Australian Electricity Generation Technology Costs – Reference Case 2010

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Prepared for:

Australian Government Department of Resources, Energy and Tourism

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This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

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The report is a corporate document that should be cited in the literature in the following manner:

Australian Electricity Generation Technology Costs – Reference Case 2010. EPRI, Palo Alto, CA and Commonwealth of Australia: November 2009.

PRODUCT DESCRIPTION

The Australian Department of Resources, Energy and Tourism (DRET) commissioned EPRI to build upon EPRI's report "Costs and Diffusion Barriers to the Deployment of Low-Emission Technologies[1] and to undertake assessment of the costs of various options for different electricity generation technologies out to 2030.

This will support the Australian Government's development of energy policy directions for Australia to 2030. It will include technologies which can help address the dual challenges of energy security and climate change, and will involve the integration of many policy objectives.

The objective of the work is to establish an up-to-date cost and performance database agreed by Australian stakeholders as supportable in the Australian context. The report also provides a levelised cost analysis of a basket of technologies in 2015 and 2030. This provides an agreed basis for comparing globally available power generation technologies and costs.

EPRI has evaluated a specific list of technologies. This report focuses on twelve key central station technologies of current and future interest to Australia. They are:

- Integrated Gasification Combined Cycle (IGCC);
- Pulverised Coal (PC);
- Combined Cycle Gas Turbine (CCCT);
- Open Cycle Gas Turbine (OCGT);
- Solar Thermal;
- Solar Photovoltaic;
- Wind;
- Tidal/Wave;
- Geothermal;
- Nuclear;
- Hydroelectric; and
- Biomass.

Due to water limitations within Australia, all cases evaluated were based on the use of dry cooling (air cooled condensing).

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[1] *Costs and Diffusion Barriers to the Deployment of Low-Emission Technologies: DEWHA, Commonwealth of Australia.* EPRI, Palo Alto, CA and Commonwealth of Australia: 2008. 1018049.

For each of the above technologies, appropriate plant size, configuration and design approaches were selected and evaluated to develop performance, emissions and cost information such that these, and the other technologies being evaluated by EPRI under this program, can be evaluated relative to each other to determine the preferred choices for the future Australian power generation mix of technologies and plants.

Results & Findings

This report includes descriptions of each technology evaluated, the results of the technical analysis including energy efficiencies and emissions quantities, plus cost estimate summaries comparing each technology regarding its installed cost and operating cost. These results are intended to assist Australian governments and stakeholders in evaluating electricity generation technologies available over the next 20 years.

Challenges & Objectives

The objective of this evaluation was to develop technical and economic information for the selected electric power generation technologies, provide descriptions of each evaluated technology including an explanation of its stage of development and commercial application for the purpose of providing usable data to power technology implementation decision makers within Australia. This information is expected to be used by stationary energy stakeholders, energy sector institutions and policy makers, including as part of the Australian Government's development of energy policy directions for Australia to 2030.

Applications, Values & Use

The evaluations reported are based on the status of commercialisation of each of the selected technologies in November 2009. Forecasts for improvements and cost impacts for these technologies are provided to assist decision makers regarding possible future gains in benefits of each of the technologies. The technical and economic information reported are expected to be combined with similar information for additional technologies evaluated by others and submitted by EPRI for use by the Australian Government.

EPRI Perspective

Consistent use of methods and data in an international environment enhances effective documentation, communication, and use of the resulting economic comparisons of research and development alternatives. Many US utilities have found EPRI's methods and data useful for generic comparisons and preliminary resource planning, even though they are not suitable for site-specific studies. It is important to understand that this evaluation was not based on detailed plant designs or equipment and material quotations such as would be performed at the time a plant is to be built. Therefore, the absolute magnitude of the pricing developed is not as important as the differences between the performance and cost values for the different technologies.

Approach

A basic plant configuration was developed for each of the technologies evaluated using input from technology experts within EPRI's subcontractor and guidance from EPRI. For each selected configuration, heat and material balance and emissions data was developed based on the selected fuels and capacities. Technical information needed for development of cost estimates was developed and provided to the EPRI's subcontractor's estimating staff. Capital cost and operating and maintenance cost estimates were developed based on US, Gulf Coast rates for equipment, materials, labour and labour productivity. These costs were then adjusted to Australian values based on adjustment factors developed by EPRI's subcontractor by liaising with their Australian and US offices.

EXECUTIVE SUMMARY

The Australian Department of Resources, Energy and Tourism (DRET) commissioned EPRI to undertake an assessment of the costs of various energy technologies out to 2030. This work is an important input to the Australian energy sector, assisting policy makers tasked with setting the direction of Australian energy policy to 2030, and providing a common basis for analysis by stakeholders within the energy industry, end users and relevant institutions.

Australia is encouraging a broad portfolio of technologies and is already committed to initiatives to accelerate the development of carbon capture and storage (CCS), renewable energy technologies (including solar and geothermal technologies) and energy efficiency to reduce the carbon intensity of Australia's electricity system. The success and timing of these technologies will be critical to managing energy security, particularly in a carbon-efficient economy. A basket of technologies will be needed on both the supply and demand side of the energy system to meet the challenges of energy security, economic prosperity and climate change.

Understanding the technical and commercial parameters of available stationary energy technologies in the Australian context will help define Australia's options for responding responsibly and cost effectively to pressures on energy systems. The cost and performance of the available technologies is also an important input to work to determine the cost of economy-transforming structural change necessitated by a response to the challenges of climate change, energy security and economic prosperity. The report provides a technical and economic assessment of globally available technologies with greatest relevance to Australia. Further, it forms the base of new entrant costs on which regional electricity system new entrant costs can be analysed, and provides a common basis for further analysis, at a technology specific and system wide level.

Key Messages

Within this context, the key messages arising from each output are summarized below.

Cost and Performance	• Many low emission technologies are currently high cost compared to traditional carbon emitting generation technologies, but costs are expected to decline as more plants are deployed and technology development leads to more efficient, lower cost plants. • There is significant uncertainty in the cost estimates for emerging low emission technologies. The accuracy of cost and performance data improves as a technology moves from research and development (R&D) towards commercial deployment. Early in the development cycle, technologies face a high degree of both technical and estimation uncertainty. • The degree of uncertainty also depends on the maturity of the component parts of the generation technology and the degree of scale up required to reach commercial application. For example, conventional coal and gas fired technologies are mature. However, adding carbon capture technology introduces the cost and performance uncertainty associated with that technology component. • Costs for new technologies are expected to decline more rapidly than mature technologies as there is greater opportunity for ‘learning by doing’, ‘technology development’ and ‘economies of scale’ to lead to more efficient, lower cost plants. • Global market conditions and the balance between supply and demand for individual technology components are another significant source of uncertainty and are expected to continue to have a significant influence on all technology costs into the future.

Levelised cost of electricity analysis	• The levelised cost of electricity analysis presented in the report can provide an indicative comparison between technologies. However, site, market and system dependant factors such as transmission and firming costs will have a very significant impact on the ultimate mix of technology required to provide an efficient and reliable system. For this reason technology cost analysis cannot be used to extrapolate energy market price outcomes. Market modelling is required to project potential electricity prices arising from market and investment outcomes. • Comparing the levelised costs of electricity for 2015 and 2030 shows that the range of costs across all technologies narrows considerably by 2030. This is largely driven by the fact that less mature technologies have much steeper learning curves and therefore face more rapid cost reductions than mature technologies. This is particularly the case for solar technologies. • However, there is significant uncertainty in predicting future costs via learning curves, particularly where technologies are evolving rapidly opening up the possibility of unforeseen step changes in cost or performance. In addition ‘learning curve’ based cost reductions are sensitive to the rate of

	assumed technology deployment which for low emission technologies will be driven by a global policy framework that is difficult to predict.

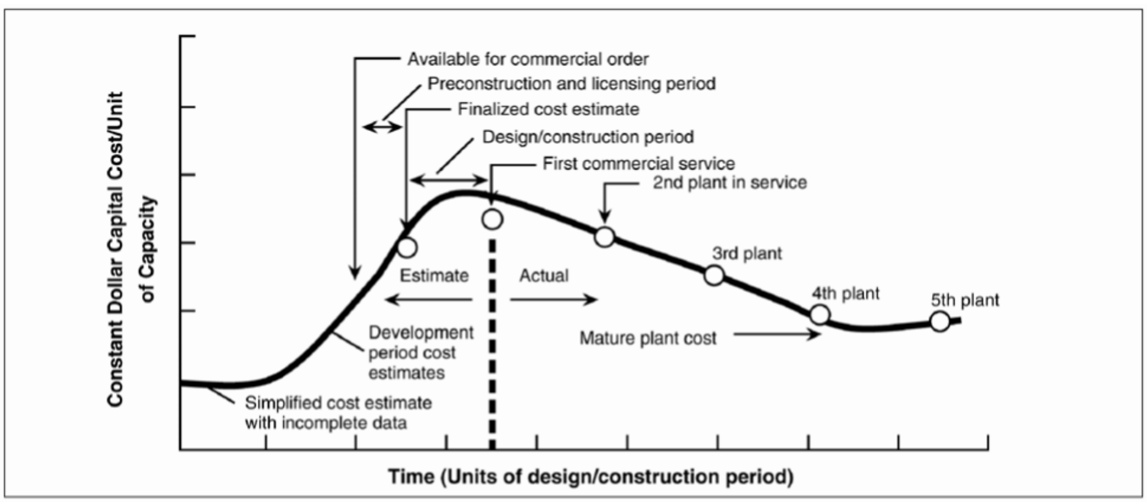
Methodology Overview

This report provides two separate but related outputs – the 2015 and 2030 cost[2] and performance data for selected technologies (including a discussion on the status and attributes of each)[3]; and an analysis of the levelised costs of each technology using a common methodology and set of assumptions.

The results of any study are closely dependent on its input data, parameters and assumptions. This study is no different, and its results must be interpreted within the context set by the parameters and assumptions outlined in the body of the report and summarized under *Key Assumptions*.

Also of importance in interpreting the results is the implication of the relative position of each technology on the capital cost learning or 'Grubb' curve. As a technology moves along the continuum of development, the accuracy of performance and cost estimates tends to improve. At the R&D level, technologies face a high degree of both technical and estimation uncertainty. The bandwidth of the uncertainty depends on the number of new and novel parts in a technology and the degree of scale-up required for commercial deployment. ES-1 illustrates, in general, the sequence of steps and the potential impact on cost.

ES 1 General Capital Cost Learning Curve



[2] 2009 real AUD

[3] Technologies for which cost and performance data was calculated were selected on the basis of several criteria, including the extent to which commercial information could be verified, its relevance in the Australian context, its position on the development and deployment curve and the degree to which it provided a 'marker' for other emerging technologies.

The technologies analysed in this report have different levels of technical maturity, resulting in different levels of cost and performance uncertainty and different levels of potential learning related cost reductions for the different technologies.

In addition to development status, market conditions and the balance between supply and demand for technology components has a significant impact on estimated costs. Where possible this report has adjusted technology costs to remove short term cyclical fluctuations in technology prices.

The levelised cost of electricity analysis in this report uses a set of core technical and economic parameters and assumptions to enable a relatively consistent comparison of electricity generation technologies. As with the cost and performance assumptions, these are set out in the body of the report and summarized below.

A sensitivity analysis was performed for each technology to identify the impact of changes in the capital cost, plant life, fuel cost or resource quality, total operational and maintenance (O&M) and CO_2 transport and storage on the levelised cost of electricity. These sensitivity analyses are set out and discussed at ES-2 and ES-3.

Key assumptions summary

To perform the analysis presented in this report in a consistent manner, a clear design basis was established. Consistent assumptions make it possible to compare costs and performance for a range of technologies. Section 3 of the report presents the full detail of the design basis assumptions.

- All base-load technologies are assumed to run at 85% capacity factor. Peaking plant is assumed to have a capacity factor of 10%. Specific capacity factors apply to intermittent renewable technologies.
- All sites are a generic greenfield site in Australia at an elevation of 111 meters, with ambient temperature of 25°C and 60% relative humidity.
- Coal supply is assumed to be based on characteristics of Hunter Valley black coal and Latrobe Valley brown coal. The coal plant sites are assumed to be mine mouth with conveyors delivering coal from the mine to the site with storage sized for 5 days generation.
- No SO_2 or NOx reduction systems are included due to the very low sulphur content of Australian coal, unless SO_2 reduction is required by the CCS technology.
- For all technologies, dry cooling systems are necessary.
- Cost boundaries include all equipment required to generate electricity (boilers, turbine generators, solar collectors, etc.) and all support facilities needed to operate the plant (emissions control equipment, wastewater-treatment facilities, offices, etc.).
- The cost boundary also includes the connection equipment, but switchyard and associated transmission line costs are not included due to system-specific conditions.
- All technologies that include CO_2 capture and storage capability have a capture rate of 85-90%. The recovered CO_2 contains no more than 100 ppmv total sulphur and is compressed to 16 MPa before exiting the plant boundary.

- CO_2 compression equipment and energy penalties are included for plants with carbon capture. Capital costs for CO_2 pipeline and storage area for sequestration are not included in cost and performance data. A nominal AUD20/tonne for transport and sequestration has been included for levelised cost of electricity analysis.
- The levelised cost of electricity for wind and solar technologies was calculated using different resource qualities. Resource quality categories are set out at Table 8-10 for wind. For solar thermal technologies, a range of direct normal insolation (DNI) of 5, 6 and 7 $kWh/m^2/day$ was used. For reference, some Australia specific DNIs are: Canberra = 4.9 $kWh/m^2/day$; Mildura 5.8 $kWh/m^2/day$; and Alice Springs 7.2 $kWh/m^2/day$. A DNI of 6.7 $kWh/m^2/yr$ was applied to photovoltaic technologies. Similarly, the levelised cost of nuclear, coal and gas technologies used a range of fuel prices as set out at Table 10-2.
- The cost estimating basis is presented in detail in Section 4 and is summarised below:
  - Total Plant Cost (TPC) and O&M cost estimates carry an accuracy of +/-30%
  - All capital and O&M costs are presented as "overnight costs" expressed in June 2009 Australian dollars
  - The capital cost estimate includes all anticipated costs for equipment and materials, installation labour, professional services (engineering and construction management), and contingency.
- The following items are excluded from the capital costs:
  - Escalation to period-of-performance
  - All taxes, with the exception of payroll taxes
  - Site specific considerations – including but not limited to seismic zone, accessibility, local regulatory requirements, excessive rock, piles, lay down space, etc
  - CO2 injection wells, pipelines to deliver the CO2 from the generation plant fence to the storage facility and all administration supervision and control costs for the facility. (However, the levelised cost of electricity analysis includes a nominal AUD20/tonne for transport and sequestration to cover these costs)
  - Additional premiums associated with an engineer, procure and construct (EPC) contracting approach
  - Tariffs that may be charged for importing equipment to Australia or shipping charges for this equipment
- The production costs or operating costs and related maintenance expenses (O&M) pertain to those charges associated with operating and maintaining the power plants over their expected life. These costs include:
  - Operating labour
  - Maintenance – material and labour
  - Administrative and support labour
  - Consumables
  - Waste disposal
  - Co-product or by-products credit

- A 7.5% allowance has been added on top of TPC to account for project specific costs such as site and technology selection studies, rights of way, road modifications and upgrades and permitting etc.
- Levelised cost of electricity costs are based on total capital required (TCR), which consists of the following costs:
  - Total plant investment at the in-service date, including an allowance for funds used during construction (AFUDC), sometimes called “interest during construction”
  - Owner costs, such as: prepaid royalties; preproduction (or startup) costs; inventory capital (fuel storage, consumables, etc.); initial cost for catalyst and chemicals; and land

Many factors contribute to the overall uncertainty of an estimate. They can generally be divided into four generic types.

1. *Technical*—Uncertainty in physical phenomena, small sample statistics, or scaling uncertainty.
2. *Estimation*—Uncertainty resulting from estimates based on less-than-complete designs.
3. *Economic*—Uncertainty resulting from unanticipated changes in cost of available materials, labour, or capital.
4. *Other*—Uncertainties in permitting, licensing, and other regulatory actions; labour disruption; or weather conditions.

As a technology moves along the continuum of development from R&D through commercial installation, the type of risk—and the corresponding uncertainty—tends to change. At the R&D level, technologies face a high degree of both technical and estimation uncertainty. The extent of the uncertainty depends on the number of new parts in a technology and the degree of scale-up required to reach commercial size.

Successful R&D efforts resolve many technical uncertainties, but others persist until initial demonstration. There are many examples of technical uncertainties.

- Unanticipated interactions between system elements that previously were independently tested.
- Incompatibilities between materials or incompatibilities between utility operation and the industries from which the new technology was adapted.
- Unanticipated operating problems which become operationally significant.

Demonstration and commercialisation reduce technical and estimation uncertainties, but economic and other uncertainties always remain. The level of these uncertainties depends largely on the magnitude of capital investment, length of time for field construction, and number of regulatory agencies involved in the project. Recently, this economic uncertainty has been even more extensive with highly volatile pricing that has been seen in the past two years for power plant equipment due to market and macro-economic forces.

Large differences between original cost estimates and actual installed costs have been common. Some of these differences have resulted from the type of estimate given, such as a “goal” type of estimate without explicit consideration of the likelihood of achievement. In order to reduce misunderstandings, quantifying uncertainty should be an explicit part of developing cost estimates.

Because of the large amount of uncertainty surrounding the estimates presented in this report, results should be viewed as a range of costs rather than a set cost point. The charts presented in the results section show these cost ranges and the general trend in relative costs among technologies. The tornado diagrams presented in the results section show the effect that different assumptions and uncertainties can have on the final levelised cost of electricity results.

Technologies

EPRI is evaluating a number of technology alternatives in support of the above program. This report focuses on twelve key central station technologies of current and future interest to Australia.

- Integrated Gasification Combined Cycle (IGCC)
- Pulverised Coal (PC)
- Combined Cycle Gas Turbine (CCGT)
- Open Cycle Gas Turbine (OCGT)
- Solar Thermal
- Solar Photovoltaic
- Wind
- Tidal/Wave
- Geothermal
- Nuclear
- Hydroelectric
- Biomass

For the pulverised coal fired options, two Australian coals were selected. They were Latrobe Valley Brown Coal and Hunter Valley Black Coal. Natural gas was used for all of the combustion turbine evaluations.

Since the Integrated Gasification Combined Cycle (IGCC) plants are limited in size selection based on the sizes of combustion turbines available, all IGCC cases were evaluated with GE 9FA combustion turbines. This resulted in a difference in the generated and sent-out output of each case depending on how much auxiliary power was consumed by the various systems and how much steam was used in the process versus supplied to the steam turbine generator. For the IGCC plants, only Hunter Valley Black coal was used as a feedstock since reliable cost and performance data is not available for the gasification technologies best suited for using high-moisture brown coal.

The pulverised coal plants can be individually sized; hence they were all selected to be at or close to 750 MWe sent-out capacity. Therefore, the generated output capability of these plants varied based on the amount of auxiliary power used by plant systems and the amount of steam used for the CO_2 capture system versus the amount provided to the steam turbine generator.

The combined cycle gas turbine plants were configured with GE 9FA combustion turbines and the generated and sent-out power outputs varied based on the auxiliary requirements of the CO_2 capture process. The open cycle gas turbine plant was configured with a GE 9E combustion turbine without CO_2 capture. The GE 9E combustion turbine was selected for the open cycle plant due to its better cycling capability and lower per start cost than the GE 9FA.

The solar plant was based on parabolic trough and central receiver technology and included a six hour energy storage system based on molten salt as the energy storage medium.

All of the coal fired technologies and the combined cycle gas turbine systems were considered to be base load facilities and were evaluated based on a capacity factor of 85%. The open cycle gas turbine plant was considered as a peaking load facility operating at the 10% capacity factor. The solar plant, since it operates with free fuel, was considered to operate whenever sunlight could provide energy (plus use of the stored thermal energy).

The evaluations included selection of the plant configurations for each technology, performance of heat and material balance calculations for each case using commercially available software and information from within the existing EPRI and subcontractor technology data bases. Cost estimates were prepared for each case evaluated based on US Gulf Coast costs and then, using factors developed by EPRI's subcontractor, adjusted to Australian costs. All cost estimates were based on June 2009 currency exchange rates and performed on an "overnight" basis such that no escalation has been included to a future date or for cost escalation that could occur during a project's execution. This provides a consistent basis for comparison between the technologies.

It is important to understand that this evaluation was not based on detailed plant designs or equipment and material quotations such as would be performed at the time a plant is to be built. Therefore, the absolute magnitude of the pricing developed is not as important as the differences between the performance and cost values for the different technologies.

Results

As described above and throughout the report, there are degrees of uncertainty surrounding all aspects of the capital cost and levelised cost of electricity estimates presented. The following charts show the combined impact of uncertainty ranges in plant capital cost, fuel cost, project and site specific costs, and CO_2 transportation and storage costs. While they still may not capture the absolute extremes of cost estimates, they provide a broader range of estimates to reflect the uncertainties described above.

The low end estimates of the charts assume a best case scenario: capital cost estimates and fuel prices are at the low end of the sensitivity ranges investigated in this study, project and site specific costs are assumed to add only 5% to the TPC (baseline is 7.5%), CO_2 transportation and storage cost is assumed to be only AUD10/tonne (baseline is AUD20/tonne), and, for renewable technologies, the best available resource was assumed (DNI = 7 kWh/m^2/day for parabolic trough and central receiver; wind class 6 (average wind speed of 8.4 m/s) for wind turbines).

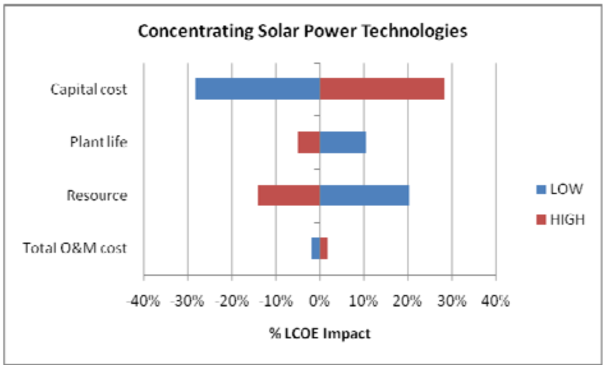
The high end estimates of the charts assume the higher side of the uncertainties: capital cost estimates and fuel prices are at the high end of the sensitivity ranges investigated in this study, project and site specific costs are assumed to add 10% to the TPC, CO_2 transportation and storage cost is assumed to be AUD30/tonne, and, for renewable technologies, the worst available resource was assumed (DNI = 5 kWh/m^2/day for parabolic trough and central receiver; wind class 3 (average wind speed of 6.7 m/s) for wind turbines).

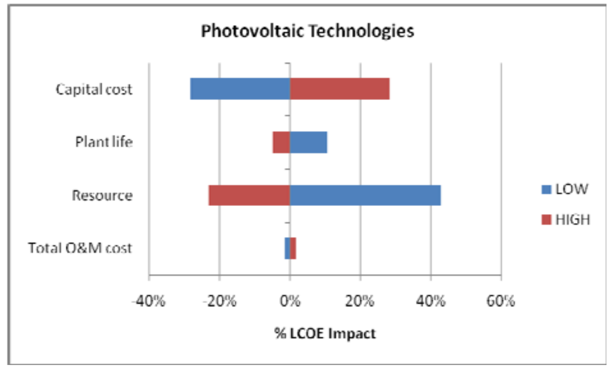
Multi-dimensional sensitivity analysis was also conducted on 2015 technology levelised costs of electricity. These sensitivity analyses are presented as 'Tornado' graphs showing the effect of different assumptions on the levelised cost of electricity results. Capital costs were varied by +/-30% of the baseline cost results. For all technologies except for the wind turbine, the plant life was varied between 20 years and 40 years with a baseline lifetime of 30 years; for wind, the plant life was varied between 15 and 20 years with a baseline of 20 years. For fossil fuel technologies, fuel costs were varied based on the same fuel sensitivity ranges presented in Table 10-2, close to +/-30%. For renewable technologies, the resource was varied based on the resource ranges used throughout the report: 5-7 kWh/m^2/day for the concentrating solar technologies with a baseline of 6 kWh/m^2/day and wind class 3-6 for the wind turbines with a baseline of class 5. For photovoltaic technologies, the capacity factor was varied by +/-30%. CO_2 transportation and storage costs were varied by +/- 50% (AUD10/tonne and AUD30/tonne) on a baseline of AUD20/tonne.

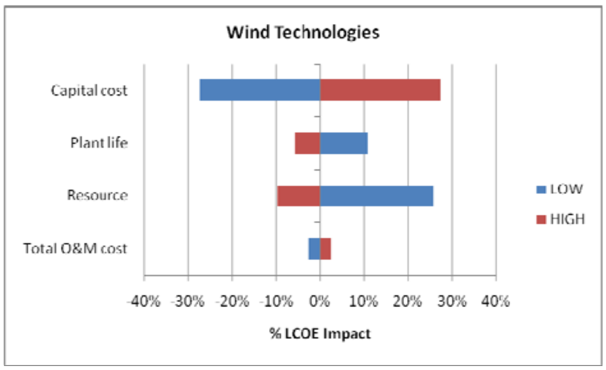
Sensitivity analysis allows comparison of the influence of different parameters on the levelised cost of electricity (LCOE) for each technology. In all cases, it can be seen that extending the plant life (the "high" estimate) reduces the LCOE by expanding the number of years over which capital costs are recovered.

Improved renewable resource and higher capacity factors also reduces the LCOE by increasing the amount of electricity produced and, therefore, reducing the per-unit cost of electricity. ES-2 highlights that capital cost and resource quality has a significant influence on the LCOE outcomes. Some technologies are only capable of operating for short periods (due to fuel limits) or face commercial incentives to operate for short periods of time (due to high relative fuel costs). Shorter operating periods for these technologies means that their capital costs must be recovered over shorter operating periods. As a consequence these technologies have a LCOE which is very sensitive to capital, fuel and resource costs.

ES 2 Tornado Diagrams: Renewables

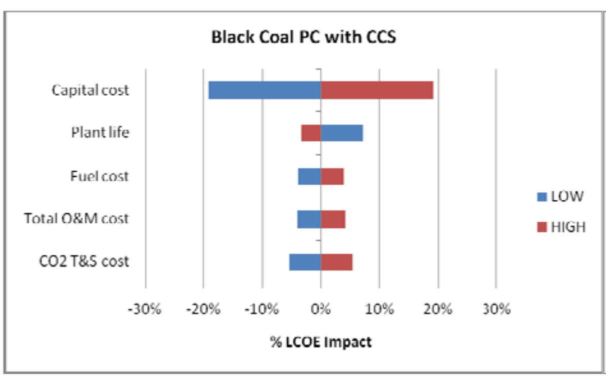


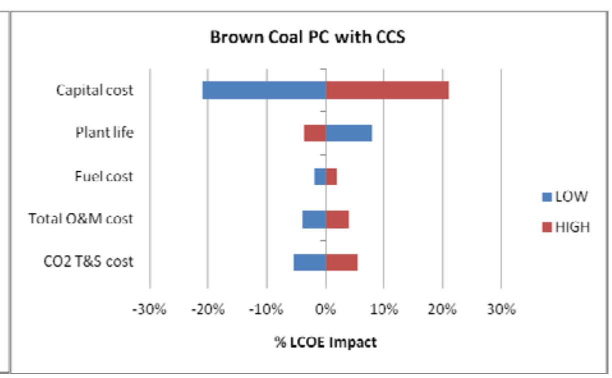


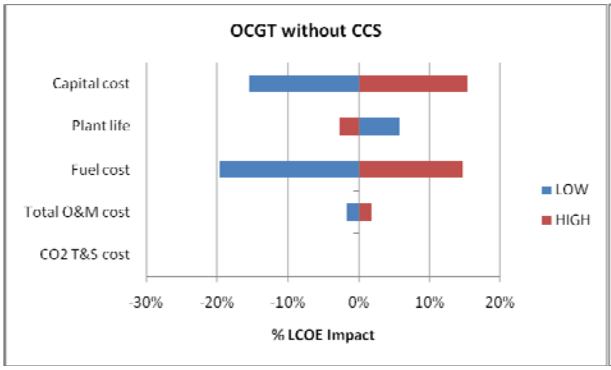


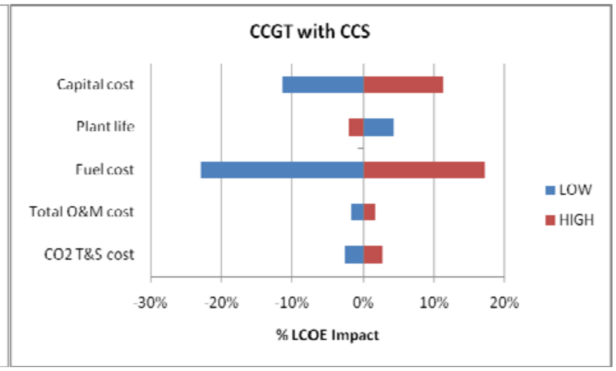
For plants with high capital costs but low fuel costs, such as pulverized coal and IGCC plants, the effect of capital cost variation is much higher than the effect of the fuel cost. In contrast, for plants with lower capital costs and higher fuel costs, like the natural gas plants, the variation in fuel cost has a much larger effect on the levelised cost of electricity than variation in capital costs. This effect can be seen when comparing the sensitivities at ES-3.

ES 3 Tornado Diagrams: Coal and Natural Gas









Comparison of levelised cost outcomes

The levelised cost analysis for studied technologies enabled a relatively consistent comparison between 2015 and 2030, and across technologies at 2015 and 2030.

ES-4 sets out the levelised cost ranges for fossil fuel technologies, both near term in 2015 and with anticipated improvements in 2030. Costs for fossil fuel technologies without CO_2 capture are not presented for 2030 due to the assumption that new plants in 2030 will need to be low emission technologies, other than peaking units such as OCGT technology.

The learning effect on the CCS component of the represented technologies can be clearly identified. The most dramatic of these learning effects is in the IGCC black coal with CCS. This is a result of IGCC being high on the learning curve as so few have been built, thereby providing greater opportunities for learning by doing across the entire plant.

ES 4 Maximum Range for Fossil Techs (2015 vs 2030)

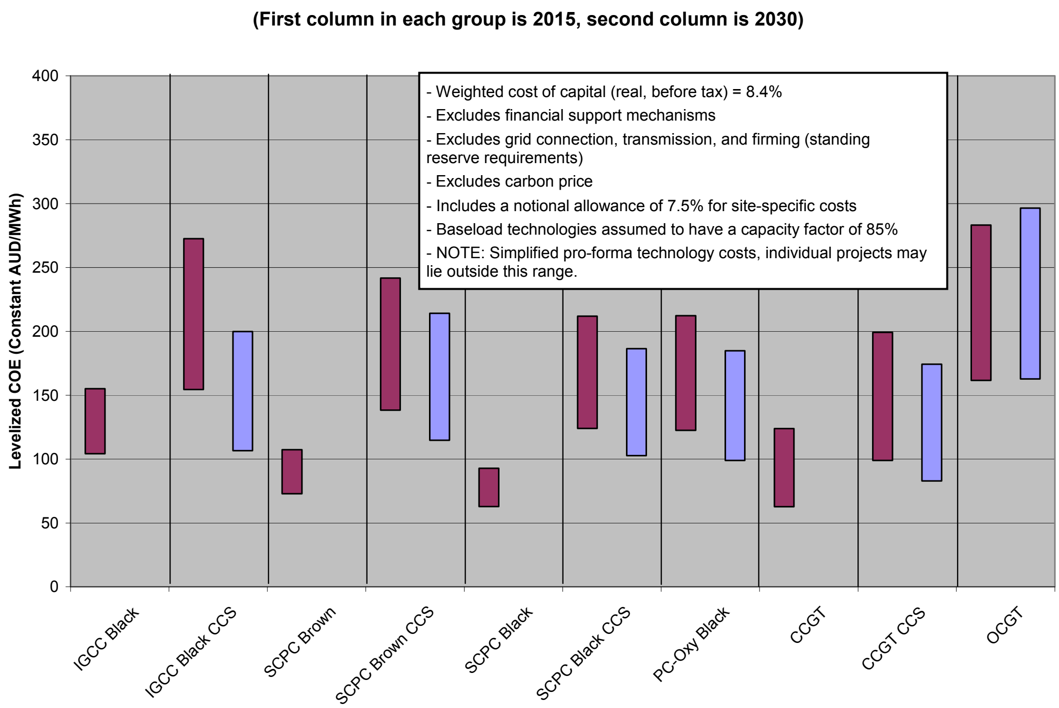
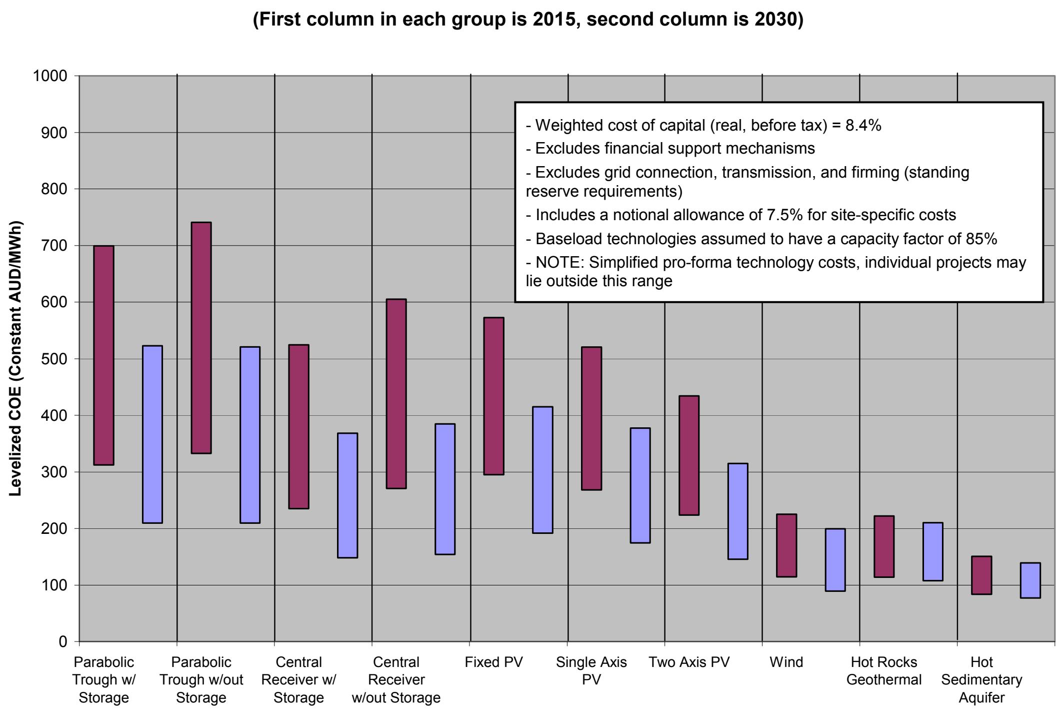


Figure ES-5 shows the levelised cost ranges for renewable technologies, both near term in 2015 and with anticipated improvements in 2030.

