project) is proposed as an opportunity to develop an integrated gasification combined cycle (IGCC) power station with carbon capture and storage (CCS) near Wandoan in Queensland's Surat Basin.

While IGCC, pre-combustion capture and CO_2 transportation and storage have been proven individually, no coal power generation facility has integrated these technologies to provide electricity with significantly reduced carbon emissions. By integrating IGCC with CCS, the Project would be of international significance and set new standards for low emission technologies.

Planning for the Project began in 2008 with initial concept and definition studies. In September 2009, the integrated Project was jointly nominated by the Queensland Government and ACALET for consideration by the Australian Government under the CCS Flagships Program, part of the Clean Energy Initiative, which aims to support the research, development and demonstration of low emission technologies.

In December 2009, the CCS Flagships Program shortlisted the integrated Project for advancement to the pre-feasibility stage of development.

1.2 Integrated Project objective

The integrated Project objective is to demonstrate at industrial scale by 2020:

- The generation of electricity with low CO_2 emissions using coal feedstock.
- The long-term secure geological storage of CO_2.

The Project also aims to:

- Pursue so far as is practical a commercial approach to the development of the Project and identify issues and obstacles which will require government support by way of legislation, grant funding, or change to public policy and seek appropriate resolution.
- Acquire and maintain a 'social licence to develop and operate' the Project through effective management of stakeholder relations.
- Secure available debt funding on acceptable terms required to fund part of the Project.
- Secure sufficient non-commercial grant and other funding or equivalent instruments to close the gap between available commercial funding and the total funding required to be financially viable for both the IGCC with CO_2 capture plant and the CO_2 transportation and storage elements.

1.3 Project structure

Utilising the Project partners' strengths and experience, the Wandoan IGCC with CCS Project is being developed in two integrated components:

- The Wandoan Power Project (Wandoan Power) comprising an IGCC power station with pre-combustion carbon capture – a development by the Wandoan Power Consortium (a joint venture between Queensland energy generator Stanwell Corporation and global technology provider GE Energy).
- Carbon transport and storage facilities being developed by CTSCo, a subsidiary of global mining company Xstrata Coal.

1.4 Purpose of this report

In 2010, Stanwell Corporation Limited (Stanwell) and GE Energy LLC (GE) working as the Wandoan Power Consortium (the Proponents) undertook a pre-feasibility study to assess the viability of an IGCC power station capturing 90% of CO_2 from the fuel stream for transport and storage by CTSCo. The Wandoan Power pre-feasibility program was funded jointly by the Australian Government, ACA Low Emission Technologies Limited (ACALET), Stanwell and GE. CTSCo received funding from the Australian Government, ACALET and the Queensland Government.

This report discusses pre-feasibility investigations into the viability of developing the IGCC power station with carbon capture at a site near Wandoan.

This report seeks to share the knowledge gained during the pre-feasibility study. The knowledge sharing focuses on the Wandoan Power (IGCC with carbon capture) component of the integrated Project. For knowledge related to carbon transport and storage investigations refer to the CTSCo Knowledge Sharing Report.

1.5 Wandoan Power Project description

Wandoan Power is proposed as an opportunity to demonstrate coal-fuelled power generation with low CO_2 emissions by capturing CO_2 that is ready for carbon transport and storage.

Power station technology

The power station will use GE's IGCC technology with up to 90% capture of carbon from the gasification fuel stream.

Prior to the pre-feasibility study, Stanwell conducted a review of suitable technology options and found GE's gasification technology is the most commercially mature option for achieving industrial scale coal-fuelled power generation with a high rate of CO_2 capture. Globally, nearly 70 gasification plants have been supplied with GE technology and more than half of these separate and capture up to 90% CO_2 from their processes. Furthermore, almost half of all existing and planned IGCC plants worldwide use GE technology.

Further discussion regarding technology selection is included in section 4.1.

Configuration and size

Using GE's commercially available gasification and power generation technology, the single train IGCC plant is expected to produce 341MW of sent out generation, assuming 90% capture of CO_2 (75Mt over 30 years).

The proposed configuration has not changed since the concept study. However the pre-feasibility study has improved the level of engineering definition with the calculated sent out capacity increasing from 334MW to 341MW. Efficiency has also increased to 29.1% (HHV basis).

This size and configuration enables Wandoan Power to demonstrate technology performance at industrial scale. While a two-train configuration, doubling the size of the power station, does offer economies of scale on a levellised cost of electricity basis, it would increase the total project cost and require a greater amount of total funding.

In addition, the amount of CO_2 captured from a two train plant would be approximately five million tonnes per annum. An increase in plant size and the amount of CO_2 captured would have significant implications for the scale and maturity of the required CO_2 storage program.

Development timeframe

The target date for commercial operation of the project is 2017/18 or as soon after this date as is practicable. This target date is aligned with the G8 goal of deploying 20 large-scale CCS projects by 2020.

However, the rate at which Wandoan Power progresses is dependent upon the willingness of funding stakeholders to support the project by funding further development.

Anticipated delivery strategy

The next task is to select, on a competitive basis, an engineer, procure and construct (EPC) contractor to build the power project with GE being a nominated subcontractor for provision of gasification technology, power generation and gasification equipment.

The Wandoan Power Proponents are in the final stage of a carefully structured competitive EPC selection process designed to ensure the best prospect of value for money. The selection process has been designed to identify EPCs that are highly experienced and well qualified in design, procurement, construction and start-up of commercial scale, state-of-the-art, reliable and commercially proven and safe gasification and combined cycle plants.

The selection will be finalised if the project is selected under the CCS Flagships Program to proceed into a feasibility study phase.

Location

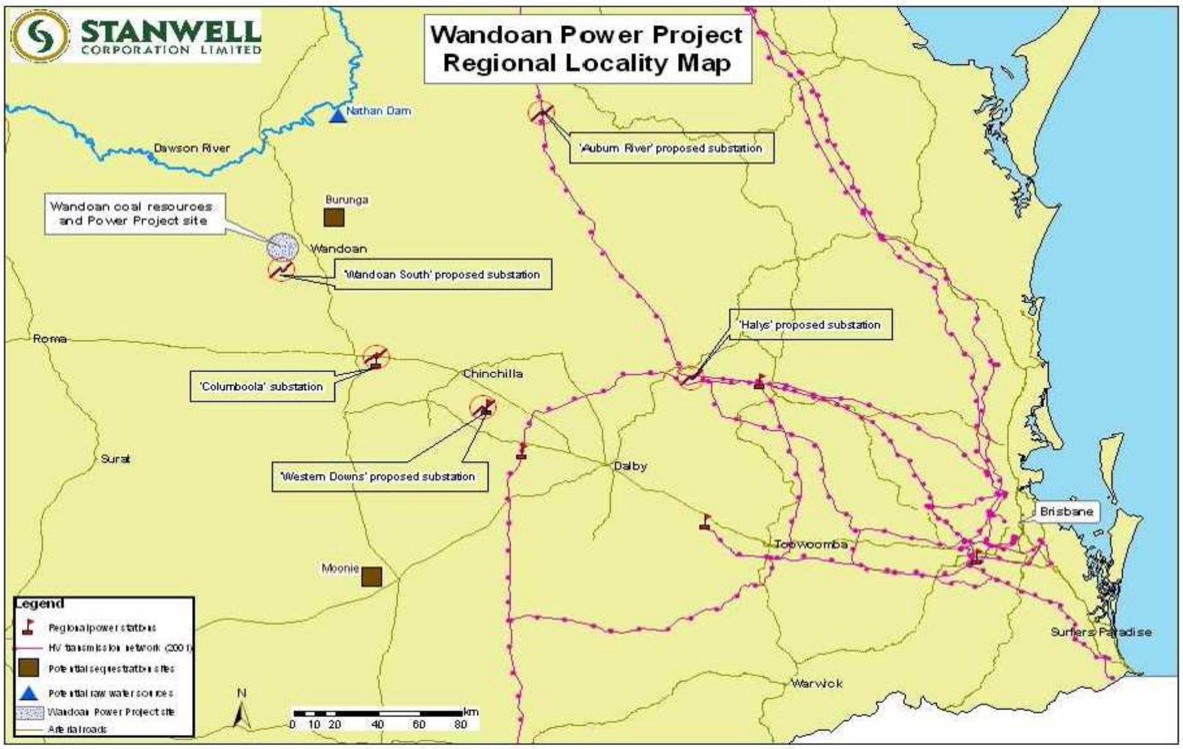
Wandoan Power's proposed location is shown in the map presented below in Figure 1-1. The Surat Basin is the preferred project location because it is close to the Queensland electricity load centre. Locations further north (e.g. the Bowen Basin) or north-west (the Galilee Basin) would create significant challenges for achieving commercially-viable connection to the electricity transmission grid.

Within the Surat Basin the Wandoan Coal resource is preferred due to its large size and anticipated low mining cost based on favourable strip ratios and economies of scale. A location adjacent to the coal resource enables the project to avoid the cost of transporting coal by rail.

Other project resource requirements (water and natural gas) are generally available in the Surat Basin.

A site close to the proposed Wandoan Coal Mine has been selected and secured via a purchase option agreement. Preliminary environmental and geotechnical investigations have also been undertaken and have confirmed from these perspectives the site's suitability for a power station.

Figure 1-1 Wandoan Power Project regional locality map



1.6 Market assessment

The Australian Energy Market Operator (AEMO) currently forecasts that due to steady demand growth, Queensland will need at least 3,000MW of additional generation capacity by 2018. As there is limited transfer capacity with other regions of the National Electricity Market most of this new power station capacity will probably be located in Queensland.

Australian and Queensland Government policy and regulation determine which power generation technologies can be considered and influence their commercial viability. A major policy objective in Australia is long-term reduction of CO_2 emissions, initially through limiting deployment of high emission coal-fuelled power stations. However, at this point in time the range of alternative technologies with lower CO_2 emission intensity is limited.

Coal-fuelled power generation with carbon capture and storage has the potential to achieve significant reductions in CO_2 emissions and contribute to reducing Global Warming Potential. Of the various technologies for capturing CO_2, the only one currently ready for industrial scale deployment at high capture rates is IGCC with 90% pre-combustion capture of CO_2 from the fuel stream.

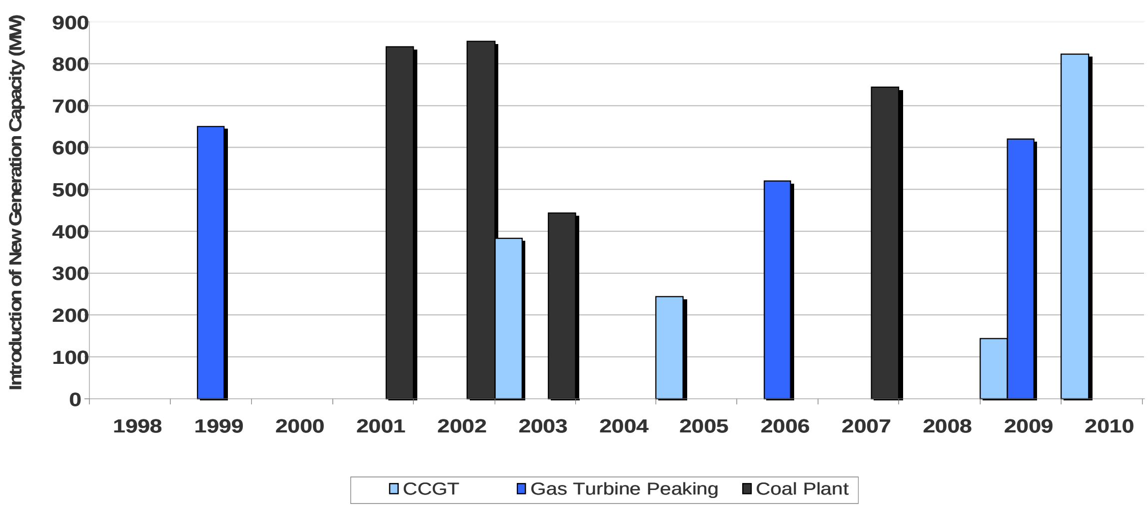
1.6.1 Market Description

As at 2010/11 the Queensland region of Australia's interconnected National Electricity Market (NEM) features typical peak load demand of approximately 6,000 to 8,000MW depending upon daily weather and economic factors. At off-peak times (late evening to early morning) demand typically reduces to levels ranging from 4,000 to 5,000MW. Annual energy demand for 2009/10 was approximately 45,000 GWh.

Queensland's maximum electricity demand is usually experienced in summer when hot weather drives high air conditioning demand. Summer 2009/10 maximum demand was 9,070MW. NEM operator AEMO has forecast that maximum demand for the current 2010/11 year could range between 9,702MW and 10,524MW with probability of event (POE) ranging, from 90% to 10%[2]

Most of Queensland's demand for electricity is supplied from more than 12,000MW of generation plants located in this state. Pulverised coal-fuelled power stations installed progressively over the past four decades constitute the bulk of this capacity including four supercritical power stations commissioned between 2001 and 2007. Approximately 3,000MW of gas turbine plants have been installed over the past twelve years mostly fuelled with coal seam gas (CSG) produced in Queensland. The technology profile of plant installed over the past decade is illustrated in Figure 1-2 below.

Figure 1-2 Queensland electricity generation new plant capacity by type



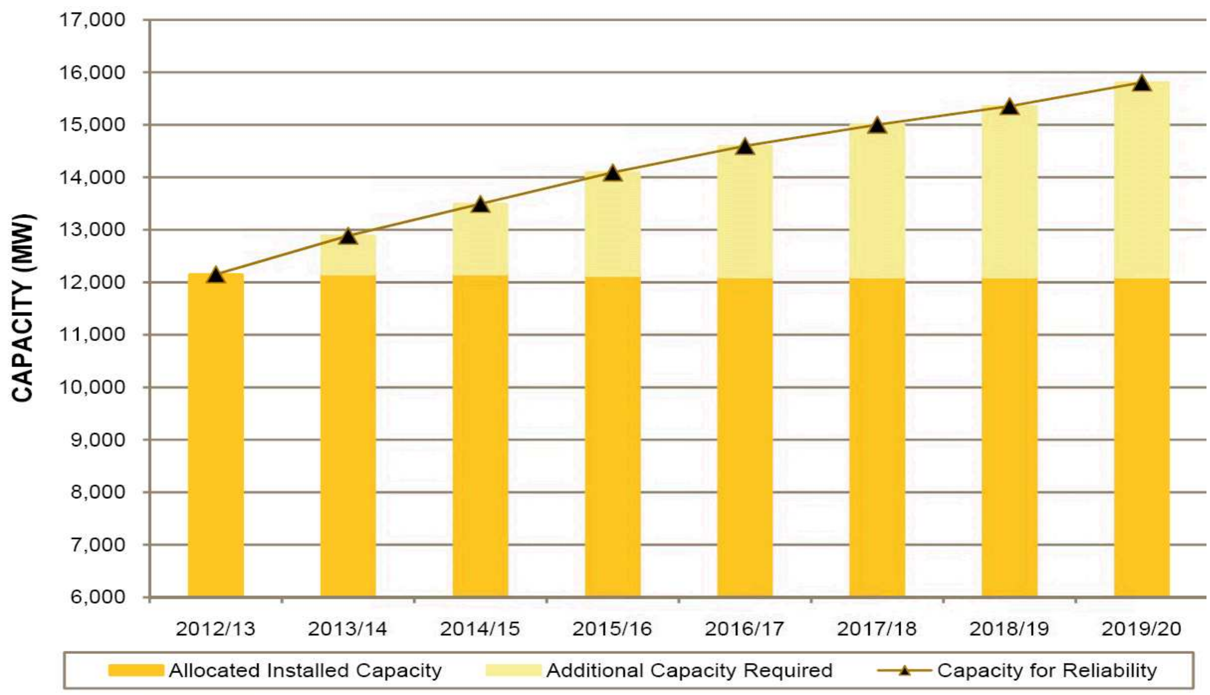
[2] AEMO 2010 Electricity Statement of Opportunities Table 4.8 Queensland summer maximum demand projections (MW), http://www.aemo.com.au/planning/0410-0054.pdf

1.6.2 Market projections

AEMO produces an annual Electricity Statement of Opportunities (ESOO), which informs NEM participants about expected and forecasted changes to supply and demand for electricity by region. The latest available ESOO includes medium growth scenario forecasts that over the next ten years electrical energy consumption in Queensland will grow by 3.9% per annum and maximum demand will grow by 4.1% per annum.[3] Based on the medium growth scenario AEMO indicates that Queensland could need 3,000MW of new generation capacity by 2017/18.[4]

Historical and forecast growth in demand for electricity in Queensland indicate good investment prospects for introduction of new power generation capacity over the next decade. Just as the existing Queensland market requires a mix of plant types (baseload, shoulder and peaking) it is likely that a combination of plant types (baseload, shoulder and peaking) will be needed to meet the overall growth in demand.

Figure 1-3 Queensland summer supply demand outlook



Source - AEMO 2010 Electricity Statement of Opportunity Chapter 7 Figure 7.2. Reproduced with the kind permission of AEMO)

[3] AEMO 2010 Electricity Statement of Opportunity Chapter 4

[4] AEMO 2010 Electricity Statement of Opportunity Chapter 7 Figure 7.2

2. Pre-feasibility study outcomes

2.1 Key pre-feasibility findings

The key aspects proposed for Wandoan Power have not fundamentally changed from those originally developed in the preceding concept/scoping study phase.

A number of valuable insights have been gained with the following key findings:

Viability of technology confirmed

GE's technology for an IGCC plant with 90% CO_2 capture is technically viable and can be deployed in Queensland at industrial scale as part of an integrated carbon capture and storage (CCS) project generating 341MW sent out at design temperature of 28°C with a CO_2 intensity of approximately 119 kg/MWh sent out. This CO_2 intensity is significantly lower than that of conventional fossil fuel power generation technologies e.g. black coal at 850-950 kg/MWh and gas-fuelled CCGT at approximately 400 kg/MWh.

Gasification learnings identified

In the course of its pre-feasibility engineering work GE identified a number of key technical learnings which have direct applicability to Wandoan Power and could deliver cost reductions and/or performance benefits. Among these learnings:

- **Simplification of Zero Process Water Discharge (ZPWD) thermal section:** A typical ZPWD Thermal Section contains three processes: evaporation, crystallisation, and salt drying. Since the Wandoan coal feedstock is a low chloride coal, the grey water blowdown flow-rate, its characteristic, and the ZPWD treatment effectiveness enable the Thermal Section to reduce from three to two processes: evaporation and salt drying. The elimination of crystallisation process reduces both capital and operating costs.
- **Syngas expander:** A turbo expander was included in the project for generation of power utilising the required drop in pressure in the syngas stream leaving the Acid Gas Removal (AGR) enroute to the gas turbine. GE's application of a high-pressure gasifier design in the Wandoan configuration ultimately allows the expander to generate more power. Normal design for controlling pressure in the clean syngas off the AGR to the gas turbine would be regulating the drop across a control valve.
- **No air extraction:** Gas turbine air extraction is commonly utilised for low-Btu, non-capture syngas fuel applications to maximise plant output by reducing the ASU main air compressor auxiliary load. Wandoan Power's high-hydrogen syngas fuel, resulting from 90% CO_2 capture and high rating point ambient temperature for normal operation, allows for introduction of nitrogen for increased mass flow to the gas turbine, increasing the gas turbine output. The loss of gas turbine output due to air extraction would be higher than the ASU auxiliary load reduction so air extraction is not recommended.

- **Superheated medium pressure steam:** The majority of the residual heat in the shift section is utilised to generate steam. The temperature profile between the first and second shift reactor is suitable to generate and superheat medium pressure steam, which is more valuable than low pressure steam. Sending medium pressure steam to the steam turbine allows the steam to expand across both the medium and low pressure sections of the turbine, thus producing more output than generation of only low pressure steam from the shift section.
- **Expanded radiant gasification train:** An expanded-size gasifier and radiant syngas cooler was applied in the Wandoan pre-feasibility study. This product is capable of producing enough syngas to fully load a single 9F syngas Gas Turbine and achieve optimised steam make for 90% carbon capture. Compared with a US based 60Hz project the scale-up factor for the gasifier is approximately 1.4 and for the radiant syngas cooler is less than this value. This level of scale-up is considered to be manageable.

Potential site selected and investigated

The Wandoan area in Queensland was selected using traditional power station criteria (e.g. proximity to fuel, water, and transmission connection) and additionally because it is within a reasonable distance of prospective sites for CO_2 storage.

A specific site near the town of Wandoan has been selected and secured with a purchase option agreement. This site has been evaluated and found to be suitable for location of the proposed power station from engineering, infrastructure and environmental perspectives.

Development approval strategy selected

Various options have been considered for obtaining the necessary project development approvals and an approval strategy has been selected which offers a good prospect of success.

Integrated stakeholder relations strategy agreed

The integrated Project Proponents and Funding Stakeholders have agreed that successful development of a CCS project requires exemplary management of stakeholder relations and this consensus has formed the basis for an agreed stakeholder relations strategy going forward.

Schedule for integrated CCS by 2017/18 developed

If the integrated Project is developed with CO_2 storage exploration in parallel with power station design, then demonstration of integrated CCS could commence in 2017/18 at the earliest. It is expected that CTSCo will need a substantial quantity of CO_2 with defined quality and availability for ‘proving-up’ geological storage resources through CO_2 injection and plume monitoring. Such a source of CO_2 is currently not available via existing production processes. Wandoan Power will be able to provide this necessary source of CO_2 once it is operational.

If power station design is scheduled to commence only after a program of CO_2 storage exploration has been undertaken (drilling and core analysis) then it would become very difficult to achieve a large-scale integrated CCS demonstration before 2020.

Capable EPC contractors identified and shortlisted

The project has investigated market interest in development of Wandoan Power through an exercise to procure the services of a major construction firm to undertake front-end engineering and design (FEED) during the feasibility study phase. A selection process has been designed to identify EPCs that are highly experienced and well qualified in design, procurement, construction and start-up of commercial scale, state-of-the-art, reliable and commercially proven and safe gasification and combined cycle plants.

Prospective EPCs have been assessed using specific selection criteria including: experience with and ability to manage large turn-key projects, general commercial approach, knowledge of local codes and labour, local presence, partnerships and alliances, on-site capabilities, financial strength, work history with the technology, quality management, workplace health and safety and environmental management

After considering a long list of ten candidates three firms have been shortlisted for further consideration. Any one of these three firms has the capability to complete FEED in conjunction with GE and then proceed to deliver the project under a lump sum turn-key contract.

EPC procurement strategy enables feasibility study budget to be reduced

This EPC procurement effort has enabled Wandoan Power to firm up its budget for the feasibility phase of the project. The target budget of $75 million over two years is significantly lower than earlier estimates developed during the scoping phase of this project. Finalisation of this budget can be undertaken once the outcome of the CCS Flagships Program is known.

Project funding explored

Wandoan Power has developed a model for funding the project which enables a combination of grant funding and commercial funding. For the commercial funding portion, the opportunity to access US Ex-Im Bank finance has been explored and it appears that there is a good prospect of securing a substantial debt facility provided that normal project finance arrangements are in place. These arrangements would need to address the fact that this demonstration project will require a revenue stream comparable with that required for scalable renewable energy projects such as large-scale solar thermal projects.

Alternative CO_2 technologies compared

Stanwell and GE have surveyed various other industrial scale coal-fuelled CO_2 capture projects under evaluation, definition or deployment. Globally, only one of the 37 projects (Kemper IGCC) is proceeding to construction. Many of the other proposed projects aim to demonstrate the partial capture of CO_2 by retrofitting post combustion capture equipment to existing power station units. However, there are some issues which need to be better understood when comparing IGCC-based pre-combustion capture projects with post combustion capture projects:

- **Scale-up risk:** Post combustion capture technologies have not been deployed at any significant scale with the largest deployments in the world to date being two 25MWe scale pilot projects. This means that the development of larger scale post combustion capture projects is subject to considerable schedule, cost and performance risk.
- **Integration:** To date, most post combustion capture projects are proposed as add-on retrofits processing a small slipstream from existing pulverised coal power plants. This means that significant engineering development is still required to attain the high level of process integration

required for existing or new plants if they are to achieve high levels of CO_2 capture with acceptable levels of energy efficiency.