An important message is the change in levelised cost of electricity driven by different learning curves. It is worth noting that improvements in onshore wind are much smaller than most other renewable technologies represented in ES-5, reflecting the relative maturity of the technology. The smaller rate of change in Hot Rocks Geothermal (HDR) and Hot Sedimentary Aquifer (HSA) technologies reflects the maturity of above-ground technology components for HDR and HSA more generally.

ES 5 Maximum Range for Renewable Techs (2015 vs 2030)

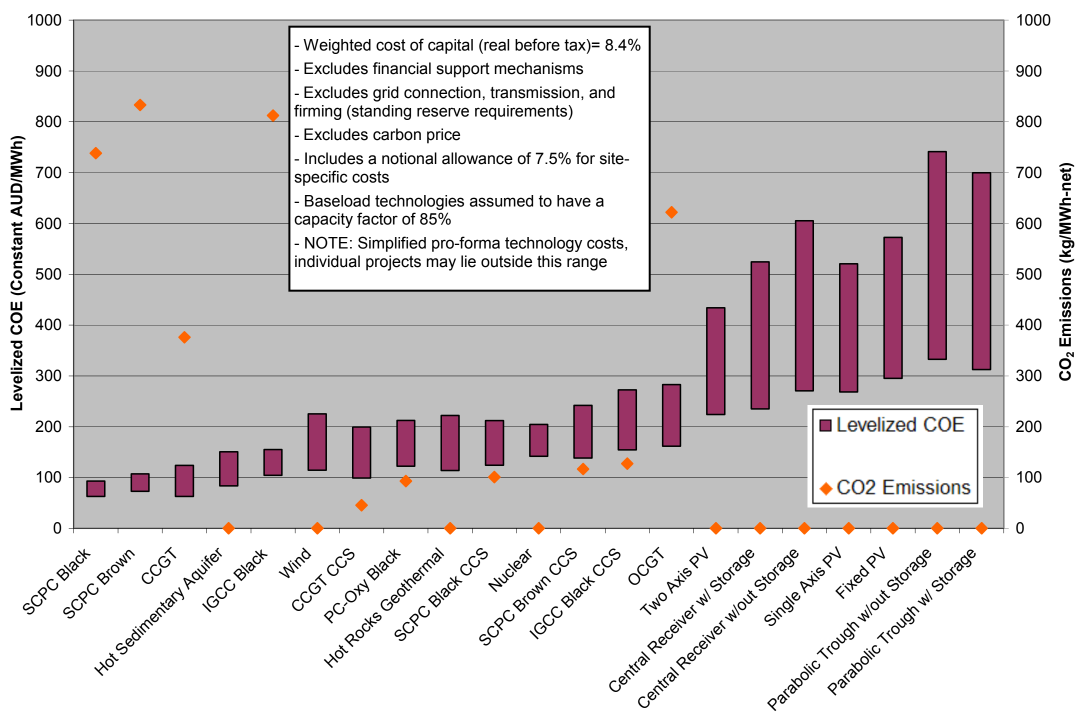


Assumptions of the potential future improvements in fossil and renewable technologies for 2030 are provided along with the technology descriptions in Section 6 of this report. Sensitivity analysis details are included in Section 10.

ES-6 and ES-7 show a comparison of all technologies, both fossil and renewable, in 2015 and 2030. They also show the anticipated CO_2 emissions associated with the different technologies. Costs for technologies without CO_2 capture are not presented for 2030 due to the assumption that new plants in 2030 will not be permitted without being low emission technologies, other than peaking units such as the OCGT. The maximum range charts show the minimum and maximum LCOE results for all of the technologies included in the report, sorted on the mid-point or base LCOE for all technologies. The maximum values include the high end of the capital range, the high end of the site specific assumptions, the highest fuel cost/lowest available resource (where applicable), and the highest CO_2 transport and storage assumption (where applicable). The minimum values include the low end of the capital range, the low end of the site specific assumptions, the lowest fuel cost/highest available resource (where applicable), and the lowest CO_2 transport and storage assumption (where applicable). Also included on the right axis of both charts are the specific CO_2 emissions for each technology.

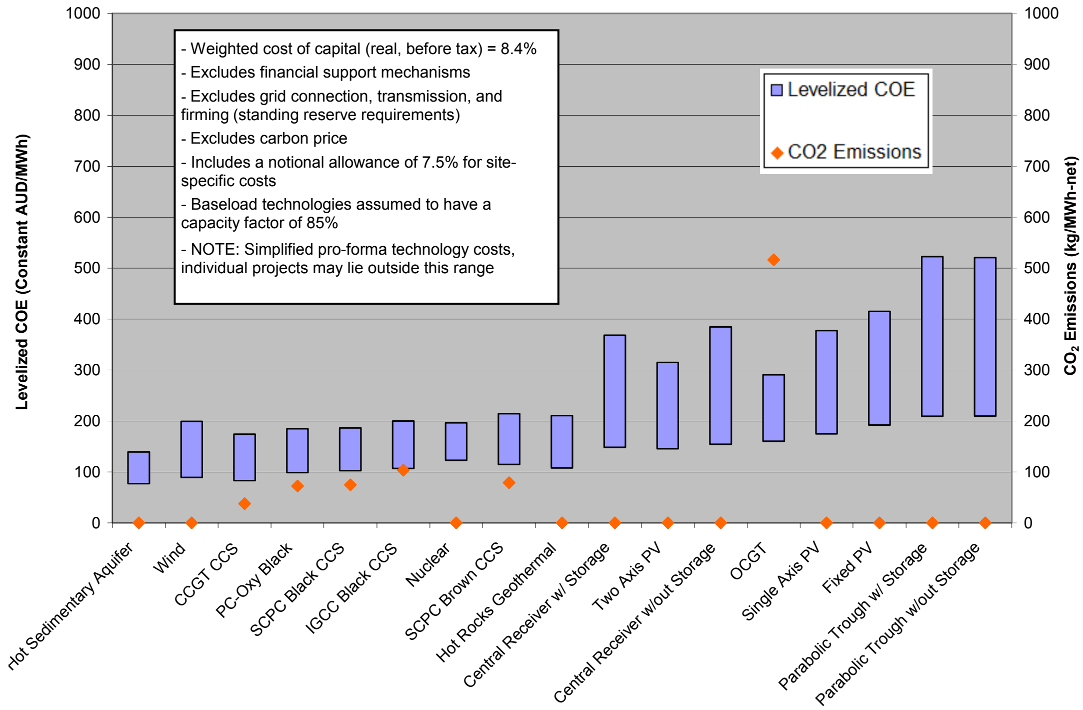
ES-6 sorts 2015 levelised cost ranges for all technologies. The chart shows that the higher emissions technologies are generally at the low end of the cost range with the exception of OCGT, which is particularly suited to low capacity factor peaking duties within electricity systems. Also of note is a significant jump in costs between OCGT and the basket of solar technologies. Technologies which have higher levelised costs are unlikely to be able to compete in the absence of other supporting influences.

ES 6 Sorted Technology Maximum Ranges (2015)



Comparing the levelised costs for 2015 (ES-6) and 2030 (ES-7) show that the overall band of levelised costs across all technologies narrows considerably by 2030. This is largely driven by the fact that the emerging technologies at the top end of the range in 2015 have more significant cost reduction opportunities than the more mature technologies at the bottom end of the cost ranges.

ES 7 Sorted Technology Maximum Ranges (2030)



Process and review

To ensure the report's output is consistent with Australian conditions, a comprehensive stakeholder consultation process was built into the program.

EPRI accessed a small group of Australian industry advisors (Advisory Group) who reviewed the key assumptions and provided input for key parameters. This provided additional perspective and guidance on the Australian power industry. The industry advisory group included representatives from the following companies:

- Australian National Low Emissions Coal Research and Development Limited (ANLEC) Clean Energy Council
- Commonwealth Scientific and Industrial Research Organisation (CSIRO)
- HRL Limited (HRL)
- Rio Tinto
- Verve Energy
- ZeroGen

This Advisory Group also provided access to other Australian industry experts and sources of information as required.

The DRET also harnessed the expertise of stakeholders participating in the Stakeholder Reference Group (SHRG) established by the Australian Energy Market Operator (AEMO) to provide technical and commercial advice on modelling of the stationary energy sector to 2030. Members of this reference group include representatives from:

- Australian Academy of Technological Sciences and Engineering (ATSE)
- Australian Energy Market Operator (AEMO)
- Australian Geothermal Energy Association (AGEA)
- Australian National Low Emissions Coal Research and Development Limited (ANLEC)
- Australian Petroleum Production & Exploration Association (APPEA)
- Australian Pipeline Industry Association (APIA)
- Australian Solar Institute (ASI)
- ACIL Tasman
- Clean Energy Council
- Commonwealth Scientific and Industrial Research Organisation (CSIRO)
- DOMGAS Alliance
- Energy Networks Association (ENA)
- Energy Retailers Association of Australia (ERAA)
- Energy Supply Association of Australia (ESAA)
- Energy Users Association of Australia (EUAA)
- Grid Australia
- Major Energy Users (MEU)
- Minerals Council of Australia
- National Generator's Forum (NGF)
- Oakley Greenwood
- Verve Energy
- ZeroGen

The SHRG provides a consistent reference group for advice and consultation across the range of modelling and analysis activities for the DRET and the AEMO. The group continues to provide advice on the key input strands to the modelling, of which the EPRI report is a key component.

The SHRG considers that the cost and performance data set out in this report for each of the technologies are within the range expected for 2015 and 2030, given Australian project experience. Similarly, stakeholders agree that the LCOE set out in this report identifies appropriate relativities between technologies and cost ranges that are consistent with expectations in the Australian context.

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1
INTRODUCTION AND STATEMENT OF WORK

1.1 Introduction

The Australian Government Department of Resources, Energy and Tourism (DRET) commissioned EPRI to undertake an assessment of the costs of different energy technologies to 2030. This work is an important input to the Australian energy sector, assisting policy makers tasked with setting the direction of Australian energy policy to 2030, and providing a common basis for analysis by stakeholders within the energy industry, end users and relevant institutions.

Understanding the technical and commercial parameters of available stationary energy technologies in the Australian context will help define Australia's options for responding responsibly and cost effectively to pressures on energy systems. The cost and performance of the available technologies will also determine the cost of economy-transforming structural change necessitated by a response to the challenges of climate change, energy security and economic prosperity. The report provides a technical and economic assessment of globally available technologies with greatest relevance to Australia. Further, it forms the base of new entrant costs on which regional electricity system new entrant costs can be analysed, and provides a common basis for further analysis, at a technology specific and system wide level.

1.2 Objectives

The DRET commissioned EPRI to build upon its report 'Costs and Diffusion Barriers to the Deployment of Low-Emission Technologies'[1] and undertake assessment of the costs of the various options for different energy technologies to 2030.

EPRI undertook an assessment of how the costs of delivered energy across different technologies are expected to evolve to 2030. The starting point was capital and operating costs for near-term deployment of the conventional and alternative energy technologies listed in Task 1 below. "Near-term" means the power plant should be available for start-up around the 2015 time frame.

Where possible, the costs have been referenced to existing EPRI project studies, noting the stage of development of the project. Not all technologies will be available for near-term commercial deployment, and are so noted. Criteria for commercial deployment, such as demonstrated scale, were established. Also, the level of cost data available for certain technologies such as tidal/wave, geothermal, and hydro is currently expected to be more speculative and is noted in

[1] Costs and Diffusion Barriers to the Deployment of Low-Emission Technologies: DEWHA, Commonwealth of Australia. EPRI, Palo Alto, CA and Commonwealth of Australia: 2008. 1018049.

the report. These technologies include more discussion of technology status and cost trends, as opposed to more detailed cost and performance estimates.

By 2020 more technologies are expected to be available for commercial deployment. For example, by 2020 carbon sequestration is expected to be demonstrated at a sufficient scale to allow deployment of technologies incorporating CCS. The capital cost and performance estimates for near-term technologies are expected to be similar for the 2015 and 2020 time frames. Therefore only one set of detailed cost and performance data was developed for each near-term technology; however the portfolio of available 2020 options is reviewed and discussed.

Projected improvements in the technologies resulted in a set of longer term capital and operating cost estimates. In this case, “longer term” means that the power plant should be available for start-up around the 2030 time frame. The status of each technology is discussed and it will be placed on the technology development curve.

The carbon dioxide emission intensity is tabulated for each technology. Comments are included for additional deployment costs, such as grid connectivity, CO_2 disposal infrastructure, and local or grid energy storage requirements. In some cases, such as wind and geothermal, transmission availability may limit the penetration rates for these technologies and appropriate commentary is included in the report.

Levelised cost of electricity (COE) was calculated for each available near-term (2015) and longer term (2030) technology based on project financial parameters, and fuel costs. As discussed above, the portfolio of technology options is more limited in the 2015 time frame.

To provide additional perspective and guidance on the Australian power industry, EPRI worked with a small group of Australian industry advisors (Advisory Group) who reviewed the key assumptions, provided input for key parameters, and reviewed the study results. The industry advisory group included representatives from the following companies:

- Clean Energy Council
- Commonwealth Scientific and Industrial Research Organisation (CSIRO)
- HRL Limited
- Rio Tinto
- Verve Energy
- ZeroGen

The Advisory Group also provided access to other Australian industry experts and sources of information as required.

The EPRI project team would also like to acknowledge the efforts of ACIL Tasman, and the Australian Stakeholder Reference Group in support of this study. Their contributions provided additional insight into power plant construction economics in Australia.

1.3 Task Descriptions

Task 1: Establish the Design Basis

The first step in this evaluation was to establish the technical parameters of the various power generation technologies, to characterise the site conditions, to establish the fuel properties, and to establish the emissions criteria for the plant design.

Task 2: Develop Pricing Parameters

Pricing was prepared using proprietary parametric cost estimating models developed by EPRI's subcontractor, WorleyParsons, and adjusted for the market conditions in Australia. These adjustments from US Gulf Coast costing included bulk materials, engineered materials, major equipment, installation labour, and labour productivity. Representative lists were prepared to capture the following:

- bulk materials;
- engineered materials; and
- major equipment

Prices for these representative materials and labour were estimated in Australia and the United States. Adjustment factors were generated to apply to the baseline cost estimates listed below.

The major equipment was defined from past projects and sizes and weights were sent to obtain Australian estimates of crew mixes, installation labour hours, and costs. These were compared to the practices in the US and installation labour costs and productivity factors were developed to apply to the baseline cost estimates listed below.

Task 3: Develop Performance Parameters

Performance parameters were developed from in-house data for the technologies included in this evaluation. Performance parameters included sent-out output, sent-out heat rate, auxiliary power consumption, air emissions, and water consumption figures.

Task 4: Develop Plant Characteristics

For each technology area and based on in-house and public information, a brief overview summarised the technologies including:

- a brief description of the technologies;
- survey of the technology development status;
- current and projected technology performance and costs;
- major technical issues and future development direction/trends;
- development and commercialisation timeline; and
- relevant business issues.

Task 5: Develop Baseline Capital Cost Estimates

Baseline cost estimates were prepared for each technology using in-house parametric models. These baseline estimates will be prepared for US Gulf Coast conditions.

A mutual definition of project boundaries was established to allow capital costs to be estimated consistently. Allowances were agreed to based on public information for off-sites such as transmission lines, fuel pipelines, water pipelines, CO_2 pipelines, fuel unloading/handling facilities, roadways, railroads, etc. Other owner's costs were excluded. Equipment, material, and installation costs were based on EPRI's subcontractor's information and data bases, not solicited through data requests from third-party vendors.

Task 6: Develop Baseline Operation and Maintenance (O&M) Cost Estimates

Plant staffing levels and maintenance expenses were defined and divided into fixed and variable components. Assumptions for chemical costs and byproduct value were established to determine annual chemical costs and byproduct sales.

Task 7: Revise Baseline Capital and O&M Estimates

Using the adjustment factors for Australian market conditions, the capital and O&M cost estimates were adjusted to Australian costs and summarised.

Task 8: Develop Levelised Cost of Electricity Estimates

The constant dollar levelised cost of electricity (LCOE) for each technology was estimated based on a simplified version of the Revenue Requirement Methodology. The simplified COE methodology utilised a spreadsheet approach to ensure transparency of the results. Financial parameters, including assumed capacity factors, were reviewed by the Advisory Group. LCOEs were developed for available near-term (2015) and longer term (2030) technologies. The LCOEs are broken down into capital, O&M, and fuel cost components.

Task 9: Prepare Final Report

A report summarising the methodology, assumptions, and key findings of the study was prepared for review by the Advisory Group and DRET.

2 BACKGROUND AND GENERAL APPROACH

2.1 INTRODUCTION

A comprehensive list of fossil, renewable, and nuclear technologies was selected for the overall evaluation. They are shown in Table 2-1 to 2-4. The plant sizes indicate the "nominal" sent-out ranges that were established at the beginning of the study. The actual sent-out power for each case is tabulated in the later performance and cost sections.

For all of the technologies selected, the cycle configurations, equipment included and materials used are currently available and used commercially in power plant systems. These technologies do not represent projected potential advancements over currently available systems. Areas where each technology may be expected to improve through the application of advancements are projected within the Technology Descriptions included in Section 6.

Due to shortages of water availability throughout Australia, each of the technologies evaluated have been configured with air cooling of the condensers and auxiliary equipment to minimise water consumption. The amount of water used by each technology for the size of plant selected is included within the technology performance results.

Consistent with Australian practice on air emissions, each configuration evaluated includes particulate emissions control (except the natural gas fired turbines). Control of NO_X and SO_2 emissions is not included except where required by the carbon capture technologies to prevent poisoning of the amines and chemicals used in those processes.

Cost estimates were developed based on US Gulf Coast costs and rates upon completion of heat and material balance performance evaluations which identified the required capacity of the key plant components and also defined the plant efficiencies, emissions and key flow rates. These estimates were then adjusted to Australian costs via the use of adjustment factors developed jointly between the EPRI's subcontractor's Australian and US offices.

The cycle configuration of each plant evaluated is provided in later sections. The sent-out capacity of the Integrated Gasification Combined Cycle (IGCC) plants vary between the cases due to constraints of the gas turbine equipment selected. All of the IGCC alternatives were configured with GE 9FA gas turbines as the primary power generation components and these were arranged as 2+1 combined cycle units. The pulverised coal (PC) plants were able to be specifically sized at the pre-selected 750 MWe sent-out. For the combined cycle gas turbine (CCGT) units, these were also based on 2+1 arrangements of GE 9FA gas turbines, similar to the IGCC plants. The open cycle gas turbine (OCGT) plant was based on a GE 9E machine with a generated output of 116 MWe at the selected 25 °C (77°F) ambient condition. The GE 9E combustion turbine was selected for the open cycle plant due to its better cycling capability and lower per start cost than the GE 9FA. Inlet air cooling was not included on either the CCGT or OCGT plants.

Table 2-1
Fossil Technologies

Technology Type	Size, MWe (sent-out basis)	2015-2020	2030
Integrated Gasification Combined Cycle (IGCC)			
Brown coal	700-800 MW	D	D
Brown coal, with CCS (85-90%)	600-700 MW	D	D
Black coal	700-800 MW	C&P	C&P
Black coal, with CCS (85-90%)	600-700 MW	C&P	C&P
Pulverised Coal (PC)			
Brown coal, no NO_X/SO_2 controls	750 MW	C&P	C&P
Brown coal, with CCS (90%) & NO_X/SO_2 controls as reqd	750 MW	C&P	C&P
Black coal, no NO_X/SO_2 controls	750 MW	C&P	C&P
Black coal, with CCS (90%) & NO_X/SO_2 controls as reqd	750 MW	C&P	C&P
Oxy-combustion with black coal	750 MW	C&P	C&P
Combined Cycle Gas Turbine (CCGT)			
Without CCS	600-800 MW	C&P	C&P
With CCS	500-700 MW	C&P	C&P
Open Cycle Gas Turbine (OCGT)			
Heavy Duty	100-150 MW	C&P	C&P
Aeroderivative	100 MW	D	D

Note: C&P = Cost and performance, D = Discussion only

Table 2-2
Solar and Wind Technologies

Technology Type	Size, MWe (sent-out basis)	2015-2020	2030
Solar Thermal			
Parabolic trough w/6 hours storage (also w/o storage)	200-300 MWe *	C&P	C&P
Central receiver w/6 hours storage (also w/o storage)	200-300 MWe *	C&P	C&P
Linear Fresnel w/6 hours storage (also w/o storage)	100-300 MWe *	D	D
Parabolic dish	50-300 MWe *	D	D
10% solar/coal hybrid	200 MWe	D	D
15% solar/CTCC hybrid	350 MWe	D	D
Solar Photovoltaic (PV)			
Utility scale centralised PV, fixed flat plate PV	1x5 MWe, 10x5 MWe	C&P	C&P
Utility scale centralised PV, single axis tracking PV	1x5 MWe, 10x5 MWe	C&P	C&P
Utility scale centralised PV, two axis tracking	1x5 MWe, 10x5 MWe	C&P	C&P
Concentrated PV	1-50 MW *	D	D
Residential scale PV	50-100 kW	D	D
Wind			
On-shore wind (class 3, 4, 5, & 6)	25x2 MW, 100x2 MW, 250x2 MW *	C&P	C&P
Off-shore wind (class 5 & 6)	80x2.5 MW - 50x10 MW *	D	D

Note: C&P = Cost and performance, D = Discussion only.
*** Upper size ranges may only be achievable for long term deployment**

Table 2-3
Other Renewable Technologies

Technology Type	Size, MWe (sent-out basis)	2015-2020	2030
Tidal/Wave			
Tidal In Stream Energy Conversion (TISEC)	1.5 MW, 100 MW *	N/A	D
Wave Energy Conversion (WEC)	1.5 MW, 100 MW *	N/A	D
Ocean currents	1-5 MW *	N/A	D
Geothermal			
Hot Rock (HR) Geothermal	10-25 MW *	D	D
Hydrothermal flash	50 MW	D	D
Hydrothermal (Hot Sedimentary Aquifer (HSA)) binary	30 MW	D	D
Hydroelectric			
Small hydro plants	<10 MW	D	D
Biomass			
10% biomass co-fired with coal, CFB boiler	200 MW	D	D
5% biomass co-fired with coal, PC boiler	200 MW	D	D
20% ToP biomass co-fired with coal, PC boiler	200-300 MW *	D	D
100% biomass direct combustion, FCB plant	50 MW	D	D
Biomass gasifier with syngas to PC boiler		D	D

Note: C&P = Cost and performance, D = Discussion only.
*** Upper size ranges may only be achievable for long term deployment**

Table 2-4
Nuclear Technologies

Technology Type	Size, MWe (sent-out basis)	2015-2020	2030
Nuclear (including nuclear decommissioning cost)			
Generation III/III+ (with seawater cooling)	1100-1600 MW	C&P	C&P

Note: C&P = Cost and performance, D = Discussion only

3
DESIGN BASIS

3.1 Introduction

This section provides a guideline of the assumptions made when assessing the various power generation technologies examined in this study. It outlines the technical parameters of the plants, characterises the site conditions, and establishes fuel properties and emissions criteria, where applicable. Establishing a clear design basis makes it possible to compare costs and performance for a range of technologies in a consistent manner.

3.2 Fossil Fuel Technologies

Duty Cycle, Size, Location, and Cost Boundary

Duty Cycle

The fossil fuel plants in this study are base load units with the exception of the open cycle gas turbine (OCGT), which is a peaking unit. Base load units are characterised by high availability and high efficiency, but generally have less flexibility in their output and are less efficient under part-load conditions, thus minimising their use as load-following units. A capacity factor of 85% is assumed for all of the base load fossil fuel units.

Peaking units, like the open cycle gas turbine, typically have lower capital costs, shorter construction time, quicker start-up and higher flexibility in their plant output compared to base load units. However, they generally have higher fuel costs and can be less efficient and, therefore, run less frequently than base load units. A capacity factor of 10% is assumed for the OCGT.

Generating Unit Size

The base load fossil fuel plants in this study range from 500 MW to 750 MW. Integrated gasification combined cycle (IGCC) units with and without CCS are between 500 MW and 750 MW. The sent-out capacity of the IGCC plants varies for each case since their output capacity is dictated by the size and type of gas turbine used as a primary power generator for this technology. Pulverised coal (PC) units are 750 MW, both with and without CCS. The combined cycle gas turbine (CCGT) plants are 2+1 units between 600 MW and 800 MW without CCS. The open cycle gas turbine is 100 to 150 MW and the thermal solar plant is 200 MW. All plants considered generate electricity that is delivered to the local grid at a frequency of 50 Hz.

Location

The site location chosen for this study is a generic Greenfield site in Australia at an elevation of 111 meters. The sites for the brown and black coal technologies are assumed to be mine mouth, removing the need for a nearby railroad for fuel delivery purposes. For all technologies, dry cooling systems are necessary and, therefore, no assumption was made about the site's proximity to a raw water supply.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For example, the cost boundary for a steam plant includes all major parts of the unit, such as boiler and turbine generator, and all support facilities needed to operate the plant. These support facilities include fuel receiving/handling and storage equipment; emissions control equipment for particulate, SO_2 and CO_2, when included in the plant design; wastewater-treatment facilities; and shops, offices, and cafeteria. CO_2 compression equipment and energy penalties are included for plants with CCS, but the capital costs for the CO_2 pipeline and storage area for sequestration are not included. However, a dollar per tonne allowance for the cost of the CO_2 transport and storage is included as a separate line item in the levelised cost of electricity tabulations.

The cost boundary also includes the interconnection substation (to a single point connection), but not the switchyard and associated transmission lines. The switchyard and transmission lines are generally influenced by transmission system-specific conditions and, hence, are not included in the cost estimate. Though typically included within the cost boundary for EPRI estimates, the estimates included in this study do not include a railroad spur or cooling water intake structures due to the assumptions that these plants are mine mouth and utilise dry-cooling, thus negating the need for rail connections or cooling water intake structures.

The capital costs throughout this study do not include tariffs that may be charged for importing equipment to Australia. The costs do include shipping charges for this equipment. Contingencies for all fossil technologies have been included. The amount of contingency varies between the technologies and systems based on assessment of cost risk of the various areas. The selected values are considered appropriate for the state of experience for the various areas.

Ambient Conditions

Average Ambient Temperature Operation

The annual average ambient air conditions for Australia used throughout this study are listed below. They are based on ambient conditions given in the *Technical Guidelines – Generator Efficiency Standards* from the Australian Greenhouse Office in December 2006[1].

- Dry bulb temperature 25°C
- Wet bulb temperature 19.45°C
- Relative humidity 60%
- Atmospheric pressure 1.00 bar
- Equivalent altitude 111 m

[1] *Technical Guidelines – Generator Efficiency Standards.* Australian Governments, Australian Greenhouse Office, Department of the Environment and Heritage. December 2006.

Evaporative inlet air cooling was not included on the gas turbine-based power plants.

Fuel Systems

Fuel Types and Characteristics

Two coal types are considered for the coal-fired technologies: Hunter Valley black coal and Latrobe Valley brown coal. The characteristics and analyses of these coals are presented in Table 3-1 and are based on reference coals given in the *Technical Guidelines – Generator Efficiency Standards* from the Australian Greenhouse Office in December 2006. For greater efficiency of brown coal use, its high moisture content must be reduced to 32 wt% moisture before combustion for the PC plants and to12 wt% before gasification. This leads to an increased diversion of syngas or steam from the low pressure turbine to the coal drying unit. Black coal will also require drying for gasification applications to 2 wt% moisture to ensure that the pulverized coal flows freely through the lockhopper pressurization and feed injection systems.

The plant sites are assumed to be mine mouth with conveyors delivering coal from the mine to the site. Coal storage is sized for 5 days' storage.

Table 3-1
Australian Coal Characteristics

	Black Coal (Hunter Valley)	Brown Coal (Latrobe Valley)
Coal Composition		
Moisture	7.50	61.50
Carbon	60.18	26.31
Hydrogen	3.78	1.85
Nitrogen	1.28	0.23
Chlorine	0.00	0.00
Sulfur	0.43	0.15
Oxygen	5.63	9.16
Ash	21.20	0.80
Ash Mineral Analysis	N/A	N/A
Heating Value (as received)		
Higher MJ/kg (Btu/lb)	24.82 (10,679)	9.92 (4,269)
Lower MJ/kg (Btu/lb)	23.84 (10,257)	8.06 (3,466)

Natural gas composition is also based on the reference gas given in the *Technical Guidelines – Generator Efficiency Standards*. Table 3-2 shows the natural gas composition and heating values used in this analysis.

Table 3-2
Natural Gas Characteristics

Natural Gas Composition	Mole % (Dry Basis)
Methane	90.91
Ethane	4.50
Propane	1.04
n-Butane	0.21
i-Butane	0.13
Helium	0.04
Nitrogen	1.11
Carbon Dioxide	2.06
Heating Value	
Higher MJ/SCM (Btu/SCF)	38.55 (1,035)
Lower MJ/SCM (Btu/SCF)	34.77 (934)

Resource Potential

The majority of black coal in Australia is available in New South Wales and Queensland while brown coal is found exclusively in Victoria. Figure 3-1 shows a map of the black coal resources in Australia.

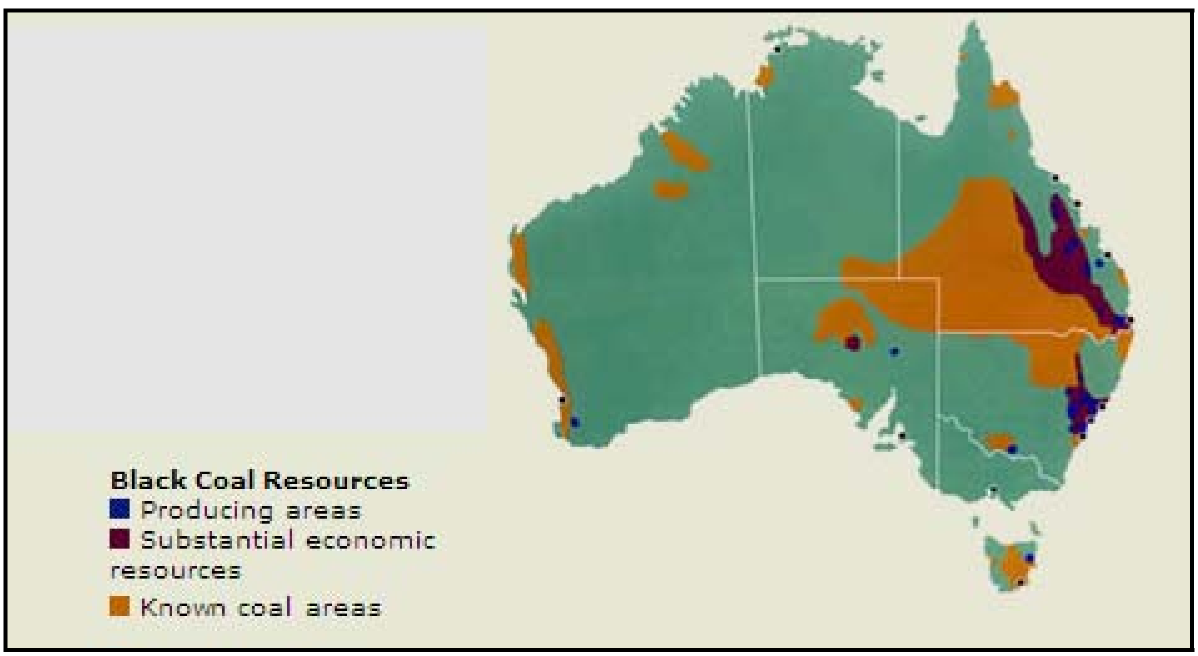


Figure 3-1
Australian Black Coal Resources

Other Factors

CO_2 Capture and Storage

All technologies that include CO_2 capture and storage have a CO_2 capture rate of 85-90%. The recovered CO_2 contains no more than 100 ppmv total sulphur and is compressed to 160 bar (2,321 psi) before exiting the plant boundary. The reasons for this relatively high CO_2 purity requirement are as follows:

- Legislative and environmental permitting considerations at State, Territory and Commonwealth levels.
- Technological issues including dynamic events such as compressor/pipeline/well trips and start up/shut down can play an important part in emissions profile and meeting permit conditions (i.e. the need to vent the CO_2 stream during upsets). Having low H_2S in the CO_2 to be vented will likely be an important part of any environmental compliance strategy.
- Public acceptance issues given the toxicity of H_2S.

The CO_2 pipeline and storage area for sequestration are not included in these capital cost estimates.

Emissions Criteria

Existing coal-fired power plants in Australia are not required to include any sulphur dioxide (SO_2) or nitrogen oxide (NO_X) controls due to the very low sulphur content of the coals. Except for reductions of SO_2 required for process reasons, no SO_2 or NO_X reduction systems are included. Typically the CCS technologies require control of SO_2 to avoid poisoning of amines used in these processes. For amine-based capture systems this will require removal of SO_2 down to a level of ~10 ppmv. Particulate emissions are controlled via the use of electrostatic precipitators for the pulverized coal units. Other than dry low NO_X combustors used in the gas turbines, no additional emissions controls are added.

Dry Cooling

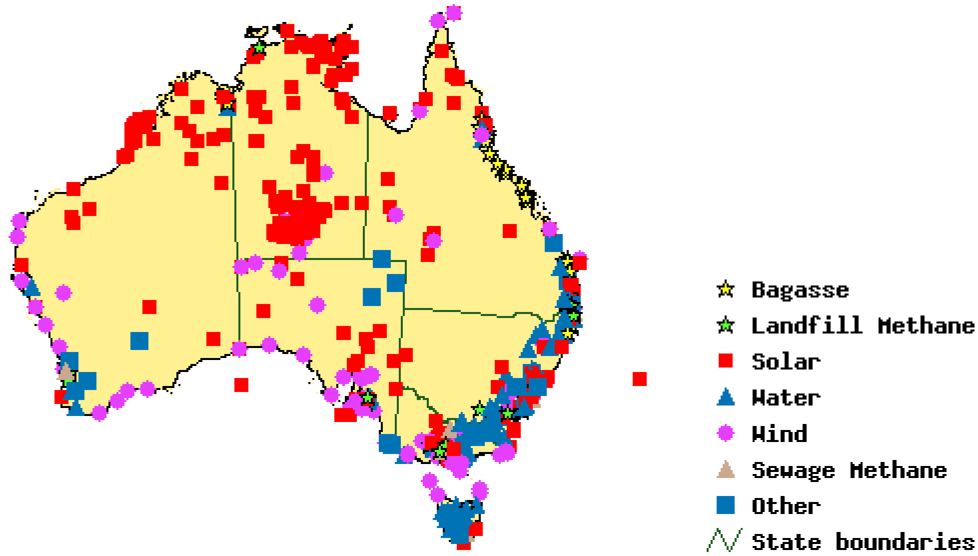
Due to limited water supply in Australia, dry cooling systems are necessary for all plant units.

Ash Handling

Due to water supply conditions in Australia, ash removal is handled dry.

3.3 Renewable Technologies

The Australian Greenhouse Office has compiled the locations of renewable energy power stations operating throughout the country. Figure 3-2 shows the locations and types of renewable projects.



(Source: Australian Government, Australian Greenhouse Office)

Figure 3-2
Renewable Energy Projects in Australia

Wind Turbines

Generating Unit Size

The onshore wind farms investigated in this study all consist of 2 MW turbines. The three farm sizes investigated include 50 MW, 200 MW, and 500 MW.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For wind farms, this area includes interconnections among the turbines and a substation, in addition to the wind turbines, foundations, and control systems. The capital costs throughout this study do not include tariffs that may be charged for importing equipment to Australia. They also do not include government taxes or shipping charges for this equipment.

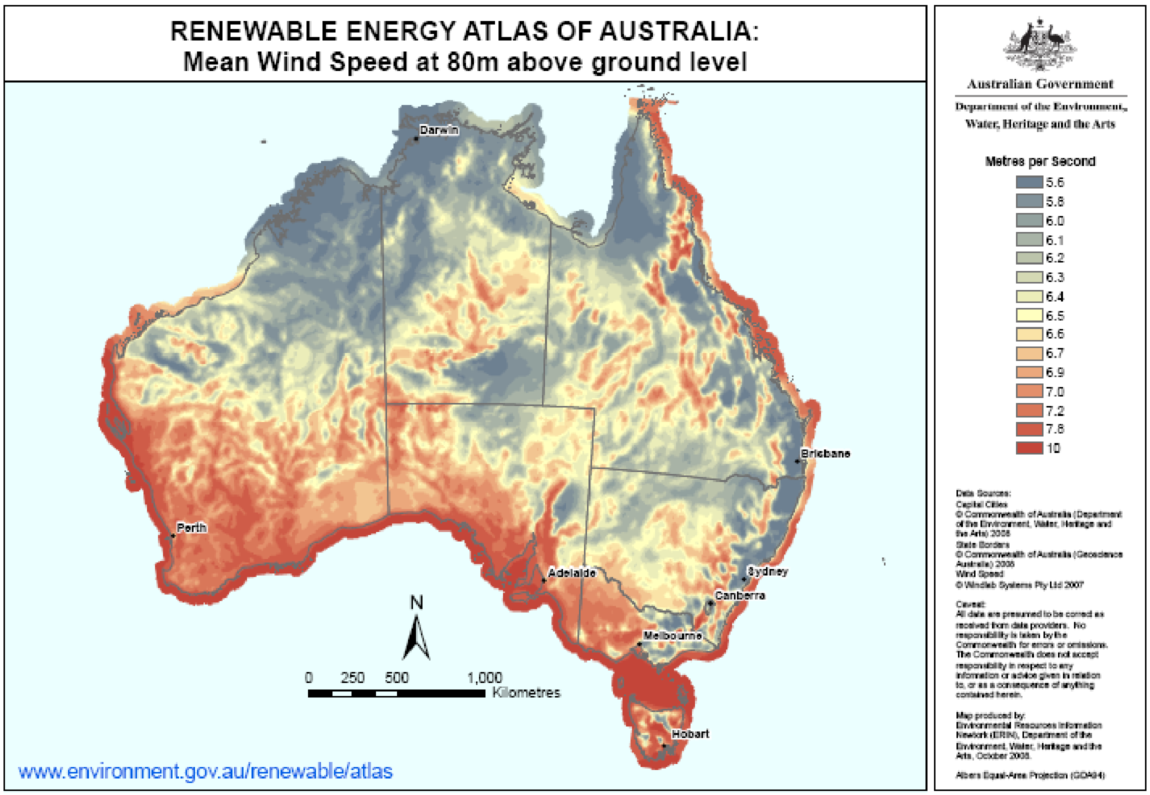
Resource Potential

Wind classes of 3, 4, 5, and 6 are evaluated. Table 3-3 shows the wind speed range for each class.

Table 3-3
Wind Speed Classes

Wind Class	Wind Speed Range
3	6.4 to 7.0 m/s
4	7.0 to 7.5 m/s
5	7.5 to 8.0 m/s
6	8.0 to 8.8 m/s

Figure 3-3 shows the average speed in m/s of wind resources available in Australia.



(Source: Australian Government: Departement of the Environment, Water, Heritage and the Arts http://www.environment.gov.au/settlements/renewable/atlas/pubs/mean-wind-speed.pdf)

Figure 3-3
Wind Resources in Australia

Off-Shore Wind

Off-shore wind has recently become a technology of interest globally. Offshore wind uses bigger wind turbines to take advantage of the higher wind speeds that are available along coastlines. While off-shore wind farms will not be evaluated in detail, they are discussed in the wind section of this report.

Solar Thermal

Generating Unit Size

Both the parabolic trough plant and the central receiver plant evaluated for this study are 200 MW. Solar thermal plants were evaluated with and without six hours of molten salt thermal storage.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For solar thermal plants, this area includes the collectors, any thermal storage units, the steam generating unit, and the power island; as well as any support facilities needed to operate the plant and an interconnection substation. The capital costs throughout this study do not include tariffs that may be charged for importing equipment into Australia. They also do not include government taxes or shipping charges for this equipment.

Resource Potential

Concentrating solar power (CSP) technologies, such as parabolic trough and central receiver, require direct normal irradiance (DNI). This requirement means that incident sunlight must strike the solar collectors at an angle of 90 degrees in order for the sunlight to be reflected onto the receivers. Figure 3-4 shows worldwide solar DNI data. The DLR-ISIS images were obtained from the Institute of Atmospheric Physics, German Aerospace Center (DLR)[2]. The long-term variability of direct irradiance was derived from ISCCP data and compared with re-analysis data[3]. Australia has one of the best solar resources in the world.

2 Lohmann, S., C. Schillings, B. Mayer and R. Meyer, (2006a). Institute of Atmospheric Physics, German Aerospace Center (DLR).

3 "Long-term variability of solar direct and global radiation derived from ISCCP data and comparison with reanalysis data**."** S. Lohmann, C. Schillings, B. Mayer and R. Meyer. *Solar Energy*, Volume 80, Issue 11, November 2006, pp. 1390-1401

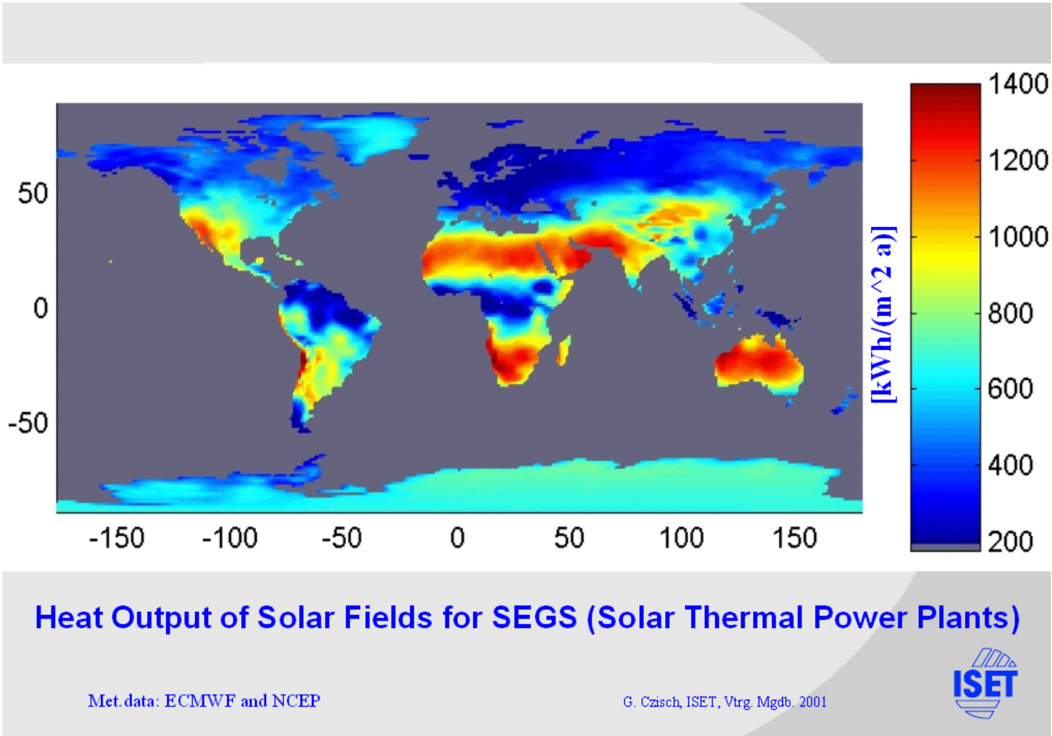


Figure 3-4
Worldwide DNI Data

The figures below show the availability of solar energy in Australia. Figure 3-5 shows an annual average of the number of hours the sun shines daily, and Figure 3-6 shows an annual average of daily solar exposure throughout Australia.

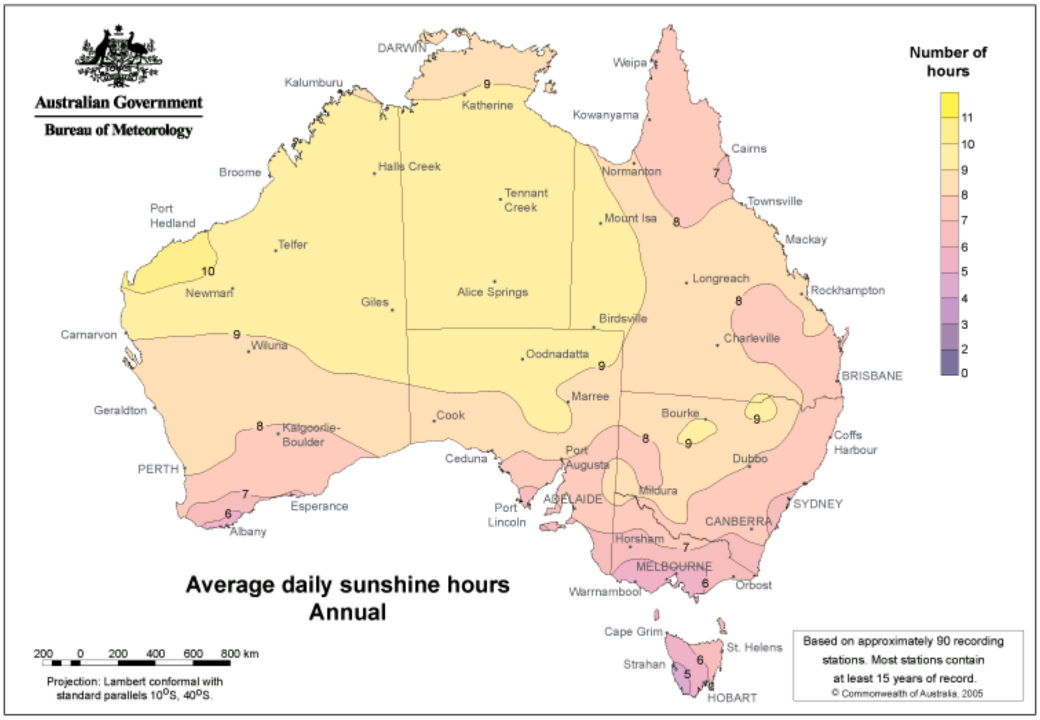


Figure 3-5
Australian Annual Average Number of Sunshine Hours per Day

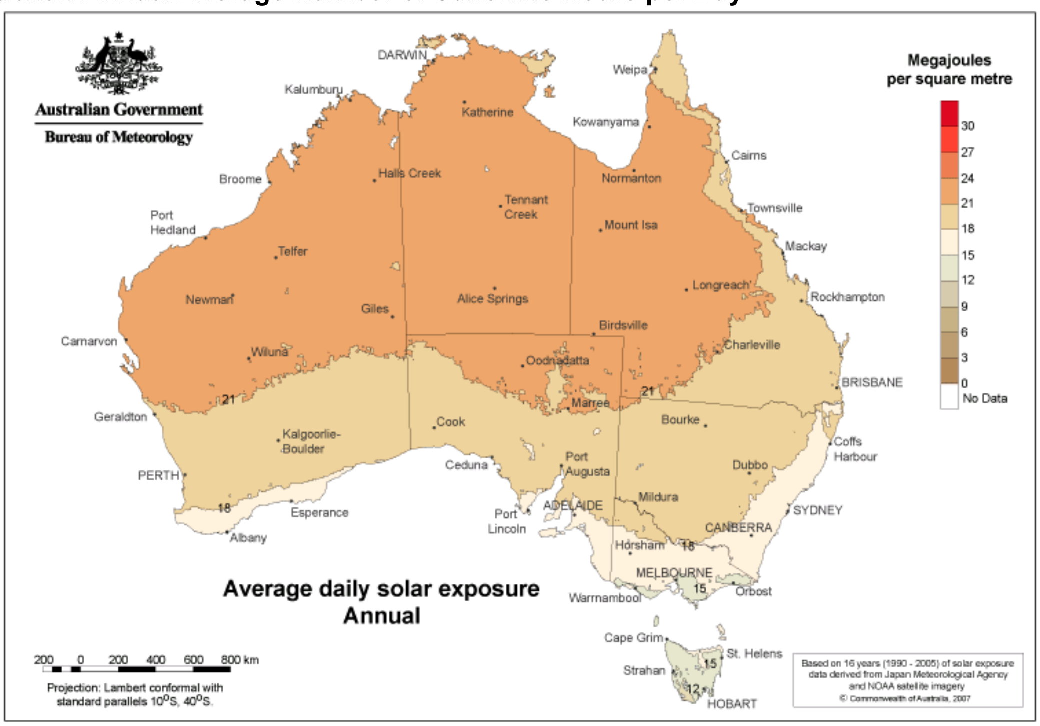


Figure 3-6
Australian Annual Average Solar Exposure per Day

Parabolic Dish and Linear Fresnel

Parabolic dish and linear Fresnel are two additional concentrating solar thermal technologies that are under development. Detailed evaluations of these technologies are not included in this report. However, a discussion of the technology status and cost trends is included.

Solar Thermal Hybrids

Some research has been conducted to look at using solar thermal solar steam in conjunction with a fossil fuel plant, either coal or natural gas. While these hybrid solar thermal/fossil plants are not evaluated in detail, they are discussed in the solar thermal section of this report.

Solar Photovoltaics

Generating Unit Size

The solar photovoltaic (PV) systems evaluated in this study will be utility-scale systems, both 1 x 5 MWe and 10 x 5 MWe plants. However, the potential does also exist for solar PV systems to be installed and integrated into the electricity grid as small-scale distributed resources for residential, commercial, industrial, institutional, business-park, and subdivision uses. Fixed flat plate, single-axis tracking, and double-axis tracking PV systems are all evaluated.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For solar photovoltaic (PV) plants, this area includes the solar PV arrays, support structures, inverters, a solar tracker if required, wiring, and an interconnection substation.

Resource Potential

See Resource Potential in the Solar Thermal subsection.

Concentrating PV

Concentrating PV systems are being researched as a next generation of PV technologies. While concentrating PV plants are not evaluated in detail, they are discussed in the solar photovoltaics section of this report.

Geothermal

Generating Unit Size

Commercial scale Hot Rock (HR) Geothermal and Hot Sedimentary Aquifer (HSA) units have not yet been installed. Current plants under design are in the range of 10 to 15 MW_e with future commercial-scale plans up to hundreds of megawatts.

Cost Boundary

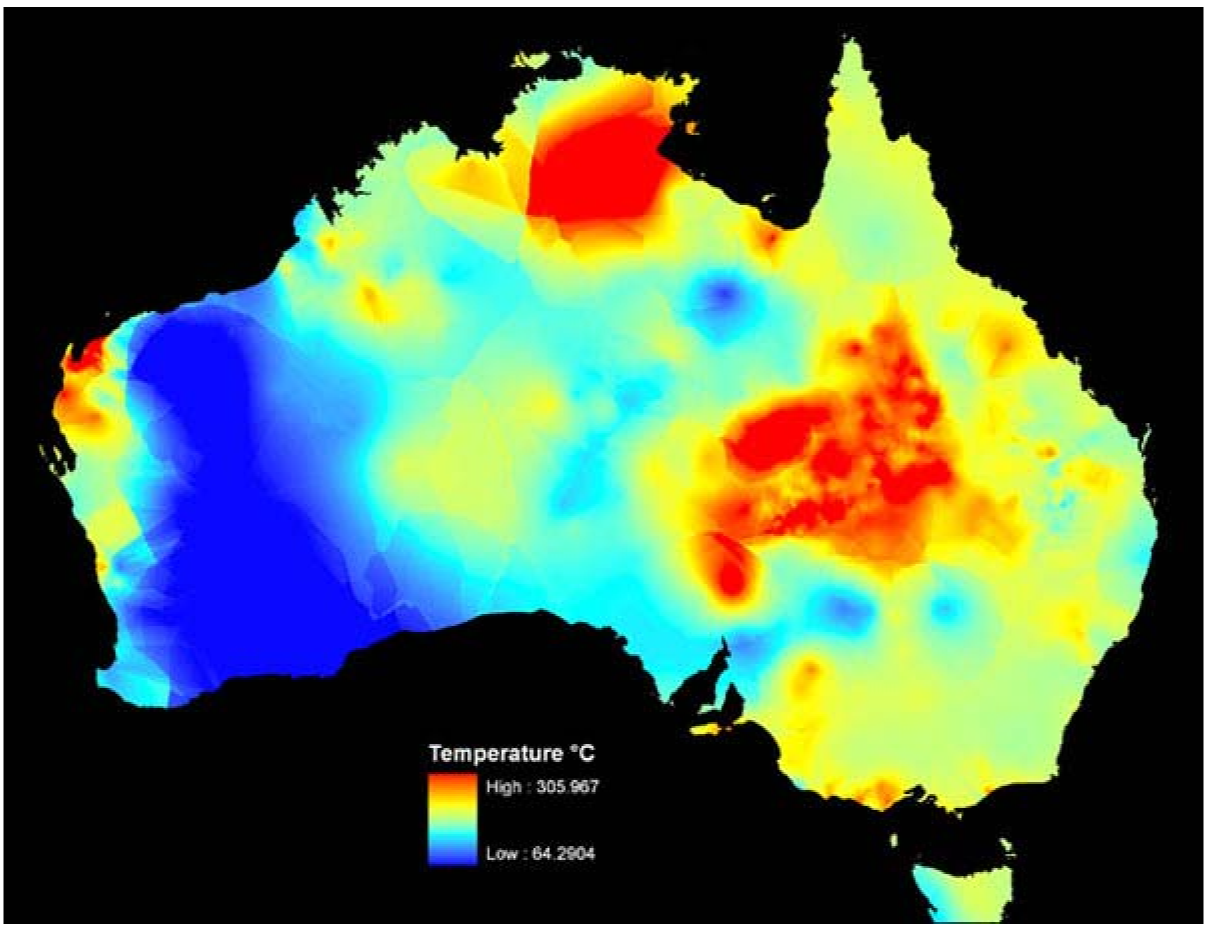
The generating unit boundary includes the area in which all unit components are located. For geothermal units this includes not only the power block and its associated balance of plant, but also the drilling and facilities of the production and injection wells and their associated piping.

Due to the more speculative nature of HR and HSA technology at this time, cost discussions have focussed on a discussion of the technology status and cost trends as opposed to more detailed cost and performance estimates.

Resource Potential

HR resources are characterised by man-made reservoirs of hot water created by fracturing geothermally-heated hot rock formations at depths of 2,000 to 10,000 meters. Surface water is then pumped into the hot fractures and most of that water is recovered through production wells. Rock temperature reaches commercial usefulness at depths of about three kilometres or more. Traditional hydrothermal systems rarely require drilling deeper than three kilometres, but the technical limit for current drilling technology is to depths greater than 10 kilometres.[4]

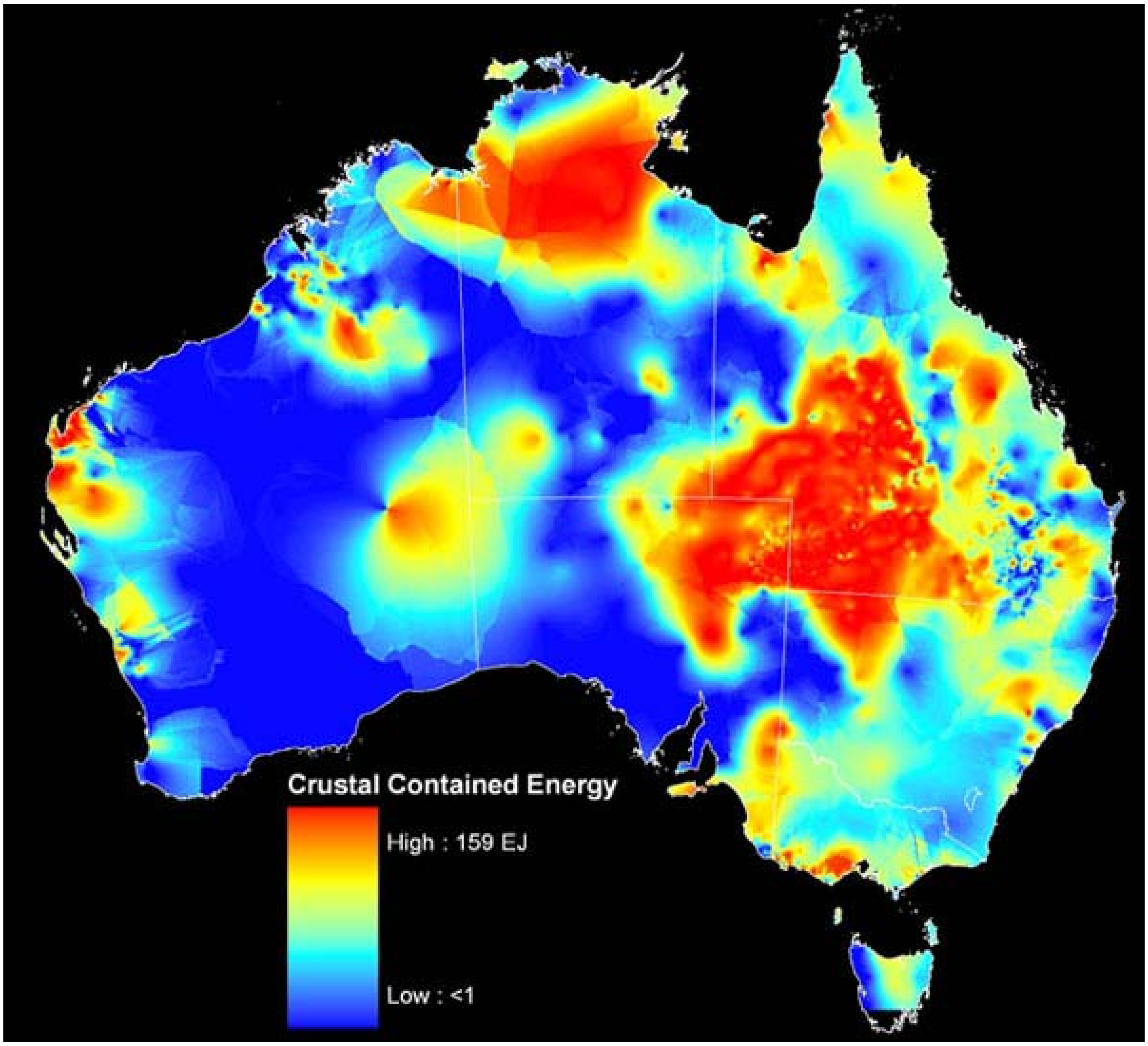
Figure 3-7 and Figure 3-8 show the distribution of crustal temperature and contained energy within Australia.



(http://www.ga.gov.au/ausgeonews/ausgeonews200709/geothermal.jsp)

4 *Renewable Energy Technical Assessment Guide – TAG-RE: 2008* EPRI, Palo Alto, CA: 2008. 1015801.

Figure 3-7
Crustal temperature at five km depth



(http://www.ga.gov.au/ausgeonews/ausgeonews200709/geothermal.jsp)

Figure 3-8
Distribution of crustal energy

Other Geothermal Technologies

Though they will not be covered in detail, the geothermal section of this report briefly discusses hydrothermal flash and binary geothermal systems, reverse air conditioning cycles, solar-geothermal hybrid plants, geo-pressurized, and down the hold closed geothermal technologies.

Tidal

Generating Unit Size

Tidal in-stream energy conversion (TISEC) devices have not yet been installed at commercial scale. Units that are under development range in rated capacity from 7 kW to over 2 MW[5]. The size of a commercial facility made up of multiple units will depend on the size of the tidal opening used for the plant (generally the narrowest constriction of the area being utilised) and the tidal hydrokinetic energy available. Currently, EPRI studies limit the plant size estimates to extracting 15% of the available power so as to conservatively avoid significant ecological effects. As further research is conducted to better understand the impact of large-scale kinetic power extraction on ecosystems, this percentage may be increased. A feasibility study conducted by EPRI resulted in tidal facilities ranging in average power from 1.6 MW to 130 MW.[6]

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For a TISEC plant, this includes the individual tidal units, which consist of the rotor, drive train including the gear box and generator, and support structure, as well as the interconnection equipment. Due to the more speculative nature of current TISEC technology, discussions consider the technology status and cost trends as opposed to more detailed cost and performance estimates.

Resource Potential

A number of characteristics should be considered when assessing a suitable in-stream tidal site. There must be a high annual current flow resulting in a large amount of fast moving water. The depth of the seabed must allow room for navigation clearance, if necessary, and the seabed must be suitable for mounting the TISEC unit. Construction costs will be reduced if there is a nearby harbour or marina with sufficient space for assembling and deploying the plant, and interconnection costs will be reduced if there is a nearby substation close to shore and a transmission and distribution system suitable for flowing power to the grid. Finally, siting the plant in a location with minimal conflict with other uses of the sea space, such as fishing, kelp farming, or whale migration, and a local community that is receptive to the idea of tidal power will reduce opposition to the construction of the plant.

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5 *Survey and Characterization Tidal In Stream Energy Conversion (TISEC) Devices.* EPRI, Palo Alto, CA: 2005. EPRI TP-004-NA

6 *North American Tidal In-Stream Energy Conversion Technology Feasibility Study.* EPRI, Palo Alto, CA: 2006. EPRI TP-008-NA

Wave

Generating Unit Size

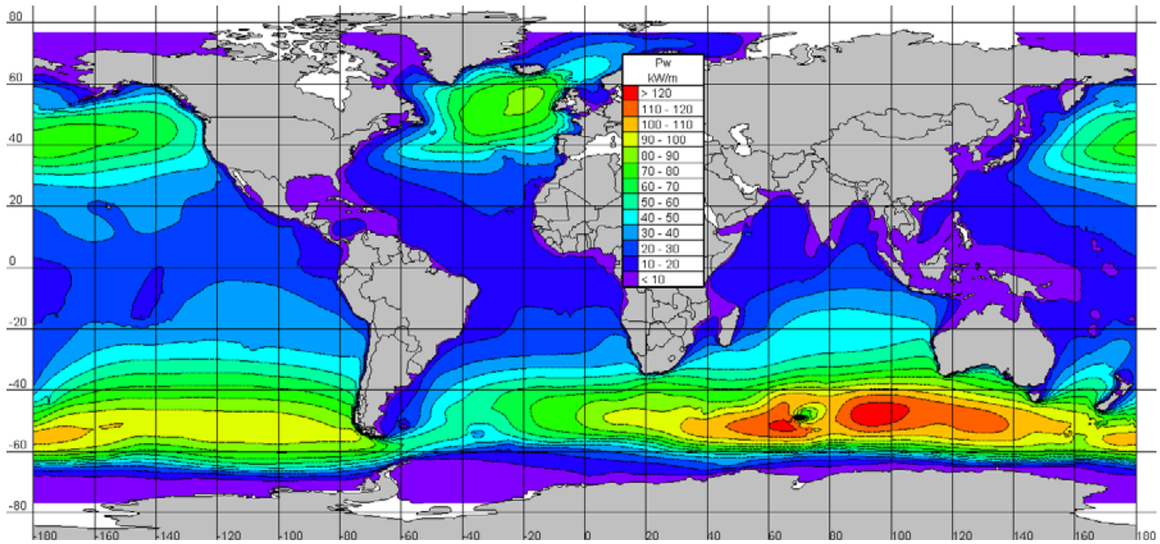
Commercial-scale wave energy conversion (WEC) plants have not yet been built. However, a number of companies are working to develop WEC units and preliminary permits have been issued for pilot and commercial scale plants. Units under development range from 150 kW to 500 kW per unit. Pilot scale demonstrations are being planned for 1.5 MW plants with the possibility of expansion as performance is proven. In the United States, preliminary permits, which give the permit holder the first right of refusal to a site for a three-year period to study the site and file a construction license application, have been granted for up to 100 MW facilities.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For wave energy plants, this includes the power conversion module, subsea cables, and mooring or support structures. Due to the more speculative nature of current WEC technology, discussions consider the technology status and cost trends as opposed to more detailed cost and performance estimates.

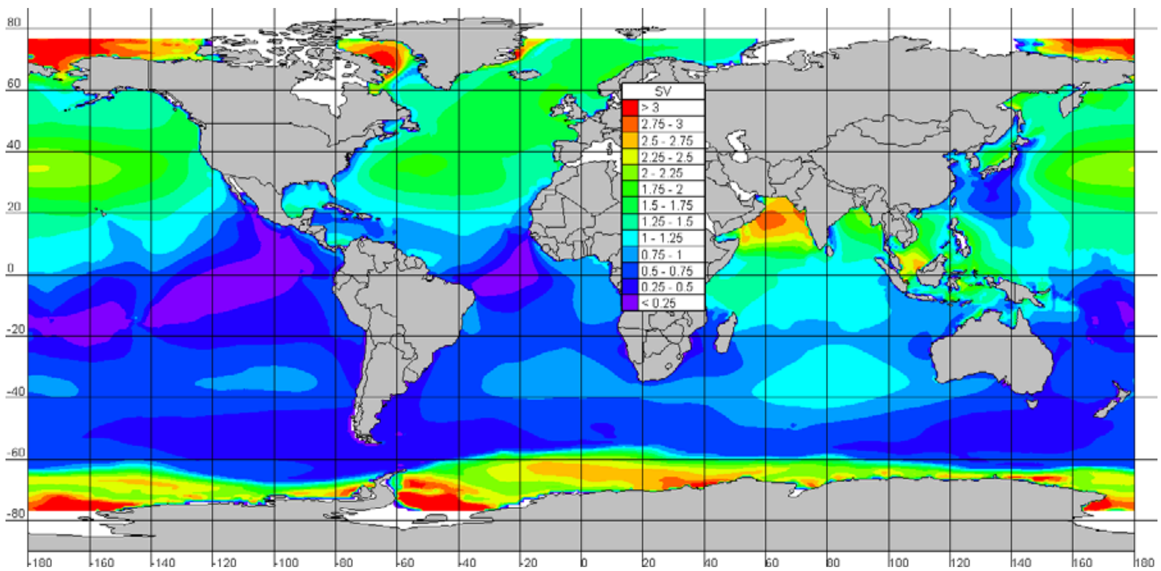
Resource Potential

A number of characteristics should be considered when assessing a site for a WEC facility, many of which are similar to TISEC site requirements. Most importantly, there must be high annual wave energy, preferably with as little seasonal variability as possible. Figure 3-9 shows the global distribution of annual wave power and Figure 3-10 shows the global distribution of the seasonal variability index, which is the difference between the wave energy of the season with the highest wave energy and the lowest wave energy, divided by the average annual wave energy. The sea floor must be sufficiently deep and must be suitable for anchoring the wave energy unit and burying the cable. Proximity to a nearby harbour or marina with sufficient space for assembling and deploying the plant and a nearby substation close to shore and a transmission and distribution system suitable for flowing power to the grid will reduce construction and integration costs. Finally, siting the plant in a location with minimal conflict with other uses of the sea space and a local community that is receptive to the idea of wave power will reduce opposition to the construction of the plant.



(ISOPE-2008-579 A Global Wave Energy Resource Assessment Andrew Cornett)

Figure 3-9
Global distribution of annual mean wave power



(ISOPE-2008-579 A Global Wave Energy Resource Assessment Andrew Cornett)

Figure 3-10
Global distribution of wave power seasonal variability index

Biomass

Biomass technologies are not evaluated in detail. However, a discussion of biomass, both for co-firing with coal in PC and CFB plants and for 100% biomass combustion for power and combined heat and power applications, are included.

3.4 Nuclear Technology

Generating Unit Size

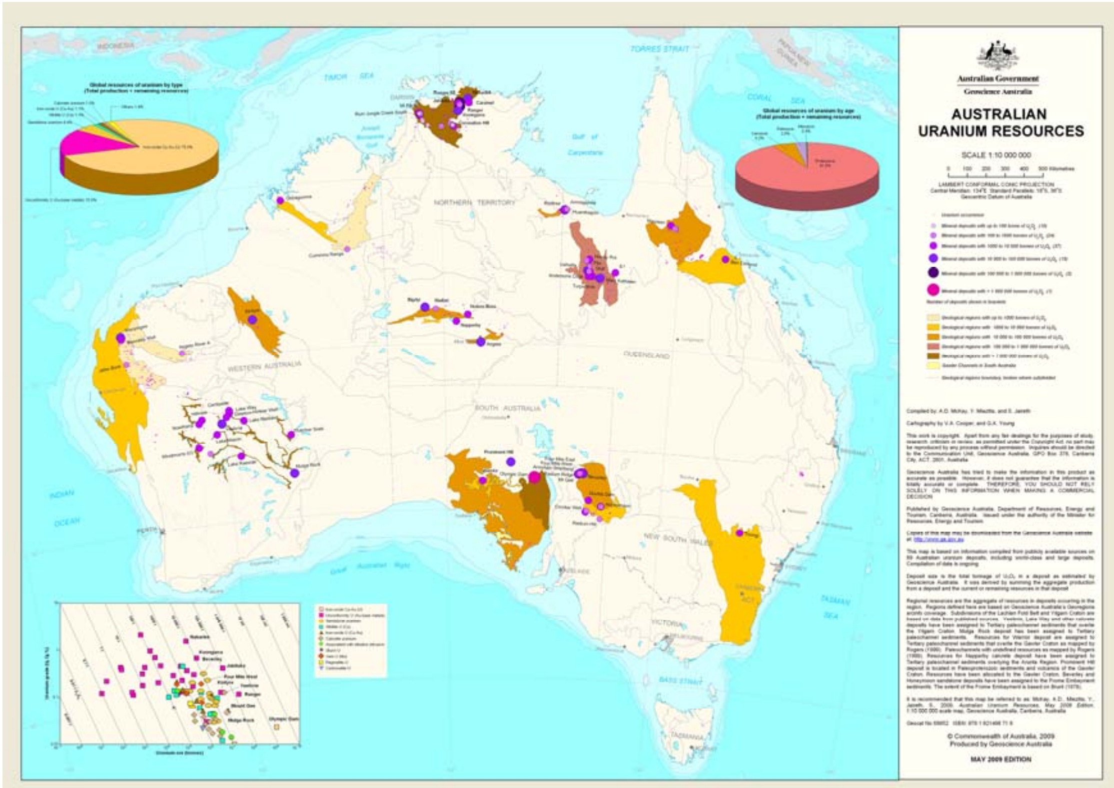
The primary Generation III/III+ nuclear reactor designs being pursued for design certification in the US include the following: Westinghouse AP1000, GE/Hitachi & Toshiba Advanced Boiling Water Reactor (ABWR), GE/Hitachi (Economic Simplified Boiling Water Reactor (ESBWR), Mitsubishi Nuclear Energy Systems (MNES) Advanced Pressurised Water Reactor (APWR), Atomic Energy of Canada Limited (AECL) Advanced CANDU Reactor (ACR-1000), and Areva Evolutionary Pressurised Reactor (ERP). These plants range in size from 1,100 MW to 1,600 MW. Estimates within this report will cover the range of these plants.