- **CO_2 specification uncertainty:** Uncertainty and potential volatility surround CO_2 specification as post combustion capture processes have not yet been fully engineered for deployment at large scale with high levels of integration with power plants.

Stanwell has prepared a report surveying various large-scale, coal-fuelled power generation projects with carbon capture. In addition, Wandoan Power has also prepared a discussion paper on some of the issues of concern with regard to post combustion capture technology. These documents are provided as Appendix 1 and 2 respectively.

2.1.1 Project cost estimates and economic analysis

Key aspects of the pre-feasibility cost estimation and analysis are summarised below

Project capital cost estimated to -20% to +25% level of accuracy

Wandoan Power's pre-feasibility study estimate is that the Total Installed Cost of the IGCC power station with CO_2 capture plant will be $3,773 million based on current costs and exchange rates. The estimate is generally to -20% to +25% accuracy. This means that the final capital cost is expected to be within a range from $3,020 million to $4,720 million.

WorleyParsons and GE have provided most of the information used to develop the estimated capital cost. Their work has been performed to a prescribed standard (AACE[5]Class 4) and is based on the assumption that the project would be built using a high level of onsite fabrication.

A major driver of the project's estimated capital cost is the high cost of doing work in a relatively remote Australian location. Preliminary engineering analysis by Worley Parsons and GE has identified some specific cost reduction opportunities including increased fabrication offsite, site layout adjustments and design enhancements. These cost reduction opportunities, worth in total approximately $200 million, have been taken into account by Wandoan Power in estimating the Total Installed Cost.

Further cost reduction may be achieved through some targeted cost reduction activities including value engineering of the design and construction approach (aiming for more modularisation) together with some trade-off analysis of potential alternative project locations and optimisation of scope versus performance requirements.

Comparative analysis

To assist various stakeholders to understand the Wandoan Power cost estimate in a way that supports comparative analysis across technologies and globally this report also presents a normalised cost estimate based on generic assumptions and publicly available information from a U.S. based IGCC project. This 'cost walk' exercise makes a number of stepped cost and performance adjustments to the publicly available project costs associated with the above-mentioned project, which were reported at the

[5] Association for the Advancement of Cost Engineering. For more information refer www.aacei.org.

time of the analysis, to arrive at an estimated cost for single train 50 Hz project with 90% carbon capture located at Wandoan. Using a USD/AUD exchange rate of 1.00, results in an estimated Total Installed Cost for Wandoan Power of USD 3,067 million or USD 8,993 /kW. This figure is within the accuracy of Wandoan Power's pre-feasibility capital cost estimating range.

This 'cost walk' analysis indicates that a Wandoan sized 50Hz IGCC plant with 90% CO_2 capture normalised to ISO conditions and located in the US gulf coast region would cost USD 4,798 / kW. The incremental site specific cost of building the plant in Australia at Wandoan adds USD 4,195 / kW. The difference reflects a variety of factors including site ambient conditions (significantly warmer), local logistical requirements and local construction costs.

Levellised cost of electricity

Wandoan Power's pre-feasibility study financial modelling indicates that if the project is developed with a grant funding contribution of $1,800 million applied to the construction phase then the project's levellised cost of electricity is $192/MWh in current dollars. As this figure includes the cost of procuring a CO_2 offtake service from CTSCo (refer 6.2.1 below) and an assumed cost of capital, it gives an idea of the average revenue that the plant owners would have to achieve to break even.

This cost is higher than current electricity prices in Australia which are based on fossil fuel technologies with high carbon emissions. However, the estimated levellised cost is competitive with costs for other scalable low emission technologies such as solar thermal.

2.2 Key planning decisions

AACE methodology

The Association for the Advancement of Cost Engineering (AACE) framework[6] for cost estimate development provided a valuable, industry-accepted approach for assessing the maturity of the project. Initially, Wandoan Power developed its scope of work for the pre-feasibility study absent this framework. Adopting the AACE framework to determine how to refine the original pre-feasibility study scope of work enabled Wandoan Power to have a better ongoing dialogue with all of the Funding Stakeholders about objectives, outcomes and maturity of the project.

Monthly Steering Committee

While the Project Proponents maintained responsibility for day-to-day administration of the project, a Steering Committee was established, as required by the project funding agreements, to oversee implementation of the pre-feasibility study. The Steering Committee comprised representatives of the integrated Project Proponents and each of the Funding Stakeholders. Each party appointed their own representatives who together combined experience in commercial project development, legislation, geology and power station technology. Furthermore, all members possessed the necessary understanding of the project to provide meaningful input to the meetings.

[6] For more information on the AACE framework refer to www.aacei.org.

The key functions of the Steering Committee were to:

- Provide strategic advice on the work to be undertaken as part of the pre-feasibility study taking into account information both internal and external to the project.
- Review project reports including monthly financial and progress reports.
- Establish review processes for evaluating the progressive performance of the project.
- Approve changes to the project scope, structure and/or schedule, and where necessary approve changes to project expenditure or release of contingency funds.

These monthly meetings became an extremely valuable forum in which to report progress, receive guidance, and ensure common understanding amongst all parties of any issues that arose. This forum also revealed where stakeholders were not aligned on goals for the project development, such as the announcement in late 2010 by Queensland that it would no longer support power station development but instead focus its resources exclusively on underground CO_2 storage development. The monthly meeting was well run and parties prepared and circulated relevant topics and papers for discussion at the meeting, which facilitated a continuous communication flow amongst all concerned.

2.3 Lessons learned

There have been a number of key lessons learned about project management and delivery from the pre-feasibility study.

Early alignment of objectives, timelines and funding

The integrated Project involved two project components (Wandoan Power and CTSCo) and three funders operating in accordance with a number of funding and coordination agreements. Putting these agreements into place required considerable resources on the part of both proponents and funders. Executing the pre-feasibility study work and complying with the various requirements took significant administration and coordination effort and presumed an alignment of strategy and intent which was not always apparent. Indeed, during the course of the pre-feasibility study strategic divergence was exhibited over issues such as the timetable for demonstrating CCS and responsibility for provision of funding support. Execution of projects demonstrating CCS which by their very nature are large, expensive and long term could be achieved more quickly and effectively if available funding resources were pooled and distributed through a single coordinating agency which has the necessary administrative capacity and technical expertise. Such an approach would require early alignment of objectives, timelines and funding principles on the part of all interested funding stakeholders.

To facilitate ongoing alignment and knowledge sharing funder representatives could even be embedded into project teams.

Continuity of project funding

Establishing a better coordinated process for delivery of funding for CCS would assist project proponents in developing and retaining project team expertise and strategic relationships with contractors and other key counterparties. Conversely, if funding is trickled out for particular stages and then followed by long periods of funding assessment activity, project proponents will struggle to retain key people and subsequently incur significant costs and delays in mobilisation for future phases of work.

Role of governments in legislation, regulation and policy

The development of a new technology such as CCS will require a number of legislative, regulatory and policy decisions to be made during the project development lifecycle. If governments make satisfactory decisions in a timely fashion then the process of project development will not be hindered. Given the newness of some aspects of CCS, it is inevitable that governments need to be informed by project proponents about the issues that need decisions. A close working relationship between project proponents and regulators appears to be the most appropriate way for the necessary regulatory decision making to occur. This means that regulatory activities need to feature clearly in the scheduling of project activities and all parties need to have clear visibility of the consequences for the project if decisions are not made in accordance with project schedule expectations.

By way of example, it is clear based on various technical and economic studies that a CCS project is likely to require a higher level of revenue than that indicated by current electricity prices in Australia. This issue will have to be addressed very soon if there is to be any meaningful progress in development of CCS in Australia. Project proponents would be prepared to undertake some further work during a feasibility study phase but only with the expectation that the relevant government and regulatory agencies are working within a defined timeframe to introduce suitable revenue support mechanisms. These support mechanisms would have to be achieved before the project can reach a Financial Investment Decision.

For further discussion of issues relating to regulatory and legislative uncertainty for Wandoan Power refer to section 3.3.

Project structure involving separate proponents for capture and storage

The two component project structure (Wandoan Power and CTSCo) helped each party to focus on their strengths. However, a good flow of information between the projects at multiple levels was needed for this arrangement to work effectively and was facilitated by working in offices located close together. Early on, risk, high-level schedule and stakeholder relations were identified as key activities which required a joint or closely coordinated approach. The integrated Project Proponents took a coordinated and transparent approach to development of a risk register including using the same consultants to do this work for both CTSCo and Wandoan Power. Joint policies and protocols were established for stakeholder relations and a single point of contact was established for dealing with stakeholders. A high-level, joint integrated schedule was also developed.

Having commercial organisations with different strengths and experience also facilitated earlier ‘commercial thinking’ and consideration of matters for CO_2 offtake and CO_2 service such as due diligence.

Targeted site selection for detailed study

Selecting a specific site enabled the study to be sufficiently detailed to understand the development approvals that would be required and prepare for the environmental permitting process as Australia has a non-prescriptive approach to environmental permitting. For example, environmental permit limits for air-borne emissions such as NOx are calculated on a project specific basis. The limits are derived from air emission modelling to verify that the expected plant emissions will maintain ground level concentrations (GLC) significantly lower than the Environmental Protection Agency's GLC guidelines. This can create challenges around new technology for project decision making. Given this non-prescriptive approach and regulators who are unfamiliar with the technology, commencing detailed permitting early draws out these issues and facilitates discussion with regulators. Undertaking this initial dialogue with environmental regulators during the demonstration project should lead to simpler requirements being set for projects that follow after.

Traditional power station site selection assumptions

Learnings from this project have demonstrated that the traditional assumptions used in standard power station site selection (such as proximity to fuel and water) are not always applicable to new power generation technologies. The drivers of project economic feasibility are generally the same but their relative impact is different for this project compared to existing power generation technologies. This will result in different project decision making. For example, capital expenditure and fuel cost are both significant drivers for any power project but their relative importance is different based upon the generation technology.

Incentivisation and facilitation of private sector investment in CCS

Incentivisation and facilitation can be provided in various ways including cash, regulatory arrangements and taxation incentives.

During the course of the pre-feasibility study it became apparent that there is scope for clearer thinking about how to provide incentivisation and facilitation that would encourage significant investment by the private sector in CCS. This could entail clarification of assumptions about what activity is reasonable to expect private sector firms to invest in as research and development and what work is of a nature that requires public sector support. At present there are no obvious high level principles or shared assumptions that form a framework for ongoing decision making.

With regard to taxation, it is noted that the coal industry is a significant funding stakeholder in CCS together with various governments. Unlike governments, the coal industry is able to benefit from taxation incentives, particularly through research and development concessions. Project proponents who are tax paying entities have to consider complexities such as being taxed on grants which may be received from governments. Given the innovative nature and large size of CCS demonstration projects there appears to be scope for simplifying and clarifying the taxation incentives that apply to private sector investments in demonstration projects. This could be done by designating special arrangements that apply to major CCS demonstration projects that need to be jointly funded by government and private sector investors. This would have the benefit of ensuring that project proponents and funding stakeholders could focus on the project itself rather than having to continually address issues of uncertainty about taxation implications.

3. Project management approach and outcomes

3.1 Pre-feasibility study project delivery

The project management processes and procedures used by the Proponents to deliver the pre-feasibility study requirements followed the Project Management Body of Knowledge (PMBOK)[7].

Within the pre-feasibility phase, key roles and responsibilities were identified and established for the Proponents, counterparties and service providers. A detailed project plan and schedule was established which incorporated a traditional Work Breakdown Structure.

Risk assessments were initiated during the pre-feasibility study. These would continue throughout the entire project life as each phase is implemented utilising the risk review processes established by the procedures as noted above.

A Project Execution Plan was established via the overall project plan and schedule. This incorporated all aspects of the project requirements to facilitate a successful pre-feasibility study and identified future work phases. Along with the plan and schedule, a Division of Responsibility was established, which clearly delineated the various pre-feasibility study responsibilities for each Proponent and service provider.

These processes would continue into the feasibility study phase and for all subsequent project phases.

3.1.1 Service providers

The three major contributors to the pre-feasibility study were:

- Wandoan Power
- Worley Parsons (Owner's Engineer and balance of plant work)
- GE Gasification (Preliminary Engineered Equipment Package)

Wandoan Power engaged a range of technical and professional service providers to advise and assist with the execution of the pre-feasibility study activities.

[7] PMBOK is a guide developed by the Project Management Institute, which presents a set of standard terminology, essential inputs, tools, techniques and processes required to achieve an effective project management program. For more information refer to http://www.pmi.org/PMBOK-Guide-and-Standards.aspx

Table 3-1 Pre-feasibility study service providers

Provider	Service
Blake Dawson Waldron	Site purchase option agreements
E A Burke and Associates	Property consultant
Environ	Site due diligence
Freehills	EPC procurement
Fugro	Aerial imaging and spatial data
GE Gasification	Gasification and power block engineering, cost estimation
Hill Michael (HMAC)	Transmission connection options analysis and costing
IMEMS	Environmental advice
Katestone Environmental	Air emission analysis
Knack PR	Stakeholder communications
Minserve Group	Coal supply evaluation
Minter Ellison Lawyers	Coal supply agreements, land tenure and development approvals strategy
Numac Drilling	Geotechnical services
Pinnacle Risk Management	Technical hazard study
RLMS	Easement identification
Scorpio Consultants	EPC procurement
Sinclair Knight Merz (SKM)	Risk management
Spinifex Consulting	Cultural Heritage management
Taylor Byrne	Land valuation
WorleyParsons	Engineering, cost estimation, environment and social

3.2 Risk management strategies

3.2.1 Overview

Wandoan IGCC with CCS Project Integration

A coordinated and comprehensive risk management process was implemented during the pre-feasibility phase. The integrated Project's risk management system is being implemented in compliance with the relevant standard ISO31000. This system focused on the relevant issues for this phase of the Project and would address the changing assessment and evaluation of risk through succeeding phases.

The clear definition of the Project objective was a critical step in the risk management process. The objective of the integrated Project is to demonstrate that electricity can be produced at industrial scale with low CO_2 emissions using coal feedstock, GE's IGCC with CO_2 capture technology and long-term geological storage of CO_2.

The Proponents (for both Wandoan Power and the CTSCo Project) engaged SKM to provide risk management services to the Project. SKM was engaged in October 2009 to review a preliminary risk register that had been developed by the integrated Project Proponents. Following this phase of work, SKM has continued to advise and assist the Proponents with the identification, analysis, evaluation and treatment of project risks including facilitation of a risk review exercise in December 2010.

3.2.2 Current risk management strategy

Wandoan Power has in place a risk management system, which is designed, and is being implemented to comply with ISO31000 Risk Management Principles and Guidelines.

Wandoan Power's risk management system focused upon the issues which were relevant and significant to the pre-feasibility phase. The risk management process will cope with changing assessment and evaluation of risk as Wandoan Power progresses through succeeding phases so that effort is directed to the most important issues.

Key project controls in place for Wandoan Power are:

- Risk management system (discussed above).
- Project leadership and organisation.
- Design Basis Report.
- Project schedule, integrated at a high level and managed separately at a detailed level for the Wandoan Power and CTSCo projects.
- Project budget.
- Financial model.
- Integrated stakeholder engagement system with CTSCo.
- Steering Committee (including Funding Stakeholders as members), that oversees the Wandoan Power and CTSCo elements of the integrated Project and progress towards project goals.

3.3 Legislative / regulatory processes

Key areas of legislative uncertainty for Wandoan Power are:

- Ensuring that the plant's operation can be accommodated by the regulatory mechanisms of the National Electricity Market. It is likely that an IGCC plant capturing a high level of CO_2 for transport and storage will have an extended commissioning period. During this extended commissioning period the plant operators will need considerable flexibility in determining how to operate the plant and this may involve being granted special dispensations from compliance with normal plant dispatch arrangements.
- Achieving a sufficient revenue stream which could involve a combination of carbon pricing together with other price support arrangements intended to encourage the deployment of low emission power generation technology (similar to that which is already in place for renewable energy).
- Award of tenements for exploration under Queensland's *Greenhouse Gas Storage Act 2009*. Until a suitable CO_2 storage exploration program can be undertaken, investment in CO_2 capture technology projects such as Wandoan Power cannot be de-risked.

3.4 Public communication strategies

The Proponents recognise that stakeholder acceptance or a 'social licence to operate' is one of the most critical non-technical aspects of the Project. Wandoan Power and CTSCo share a significant number of stakeholders and as such the Project Proponents have worked hard from the beginning to integrate their stakeholder engagement strategies.

Integrated stakeholder engagement is crucial to clear, consistent and credible communication – in essence, a unified voice is needed from all participants to best position the Project with stakeholders and maintain a 'social licence to operate'.

During the pre-feasibility study phase careful consideration was given to the nature and timing of community engagement with plans being developed and refined for activities particularly in the Wandoan region.

Wandoan Power conducted some preliminary early engagements with landowners, near neighbours, the local community and council during the pre-feasibility study phase but sought to manage expectations given the uncertainty and preliminary status of the project.

The project accepted opportunities to present information at two meetings of an existing Wandoan community forum. At these meetings Wandoan Power focused on the power station development and associated potential impact. Xstrata Coal also attended these meetings to update the community on its Wandoan Coal Mine Project, as well as answer any enquiries specifically relating to the carbon transport and storage element of this Project. Local councillors and community members in attendance saw the benefit of a power station located in Wandoan as it would provide economic benefits to the region and well-paid, permanent jobs for skilled employees. Wandoan Power has also had various discussions with industry and government stakeholders.

Through research, early engagements and ongoing situation analysis, the Project has developed a baseline understanding of the challenges that could influence stakeholder acceptance, including the following key stakeholder challenges and opportunities:

- CCS is perceived as relatively new and is not widely understood. Many stakeholders will not have an existing frame of reference for the technologies involved which could create concern for these stakeholders. Education based on relevant research will be critical to establishing a foundation of common understanding and mitigating this risk.
- There is increasing sensitivity to the resources sector activities evolving within the Surat Basin, with concerns about their potential and cumulative impacts. While much of the current sensitivity is in relation to CSG, UCG and mining activities, communities and individuals have demonstrated that they expect projects to engage with them in a meaningful way – they expect their questions, concerns and fears to be listened to and addressed by project proponents and government. In particular, the experience of CSG and UCG industries has highlighted the increased challenge when the technology is unfamiliar to communities.

  Furthermore, action groups in the Surat Basin have demonstrated a significant ability to influence public perception and community acceptance. Therefore meaningful engagement will be essential.

The Project has conducted extensive analysis and benchmarking of Australian and international CCS projects, several of which have been models of community engagement, but where others have delivered useful lessons in how not to engage with stakeholders. Those experiences have been used to develop the strategies and plans for the Project's stakeholder relations.

While the pre-feasibility phase included significant efforts in planning stakeholder relations, the feasibility phase will be very much focused on effectively implementing a broader stakeholder relations program. As the Project progresses, into and through the feasibility study phase, it will become more visible to the community as CTSCo undertakes increasing amounts of field work and Wandoan Power allocates more resources to evaluating the proposed power station site and infrastructure corridors.

As such, comprehensive stakeholder engagement plans have been developed for implementation during future phases of the Project. However, the Proponents recognise above all that the environment for these projects is very dynamic and that approaches need to flexible and responsive to changing circumstances.

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4. Process and performance data

4.1 Technology selection

The selection of a technology was significantly influenced by both government policy requirements and grant funding availability.

Government policy

Work in relation to development of a coal-fuelled power station at Wandoan dates back to 1977. Early studies proposed traditional pulverised coal combustion as the preferred generation technology. However since 2005, Queensland Government policy has precluded this option with a requirement that coal-fuelled power generation projects adopt CCS technology.

Grant funding availability

The *Clean Coal Special Technology Agreement Act 2007,* a legislated agreement between the Queensland Government and ACALET, stipulated that a significant amount of funding should be directed to an IGCC project.

Furthermore, the Australian Government's CCS Flagship Program[8] potentially offered large amounts of funding for projects that met essential eligibility criteria which included project scale, technology maturity and delivery timeframe.

- **Project scale eligibility:** This included being at a capacity that could be rapidly and effectively escalated to commercial deployment in Australia and would demonstrate a high level of CO_2 capture (moving towards 90 per cent during the project life). The scale also needed to give OEMs and EPCs sufficient confidence to provide performance and process guarantees for their technology.
- **Technology maturity eligibility:** The technology selected needed to be at a suitable degree of maturity to enable its scale-up and deployment in a large-scale demonstration project.
- **Timeframe eligibility:** The project needed to demonstrate a financial decision could be reached within a timeframe that would allow it to be operational from 2015.

[8] For more information on the CCS Flagships Program refer http://www.ret.gov.au/energy/Documents/clean-energy-program/CCS%20Flagship%20Program%20guidelines.pdf

4.1.1 IGCC technology selection

Prior to the pre-feasibility study, Stanwell analysed the options and original equipment manufacturer market conditions for CO_2 capture technology at industrial scale for the generation sector. Prospective suppliers of Integrated Gasification Combined Cycle (IGCC) plant[9], some with CO_2 capture technology were GE, Shell, Siemens, Conoco Phillips, Southern and Mitsubishi Heavy Industries (MHI).

Stanwell identified GE's IGCC with pre-combustion CO_2 capture as the preferred technology for the following reasons:

- A review of the three main technology paths for CO_2 capture from fossil-fuelled power generation[10] identified IGCC with pre-combustion capture to be the only industrial scale generation technology available for deployment and delivery of operations between 2015 and 2020.
- GE's IGCC with pre-combustion capture technology was consistent with the essential eligibility criteria of the CCS Flagships Program regarding project scale, technology maturity and timeframe.
- GE's power station technology can capture high levels of CO_2 emissions at industrial scale, with plants currently operating at 90% capture rates.
- Compared with the Edwardsport project the scale-up factor for the gasifier is approximately 1.4 and for the radiant syngas cooler it is less than this value. This level of scale is considered to be manageable for the GE technology.
- GE can provide IGCC with CO_2 capture technology on a commercial basis with bankable performance guarantees and warranties.
- GE was selected by Duke Energy to provide IGCC technology for their IGCC power station, which is scheduled for commercial operation in 2012.
- GE expressed interest in developing a 50Hz reference site for their IGCC technology.
- GE was prepared to back their technology by taking an equity participant role in the project development.
- At the time of project conception, Siemens, Conoco Phillips and Shell did not appear to have achieved a high level of design integration for IGCC plants.

MHI have built a 275MW demonstration IGCC plant using air-blown gasification technology. While this option facilitates high fuel efficiency and performance without CO_2 capture, it is less suited to the required high levels of CO_2 capture in comparison with the oxygen-blown gasification technology (as proposed for Wandoan Power).

[9] A general description of the IGCC process is included as Appendix 3
[10] The three main technology paths for CO_2 capture are pre-combustion capture, oxy-fuel combustion and post combustion capture (PCC).

During the pre-feasibility study an update to the original analysis including a global CCS project survey was conducted. The results from the updated analysis supported the original assessment and are included in Appendix 1.

4.1.2 Technology alternatives

A review of alternatives technologies for CO_2 captured was conducted in the context of the essential eligibility criteria of the CCS Flagships Program which included project scale, technology maturity and delivery timeframe (as discussed in section 4.1).

The retrofit potential of post combustion capture (PCC) and oxy-fuel combustion technologies may at first appear to make them a seemingly attractive option to produce the necessary quantities of CO_2 for testing the geological storage of CO_2 at industrial scale compared to a greenfield development like IGCC with pre-combustion capture. The potential cost savings of a retrofit project are a result of using the flue gas from an existing power plant. However given the current status of development of PCC and oxy-fuel combustion technologies this approach:

- Will likely result in a retrofit plant that does not significantly progress the development of the respective technology toward the ultimate goal of high levels of capture with low energy penalty required for commercial deployment of CCS.
- Results in a high cost of CO_2 per unit captured as using a slipstream on a large plant offers easier but limited integration, creating a high energy penalty and operating cost.
- Would be an inefficient use of the capital investment as the plant will likely be run for as short a time as possible (may be retired in five years).
- Does not explore integration/operability issues with the CO_2 transport and storage element of the style of plant that will ultimately be deployed commercially. Higher levels of capture and integration are considerably more complex.
- May not readily produce sufficient quantities of CO_2 at the required quality and availability for testing large-scale geological storage because these capture processes themselves are still currently undergoing process validation at smaller scale than that required for a large-scale CCS project.
- Has significant scale-up and cost risk because these capture processes have never been in use at large-enough scale in any plant to date.
- Would still likely require two years of project development to reach financial close (i.e. pre-feasibility study followed by a feasibility study and front end engineering and design).