Cost Boundary

The generating unit boundary includes the area in which all unit components are located. For a nuclear plant, this includes the nuclear reactor and the power block, and all support facilities needed to operate the plant, such as wastewater-treatment facilities, shops, offices, and cafeteria. The cost boundary also includes the interconnection substation, but not the switchyard and associated transmission lines. While all other technologies considered in this study assume dry cooling and, therefore, do not require cooling water intake structures, most nuclear technologies require wet cooling at this time. Whether wet cooling, and therefore cooling water intake structures, is included in the plant design will be explicitly stated with cost estimates. Only PWR design can be considered for direct dry cooling due to their use of secondary steam, as compared to BWR designs that use primary steam.

Resource Potential

Nuclear fuel typically consists of uranium dioxide enriched to 3-5% (by weight) using the uranium-235 isotope. Natural uranium, mixed oxide (MOX) consisting of both plutonium and enriched uranium oxides, thorium, and actinides are also used as nuclear fuel. Figure 3-11 shows geological regions and mineral deposits of U_3O_8 in Australia. Darker regions represent areas with greater amounts of uranium.



(http://www.ga.gov.au/image_cache/GA14065.jpg)

Figure 3-11
Australian uranium resources

4
CAPITAL COST ESTIMATING BASIS

4.1 FOSSIL PLANT ESTIMATING METHODOLOGY

Introduction

EPRI's subcontractor prepared Total Plant Cost (TPC) "Capital Cost," and Operation and Maintenance (O&M) cost estimates for each of the fossil technologies and cases evaluated.

The estimates carry an accuracy of +/-30%, consistent with the screening study level of information available for the various study power technologies.

EPRI's subcontractor used in-house database and conceptual estimating models for the capital cost and O&M cost estimates. Costs were further calibrated using a combination of adjusted vendor-furnished and actual cost data from recent design and design/build projects. Finally, costs were converted from US Gulf Coast to Australia by applying factors for material costs, labour productivity, crew rates and currency.

EPRI's subcontractor reviewed the capital costs for each cost account, comparing individual cases across all of the other cases and technologies to ensure an accurate representation of the relative cost differences between the cases and accounts.

All capital and O&M costs are presented as "Overnight Costs" expressed in June 2009 AUD.

Capital Costs are presented at the TPC level. TPC includes:

- equipment (complete with initial chemical and catalyst loadings);
- materials;
- labour (direct and indirect);
- engineering and construction management;
- contingencies (process and project); and
- an allowance for project specific costs.

Owner's costs are excluded from TPC estimates.

System Code-of-Accounts

The costs are grouped according to a process/system oriented code of accounts. This type of code-of-account structure has the advantage of grouping all reasonably allocable components of a system or process so they are included in the specific system account. (This would not be the case had a facility, area, or commodity account structure been chosen instead).

Non-CO_2 Capture Plant Maturity

The estimates include technologies having different commercial maturity levels. The estimates for the non-CO_2-capture pulverised coal (PC) and combined cycle gas turbine (CCGT) cases represent well-developed commercial technology or "n^{th} plants." The non-capture IGCC cases are also based on commercial offerings; however, there have been very limited sales of these units so far. These non-CO_2-capture IGCC plant costs are less mature in the learning curve, and the costs listed reflect the "next commercial offering" level of cost rather than mature n^{th}-of-a-kind cost. Thus, each of these cases reflects the expected cost for the next commercial sale of each of these respective technologies.

CO_2 Removal Maturity

The post-combustion CO_2 removal technology for the PC, Oxy combustion and CCGT capture cases is based on mature component technology but has not been incorporated in the power industry. This technology is currently in the initial stages of commercial scale demonstration but remains unproven in power generation applications.

The pre-combustion CO_2 removal technology for the IGCC capture cases has a stronger commercial experience base. Pre-combustion CO_2 removal from syngas streams has been proven in chemical processes with similar conditions to that in IGCC plants, but has not been demonstrated in IGCC applications. While no commercial IGCC plant yet uses CO_2 removal technology in commercial service, there are currently IGCC plants with CO_2 capture well along in the planning stages.

Contingency

Both the project contingency and process contingency costs represent costs that are expected to be spent in the development and execution of the project that are not yet fully reflected in the design. It is industry practice to include project contingency in the TPC to cover project uncertainty and the cost of any additional equipment that would result during detailed design. Likewise, the estimates include process contingency to cover the cost of any equipment modification or additional equipment that would be required as a result of continued technology development. A more detailed discussion of contingency follows later in this section.

Contracting Strategy

The estimates are based on an Engineering/Procurement/Construction Management (EPCM) approach utilising multiple subcontracts. This approach provides the owner with greater control of the project, while minimising, if not eliminating most of the risk premiums typically included in an Engineer/Procure/Construct (EPC) contract price.

The EPCM approach used as the basis for the estimates here is anticipated to be the most cost effective approach for the owner. While the owner retains the risks, the risks become reduced with time, as there is better scope definition at the time of contract award(s).

Estimate Scope

The estimates represent a complete power plant facility on a generic site. Site-specific considerations such as unusual soil conditions, special seismic zone requirements, or unique local conditions such as accessibility, local regulatory requirements, etc. are not considered in the estimates.

The estimate boundary limit is defined as the total plant facility within the “fence line” including coal receiving, but terminating at the high voltage side of the main power transformers and at the fence line for cases where CO_2 is captured.

The site is characterised as Australia.

Labour costs are based on Australian rates and productivities, in a competitive bidding environment.

Capital Costs

EPRI’s subcontractor developed the capital cost estimates for each plant using the company’s in-house database and conceptual estimating models for each of the specific technologies. This data base and the respective models are maintained by EPRI’s subcontractor as part of its commercial power plant design base of experience for similar equipment in our company’s range of power and process projects. A reference bottom-up estimate for each major component provides the basis for the estimating models. This provides a basis for subsequent comparisons and easy modification in comparing between specific case-by-case variations.

Key equipment costs for each of the cases were calibrated to reflect recent quotations and/or purchase orders for other ongoing in-house power or process projects. These include, but are not limited to, the following equipment:

- pulverised coal boilers;
- gasifiers;
- combustion turbine generators;
- steam turbine generators;
- circulating water pumps and drivers;
- cooling towers;
- condensers;
- air separation units; and
- main transformers.

The Post Combustion CO_2 costs were calibrated from in-house information.

A number of other key estimate considerations were also included.

- No vendor quotations were provided specifically for this study.
- Labour costs are based on Australian rates and productivities.
- The estimates are based on a competitive bidding environment, with adequate skilled craft labour available locally.
- Labour is based on a 51-hour work-week. Allowance for meals & travel are included.
- The estimates are based on a greenfield site.
- The site is considered to be Seismic Zone 1, relatively level and free from hazardous materials, archaeological artefacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads.
- Costs are limited to within the "fence line," terminating at the high voltage side of the main power transformers representing interconnection substation.
- Engineering and construction management were estimated as a percent of bare erected cost.
- All capital costs are presented as "Overnight Costs" in June 2009 AUD. Escalation to period-of-performance is specifically excluded.

Cross-comparisons

In all technology comparison studies, the relative differences in costs are often more significant than the absolute level of TPC. This requires cross-account comparison between technologies to review the consistency of the direction of the costs. As noted above, the capital costs were reviewed and compared across all of the cases, accounts, and technologies to ensure that a consistent representation of the relative cost differences is reflected in the estimates.

In performing such a comparison, it is important to reference the technical parameters for each specific item, as these are the basis for establishing the costs. Scope or assumption differences can quickly explain any apparent anomalies.

Exclusions

The TPC estimates include all anticipated costs for equipment and materials, installation labour, professional services (engineering and construction management), and contingency. The following items are excluded:

- escalation to period-of-performance;
- owner's costs – including, but not limited to land acquisition and right-of-way, permits and licensing, royalty allowances, economic development, project development costs, allowance for funds-used-during construction, legal fees, owner's engineering, pre-production costs, initial inventories, furnishings, owner's contingency, etc;
- all taxes, with the exception of payroll taxes;
- site specific considerations – including but not limited to seismic zone, accessibility, local regulatory requirements, excessive rock, piles, laydown space, etc;

- CO_2 injection wells;
- additional premiums associated with an EPC contracting approach; and
- import duties.

To better represent real project costs, a nominal 7.5% allowance for the cost of other project and site specific factors has been included in the TPC presented in later sections of this report.

Contingency

Project Contingency

Project contingencies have been added to each of the capital accounts to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Each bare erected cost account was evaluated against the level of estimate detail, field experience, and the basis for the equipment pricing to define project contingency.

The capital cost estimates associated with the plant designs in this study were derived from various sources which include prior conceptual designs and actual design and construction of both process and power plants.

Process Contingency

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Some examples of how process contingencies have been applied to the estimates are as follows:

- gasifiers and syngas coolers: 15% on all IGCC cases – at the next commercial offering;
- mercury removal: 5% on all IGCC cases;
- CO2 removal system: 20% on all post-combustion capture cases - process unproven for power plant applications;
- combustion turbine generator: 5% on all IGCC non-capture cases – syngas firing; 5% on all IGCC capture cases – hydrogen firing; and
- instrumentation and controls: 5% on all IGCC accounts and 5% on the PC and CCGT capture cases – integration issues.

The process contingencies as applied in this study are consistent with the Association for the Advancement of Cost Engineering (AACE) International standards.

All contingencies included in the TPC, both the project and process, represent costs that are expected to be spent in the development and execution of the project.

Project Specific Costs

Typically, EPRI cost estimates do not include project specific costs, such as site and technology selection studies, rights of way, road modifications and upgrades, permitting, and many other costs which depend on the owner and site-specific requirements. While it is difficult to calculate these types of costs for a general cost estimating study, they are costs that are none-the-less real and must be paid for via project revenue. Therefore, this study added an assumed 7.5% to the TPC to reflect an estimate of project specific costs.

Operation and Maintenance (O&M)

The production costs or operating costs and related maintenance expenses (O&M) pertain to those charges associated with operating and maintaining the power plants over their expected life. These costs include:

- operating labour;
- maintenance – material and labour;
- administrative and support labour;
- consumables;
- fuel;
- waste disposal; and
- co-product or by-product credit (that is, a negative cost for any by-products sold).

There are two components of O&M costs; fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation.

Operating Labour

Operating labour cost was determined based on the number of operators required for each specific case. The average base labour rate used to determine annual cost is AUD40/hr. The associated labour burden is estimated at 30% of the base labour rate.

Maintenance Material and Labour

Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section. The exception to this is the maintenance cost for the combustion turbines, which is calculated as a function of operating hours.

It should be noted that a detailed analysis considering each of the individual gasifier components and gasifier refractory life is beyond the scope of this study. However, to address this at a high level, the maintenance factors applied to the gasifiers vary between the individual gasifier technology suppliers. A gasifier maintenance factor of 7.5% was used for this study.

Administrative and Support Labour

Labour administration and overhead charges are assessed at rate of 25% of the burdened operation and maintenance labour.

Consumables

The cost of consumables was determined on the basis of individual rates of consumption, the unit cost of each specific consumable commodity, and the plant annual operating hours.

Quantities for major consumables were taken from technology-specific heat and mass balance diagrams developed for each plant application. Other consumables were evaluated on the basis of the quantity required using reference data.

The quantities for initial fills and daily consumables were calculated on a 100% operating capacity basis. The annual cost for the daily consumables was then adjusted to incorporate the annual plant operating basis, or capacity factor.

Initial fills of the consumables and chemicals, are different from the initial chemical loadings included with the equipment pricing in the capital cost.

Waste Disposal

Waste quantities and disposal costs were determined and evaluated in a manner similar to that applied to consumables.

Co-Products and By-products

By-products quantities were also determined and evaluated in a manner similar to that applied to consumables.

4.2 RENEWABLE PLANT ESTIMATING METHODOLOGY

Renewable technology costs were estimated by EPRI using a combination of in-house data and adjustment factors developed by EPRI's subcontractor. Recent EPRI studies were used as a baseline for the cost estimates. When necessary, these costs were adjusted to match the design basis for the current study, such as adjustments to the size of the plant or the inclusion of thermal storage. Based on information about current market trends, these baseline estimates were then adjusted to June 2009 US dollars. Once capital and O&M costs were established for a US-based plant with the same design as the design basis in mid-2009, cost estimates were adjusted to Australian dollars, based on the adjustment factors developed by EPRI's subcontractor, described in the following section.

4.3 ADJUSTMENTS TO AUSTRALIAN COSTS

The US Gulf Coast estimates for each of the technology cases evaluated were adjusted to Australian costs using adjustment factors developed between the EPRI's subcontractor's Australia offices and their US office. These adjustment factors are described below.

Labour Productivity Factors

Labour Productivity Factors were developed using the following process:

A detailed estimate for a non-specific power project was estimated using two separate approaches – one based on US Gulf Coast productivity and one based on Australian productivity. Care was taken to ensure that, for both US and Australia, installation hours accurately reflected the scope of each estimate line item. Both estimates were sorted and summarised by discipline. The resultant comparison yielded the labour productivity factors.

Rates were generally found to be within an acceptable range. One exception is structural steel with a Productivity Factor of 1.82, which is higher than anticipated. The raw data used to calculate the Productivity Factor for steel is shown in Table 4-1.

Table 4-1
Productivity Factor Data for Installation of Structural Steel

	Installation Hours		
Description	**US**	**Australia**	**Factor**
Fabricated Steel – Major Facility	318	289	0.91
Extra Heavy Members	1,688	2,204	1.31
Heavy Members	3,276	5,487	1.67
Medium Members	2,338	5,454	2.33
Light Members	1,080	2,155	2.00
Misc Steel	1,401	2,765	1.97
Total	**10,101**	**18,354**	**1.82**

As can be seen, the factor increases as the weight of the steel decreases. A thorough review of these hours provides a level of confidence with respect to the accuracy of the factor.

Crew Rate Factors

Two sets of crew rates were developed – one set for US Gulf Coast and one set for Australia. In general, crew rates are inclusive of the following cost components:

- base wages;
- fringe benefits (including superannuation);
- payroll taxes and insurance;
- indirect craft;
- site office;
- small tools and consumables;
- construction equipment;
- safety;
- balance of construction indirects; and
- contractor’s overhead & profit.

A more detailed breakdown of what items are included in each of the above components is included in Appendix B.

Costs for Australian crews were converted to US Dollars using an exchange rate of 1USD = 1.23 AUD. Crews were grouped by discipline and multiplied against the crew hours contained in the detailed estimate described above. The resultant comparison yielded the Crew Rate Factors included in Table 4-2.

An overall weighted Crew Rate Factor was calculated to be approximately 1.71, which is higher than anticipated.

A more detailed comparison of the crew rates revealed that allowances for both travel and meals were included in the Australian crew rates, as well as a remote living allowance (see Appendix A). A sensitivity study was performed to remove the travel and meal allowances. This sensitivity study indicates that, without the allowances, the revised Crew Rate Factor is approximately 1.5, which is still slightly higher than anticipated, but within an acceptable range.

The final Crew Rate Factors reflect inclusion of the travel and meal allowances since it is anticipated that they will be required.

Table 4-2
Australia Conversion Factors

	Labour Productivity Factor	Crew Rate Factor	Material Cost Factor	Currency Exchange Rate AUD / USD
Civil	1.46	1.69	0.84	1.23
Electrical Bulks	1.31	1.67	1.38	1.23
Electrical Equipment	1.20	1.65	1.08	1.23
Insulation	0.78	1.96	1.20	1.23
Instrumentation & Controls	1.19	1.80	0.91	1.23
Mechanical Equipment	1.20	1.76	1.08	1.23
Piping	1.38	1.79	1.07	1.23
Concrete	0.94	1.54	1.82	1.23
Structural Steel	1.82	1.51	1.51	1.23

Material Cost Factors

Material Cost Factors were developed using the following process:

Similar to labour productivity, a detailed estimate for a non-specific power project was estimated using two separate approaches – one based on US Gulf Coast material pricing and one based on Australian material pricing. Care was taken to ensure that, for both US and Australia, material pricing accurately reflected the scope of each estimate line item. Australian costs were converted to US dollars using an exchange rate of 1USD = 1.23 AUD. Both estimates were sorted and summarised by discipline. The resultant comparison yielded the attached Material Cost Factors.

Calculated factors are generally within an anticipated range. One exception is concrete, which represents a weighted average of concrete, reinforcing steel and formwork. The calculated Material Cost Factor for concrete is 1.82. The primary driver for this factor is the Australia in-country cost for reinforcing steel which is relatively high due to limited in-country suppliers.

The Material Cost Factor for electrical bulk materials is slightly higher than anticipated. The primary driver for the elevated factor is higher costs for cable and conduit, due to limited Australia in-country suppliers.

The Material Cost Factors for both Electrical and Mechanical equipment were developed by applying a factor for overseas freight to the US pricing. It is important to note that the US pricing includes costs for inland freight.

Additionally, in the case of the Material Cost Factor for Mechanical Equipment, certain major equipment items were excluded from the calculation since they are frequently imported. Examples are:

- gasifiers;
- Heat Recovery Steam Generators (HRSGs);
- Combustion Turbine Generators (CTGs); and
- Steam Turbine Generators (STGs).

4.4 TOTAL CAPITAL REQUIRED CALCULATIONS

After total plant cost was developed for all of the technologies, the total capital required was calculated for cost of electricity calculation purposes. The total capital requirement (TCR) includes all capital necessary to complete the entire project. It consists of the following costs:

- total plant investment at the in-service date, including an allowance for funds used during construction (AFUDC), sometimes called "interest during construction"; and
- owner costs, such as:
  - prepaid royalties
  - preproduction (or startup) costs
  - inventory capital (fuel storage, consumables, etc.)
  - initial cost for catalyst and chemicals
  - land

The owner costs included in this study were preproduction costs and inventory capital. Land costs and prepaid royalties were not included in TCR. However, the levelised cost of electricity tabulations in Section 10 of this report include a percentage allowance for other owner's cost items that are typically required for an actual project.

Preproduction Costs

Preproduction costs cover operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel and other materials during startup. For EPRI purposes, preproduction costs are estimated as follows:

- one month fixed operating costs (operating and maintenance labour, administrative and support labour, and maintenance materials). In some cases this could be as high as two years of fixed operating costs due to new staff being hired two years before commissioning the plant;
- one to three months of variable operating costs (consumables) at full capacity, excluding fuel. These variable operating costs include chemicals, water, and other consumables plus waste disposal charges;

- twenty-five percent of full capacity fuel cost for one month. This charge covers inefficient operation during the startup period;
- two percent of TPC This charge covers expected changes and modifications to equipment that will be needed to bring the unit up to full capacity; and
- no credit for by-products during startup.

Inventory Capital

The value of inventories of fuels, consumables, and by-products is capitalised and included in the inventory capital account. The typical practice for fuel and consumables inventory is shown in Table 4-3. These assumptions are based on delivery of coal by rail and will change depending on current economic conditions and transportation bottlenecks. For the mine-mouth coal plants included in this study, only 5 days of on-site coal storage is required.

An allowance for spare parts of 0.5% of the total plant cost is also included.

Table 4-3
Fuel and Consumables Inventory

Type of Unit	Nominal Capacity Factor (%)	Fuel and Consumable Inventory Days at 100% Capacity
Baseload	85	60 (5 days if mine-mouth plant)
Intermediate	30-50	15
Peaking	10	5

Note: No provision is made for natural gas storage.

5
COST OF ELECTRICITY METHODOLOGY

5.1 Introduction

This section introduces the revenue requirement method, which has traditionally been used in the electric utility industry for the economic comparison of alternatives. In a rate-of-return regulatory environment, electric utilities are allowed to recover from their customers all costs associated with building and operating a facility, which are called *revenue requirements*. These costs include the annual costs of operating a plant as well as capital additions, which are in addition to the initial costs of total plant investment described in Section 4. The components of revenue requirements and how they are calculated are described, with emphasis placed on the calculation of capital-related, or fixed charge, revenue requirements—the portion of requirements related to the recovery of the booked cost. Booked costs are essentially the Total Capital Requirement (defined in Section 4.4) at the date the plant is placed in service and includes all capital necessary to complete the entire project.

This section also describes levelised cost of electricity calculation methodology used for the results presented in Section 10.

Table 5-1 shows the economic parameters used throughout this report for capital and cost of electricity calculations.

Table 5-1
Economic Parameters

		– – Current Dollars – –		– Constant Dollars –	
Type of Security	**% of Total**	**Cost (%)**	**Return (%)**	**Cost (%)**	**Return (%)**
Debt	70	9.0	6.3	6.3	4.4
Preferred Stock	N/A	N/A	0.0	N/A	0.0
Common Stock	30	16.0	4.8	13.2	4.0
Total Annual Return			11.1		8.4
Inflation Rate	2.5				
Federal and State Income Tax Rate	30				
Discount Rate					
After Tax			9.2		7.1
Before Tax			11.1		8.4

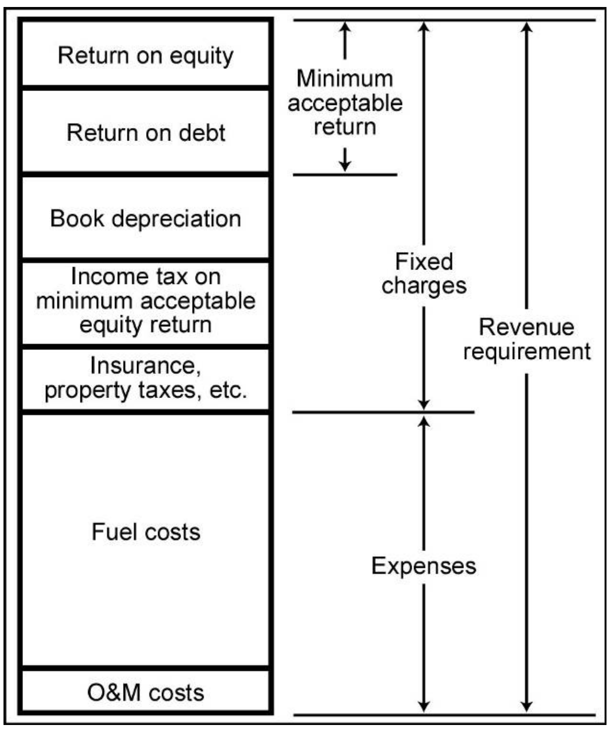
5.2 The Components of Revenue Requirements

An Overview

The revenue requirement standard in the United States is defined as follows:

> ... a regulated firm must be permitted to set rates that will both cover operating costs and provide an opportunity to earn a reasonable rate of return on the property devoted to the business. This return must enable the utility to maintain its financial credit as well as to attract whatever capital may be required in the future for replacements, expansion and technological innovation, and it must be comparable to that earned by other businesses with corresponding risks.

The components of revenue requirements can be divided into two parts: (1) the *carrying charges*, also called *fixed charges*, related to the booked cost at the time the plant enters service as well as capital additions over the life of the plant and (2) the operating expenses, which include fuel and nonfuel operating and maintenance (O&M) costs.



Note that while the above figure has grouped all O&M costs as expenses, they should be considered in their fixed and variable components in any analysis.

Figure 5-1
Revenue Categories for the Revenue Requirement Method of Economic Comparison

Utility investments in generation, transmission, distribution, and general plant can last 30 years or longer; and the booked costs are recovered over a period of time that is an approximation of the expected useful life for the particular investment. This is called the book life. Thus the booked costs for utility plants are recovered over roughly the period of time the investment is used in providing services to a utility's customers. The recovery of the booked costs is through an annual depreciation charge, which is a rough estimate of the extent to which an investment is used up, or obsolesces, each year of its useful life. The annual fixed charges include annual depreciation.

As discussed in Section 4, construction expenditures are financed and accumulate AFUDC. The sale of bonds and debentures as debt financing and the sale of common and preferred stock as equity financing are the primary means of financing utility investments.

Expenses are treated differently from the booked costs. They are recovered on an as-you-go basis, directly through revenues collected from customers.

The Nature of Fixed Charges

Fixed charges are an obligation incurred when a utility plant is placed in service, and they remain an obligation until the plant is fully depreciated. The fixed charges must be collected from customers regardless of how much or how little the facility is used or how the market value of the facility changes.

The difference between the new book value (unamortised portion of the investment) and the current market value of the plant is called a sunk cost. The important characteristic of sunk costs is that they cannot be affected by management decisions. They are obligations that must be met irrespective of management decisions other than bankruptcy. Thus, the retirement of a utility plant, for example, will not affect the obligation of the utility to pay the fixed charges. Future capital additions and expenses to operate the plant are determined by management decisions. These costs are referred to as *increment costs.*

The fixed charges themselves can, however, change. Changes in the cost of money, income tax rates, property tax rates, property assessment, or insurance rates would result in changes in fixed charges. For example, if changes in financial markets lead to lower interest rates and return on equity, the fixed charges would decline.

The Components of Fixed Charges

Annual fixed charges include the following components:

- book depreciation;
- return on equity;
- interest on debt;
- income taxes; and
- property taxes, insurance, and other taxes.

Depreciation

There are two types of depreciation. The first is *book depreciation*, which is a measure of the extent to which a utility plant is used up or becomes obsolete. Book depreciation is used in setting rates and is charged directly to customers. The second is *tax depreciation*, which is used for computing income taxes and affects the fixed charges indirectly through income taxes.

While there are a number of ways of determining book depreciation and collecting the charges from customers, the electric utility industry uses the straight-line method. The annual depreciation is the booked cost divided by the book life of the plant. The book life for fossil, nuclear, and solar plants in this study is 30 years, and the book life for wind plants is 20 years, as shown in Table 5-2. Experience suggests that scrap value of a coal plant covers around 10% of decommissioning and site reclamation. This figure is significantly higher for other technologies such as wind and some gas plant. For this study, it is assumed that the net salvage value is zero: the salvage value of a utility plant just equals the cost of reclaiming the site. Thus annual depreciation is 3.33% of initial investment for fossil and nuclear plants and 5% for renewable plants.

Table 5-2
Book Lives and Book Depreciation for Utility Plant

Plant Type	Book Life (Years)	Annual Depreciation (%)
Fossil /Nuclear/Solar Plants	30	3.33
Wind Plants	20	5.00

In regulated utility economics, depreciation charges would be used to purchase the debt and equity initially used to finance construction of a project. Within the context of a utility company facing a need to expand utility plant, depreciation represents one of the sources of funds for investment.

Tax depreciation differs from book depreciation in two respects. First, the federal government can allow for the recovery of investment for tax purposes over a period shorter than the book life of the utility plant. Second, the schedules for tax depreciation may allow for a larger portion of the recovery in the earlier years than is allowed with book depreciation.

Straight-line tax life depreciation was assumed for this Australian study. The tax life for fossil fuel, nuclear, and solar plants was assumed to be 30 years, and for a wind plant 20 years. These tax lives are consistent with the depreciation guidelines from the Australian Taxation Office (Taxation Ruling TR 2009/4). Details of this Taxation Ruling can be found at:

http://law.ato.gov.au/atolaw/view.htm?docid=TXR/TR20094/NAT/ATO/00001

Return on Equity

Equity financing is selling ownership in the utility by issuing preferred or common stock. Equity holders earn a return on their investments in a utility plant. The return is set by the public service commission and is supposed to be (1) sufficient for a utility to maintain its financial credit, (2) capable of attracting whatever capital may be required in the future, and (3) comparable to the rate earned by other businesses facing similar risks. The return is earned only on the portion of the unamortised investment—that is, the portion that has not been depreciated.

Interest on Debt

Money from debt financing is acquired by mortgaging a portion of the physical assets of the company through *mortgage bonds* or by issuing an IOU without providing physical assets as collateral through *debentures*. Both mortgage bonds and debentures carry an obligation to pay a stated return. These interest payments take precedence over returns to equity holders. As with return on equity, interest is earned only on the unamortised investment. The key characteristics of equity and debt are summarised in Table 5-3.

Table 5-3
Key Characteristics of Utility Securities

Offering	Type	Life	Obligation to Pay Return	Relative Level of Return	Vote at Annual Meeting	Liquidation Priority
First mortgage bond	Mortgage on physical assets	30-35 years	First (fixed)	Lowest	No	First
Debenture	Unsecured obligation	10-50 years	Second (fixed)	Second lowest	No	Second
Preferred stock	Part owner of company	Usually perpetual	Third (usually fixed)	Second highest	Sometimes	Third
Common stock	Part owner of company	Perpetual	Last (variable)	Highest	Yes	Last

Income Taxes

Income taxes are the product of the income tax rate and taxable income. The tax rate represents a composite of the federal and, if applicable, state income tax rates. The income tax rate used for this study is the 30% company tax rate that applies in Australia.

Because book and tax depreciation rates typically differ over the book life of a utility plant, there can be a difference between income taxes actually paid and those that *would be paid* if book depreciation were used for computing income taxes. This difference is referred to as *deferred taxes*. Deferred taxes increase over the tax life and then decline to zero by the end of the book life. The effect of accelerated depreciation for tax purposes is to shift the tax burden to the later years of operation.

Traditionally there have been two ways of treating deferred taxes. Under the *flow-through* method, the tax deferrals are flowed through to customers when they occur—that is, the lower taxes are translated directly into lower electricity rates. Under the *normalisation* method, deferred taxes are accumulated in a reserve account. With this latter method, electric utilities collect revenues as though income taxes were based on book depreciation. In the early years of an asset’s life, revenues for taxes collected from customers exceed the taxes levied by the government. In the later years, deferred taxes in the reserve account decline as annual book depreciation exceeds annual tax depreciation. Since the purpose of the normalisation method is to create an additional source of internally generated funds for new investment, the flow-through method is no longer allowed in the United States by the Internal Revenue Service. Consequently the normalisation method is used for computing revenue requirements, as agreed upon by the Advisory Group.

Property Taxes and Insurance

Property taxes and insurance are calculated as the product of the insurance and tax rate and the total capital required.

Calculating Annual Capital Revenue Requirements

The annual capital, or fixed, charge is the sum of the book depreciation, return on equity, interest on debt, income taxes, and property taxes and insurance for a given year. To calculate the lifetime revenue requirement of a plant, the present value of these annual capital charges is calculated for each year and summed to determine the total present value. The present value is calculated based on the weighted average cost of capital (WACC) or discount rate, which is the product of the cost of debt (or interest rate) and the percentage of debt financing plus the product of the cost of equity and the percentage of equity financing. For example, in this study, the nominal before tax discount rate is calculated as:

(% debt) x (cost of debt) + (% equity) x (cost of equity) = discount rate
70% x 9%/year + 30% x 16%/year = 11.1%/year

The present value for each year is calculated using the equation:

$$P/F = 1/(1 + i)^n$$

where P is the present value, F is the annual capital cost for the given year, i is the discount rate, and n is the year of the capital cost minus the year to which the costs are being present valued. For example, if the year of the cost is 2030 and the cost is being present valued to 2010, then n = 20.

The present values for each year are then summed to calculate the total present value for the plant. Using this total present value and the discount rate, the annual capital payment required for the plant can be calculated using the equation:

$$A/P = [i(1+i)^n] / [(1+i)^n - 1]$$

where A is the regular annual payment, P is the present value, i is the discount rate, and n is the number of years over which the payments are made.

The equivalent payment that must be made each year to cover the capital costs of the plant, or the annual revenue requirement, has now been calculated.

Calculating Cost of Electricity

Cost of electricity calculations combine the capital and O&M costs of a plant with the expected performance and operating characteristics of the plant into a cost per megawatt-hour basis. This procedure allows for comparison of technologies across a variety of sizes and operating conditions and allows for the comparison of the cost of electricity of a new plant with that of an existing plant. The cost of electricity typically consists of three components: the capital cost, the O&M cost, and the fuel costs. In some studies, such as this one, a fourth component, CO_2 transportation and sequestration, is also included for cases that include CO_2 capture. These different cost components, when presented independently, typically have different cost units. However, they must all have the same cost unit basis when combined to calculate the cost of electricity, typically $/MWh.

Annual Megawatt-Hours Produced

The amount of electricity produced by a plant in a given year is a key piece of information for calculating the levelised cost of electricity. The maximum number of megawatt-hours that a plant could produce in one year would occur if the plant operated at full load 24 hours a day for 365 days a year (8760 hours per year). In reality, a plant will be shut down at times during the year, either for maintenance or because the electricity is not needed and it would be uneconomic to operate the plant. The capacity factor is the ratio of the actual amount of electricity produced by the plant over the maximum amount that could be produced.

To calculate annual electricity production, the size of the plant is multiplied by the number of hours that it operates (the capacity factor of the plant multiplied by 8760 hours/year). For example, a 500 MW plant that operates with an 85% capacity factor produces 3,723,000 MWh per year. A plant that operates for more hours in a year ultimately has more hours of electricity generation over which to spread its annual revenue cost requirements.

Constant vs. Current Dollars

Cost of electricity is often presented on a levelised basis. Like the annual revenue requirement presented above, this is the consistent cost of electricity that would be necessary to be collected annually to achieve the same present value as the actual capital and operating expenses of the plant. Levelised cost of electricity can be presented in two ways: constant (or real) dollars and current (or nominal) dollars. In a constant dollar analysis, the effects of inflation are not taken into account when looking at future costs, which in current dollar analysis, the effects of inflation are taken into account. While both methods are completely valid, it is important to know which method has been used when comparing cost results. Current dollar analysis results are always higher than constant dollar results because they account for year-by-year inflation in the cost of fuel, O&M, and the cost of money. This report uses constant dollar analysis.

Capital Contribution to Cost of Electricity

Capital costs for power plants are often presented in dollars per kilowatt. Using the annual revenue requirement calculated, the cost in $/kW is multiplied by the overall size of the plant (sent-out basis) to determine the cost on a dollar basis. This revenue requirement is then divided by the number of megawatt-hours produced, as described above, to determine the capital cost on a $/MWh basis.

O&M Contribution to Cost of Electricity

Fixed O&M costs throughout this report have been presented on a dollar per kilowatt-year basis. Costs can be converted to a dollar basis by multiplying the cost on a dollar per kilowatt-year basis by the unit size. For a current-dollar analysis, the year-by-year costs are calculated using general inflation. In constant-dollar analysis, as was performed in this study, inflation is not taken into account; and, therefore, the fixed O&M costs are levelised over the life of the plant. The dollar-per-year fixed O&M costs are then divided by the annual output of the plant to calculate the fixed O&M cost of electricity.