Further discussion of the potential issues for a retrofit PCC or oxy-fuel combustion project to produce sufficient quantities of CO_2 for testing the geological storage of CO_2 at large scale (required for CCS Flagships eligibility) is included in Appendix 2.

4.2 Engineering definition

4.2.1 Project description

The basic concept is that the power station would be situated at the mine mouth and use a single washed coal feedstock from Xstrata's Wandoan Coal Project. The design coal specification is shown in Table 4-1 below. Slag will be returned to the mine for in-pit disposal.

Table 4-1 Design coal specification

Specification	Unit	Design Coal (base)	Design Coal (range)
Total moisture	wt%, ar	15.0	14-17
Equilibrium moisture	wt%, ad	10.0	
Ash	wt%, ar	9.0	8.0 – 12.0
Volatile matter	wt%, ar	38.2	36 – 44
Fixed carbon	wt%, ar	37.8	37 – 43
Ultimate analysis			
Carbon	wt%, daf	77.2	76.1 – 78.3
Hydrogen	wt%, daf	5.9	5.7 – 6.3
Nitrogen	wt%, daf	1.03	0.96 – 1.23
Sulfur	wt%, daf	0.41	0.33 – 0.53
Oxygen	wt%, daf	13.88	14.7 – 16.4
Chlorides	ppm (w, dry)	470	350 - 700
Gross heating value	MJ/kg, daf	32.28	32.1 – 32.6
AFT flow (reducing)	℃	1440	1400 - 1560
HGI		35	32 - 36
Coal size (at inlet to mill)	mm	50	

The proposed source of water for the power station is a combination of:

- CSG associated water suitably treated prior to arrival at site.
- Water from the Dawson River, accessed at a location such as the existing Glebe Weir.

The power station will be a zero liquid discharge site[11]. Water systems have been optimised for minimum cost, use and waste, and where possible, recycling. This includes the use of dry cooling for the power

[11] Zero liquid discharge subject to the design rainfall event.

block steam cycle and a zero process water discharge (ZPWD) thermal system to dispose of process wastewater from the gasification block. Remaining process wastewater from the Balance of Plant (BoP) will be disposed of in onsite evaporation ponds.

The power station's transmission connection point will be Powerlink's proposed 275kV Wandoan South substation which is located approximately 21 kilometres from the power station site.

The general plot plan for the power station is included as Appendix 4.

4.2.2 Process description

The power station consists of an IGCC with 90% CO_2 capture plant with the following main plant and equipment:

- coal grinding and slurry feed preparation
- single oxygen-blown gasifier with radiant syngas cooler (RSC) and scrubbing
- coarse slag handling
- black water flash
- fine slag handling
- water–gas shift and gas cooling
- acid gas removal (AGR) and CO_2 capture[12]
- CO_2 dehydration and compression unit
- grey water blowdown pre-treatment
- ZPWD
- sulphur recovery unit and tail gas unit
- power block consisting of GE 9F syngas combustion turbine generator (CTG), heat recovery steam generator (HRSG) and a reheat steam turbine generator (STG)
- dry cooling system for the steam turbine
- air separation unit (ASU)
- electrical systems including extra high, high, medium and low voltage systems, protection and emergency power supplies
- plant control system
- coal handling plant including overland conveyor and fully automated storage area
- slag handling plant and slag disposal system incorporating primary emplacement at mine, and emergency slag storage area

[12] The percentage of CO_2 captured (90%) is the nominal amount of CO_2 captured pre-combustion from the syngas for purposes of sequestration.

- sulphur storage area
- water storages, water treatment plants and waste water treatment plants
- BoP including compressed air plant, fire protection system, miscellaneous piping and other plant
- civil and structural works including buildings, workshops, underground services, drainage, roads and pavements, dams and access ways.

Other site infrastructure and services include:

- potable water
- demineralised water
- cooling water
- sewerage
- wastewater
- drainage
- waste management
- fire protection
- natural gas
- fuel oil
- security and access
- communications
- roads, access, bridges, rail and logistics
- accommodation
- regional office(s)
- temporary facilities for construction
- administration buildings
- maintenance buildings and facilities
- laboratory
- warehousing and stores
- maintenance equipment
- spare parts and consumables
- maintenance materials
- vehicles and mobile plant
- computer hardware and software.

Further detail regarding the process description is provided in GE Gasification's non-confidential report attached in Appendix 5.

4.2.3 Design, consumption and production parameters

The major power station design, consumption and production parameters are contained in the following table. These figures are for the normal operating case (NOC) and are based upon:

- Design Coal
- 85% capacity factor

Table 4-2 Power station design, consumption and production parameters

Parameter	Value
Design Unit Performance	
Gross power (MW)	503
Auxiliary power consumption (MW)	162
Net (sent out) power (MW)	341
Net Heat Rate (GJ/MWh HHV)	12.364
Efficiency (% HHV)	29.1
Design Ambient Conditions	
Dry bulb temperature (℃)	28
Relative humidity (% RH)	40
Elevation / barometric pressure (kPa A)	98.64
Coal, flux, oxygen and water consumption	
Coal (t/d ar)	4,156
Coal (Mtpa ar)	1.289
Oxygen (t/d)	3384
Oxygen (Mtpa)	1.050
Total water consumption (l/MWh)	1,085
Total water consumption (Ml/a)	2,755
Slag, sulphur and CO_2 production	
Coarse slag (t/d dry)	468
Coarse slag (kt/a dry)	145
Sulphur (t/d)	12.72
Sulphur (t/a)	3,946
CO_2 captured (t/d dry)	8,018
CO_2 captured (Mtpa dry)	2.49
CO_2 emitted (t/MWh sent out)	0.119

Parameter	Value
Design Life	
Project life (years)	30
Energy resource blending and stockpiling	
Blending	The coal will be processed to specification at the mine as required by the CSA Fluxant blending facilities will be included in the CHP as required
On-site stockpile capacity (t ar)	130,000 (Approx 30 days)
Miscellaneous	
Plant availability (%)	Syngas: year 1 - 65%, year 2 onwards - 85% NG: 92%
Plant transmission voltage (kV)	275

The power station is expected to operate on baseload[13] for at least the first 20 years of operation. Thereafter the plant could have an intermediate load following operation for its remaining plant life.

[13] Baseload is defined as maximum capability at all times, except when there are outages, transmission constraints, or system abnormal conditions. These events, except transmission constraints which are currently uncertain, are expected to happen irregularly.

5. Breakdown of investment and operating costs

5.1 Capital cost estimate

Wandoan Power's pre-feasibility study estimate is that the Total Installed Cost of the IGCC power station with CO_2 capture plant will be $3,773 million based on current costs and exchange rates. The estimate is generally to -20% to +25% accuracy. This means that the final capital cost is expected to be within a range from $3,020 million to $4,720 million.

A major driver of the project's estimated capital cost is the increased cost of doing work in a relatively remote Australian location. WorleyParsons and GE have provided most of the information used to develop the estimated capital cost. Their work has been performed to a prescribed standard (AACE Class 4) and is based on the assumption that the project would feature a high level of onsite fabrication.

Preliminary engineering analysis by these firms has indicated some specific cost reduction opportunities:

- increased fabrication offsite,
- site layout adjustments, and
- design modifications to the plant which were conceived during the pre-feasibility study (as discussed in section 2.1).

These cost reduction opportunities, worth in total approximately $200 million and proposed to be investigated in the next phase of development, have been taken into account by Wandoan Power in estimating the Total Installed Cost of $3,773 million.

Further cost reduction may be achieved through some targeted cost reduction activities including value engineering of the design and construction approach (aiming for more modularisation) together with some trade-off analysis of potential alternative project locations and optimisation of scope versus performance requirements.

The makeup of the Wandoan Power TIC Estimate is summarised in the table below:

Table 5-1 Wandoan Power TIC Estimate summary

	Cost ($m)	Cost breakdown		
DIRECT COSTS		**Equipment & Material**	**Labour**	**Other ***
Gasification and power island (excl bulk materials)	$903.80	$723.60	$59.20	$121.00
Gasification and power island (bulk materials and infrastructure)	$877.50	$210.30	$230.00	$437.10
Air separation unit	$227.30	$143.40	$28.50	$55.30
Balance of plant	$730.60	$306.90	$170.30	$253.50
Subtotal – Direct Costs	**$2,739.20**			
INDIRECT COSTS				
Construction support	$237.80	$77.70	$-	$160.10
EPC engineering	$289.80	$-	$-	$289.80
Contingency	$356.40	$-	$-	$356.40
Owners' costs	$350.40	$-	$-	$350.40
Subtotal – Indirect Costs	**$1,234.40**			
Cost reduction opportunities	-$200.00			
Total Installed Cost (AUD million)	**$3,773.60**			

* Other is 'subcontractor distributables' which includes equipment, overheads and subcontractors' profit.

5.2 Operating costs

The NPV of individual operating costs are presented below measured as a percentage of total operating costs. Carbon transport and storage (CTS), maintenance and coal feedstock together comprise 70% of these costs.

Table 5-2 NPV of operating costs

NPV - Operating Costs ($m)	NPV	%
CTS Cost	$564.65	18.3%
CO_2 Penalty	$150.58	4.9%
Maintenance Labour and Materials	$911.51	29.5%
Catalysts and Chemicals	$94.88	3.1%
Utilities:		
▪ Electric Power	$0.16	0.0%
▪ Natural Gas	$12.79	0.4%
▪ Water	$124.27	4.0%
Waste Disposal	$14.22	0.5%
Personnel Expenses	$145.86	4.7%
General Plant Overhead	$26.98	0.9%
Insurance	$46.04	1.5%
Feedstock Cost – Coal	$698.26	22.6%
Feedstock Cost – Flux	$31.09	1.0%
Grid Connection Charge - 1st Period	$2.23	0.1%
Grid Connection Charge - 2nd Period	$7.04	0.2%
Feedstock Cost – Gas	$0.00	0.0%
Interest Payable	$255.69	8.3%
Total Operating Cost	**$3,086.24**	100.0%

5.2.1 Annual operating costs

Annual Operating Costs in the financial model are escalated from a 2011 base at the model escalation rate of 2.5% per annum. While in practice some of these costs fluctuate from year to year, the model has levellised the costs. The following table presents the costs in operating year 5, de-escalated to 2011 dollars.

Interest Payable is excluded because this amount depends upon the level of borrowing and reduces as the loan funding is repaid.

Table 5-3 Annual operating costs

Annual Operating Costs ($m) – 2011 dollars	**($m)**	**%**
CTS Cost	$62.70	20%
CO_2 Penalty	$15.53	5%
Maintenance Labour and Materials	$98.34	32%
Catalysts and Chemicals	$10.53	3%
Utilities:		
▪ Electric Power	$0.02	0%
▪ Natural Gas	$1.38	0%
▪ Water	$13.79	4%
Waste Disposal	$1.58	1%
Personnel Expenses	$15.74	5%
General Plant Overhead	$2.91	1%
Insurance	$4.97	2%
Feedstock Cost – Coal	$77.77	25%
Feedstock Cost – Flux	$3.43	1%
Grid Connection Charge - 1st Period	$0.00	0%
Grid Connection Charge - 2nd Period	$1.00	0%
Feedstock Cost – Gas	$0.00	0%
Total Operating Cost	**$309.69**	

5.2.2 Carbon transport and storage (CTS) costs

Based on CTSCo's financial model, Wandoan Power understands that CTSCo's estimated cost to transport and store CO_2, assuming an annual CO_2 rate of 2,500,000 tonnes, is $22.80/tonne.

Based on this information, Wandoan Power has assumed that its cost of CO_2 offtake will be $25.08/tonne (2010 dollars) which includes a 10% provision for contingencies. This cost has been escalated by 2.5% per annum.

The resulting Base Case levellised nominal cost of CO_2 offtake is $38.5/tonne over the period.

5.2.3 Maintenance – labour and materials

The Owners' Engineers have applied a very high-level calculation methodology for these costs, being an assumed annual 2.48% of Total Installed Costs. It is assumed that this cost includes Sustaining Capital and major overhaul costs.

While IGCC plant has a limited history on which to benchmark these costs, at 29.5% of total operating costs, the perception is that this figure could be substantially reduced through application of further engineering analysis e.g. during a feasibility study.

A 10% reduction will reduce the costs by $91 million to 27% of total operating costs, while a 20% reduction will reduce costs to 25% of total.

5.2.4 Feedstock costs - coal

Feedstock costs are driven by a fixed rate of 3533 tonnes per day based on the GE design basis for a plant with a gross capacity of 503MW and a heat rate of 28,639 kJ/kg. This rate is adjusted by the plant capacity factor and converted to an annual consumption in Gigajoules per year.

While Wandoan has had discussions with Xstrata Coal about the supply of coal, including discussions on the contractual basis for calculating a price, no firm commitment has been arrived at. Wandoan Power has developed a range estimate of between $2.00 and $3.00 per GJ. This is based on a perception of the probable coal price gained from these discussions, as well as Stanwell's previous and more conclusive discussions held with other coal suppliers relating to the supply of coal in the Surat Basin.

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6. Environment

6.1 Introduction

An IGCC facility can offer advantages over existing pulverised coal (PC) technologies with respect to most environmental impacts. In addition to the reduced air emissions, IGCC plants typically consume significantly less water in operation than PC plants and (depending upon coal properties) produce less solid waste, with the waste (slag) being more benign than the waste produced by PC plants.

The currently available carbon management technologies for IGCC facilities are more cost effective than similar technologies for removing CO_2 from PC plant flue gases.

Environmental controls will be required to meet emission limits set by the regulators in the Development Approval.

6.2 Raw materials

6.2.1 Coal

Washed coal from the nearby proposed Xstrata Wandoan Coal Mine will fuel the power station. It will be supplied to the power station via a conveyor operated by the power station. The power station is expected to use up to 1.4 Mt of coal per year. A coal storage stockpile as well as stacking, reclaiming and conveyor infrastructure will be established on the project site. The coal delivery conveyor may extend from a transfer point at the coal mine site boundary to the project site.

6.2.2 Water

Due to water constraints resulting from the prevailing drought conditions the pre-feasibility study was based on dry cooling of the power block. These constraints are likely to be alleviated with the current easing of drought conditions and the start up of the approved CSG to LNG projects in the Surat Basin.

In the DFS/FEED the project may further investigate a number of options for cooling the steam cycle including dry cooling, evaporative water cooling using cooling towers and a hybrid system utilising a combination of evaporative and dry cooling. Some gasification processes will require the higher efficiency of evaporative cooling using a separate small cooling tower. The highest water usage would be if evaporative water cooling is used for the steam cycle in which case up to 6.5 GL/year would be required for the entire power station. If dry cooling is selected for the steam cycle then water consumption would reduce to 3.0 GL/year.

Raw water will be supplied to the site via a pipeline to an onsite water storage dam. Pre-feasibility studies have identified multiple options for water supply. The most likely options for raw water supply include utilisation of purified waste water from the CSG extraction industry located in the surrounding regions. An alternative option would be water supplied from the Dawson River.

The provision of a pipeline and supply of raw water to the power station site will be undertaken by a third party such as SunWater.

6.2.3 Natural gas

The power station requires a supply of natural gas for start-up purposes. This supply will be provided by either a pipeline to the Scotia / Peat gas fields to the east of the site or by a pipeline link to the gas fields to the south of the site. The provision of a pipeline and supply of natural gas to the power station site will be undertaken by a third party.

6.3 By-products and wastes

6.3.1 Air emissions

Impacts associated with the project can be divided into construction and operational impacts.

Construction impacts will be associated with atmospheric dust caused by construction activities such as clearing, grading, trenching and backfill. Exhaust fumes from vehicles and machinery will also be generated during the construction period.

The main air emissions with potential for environmental impacts from the operational power plant are air-borne particulates (both PM10 and total particulate matter), nitrogen oxides (NOx), sulphur oxides (SOx), carbon dioxide (CO_2) and carbon monoxide (CO). The power plant will use syngas cleanup and air quality control systems to achieve lower air emissions compared to other, advanced coal-fired generating units:

- Particulate emissions will be very low due to the wet scrubbing process proposed for syngas cleaning.
- Syngas moisture saturation and nitrogen diluent will be used for nitrogen oxides (NOx) control. Nitrogen oxides are expected to meet typical regulatory limits for current gas turbine plant.
- Sulphur oxides are expected to be very low due to sulphur removal in the syngas cleaning plant.
- Carbon monoxide levels are also expected to be very low due to conversion of CO to CO_2 in the catalyst shift reactor in the syngas cleaning plant.

During normal continuous operation, low levels of NOx, SOx, CO, CO_2, and PM produced by the gas turbine will be emitted to atmosphere via the HRSG stack. During periods of start-up and shutdown, gas turbine exhaust gas emissions will likely be slightly elevated during the transition to normal operation. During start-up, shutdown and trip conditions, syngas can be flared and other process gases sent to the thermal oxidiser. Both the flare and thermal oxidiser combust various waste gases yielding NOx, SOx, CO, CO_2 and PM.

Under normal continuous operation expected airborne emissions are summarised in Table 6-1 below:

Table 6-1 Airborne emissions summary

Emission	HRSG Stack	Thermal Oxidiser
NOx (as NO_2)	25 ppmvd (@ 15% O2) 128 kg/hr	0.4 kg/hr
SOx (as SO_2)	3.3 ppmvw 20 kg/hr	61 kg/hr
PM (total)	27 kg/hr	0.1 kg/hr
CO_2	119 kg/MWh sent out	

While the project's direct emissions to air are an important consideration, of more importance are the resulting ground level concentrations of these air emissions and the associated human and environmental health impacts. Ground level concentrations can only be predicted after extensive computer modelling that will be conducted during the feasibility study phase. Under some circumstances, ground level concentrations of air emissions can be influenced by plant design such as chimney height. Some plant design parameters such as minimum chimney stack height required to ensure compliance with guideline ground level concentrations will be assessed.

6.3.2 Water

Water produced from the cooling tower blowdown will be reused onsite while waste process water will be directed to onsite evaporation ponds. The power station will operate as a ZPWD site using thermal evaporation as the primary means of water treatment. The only remaining water discharge is uncontaminated stormwater. The plant's drainage systems will control and treat stormwater run-off, and will minimise potential erosion and sedimentation impacts during construction and operation of the power station. All potentially contaminated stormwater associated with industrial activities will be collected, treated, and reused onsite.

6.3.3 Sulphur

The sulphur compounds removed from the syngas will be converted to solid elemental sulphur which will be sold for commercial uses. Up to 4,000 tpa of sulphur is expected to be produced, dependant on sulphur content of the coal. Since solid elemental sulphur is saleable and is an internationally traded commodity, it is expected that all sulphur produced by the project will be sold for reuse. Solid sulphur is likely to be transported offsite by road.

6.3.4 Slag, filter cake solids and salt

During gasification, the mineral matter (ash), flux and some carbon from the coal form a course black glassy slag that is relatively inert. The power station is expected to produce approximately 150,000 tpa of course slag, depending on coal ash content. Beneficial reuse of the slag for commercial purposes will be pursued; however any remaining slag will be transferred to the adjoining coal mine for in-pit disposal.

Some process waters will be directed to a thermal evaporator. The solids will consist mostly of sodium salts and will be transported and disposed offsite at an appropriate facility.

6.3.5 Carbon dioxide capture

The project will capture some 90% of CO_2 in the syngas stream. The CO_2 gas stream produced by the gasification process is captured in the acid gas removal train and compressed to a high pressure supercritical state where the gas behaves more like a liquid than a gas. The total amount of CO_2 captured over the 30 year life of the project is expected to be approximately 75 million tonnes (i.e. 2.5 Mtpa). The compressed gas will be directed to a gas transmission pipeline to transport the CO_2 to geo-sequestration (storage) sites for permanent disposal. The acid gas removal train and CO_2 compression are part of this project. The pipeline and geo-sequestration of CO_2 will be undertaken by a third party (CTSCo) and is not being assessed by Wandoan Power.

During the pre-feasibility study consideration was given to the appropriate specification for CO_2 having regard to the capability of capture technologies and the implications for CO_2 transport and storage processes. For the purpose of the pre-feasibility study Wandoan Power has selected the following specification. The final CO_2 specification will be established during the feasibility study phase.

Table 6-2 CO_2 specification

Constituent	Unit	Value
Carbon dioxide CO_2)		> 95%
Methane (CH_4)	ppmv	< 40,000
Nitrogen (N_2)	ppmv	< 40,000
Nitrogen dioxides (NO_2)	ppmv	< 100
Oxygen (O_2)	ppmv	< 25
Particulates (size)	µm	0.1
Particulates (mass)	mg/Nm3	0.1 – 10
Sulfur dioxide (SO_2)	ppmv	< 100
Water (H_2O)	ppmv	< 100
Hydrogen sulphide (H_2S)	ppmv	< 150
Pressure [1]	MPag	15.17
Temperature	℃	31 – 49

Note: The required storage pressure and pipeline have yet to be assessed/designed. These will determine the required CO_2 discharge pressure from the site. The above pressure is anticipated to be a conservative assumption for preliminary design purposes.

6.3.6 General waste

During both the construction and operational periods of the project, general waste will be generated. This may include general domestic garbage, packaging material, scrap steel, batteries, grey water, sewerage, waste hydrocarbons, and oily rags. General wastes will be segregated and transported offsite by licensed contractors to be disposed in licensed waste disposal facilities.

6.4 External infrastructure services

6.4.1 Electricity transmission

The transmission of power from the site to the National Electricity Market grid will be undertaken by Queensland's transmission grid operator, Powerlink. Powerlink is in the process of constructing a new high voltage substation in the Wandoan area to serve the growing regional demand for power by various CSG gas and coal mine projects. This substation (Wandoan South) is expected to have sufficient capacity to serve as a grid connection point for Wandoan Power. The project would seek to have Powerlink construct a suitable transmission line connecting the power station to the Wandoan South Substation. The distance to be traversed by this grid connection power line is less than 25 km.

6.4.2 Workforce accommodation

The project will require access to accommodation facilities for its construction workforce. It is expected that this construction workforce will peak in excess of 2,000 persons. This figure is based on the assumption of a high-level of onsite fabrication. It would be expected that if the Proponents are able to devise alternative construction methods featuring more modularisation then the size of the construction workforce could be reduced.

The provision of an accommodation village will be undertaken by a company specialising in facilities of this nature.

6.5 Noise and vibration

Construction activities will temporarily increase noise levels in the area through the operation of vehicles and construction equipment. Given the relative remoteness of the area, construction noise impacts are considered to be low in general. Sensitive receptors in the area may need to be identified as any noise and vibration impacts will be greater in these locations. If construction activities operate on a 24 hour shift crew basis, the critical potential noise impacts typically relate to the night period. In these situations engagement will occur with the land owner to manage potential noise impacts associated with construction works.

Guidance on the assessment of operational noise impacts is provided within the Queensland EPA, Planning for Noise Control (PNC) guideline, 2004. This guideline sets outs the methods and procedures that are applicable for setting conditions relating to noise emitted from industrial premises, commercial premises and mining operations in Queensland.

A detailed noise assessment will be conducted in the feasibility study stage to clarify potential impacts based on further detailed plant design criteria, and to establish appropriate mitigation and management strategies. These strategies will be implanted to ensure that operational noise levels are within an acceptable range.

6.6 Traffic and transport

The development will generate a substantial increase in traffic on existing roads. This may result in the need to upgrade these roads.