Variable O&M is often already presented as a $/MWh costs and, therefore, do not need any conversions to find the cost of electricity contribution. As with fixed O&M, for current-dollar analysis, the year-by-year costs are calculated using general inflation while for constant-dollar analysis, the variable O&M cost remains the same throughout the life of the plant.

Fuel Contribution to Cost of Electricity

The annual cost of fuel is calculated by multiplying the fuel cost in dollars per gigajoule by the heat rate of the plant. Once again, for current-dollar analysis, the year-by-year costs are calculated using general inflation while in constant-dollar analysis, the cost remains the same throughout the life of the plant.

CO_2 Transportation and Sequestration Contribution to Cost of Electricity

Finally, for plants that include CO_2 capture, CO_2 transportation and sequestration (T&S) costs were calculated by multiplying the amount of CO_2 captured on a kilogram per hour basis by an assumed cost in dollars per kilogram for T&S and dividing by the unit size of the plant to determine the $/MWh cost. The base cost of CO_2 T&S assumed in this study is AUD20/tonne.

6
TECHNOLOGY DESCRIPTIONS, STATUS AND GRUBB CURVES

For each technology area, this section presents an overview of the technologies including:

- a brief description of the technologies;
- survey of the technology development status;
- major technical issues and future development direction/trends;
- anticipated improvements by 2030;
- development and commercialisation timeline; and
- relevant business issues.

Cost and performance estimates provided in this section are idealised for representative generating units and provide representative efficiencies (heat rates) and costs for the particular technology areas. Estimates are not intended to apply to specific energy companies at specific sites, since site-specific and company-specific conditions can vary substantially.

More specific performance and costs estimates are developed in other sections of this report. The basis for the Australia-specific costs and performance for the above technology areas is described under the Section 3–Design Basis. This design basis has been established by EPRI in consultation with the Australian industry advisory group.

The descriptions, performance and cost data presented in this section draw upon public information and on the US Technical Assessment Guide (TAG®) developed by EPRI to provide an overview of cost and performance figures of the selected technology categories. Cost estimating involves both analysis and judgments. It relies heavily on current and past data and on project execution plans, which are in turn based on a set of assumptions. The successful outcome of any project–project completion within the cost estimate–depends on adherence to an execution plan and its assumptions without deviation.

The estimates also depend to a great extent on the maturity levels of the particular technologies. These maturity levels can vary between “research” (laboratory or pilot) level to “mature” level. These different levels can introduce different amounts of uncertainty into the estimates.

As a technology moves along the continuum of development the accuracy of performance and cost estimates tends to improve. At the R&D level, technologies face a high degree of both technical and estimation uncertainty. The bandwidth of the uncertainty depends on the number of new and novel parts in a technology and the degree of scale-up required to reach commercial application. The status of technology, based on the maturity of its components is critical in meeting the cost and performance estimates when scaling up from pilot to demonstration to commercial. Figure 6-1 illustrates, in general, the sequence of steps and the potential impact on cost.

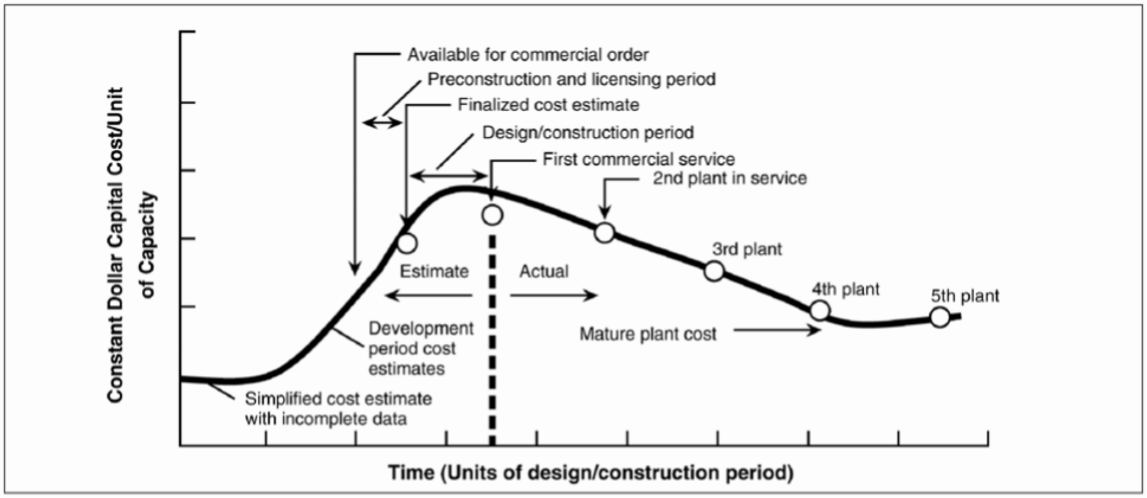


Figure 6-1
General Capital Cost Learning Curve

As the power generation technologies are quite capital intensive, there are several technical, economic and financial factors that influence the variations in capital cost from one technology to another and from one project to another. Higher uncertainty with respect to performance of a key component in a new technology will result in a more significant impact on the cost estimate. Many factors contribute to the overall uncertainty of an estimate. They can generally be divided into four generic types:

- *Technical* - Uncertainty in physical phenomena, small sample statistics, or scaling uncertainty
- *Estimation* - Uncertainty resulting from estimates based on less-than-complete designs
- *Economic* - Uncertainty resulting from unanticipated changes in cost of available materials, labour, or capital
- *Other* - Uncertainties in permitting, licensing and other regulatory actions, labour disruption, or weather conditions

Successful R&D efforts resolve many technical uncertainties, but others persist until initial demonstration. Examples of technical uncertainties that can remain include:

- unanticipated interactions between system elements that previously were independently tested;
- incompatibilities between materials or incompatibilities between utility operation and the industries from which the new technology was adapted; and
- some unanticipated operating problem that becomes significant.

Demonstration and commercialisation reduce technical and estimation uncertainties, but economic and other uncertainties always remain. The level of these uncertainties depends largely on the magnitude of capital investment, length of time for field construction, and number of regulatory agencies involved in the project.

All of the technology areas considered for Australia are between the demonstration and mature technology phases.

6.1 Fossil Technologies

Both coal- and natural gas-fired power plants were investigated in this study. Coal-fired technologies include integrated gasification combined cycle (IGCC) and pulverised coal (PC) plants burning both brown and black coal, both with and without CO_2 capture. Oxy-combustion with a black coal PC plant with CO_2 capture is also included for coal plants. Natural gas-fired plants include natural gas combined cycle plants both with and without CO_2 capture and open cycle gas turbines.

For the fossil fuel-based technologies, an advanced learning curve (Grubb curve) is shown in Figure 6-2.

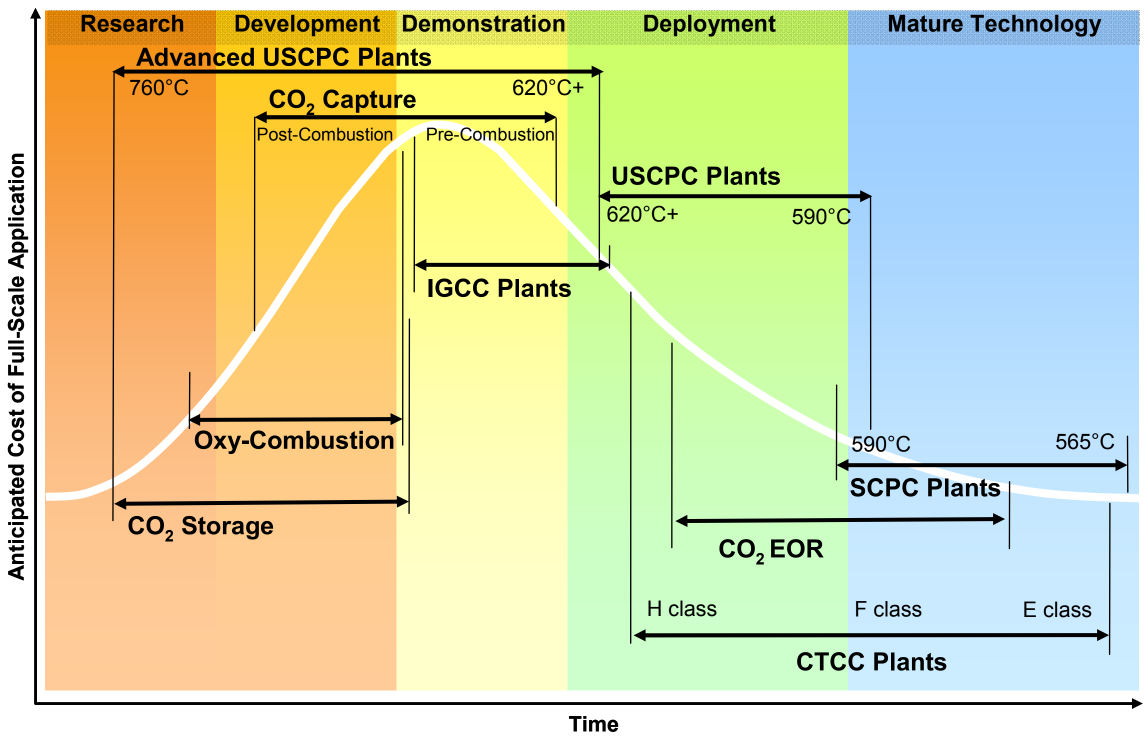


Figure 6-2
Grubb Curve for Fossil Fuel Based Technologies

Pulverised Coal (PC)

Brief Description of the Technology

Pulverised coal power generation starts by crushing coal into a fine powder that is fed into a boiler where it is burned to create heat. The heat generates steam that is expanded through a steam turbine to produce electricity. The pulverised coal type of boiler dominates the electric power industry, producing about 50% of the world's electric supply.

The heat of the steam determines the relative efficiency of the power plant. Subcritical units produce steam at temperatures around 538°C (1,000°F) and pressures around 16.5 MPa (2,400 psig). Present day supercritical pressure units generate steam at pressures of at least 24.8 MPa (3,600 psig) with steam temperatures of 565-593°C (1,050-1,100°F).

Subcritical units are more suitable for power plants intended to meet fluctuating electricity demand at different times of the day. Supercritical units work best when operated at full-load, around-the-clock to deliver “baseload” electricity. The initial cost of subcritical units is one to two percent lower than that of supercritical units. Supercritical units operate at about two percentage points higher efficiency than subcritical units (i.e., increasing from 36.5 to 38.5% efficiency on a higher heating value basis for plants with wet cooling towers).

For both the subcritical and supercritical plant configurations, the major components of a pulverised coal-fired plant include coal-handling equipment, steam generator island, turbine generator island including all balance of plant (BOP) equipment, bottom and fly ash handling systems as well as emission control equipment. Particulate emissions are typically controlled using electrostatic precipitator or fabric filter systems.

The steam generator island includes coal pulverisers, burners, waterwall-lined furnace, superheater, reheater, and economiser heat transfer surface, soot blowers, Ljungstrom air heater(s) and forced-draft and induced-draft fans. The turbine-generator island includes the steam turbine, power generator plus the main, reheat, and extraction steam piping, feedwater heaters, boiler feedwater pumps, condensate pumps, and a system for condensing the low pressure steam exiting the steam turbine. For the conditions in Australia, a dry cooling system (i.e. an air cooled condenser) will be used in accordance with the design basis established for this study.

The water/steam loop starts at the condensate pumps. The water is pumped though low pressure feedwater heaters and moderately heated before entering the feedwater pumps. Here the pressure is increased and the feedwater is sent to the de-aerator for oxygen removal and then through the high pressure feedwater heaters. The pre-heated feedwater enters the economiser section of the steam generator, recovers heat from the combustion gases exiting the steam generator, and then the heated water passes to water-wall circuits enclosing the furnace. After passing through the water-wall circuits, steam then is further heated in the convective sections and is superheated before exiting the steam generator. The high pressure, high temperature steam is then expanded through the high pressure steam turbine section. The cooler exiting steam is then returned to the steam generator for reheating to elevated temperatures and then sent to the IP and LP steam turbine where it is expanded and exits at low temperature and vacuum pressure. The steam is then condensed in an air cooled condenser and the water collected and pumped forward to start the circuit again.

A schematic diagram of a pulverised coal supercritical generating unit is shown in Figure 6-3.

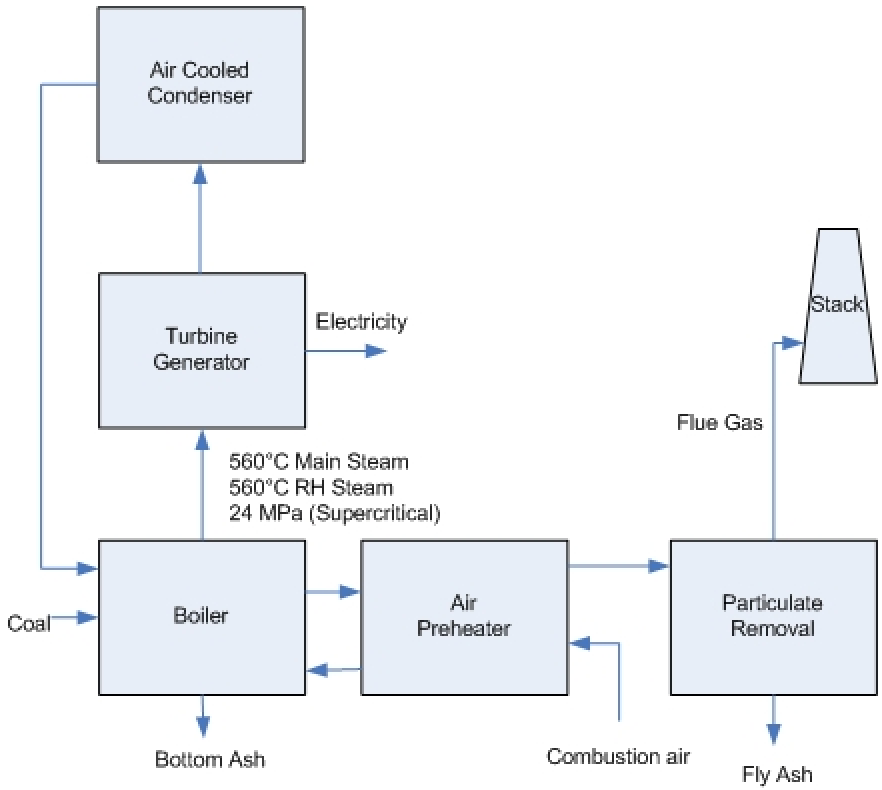


Figure 6-3
Simple Schematic of Pulverised Coal (Supercritical) Generating Unit

Concerns about greenhouse gas emissions and global warming have gained significant attention. It is likely that regulations will require new plants to permanently capture and sequester at least 85% of their CO_2 emissions. The development of technologies for Carbon Capture and Sequestration (CCS) are currently under way and they may include various options, such as post-combustion CO_2 capture processes, pre-combustion processes, oxy-fuel combustion, etc. Unfortunately, these processes all consume considerable energy, significantly reducing the plant's sent-out output and efficiency.

One of the post-combustion carbon capture technologies considered in this report is an amine-based process. Absorption of CO_2 in chemical solvents such as amines is a technology with an excellent track record in many applications. The reaction between CO_2 and amines can offer a cost-effective solution for directly obtaining high purity CO_2. When this technology is used for post-combustion CO_2 removal at a plant, the flue gas is cooled and treated to reduce its levels of SO_2 and particulates. The SO_2 will be removed using a caustic scrubber since low SO_2 levels are required to avoid poisoning of the amines. Subsequently, boosted by a fan to overcome pressure losses in the system, the flue gas is routed through an absorber. In the absorber the flue gas interacts with a lean amine solution, monoethanolamine (MEA), which flows countercurrent with the gas. This interaction absorbs the CO_2. The cleaned flue gas continues to the plant stack. The amine solution, which is now rich in CO_2, is pumped into a stripper in order to separate the amine and the gas. Steam provides the energy needed to desorb the CO_2 from the solution. The CO_2 –rich solution at the top of the stripper is condensed and the CO_2 phase is removed and sent off for drying and compression.

A coal-fired plant that employs this technology, therefore, would have additional components, such as absorbers, strippers, pumps, heat exchangers, storage tanks, condenser, drying equipment and compressors. This equipment requires a fairly large area.

Another pulverised coal technology considered in this report is the oxy-fired combustion technique for CO_2 capture. In this technology the fuel is combusted in a blend of oxygen and recycled flue gas rather than air.

Firing coal with only high-purity oxygen would result in a flame temperature too high for existing furnace materials, so the oxygen is diluted by mixing it with a slipstream of recycled flue gas. The flue gas recycle loop may include dewatering and de-sulphurisation processes. As a result, the flue gas downstream of the recycle slipstream take-off consists primarily of CO_2 and water vapour (with small amounts of nitrogen, oxygen, and criteria pollutants). After the water is condensed, the CO_2-rich gas is compressed and purified to remove contaminants and prepare the CO_2 for transportation and storage. The schematic diagram for the oxy-combustion process is shown in Figure 6-4.

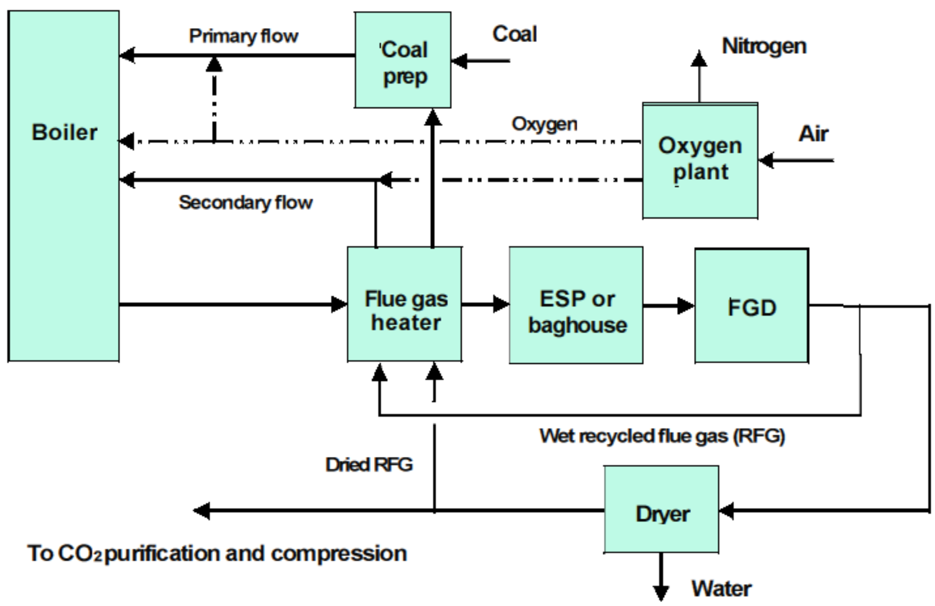


Figure 6-4
Simple Schematic of Oxy-Combustion Process

Plants that are designed for oxy-combustion employ large quantities of almost pure oxygen. Creating the oxygen stream is performed in an air separation unit (ASU). This is a large system that consumes a considerable amount of electricity. In an effort to reduce its load and penalty on power output, new, more energy-efficient oxygen separation technologies are in development. In addition, the oxy-combustion plant will have additional flue gas treatment modules, several heat exchangers to extract low grade heat, and fans and ducts for flue gas recirculation (FGR). Space must be provided for these, in addition to the CO_2 capture hardware.

For this evaluation, the particular PC technology options examined use two types of coal: Hunter Valley Black Coal and Latrobe Valley Brown Coal. As indicated in the Design Basis section of this report, Brown Coal has a very high moisture content and requires drying before it can be used in either the conventional or the oxy-fired PC plant. Owing to the high amount of water to be removed, the drying process requires a lot of energy and, therefore, energy efficiency in this process is very important. For the PC cases, the moisture content of the Brown Coal will be reduced from 60% to 32% using heat from low pressure steam in a fluidised bed drying process described in more detail in the “Anticipated Improvements” sub-section below. Black Coal does not require drying.

Technology Development Status

Pulverised coal combustion has been the prevailing mode of firing coal in power plants worldwide for more than 75 years and provides the backbone of electricity generating systems in many countries.

There are approximately 300 supercritical units in the world. During the 10-year period from the mid-1990s to the mid-2000s, Japan and South Korea dominated the new plant market and China began to show signs of rapid growth.

Since the early 1980s, there have been significant improvements in materials for boilers and steam turbines and a much better understanding of cycle water chemistry. These improvements have resulted in an increased number of new plants employing supercritical steam cycles around the world. In the international markets, where fuel cost is a higher fraction of the total Cost of Electricity (COE), the higher efficiency cycles of supercritical plants offer advantages that can result in favourable COE comparisons and lower emissions compared to subcritical plants.

The selection of supercritical versus a subcritical cycle is still dependent on many other site-specific factors, including fuel cost, emission control requirements, capital cost, load factor, local labour rates, and expected reliability and availability. With extensive favourable experience in Europe, Japan, and Korea with supercritical steam cycles during the last decade, their superior environmental performance, and the relatively small cost difference between supercritical and subcritical plants, it has become more difficult to justify new subcritical steam plants other than where unit MW ratings and commercial conditions prevent the use of large supercritical units.

Supercritical units with nominal 27.5 MPa/593°C/593°C steam conditions have an efficiency that is about two percentage points better than conventional subcritical units with steam conditions of 16.5 MPa/538°C/538°C (i.e., increasing from 36.5 to 38.5% efficiency on a higher heating value basis for plants with wet cooling towers). Their improved efficiency translates to about 5% lower emissions of SO_2, NO_X, mercury, and CO_2 per MWh allowing for somewhat smaller and less costly emissions control equipment. In addition, their improved efficiency results in lower costs for fuel and other consumable items. The savings in operating costs need to be contrasted against the slightly higher capital cost of the boiler and steam turbine. Advances incorporated in units have resulted in supercritical units with availability and reliability equivalent to subcritical units.

Potential reductions in greenhouse gas emissions, particularly CO_2, must also be considered. For coal-based technologies, one available option to reduce CO_2 emissions per unit of power produced is to increase the unit’s efficiency, so that less coal is burned per MWh generated. These increases could be accomplished by retiring an older subcritical unit and replacing it with a more efficient supercritical unit. For example, an advanced supercritical plant with steam conditions of 31.0 to 34.5 MPa and main steam temperatures of 700°C to 760°C are expected to achieve efficiencies of 46–48% (higher heating value, or HHV), and would emit approximately

18–22% less CO_2 per MWh generated than an equivalent-sized subcritical pulverised coal unit. It is estimated that if the next 10 GW of coal fired plants were to be built using more efficient supercritical technology, CO_2 emissions would be about 100 million tons less during the lifetime of those plants. This reduction would be possible even without installing a system to remove the CO_2 from the exhaust gases. In the event that CO_2 capture is required, an advanced supercritical plant would have 18–22% less flue gas to be treated and CO_2 to be captured per MWh compared to an equivalent-sized subcritical pulverised coal plant.

Significant CO_2 reductions can be achieved through efficiency gains, but further reductions in CO_2 emissions will require CCS. Adding capture processes to new plants and retrofits currently impose large sent-out power reductions and efficiency (operating costs) penalties because part of the plant's power output must be used for CO_2 capture. Extensive RD&D is under way to improve both post-combustion capture and oxy-combustion processes.

The oxy-combustion process is applicable to virtually all fossil-fuelled boiler types and is a candidate for retrofits and new power plants. Applications for large commercial size power plants considered in this report, however, still require further development.

Oxy-combustion boilers have been studied in laboratory-scale and small pilot units of up to 3 MW_t[1]. Two larger pilot units at 30 MW_t are operating, one by Babcock & Wilcox (B&W), and one by the Swedish power company Vattenfall. An Australian-Japanese project team is pursuing a 30-MWe repowering project at the CS Energy's Callide A station in Queensland. These larger tests will allow verification of the technology and provide engineering data useful for designing pre-commercial systems of about 300 MW.

Major technical Issues and Future Development Directions/Trends

Major technical issues with advancing pulverised coal technology are mostly associated with new alloys as well as operating flexibility. As the technology further progresses, new materials will be required for higher temperature and pressures. This will necessitate development of high chrome and nickel alloy pressure parts that can operate at temperatures in excess of 700ºC. This is no small challenge in terms of manufacturing steam turbine rotating components. Future units will most likely require a second reheat added to the steam cycle, and the unit will require sliding pressure design. Experience may be adopted from Japanese and European technology.

Figure 6-5 illustrates the effect of increasing the steam conditions on improved overall plant efficiency.

[1] MW_t refers to megawatts of thermal energy, as opposed to megawatts of electric power. A 3 MWt plant generally means that the energy input to the plant is 3 MW, whereas the sent out electrical energy may only be 1 MWe.

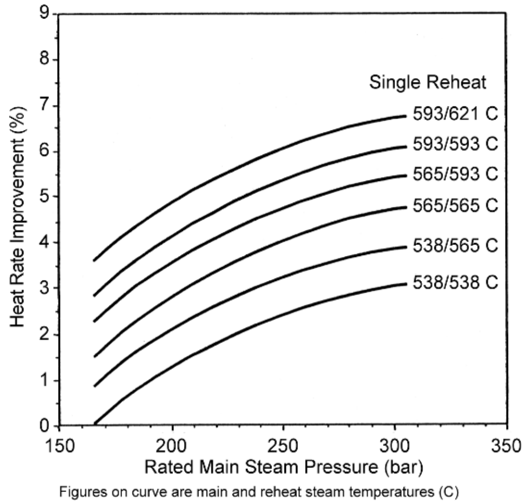


Figure 6-5
Improvement in Heat Rate with Increasing Steam Conditions

Opportunities exist for co-firing alternate fuels such as biomass materials for reducing the overall carbon footprint of the new advanced power plants. Advancements are expected in control system technology. Alternative cycles may also be a method of increasing flexibility and reducing operating costs. As always, research on methods of capital cost reduction will be warranted.

Anticipated Improvements by 2030

Supercritical Pulverised Coal with Post-Combustion Capture

E.On AG has announced its intention to build a commercial-scale SCPC with main steam temperature of 700ºC by 2016 and the US Dept of Energy is sponsoring a program to develop and test materials needed to achieve main steam conditions of 760ºC and 34.5 MPa in boilers and steam turbines. It is expected that those conditions will be available in commercial-scale plants by 2030. It is estimated that moving to 760ºC and 34.5 MPa will increase thermal efficiency by at least six percentage points compared to today's technology.

While an increase in thermal efficiency does not directly impact post-combustion capture processes, it does have an indirect beneficial impact. More efficient power plants produce less CO_2 per MWh produced and therefore a plant with a given size MW output that has higher thermal efficiency will need smaller CO_2 capture systems. This decreases the capital cost of CO_2 capture on a $/kW basis and decreases the auxiliary power load of the capture system.

In addition to improving the efficiency of the Rankine cycle by increasing steam temperature and pressure, it is expected that post-combustion CO_2 capture technology will improve dramatically by 2030. EPRI has conducted a recent survey of novel CO_2 capture technologies and has identified more than 70 organisations which are working on processes that could provide more efficient capture of CO_2 than today's MEA-based amine systems.[2] While it is impossible to predict which of those processes will eventually be deployed in commercial applications, it is reasonable to assume that some will. EPRI believes that the best of these applications could reduce the amount of steam needed for regeneration by 50% compared to today's commercial technology. Some of the advanced solvents may also produce CO_2 at a higher pressure which will reduce compressor load.

In addition to improved solvents, advancements in CO_2 compression technology are also expected by 2030. These include more efficient compressors as well as intercooling designs which capture the heat of compression and either return it to the steam cycle or use it for solvent regeneration. Overall, the anticipated advancements in solvents and compression systems could significantly decrease the overall loss in sent-out power production attributed to post-combustion capture.

For brown coal applications it is anticipated that new coal drying technologies which use low level heat from either low pressure steam or the CO_2 compressor intercoolers will dry brown coal to approximately 12 wt% moisture before it enters the boiler, as opposed to the 32 wt% that is assumed for the 2015 technology. An example of an advanced method of drying that can be employed for Brown Coal is that developed by RWE, called the WTA technology, which is essentially a fluidised bed drying process with internal waste heat utilisation. WTA stands for Wirbelschicht-Trocknung mit interner Abwärmenutzung. This technology is based on the principle of a stationary fluidised bed with low expansion. The energy required for drying is supplied via heat exchangers that are integrated in the fluidised bed dryer and heated with low pressure steam. At constant pressure, equilibrium is reached, and, depending on steam temperature, the moisture content can be adjusted and maintained constant at the desired value.

Figure 6-6 shows a schematic view of the dryer design. Coal is fed via a star feeder into the slightly pressurised dryer. A system which is installed in the dryer's upper section distributes the raw coal onto the fluidised bed surface. The actual fluidised bed with the integrated heat exchangers is located in the central section of the dryer. Heating is by low pressure steam, or alternatively (depending on the process variant), by recompressed vapour with pressure ranging between approximately 300 and 400 kPa (40-60 psig). Fluidisation is achieved by a system that is adjusted to the specific conditions of coal drying. Below the fluidising bottom, the dried coal is discharged from the fixed bed via star feeders.

[2] Program on Technology Innovation: Post-Combustion CO_2 Capture Technology Development. EPRI, Palo Alto, CA: 2008. 1016995.

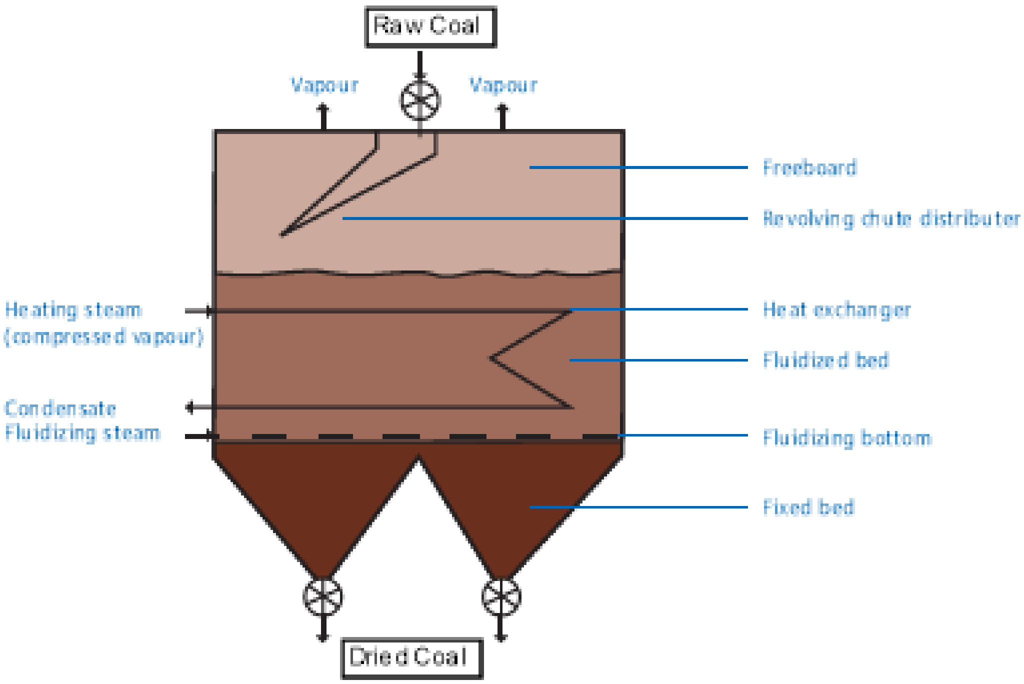


Figure 6-6
Schematic Design of Dryer

The advantages of this coal drying technology can be summarised as follows.

- Safe plant operation since drying takes place in an inert atmosphere both during normal operation and during start-up and shutdown, avoiding explosive coal mixtures.
- High drying capacity per drier unit.
- Compact design with integration of raw coal fine milling and, where required, secondary dried coal milling.
- As a result of the energetic vapour utilisation large amounts of steam and dust emissions are avoided and the discharged vapour condensate is a water source that can be used in industrial processes.
- Flexible adjustment of the plant equipment to the requirements of the individual drying task.
- High energy efficiency due to drying at low temperature levels and energetic utilisation of the evaporated coal water (through vapour condensation or mechanical vapour compression).

While it is estimated that such a system will add approximately 120AUD/kW in incremental cost, having drier coal will significantly decrease the amount of coal needed to produce a given amount of power, which will yield savings in the AUD/kW cost of the boiler and CO_2 capture systems as well as provide a significant thermal efficiency boost (at least 3 percentage points). A prototype of such a drying system is currently being tested at the Hazelwood power station in Victoria. An additional benefit of these drying processes is they may facilitate the capture of the water driven off the coal, which would make the plant a net producer of water.

At the time that this study was conducted, the ability to dry Brown Coal from 60% to 12wt% was not considered to be proven sufficiently to justify its inclusion in the 2015 technology design. Fluidised bed drying technology is sufficiently tested to justify using it to dry the Brown Coal to

30wt% moisture, and therefore that was the design assumed for the 2015 technology. The moisture that is left in the coal enters the boiler and vaporises while absorbing some of the heat of combustion of the coal. This reduces the efficiency of the process in the 2015 vintage design.

While the nickel-based alloys which will be required to achieve the 760ºC steam conditions will increase the cost of the boiler and steam turbine equipment, the impact of higher thermal efficiency will decrease the size of the auxiliary equipment including the post-combustion capture system, and there will be some additional capital cost savings in the post-combustion capture simply due to moving down the learning curve as more systems are deployed. Professor Edward Rubin of Carnegie Mellon University has conducted an analysis of learning curve histories for fossil fuel power plant systems.[3] Using the cost reduction factors he has estimated for flue gas desulphurisation as a guide for the cost reduction factors that can be expected for CCS systems in the future, we have estimated that those CCS systems will cost approximately 15% less than what we expect post-combustion capture systems to cost today even if there were no other technological improvements.

The cumulative impacts of the estimated performance and cost improvements are summarised in the table below. The improvement in thermal efficiency is expressed in terms of percentage points increase. In other words, an increase from 38.0 to 48.0% is an increase of ten percentage points.

Table 6-1
Anticipated PC+Post-Combustion Capture Technology Performance and Costs Improvements by 2030

	Black Coal		Brown Coal	
	Current Technology	**2030 Technology**	**Current Technology**	**2030 Technology**
Capital Cost (relative to current technology)	1.00	0.81	1.00	0.83
Thermal Efficiency	Base	+10.1 Pts	Base	+12.5 Pts

Oxy-Combustion PCs

PCs using oxy-combustion techniques for CO_2 in 2030 will benefit from the same thermal efficiency gains from increasing Rankine cycle steam conditions and improving CO_2 compression systems that SCPCs with post-combustion capture will enjoy. Production of oxygen with conventional cryogenic air separation plants adds a considerable parasitic load to the process. A potentially more efficient alternative being explored is to use new innovations in ceramic membranes to separate oxygen from the air at elevated temperatures. Breakthroughs in oxygen production technology are expected by 2030, although currently there is less activity in that area than there is in post-combustion capture. EPRI believes it should be possible to decrease the auxiliary power load of an ASU by up to 33% in 2030 compared to today's state-of-the-art cryogenic systems. This will greatly decrease the auxiliary power load in an oxy-combustion power plant. Overall it is anticipated that the sent-out thermal efficiency of oxy-

[3] Rubin, Edward S., "Estimating Future Costs of Power Plants with CO_2 Capture", 5th Annual Conference on Carbon Capture and Sequestration, Alexandria, VA, 2006.

combustion PCs could increase by at least eight percentage points in 2030 compared to today's technology.

The capital cost of oxy-combustion PCs could decrease by up to 20% due to both using less oxygen per MWh of electrical production thanks to a higher efficiency steam cycle and due to learning curve savings in the novel ASU and CO_2 polishing and compression technology. The estimated performance and cost improvements are summarised in the table below.

Table 6-2
Anticipated Oxy-Combustion Technology Performance and Costs Improvements by 2030

	Black Coal	
	Current Technology	**2030 Technology**
Capital Cost (relative to current technology)	1.00	0.80
Thermal Efficiency	Base	+8 Pts

Development and Commercialisation Timeline

Development of supercritical plants with improved performance, availability, and cycling capability is continuing. In the future years this trend will result in reduced capital cost. Resolution /finalisation of CO_2 regulation will have an impact on the plants that will be built in the near term and out to 2030, as the pulverised coal plant may see potential competition from IGCC. Concern over global warming may result in a return to construction of combined cycle gas turbine (CCGT) plants even though natural gas prices are high compared to coal.

A portion of the roadmap for advancing pulverised coal technology can be shown as follows:

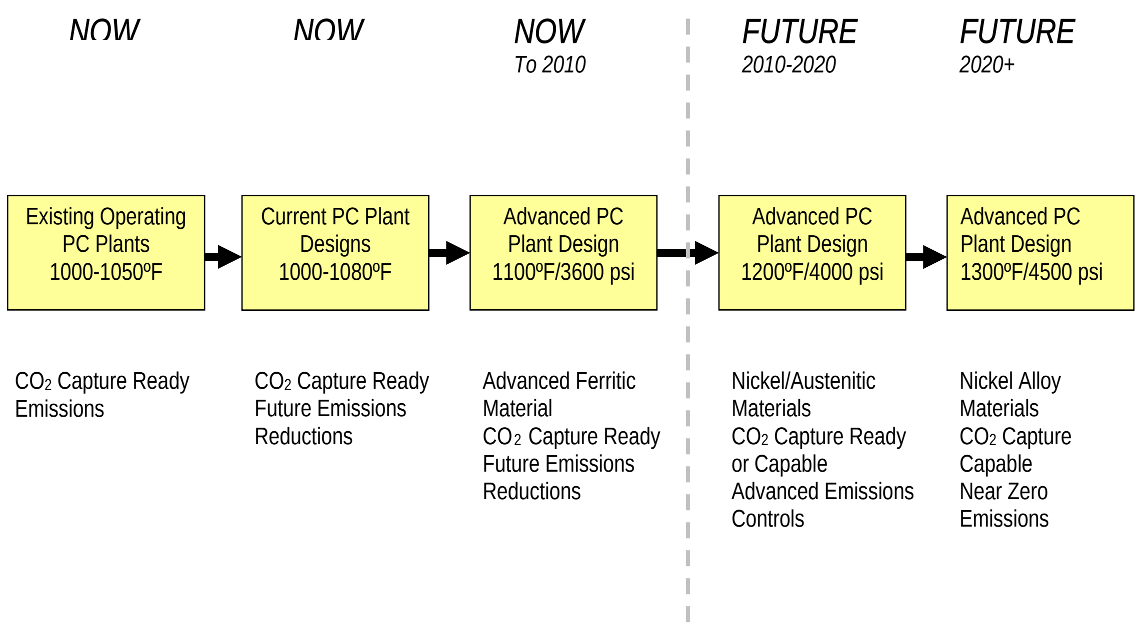


Figure 6-7
Roadmap for Advancing Pulverised Coal Technology

Relevant Business Issues

The future utilisation of the pulverised coal technology will be affected by the price differential, on a GJ basis, between coal and natural gas. As mentioned above, the pulverised coal technology will see competition from NGCC or IGCC. Furthermore, it is noted that economics and practicality are not as favourable for lower grade coals (coals with HHV less than 14 GJ/kg).

There will be a global market for purchasing equipment. Other business indicators will be the willingness of US, Japanese and European OEMs to continue research and development into efficiency improvements within the regulatory climate resulting from concerns over global warming.

Stable regulatory requirements are necessary for prudent investment in new coal-fired power plants to predict financial risk. In addition, these regulations should be periodically reviewed for cost-benefit justification. Coal fired power plants require investors and lenders to commit to financing projects with investment recovery times of up to 30 years. In addition, there are long lead times for permitting and construction before the plants begin production. For financing to be obtained at competitive rates over these timeframes the outlook for the marketing of the output and the operational constraints must be fairly stable. The public policy environment has much to do with the stability of both fuel and operating costs over the life of the plant and can affect the financing costs dramatically.

Changing environmental regulations affect the long-term viability of coal-fired power projects. While recognising the legitimate environmental risks associated with coal, the regulations and requirements for coal fired plants need to be well defined. Determining the required flue gas emission reduction technologies to be used and then allowing the plant to operate for enough time to recover the costs associated with installation and use of the technologies should be a commitment at the time the operating permit is issued.

Integrated Gasification Combined Cycle (IGCC)

Brief Description of the Technology

An Integrated Gasification Combined Cycle, or IGCC, is a technology that turns coal into gas - synthesis gas or syngas. The gasification plant then removes impurities from the raw syngas before it is combusted. This results in lower emissions of sulphur dioxide, particulates and mercury.

The plant is called "integrated" because heat recovery in the gasification unit is integrated with the plant's combined cycle. Additionally, the gas turbine compressor provides pressurised air used in the air separation unit that produces oxygen for the gasification process. The syngas produced is used as fuel in a gas turbine which produces electrical power. To improve the overall process efficiency, heat is recovered from both the gasification process and also the gas turbine exhaust in 'Waste Heat Boilers' producing steam. This steam is then used in steam turbines to produce additional electrical power.

A schematic diagram of the IGCC power plant is shown in Figure 6-8. It is the integration of the system components that brings the most important advantage of IGCC plants.

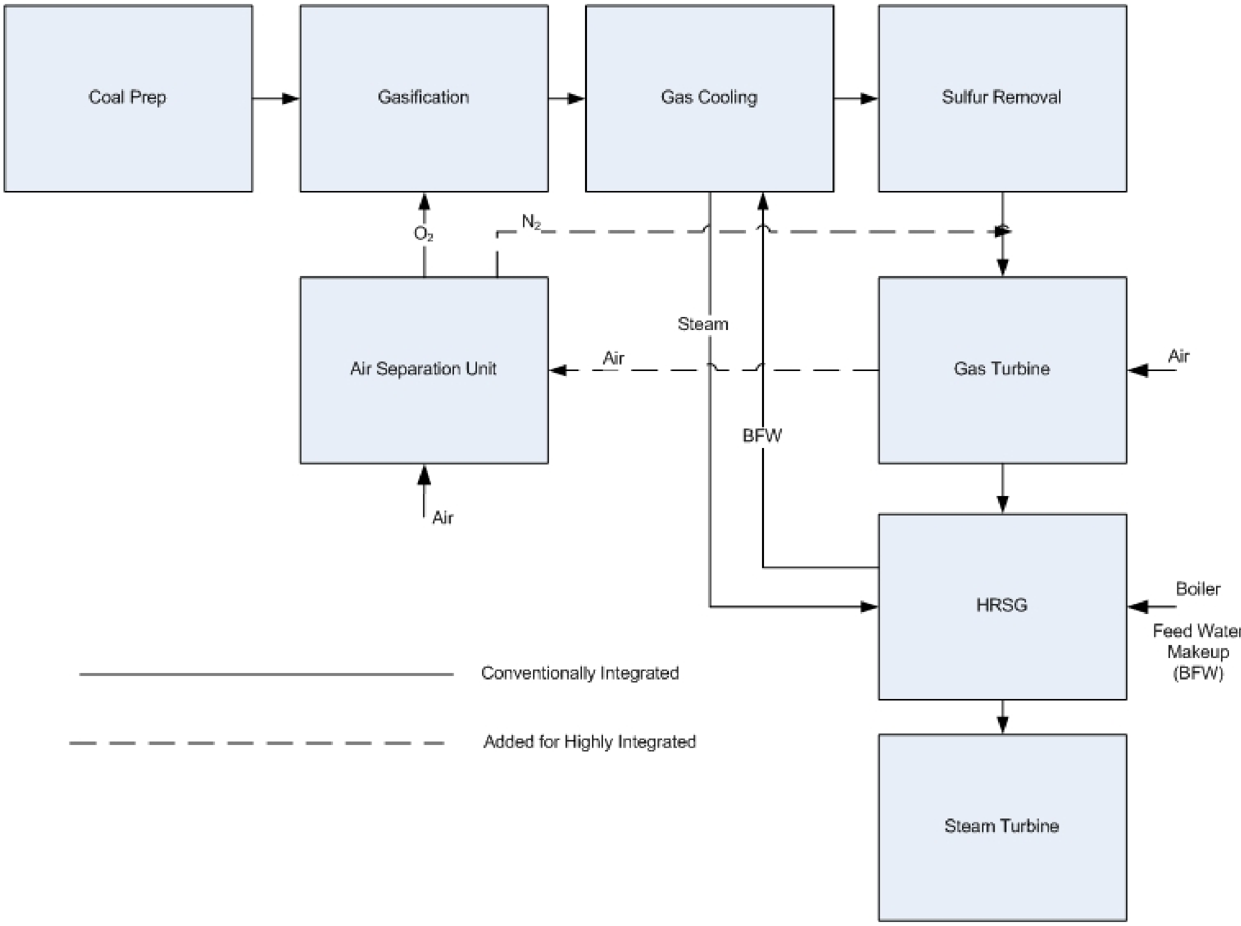


Figure 6-8
Schematic of an IGCC Power Plant

Gasification

Appropriately sized and prepared coal is fed into the gasifier along with oxygen that is produced in an on-site air separation unit. Oxygen and water as steam reacts with carbon to produce a fuel gas ("syngas") composed mainly of carbon monoxide (CO) and hydrogen (H_2). The combination of heat, pressure, and steam breaks down the feedstock and creates chemical reactions that produce the H_2 and CO. Feedstock minerals become an inert, glassy slag product used in road beds, landfill cover, and other applications.

A gasifier differs from a combustor in that the amount of air or oxygen available inside the gasifier is controlled to maintain a reducing atmosphere. This "partial oxidation" process provides the heat required for the gasification reactions. Rather than burning, most of the carbon containing feedstock is chemically broken apart to produce syngas. Syngas is primarily hydrogen, carbon monoxide, and other gaseous constituents, the composition of which can vary depending upon the conditions in the gasifier and the type of feedstock.

There are three types of gasification technologies: fixed bed; fluidised bed; and entrained flow.

In addition, gasifiers are either air-blown or oxygen-blown. Most of the commercially available entrained-flow gasifiers are oxygen-blown, though KBR and Southern Company are marketing its air-blown transport gasifier for use with lower rank coals, and Mitsubishi Heavy Industries is marketing an enriched air-blown entrained-flow gasifier.

The type of gasifier considered for this report is the Shell entrained-flow oxygen-blown gasifier with dry coal feed. The Shell gasification technology uses a compact, single-stage, upflow gasifier to achieve high gasification efficiency. The technology can handle a wide variety of coals from anthracite to lignite. Dry pulverized coal is mixed with oxygen and moderator steam in opposed burners located near the bottom of the reactor. Hot, raw gas and fly slag exit the top of the vessel while liquid slag flows down the water-cooled membrane wall to a quench pool and discharge opening at the bottom of the vessel. Cooled, recycled gas is added at the top of the vessel to quench the hot raw product gas and to harden any entrained molten slag before the gas enters the syngas cooler. The firetube type syngas cooler generates steam at one or two pressures while recovering high-level heat from the quenched raw gas. Solids and condensed liquids are removed in a dry solids removal system, comprising a cyclone and barrier filter, and a wet scrubber using an acid gas clean up stage for H_2S.

Combined Cycle

Combustion of the syngas is completed in the gas turbine, thus integrating high-efficiency combined cycle gas turbine technology with the gasification systems. The syngas is burned in the gas turbine combustors with high pressure air and the resulting combustion gases drive the turbine which generates electric power. Nitrogen from the air separation unit can also be expanded through the gas turbine to increase power production and to reduce NO_X emissions. The steam generated in the gasification process is combined with the steam produced in the gas turbine heat recovery steam generator (HRSG) and fed to the steam turbine-generator.

Compressed air from the gas turbine can be channelled back to the gasifier or the air separation unit. In addition, exhaust heat from the gas turbine and heat recovered from the syngas clean-up cooling system are used to generate steam for a steam turbine-generator.

Power is produced both from the combustion and steam turbines. The use of gas turbines and a steam turbine constitutes the “combined cycle” aspect of IGCC and is one reason why gasification-based power systems can achieve high power generation efficiencies. In a typical IGCC unit, about 60% of the sent-out power output is generated by the gas turbine(s) and about 40% by the steam turbine. Due to the relatively high efficiencies of modern combined cycle technology, the overall thermal efficiency of an IGCC plant is in the 38-41% HHV range for US eastern bituminous coal.

Syngas is a low-energy-density fuel with a heating value of about 250 Btu per standard cubic foot (9.314 MJ/Nm^3), roughly one-quarter that of natural gas. As a result, operation of gas turbines on syngas requires a higher volumetric flow through the gas turbine combustors to achieve the same turbine-section heat input as operation on natural gas. Currently, operating advanced gas turbines on high hydrogen content syngas requires turbine inlet temperatures to be slightly lower than those used when firing natural gas because of differences in aerodynamics, heat transfer, and erosion issues.

Nonetheless, gas turbines have been designed to accommodate higher fuel mass flow and lower flame temperatures associated with firing syngas. In many cases, despite the lower firing temperature, the higher mass flow allows an increase in gas turbine power rating. Some turbine designs are modified with stronger drive shafts and larger generators to take advantage of this capacity. In addition, to control NO_X, syngas is diluted with nitrogen to lower the flame temperature. The dilution with nitrogen provides additional mass and motive force to the gas turbine, increasing the MW output.

There are many variations on the basic IGCC scheme shown in Figure 6-8, especially in the degree of integration. All of the current coal based plants integrate the steam systems of the gasification and power block sections. Typically, boiler feed water is preheated in the HRSG and passed to the gasification section, where saturated steam is raised from cooling of the raw syngas. The saturated steam passes to the HRSG for superheating and reheating prior to introduction, with additional HRSG superheated steam, to the steam turbine for power production

Syngas Treatment and CO_2 Capture

A major advantage of gasification-based energy systems relative to conventional coal combustion is that the carbon dioxide produced by the process is in a concentrated high-pressure gas stream. The partial pressure of carbon dioxide in the syngas, following the water-gas shift reaction step, is much higher than that in post combustion flue gas. This is especially true for oxygen-blown gasifiers, though air-blown gasifiers also provide a higher partial pressure of carbon dioxide than in ambient-pressure flue gas. This higher pressure makes it easier and less expensive to separate and capture carbon dioxide from syngas than from flue gas. Once the carbon dioxide is captured, it can be sequestered (prevented from escaping to the atmosphere).

The IGCC technology is able to achieve low air emissions through:

- removing the emission forming constituents from reduced syngas volumes under pressure prior to combustion, IGCC can meet extremely stringent air emission standards;
- removing >99% sulphur;
- achieving NO_X emissions at <20ppmv at 15% O_2 in the gas turbine exhaust (about 30 g/GJ for new IGCC). These levels can probably be lowered with further combustor modifications. SCR can be used, but the economics are not yet established;
- achieving CO emissions at 1–2ppmv at 15% O_2 (<0.08 kg/MWh); and
- ensuring particulate emissions are at an undetectable level.

In this evaluation, the IGCC plants without carbon capture will use the MDEA process for sulphur removal with a Claus unit. IGCC plants with carbon capture will use two-stage Selexol units from a water-gas shifted feed gas and a Claus unit for recovering sulphur.

Under the reducing conditions of gasification, sulphur in the coal is converted primarily to hydrogen sulphide (H_2S), with ~3-10% converting to carbonyl sulphide (COS). This typically necessitates the use of a COS hydrolysis reactor to convert the COS to H_2S prior to H_2S removal by an acid gas recovery (AGR) system.

The most common AGR processes use the chemical solvent methyldiethanolamine (MDEA) or a physical solvent such as Selexol, which is a mixture of dimethyl ethers or polyethylene glycol. The chemical solvent reacts with the acid gases and requires heat to reverse the reactions and release the acid gases. Physical absorbents dissolve acid gases and require pressure as the driving force for absorption and pressure release for regeneration.

CO_2 can be separated from syngas by AGR, the same process used to separate sulphur species. However, achieving higher levels of CO_2 capture will require adding a water-gas shift reactor prior to separation. This contains a catalyst that, in the presence of water, "shifts" carbon monoxide (CO) in the syngas to CO_2 and hydrogen:

$$CO + H_2O \rightarrow H_2 + CO_2$$

A single-stage shift reactor can achieve most of the CO conversion (80-85%). To achieve additional CO conversion requires additional shift reactors at increased capital cost. The CO_2 in the shifted syngas is removed via contact with the solvent in an absorber column, leaving a hydrogen-rich gas for combustion in the gas turbine.

The water-gas shift reaction releases heat, which decreases the chemical energy contained in the syngas. Consequently, in order to supply the same fuel energy to the gas turbine after passing the syngas through a water-gas shift reactor, 5-10% more syngas would have to be produced.

The heat released during the shift reaction is typically used to produce high or intermediate pressure steam.

The water-gas shift option increases CO_2 concentration which allows CO_2 capture to take place at the pre-combustion stage at elevated pressure, taking advantage of higher partial pressures, rather than at the atmospheric pressure of post-combustion flue gas, permitting capital savings through smaller equipment as well as lower operating costs.

The impact of current CO_2 removal processes on IGCC plant thermal efficiency, sent-out plant output, and capital cost is significant. In particular, the water-gas shift reaction reduces the heating value of syngas to the turbine. Because the gasifier outlet ratios of CO to CH_4 to H_2 are different for each gasifier technology, the relative impact of the water-gas shift reactor process also varies. In general, however, it can result in approximately a 10% fuel energy reduction for full shift.

Heat regeneration of chemical (and sometimes physical) solvents reduces the steam available for power generation. In addition, solvents need to be depressurised to release captured CO_2 and must be repressurised for reuse. Cooling water consumption, or dry cooling load, increases for solvents which need cooling after regeneration and for pre-cooling and interstage cooling during compression of separated CO_2.

Coal Drying

One important consideration for coal preparation for IGCC plants is the coal quality and the drying of coal. Coal must be dried to ensure free flowing high density coal feed at the high operating pressure of the gasification process. While both Hunter Valley Black Coal and Latrobe Valley Brown Coal were evaluated in the PC cases, only Hunter Valley Black Coal was used in the IGCC evaluation. Brown coal has a very high moisture content of 61.5wt% and the Black Coal has a moisture content of 7.5wt%. For the two types of coal, the moisture content after drying would need to be 2wt% for black coal and 12wt% for brown coal.

The drying process requires a lot of energy, especially for brown coal. One drying system that may be considered for use with brown coal is the WTA technology developed by RWE. This system is a fluidised bed drying process with internal waste heat utilisation. However, in an IGCC plant there are a number of systems and subsystems from which low grade heat is available, so that extraction steam from the steam turbine can be minimised. As discussed in the PC section above, at the time this study was conducted the ability to dry coal from 61.5 wt% moisture to 12 wt% was not sufficiently proven. Consequently, it was decided to use combustion of clean syngas in conventional coal drying equipment to achieve the required moisture level for the coal. Particularly in the case of brown coal, this drying option has a significant negative impact on the overall thermal efficiency of the power plant and it was determined that it was far too uneconomical to pursue brown coal IGCC at this time; therefore, only black coal IGCC was evaluated for cost and performance. Significant progress is being made with the WTA and other advanced coal drying technologies, and EPRI believes the decision to not include such a drying process can be re-visited within the next year or two.

Brown Coal Technologies

While brown coal IGCCs were not evaluated in this study due to the high efficiency penalty of coal drying and, therefore, high plant cost, this section briefly describes two IGCC technologies that are under development for use with high moisture coals – the HRL Integrated Drying & Gasification Combine Cycle (IDGCC) and the KBR Transport Integrated Gasification (TRIG) system.

In the 1990s, HRL Limited in Victoria initiated work on an integrated coal drying and gasification process particularly aimed at more efficient use of the very high moisture content brown coals of the Latrobe Valley. The gasifier is a fluid bed gasifier that uses the hot syngas from the gasifier to dry the incoming coal in an entrained upflow dryer. Brown coal is fed to the dryer via lock hoppers and pneumatic conveying. The moist (and partially cooled gas) from the dryer then passes to a gas filter and the cleaned gas is fired in a gas turbine combined cycle.

A 15 MW development unit was built at Morwell in the Latrobe Valley and tested 1996-7. The gas turbine used was a European Gas Turbine Company (EGT) Typhoon of ~5 MW. Air was extracted from the gas turbine compressor to supply the gasifier. EPRI provided consultation for the IDGCC technology development and the 15 MW unit. In 2008, HRL announced a 400 MW project in the Latrobe Valley, based on a scale up of its IDGCC technology with AUD100 million support from the Australian Government and AUD50 million from the State of Victoria. HRL entered into a joint venture with the Harbin Boiler Company of China. Harbin was planned to be the EPC contractor with erection being handled by a local company. The plant will have two gasifiers and a single gas turbine. In 2009 HRL announced the establishment of Dual Gas Pty Ltd to further develop the IDGCC project. The project may now be larger at 550 MW using some additional natural gas as start up and supplemental fuel in addition to the syngas from IDGCC. While previous project press releases had mentioned Harbin Boiler as a partner, they were not mentioned in the latest press announcement.

Latrobe Valley Brown Coal has low sulphur content and currently there are no regulations in Australia for SO_2 emissions. Therefore the current design does not include any sulphur removal. The project justification therefore rests primarily on the increase in efficiency of the IDGCC over traditional PC plants for a claimed 30% reduction in CO_2 emissions. If sulphur removal was required it would be necessary to cool down the raw syngas, thereby condensing out much of the moisture and reducing the mass flow to the gas turbine with a subsequent significant reduction in power output. However, if capture was required the high moisture content would be an advantage for the shift reaction. Although at the current state of the art it would still be necessary to cool the shifted gas further for the removal of H_2S and CO_2. HRL has worked with CO_2CRC on flow schemes for adding CO_2 capture. Initial estimates for capture have been quoted as an increase of 40% in capital cost with a 10% loss of power. HRL believes that it would be able to achieve CO_2 emissions of 200 kg/MWh (440 lb/MWh).

KBR's TRIG system is being developed by Southern Company and KBR based on KBR's catalytic cracker technology which has been used for decades in petroleum refineries. The gasifier operates at considerably higher circulation rates, velocities, and riser densities than a conventional circulating bed, resulting in higher throughput, better mixing, and higher mass and heat transfer rates. Since the gasifier uses a dry feed and does not slag its ash, it is particularly well suited for high moisture fuels such as sub-bituminous coal and lignite. The developers of the Transport Gasifier feel that it offers a number of features.

- The design provides a simpler, more robust method for generating power from coal than other available alternatives.
- It operates at a temperature below the melting point of ash, providing the potential for more reliable operation than slagging gasifiers.
- It is unique among coal gasification technologies in that it is cost-effective when handling low rank coals and when using coals with high moisture or high ash content. These coals make up half the proven US and worldwide coal reserves.
- In addition, the transport gasifier is the only gasification technology currently offered in both air- and oxygen-blown operation.

A KBR transport pilot plant that can feed 30-60 tons/day (27-54 tonnes/day) of coal and is capable of operating in either air or oxygen mode is installed at the Power Systems Development Facility (PSDF) in Wilsonville, Alabama in the US. The test program, supported by the US DOE, Southern Company, EPRI, KBR, Siemens, Peabody, Burlington Northern Santa Fe Railway (BNSF) Railway, the Lignite council and others, was initiated in 1996. The PSDF provides a test bed for many other gasification related component developments and improvements. The coal feeder for low rank coals can now handle modestly dried coals with the moisture content reduced (mostly surface moisture) only to the level of ~22% for Wyoming's Powder River Basin (PRB) sub-bituminous coal and 25-27% for North Dakota and Mississippi lignite. Test runs on a variety of coals have been conducted on the gasifier at Wilsonville in both air blown and oxygen blown mode. The use of lower rank coals of higher reactivity is advantageous and with such coals carbon conversions of > 95% have been achieved.

In 2004, US utilities Southern Company and Orlando (Florida) Utilities (OUC) submitted a proposal for an air blown 285 MW IGCC project based on the KBR TRIG system in response to the US Department of Energy's (DOE) second solicitation under the Clean Coal Power Initiative (CCPI). While the proposal was accepted, permits were approved, and construction was initiated in September 2007, the project was abruptly terminated in November 2007 due to growing uncertainty about greenhouse gas regulations within the US.

Following the cancellation of the Orlando project, Southern Company has continued with the development of a nominal 585 MW KBR air blown IGCC project to use the local lignite in Kemper County, Mississippi. The plant design will use Siemens 5000°F gas turbines and will incorporate about 65% CO_2 capture with potential opportunities for both EOR and saline reservoir sequestration, most likely to be sold to Denbury Resources for EOR. The project is in the permitting stages and undergoing proceedings for need for new base load power and cost recovery rate schemes. Southern Company estimates that the project would be completed in 2013 or 2015 depending on the rate of recovery from the current economic recession.

A Chinese IGCC project seeking government approval in Dongguan in Guandong Province has also opted for KBR and Southern design. The gasification process is to be integrated with GE gas turbines that already exist at the site (2 x 6B and 9E). The target is to be operational in 2011 and if that could be accomplished it would potentially offer invaluable lessons for the larger Kemper IGCC project in Mississippi. One of the attractions of the KBR technology for Dongguan is that it should enable them to use higher moisture cheaper coals. Dongguan plans to follow up the 120 MW unit with four 200 MW units at the site.

Technology Development Status

Currently two coal-based, commercial sized IGCC plants are operating in the US. Three more are in Europe and one is in Japan, with a total installed capacity of about 1700 MW.

Although experience is limited with gasification in coal-fired power plants, it is supplemented by about 2500 MW of IGCC based on gasifying liquid petroleum residues in refineries and by multiple coal-based gasification units at chemical plants around the world, which have many years of experience in operating gasification and related gas cleanup processes. The most advanced of these chemical units are similar to the front end of a modern IGCC facility. Similarly, several decades of experience firing natural gas and petroleum distillate have made the basic combined cycle a mature generating technology.

Recently, power companies on five continents announced plans to build (or are considering) new coal-based IGCC power plants. Much of this interest is motivated by the potential for IGCC power plants to more economically capture their CO_2 emissions.

A number of lessons have been learned from past research, development and demonstration of coal IGCC plant operations.

- IGCC's very low SO_2, NO_X, and particulate emissions are below recent PC plants permit limits.
- GE, E-Gas and Shell gasifiers have been successfully demonstrated at commercial size.
- GE 7FA gas turbines perform well in IGCC application. All OEMs have now adopted multiple can annular combustors.
- The high degree of integration in IGCC plants has the down side of making the startup process more complex. In addition, increased integration can lead to decreased reliability due cascading effects.
- IGCC and gasification processes are currently being commercially used in many plants based on the gasification of petroleum residuals providing power, steam, and hydrogen.

- Future advances in gas turbine technologies have the potential to improve efficiency and lower cost.
- Existing single-train IGCC coal plants have not yet achieved their yearly availability targets of 85%, although on a quarterly basis the targets have been achieved, creating the expectation that yearly targets will be achieved in mature plants.
- Areas for gasification improvement are carbon conversion, longer refractory life (although this is not an issue for membrane wall gasifiers), longer fuel injector tip life, and reduced syngas cooler (SGC) fouling.
- Production of oxygen with cryogenic air separation plants adds a considerable parasitic load to the process. A potentially more efficient alternative being explored is to use new innovations in ceramic membranes to separate oxygen from the air at elevated temperatures.
- Development of high temperature AGR process.
- An especially important goal for coal gasification technology improvement is to develop inexpensive membranes that can selectively remove hydrogen from syngas so that it can be used as a fuel for future fuel cells or refineries, or perhaps one day as a substitute for gasoline in a hydrogen-powered automobile.
- Future concepts that incorporate a fuel cell or fuel cell-gas turbine hybrid promise higher efficiencies.

Major Technical Issues and Future Development Direction/Trends

The degree of integration of the gas turbine with the air separation unit (ASU) is the part of the design that varies most among IGCC plants. European plants are usually highly integrated with all the air for the ASU taken as a bleed of extraction air from the gas turbine compressor. US plant designs are less integrated, and the ASUs have their own separate air compressors. The major design variations between the European and US plants lies in gas turbine selection and differences in philosophies about the importance of efficiency compared to availability. The more highly integrated designs result in higher plant efficiency, since the auxiliary power load is lowered by the elimination of the separate air compressor. However, there is a loss of plant availability and operating controllability for the highly integrated system. Startup time is longer with this design as the gas turbine must be run on more expensive secondary fuel before extraction air can be taken to the ASU for its cool-down and startup.

The performance of the coal gasifier in terms of efficiency is affected principally by the quality of the coal. Coal quality has the following effects:

- entrained gasifiers perform best with low ash bituminous coals;
- sub-bituminous coal and lignite can be processed, but the generally higher oxygen consumption and lower gasifier cold gas efficiency (CGE) makes their use less economic unless they are low cost (for example, mine mouth);
- high-ash coals (>20%) are not recommended for entrained slagging gasifiers; and
- low-rank and high-ash coals are more suited to fluid-bed gasifiers. However, the fluid-bed gasification processes are not as developed as entrained bed designs.

Development of this technology is continuing. Further efforts are necessary to demonstrate improvement in performance, reducing capital costs, improving availability and cycling capability, as well as to demonstrate viability with low rank coals.

In the near term the major trends are the development of standardised designs to reduce cost and construction time, improve reliability and develop the designs for fuel flexibility.

Anticipated Improvements by 2030

The current performance and cost for the particular IGCC options examined in this report are reported in Section 7. While today's IGCC technology has efficiencies that are comparable with combustion-based coal power technology, it currently has significantly higher capital costs. It is a technology that currently sits at the top of the technology development learning curve (see Figure 6-2), and should benefit more than PC-based technology from savings derived by simply duplicating designs and learning better ways to construct and operate the plants.

In addition to learning curve derived savings, there are also a number of potential technical improvements in IGCCs which could improve efficiency and reduce cost. One of these is using higher firing temperature gas turbines (GTs). The current technology IGCC cases are based on so-called "F class" GTs which have a firing temperature on syngas of circa 1300ºC. Natural gas fired CTs are now available in the G and H firing class and MHI has announced the development of J class GT. The H class turbines have a firing temperature approximately 120ºC hotter than F class machines. The higher firing temperature provides higher thermal efficiency, which means a smaller gasification system is needed to provide a given amount of power production. It is expected that H class or hotter firing temperatures will be available for IGCCs in 2030 and this will increase thermal efficiency by 2.5 to 3 percentage points.

Advances in oxygen production will benefit IGCCs just as they will oxy-combustion plants although the impact will be smaller on IGCCs since they use less O_2 per MWh than is used in oxy-combustion.

A large potential advancement in IGCC technology which should be ready for commercial deployment in 2030 is so-called warm gas clean-up which will allow removal of sulphur compounds and CO_2 at temperatures well above ambient conditions. This will decrease the amount of heat exchange equipment needed in an IGCC and will also improve the thermodynamic efficiency. CO_2 separation via membranes will allow CO_2 to be produced at higher pressure which will decrease the auxiliary power load of the CO_2 compression system, and the use of more efficient compressors will benefit IGCCs in the same way that they will improve post-combustion and oxy-combustion capture economics. Taken together these improvements in CO_2 capture and compression could increase IGCC thermal efficiency by more than three percentage points while also decreasing capital cost.

A final anticipated improvement is the use of liquid CO_2 coal slurry to feed an entrained flow gasifier rather than using a more expensive dry feed system. Liquid CO_2 has a much smaller heat of vaporisation than water, and it also has a lower viscosity. This means more coal can be carried in the slurry and less oxygen is needed in the gasifier. If such a design were incorporated into a gasifier with a syngas water quench design, as opposed to the designs with syngas coolers assumed for the current technology cases, EPRI believes significant capital cost savings (circa

10-12%) could be obtained without sacrificing thermal efficiency. Similar gains may come from dry solids pumping to remove the complexity of lock hoppers.

For brown coal applications, EPRI believes advanced coal drying technologies will soon enable the use of low level heat, such as that from the CO_2 compressor intercoolers, to dry coal rather than burning syngas or H_2 derived from the gasification system as was assumed for the current brown coal cases. This could significantly decrease the capital cost by decreasing the amount of syngas that the gasifiers must produce, and it will improve the thermal efficiency of the process. An additional benefit of these drying processes is they may facilitate the capture of the water driven off the coal so that it can be reused in the gasification process such as the raw water supply for the demineralised water production system.

Overall the anticipated improvements in IGCC technology by 2030 are summarised in Table 6-3.

Table 6-3
Anticipated IGCC+CCS Technology Performance and Costs Improvements

	Black Coal	
	Current Technology	**2030 Technology**
Capital Cost (relative to current technology)	1.00	0.61
Thermal Efficiency	Base	+6.7 Pts

Development and Commercialisation Timeline

IGCC plant development will benefit from new gas turbine models with higher firing temperatures, greater efficiencies, and larger power outputs, which should result in reduction in the cost of electricity. For plants coming on-line circa 2020, the larger size G-class turbines—Mitsubishi Heavy Industries' M501G (60 Hz) and M701G (50 Hz), which operate at higher firing temperatures (relative to F-class machines)—can improve efficiency by 1 to 2% while also decreasing capital cost per kW capacity. H-class gas turbines, coming on-line later, will provide a further increase in efficiency and capacity.

The development of advanced gasification processes, currently in the R&D stages, will make significant advancements by 2025-2030, and advanced integration of GT, ASU and emission controls can be expected by that timeframe. Lower cost oxygen production technologies such as the Ion Transport Membrane (ITM) process being developed by Air Products promise to improve the economics and efficiency of future IGCC power plants.

Relevant Business Issues

The future utilisation of the IGCC technology will be affected by the price of natural gas and possible competition from combined cycle gas turbines (CCGTs). It may also see competition from modern PC technology depending on whether or not removal of CO_2 is required. Several studies of coal technologies have shown that if CO_2 removal is required by CO_2 emission regulations, the incremental cost of removal is less expensive in IGCC plants from syngas under pressure prior to combustion than from PC plants with post combustion removal at ambient pressures.