There will also be a need to provide for the transport of heavy, large equipment loads to and from the power station. The need and locations of the upgraded roads will be investigated during the project's feasibility study phase.

The establishment of new and upgraded roads would involve stakeholder (including landowners) consultation and accepted industry practices would be applied in these situations.

6.7 Socio-economic aspects

The town of Wandoan is currently facing some challenges due to an increase in regional development led by the resources sector. A number of projects currently proposed are likely to be completed prior to the power station. These projects would require some infrastructure upgrades and contribute to a development legacy. However, the IGCC power station will place additional pressure on the area's accommodation stock and urban services. These demands will be greatest during the construction phase of the project.

The socio-economic impact of the power station is potentially significant due to the size and long-term nature of the project and the effects of other projects operating within the region. A comprehensive socio-economic assessment of the development area will be undertaken during the feasibility study phase to identify any adverse effects on people, their livelihoods and lifestyles, and the economy in the area to ensure that any impact is properly managed and positive effects are enhanced.

Potential socio-economic effects may include, but not be limited to:

- Increased demand for construction and operational workforce resulting in a shortage of local skilled and unskilled labour.
- Influx of construction workforce pushing up costs of housing, accommodation, rents and goods and services.
- Impact on community values and lifestyles as a result of changed regional dynamics.
- Increase in employment, service and supply opportunities to boost the local economy.
- Increase in demand for social services such as schools, leisure and recreation, medical support, hospitals and police.
- Road safety compromised if increased traffic movements are not managed effectively.
- Competing demand for land resource (e.g. agriculture versus resource sector use).

7. Health and safety

7.1 Health and safety requirements

Wandoan Power's health and safety objective is to ensure risks of an illness or injury as a direct result of the project are identified and then eliminated or mitigated and managed for all personnel working on the project, including any visitors or general public.

This includes minimising the health and safety risks through all project phases and establishing an underpinning culture originating with senior project management and driven throughout the project from top to bottom that rates safety and hazard awareness above all else.

These objectives shall be achieved by:

- Establishing detailed risk management processes to identify potential risks and effectively implementing those processes.
- Implementing a continuous training program for the life of the project for all personnel to familiarise themselves with the procedures, processes and risks associated with the project.
- Introducing control measures to eliminate or reduce the risks to an acceptable level.
- Incorporating recognised Occupational Health and Safety (OHS) standards into the design, engineering, construction, commissioning and operation of the project.
- Ensuring compliance with relevant statutory provisions, codes of practice and Australian Standards.
- Dedicating the resources to ensure effective and efficient systems and processes are implemented.
- Implementing detailed OHS Management Plans for all site works.
- Measuring and reviewing objectives and targets and implementing audit systems.

As Wandoan Power transitioned into the site mobilisation, construction, commissioning, start-up, operation and maintenance phases of the project, rigorous procedures and processes would be implemented that comply with relevant OHS legislation and focus on developing a safety culture.

7.2 Hazard analysis

A preliminary hazard study has been conducted. It is proposed that additional hazard analysis studies will be completed in future project development, implementation and operational stages as part of the ongoing risk identification process to investigate the risks associated with the project for workers, visitors and the public.

Appendix 1

Review of Large-Scale Coal-Fuelled Power Generation Projects with CO_2 Capture.

WandoanPower
a carbon solution

STANWELL CORPORATION LIMITED

ABN 37 078 848 674

Review of Large-Scale Coal-Fuelled Power Generation Projects with Carbon Capture

Prepared by Stanwell Corporation Limited

February 2011

Principal Authors: Trevor Gleeson and Anthony Chu

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1 Executive Summary

Study Methodology

This report aims to establish any significant shifts in commercial maturity and trends for coal-fuelled pre-combustion capture (IGCC), post combustion capture (PCC) and oxy-fuel technologies since the start of the Wandoan IGCC project in early 2009.

The report analysed carbon, capture and storage (CCS) projects globally, based on a wide range of online published sources accessed during December 2010/January 2011. The two main sources of data were project databases from the US Department of Energy's (DOE) National Energy Technology Laboratory (NETL) and the Global Carbon Capture and Storage Institute (GCCSI). This information was cross-referenced with other online databases, web-based data and reports and compiled into a new and independent Stanwell database.

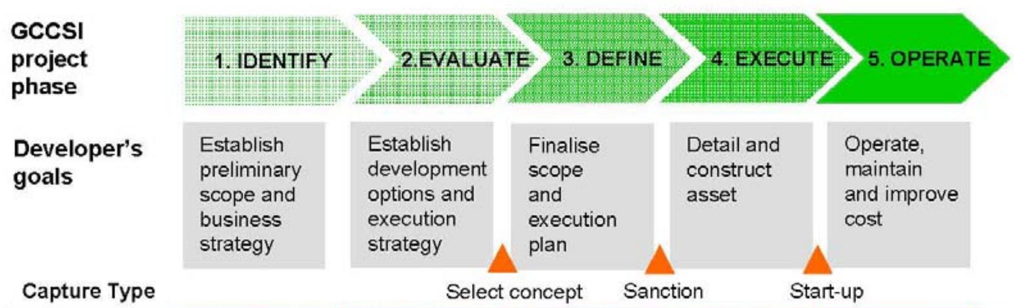
Results

The GCCSI *Status of CCS Overview 2010*, released in October 2010 (GCCSI, 2010a), notes approximately:

- 240 projects of various scales and at various stages of development that address at least one part of the CCS chain. These include R&D, demonstration and large-scale commercial projects.
- 150 "integrated" projects that incorporate the full CCS chain of capture, transport and storage.
- 80 "large-scale industrial projects" at various stages of development; around half of these are coal-fuelled power generation projects.

The Stanwell database focuses on "large-scale coal-fuelled power generation projects with carbon capture". Thirty seven projects meeting these criteria were identified, which is consistent with the GCCSI database. These projects were evenly split between pre-combustion and post combustion (16 each) with four or five oxy-fuel projects.

This data was further analysed according to the stage of project development, applying the same definitions used by the GCCSI. The results are provided in the table below. The classification between *evaluate* and *define* is somewhat subjective, particularly with limited publicly available information.



Capture Type	1. Identify	2. Evaluate	3. Define	4. Execute	5. Operate	Total
Pre-combustion	0	9	6	1	0	16
Post combustion	0	5	11	0	0	16
Oxy-fuel	2	0	2	0	0	4
Oxy or pre-combustion	0	1	0	0	0	1
Total	2	15	19	1	0	37

Only one coal-fuelled power generation project has moved through to the *execute* stage. The Southern Company Kemper County 524MW net air-blown IGCC project is due for commissioning in 2014 at a reported cost of US$2.88 billion. This project is fuelled with lignite.

Most projects are in the *define* stage (19 of 37). There is significant competition for limited funding for these projects to move to the *execute* stage.

PCC

While PCC with amine scrubbers has been widely used in the chemical and petroleum industry for many years, modified amine processes that are effective on coal-based flue gas have only been demonstrated at scales of up to 20MWe equivalent over the last 15 years. (EPRI, 2010a) Scale up by a factor of 10 or more is now proposed in the current suite of planned large-scale demonstrations.

Eleven PCC projects are identified in the *define* stage, but only seven of these have any significant levels of government/external funding announced and this may still not be sufficient to ensure the projects proceed. These seven projects are retrofits on existing plants with partial CO_2 capture on a single unit[1] or slipstream of flue-gas, and are scheduled for operation between 2013 and 2015. Project development on an existing power station arguably enables lower upfront capital cost, faster project permitting and is less subject to the normal constraints of building new generation capacity in a power market, particularly during times of slow or zero electricity demand growth. The reported capital cost of these seven projects ranges from US$670 million to US$1.7 billion.

The three North American projects, Mountaineer (235MW), Boundary Dam (120MW) and Pioneer (450MW) appear to be well-supported with a reasonable proportion of the total funding requirement secured from external sources and look the most prospective to proceed. Mountaineer and Pioneer are both based on the Alstom Chilled Ammonia capture process, which has only recently been demonstrated at the 20MW scale and hence will likely have higher technical scale-up risks. Boundary Dam is lignite fuelled and uses Cansolv amine solvents.

The four European projects: Porto Tolle (250MW), Maasvlakte (250MW) Belchatow (250MW) and Janschwalde (250MW), also have significant external European funding announced, largely from the European Energy Program for Recovery, but these projects seem less certain with more caution in Europe around coal-fuelled investment.

The UK Longannet Project (300MW) is the only project left in the UK CCS Demonstration Competition, which appears promising, however, no funding has yet been announced.

These five European projects all propose to use advanced amine capture processes.

Even if these partial CO_2 capture projects are successfully demonstrated, it will be a significant step up in integration complexity to move to full CO_2 capture (>90%) on a typical coal unit of 300 to 750MW. Several such projects are proposed, but appear to be at an earlier stage of development (e.g.Tenaska Trailblazer (600MW), Entergy Nelson 6 (585MW), Romanian CCS Demo (330MW Chilled Ammonia)).

Pre-Combustion (IGCC)

There are 16 IGCC projects with capture under active development. The Kemper County Project has progressed to the *execute* stage. Six projects are considered in the *define* stage with operation scheduled from 2014 to 2016.

[1] Boundary Dam is the exception to this. Capture is being applied to a 150MW unit with a target of capturing 1 M tpa CO2 which will require more than 90% capture.

The Texas Clean Energy Project (245MW net), Hydrogen Energy California Project (250MW net) and Good Spring Future Fuels project (270MW net) have had significant supporting funding announced from the US DOE.

The Nuon Magnum Project (1200MW with partial capture) seems well supported by government and utilities, but details of funding could not be found. The level of capture to be incorporated also seems a little uncertain.

GCCSI note the German RWE Goldenbergwerk Project (320MW\) and Chinese Dongguan Taiyangzhou Project (750MW with partial capture) as in the *define* stage, however, there is little information available about the cost of these projects and level of funding secured, which casts some doubt on how close the projects are to financial close.

There are a further nine projects classified in the *evaluate* stage. Target operation dates range from 2014 to 2021 and reported capital costs range from US$1 to 5.2 billion. The real development status of these projects is often difficult to assess as there is limited cost or funding information available.

Several other proposed IGCC projects have been cancelled or put on hold in the wake of the global financial crisis with issues including:

- limited demand for new generation
- tightened capital markets and reduced government spending
- windows of opportunity closing e.g. CO_2 for EOR
- CO_2 storage delays/opposition or failure to be part of an integrated CCS project
- high capital cost.

Technical issues do not appear to be a major factor in the project delays.

Oxy-fuel

Oxy-fuel is still at an early stage of technical maturity, however, four or five large-scale projects are noted. The most advanced appear to be the Spanish Compostilla Project (320MW) and the German Janschwalde Project (250MW), with both scheduled for operation by late 2015. The European Energy Program for Recovery has announced €180 million for each of these projects; the same as several other PCC projects.

Conclusion

There are 37 large-scale coal-fuelled power generation projects with CO_2 capture that appear to be actively under development. Equal numbers of post combustion and pre-combustion capture projects are being pursued, although there is a larger number of retrofit PCC projects that appear closer to reaching the *execute* phase. PCC on an existing power station arguably enables lower up-front capital cost, faster project permitting and is less subject to the normal constraints of building new generation capacity in a power market, particularly during times of slow or no growth.

However, the most advanced PCC projects are only targeting partial CO_2 capture and are scaling up technology by a factor of 10 or more over the previous successful demonstration, which introduces significant technical and commercial risk. Demonstrating full capture (>90%) on large-scale commercial coal units (which will ultimately be required) will require higher levels of process integration and involve greater scale up risk again and more development time.

Despite several IGCC projects being cancelled or put on hold in the last couple of years due to a range of factors, the impediments do not appear to be technical. There is still a strong pipeline of projects being actively developed.

At this time IGCC with capture still appears to be the most mature, lowest risk technology for the goal of deploying large-scale, commercial, coal-fuelled power generation with low CO_2 emissions by 2020.

2 Project Scope

2.1 Objectives

- Review CCS projects being developed around the world with a focus on large-scale projects with coal as the primary feedstock and electricity as the primary product.
- Assess the relative maturity of the main capture technologies (pre-combustion, post combustion and oxy-fuel) and any significant developments and trends since the start of the Wandoan Power Project in early 2009. Effective integration with a CO_2 storage project is outside the scope of this assessment.

2.2 Review methodology

Early in the review it became apparent that that no single database in the public domain could extensively provide the desired, up to date, information on all global CCS projects. Therefore, the research material was obtained from a variety of databases, each with their particular strengths and limitations, as outlined in the following sections.

In determining suitable sources of data, the search was limited to data published no earlier than 2009 and initially focused on publications from reputable government/academic organisations actively involved in promoting CCS technology. This approach was adopted in order to help strengthen the credibility of the collated data. Hence, two reference documents form the main basis of the review on global CCS projects:

- Global CCS Institute Database spreadsheet on large-scale integrated projects – published November 2010 (GCCSI, 2010b).
- The CCS projects spreadsheet from the US Department of Energy's National Energy Technology Laboratory (NETL) – last updated October 2010 (NETL, 2010).

These databases provided comprehensive lists of global CCS projects, albeit with little depth on specific project details. Accordingly, Google search results with online material published no earlier than 2010 were used to cross-reference and expand on the project-specific data in the spreadsheets. Specifically, the range of online material included media press releases, independent assessment findings and commercial information published by project proponents. These project-specific references were documented within the compiled spreadsheet.

This cross-referencing process was also complemented with several other smaller web-based CCS project databases, such as those maintained by the Massachusetts Institute of Technology (MIT) and the Zero Emission Resource Organisation (ZERO).

Furthermore, over the course of the two month period from December to January, Google Alerts were used on a daily basis in order to stay informed of the latest announcements on CCS project and technology developments. Any relevant updates to CCS project developments were readily recorded in the spreadsheet.

Finally, as a further check for consistency in the late stages of report finalisation, the compiled database was compared with the findings from several reports published by the Electric Power Research Institute (EPRI) in December 2010.

2.3 Primary Databases

2.3.1 Global CCS Institute

The Global CCS Institute produced a database in November 2010 (GCCSI, 2010b), which specifically lists large-scale, integrated CCS projects of any nature (i.e. power plants, chemical processing plants, industrial processes, and carbon transport and storage network systems). Their definition of 'large-scale' projects reflected the criteria imposed by the G8 summit in 2009 on carbon emission abatement strategies. 'Large-scale' was defined as CO_2 capture rates of 800kt/yr for coal-based power projects and 400kt/yr for other CCS projects (or the MWe equivalent of those capture rates for capture-only projects). Also, the database only listed 'integrated' projects, which demonstrate the full chain of the CCS process (capture, transport and storage).

CCS projects recognised by the GCCSI were considered to have a reasonable amount of credibility, given the primary role of GCCSI for facilitating knowledge sharing and commercial deployment of global CCS projects.

The GCCSI database helped to identify the more advanced or credible coal-based large-scale projects in power generation, which were of particular interest to this review. However, it provided a limited extent of detail (e.g. the chosen carbon capture technology provider). Additional information on these projects was sought from other databases or sources.

2.3.2 NETL/DOE

The CCS project database published by NETL of the US DOE provided the most comprehensive list of global CCS projects of any nature and was readily available for public access. The NETL database listed projects of all scales and CCS types (e.g. capture-only, storage-only). Hence, it was a relatively useful reference for gathering general information on many of the CCS-related projects around the world, ranging from completed R&D activities to developing industrial-scale demonstrations.

Although the NETL website stated that it was last updated in October 2010, it appeared that the database was not constantly updated and maintained, and often did not list suitable reference links that readily provided specific project details.

Most of the data appears to reflect the state of CCS projects in 2008-2009, with little being done to track the progress of projects. Nevertheless, this was recognised as a limitation due to the rather large size and range of information in the database, which had been valuable for appreciating the complexity and wide range of projects and activities with a role in the development of CCS.

2.3.3 MIT

Generally, the web-based CCS database compiled by MIT (MIT, 2010) was well maintained, and included projects of all scales and types. It was a convenient source for acquiring more project details, particularly for those that were more advanced or prevalent in the media. Also, it was noted that updates on project developments were regularly documented on the database from press releases, and useful reference links were readily provided for further information.

Several inconsistencies were encountered - e.g. a non-existent scale-up of a pilot project was listed, and there was an incorrect classification of the capture type used for one project.

However, specific to this review, a particularly useful feature of the MIT database was a sorted list of power generation projects with CCS integration. This allowed for ease of cross-referencing data and checking consistencies.

2.3.4 Others

Several other databases were also utilised for providing background information.

Zero Emission Resource Emission (ZERO)

- Web-based database, Norwegian-based organisation (ZERO 2010).
- Provided a relatively large list of CCS projects with useful background information to a certain extent, but it was not uncommon to find inconsistent data when compared to other sources.

- Lack of useful reference links.

Carbon Sequestration Leadership Forum (CSLF)

- Well-reputed organisation that actively promotes CCS technology deployment, but published a relatively small list of recognised/endorsed projects on their website.
- Their focus was rather narrow – did not list many large-scale projects, and appeared to mainly include R&D or pilot scale projects.
- Provided very useful reference links for project specific details, but some were outdated, especially for older projects (CSLF 2010).

2.4 Challenges Encountered during comparison of databases

2.4.1 Definitions

Several inconsistencies were noted among the CCS-related definitions used by the databases. Those that posed particularly significant challenges to the data collection process are outlined below.

New vs. Retrofit

- In some cases, ambiguity arose from labeling the base plant rather than the actual capture plant.
- For example, some projects were announced as having 'new' units, but in fact were using retrofit capture units – the base plant was planned to be newly built first, but carbon capture units were to be actually retrofitted later.

  Hence, particular caution was exercised in order to distinguish these occasionally misinterpreted definitions among the databases.

CCS-ready

Some projects were claimed to be actively involved in CCS efforts by stating that their facilities were 'CCS-ready'. However, this term was often loosely defined, ranging from projects performing studies into all facets of the CCS chain for potential retrofitting, to others merely leaving physical space on their facility and considering retrofitting capture units if/when CCS capture technology is commercially proven. For this review, projects of the latter sort were not considered to be valid CCS activities, and thus were not included in the compiled database.

2.4.2 Project Reporting

For most projects based in countries such as Europe, US, Canada and Australia, announcements of CCS projects were readily found. Conversely, information on CCS projects pursued in countries such as China, Korea and Japan was relatively scarce (or not readily available in English) and hence additional effort was required to obtain further details on them.

2.4.3 Project Scale and Status

The scale of a project was initially difficult to define, having to consider base plant size, capture plant size, capture rate and the total amount of carbon captured.

However, this was resolved by using the GCCSI definitions for project scale published in the 2009 report, *Strategic Analysis of the Global Status of Carbon Capture and Storage* (GCCSI, 2009) and the later July 2010 update (GCCSI, 2010c). For CCS and storage-only projects, the project scales were classified according to the CO_2 injection rate. For capture-only projects, an additional method of scale classification was based on the capture unit size in equivalent MWe. The specific method for scale classification can be found in Part 5 (Synthesis) of the above referenced report on Table 3-1, p59 (GCCSI, 2009).

On the other hand, a persistent challenge during data collection involved inconsistent reporting on project status. Generally, unless recent press releases were available (i.e. within 2010), information about the current status of most large-scale projects was not readily available. It seems projects often became silent as funding ran out or they were seeking funding for the next stage. Several projects had not announced any signs of progress since 2008/2009, which raised high levels of uncertainty as to whether they had been delayed or cancelled.

2.4.4 Expected Commissioning and Operation dates

As a general observation, many reported project schedules and operation dates appear to be highly optimistic. Most project schedules made best-case scenario assumptions on critical aspects of project development, such as permitting/approval processes, securing sufficient funding, and finding viable storage options for the carbon captured. Also, the commissioning and operation dates announced by most projects were often found to be unclear as to whether they referred specifically to the base plant, the capture unit or both. For simplicity, it was assumed that announced commissioning or operation dates referred to the capture unit when specific information was unavailable.

2.4.5 Capture Unit Size

There was a degree of uncertainty associated with the size of the capture unit reported to be used in oxy-fuel and post-combustion capture projects, especially those of larger scale. With particular regards to large-scale post-combustion capture technologies, it was found that most of these projects did not report the actual size of the flue gas stream being processed for capture, but only gave the size of the base unit to which capture was being applied and sometimes only the entire power station size. It was commonly observed that only smaller slipstreams of the flue gas emitted by the base unit were being processed for capture. This introduced a level of uncertainty around the reported levels of capture.

2.4.6 Project Cost Estimates

It was observed that those projects that were successful in securing public funding or planning to apply, more readily disclosed project cost information. Understandably, projects developed entirely under private funding were not required to disclose cost estimates, as it is generally considered commercially sensitive information.

A few projects only provided what appeared to be limited cost estimates for specific stages in the project, rather than the total cost (e.g. providing only feasibility study costs). In some cases, this led to a degree of uncertainty as to whether the provided cost estimate truly reflected the entire project scale.

Thus, it was difficult to find total cost estimates for all of the projects listed in the compiled database.

3 Global Overview of CCS Projects

3.1 Summary

The *Status of CCS Overview 2010* by the GCCSI, released in October 2010 (GCCSI, 2010a), provides a good overview of all CCS projects and developments.

It notes approximately:

- 240 projects of various scales and at various stages of development that address at least one part of the CCS chain. These include R&D, demonstration and large-scale commercial projects.
- 150 “integrated” projects that incorporate the full CCS chain of capture, transport and storage.

- 80 “large-scale industrial projects” at various stages of development.

Further analysis of this data shows:

- around half of the large-scale industrial projects are coal-based (see first column in Table 3.1)
- of the coal-based projects, there is an even split between pre and post combustion capture projects. Oxy-firing and projects with undefined capture technology make up the remainder (5 of 37).

Table 3-1 Large-scale Capture Projects identified by GCCSI November 2010

Capture Type	Coal	Non-Coal*	Total
Gas processing	0	13	13
Oxy-fuel	3	1	4
Post combustion capture	15	6	21
Pre-combustion capture	17	15	32
Other (pre, post, oxy, non-specified)	2	6	8
Total	**37**	**41**	**78**

*Non-coal includes chemicals and poly-generation where electricity is not the primary product

These findings are validated by the independently compiled Stanwell database as described in the previous section. The Stanwell database similarly identifies 37 large-scale coal-based projects as shown in Table 3.2.

Table 3-2 Large-scale Capture Projects identified by Stanwell

Capture Type	Coal	Non-Coal	Total
Pre-combustion	16	1	17
Post Combustion	16	1	17
Oxy-fuel	4	1	5
Oxy or Pre-combustion	1	0	1
Total	**37**	**3**	**40**

This table only includes power generation projects and hence the “non coal” column does not directly align with the GCCSI table, which includes projects where power generation is not the primary aim (e.g. chemicals, poly-generation).

The Stanwell database has been used to further analyse and contrast the large-scale, coal-based pre and post combustion capture projects.

Appendix 1 provides a summary of all the large-scale, coal-fuelled CCS projects identified in the Stanwell database.

3.2 Pre-commercial Scale Projects (Bench, Pilot, Demo)

The previous section considers only large-scale coal-based projects on the road to commercial deployment. There is also a significant pipeline of new technology variants being developed at the bench, pilot and demonstration scales. Table 3.3 below highlights that there appears to be more PCC technologies being tested at the pre-commercial scale (25) than for pre-combustion (4).

This appears to indicate that PCC is less mature than pre-combustion technologies. This may also mean that there are many promising new PCC technologies being developed, but these could take a long time to reach technical and commercial maturity. The larger number of PCC projects might also reflect the fact that PCC technologies are easier test at smaller scale, via flue-gas slipstreams on existing coal-fuelled generation plants.

Table 3-3 All Coal-fuelled Power Generation Projects with Carbon Capture

Scale	Pre	Post	Oxy	Undecided	Total
Bench	0	3	1	0	4
Pilot	1	15	0	0	16
Demo	3	7	2	0	12
Large-scale	16	16	4	1	37
Total	**20**	**41**	**7**	**1**	**69**

3.3 Coal-Fuelled Large-scale Project Development Status

Table 3.4 highlights the stage of project development from the Stanwell database using the same definitions as the GCCSI. Stanwell's assessment differs from the GCCSI for some projects.

Only one coal-based power generation project has moved through to the *execute* stage. The Southern Company Kemper County, 524MW, net air-blown IGCC project has commenced construction and is due for commissioning in 2014. This project uses lignite fuel.

Most projects are in the *define* stage (19 of 37). There is significant competition for limited funding for these projects to move to the *execute* phase.

While there are more PCC projects than pre-combustion capture projects in the *define* stage, the PCC projects tend to be smaller, capture less CO_2 and are attached to a host project that is already built or committed to be built, making early stage development easier. These issues are further discussed in Section 4.

Table 3-4 Coal-fuelled Large-scale Project Development Status

GCCSI project phase	1. IDENTIFY	2.EVALUATE	3. DEFINE	4. EXECUTE	5. OPERATE	
Developer's goals	Establish preliminary scope and business strategy	Establish development options and execution strategy	Finalise scope and execution plan	Detail and construct asset	Operate, maintain and improve cost	
		Select concept	Sanction	Start-up		
Capture Type						**Total**
Pre-combustion	**0**	**9**	**6**	**1**	**0**	**16**
Post combustion	**0**	**5**	**11**	**0**	**0**	**16**
Oxy-fuel	**2**	**0**	**2**	**0**	**0**	**4**
Oxy or pre-combustion	**0**	**1**	**0**	**0**	**0**	**1**
Total	**2**	**15**	**19**	**1**	**0**	**37**

Table 3.5 shows the equivalent project status from Stanwell analysis of the published GCCSI November 2010 database extract, which is generally consistent with Table 3.4. The Stanwell analysis suggests more pre-combustion projects have moved through from the *evaluate* to the *define* stage than the GCCSI analysis. The definition between the two stages is blurred and the status assessment can be somewhat subjective with limited information.

Table 3-5 GCCSI Coal-fuelled Large-scale Project Development Status

Capture Type	Identify	Evaluate	Define	Execute	Operate	Total
Oxy-fuel	1	0	1	0	0	**2**
Oxy-fuel and post combustion	1	0	0	0	0	**1**
Post-combustion	1	3	11	0	0	**15**
Pre-combustion	2	10	2	2	1	**17**
Pre-combustion and gas processing	0	0	0	0	0	**0**
Pre and post combustion	0	0	1	0	0	**1**
Various, not specified and other	0	1	0	0	0	**1**
Total	**5**	**14**	**15**	**2**	**1**	**37**

Table 3.6 provides the equivalent status analysis for all large-scale CCS projects. It shows that *gas processing* and *non-coal pre-combustion* capture projects are generally further advanced with six already in *operate* and two now in the *execute* stage.

Table 3-6 GCCSI All Large-scale CCS Project Development Status

Capture Type	Identify	Evaluate	Define	Execute	Operate	Total	Coal-based
Gas processing	0	2	3	2	6	13	0
Oxy fuel	1	1	1	0	0	3	2
Oxy-fuel and post combustion	1	0	0	0	0	1	1
Post-combustion	1	7	13	0	0	21	15
Pre-combustion	3	15	8	3	3	32	17
Pre-combustion and gas processing	0	0	1	0	0	1	0
Pre and post combustion	0	2	1	0	0	3	1
Various, not specified and other	0	4	0	0	0	4	1
Total	**5**	**31**	**27**	**5**	**9**	**78**	**37**

3.4 New Build and Retrofit

As can be seen from Table 3.7 below from the Stanwell database, most PCC projects are retrofits while almost all the pre-combustion projects are new builds.

Table 3-7 Retrofit and New Build Projects

Capture Type	Retrofit	New	Total
Pre-Combustion	1	15	16
Post Combustion	10	6	16
Oxy-fuel	2	2	4
Oxy or Pre-combustion	0	1	1
Total	**13**	**24**	**37**

4 Post Combustion Capture Projects

4.1 Overview

- 16 large-scale PCC projects have been identified under active development.
- None of these projects have yet progressed to *execute* phase.
- Eleven of these have been identified in the *define* stage, but only seven of these have significant external funding support which may still not be sufficient for the projects to proceed. Development hurdles other than external funding may still need to be cleared.
- The most advanced of the seven projects range in cost from US$670 million to $1.7 billion.
- While PCC with amine scrubbers has been widely used in the chemical and petroleum industry for many years, modified amine processes that are effective on coal-fuelled flue-gas have only been demonstrated at scales of up to 20MWe equivalent over the last 15 years (EPRI, 2010a).

- Scale-up by a factor of 10 or more is now proposed in the current suite of seven demonstrations noted above. These are mostly retrofits on existing plants with partial CO_2 capture on a single unit or slipstream of flue-gas, and are scheduled for operation between 2012 and 2015.
- Further scale-up to full CO_2 capture (>90%) on a typical coal unit of 300 to 750MW with increased heat and host plant integration to keep efficiencies high and overall capture costs low, will add increased technical and commercial risk and likely require more development time[2].

4.2 Commercial PCC Technologies

Amine based solvent capture technologies have been widely used in the gas processing and chemical industries for many years and are technically mature. Using these solvents on flue-gas from coal-fuelled generating plant significantly reduces plant output and creates operational issues due to contaminants in the coal (e.g. SOx and NOx).

New approaches and technologies are now under development to address these issues; ranging from modified solvents, through solid sorbents to new membrane technologies. While some of these look promising, they will likely take decades to reach commercial maturity.

The most commercially advanced technologies remain solvent-based and many of these have now been demonstrated on coal-fuelled flue-gas in pilot plants at scales of up to 20MWe equivalent over the last fifteen years. Larger scale demonstrations of 200MW or greater are now being proposed. This scale up of 10 times (or more) introduces significant project risk that should not be underestimated (EPRI, 2010a).

Chilled Ammonia is the most significant technology development and is being fast tracked by Alstom for commercial development. Chilled Ammonia has recently been demonstrated at the 20MW scale at the AEP Mountaineer Plant.

There are at least six companies developing technologies for large-scale post combustion capture on coal-fuelled generation plant (EPRI, 2010a). Table 4.1 provides an overview of the key PCC projects under development.

The proponents are:

- Aker - advanced amine
- Alstom – advanced amine and chilled ammonia
- Cansolv - advanced amine
- Fluor - advanced amine
- HTC Purenergy - advanced amine
- Mitsubishi Heavy Industries - advanced amine

An excellent overview of these technologies and proposed projects is provided in the recent EPRI report *Demonstration Development Project: Large-scale Post Combustion CO_2 Capture Retrofit Demonstration Project Review, December 2010 (*EPRI, 2010a). This is recommended reading.

[2] Personal communications with EPRI

Table 4-1 Large-scale Coal-fuelled Post Combustion Capture Projects Under Development

Project	New/ Retrofit	Base Plant/Unit Size (MW)	Capture Unit Size (MW) *Note 2	CO_2 Capture Amount (Mtpa)	Project Operation Date	Capture Technology	Country	Proponents	External Funding Amount *Note 3	Estimated Project Cost	% External Funding	Currency
Define Stage (*Note 1)												
American Electric Power (AEP) - Mountaineer	Retrofit	1300	235	1.50	in 2015		United States	American Electric Power, Alstom, RWE, National Energy Technology Laboratory (NETL), and Battelle Memorial Institute	334,000,000	670,000,000	50%	US Dollar
Ayrshire Power Station (Hunterston)	New	1852 (gross), 1625 (net, with CO_2 Capture)		2.00	commissioning in 2017	Doosan Babcock / HTC Purenergy (Amines)	United Kingdom	Ayrshire Power (Peel Energy), Doosan Power Systems, Fluor, Petrofac		3,000,000,000	0%	British Pound
Belchatow CCS Project (retrofit demo followed by new full-scale unit)	New	858 (gross, new full-scale), 250 (retrofit, demo)	250	0.10 (demo), 1.80 (full scale)	2013 (demo), 2015 (full-scale)	Dow Chemical and Alstom (Advanced Amine Process)	Poland	Alstom, Polska Grupa Energetyczna Elektrownia Belchatow SA (PGE EBSA)	180,000,000	580,000,000	31%	Euros
Boundary Dam Integrated CCS Demonstration	Retrofit	150	120	1.00	in 2013	Cansolv DS-103™ solvent (Amines)	Canada	SaskPower, Fluor; Hitachi Ltd, Babcock &Wilcox Canada Ltd, Neill and Gunter Ltd, Air Liquide, SNC Lavalin-Cansolv	240,000,000	1,400,000,000	17%	Canadian Dollar
Pioneer Project (Keephills)	Retrofit	450		1.00	in 2015	Alstom Chilled Ammonia Process	Canada	TransAlta, Capital Power, Alstom Canada (capture), Enbridge (transportation and storage)	784,000,000	1,700,000,000	46%	Canadian Dollar
Porto Tolle	Retrofit (one unit)	1,980	250	1.00	2012 (plant), 2015 (storage)	Aker Clean Carbon (Amines)	Italy	Enel	400,000,000	800,000,000	50%	Euros
Rotterdam Afvang en Opslag Demo (ROAD), E.ON Maasvlakte	Retrofit (one unit)	1100 (gross)	250	1.10	2013 (plant), 2015 (capture)		Netherlands	E.ON Benelux, Electrabel, Alstom	330,000,000	1,200,000,000	28%	Euros
Scottish Power - Longannet Project	Retrofit	2304 (gross)	300	2.00	in 2014		United Kingdom	Scottish Power, Shell, National Grid, Aker Clean Carbon			0%	Euros

Project	New/ Retrofit	Base Plant/Unit Size (MW)	Capture Unit Size (MW) *Note 2	CO_2 Capture Amount (Mtpa)	Project Operation Date	Capture Technology	Country	Proponents	External Funding Amount *Note 3	Estimated Project Cost	% External Funding	Currency
South Korea CCS1	New	500		1.50	in 2017		South Korea	*Confidential*			0%	US Dollar
Tenaska Trailblazer Energy Center	New	765 (gross), 600 (net)		4.00 (85-90%)	in 2016	Fluor Econamine FG Plus (Amines)	United States	Tenaska Inc., Fluor	7,700,000	3,500,000,000	0%	US Dollar
Vattenfall Janschwalde	Retrofit	250	250	0.50	in 2015	Alstom Chilled Ammonia Process	Germany	Vattenfall	180,000,000	1,500,000,000	12%	Euros
Evaluate Stage (*Note 1)												
Bow City Power Plant CO_2 Capture Project	New	1,000		1.00 (20%)	in 2016	Amines	Canada	Bow City Power Ltd., Luscar			0%	US Dollar
Entergy Nelson 6 Carbon Capture & Sequestration Project	Retrofit	585 (gross)		4.00			United States	Tenaska Inc., Entergy Corporation	825,600		0%	Australian Dollar
Romanian CCS Demo Project	Retrofit (one unit)	330	330	1.50		Alstom Chilled Ammonia Process	Romania	Romania's Institute for Studies and Power Engineering (ISPE), Alstom	2,550,000		0%	Australian Dollar
RWE CCS Eemshaven	Retrofit	814 (gross)		0.20 - 1.20	in 2015		Netherlands	RWE			0%	US Dollar
Sargas Husnes Norwegian Clean Coal Plant Project	New	400		2.60 (95%)	in 2015		Norway	Sargas, Tinfos, Sør-Norge Aluminium, Eramet		700,000,000	0%	US Dollar

Note 1: Project status is as defined by WorleyParsons within the 2009 GCCSI report, Strategic Analysis of the Global Status of Carbon Capture and Storage

Note 2: For several cases, this information was not readily identifiable. However, the capture size was defined as either the size of the unit fitted with capture, or the calculated effective capture unit size with full capture. In general, the size of the unit fitted with capture had been as identified in the Base Plant/Unit Size column, although a slipstream of this amount may only be processed. As an indicative reference figure, a 250MW capture unit typically corresponds to capture rates of up to 1.0 Mtpa.

Note 3: Refer to full table at the end of this report for the sources of external funding where applicable.

4.3 CO_2 Capture Levels, Plant Size and Integration

The majority of the proposed PCC projects will only capture a proportion of the total plants emissions; either by:

- applying capture to only one unit of a larger plant;
- using a slipstream of the total flue-gas; or
- a combination of these.

For most projects the overall level of capture is in the range 20 to 50%[3] with varying levels of integration with the base plant, whether retrofit or new. Capture levels appear to be driven by the available capture unit size, which is typically the next logical scale up from the previous demonstration size (e.g. 20MW to 200MW). They also seem driven by external funding criteria (e.g. 0.8 million tpa of CO_2) or the need to demonstrate "capture readiness" to obtain approval for the base plant in a staged development. This capture flexibility is a theoretical advantage for PCC.

Lower levels of capture potentially makes plant integration easier, particularly with retrofits, as there is more scope to work within the limits of existing plant components. This approach can lower the overall technical and operational risk of the project. However, there are many trade-offs to be made between up-front capital expenditure, overall thermal efficiency, operating cost and overall project risk. Each project may have different objectives and approach to this balance[4].

Demonstration of partial capture is a step on the way to full capture (say 90%), which is the ultimate aim for new build coal plants. Full capture increases the level of complexity and integration required to maintain thermal efficiency levels and to keep overall operating and CO_2 abatement costs low[5]. Some large-scale projects over 500MW are now being proposed with up to 90% capture. However these projects present a significant step up in risk profile and seem to be at an earlier stage of development. Successful demonstration with partial capture does not automatically translate to full capture[6].

4.4 Development Roll-out and Funding

Each of the main technology proponents has at least one large-scale demonstration project proposed for commissioning in the next six years as shown in Table 4.2 below, which aims to identify the advanced projects more likely to proceed. All projects will require a significant level of external/public funding to proceed and while this has been announced for some projects, none have moved through to the *execute* phase. There may still be other project hurdles to overcome such as permitting or commercial finance.

[3] Boundary Dam is the exception to this in the suite of most advanced near term potential projects. Capture is being applied to a 150MW unit with a target of capturing 1 M tpa CO_2 which will require more than 90% capture.

[4] Personal communications with EPRI February 2011

[5] Personal communications with EPRI February 2011

[6] Personal communications with EPRI February 2011

Table 4-2 Proposed Large-scale PCC Project roll-out

Capture Technology	Technology Provider	Announced Operation Year						
		2011	2012	2013	2014	2015	2016	2017
Amines/Amine-based Solvents	Aker Clean Carbon		Porto Tolle (250MW)		Scottish Power - Longannet Project (300MW)			
	Cansolv			Boundary Dam Integrated CCS Demo (150MW)				
	Doosan Babcock / HTC Purenergy							Ayrshire Power Station (400MW)
	Dow Chemical / Alstom					Belchatow CCS Project (250MW)		
	Fluor Econamine FG Plus						Tenaska Trailblazer (600MW)	
	TBA					E.ON Maasvlakte (250MW)		
Chilled Ammonia	Alstom					American Electric Power - Mountaineer (235MW)		
	Alstom					Pioneer Project (450MW)		
	Alstom					Vattenfall Janschwalde (250MW)		

some external funding secured

minimal or no funding secured

The Mountaineer, Pioneer (Keephills) and Boundary Dam Projects in North America have respectively secured public funding of 50%, 46% and 17 % of total estimated project cost and appear likely to proceed.

Four European projects also have significant public funding announced. Several recently received $180 m Euro each from the European Energy Program for Recovery, but this still may not be sufficient to move them forward. Investment in coal generation seems more cautious in Europe at present. Based on reported project cost, the proportion of funding announced stands at, Belchatow (31%), Porto Tolle (50%), Janschwalde (12%) and Maasvlakte (28%).

The seven most advanced projects range in cost from US$670 million to $1.7 billion.

The Longannet Project in Scotland remains the only participant in the UK CCS Demonstration Competition, which appears promising, however, no funding announcements have been made.

The Ayrshire project in the UK appears well advanced, but with no funding announced.

In addition to securing public external funding, project permitting and the normal project development hurdles for all these projects still need to be cleared.

The GCCSI has provided some study funding to the Romanian CCS Demo, Entergy Nelson 6, and Tenaska Trailblazer projects, but these seem to be in early stage development and with limited information available.

A very useful summary of many of these projects can be found in the recent EPRI report (EPRI 2010a).

5 Pre-Combustion Capture Projects (IGCC)

5.1 Overview

- In the past two years several proposed IGCC with capture projects have reached advanced stages of development, but have not proceeded.
- Despite this, sixteen coal-fuelled IGCC power projects appear to remain under active development.
- The Southern Company Kemper County 524MW IGCC project has progressed to the *execute* stage and has started construction. The total reported project cost is US$2.88 billion supported by $270 million DOE funding and $133 million of tax credits. It is due for commissioning in 2014 and uses lignite fuel.
- A further six projects are in the *define* stage and still reporting an operational start date around 2015.
- The estimated capital cost of IGCC projects in the *define* stage ranges from US$1.8 to 2.3 billion, which is typically higher than the current suite of PCC retrofit projects under development.
- Estimated capital cost for IGCC across all development stages ranges from $1 to 5.2 billion.
- IGCC projects are typically new build and hence need to overcome the normal hurdles of entry to the power market. Funding and demand for coal-fuelled power are significant issues.

5.2 Commercial IGCC with Capture Technologies

Gasification technologies with CO_2 capture have been widely used in the chemical industry for many years and are considered mature. Several coal-based gasification plants for power generation (IGCC) without CO_2 capture are now also in operation. There is currently no coal-based IGCC plant with capture in operation, although the first is now under construction (Kemper County).

Adding CO_2 capture to an IGCC is relatively straightforward and well proven in the chemical industry. However, running the gas turbine on high hydrogen fuel has presented some challenges, which are being addressed and will be demonstrated in the suite of proposed projects.

At least nine technology suppliers are developing commercial gasification technologies with the aim of adding capture for the power generation market. Some only offer the gasification or a limited range of the power system and capture components, which require further bundling with other suppliers to build a complete generation plant. EPRI states only GE Energy and MHI currently offer a full commercial package with capture from coal to power out (EPRI 2010b).

The key IGCC technology proponents are:

- GE Energy
- ConocoPhillips
- Shell

- Mitsubishi Heavy Industries (MHI)
- ECUST (East China University of Science and Technology)
- TPRI (Thermal Power Research Institute)
- Siemens
- KBR/Southern Co

All these suppliers have been actively involved in either past demonstration activities or a current proposed IGCC with CCS demonstration project.

There are significant economies of scale with IGCC projects, which drives toward larger project sizes in the range 270 to 700MW net. When capture is added, it is usually designed for a high level of capture (e.g. >80%), resulting in significant CO_2 streams of typically 1 to 4 million tpa. The capital cost of such new build, “first of a kind” plant can be high, in contrast to partial capture, retrofit, PCC projects with much smaller CO_2 capture streams.

Table 5.1 provides a list of large- scale, coal-based IGCC projects with capture under development.

A good description of each of these technologies and current commercial development status is provided in the recent EPRI report, *Coal Technologies with CO2 Capture – Status, Risks, and Markets 2010* (EPRI 2010b).

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Table 5-1 Large-scale Coal IGCC with Capture Projects Under Development

Project	New/ Retrofit	Base Plant/Unit Size (MW)	CO_2 Capture Amount (Mtpa)	Project Operation Date	Gasifier Technology	Country	Proponents	External Funding Amount *Note 2	Estimated Project Cost	External Funding	Currency
Execute Stage (*Note 1)											
Southern Company Kemper County Project	New	524 (net)	2.50 (67%)	in 2014	Southern Co/KBR "TRIG"	United States	Southern Company, Mississippi Power, KBR	403,000,000	2,880,000,000	14%	US Dollar
Define Stage (*Note 1)											
Dongguan Taiyangzhou IGCC with CO_2 capture project	New	800 (gross), 750 (net)	1.00		Southern Co/KBR "TRIG"	China	Dongguan Taiyangzhou Power Corporation, Xinxing Group, Nanjing Harbin Turbine Co Ltd.			0%	
Good Spring IGCC, Future Fuels	New	270	1.00	in 2014	Thermal Power Research Institute	United States	Future Power PA, China's Thermal Power Research Institute			0%	
Hydrogen Energy California (HECA) Project	New	390 (gross), 250 (net)	2.00	in 2016	GE	United States	Hydrogen Energy International LLC (BP Alternative Energy and Rio Tinto. Occidental Petroleum)	308,000,000	2,300,000,000	13%	US Dollar
Nuon Magnum IGCC Plant with Capture Option	New	1,200	1.30	2011(power plant), 2015 (CCS)	Shell	Netherlands	Nuon		1,800,000,000	0%	Euros
RWE Goldenbergwerk IGCC Plant with CO_2 Storage (maybe on hold)	New	450 (gross), 320 (net)	2.60	2015 (plant), 2020 (storage)		Germany	RWE nPower		2,000,000,000	0%	Euros
Texas Clean Energy Project (TCEP)	New	400 (gross), 245 (net)	2.90	mid 2014	Siemens	United States	Summit Power Group, Inc., Siemens, Fluor	450,000,000	2,070,000,000	22%	US Dollar
Evaluate Stage (*Note 1)											
Duke Energy - Edwardsport Plant (CCS ready, viability studies ongoing till 2011)	Retrofit	630 (net)			GE	United States	Duke Energy, GE, and Bechtel		2,880,000,000	0%	US Dollar
Erora Group - Cash Creek IGCC	New	770 (gross), 630 (net)	2.00	in 2015		United States	ERORA Group			0%	US Dollar
GreenGen Project in China	New	400		in 2018	Thermal Power Research Institute	China	GreenGen Co. Ltd.		1,000,000,000	0%	US Dollar
Osaki CoolGen IGCC Demonstration Plant	New	170		2017 (startup), 2021 (CO_2 capture)		Japan	Osaki CoolGen Corporation (J-Power & Chugoku Electric)			0%	
Progressive Energy IGCC Project,Teesside/Eston Grange (maybe on hold)	New	800				United Kingdom	Progressive Energy	240,000	7,200,000 (study spend)	3%	British Pound
SCS Energy PurGen One	New	750 (gross), 500 (net)	4.00	in 2014		United States	SCS Energy		5,200,000,000	0%	US Dollar
Southern California Edison IGCC Project (maybe on hold)	New	500 (net)	2.50	in 2017		United States	Southern California Edison, Southeast Regional Carbon Sequestration Partnership (SECARB), Electric Power Research Institute (EPRI)		50,000,000 (study spend)	0%	US Dollar
Sweeny Gasification Project	New	680 (net)	3.00	in 2015	ConocoPhillips E-Gas™ Technology	United States	ConocoPhillips	3,000,000		Unknown	US Dollar
Wandoan Power IGCC CCS Project	New	400 (gross), 330 (net)	2.50	in 2017	GE	Australia	General Electric, Stanwell Corporation, Xstrata Coal			0%	US Dollar

Note 1: Project status is as defined by WorleyParsons within the 2009 GCCSI report, *Strategic Analysis of the Global Status of Carbon Capture and Storage*

Note 2: Refer to full table at the end of this report for the sources of external funding where applicable

5.3 Development Roll-out and Funding

The Stanwell database identifies 16 coal-fuelled IGCC with capture projects under active development.

The Southern Company Kemper County 524MW IGCC Project has progressed to the *execute* stage and has started construction. The total reported project cost is US$2.88 billion; supported by $270 million DOE funding and $133 million of tax credits. It is due for commissioning in 2014 and uses lignite fuel.

A further six projects are in the *define* stage and still reporting operational start dates around 2015.

Table 5.2 highlights the most advanced project for each of the major gasification technology suppliers. Four of these projects are in the *define* stage.

The Texas Clean Energy Project, Hydrogen Energy California Project and Good Spring Future Fuels Project have significant supporting funding announced from the US DOE.

The Nuon Magnum Project seems well supported by industry and government, however details of funding could not be found. The level of capture to be incorporated also seems a little uncertain.

GCCSI note the German RWE Goldenbergwerk Project and Chinese Dongguan Taiyangzhou Project as in the *define* stage (GCCSI 2010b). However, there is limited technical or cost information available about these projects or the level of funding secured, which casts some doubt on how close the projects are to financial close. EPRI note Goldenbergwerk as on hold. These projects are not included in Table 5.2.