Although IGCC plants can meet extremely stringent air emission standards, association with coal may result in poor public perception. On the other hand, IGCC plants have demonstrated sulphur removal rates of ~99%. The elemental sulphur or sulphuric acid can be sold for use in fertilizer manufacturing to help offset plant operating costs.

There will be a global market for purchasing equipment associated with IGCC plants. Other key business indicators for advanced plants will be the willingness of OEMs and energy agencies to continue R&D work into efficiency improvements with regulatory climate resulting from concerns over global warming.

There are other business considerations which may be assessed in detail when planning a particular IGCC project. As the IGCC plant can produce valuable chemical products (H_2 and other co-products), its economic performance can be enhanced by locating the plant adjacent to a chemical plant to which these byproducts can be sold. In addition, various business approaches may be examined relative to one entity owning and operating the entire IGCC plant, or having separate owner/operators for the various parts of the plant (ASU, Gasification/Cleanup System, power block).

Combined Cycle Gas Cycle Turbine (CCGT)

Brief Description of the Technology

CCGT technology provides some of the highest plant efficiencies currently attainable among the various technologies examined in this study. This technology is based on generating power by combining gas turbines and steam turbine technologies (Brayton and Rankine cycles). Power is generated first in the gas turbines (Brayton Cycle) by burning fuel and the exhaust heat of the gas turbine is recovered in a heat recovery steam generator (HRSG) which provides steam to the steam turbine for generating additional power (Rankine Cycle). A simple schematic of a Combined Cycle Gas Turbine arrangement is shown in Figure 6-9, and a more detailed schematic showing steam cycle details is shown in Figure 6-10.

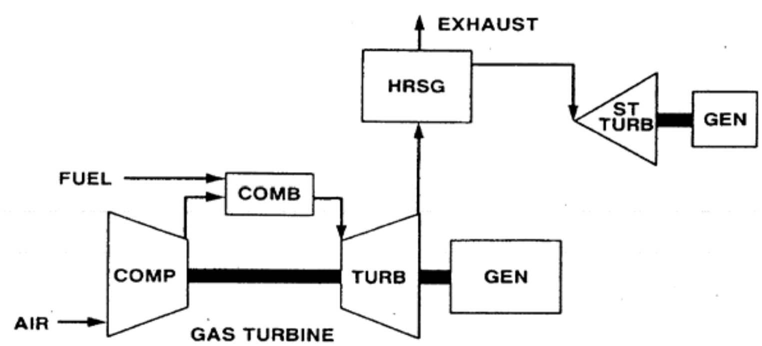


Figure 6-9
Simple Schematic of CCGT

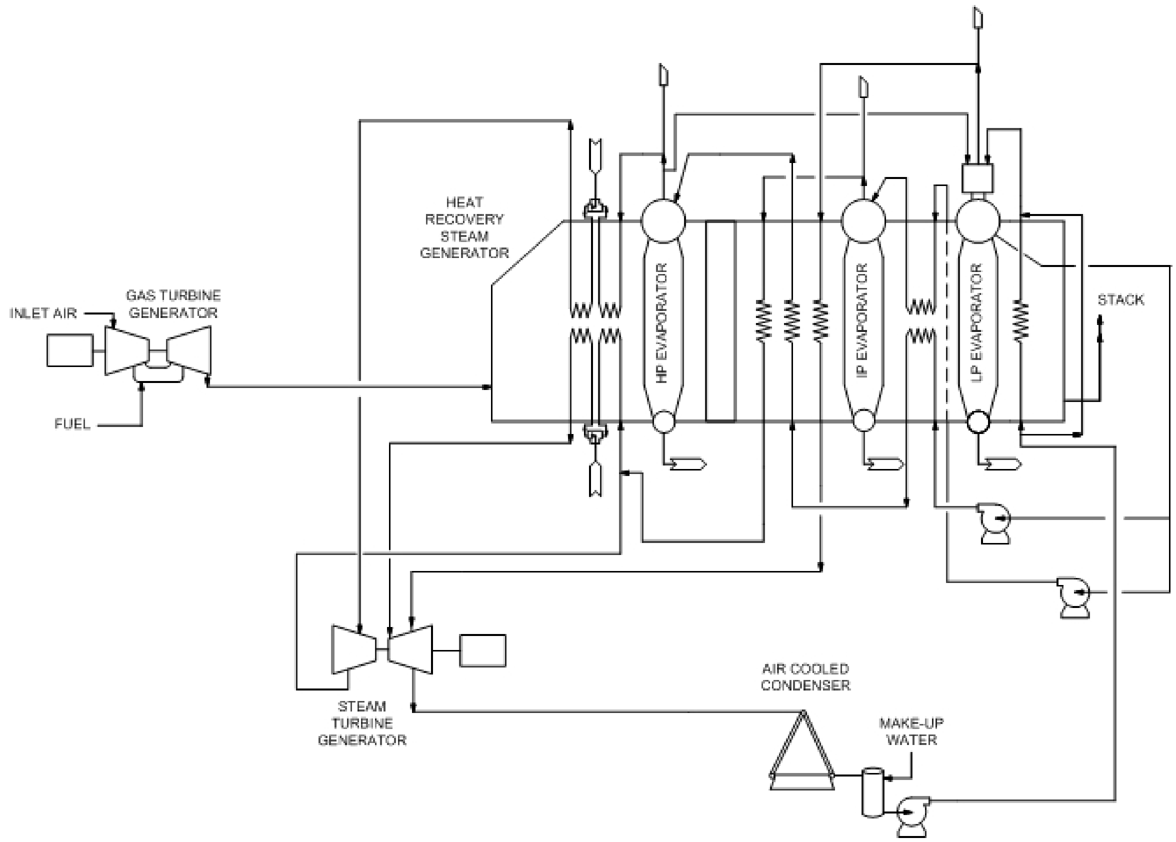


Figure 6-10
Schematic of a CCGT Generating Unit

A gas turbine (GT) includes an air compressor, a combustor, and an expansion turbine. Gaseous or liquid fuels are burned under pressure in the combustor, producing hot gases that pass through the expansion turbine, driving the air compressor. The shaft of the gas turbine is coupled to an electric generator which is driven by the mechanical energy produced by the gas turbine.

The hot exhaust gas from the gas turbine passes through a heat recovery steam generator (HRSG) where it exchanges heat with water producing steam. The exhaust gas is cooled to between 80°C (176°F) and 135°C (275°F) before exiting through the HRSG stack. Initial designs for CCGT's incorporated exhaust gases entering the HRSG at about 538°C (1000°F), while more recent designs incorporate exhaust gas higher than 593°C (1100°F). Depending on the selected gas turbine, the steam conditions from the HRSG range anywhere between 4.32-17.23 MPa(g) (700–2500 psig) with temperatures of 482-565°C (900–1050°F). The steam produced in the HRSG is used to drive a steam turbine generator (STG). Usually about two-thirds of the total power is produced from the gas turbines and one-third from the STG. The steam from the steam turbine is condensed, and the condensate is returned to the HRSG by condensate pumps. For the Australian study the condenser/cooling tower combination shown schematically on Figure 6-10 will be replaced with an air cooled condenser in accordance with the design criteria established for this evaluation.

The condensate from the condenser hotwell is pumped to the LP drum of the HRSG. Feedwater pumps then forward the feedwater to the steam drum/evaporator circuit through high pressure economiser(s). The steam generated in the steam drum is superheated in the front section of the HRSG and routed to the inlet of the steam turbine.

In application, this basic cycle can have various additions/enhancements depending on the selected gas turbine class, size of the plant, operating flexibility requirements, emission control requirements, etc.

There are various types and categories of gas turbines available in the market today. These include the earlier designed E or lower class turbine models, the state-of-the-art heavy-duty F, G and H class turbine models, and the aeroderivative gas turbines that are generally used in power, CHP (Combined Heat and Power), and industrial applications. These gas turbines are available in certain given sizes (ratings). Their efficiencies are strongly influenced by several factors such as inlet mass flow, compression ratio and expansion turbine inlet temperature. The earlier design of heavy duty gas turbines had maximum turbine inlet temperatures ranging anywhere between 815-1093°C (1500-2000°F). More recent state-of-the-art heavy-duty gas turbine designs have turbine inlet temperatures that reach over 1315-1371°C (2400-2500°F). These turbines are designed with innovative hot gas path materials and coatings, advanced secondary air cooling systems, and enhanced sealing techniques that enable higher compression ratios and turbine inlet temperatures. The advancements made in the newer gas turbines by the manufacturers are generally down-flowed into the earlier models for efficiency and power output improvements.

Combined cycle plants can operate with both conventional and advanced gas turbines. With gas turbines running at higher turbine inlet temperatures that result in higher exhaust temperatures, it is possible to include a reheat stage in the steam turbine. This further increases the efficiency in the bottoming cycle.

The combined cycle gas turbine can be built up from the discrete size gas turbine. The HRSG and steam turbine are sized to the exhaust energy available from the gas turbine. There are various configurations of combined cycles with various numbers of HRSG pressure levels. The best heat rates are obtained in combined cycles in which the steam cycle requirements are matched by maximising the recoverable energy from the gas turbine exhaust. Therefore, various optimised combined cycles can be constructed from a combination of the basic components. The combined cycle plants can be further characterised by:

- the steam cycle (i.e. reheat or non-reheat);
- HRSG pressure levels (i.e. single pressure, two-pressure, three-pressure); and
- the number of turbine generator shafts/arrangement (such as single shaft or multi-shaft).

Schematic arrangements of single shaft and multi-shaft combined cycles, and a schematic of a three-pressure reheat HRSG are shown in Figure 6-11 and Figure 6-12, respectively.

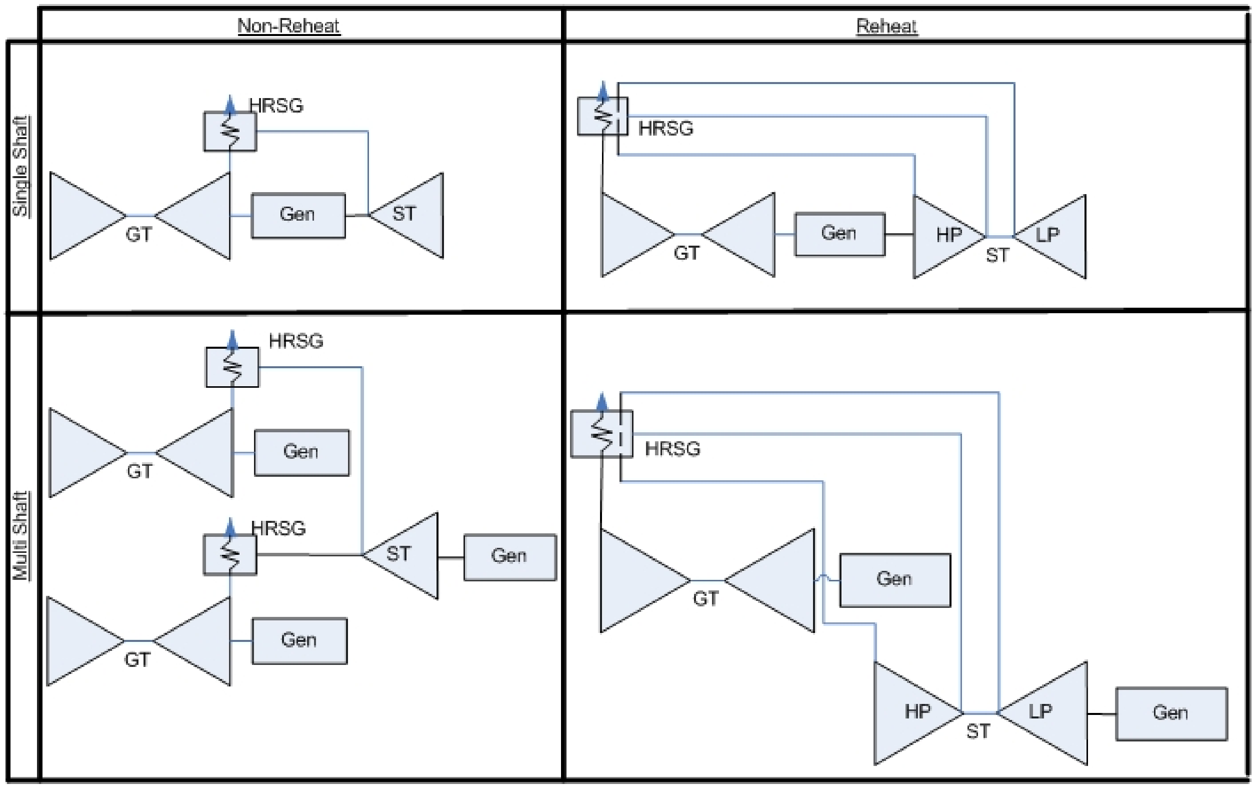


Figure 6-11
Schematic Arrangements of Single Shaft and Multi Shaft Combined Cycles

A single shaft design has several advantages.

- One less generator, main transformer and associated auxiliaries (simpler high-voltage system) and smaller overall space requirement (better fit for long, narrow sites).
- Simpler steam piping (no HRSG cross-tie piping, intercept valves, superheater relief, main steam and reheat steam non-return valves).
- Axial or side exhaust on LP steam turbine instead of downward exhaust (if steam turbine is small enough).
- Slightly higher efficiency at <50% load (assuming one train is completely shut down).
- Smaller increments of capacity can be added with standard design (quicker to build).

However there are also disadvantages associated with a single shaft design.

- One additional steam turbine, condenser, circulating water system and associated auxiliaries.
- Lacks flexibility to operate gas turbine without steam turbine (unless synchronising clutch installed).
- Full load efficiency slightly lower (smaller, less efficient steam turbines, more lube oil and controls, partially offset if higher efficiency hydrogen-cooled generators used instead of air-cooled generators).
- The long shaft length (if dimension is a constraint).

- Building costs possibly higher (depending on desire for steam turbine in building vs gas turbine enclosures outdoors).
- Slightly higher capital cost and maintenance cost (depends on plant specifics).
- Steam turbine vendor typically must be the same as gas turbine vendor.

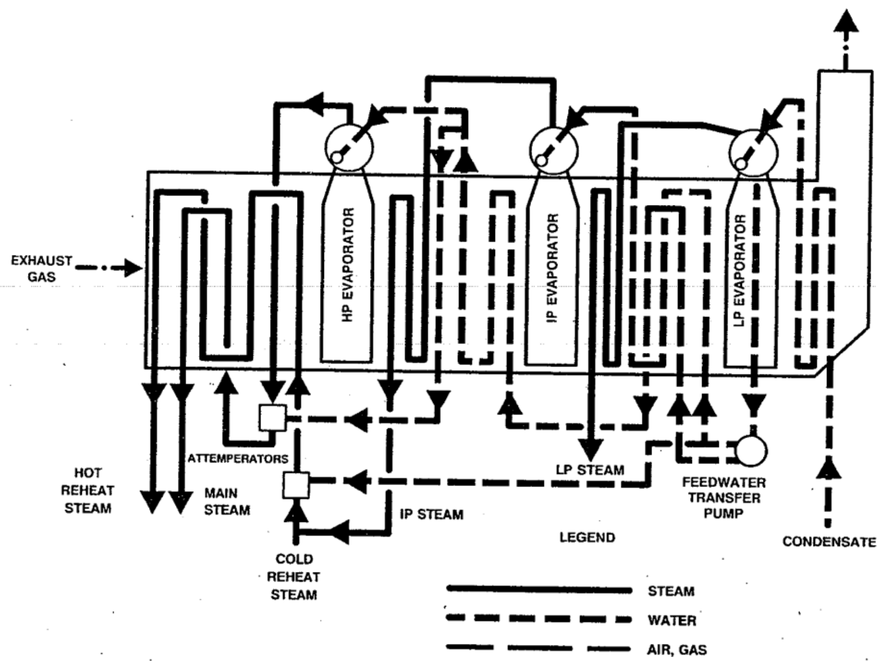


Figure 6-12
Schematic of Three Pressure HRSG

The combined cycle configuration for the purposes of this report will be a multi-shaft, reheat, three-pressure cycle based on the GE 9FA gas turbine. It will consist of 2-9FA gas turbines, each exhausting into a separate HRSG, and a common steam turbine-generator.

Additional features of a combined cycle plant can be the inclusion of supplementary firing in the HRSGs, which would allow a plant to increase power output at a slight expense of cycle efficiency.

Operating flexibility requirements may require a plant to include a gas turbine bypass stack (subject to regulatory approval), and a steam turbine bypass system (these are shown schematically on Figure 6-10).

Site conditions such as temperature and site elevation have a significant effect on gas turbine output. These factors affect the mass flow through the compressor. Higher altitude and higher air inlet temperature result in a decrease in the mass flow of air through the compressor resulting in a proportional drop in output. This also causes the entire combined cycle output to also decrease due to the reduction of gas turbine exhaust flow.

The major criteria emissions from natural gas fired combined cycles include nitrogen oxides (NO_X), carbon monoxide (CO) and Volatile Organic Compound (VOC). In earlier designs, NO_X emissions were controlled by injecting water or steam into the gas turbine combustor. Currently,

NO_X emissions are controlled by dry low-NO_X (DLN) combustors with gas firing and with addition of water or steam during oil firing. Additional reduction in NO_X emissions can be achieved by installing a selective catalytic reduction system (SCR) in the HRSG. Similarly, CO and VOC emissions can also be controlled by installing oxidation catalysts in the HRSG. In addition to higher efficiency, a natural gas fired combined cycle plant reduces the CO_2 emissions by about half per kW of power generation compared to similar capacity coal fired plant.

Technology Development Status

Combined cycle technology is a mature technology for power plants. Continuing manufacturer research and operator experience have now resulted in reliable, highly efficient combined-cycle plants that are, in many cases, the type of plant chosen to meet new intermediate or baseload needs.

Combined cycle gas turbine units are chosen by utilities for power generation when they desire shorter installation time compared to pulverised coal plants, low emissions, lower water consumption and real estate requirements, and relatively low total plant capital cost. In addition, gas turbines, when utilised in a combined cycle, have achieved high plant availability in addition to demonstrating the highest plant efficiency. For baseload operation, operating data on CCGT and gas turbine with HRSGs indicate that properly operated and maintained facilities can result in annual operating availability factors exceeding 90%, and in many cases mid-90% plant availability factors. By using natural gas as fuel, such plants produce reduced emissions, achieve excellent heat rates, and offer the utility flexibility regarding dispatch and loading. If such a CCGT is designed with multiple gas turbines driving a single steam turbine, the utility has the option of achieving better heat rate at part load by turning off one or more gas turbines as is required to meet the load demand.

Gas turbines can also be fired with alternate fuels (typically oil), however, the emissions profiles will be higher compared to the natural gas fuels. The alternate fuels have to meet the operational standards set by the turbine manufacturers.

CCGT units have become larger in size as the technology has advanced. The move toward larger CCGT units has been motivated by capital cost economy-of-scale and improvement in efficiency. The trend to larger size is evidenced by the fact that in 1994 there were 10 CCGT models available in the range of 350 MW–750 MW, whereas in 2008 there are 27 models available in the same size range. In 1994 the largest CCGT unit was 750 MW while in 2008 the largest unit was 1,000 MW.

Leading vendors for state-of-the-art heavy duty gas turbines are GE Energy, Siemens Energy, Alstom Power, and Mitsubishi Heavy Industries (MHI). Leading vendors for state-of-the-art aeroderivative units are GE, Pratt & Whitney and Rolls-Royce. The leading STG Vendors include GE, Siemens, Alstom, MHI, Toshiba, and Hitachi among others.

Most major manufacturers have developed optimised CCGT packages, and offer various single shaft and multi-shaft arrangements. Although single shaft has been popular outside the US, they have not been used in the US market except where single shaft design is mandated by OEM such as GE’s “H” class application.

Major Technical Issues and Future Development Directions/Trends

The state-of-the-art heavy-duty gas turbines operating in combined cycles have accumulated significant operating experience and the "F" class machines are operating on natural gas at firing temperatures of 1260°C (2300°F) and higher. They incorporate improved bucket cooling technologies and advanced coatings. This technology continues to improve and is expected to achieve greater than 1315°C (2400°F) firing temperatures and includes features developed from aeroderivative gas turbines. They will offer dry low-NO_X combustors and will have further improved cooling, improved bucket quality and durability.

Combined cycles in the future will be based on advanced heavy-duty gas turbines which will operate at even higher firing temperatures and high pressure ratios, and will include more aero-dynamic features. The recently announced machines by Siemens & MHI ("H" and "J" technologies) are incorporating advanced air cooling and steam cooling technologies to allow turbine inlet temperatures well above 1426°C (2600°F) (MHI's J technology claims to operate at over 1649°C (3000°F) turbine inlet temperature) which further increases efficiency. With these advanced gas turbines a more efficient reheat steam turbine cycle can also be selected for higher efficiency for the bottoming cycle. With these newer machines and upgraded materials (new alloys for pressure parts in HRSGs), combined cycle efficiencies can approach about 60% (HHV basis).

The potential impacts of including CO_2 capture in CCGT must be considered, as this will significantly affect plant performance and total project cost. In addition, CO_2 from the natural gas-fired combined cycle flue gas poses an additional problem. CO_2 concentration in a combined cycle plant's flue gas is only four percent compared to 12 to 15 percent for coal. Furthermore, the flue gas flow in a natural gas-fired plant is about 50 percent greater than in a coal fired power plant per megawatt of capacity because ambient air is used as the compressible medium by the gas turbine. Thus, the lower CO_2 concentration in exhaust gas combined with the higher flue gas flow rate could potentially double the cost per ton of capturing carbon.

Anticipated Improvements by 2030

Natural gas fired combined cycles will benefit from many of the same technology advances that will improve coal-based power generation technology by 2030. The higher firing temperature gas turbines which improve IGCC thermal efficiency will also improve CCGT efficiency and the more efficient post-combustion capture and CO_2 compression technologies anticipated for SCPCs can also be used on CCGTs.

In comparison with today's technology, the thermal efficiency of a CCGT with post-combustion capture of CO_2 is expected to increase by at least eight percentage points by 2030, and the capital cost could decrease by up to 18%. The estimated performance and cost improvements are summarised in the table below.

Table 6-4
Anticipated CCGT+CCS Technology Performance and Costs Improvements by 2030

	Current Technology	2030 Technology
Capital Cost (relative to current technology)	1.00	0.82
Thermal Efficiency	Base	+8 Pts

Development and Commercialisation Timeline

The developments and enhancements to the existing combined cycle gas turbines is an ongoing process. In today's market, the two main areas of interest to plant operators are achieving minimum load while meeting emission limits and in realising maximum output with minimum startup time. GT manufacturers are currently adapting their combined cycle technologies to improve cycling capability of the entire plant and not only individual components. This requires the optimisation of interaction between the main components – gas turbine, steam turbine, generator – and the major balance of plant equipment (such as HRSG, water and steam systems, etc.) and the control system. Siemens for example has designed a new type of once-through HRSG which enables an increased number of fast starts. These efforts are in response to the growth in peaking and cycling power generation in recent years and this will continue through 2015 and beyond.

In the advanced gas turbine area (G, H, and J Class engines), manufacturers of combined cycle packages have made significant progress. Mitsubishi's G Class and GE's H Class machines are already in operation, and Mitsubishi's J technology machine is currently undergoing the company's verification program at its Takasago R&D centre. In 2007 in Germany, Siemens started testing its 340 MW SGT5-8000H machine in open cycle. This unit will then be integrated into a 530 MW combined cycle in 2010, and commercial operation of the combined cycle is scheduled to start in 2011.

Combined cycles based on these advanced machines are making it possible to break the 60% combined cycle (LHV) efficiency barrier, and it is expected that by 2020-2030 all these technologies will be mature technologies.

Relevant Business Issues

The greatest advantage of natural gas-fired combined cycle plants are their low capital cost and high efficiency (compared to other current technologies). Market restructuring and deregulation also favours this technology over traditional coal or nuclear plants for new base load capacity due to better short-term economics and concern over global warming (compared to PC-fired plant). A resurgence in merchant plant markets and growth in traditional utility power generation, especially peaking, may require this technology to be implemented with fast start capability.

CCGT units have a much higher efficiency than PC technologies. For CCGT units with outputs of 100 MW to 800 MW, the efficiency ranges from 50% to 60% on LHV basis or 45% to 54% on an HHV basis. This efficiency range is three to 12 percentage points better than supercritical PC units. Moreover, the efficiency of CCGT units is seven to 16 percentage points better than subcritical PC units. This means that CCGT units have a relative efficiency advantage of 30 to 40% compared to PC units. However, availability and price of natural gas are also key business indicators. It follows that on a strictly fuel-cost basis, CCGT units are favoured when natural gas prices are no more than 30 to 40% greater than coal prices (on a $/MMBtu, basis). However, with natural gas currently over AUD8 per MMBtu and coal under AUD1.50 per MMBtu, capital cost differences must also be considered. It is estimated that the capital cost for pulverised coal-fired plants is 2-3 times that of the CCGT plant on a per kW basis for plants with similar capacity.

It should be noted that if CO_2 removal is mandated by regulations, cost and plant performance will be substantially affected. In addition, spikes in plant capital cost due to recent significant increase in escalation of equipment and materials costs also impacts economics.

Open Cycle Gas Turbine (OCGT)

Brief Description of the Technology

An open cycle gas turbine is one in which the working fluid remains gaseous throughout the thermodynamic cycle (Brayton cycle). This thermodynamic cycle consists of an adiabatic compression, isobaric heating, adiabatic expansion, and isobaric cooling. The schematic arrangement of a basic open cycle gas turbine arrangement is shown in Figure 6-13. The gas turbine includes an air compressor, a combustor, and an expansion turbine. Air is compressed and then mixed with gaseous or liquid fuels to be burned under pressure in the combustor, producing hot gases that pass through the expansion turbine. The shaft of the GT is coupled to both the air compressor and an electric generator such that mechanical energy produced by the GT drives the electric generator as well as the air compressor.

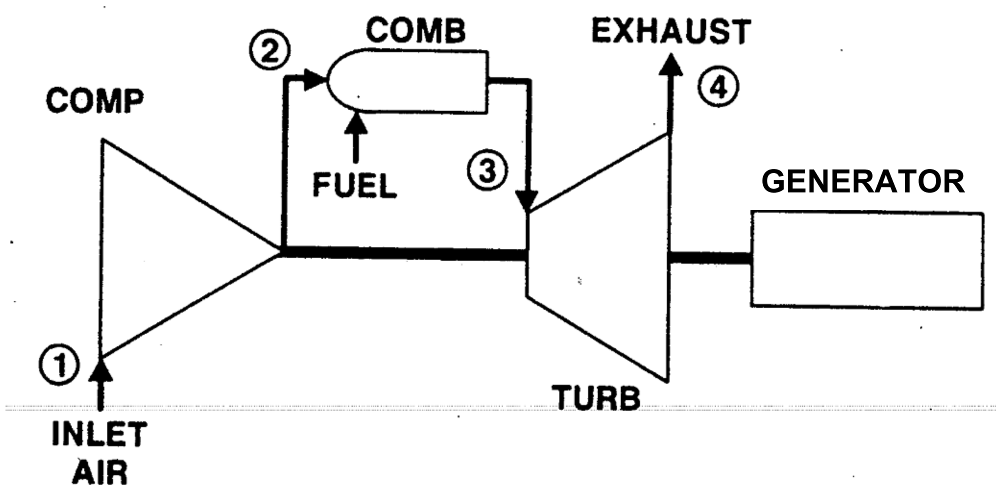


Figure 6-13
Schematic of an Open Cycle Gas Turbine

In the expansion turbine section of the GT the energy of the hot gases is converted into work. This conversion actually takes place in two steps. In the nozzle section of the turbine, the hot gases expand and a portion of the thermal energy is converted into kinetic energy. In the subsequent bucket section of the turbine, a portion of the kinetic energy is transferred to the rotating buckets and converted to work.

Some of the work developed by the turbine is used to drive the compressor, and the remainder is available for useful work at the output flange of the gas turbine. Typically, more than 50 % of the work developed by the turbine sections is used to power the axial flow compressor.

There are various types of gas turbines such as heavy-duty industrial, aeroderivative, and advanced heavy-duty gas turbines. Unit sizes are available in a wide range (from 2 MW and smaller to 330 MW and larger). They also have different shaft arrangements. The gas turbine shown in Figure 6-13 is configured with one continuous shaft. Therefore, in this arrangement all compressor and expansion turbine stages operate at the same speed. These units are typically used for generator-drive applications where significant speed variation is not required.

A schematic of an open cycle two-shaft GT can be seen in Figure 6-14. The low-pressure or power turbine rotor is mechanically separated from the high-pressure turbine and compressor rotor. This unique feature allows the power turbine to be operated at a wide range of speeds, and makes two-shaft gas turbines ideally suited for variable-speed applications. All of the work developed by the power turbine is available to drive the load equipment, since the work developed by the high-pressure turbine supplies all the necessary energy to drive the compressor.

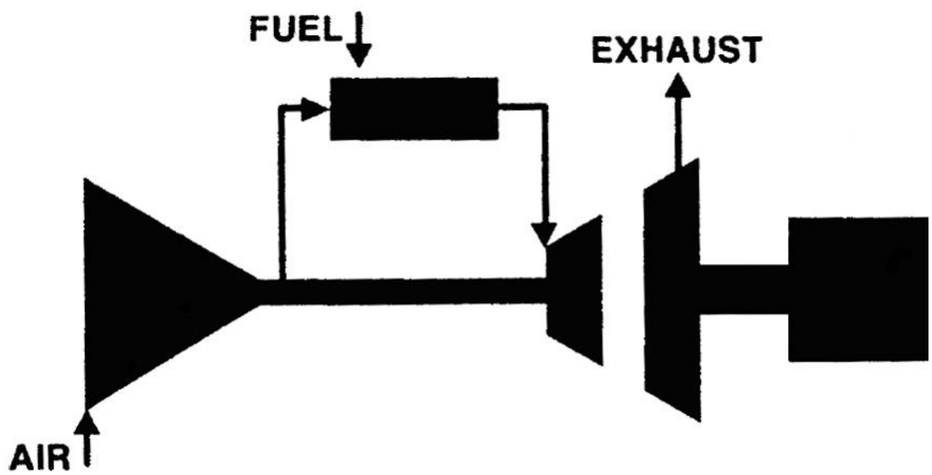


Figure 6-14
Schematic of an Open Cycle Two-Shaft Gas Turbine

The main advantages of open cycle GTs include flexibility in siting, low emission levels with natural gas fuel, low capital cost and short construction time. These advantages make them attractive for peaking duty applications. Peaking duty open cycle plot arrangements can be designed to allow for later conversion to combined cycle through staged development.

For the purposes of the Australian study, the gas turbine model to be used in peaking service will be the GE 9E heavy duty model with an ISO (i.e. @ 15ºC, at sea level, and 60% relative humidity) rating of 126 MW. This unit will be operated in peaking service with an annual capacity factor of 10%.

For a peaking unit the plant arrangement, besides the gas turbine-generator, will also contain various appurtenances and auxiliary systems. These include air inlet structures with inlet filters, fuel system, gas turbine accessory compartments, lube oil system, cooling water system, water wash system, electrical system components, an exhaust stack; and electrical connection for transmitting electrical output (i.e. circuit breaker, step up transformer).

It is noted that the performance of a GT is affected by a number of factors (ambient temperature, relative humidity, fuel type, inlet pressure drop, outlet pressure drop, site elevation, etc.) Higher ambient temperatures result in less dense air and lower ambient temperatures result in more dense air. Because the gas turbine is an ambient air-breathing engine, its performance will be changed by anything affecting the mass flow of air intake to the compressor. Figure 6-15 shows a typical Open Cycle Compressor Inlet Temperature performance curve. This shows the correction factors for open cycle heavy duty GTs to be applied to generated output, heat rate, exhaust flow and heat consumption. An open cycle altitude correction curve (Figure 6-16) shows the affect of site elevation on GT output and fuel consumption.

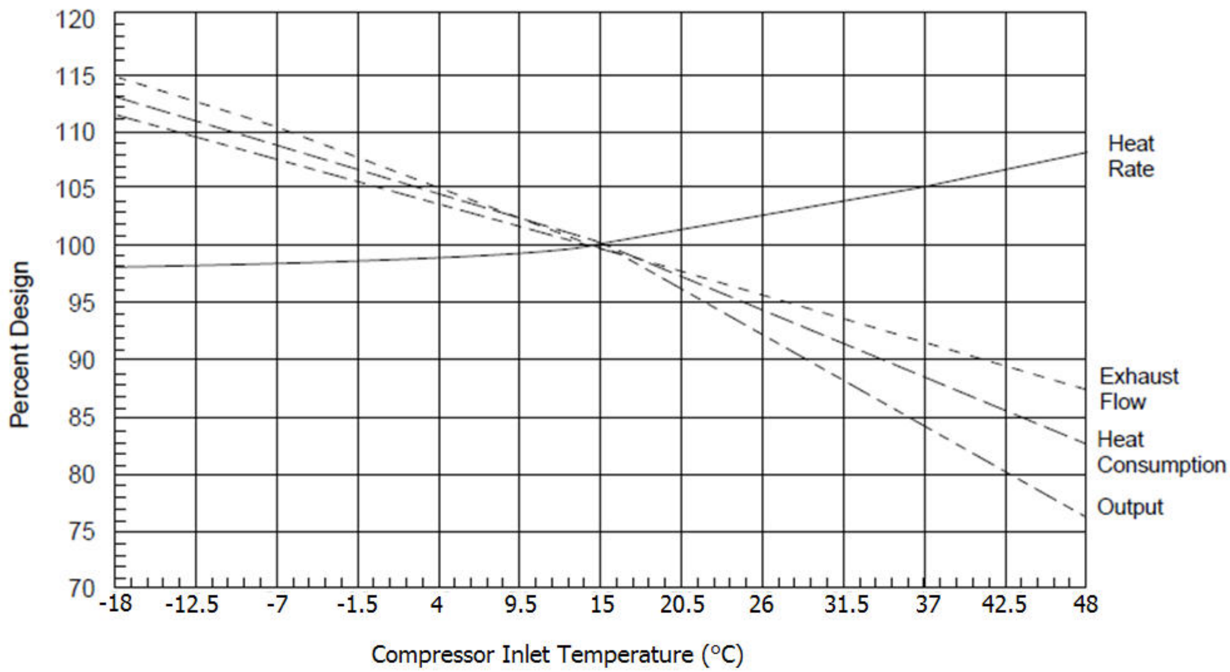


Figure 6-15
Open Cycle Compressor Inlet Temperature Performance Curve

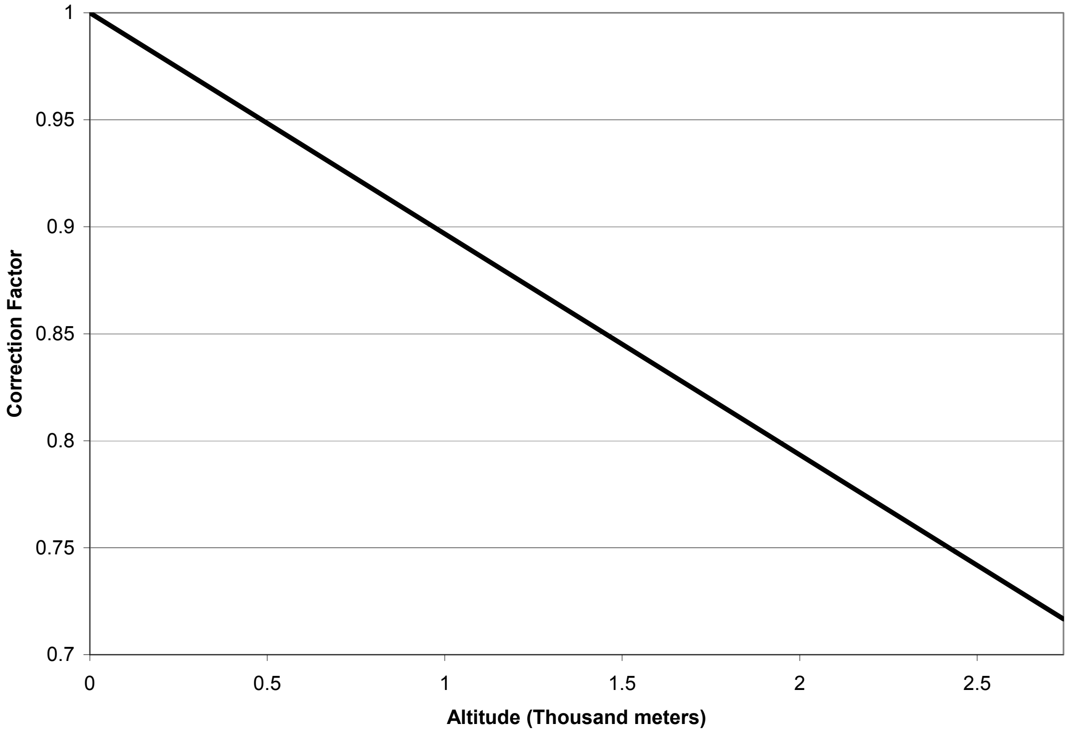


Figure 6-16
Open Cycle Altitude Correction Curve

As can be seen, the power output of a GT is very sensitive to ambient temperature. Maximum power typically drops about 0.7% for each degree Centigrade increase in ambient temperature. For example, a GT with an output rating of about 126 MW at 15ºC ambient temperature at sea level drops to about 115 MW at 32ºC ambient. The reference site conditions (as per ISO standards) for data presented are 15ºC, 60% relative humidity, and sea level elevation.