The Sweeny Gasification Project is still in the earlier *evaluate* stage.

Table 5-2 Proposed Large-scale Coal IGCC with Capture Project Roll-out

Technology Provider (gasifiers)	Announced Operation Year					
	2011-2013	2014	2015	2016	2017	2018
ConocoPhillips			Sweeny Gasification Project (680MW)			
GE				Hydrogen Energy California -HECA (250MW)	Wandoan Power Project (330MW)	
Shell			Nuon Magnum (1200MW partial capture)			
Siemens		Texas Clean Energy Project (245MW)				
Southern Co / KBR		Southern Company Kemper County (524MW)				
Thermal Power Research Institute (TPRI)		Good Spring, Future Fuels (270MW)				GreenGen Project (400MW)

under construction
some external funding secured
no or minimal funding secured

In addition to the Sweeny Project, there are a further eight projects classified in the *evaluate* stage. Target operation dates range from 2014 to 2021. The real development status of these projects is often difficult to assess. Limited cost or funding information is available. EPRI note the Southern Californian Edison project is on hold, however we have retained it as *evaluate*, as has the GCCSI.

Several other proposed IGCC projects have been cancelled or put on hold in the wake of the global financial crisis with issues including:

- limited demand for new generation
- tightened capital markets and reduced government spending
- windows of opportunity closing e.g. CO_2 for EOR
- CO_2 storage delays/opposition or failure to be part of an integrated CCS project
- high capital cost

Technical issues do not appear to be a major factor in the project delays.

These projects are included in the Stanwell database, but have been classified as *cancelled* or *on hold* and are not reported as part of the 16 active projects in Table 5.1

6 Oxy-fuel Combustion Projects

6.1 Overview

- Oxy-fuel is still at the pilot demonstration scale and while some larger scale projects have been proposed they are likely some years away.
- Oxy-fuel is not yet the technology of choice for early deployment of low risk large-scale CO_2 capture from coal.

6.2 Technology Development Status, Rollout and Funding

Oxy-fuel technology is still at a relatively early stage of technical development. Several small-scale demonstration projects are underway, but only four large-scale oxy-fuel projects have been identified as per Table 6.1. Stanwell has not reviewed these projects to any depth.

The most advanced projects appear to be Compostilla and Janschwalde.

The 320MW Compostilla Project in Spain and Vattenfall's Janschwalde 250MW project in Germany have secured 180 million Euro funding, the same as other PCC projects. The target commissioning date is 2015 for both projects.

Vattenfall's Janschwalde 250MW project is on the same site as the 250MW Janschwalde PCC project.

The US FutureGen Project recently switched from an IGCC to a smaller oxy-fuel project. It is strongly supported by the US Government and power utilities, but is now back at the *identify* stage.

Little information is available on the South Korea CCS2 Project which may be oxy-fuel or IGCC. GCCSI classify it at the *evaluate* stage.

Very little recent activity is apparent on the local Australian based Coolimba Power Project.

Table 6-1 Large-scale Coal Oxy-fuel Projects Under Development

Project	New/Retrofit	Base Plant/Unit Size (MW)	CO_2 Capture Amount (Mtpa)	Project Operation Date	Country	Proponents	External Funding Amount *Note 2	Estimated Project Cost	% External Funding	Currency
Define Stage (*Note 1)										
Compostilla Project	New	320	0.90	late 2015	Spain	Endesa, CUIDEN, Foster Wheeler	180,000,000	200,000,000	90%	Euros
Vattenfall Janschwalde	New	250	1.30	in 2015	Germany	Vattenfall	180,000,000	1,500,000,000	12%	Euros
Evaluate Stage (*Note 1)										
South Korea CCS2 (oxy-fuel or pre-combustion)	New	300.00		in 2018	South Korea	Korean Electric Power Corportion (KEPCO)			0%	US Dollar
Identify Stage (*Note 1)										
Aviva Corp Coolimba Oxy-Fuel Project (CCS-ready)	Retrofit	400 - 450	2.90		Australia	Aviva Corporation Ltd., AES		1,000,000,000	0%	Australian Dollar
FutureGen 2.0	Retrofit	200	1.30	in 2016	United States	FutureGen Industrial Alliance Inc. - Anglo American LLC, BHP Billiton, China Huaneng Group, Consol Energy Inc., E.ON U.S., Foundation Coal, Peabody Energy, PPL Energy Services Group, Rio Tinto Energy America, Xstrata Coal and Excelon, Caterpillar, Air Liquide	1,000,000,000	1,000,000,000	100%	US Dollar

Note 1: Project status is as defined by WorleyParsons within the 2009 GCCSI report, Strategic Analysis of the Global Status of Carbon Capture and Storage
Note 2: Refer to full table at the end of this report for the sources of external funding where applicable.

7 Conclusions

There are thirty seven large-scale coal- fuelled power generation projects with CO_2 capture that appear to be actively under development. Equal numbers of post combustion and pre-combustion capture projects are being pursued, although there is a larger number of retrofit PCC projects that appear closer to reaching the *execute* phase. PCC on an existing power station arguably enables lower up-front capital cost, faster project permitting and is less subject to the normal constraints of building new generation capacity in a power market, particularly during times of slow or no growth

However, the most advanced PCC projects are only targeting partial CO_2 capture and are scaling up technology by a factor of 10 or more over the previous successful demonstration, which introduces significant technical and commercial risk. Demonstrating full capture (>90%) on large-scale commercial coal units (which will ultimately be required) will require higher levels of process integration and involve greater scale up risk again and more development time.

Despite several IGCC projects being cancelled or put on hold in the last couple of years due to a range of factors, the impediments do not appear to be technical. There is still a strong pipeline of projects being actively developed.

At this time IGCC with capture still appears to be the most mature, lowest risk technology for the goal of deploying large-scale, commercial, coal-fuelled power generation with low CO_2 emissions by 2020.

8 References

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Appendix 1: Active Large-scale Coal-fuelled Generation Projects with Carbon Capture

This table is an extract from the Stanwell Excel database of all global CCS projects developed. Please see Stanwell for access to this database.

Appendix 1 Active Large-scale Coal-fuelled Generation Projects with Carbon Capture

Project	New/ Retrofit	Capture Type	Base Plant/Unit Size (MW)	Capture Unit Size (MW) *Note 1	CO_2 Capture Amount (Mtpa)	Status *Note 2	Project Operation Date	Capture / Gasifier Technology	Country	Proponents	External Funding Source	External Funding Amount	Estimated Project Cost	Currency	Project Link	
Compostilla Project	New	Oxy-fuel	320.00		0.90	Define	late 2015		Spain	Endesa, CUIDEN, Foster Wheeler	European Energy Programme for Recovery (EEPR)	180,000,000	200,000,000	Euros	http://www.zero.no/ccs/projects/compostilla	http://sequestration.mit.edu/tools/projects/compostilla.html
Aviva Corp Coolimba Oxy-Fuel Project (CCS-ready)	Retrofit	Oxy-fuel	400.00 - 450.00		2.90	Identify			Australia	Aviva Corporation Ltd., AES			1,000,000,000	Australian Dollar	http://www.zero.no/ccs/projects/coolimba	
FutureGen 2.0	Retrofit	Oxy-fuel	200.00		1.30	Identify	in 2016		United States	FutureGen Industrial Alliance Inc. - Anglo American LLC, BHP Billiton, China Huaneng Group, Consol Energy Inc., E.ON U.S., Foundation Coal, Peabody Energy, PPL Energy Services Group, Rio Tinto Energy America, Xstrata Coal and Excelon, Caterpillar, Air Liquide	US DOE Recovery Act Fund	1,000,000,000	1,000,000,000	US Dollar	http://www.futuregenalliance.org/	
South Korea CCS2	New	Oxy-fuel or Pre-Combustion	300.00		1.50 - 2.50	Evaluate	in 2018		South Korea	Korean Electric Power Corportion (KEPCO)				US Dollar	http://www.ingegneria.unige.it/documenti/comunicazioni/Doc_IEA/Korea%20-%20Jae-Keun%20LEE.pdf	
American Electric Power (AEP) - Mountaineer	Retrofit	Post-Combustion	1,300.00	235.00	1.50	Define	in 2015		United States	American Electric Power, Alstom, RWE, National Energy Technology Laboratory (NETL), and Battelle Memorial Institute	US DOE Clean Coal Power Initiative	334,000,000	670,000,000	US Dollar	http://sequestration.mit.edu/tools/projects/aep_alstom_mountaineer.html	
Ayrshire Power Station (Hunterston)	New	Post-Combustion	1852.00 (gross), 1625.00 (net, with CO_2 Capture)		2.00	Define	commissioning in 2017	Doosan Babcock / HTC Purenergy (Amines)	United Kingdom	Ayrshire Power (Peel Energy), Doosan Power Systems, Fluor, Petrofac			3,000,000,000	British Pound	http://www.ayrshirepower.co.uk/planning-application/volume-1-environmental-statement	
Belchatow CCS Project (retrofit demo followed by new full-scale unit)	New	Post-Combustion	858.00 (gross, new full-scale), 250.00 (retrofit, demo)	250.00	0.10 (demo), 1.80 (full scale)	Define	2013 (demo), 2015 (full-scale)	Dow Chemical and Alstom (Advanced Amine Process)	Poland	Alstom, Polska Grupa Energetyczna Elektrownia Belchatow SA (PGE EBSA)	European Commission	180,000,000	580,000,000	Euros	http://www.elbelchatow.bot.pl/print.php?dzid=205&did=2352	http://www.cslforum.org/publications/documents/Warsaw2010/Wroblewska-PGTG-BelchatowPresentation-Warsaw1010.pdf
Boundary Dam Integrated CCS Demonstration	Retrofit	Post-Combustion	150.00	120.00	1.00	Define	in 2013	Cansolv DS-103™ solvent (Amines)	Canada	SaskPower, Fluor; Hitachi Ltd, Babcock &Wilcox Canada Ltd, Neill and Gunter Ltd, Air Liquide, SNC Lavalin-Cansolv	Canadian Government	240,000,000	1,400,000,000	Canadian Dollar	http://www.globalccsinstitute.com/resources/projects/boundary-dam-integrated-ccs-demonstration	http://www.leaderpost.com/technology/SaskPower+defers+decision+proposed+carbon+capture+project+Estevan/3959919/story.html
Pioneer Project (Keephills)	Retrofit	Post-Combustion	450.00		1.00	Define	in 2015	Alstom Chilled Ammonia Process	Canada	TransAlta, Capital Power, Alstom Canada (capture), Enbridge (transportation and storage)	Canadian Government - Clean Energy Fund and ecoENERGY Technology Initiative, Government of Alberta's CCS Fund, Alberta EcoTrust Grant program, Global CCS Institute	784,000,000	1,700,000,000	Canadian Dollar	http://www.projectpioneer.ca/	http://www.ccsassociation.org.uk/events/Canada/TransAlta%20Project%20Pioneer%20London%2003%2008%2010%20with%20animation_ver2.pdf
Porto Tolle	Retrofit (one unit)	Post-Combustion	1,980.00	250.00	1.00	Define	2012 (plant), 2015 (storage)	Aker Clean Carbon (Amines)	Italy	Enel	European Commission	400,000,000	800,000,000	Euros	http://zeportotolle.com/	
Rotterdam Afvang en Opslag Demo (ROAD), E.ON Maasvlakte	Retrofit (one unit)	Post-Combustion	1100.00 (gross)	250.00	1.10	Define	2013 (plant), 2015 (capture)		Netherlands	E.ON Benelux, Electrabel, Alstom	Dutch Government, European Commission's European Economic Recovery Plan	330,000,000	1,200,000,000	Euros	http://sequestration.mit.edu/tools/projects/maasvlkte.html	
Scottish Power - Longannet Project	Retrofit	Post-Combustion	2304.00 (gross)	300.00	2.00	Define	in 2014		United Kingdom	Scottish Power, Shell, National Grid, Aker Clean Carbon	UK CCS Demonstration Competition			Euros	http://www.scottishpower.com/uploads/CockenziePowerStation.pdf	
South Korea CCS1	New	Post-Combustion	500.00		1.50	Define	in 2017		South Korea	*Confidential*				US Dollar	http://www.ingegneria.unige.it/documenti/comunicazioni/Doc_IEA/Korea%20-%20Jae-Keun%20LEE.pdf	

Project	New/ Retrofit	Capture Type	Base Plant/Unit Size (MW)	Capture Unit Size (MW) *Note 1	CO_2 Capture Amount (Mtpa)	Status *Note 2	Project Operation Date	Capture / Gasifier Technology	Country	Proponents	External Funding Source	External Funding Amount	Estimated Project Cost	Currency	Project Link	
Tenaska Trailblazer Energy Center	New	Post-Combustion	765.00 (gross), 600.00 (net)		4.00 (85-90%)	Define	in 2016	Fluor Econamine FG Plus (Amines)	United States	Tenaska Inc., Fluor	Global CCS Institute	7,700,000	3,500,000,000	US Dollar	http://www.tenaskatrailblazer.com/	
Vattenfall Janschwalde	Retrofit & New	Post-Combustion (250MW boiler, retrofit), Oxyfuel (250MW boiler, new)	500.00	250.00	1.80 total (0.5 post-combustion, 1.3 oxy-fuel)	Define	in 2015	Alstom Chilled Ammonia Process	Germany	Vattenfall	European Energy Programme for Recovery (EEPR)	180,000,000	1,500,000,000	Euros	http://www.vattenfall.com/en/ccs/janschwalde.htm	
Bow City Power Plant CO_2 Capture Project	New	Post-Combustion	1,000.00		1.00 (20%)	Evaluate	in 2016	Amines	Canada	Bow City Power Ltd., Luscar				US Dollar	http://environment.alberta.ca/documents/Luscar_PDD.pdf	
Entergy Nelson 6 Carbon Capture & Sequestration Project	Retrofit	Post-Combustion	585.00 (gross)		4.00	Evaluate			United States	Tenaska Inc., Entergy Corporation	Global CCS Institute	825,600		Australian Dollar	http://www.globalccsinstitute.com/resources/projects/tenaska-entergy-nelson-6-project	
Romanian CCS Demo Project	Retrofit (one unit)	Post-Combustion	330.00	330.00	1.50	Evaluate		Alstom Chilled Ammonia Process	Romania	Romania's Institute for Studies and Power Engineering (ISPE), Romanian National Institute for Research and Development of Marine Geology and Geoecology, Alstom	Global CCS Institute	2,550,000		Australian Dollar	http://www.bellona.org/news/news_2010/Romania_CCS_project_launch	http://www.kooperation-international.de/niederlande/themes/info/detail/data/51087/backpid/15/
RWE CCS Eemshaven	Retrofit	Post-Combustion	814.00 (gross)		0.20 - 1.20	Evaluate	in 2015		Netherlands	RWE				US Dollar	http://www.co2-cato.nl/cato-2/locations/regions/northern-netherlands/rwe-eemshaven	
Sargas Husnes Norwegian Clean Coal Plant Project	New	Post-Combustion	400.00		2.60 (95%)	Evaluate (Quiet since 2008)	in 2015		Norway	Sargas, Tinfos, Sør-Norge Aluminium, Eramet			700,000,000	US Dollar	http://www.sargas.no/	http://sequestration.mit.edu/tools/projects/sargas_husnes.html
Southern Company Kemper County Project	New	Pre-Combustion	524.00 (net)		2.50 (67%)	Execute	in 2014	Southern Co/KBR "TRIG" (air-blown gasifier)	United States	Southern Company, Mississippi Power, KBR	US DOE Clean Coal Power Initiative, Internal Revenue Service investment tax credits	403,000,000	2,880,000,000	US Dollar	http://www.mississippipower.com/kemper/default.asp	http://gasification-igcc.blogspot.com/2010/12/mississippi-power-breaks-ground-on.html
Dongguan Taiyangzhou IGCC with CO_2 capture project	New	Pre-Combustion	800.00 (gross), 750.00 (net)		1.00	Define		Southern Co/KBR "TRIG" (air-blown gasifier)	China	Dongguan Taiyangzhou Power Corporation, Xinxing Group, Nanjing Harbin Turbine Co Ltd.					http://www.globalccsinstitute.com/resources/projects/dongguan-taiyangzhou-igcc-co2-capture-project	
Good Spring IGCC, Future Fuels	New	Pre-Combustion	270.00		1.00	Define	in 2014	Thermal Power Research Institute (gasifiers)	United States	Future Power PA, China's Thermal Power Research Institute	US DOE Recovery Act Fund				http://www.pennenergy.com/index/power/display/8740087947/articles/pennenergy/power/coal/2010/12/good-springs_270mw.html	http://www.gasification.org/uploads/downloads/Conferences/2010/15DOUGLAS.pdf
Hydrogen Energy California (HECA) Project	New	Pre-Combustion	390.00 (gross), 250.00 (net)		2.00	Define	in 2016	GE (gasifiers)	United States	Hydrogen Energy International LLC (BP Alternative Energy and Rio Tinto. Occidental Petroleum)	US DOE Clean Coal Power Initiative	308,000,000	2,300,000,000	US Dollar	http://www.hydrogenenergycalifornia.com/	
Nuon Magnum IGCC Plant with Capture Option	New	Pre-Combustion	1,200.00		1.30	Define	2011(power plant), 2015 (CCS)	Shell (gasifiers)	Netherlands	Nuon	Dutch Ministry of Finance		1,800,000,000	Euros	http://www.nuon.com/company/Innovative-projects/magnum.jsp	http://sequestration.mit.edu/tools/projects/nuon_magnum.html
RWE Goldenbergwerk IGCC Plant with CO_2 Storage (maybe on hold)	New	Pre-Combustion	450.00 (gross), 320.00 (net)		2.60	Define	2015 (plant), 2020 (storage)		Germany	RWE nPower	RWE (1 billion Euros)		2,000,000,000	Euros	http://www.rwe.com/web/cms/en/2688/rwe/innovations/power-generation/clean-coal/igcc-ccs-power-plant/	http://www.globalccsinstitute.com/resources/projects/rwe-goldenbergwerk-huerth
Texas Clean Energy Project (TCEP)	New	Pre-Combustion	400.00 (gross), 245.00 (net)		2.90	Define	mid 2014	Siemens (gasifiers)	United States	Summit Power Group, Inc., Siemens, Fluor	US DOE Clean Coal Power Initiative, US DOE Recovery Act Fund	450,000,000	2,070,000,000	US Dollar	http://sequestration.mit.edu/tools/projects/tcep.html	http://www.carboncapturejournal.com/displaynews.php?NewsID=603&PHPSESSID=400t64rno75ig1vt86b75e42t1
Duke Energy - Edwardsport Plant (CCS ready, viability studies	Retrofit	Pre-Combustion	630.00 (net)			Evaluate		GE (gasifiers)	United States	Duke Energy, GE, and Bechtel			2,880,000,000	US Dollar	http://www.duke-energy.com/about-us/edwardsport-overview.asp	

Project	New/ Retrofit	Capture Type	Base Plant/Unit Size (MW)	Capture Unit Size (MW) *Note 1	CO_2 Capture Amount (Mtpa)	Status *Note 2	Project Operation Date	Capture / Gasifier Technology	Country	Proponents	External Funding Source	External Funding Amount	Estimated Project Cost	Currency	Project Link	
ongoing till 2011)																
Erora Group - Cash Creek IGCC	New	Pre-Combustion	770.00 (gross), 630.00 (net)		2.00	Evaluate	in 2015		United States	ERORA Group				US Dollar	http://www.sourcewatch.org/index.php?title=Cash_Creek_Generation	
GreenGen Project in China	New	Pre-Combustion	400.00			Evaluate	in 2018	Thermal Power Research Institute (gasifiers)	China	GreenGen Co. Ltd.			1,000,000,000	US Dollar	http://www.greengen.com.cn/en/index.asp	http://sequestration.mit.edu/tools/projects/greengen.html
Osaki CoolGen IGCC Demonstration Plant	New	Pre-Combustion	170.00			Evaluate	2017 (startup), 2021 (CO_2 capture)		Japan	Osaki CoolGen Corporation (J-Power & Chugoku Electric)					http://www.jpower.co.jp/english/ir/pdf/2010-11.pdf	http://www.hitachi.com/New/cnews/100609/20100609e_2_PS_fin.pdf
Progressive Energy IGCC Project,Teesside/Eston Grange (maybe on hold)	New	Pre-Combustion	800.00			Evaluate			United Kingdom	Progressive Energy	Tees Valley Industrial Programme	240,000	7,200,000 (study spend)	British Pound	http://www.zero.no/ccs/projects/progressive-energy-2013-teesside-pre-combustion-project	http://carbon.energy-business-review.com/news/uk_government_awards_gbp13m_for_carbon_capture_project_100806#
SCS Energy PurGen One	New	Pre-Combustion	750.00 (gross), 500.00 (net)		4.00	Evaluate	in 2014		United States	SCS Energy			5,200,000,000	US Dollar	http://www.purgenone.com/about-purgen-one.php	
Southern California Edison IGCC Project (maybe on hold)	New	Pre-Combustion	500.00 (net)		2.50	Evaluate	in 2017		United States	Southern California Edison, Southeast Regional Carbon Sequestration Partnership (SECARB), Electric Power Research Institute (EPRI)			50,000,000 (study spend)	US Dollar	http://www.edison.com/pressroom/pr.asp?id=7011	http://new.globalccsinstitute.com/southern-california-edison-igcc-project
Sweeny Gasification Project	New	Pre-Combustion	680.00 (net)		3.00	Evaluate	in 2015	ConocoPhillips E-Gas™ Technology (gasifiers)	United States	ConocoPhillips	US DOE	3,000,000		US Dollar	http://www.globalccsinstitute.com/resources/projects/sweeny-gasification	
Wandoan Power IGCC CCS Project	New	Pre-Combustion	400.00 (gross), 330.00 (net)		2.50	Evaluate	in 2017	GE (gasifiers)	Australia	General Electric, Stanwell Corporation, Xstrata Coal				US Dollar	http://www.m2cms.com.au/uploaded/33/FACT_SHEET_Project_summary.pdf	

Note 1: For several cases, this information was not readily indentifiable. However, the capture size was defined as either the size of the unit fitted with capture, or the calculated effective capture unit size with full capture. In general, the size of the unit fitted with capture had been as identified in the Base Plant/Unit Size column, although a slipstream of this amount may only be processed. As a very generalised reference figure, a 250MW capture unit typically corresponds to capture rates of up to 1.0 Mtpa.

Note 2: Project status is as defined by WorleyParsons within the 2009 GCCSI report, *Strategic Analysis of the Global Status of Carbon Capture and Storage*

Appendix 2

CO_2 Capture Technology Selection and its Role in Moving CCS Forward

CO_2 Capture Technology Selection and its role in moving CCS forward

Introduction

The successful validation of Carbon Capture and Storage (CCS) in Australia requires a strategy for 'proving-up' geologic storage resources. A key component of such a strategy will be the ability to source a timely and reliable supply of CO_2 of the necessary quantity and quality.

The exact amount of CO_2 required to prove-up CO_2 storage in Queensland's most prospective location, the Surat Basin, is yet to be established. However the Global CCS Institute has defined a large-scale CCS project as one which captures and stores at least 850,000 tonnes of CO_2 per year.

For a large-scale CCS project the choice of CO_2 capture technology is of prime importance and proper consideration of steady state and dynamic operational and chemical capture compatibility with CO_2 transport and storage will be critical to success. The only CO_2 capture technology available at this time that meets all of these criteria is Integrated Gasification Combined Cycle (IGCC) with pre-combustion CO_2 capture.

Relying on the capture technology alternatives of post-combustion capture (PCC) or oxy-fuel combustion to provide the necessary source of CO_2 will significantly increase the level of risk to achieving a successful large-scale validation of CCS in Australia. This paper discusses some key questions regarding the status of these capture technologies.

What PCC projects are currently operating, or are at the detailed planning/implementation phase?

Using post-combustion CO_2 capture (PCC) as a source of CO_2 is a technically feasible concept however PCC is not in use at large-enough scale in any coal fired plant today. The largest post-combustion capture projects that are currently in test are limited to 25 MWe in size as contrasted with the approximate 150 MWe size as would be necessary to supply of the order of one million tonnes per year of CO_2 for sequestration. Even the earliest of the planned large scale demonstrations (Table 1) will not begin operation in a time frame that can provide data and experience to reduce the risk of a PCC alternative to an equivalent level provided by the Wandoan Power Project.

Table 1 – Post Combustion Capture demonstration

Project	Type	Scale	% CC	Developer	Tech	Schedule
Trailblazer	New	600MW(Net)	85 - 90%	Tenaska	Fluor Econamine	2011 FEED COD 2016 (?)
WA Parish	Retrofit	60MWe Slipstream	90%	NRG Energy	Fluor Econamine	FEED May 2011 Test start 2014
Plant Barry	Retrofit	Phase 1 25 MWe	90%	Southern Company	MHI KS-1	In test
	Retrofit	Phase 2 160 MW	90%		MHI KS-1	Cancelled
Boundary Dam	Retrofit	110MW	90%	Saskatchewan Power	Shell Cansolve	Phase 1, 2013 Phase 2, 2015
Antelope Valley	Retrofit	120MWe Slipstream	90%	Basin Electric	HTC Pure Energy PowerSpan	Cancelled
Mountaineer	Slipstream Pilot	20MWe	90%	AEP	Alstom Chilled Ammonia	In test
	Retrofit	235MWe Slipstream	85 - 90%			Pending
Belchatow Phase II	New w/retrofit	260MWe Slipstream	90%	PGE EB	Alstom Advanced Amine	FEED complete 2014-2015 COD
Keephills 3	Retrofit	~150MWe Slipstream	90%	TransAlta Project Pioneer	Alstom Chilled Ammonia	FEED 2011 COD 2015
Porto-Tolle	Retrofit	250MW Slipstream	85 - 90%	ENEL	Aker Amine	FEED 2011

What technology and scale-up issues/risks exist for deployment of PCC/oxy-fuel combustion as part of a large 'industrial' scale plant?

A major technology risk associated with PCC and oxy-fuel combustion at the scale required is the inability to achieve the necessary quality and reliability of CO_2 produced. In contrast it is noted that pre-determined and consistent CO_2 quality is routinely achieved in industrial, chemical and refining applications of pre-combustion capture.

The quality of CO_2 required for CCS will need to consider the following:

- The potential for certain contaminants to cause environmental, health and/or safety problems as might be incurred from pipeline failure or leakage, plant release or venting operations.
- The interaction of contaminants in the CO_2 with one another.
- The interaction of contaminants in the CO_2 with the geological formation and the fluids in the formation. For example the impact various contaminants in the CO_2 have upon the injectivity and fluid flow in a geological formation.
- Pipeline transport requirements
- The potential for various contaminants to cause corrosion and fouling.

If the required CO_2 quality is not consistently met, the result could be very costly in terms of pipeline damage, plugging of injection wells and loss of reservoir capacity.

High reliability of CO_2 supply is also important to proving capacity, injectivity and the veracity of models of the geologic fate and transport of injected CO_2. High CO_2 availability with pre-combustion carbon capture is already being achieved at the commercial Coffeyville and Eastman plants that operate at greater than 90% availability.

For PCC and oxy-fuel combustion scaling from small pilots to industrial scale and operation will result in unknown and unproven reliability and quality issues and risks. Scale-up challenges specific to amines required for most PCC processes will be due to:

- Necessary '10 to 1' scale-up to provide the required quantity of CO_2 exceeds the typical "3 to 1" comfort level.
- Beyond the range of computational fluid dynamics (CFD) model validation techniques (e.g. skinny-to-fat scrubbers).
- Mass transfer and contactor effectiveness.
- Build-up and precipitation of contaminants over extended operation and potentially hazardous waste.
- Long-term increase in boiler and air pre-heater in-leakage causing solvent degradation.
- Corrosion mechanisms and materials of construction.

- Design features to deal with upset conditions (water wall leaks, air pre-heater failure, etc.) causing contamination and loss of solvent inventory.
- Heat and mass integration complexity and controls development.
- Provisions for start-up/shutdown, load following and time to stable operations.
- Contraction of fuel envelope.
- Control of particulate and vapour emissions.

How well established are the cost and performance characteristics of PCC/oxy-fuel combustion for retrofit deployment at industrial scale e.g. >100 MW?

Retrofitting a large industrial scale PCC plant or oxy-fuel combustion to an existing coal-fired power plant is a project of similar scale and more complexity than building a new plant.

Extensive project development studies including pre-feasibility study (PFS), definitive feasibility study (DFS) and front end engineering design (FEED) to properly define cost and schedule will be necessary before seeking project financial close.

Retrofit cost, performance and impact will be specific to each site, plant and its characteristics, and the capture technology selected. For example:

- Site layout and available space
- Base plant boiler type and heat rate
- Coal type(s) and envelope
- Load profile (turndown, cycling, etc.) and operability
- Plant control system capability
- Boiler in-leakage and need for refurbishment
- CO_2 end-use and required quantity, quality and availability
- Induced Draft/Forced Draft fan capacity
- Steam supply integration: turbine configuration, extraction location and impact on steam turbine performance
- Can steam turbine operate at reduced load?
- Water supply and water balance
- Replacement power and CO_2 characteristics
- Existing emissions performance and upgrade requirements (SOx, NOx, PM)
- Local permitting requirements (venting, flue gas reheat, etc.)

Costs for retrofitting PCC will be highly dependent on the site, plant and layout. Labor productivity for a 'brownfield' installation will be significantly lower compared with that on 'greenfield' installations. As an example, EPRI[1] and DOE[2] have estimated capital expenditure (CAPEX) ($/KW) for retrofitting PCC at favorable sites to be comparable to the cost of building a new plant without CCS. It should also be recognised that estimates of levellised cost of electricity for a PCC retrofit that will be operational only during the term of a testing campaign would be extremely high and heavily weighted by capital recovery.

How long is it likely to take to engineer, procure and construct a project based upon PCC/oxy-fuel combustion for retrofit deployment at industrial scale e.g. >100 MW?

For a retrofit project that is going to produce in the order of one million tonnes CO_2 per annum, the development, construction and commissioning timeframe will be similar to that of a new build project.

Extensive project development studies including pre-feasibility, feasibility and engineering design phases will be necessary to properly define cost and schedule prior to seeking project financial close.

It is estimated that it would take at least five years from commencement of project development to completion of construction.

What are the major limitations of a project based upon PCC/oxy-fuel combustion for retrofit deployment at industrial scale e.g. >100 MW?

While slipstream demonstrations provide valuable data on stand-alone capture process capability, they do not provide validation of cost and performance data of CCS on new, purpose built plants that incorporate CO_2 capture for their entire fuel or flue gas.

As compared to retrofit PCC or oxy-fuel combustion, a new build fully integrated plant is required for the successful validation of CCS in Australia. Such a plant will prove the effectiveness of design, materials' choices and control strategies that guarantee operational flexibility while maintaining process flow balances between major power and process components, control of dynamic and chemical interactions and the longer term impact of build-up of secondary and tertiary compounds within solvent regeneration and recycle loops. Successful large-scale and commercially relevant demonstrations are critical to prove

[1] An Engineering and Economic Assessment of Post-Combustion CO2 Capture for 1100℉ Ultra-Supercritical Pulverized Coal Power Plant Applications: Phase II Task 3 Final Report. EPRI, Palo Alto, CA: 2010. 1017515

[2] Ciferno, J. P. Carbon Dioxide Capture from Existing Coal-Fired Power Plants. U.S. Department of Energy; National Energy Technology Laboratory: Pittsburgh, PA, December, 2006; DOE/NETL - 401/120106

that geologic sequestration of CO_2 is a safe and environmentally acceptable solution for low carbon coal power.

Summary

PCC and oxy-fuel combustion technology experience for coal-fired plants is currently limited to pilot and proposed sub-commercial demonstrations. No demonstrations have been completed at industrial scale nor in a fully integrated plant configuration.

A substantial investment program will be required to progressively scale up various PCC and oxy-fuel technologies and de-risk them so that they can be evaluated for suitability for commercial deployment. It is likely that a number of projects will need to be undertaken at different scales including a mix of slipstream retrofit and integrated full capture new build projects.

Relying at this time on capture technology of this limited maturity will significantly increase the risks to a successful validation of CCS in Australia.

Appendix 3

IGCC with CO_2 Capture Process Summary

WandoanPower
a carbon solution

Gasification technology

Gasification technology and Wandoan Power

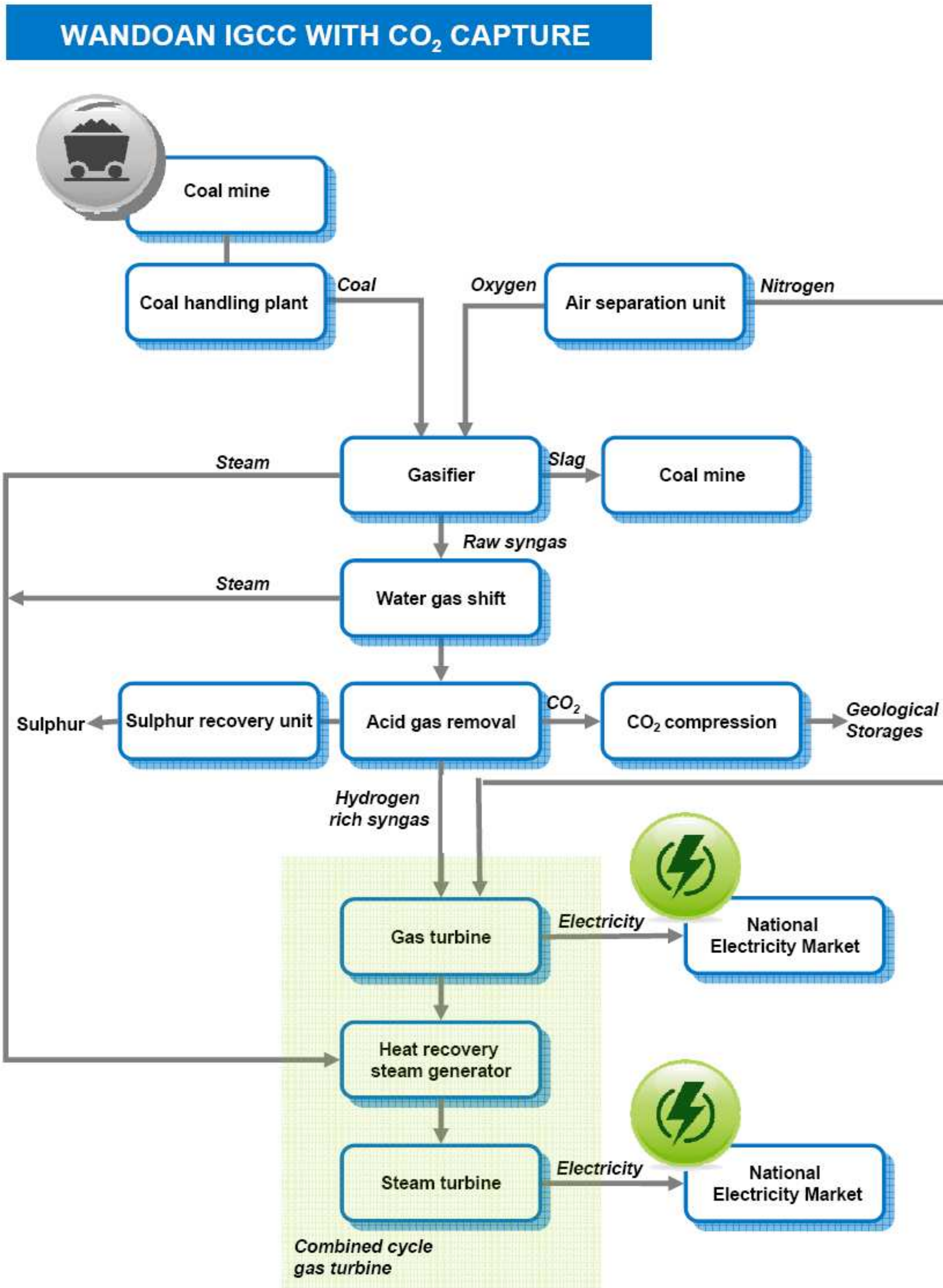
Introduction

Gasification is a process that converts carbon-containing materials, such as coal, to a syngas which can be used as a fuel in a gas turbine to produce electricity or as feedstock to produce products such as chemicals, fertilisers, a natural gas substitute, hydrogen and transportation fuels.

The Wandoan Power Project (Wandoan Power) will use GE's commercially available gasification and power technologies configured as an integrated gasification combined cycle (IGCC) plant integrated with pre-combustion carbon capture technology. The main process blocks are illustrated in Figure 5.1 and described at a high level in the remainder of Section 5.1. Further detail is provided in Section 7 of this report.

GE's gasification technology is discussed generally in section 5.2.

Figure 1 - Wandoan IGCC with CO_2 capture process



Coal is crushed and mixed with water then injected as a slurry with oxygen into a high temperature pressurised reactor, the gasifier. The conditions inside the gasifier break apart the chemical bonds of the coal slurry feedstock, forming a raw syngas which consists primarily of hydrogen and carbon monoxide together with smaller quantities of methane, carbon dioxide, hydrogen sulphide, and water vapour.

The gasifier also produces slag which is a black glass-like by-product composed primarily of sand, rock, and minerals from the feedstock. Slag has potential for beneficial use e.g. road base or sand blasting.

Air separation unit

An air separation unit (ASU) uses electrical power from the power station to extract from atmospheric air two elements: oxygen and nitrogen. Oxygen is input to the gasifier (instead of air) to improve the gasification reaction. Nitrogen is used as a diluent for the syngas sent to the gas turbine.

Syngas clean-up and CO_2 capture

Raw syngas is cleansed by various processes to remove CO_2 and impurities such as particulates and sulphur. Elemental (yellow) sulphur is captured with a sulphur recovery unit (SRU) to become an economic by-product.

The water-gas shift reaction is used to increase the level of CO_2 available for capture. In the acid gas removal (AGR) stage a solvent is used to remove acid gas and CO_2 from the syngas. The captured CO_2 stream is dehydrated and compressed ready for transport by pipeline to a storage site.

A clean hydrogen-rich syngas stream is sent as fuel to the combustion turbine for power generation. The clean syngas is then used as the fuel for the gas turbine.

Power plant

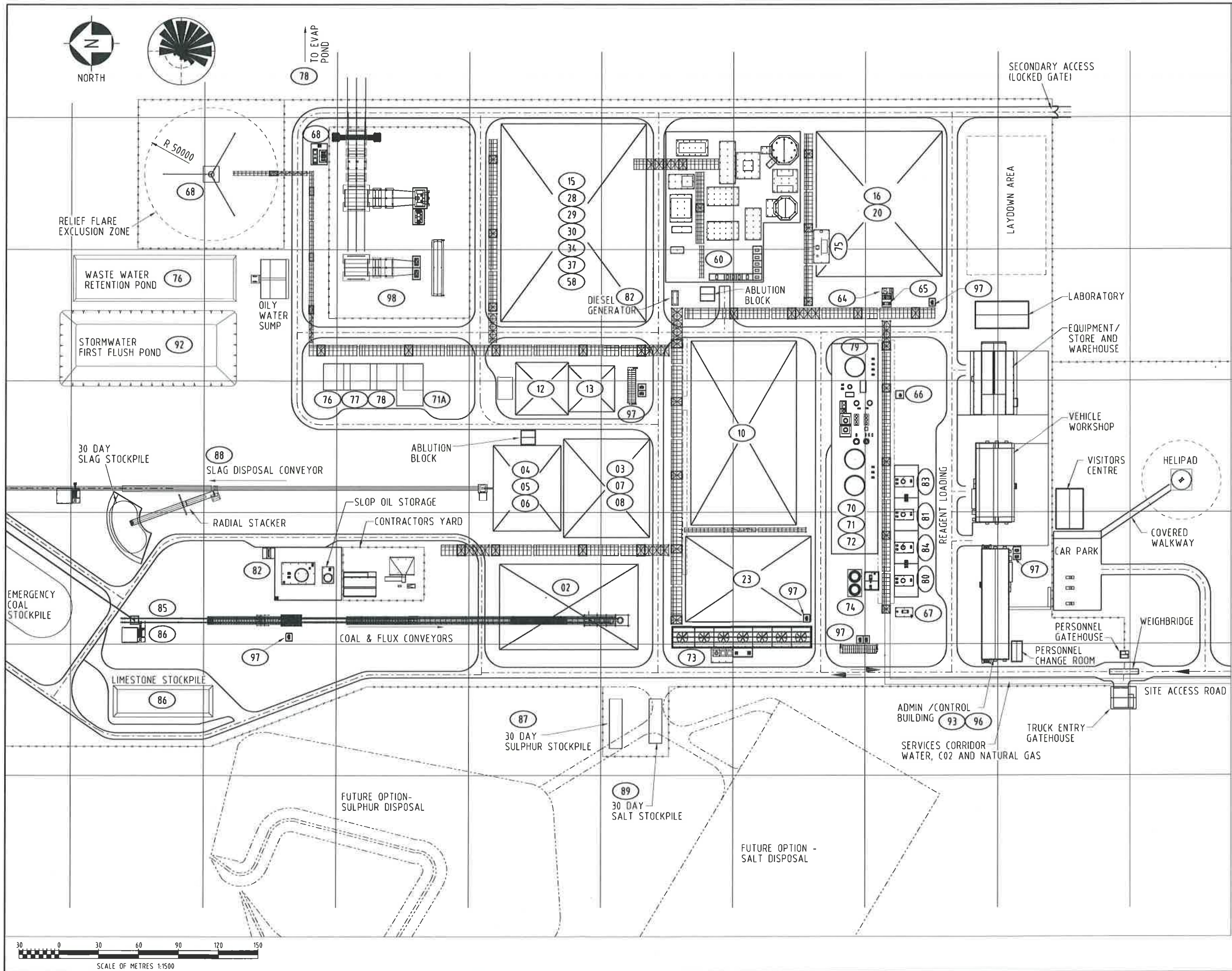
The power plant combines a gas turbine and a steam turbine into a combined cycle unit.

Clean syngas from the gasification process area is combusted in the gas turbine to produce electricity. After carbon capture the syngas has a high level of hydrogen compared to normal syngas or natural gas. nitrogen (from the ASU) is used as a diluent to regulate the level of hydrogen in the clean syngas. The gas turbine is a standard GE 9F adapted to operate on a mix of high hydrogen syngas and nitrogen.

The excess heat from both the gas turbine and the gasification reaction is then captured using a heat recovery steam generator (HRSG). This steam is sent to a steam turbine to produce additional electricity.

Appendix 4

Wandoan Power General Site Plot Plan



AREA CODE CLASSIFICATION

CODE	AREA DESCRIPTION	AREA RESPONSIBILITY
00	GENERAL	GE - GASIFICATION
01	COAL HANDLING	XSTRATA
02	COAL GRINDING AND SLURRY PREPARATION	GE - GASIFICATION
03	GASIFICATION AND SCRUBBING	GE - GASIFICATION
04	COARSE SLAG HANDLING	GE - GASIFICATION
05	BLACK WATER SYSTEM	GE - GASIFICATION
06	FINE SLAG HANDLING SYSTEM	GE - GASIFICATION
07	CONDENSATE AMMONIA STRIPPER	GE - GASIFICATION
08	LOW TEMPERATURE GAS COOLING SYSTEM	GE - GASIFICATION
10	ACID GAS REMOVAL SYSTEM	GE - GASIFICATION
12	SULPHUR RECOVERY UNIT	GE - GASIFICATION
13	TAIL GAS UNIT / THERMAL OXIDISER	GE - GASIFICATION
15	H2 / N2 BLENDING	GE - GASIFICATION
16	GREY WATER PRE-TREATMENT	GE - GASIFICATION
20	ZPWD THERMAL SYSTEM	GE - GASIFICATION
23	C02 COMPRESSION & DEHYDRATION	GE - GASIFICATION
28	GAS TURBINE	GE - POWER
29	HRSG WATER SIDE	GE - POWER
30	HSRG STEAM SIDE	GE - POWER
34	STEAM TURBINE	GE - POWER
37	STEAM CONDENSATE	GE - POWER
58	STEAM, CONDENSATE & FEEDWATER SYSTEMS	GE - POWER
60	AIR SEPARATION UNIT	VENDOR / B.O.P
64	PLANT AIR SYSTEM	BALANCE OF PLANT
65	INSTRUMENT AIR SYSTEM	BALANCE OF PLANT
66	SERVICE NITROGEN	BALANCE OF PLANT
67	NATURAL GAS CONDITIONING SYSTEM	BALANCE OF PLANT
68	RELIEF NETWORK AND FLARE	BALANCE OF PLANT
70	RAW WATER TREATMENT PACKAGE	BALANCE OF PLANT
71	DEMINERALISATION PACKAGE	BALANCE OF PLANT
71A	CONDENSATE POLISHER PACKAGE	BALANCE OF PLANT
72	POTABLE WATER TREATMENT	BALANCE OF PLANT
73	COOLING WATER SYSTEM	BALANCE OF PLANT
74	FIRE WATER	BALANCE OF PLANT
75	AUXILIARY BOILER	BALANCE OF PLANT
76	WASTE WATER SYSTEM	BALANCE OF PLANT
77	SEWAGE TREATMENT	BALANCE OF PLANT
78	EVAPORATION POND & BLOWDOWN TREATMENT	BALANCE OF PLANT
79	SERVICE WATER SYSTEM	BALANCE OF PLANT
80	SELEXOL STORAGE AND DISTRIBUTION	BALANCE OF PLANT
81	GLYCOL STORAGE AND DISTRIBUTION	BALANCE OF PLANT
82	DIESEL STORAGE AND DISTRIBUTION	BALANCE OF PLANT
83	CAUSTIC STORAGE AND DISTRIBUTION	BALANCE OF PLANT
84	AMMONIUM LIGNOSULPHONATE	GE - POWER
85	COAL SUPPLY AND STORAGE	BALANCE OF PLANT
86	FLUX SUPPLY AND STORAGE	BALANCE OF PLANT
87	SOLID SULPHUR HANDLING	BALANCE OF PLANT
88	SLAG HANDLING	BALANCE OF PLANT
89	SALT AND WASTE SOLIDS	BALANCE OF PLANT
91	BULK EARTHWORKS, ROADS AND FENCING	BALANCE OF PLANT
92	STORMWATER	BALANCE OF PLANT
93	BUILDINGS AND STRUCTURES	BALANCE OF PLANT
94	PIPING AND PIPERACKS	BALANCE OF PLANT
96	DCS	BALANCE OF PLANT
97	SUBSTATIONS AND DISTRIBUTION TRANSFORMERS	BALANCE OF PLANT
98	SWITCHGEAR AND SWITCHYARD	POWERLINK

KEY

DENOTES FENCE LINE

INFORMATION ONLY
NOT TO BE USED
FOR CONSTRUCTION

REV	DATE	REVISION DESCRIPTION	DRAWN	DRAFT CHK	DESIGNED	ENG CHK	APPROVED	CUSTOMER
1	18-4-2011	CLIENT COMMENTS INCORPORATED						
0	01-12-2010	ISSUED FOR APFS	PB	PV	PM	PM	GE	

REF DRAWING No	REFERENCE DRAWING TITLE
101001-00174-00-ME-DLP-0001	OVERALL SITE PLAN

A1 SHEET SCALE 1:1500

ENGINEERING AND PERMIT STAMPS (As Required)

OneWay to zero harm

WORLEYPARSONS PROJECT No. 101001- 00174

CUSTOMER

Wandoan Power
a carbon solution

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WANDOAN POWER APFS PROJECT
GENERAL SITE
PLOT PLAN

DRG No 101001-00174-00-ME-DPP-0001 REV 1

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Appendix 5

Wandoan Power Project: Non-Confidential Report

WANDOAN POWER PROJECT

NON-CONFIDENTIAL REPORT

Prepared by GE Infrastructure Technology LLC for the Wandoan Power Project.

1.0 Executive Summary

GE Energy (USA), LLC (GE) is pleased to provide the Accelerated Pre-Feasibility Study (APFS) Package for GE's gasification and power generation technology for the Wandoan facility located in Queensland, Australia. The Facility is being developed by Stanwell/WPGE and shall be designed to produce electric power from a coal feedstock. The feasibility study addressed definition of major process streams, developed major process drawings, prepared major process equipment specifications, estimated system effluents, and identified of utility and chemical requirements.

There are following process areas in this facility:

- Coal Grinding and Slurry Preparation
- Gasification and Scrubbing
- Coarse Slag Handling
- Black Water Flash
- Fines Slag Handling
- Shift and Gas Cooling
- Acid Gas Removal (AGR)
- Sulfur Recovery Unit (SRU)
- Tail Gas Treatment
- Fuel Gas Preparation
- CO_2 Compression and Dehydration
- Zero Process Water Discharge (ZPWD)
- Power Block

Other process facilities such as feedstock handling, air separation, utilities and balance of plant systems are outside of GE's scope.

The Wandoan IGCC project uses GE's gasification technology to convert coal feedstock into syngas, which is then cleaned and burned in a combined cycle power plant to produce electricity. The APFS configuration is designed for ZPWD to minimize water usage and to capture 90% CO_2 (nominal, +/-2%) via shift and cooling, extraction of CO_2 from syngas to a solvent, stripping of the CO_2 from the solvent to a CO_2-rich stream, and compression and treatment of the CO_2-rich stream. This IGCC unit is intended to produce an estimated gross power output of 503 MW and a net power output of 341 MW.

2.0 Process Description

Overview of Gasification

This project uses GE's gasification technology. GE's Gasifier feeds coal and water slurry along with oxygen into a refractory lined reactor vessel. The Gasifier operates between 1260°C and 1480°C. Part of the feed to the Gasifier is initially oxidized very rapidly providing the necessary heat for the gasification reactions. The feed to the Gasifier passes through the pyrolysis temperature region very rapidly (in a few thousandths of a second) and the gasification reactions determine the Gasifier chemistry and performance.

Overall gasification reactions are shown in Table 2-1, Primary Gasification Reactions. Some of these reactions are actually endothermic, meaning that they require heat input to go forward (unlike combustion, which is completely exothermic).

Table 2-1. Primary Gasification Reactions

Devolatilization/Pyrolysis = CH_4 + CO + Oils + Tars + C (char)	
$C + O_2 \rightarrow CO_2$	Oxidation - exothermic – rapid
$C + \frac{1}{2} O_2 \rightarrow CO$	Partial oxidation - exothermic – rapid
$C + H_2O \rightarrow CO + H_2$	Water gas reaction - endothermic – slower than oxidation
$C + CO_2 \rightarrow 2CO$	Boudouard reaction - endothermic – slower than oxidation
$CO + H_2O \rightarrow CO_2 + H_2$	Water gas shift reaction – exothermic – rapid
$CO + 3H_2 \rightarrow CH_4 + H_2O$	Methanation – exothermic
$C + 2H_2 \rightarrow CH_4$	Direct methanation – exothermic

Source: Multiple Publicly Available Sources
Notes:
C = carbon
CH_4 = methane
CO = carbon monoxide
CO_2 = carbon dioxide
H_2 = hydrogen
H_2O = water
O_2 = oxygen

Gasification is a chemical conversion process. It occurs in a reducing environment. Gasification differs from combustion in that gasification produces syngas, an intermediate product that can then be used for other purposes such as generating electricity or producing chemicals. Typical components of syngas from an oxygen-blown gasifier are shown in Table 2-2, Components of Syngas from Oxygen-Blown Gasification.

Table 2-2. Components of Syngas from Oxygen-Blown Gasification

Constituent	Percent by Volume
H_2	25-30
CO	25-40
CO_2	10-20
H_2O	15-25
CH_4	0-0.2
H_2S + COS	0 – 1.4
N_2 + Ar	1.7 – 2.5

CO_2 = carbon dioxide
COS = carbonyl sulfide
H_2 = hydrogen
H_2O = water
H_2S = hydrogen sulfide
N_2 = nitrogen

The primary components of syngas are CO and H_2. The syngas must be thoroughly processed to remove undesired components prior to further use, especially if it will be used in a combustion turbine or for producing chemicals.

Project description

The Wandoan Power Project is an Integrated Gasification Combined-Cycle (IGCC) power generation facility with 90% carbon capture capability (the facilities for carbon sequestration are not in GE's scope of work).

IGCC Process Description

A schematic sketch of GE's IGCC process for Wandoan Power Project is presented at the end of this section. Process areas are described in the following section.

Coal Grinding and Slurry Preparation

Fresh feedstock (coal) is continuously delivered from the Coal Hopper(s) to the Grinding Mill(s). Fluxant is also continuously conveyed from the Fluxant Hopper(s) to the Grinding Mill(s). The Grinding Mill(s) crush the fresh feedstock, fluxant, and recycled Gasifier solids (fine slag/ash and unconverted carbon) with water to form slurry. The slurry is pumped into the Slurry Tank, which is sized to provide several hours of storage.

Gasification and Scrubbing

GE's Gasifier is a slurry-fed, pressurized, entrained flow, slagging downflow gasifier, consisting of a refractory-lined pressure vessel capable of withstanding the required gasification process temperature and pressure range. For the gasification reaction, slurry and oxygen are introduced into the Gasifier through a specialty equipment item called the Feed Injector.

The slurry is pumped from the slurry tank to the Gasifier by a Slurry Charge Pump. This high pressure metering pump supplies a steady, controlled flow of slurry to the Feed Injector. The slurry and a measured amount of high pressure oxygen from the Air Separation Unit react in the Gasifier reaction chamber at high temperatures to produce syngas. The feedstock is almost totally gasified in this environment to form syngas consisting principally of H_2, CO, CO_2, and water.

Hot syngas, along with slag with unconverted carbon from the Gasifier reaction chamber flow down into the Radiant Syngas Cooler (RSC). The RSC is a high-pressure (HP) steam generator. Heat is transferred primarily by radiation and convection from the hot syngas to the boiler feedwater. Coarse slag and a portion of the unconverted carbon settle to the bottom of the RSC from where they enter the coarse slag handling section.

The syngas from the Gasifier enters the Syngas Scrubber where solids are removed from the syngas. Raw syngas from the overhead of the Syngas Scrubber is routed to the shift reactors and low temperature gas cooling section. Water condensed from the syngas in the shift and low temperature gas cooling section is returned as process condensate to the Syngas Scrubber.

Coarse Slag Handling

The coarse slag handling section removes coarse solid material from the Gasifier. Slag is comprised of ash and unconverted carbon component that exits the Gasifier. Coarse slag exiting the bottom of the RSC is crushed by the Slag Crusher and flows into the Lockhopper. After the solids enter the Lockhopper, the particles settle to the bottom. The solids that have accumulated in the Lockhopper are water-flushed into the Slag Sump, using process water return from the fine slag handling section. In the Slag Sump, the slag is separated from the water. The slag is washed and the discharged washed low carbon slag is removed from site for disposal. The fine slag recycle from the Slag Sump is pumped to the fine slag handling section and then recycled to grinding and slurry preparation section.

Black Water Flash and Fine Slag Handling

The water utilized in the gasification and scrubbing and slag handling sections is referred to as black water. This black water is sequentially let down in pressure through a series of flash drums where all dissolved gases flash out of the black water. The dissolved gases are combined and sent to the SRU. The bottoms of the last stage flash flow to the settler tank where the solids are concentrated. The overflow process water from the settler is pumped to the syngas scrubbing section. Part of the process water is also sent to the Lockhopper for flushing in the coarse slag handling section. The remaining is discharged as gasification blowdown water to the GWPT system. Most or all of the settler bottoms are pumped to the grinding and slurry preparation section to recycle fines.

Shift and Gas Cooling

Raw syngas from the Syngas Scrubber is heated by hot effluent from shift reactor to increase the syngas temperature required for shift reaction. Syngas is then successively fed to multiple stages of shift reactors. In the shift reactor, carbon monoxide reacts with water vapor in the presence of a catalyst to form carbon dioxide and hydrogen. Since the shift reaction is highly exothermic, the heat of reaction is removed in an integrated manner through a series of heat exchangers.

A small portion of process condensate from the low temperature gas cooling (LTGC) section is stripped in the Condensate Ammonia Stripper to prevent the build-up of ammonia in the system. The Condensate Ammonia Stripper overhead vapor is combined with sour gas from the Vacuum Pump Package and is sent to the SRU.

Acid Gas Removal

The AGR process utilizes the physical solvent Dimethyl Ethers of Polyethylene Glycol (DEPG) to remove sulfur compounds and CO_2 form the raw syngas. The AGR process removes sulfur compounds as acid gas and most of the CO_2 from the raw syngas stream before it is burned in the combustion turbine. The acid gases are sent to the SRU, where H_2S is converted to elemental sulfur. The captured CO_2 is recovered in multiple flash drums. The product CO2 streams are then sent to the CO_2 Compression and Dehydration Unit. The resulting clean syngas stream is then routed to a blending unit prior to going to the combustion turbine.

Sulfur Recovery Unit (SRU)
The Sulfur Recovery Unit (SRU) converts H_2S to elemental sulfur. The main feed to the SRU is the acid gas from the AGR. The SRU contains a Claus unit.

Typically one-third of the H_2S in the total acid gas is combusted in reaction furnace with a mixture of combustion air and O_2 to form SO_2. The hot gases from the reaction furnace which contain a mixture of H_2S and SO_2 along with other constituents likes N_2, CO_2 and H_2O are cooled in a waste heat boiler and are then passed over a series catalytic reactors and sulfur condensers to form elemental sulfur. The effluent gas from the catalytic reactor stage is cooled to condense out the elemental sulfur. The liquid elemental sulfur is drained into the Sulfur Tank. The liquid sulfur then moves to the Sulfur Block Forming unit, which produces large sulfur blocks that will be temporarily stored on site prior to off site disposal.

Tail Gas Treatment
The Thermal Oxidizer (TO) is configured as a single train sized to handle the design flow. The TO uses the principle of thermal oxidation, where sulfur species form the SRU tail gas are combusted with O_2 in air at high enough temperature to ensure complete oxidization. The resulting stream mainly contains N_2, CO2, H_2O and small quantities of SO_2 that is released to the atmosphere. Typically TO is a refractory lined vessel provided with a combustion chamber and a burner.

Fuel Gas Preparation

The clean syngas from the AGR flows to the Syngas Expander where the clean syngas is expanded to generate power. It then flows to the Nitrogen / Syngas Mixing Tee. Nitrogen flows to the Nitrogen / Syngas Mixing Tee to mix with the clean syngas. The clean syngas blended with nitrogen is heated by the Syngas Performance Heater and sent to the Gas Turbine. High-pressure boiler feedwater from the Heat Recovery Steam Generator (HRSG) Economizer is used to heat up the clean syngas in the Syngas Performance Heater.

CO2 Compression and Dehydration

The CO_2 compression system compresses captured product CO_2 from the AGR and delivers it at the required pipeline system pressure. The compression system is a multi-stage compressor system with adequate intercooling and knock out drums to remove moisture. The CO_2 compression unit is divided in two sections namely low-pressure and high-pressure compression section.

A CO_2 Dehydration Package is used to remove water from the captured CO_2. The CO_2 Dehydration Package is optimally placed between the compression low-pressure and high-pressure stages of the product CO_2 compression system. The dehydration system receives wet CO_2 and then delivers back dry CO_2 to the high-pressure section of product CO_2 compression system. The dehydration package uses a liquid desiccant for dehydration.

The dry gas from the dehydration unit is then further compressed in the high-pressure section to achieve the desired pressure at the battery limit.

Zero Process Water Discharge (ZPWD)

A small portion of grey water is the only blowdown of process water from the gasification unit. To minimize grey water blowdown, the plant reuses grey water in various functions within the gasification process. However, concentration of unwanted salts in grey water requires a continuous blowdown stream as wastewater out of the system.

Grey water typically contains suspended soot, char (unconverted carbon), ash, and dissolved salts from feedstock constituents. It is an industrial wastewater stream that can be disposed after proper treatment. Another option, which will be used in this project, is the concentration and disposal of the salts in grey water and the recycle of the treated water. This is the Zero Process Water Discharge (ZPWD) process, which includes grey water pretreatment and a thermal section. Besides the advantages of water conservation and no future water pollution concerns, ZPWD eliminates both expenses of the discharge permit application and compliance for industrial wastewater discharge.

A) Grey Water Pretreatment (GWPT)

The GWPT for the Wandoan project has unit operations to remove scaling components and suspended solids and to strip ammonia from grey water blowdown. The unit processes are softening/clarification/solids handling, multimedia filtration, and ammonia stripping.

1) Softening / Clarification / Solids Handling

In the softening / clarification / solids handling unit operation, the suspended solids and the dissolved scaling components in the feed grey water are removed. The feed water may be heated to a desired temperature to increase rates of reactions and to minimize fluctuations in temperature through various processes. Treatment chemicals are added to grey water to soften the water and reduce scaling constituents. Suspended and precipitated solids are concentrated in a clarifier and the resultant solids from the bottoms of the clarifier are dewatered. The dewatered solids cake is disposed. The reduction of scaling components in grey water is necessary for reliable operation of downstream process units.

2) Multimedia Filtration

The clarifier grey water overflow contains some suspended solids. The suspended solids are separated in a multimedia filter for preventing fouling of downstream process units. The filtered water as a GW Ammonia Stripper feed water should contain a very low concentration of suspended solids.

3) Ammonia Stripping

The final pretreatment unit operation for the GWPT system is ammonia stripping of the filtered grey water. The resultant stripped grey water contains less than 50 ppmw of ammonia and less than 10 ppmw suspended solids. The pretreated grey water is ready for further treatment in the downstream thermal section.

B) Thermal Section (TS)

The TS for the Wandoan project has unit operations to produce a relatively dry salt mixture and to recover of clean water from wastewater for using in the gasification process. The two unit operations are evaporation and salt drying.

1) Evaporation

A highly effective evaporator is used to convert the pretreated grey water into clean water (distillate) and high salinity water (brine). The clean water is reused in the gasification process and the brine is processed in salt drying.

2) Salt Drying

Two salt dryers with large heating surface area are used for reducing water content of the brine. A salt mixture is formed on the drying surface during brine processing and is removed for disposal offsite.

Power Block

The combined cycle plant consists of the Gas Turbine, HRSG, and the Steam Turbine. The syngas is combusted in the Gas Turbine, which makes electrical power while generating CO_2 emissions at a level similar to the combustion of natural gas. Hot exhaust gases (mostly water, nitrogen and oxygen, with some CO_2) from the Gas Turbine are passed through an HRSG to recover most of the thermal energy in the exhaust gas steam. The steam from the HRSG is combined with the steam that is generated in the RSC, and the combined stream is sent to the Steam Turbine, which makes additional electrical power.

The combined cycle plant takes advantage of the GE 9F Syngas Turbine, developed specifically for combined cycle applications, with features to enable integration with a gasification system. High combined cycle efficiency in the 9F Syngas Turbine results from the high specific power of the Gas Turbine that is achieved by its efficient compressor and turbine and its high firing temperature.

The 9F Syngas Turbine is based upon GE's 9FA Gas Turbine. This turbine utilizes GE's Multi Nozzle Quiet Combustion (MNQC) system that has been used on E- and F-class turbines for syngas and low-BTU fuel applications for more than 10 years. Combustion system durability and emissions have been verified during full scale laboratory testing at 9F conditions. The 9F Syngas hot gas path design can accommodate the higher mass flow level associated with operation on syngas fuel and diluent injection for NOx abatement. Gas Turbine accessories for adapting to a high hydrogen application include the fuel gas control skid, natural gas fuel system (startup or secondary fuel with steam injection for emissions control), and nitrogen injection system for NOx control. The Gas Turbine diluent control, lubrication, and hydraulic power systems are included in an integrated skid.

The exhaust from the Gas Turbine is discharged through an HRSG, where heat is recovered prior to venting the exhaust to the atmosphere. The HRSG allows recovery of thermal energy at two pressure levels, including superheating, reheating, evaporative and economizing duties, providing steam for the Steam Turbine. The HRSG is integrated with the plant steam, boiler feed water, and condensate handling systems, and provides superheat and reheat for any syngas cooler high pressure steam. The application calls for a single reheat, condensing steam turbine. This includes a high pressure (HP) section and combined intermediate/low pressure (IP/LP) section. The IP/LP section is single-flow with an axial-facing exhaust and last-stage buckets suitable for low condenser pressures. This design is suitable for inlet throttle steam conditions of 12.4 M Pa (g) and 540+ °C and a reheat temperature of 540+ °C. The reheat design assures high thermal efficiency and excellent reliability, based on a large experience base.

3.0 Design Basis

The following section presents the design basis for this study.

Table 3.1. General Information

GE GASIFICATION GENERAL INFORMATION	NORMAL OPERATING CONDITION *(1)*
GASIFIER SIZE AND OPERATING CONDITIONS	
Number of Radiant Gasifiers	1
Gasifier Temperature, °C	1260 – 1480
Gasifier Pressure, MPa (g) (Nominal)	6.55
NUMBER OF TRAINS	# Of Trains
GE Gasification Plant will consist of the following:	
• Coal Grinding Trains	2
• Slurry Feeding Trains	1
• Gasifier, RSC, Slag Handling, Syngas Scrubbing, and LTGC with Shift Trains	1
• AGR, SRU, TGU, CO2 Compression and Dehydration Trains	1
• Black Water Flash and Grey Water Trains	1
• Black Water Settling Trains	2

Table 3.2. Feedstock Summary

GE GASIFICATION FEEDSTOCK SPECIFICATIONS	WASHED COAL 100% COAL
COAL ULTIMATE ANALYSIS, GHV AND MOISTURE CONTENT	
FEEDSTOCK:	NOC Coal
Ultimate Analysis, Weight Percent, *(2)*	Dry Basis
Carbon	69.00
Hydrogen	5.30
Nitrogen	0.90
Sulfur	0.40
Oxygen	13.80
Ash	10.60
Total, Dry Basis	100.00
Moisture Content, As Received, Weight Percent	15
Moisture Content, Equilibrium, Weight Percent	10
Chlorine Content, PPM by Weight, Dry Basis	470
As received KJ/Kg from Customer	
Gross Heating Value, Dry, KJ/Kg (Estimate)	28,639
ASH:	
Composition, Weight Percent, Dry Basis	
P_2O_5	0.08
SiO_2	51.07
Fe_2O_3	3.08
Al_2O_3	28.65
TiO_2	1.55
Mn_3O_4	0.03
CaO	6.67
MgO	1.75
K_2O	0.60
Na_2O	2.78
SO_3	3.20
BaO	0.18
SrO	0.33
ZnO	0.02
LiO_2	0.01
Total	100.00

Table 3.3. Feed and Product Summary

FEED SUMMARY	
Coal Solid, Dry Basis, MTPD	3533
Moisture, MTPD	623
Total Coal Feed, MTPD	4156
Pure Oxygen, MTPD	3384
Total Oxygen Feed, MTPD	3586
PRODUCT SUMMARY	
Gross Power, MW	503
Net Power, MW	341
Carbon Dioxide, MTPD *(4)*	8023
Slag, Dry Basis, MTPD	468
Sulfur, MTPD	13
Filter Cake, Dry Basis, MTPD	7
Salt, Dry Basis, MTPD	6

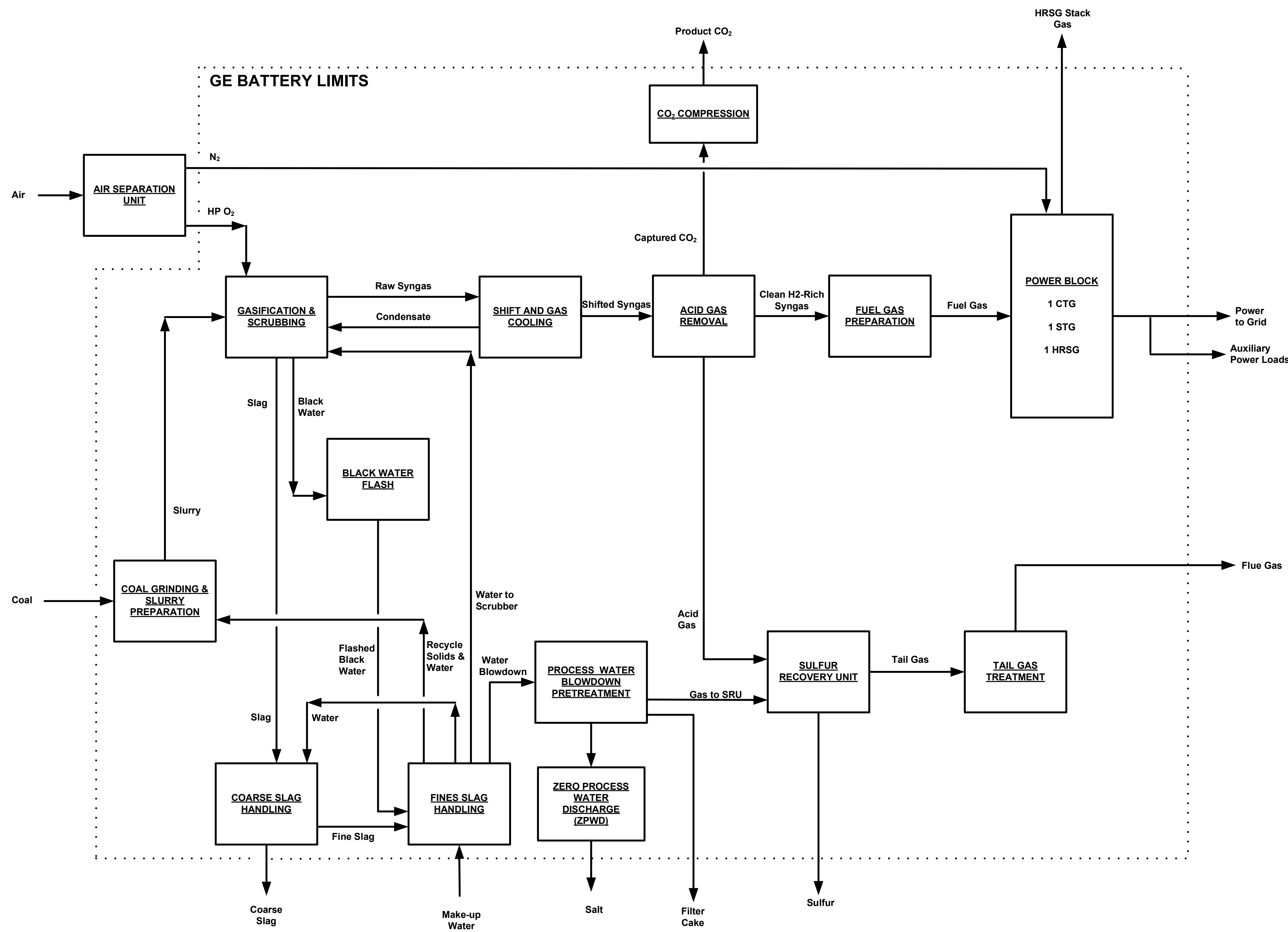
NOTES

(1) "Normal Operating Conditions" (NOC) comprise a set of consistent data for the expected plant operations on a normal operating day (28°C, 40% Humidity, and 98.64 kPa A).

(2) The feedstock ultimate analysis for the coal composition was provided by Stanwell to GE.

(3) Total plant capacity is defined as the production of 100% of the total synthesis gas produced.

(4) This study is based on 90% carbon dioxide capture.



NOTES

1. PREPARED BY GE ENERGY (USA), LLC FOR WANDOAN POWER PROJECT NON-CONFIDENTIAL REPORT.

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WANDOAN POWER PROJECT APFS
PROCESS FLOW SKETCH

SIZE | ORDER # | GE DWG NO. | SHEET 1 OF 1 | GE REV