Generally, it is not possible to control the factors that affect gas turbine performance. Most are determined by the planned site location and the plant configuration. However, in the event additional output is needed, there are several possibilities which may be considered to enhance performance. These include:

- inlet cooling (lowering the compressor inlet temperature can be accomplished by the installation of an evaporative cooler or inlet air chiller in the inlet ducting downstream of the inlet filters);
- steam or water injection for power augmentation (and NO_X control); and
- increasing firing temperature for peaking operation. In recognition of shorter operating hours it is possible to increase firing temperature to generate more output. The penalty for this type of operation is shorter inspection interval requirements. Despite this, running a GT at peak firing temperature may be a cost effective way to obtain more kilowatts without the need for additional peripheral equipment.

In some cases, open cycle GTs are used in conjunction with heat recovery steam generators (HRSGs) to produce steam. In this configuration, all steam produced is used for process purposes such as in a refinery, for enhanced oil recovery, or in a steam-injected gas turbine (STIG) cycle.

STIG cycles are more frequently used with aeroderivative turbines, and they can offer heat rate improvement in addition to increased outputs and reduced NO_X emissions.

Technology Development Status

Open cycle gas turbine plants are a mature generation technology. There are various types and categories of gas turbines available in the market today. These include the earlier designed E class turbine models, the state-of-the-art heavy-duty F, G, and H class turbine models and the aeroderivative gas turbines that are generally used in power, CHP (Combined Heat and Power), and industrial applications. These gas turbines are available in certain given sizes (ratings). Their efficiencies are strongly influenced by several factors such as inlet mass flow, compression ratio and expansion turbine inlet temperature. The earlier design of heavy duty gas turbines had maximum turbine inlet temperatures ranging anywhere between 800-1100ºC. More recent state-of-the-art heavy-duty gas turbine designs have turbine inlet temperatures reach as high as 1300-1375ºC. These turbines are designed with innovative hot gas path materials and coatings, advanced secondary air cooling systems and enhanced sealing techniques that enable higher compression ratios and turbine inlet temperatures. The advancements made in the newer gas turbines by the manufactures are generally down-flowed into the earlier models for efficiency and power output improvements.

Gas turbines can also be fired with alternate fuels, however, the emissions profiles will be higher compared to the natural gas fuels. The alternate fuels have to meet the operational standards set by the turbine manufacturers.

The major emissions from CTs are nitrogen oxides (NO_X). NO_X emissions have been controlled by injecting water or steam into the combustor. Several manufacturers offer dry low-NO_X (DLN) combustors commercially, where low levels of NO_X are achieved without having to inject water or steam.

Leading vendors for state-of-the-art heavy duty gas turbines and steam turbines are GE Energy, Siemens Energy, Alstom Power and Mitsubishi Heavy Industries (MHI). Leading vendors for state-of-the-art aeroderivative units are GE, Siemens, Pratt & Whitney and Rolls-Royce.

Major Technical Issues and Future Development Directions/Trends

Turbine efficiency is strongly influenced by the expansion turbine inlet temperature. Earlier designs of CTs for stationary applications (heavy duty) had maximum inlet temperatures of approximately 1100ºC (so-called E class designs). More recent GT designs have turbine inlet temperatures of 1300ºC or hotter. This higher inlet temperature reduces the heat rate by about 10%.

The state-of-the-art heavy-duty gas turbines including the E-class machines have accumulated significant amounts of operating experience and the F-class machines are operating at firing temperatures of 1300ºC and higher. They incorporate improved bucket cooling technologies and advanced coatings. This technology continues to improve and is expected to achieve 1300ºF plus firing temperatures and include features developed from aeroderivative gas turbines. They will include dry low-NO_X combustors and will have further improved cooling, improved bucket quality and durability. These will result in modest improvements in performance in the shorter term, and these units will provide a lower cost alternative to advanced turbines.

Fuel efficient operation requires that part loads can be carried without significant loss in heat rate. Part-load operation may be achieved most efficiently by closing the Inlet Guide Vanes (IGVs) at the compressor inlet. This method permits maintenance of the full-load operation down to the limit of the IGVs. For most units this will result in typically 70-80% of full load. At this point the GT heat rate climbs as shown on the following generic part-load curves.

Figure 6-17, Open Cycle Part-Load Performance Curve, is a generic representation showing two conditions. First, part load is achieved by reducing fuel input without closing the IGVs. Second, IGVs are closed followed by reducing fuel input. Heat rate deteriorates as part-load output becomes lower.

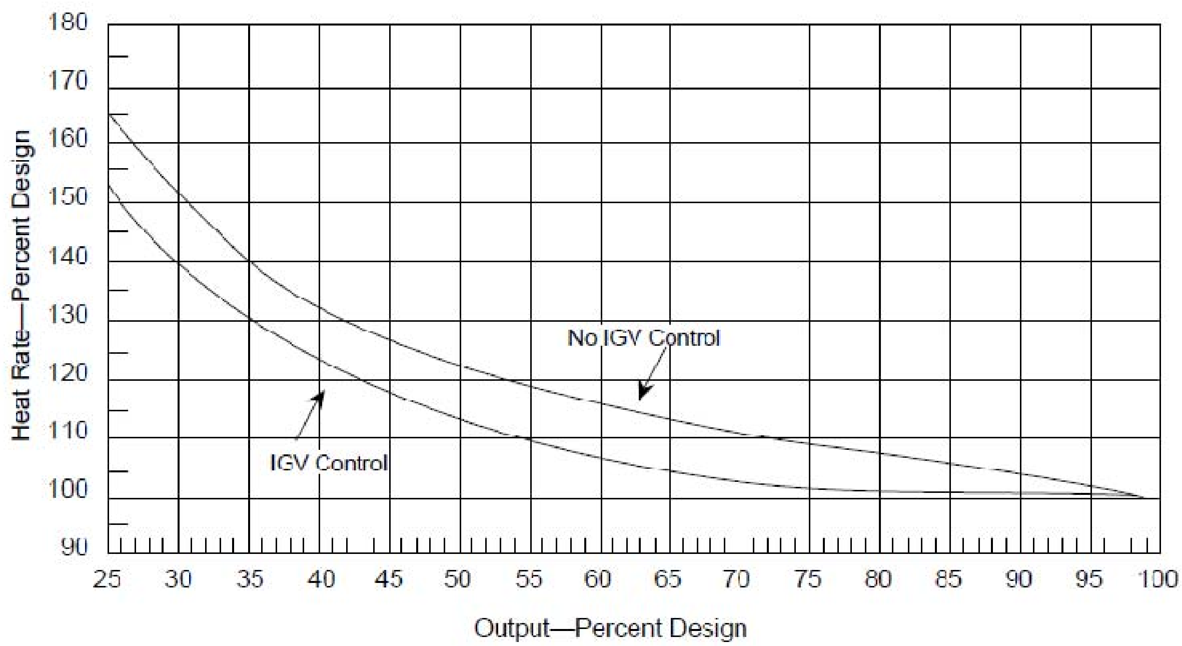


Figure 6-17
Open Cycle Part-Load Performance Curve

Aeroderivative gas turbines will have higher firing temperatures and their most important applications will be in industrial cogeneration. They will be available with dry low-NO_X combustors. Some will be offered as quick delivery pre-packaged units.

Advanced heavy-duty gas turbines will operate above 1400ºC turbine inlet temperatures, and with high pressure ratios. They will incorporate advanced air cooling systems and the use of ceramics.

Carbon capture for open cycle gas turbines is not considered for peaking duty applications due to the low capacity factor of 10% for these services.

Anticipated Improvements by 2030

In comparison with today's technology, the thermal efficiency of an OCGT is expected to increase by more than six percentage points by 2030. However, it is anticipated that a price premium would be associated with that level of performance and the capital cost could increase by up to 10%. The estimated performance and cost changes are summarised in the table below.

Table 6-5
Anticipated OCGT Technology Performance and Cost Changes by 2030

	Current Technology	2030 Technology
Capital Cost (relative to current technology)	1.00	1.10
Thermal Efficiency	Base	+6.8 Pts

Development and Commercialisation Timeline

The developments and enhancements to the existing gas turbines is an ongoing process. GT manufacturers are currently adapting their technologies to the requirements of operating flexibility and fast start capability. These efforts are in response to the growth in peaking and cycling power generation in recent years and this trend is expected to continue through 2015 and later years.

In addition to the gas turbine internal performance enhancement, there are additional “external” performance enhancement technologies (such as evaporative cooling, inlet air chilling, steam injection, etc.) available commercially today. These technologies are expected to continue to be available through the years 2025-2030.

Relevant Business Issues

The key features of open cycle GT plants are low capital cost, short construction time, flexibility in siting, capability of operation on liquid or gaseous fuel, and low emission levels with natural gas fuel. These advantages make them attractive for peaking duty applications. In addition, with proper advanced site planning they can be subsequently converted to combined cycle plants. However, key issues include long-term natural gas availability, transportation and pricing.

Other key business indicators are spikes in capital costs due to significant recent escalation of equipment and materials costs which impacts economics.

6.2 Renewable Technologies

A large range of renewable technologies, from those in early development stages to those that are considered commercially proven technologies, are discussed in this report. Solar technologies investigated include solar thermal technologies such as parabolic troughs, power towers, compact linear Fresnel receivers, and parabolic dish/engines, as well as solar photovoltaic technologies including fixed, single- and double-axis tracking, and concentrating PVs. Wind is discussed for both on-shore and off-shore applications. Wave energy conversion, tidal in-stream energy conversion, and ocean current technologies are discussed in the ocean energy section. A range of geothermal and biomass technologies are described and hydroelectric power is also briefly mentioned. Figure 6-18 shows the Grubb curve for this range of renewable technologies. As will be discussed later, the maturity level of geothermal power varies widely among the various applications of geothermal technology. Some are quite mature while some are still in the R&D phases. The geothermal point in Figure 6-18 represents an average of all geothermal technologies.

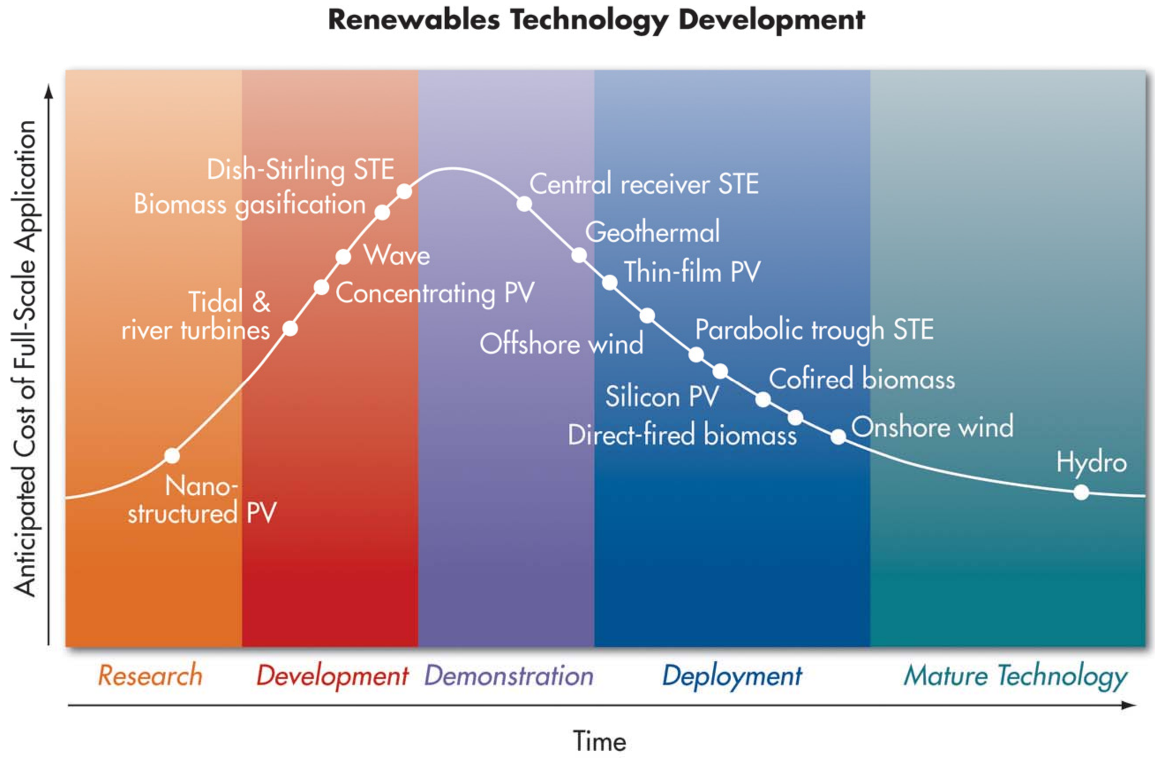


Figure 6-18
Grubb Curve for Renewable Technologies

Solar Thermal Technologies

Brief Description of the Technology

Solar thermal technologies use sunlight to heat a medium and then use that medium to drive a power generation system. Using mirrors, the sun's energy can be concentrated up to 1,000 times. The concentrated sunlight is then focused onto a receiver containing a gas or liquid that is heated to high temperatures and used to generate steam to drive a power generation system.

Three of the technologies described below—parabolic trough, power tower, and compact linear Fresnel—are based on the concept of concentrating direct normal irradiation or insolation (DNI) to produce steam used in electricity generating steam turbine cycles. In these technologies the solar power generating systems use glass mirrors that continuously track the position of the sun while absorbing its solar radiation energy. The absorbed solar energy can be harnessed and transferred in two ways: indirectly or directly. The indirect method uses a heat transfer fluid (HTF) which absorbs solar radiation energy and transfers the heat to water via a series of solar steam generator heat exchangers, thus indirectly producing steam. The direct method eliminates the HTF step by circulating water directly through the concentrated solar radiation path, thus directly producing steam. The fourth—parabolic dish/engine—uses concentrated solar to heat a working fluid that drives an engine.

There are four solar technologies described in this report.

- Parabolic Trough - Synthetic Oil HTF & Direct Steam, herein after "trough"
- Power Tower / Central Receiver - Molten Salt & Direct Steam, herein after "tower"

- Compact Linear Fresnel Reflector (CLFR) - Direct Steam
- Parabolic Dish/Engine – Working Fluid

Parabolic Trough

Trough technology concentrates DNI using single-axis tracking, parabolic trough-shaped reflectors, onto a vacuum absorber pipe or heat collection element (HCE) located at the focal line of the parabolic surface (Figure 6-19). A high temperature heat transfer fluid such as synthetic oil absorbs the thermal energy as it flows through the HCE. Heat collected in the HCE is transported to a series of shell-and-tube heat exchangers-collectively termed a solar steam generator (SSG). In a stand-alone solar power plant, the superheated steam (~370ºC) expands through a conventional steam turbine to generate electricity.

Figure 6-20 below shows a schematic diagram representing a parabolic trough solar field integrated into a fossil-fuelled combined cycle power plant. No new steam turbine, condensing, or electrical generation equipment is necessary. The solar steam simply replaces steam (i.e. MW) that would have otherwise been generated with fossil fuel consumption. Note, the solar generated steam can not be fed directly into a traditional combined cycle steam turbine, it first must be superheated by the HRSG superheater section.

The solar field consists of several hundred to several thousand parabolic trough solar collectors, known as solar collector assemblies (SCAs). Rows of SCAs are aligned on a north-south axis, allowing the single-axis troughs to track the sun from east to west during the day (Figure 6-21) Parabolic trough systems can be coupled with thermal energy storage (TES) to enhance the ability to dispatch the power plant. The current viable TES technology is the indirect molten salt two-tank system.

Some important site requirements for a parabolic trough system include having a land slope between 1% and 3% to minimise the trough tilt angle, and a large square to rectangular-shaped land area allowing for north-south SCA row arrangement.

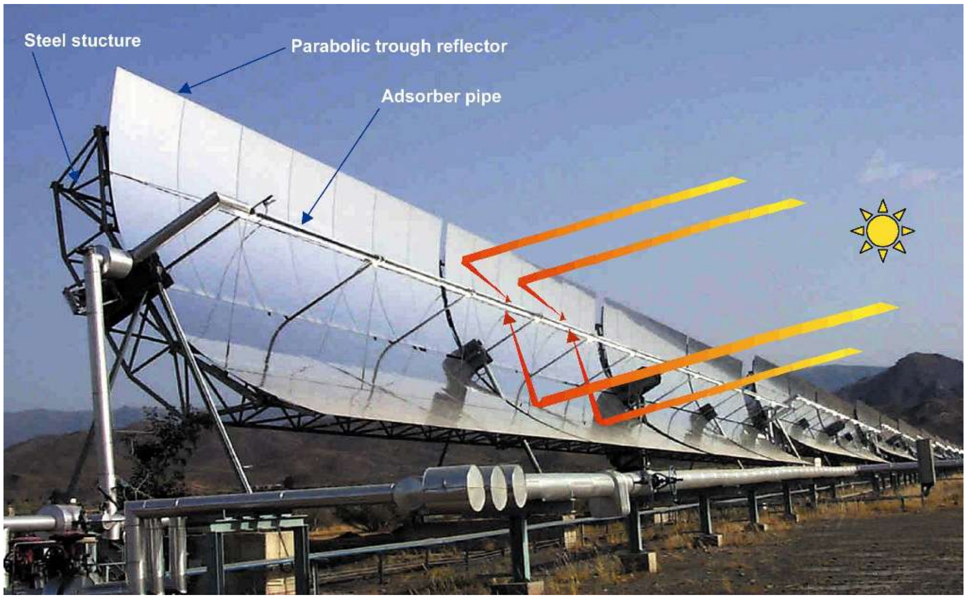


Figure 6-19
Parabolic Trough

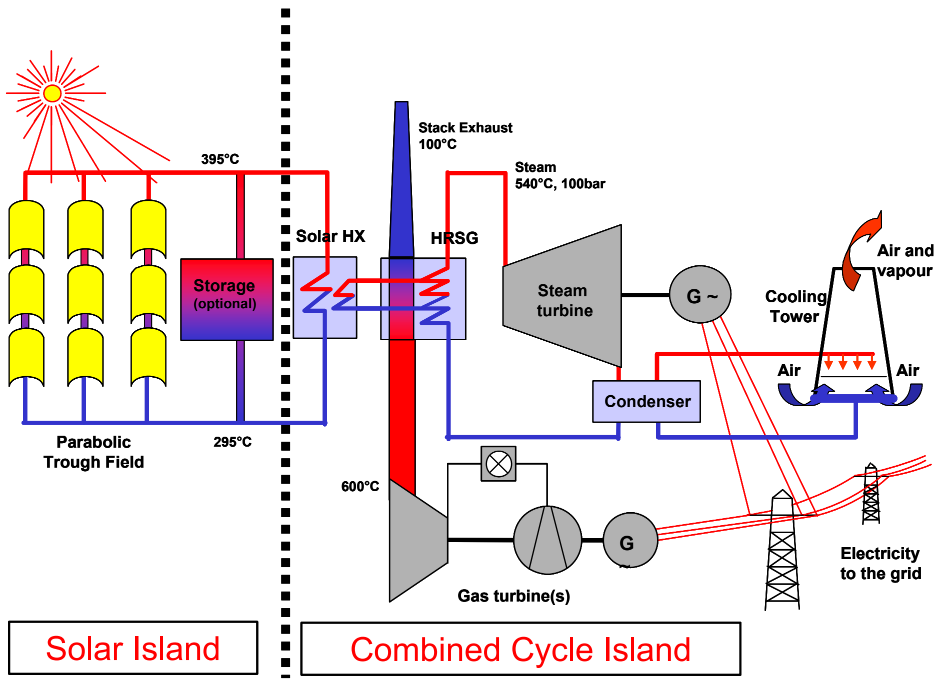


Figure 6-20
Solar Parabolic Trough System Integrated with Combined Cycle Plants

Figure 6-21
Parabolic Trough North-South Axis View

An alternative to using HTF and an SSG is currently being developed and is known as Direct Steam Generation (DSG). It generates steam directly in the solar field, omitting the HTF to water heat transfer process and allowing for potentially higher steam temperatures, thus improving thermodynamic efficiency. Furthermore, replacing HTF oil with water significantly reduces consumable costs, environmental hazards, and O&M costs. Nevertheless, directly generating steam in the solar field introduces the instability of two-phase flow in the receiver tubes and the risks associated with temperature gradients in the receiver tubes. Cost and performance issues will need to be addressed due to the high vapour pressure of water which will require thicker HCE system components when compared to synthetic oil HTF. For reference, vapour pressure of water at 343ºC is about 152 bara versus 5 bara for a typical synthetic oil.

Utilising molten salt HTF, as opposed to synthetic oil, has the potential of obtaining 565ºC+ steam, without the cost/performance issues associated with using water as the HTF described above. However, significant engineering and O&M issues arise due to the high freezing temperature of molten salts.

Power Tower/Central Receiver

A power tower/central receiver uses two-axis sun-tracking mirrors called heliostats to redirect DNI to a receiver at the top of a tower (Figure 6-22 & Figure 6-22). Molten nitrate salt HTF at 287ºC is pumped out of the “cold” tank, through the receiver, and into the “hot” tank at 565ºC. The “hot” tank delivers the molten salt to the SSG where superheated steam is produced and expanded through a conventional steam turbine producing electricity. Currently molten nitrate salt has been used as the common HTF because of its superior heat transfer and energy storage capabilities.

Figure 6-22
Picture of Central Receiver Plant

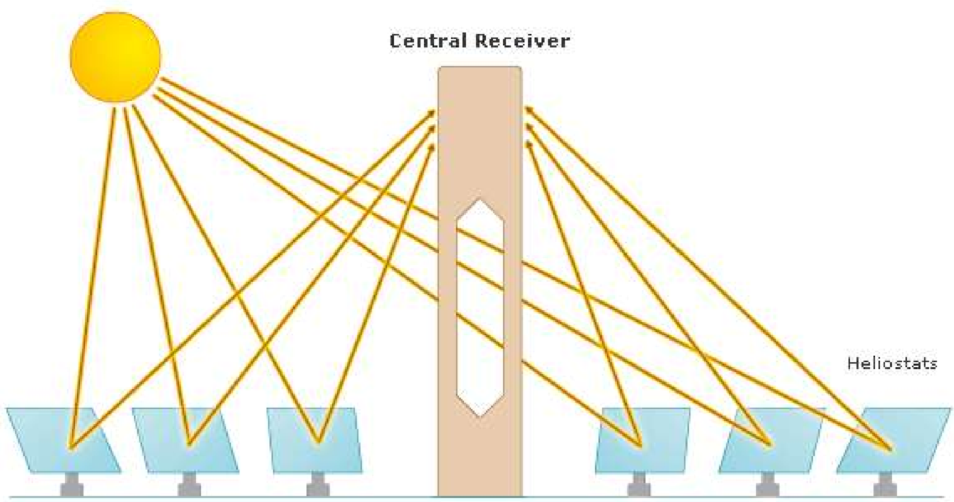


Figure 6-23
Heliostat to Receiver Sun Path

The ability of molten salt HTF to be heated to 565ºC and generate steam at 538ºC results in relatively higher cycle efficiencies than achievable with the lower temperature steam of the typical synthetic oil HTF parabolic trough plant. The elimination of oil also reduces environmental risks due to leaks and reduces consumable costs because salt is typically significantly cheaper than synthetic oil. However, molten salt has a relatively high freezing point at 221ºC. To maintain salt in the liquid state a significant electrical freeze protection system must be employed. A natural gas auxiliary boiler could also be used for this. Accounting for the carbon footprint associated an electrical molten salt freeze protection system requires that one make an assumption about the carbon intensity of the electricity that was used for the electric heat tracing. This will have very minor contribution to CO_2 emissions from this technology on a kg/MWh basis. Another disadvantage of this technology is that each mirror must have its own dual-axis tracking control; as a result, tower plants also have larger parasitic loads associated with mirror tracking relative to parabolic trough systems. Unlike the synthetic oil HTF parabolic trough system, power tower technology using molten salt allows for direct thermal energy storage (i.e. HTF is same fluid as storage media) to be integrated into the system, allowing for substantial cost reduction of the TES system compared to an indirect TES system because oil to salt heat exchangers are eliminated. Figure 6-24 shows a schematic diagram of the primary flow paths in a molten-salt solar power tower/central receiver plant with an integrated two-tank thermal energy storage system.

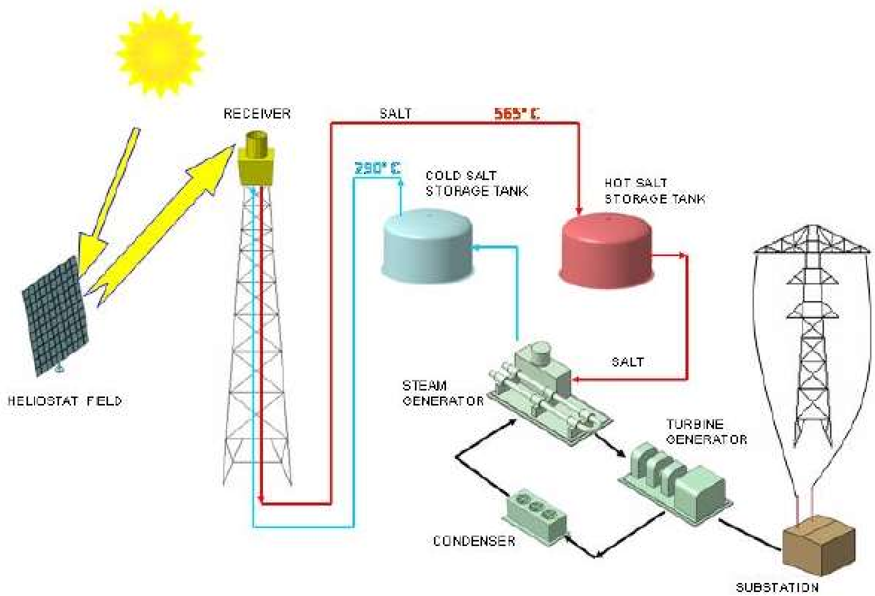


Figure 6-24
Schematic of Molten-Salt Power Tower System

Power tower designs have a fixed number of heliostats (solar field size) and a fixed tower height; the alternating plant design variables are the steam turbine/power block and storage capacities. More specifically, with a larger turbine plant output is higher at peak solar insolation periods, but less energy is available for storage, whereas a smaller turbine allows for more stored energy, and thus a higher capacity factor, but less peak output to the grid. The optimum balance is highly dependent upon the planned dispatch profile.

Some important site requirements include having a level land area; however the requirements are less stringent than with the trough design, in principle, because of the two-axis mirror tracking. Having a continuous parcel of land able to accommodate an ovular-shaped footprint is also a valuable feature. The footprint of tower systems is relatively larger than a trough based plant.

Compact Linear Fresnel Reflector

The Compact Linear Fresnel Reflector (CLFR) system uses multiple parallel mirrors to focus direct normal insolation onto a single elevated receiver. The mirrors are flat or elastically curved reflectors that are mounted on a sun tracker. Similar to the parabolic trough plant, rows of reflectors are typically placed on a north-south axis, allowing the single-axis mirror to track the sun from east to west during the day (Figure 6-25). CLFR systems are less optically efficient than trough, but offer the potential of reduced capital costs (on mirror area basis).

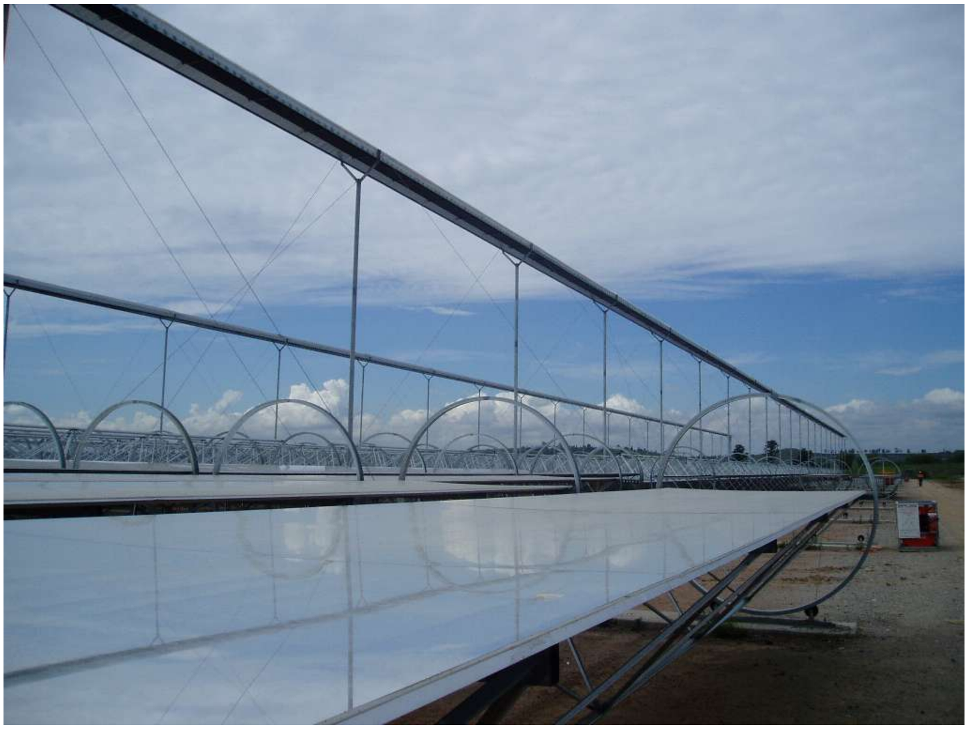


Figure 6-25
CLFR Mirrors and Receiver

CLFR technology uses water as the HTF, thus employing a direct steam generation process. The concentrated heat boils water within a receiver composed of specially coated steel tubes in an insulated cavity producing saturated steam (superheated steam is in development) which is then delivered to a conventional steam turbine or alternate user. The in-field HTF piping/components need to be thicker than parabolic trough field HTF piping due to the higher vapour pressure of water compared to synthetic oil and this is a significant consideration when the solar arrays are located remotely from the power block.

Figure 6-26 shows a typical CLFR configuration. The linear Fresnel reflector system is a modular system. A large-scale system will consist of multiple arrays of mirrors and receivers. Land requirements are less demanding than for parabolic trough and power tower plants for a given field MWth output.

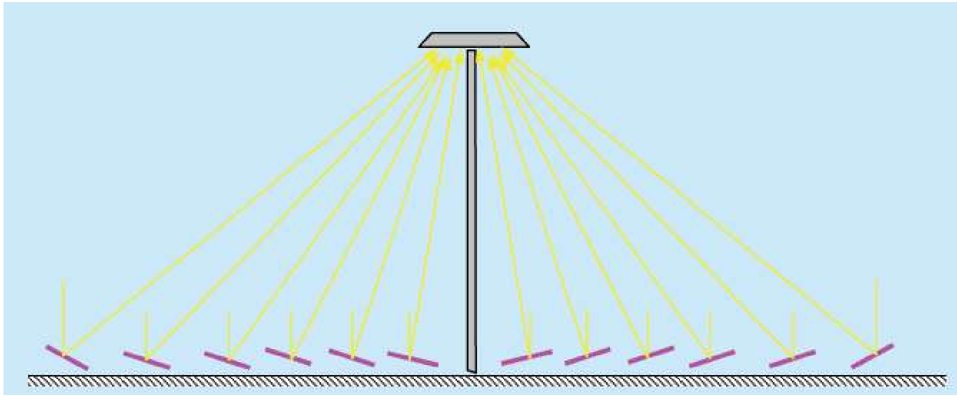


Figure 6-26
Mirror to Receiver Sun Path

Parabolic Dish/Engine

Dish/engine systems use an array of mirrors made from stretched membranes or flat glass facets to form a parabolic dish that focuses solar energy onto a receiver located at the focal point of the dish. The sunlight heats a working fluid in the receiver tube and used to generate electricity in a small engine attached directly to the receiver. The engine in a dish/engine system converts heat to mechanical power in a manner similar to conventional engines—by compressing a working fluid when it is cold, heating the compressed working fluid, and then expanding it through a turbine or with a piston to produce work. The mechanical power is converted to electrical power by an electric generator or alternator. Many thermodynamic cycles and working fluids have been considered for dish/engine systems, but the Stirling and open Brayton (gas turbine) cycles are generally favored with helium or hydrogen as typical working fluids. Conventional automotive Otto and Diesel engine cycles are not feasible in this application because of the difficulties in integrating them with concentrated solar energy. Figure 6-26 shows the dish/engine system being tested at the DOE Mesa Top Thermal Test Facility.

(Source: NREL)

Figure 6-27
25-kW SAIC Dish/Engine System at the DOE Mesa Top Thermal Test Facility

Parabolic dish/engine systems have the potential of achieving higher efficiency, greater modularity, and more autonomous operation than other CSP technologies. The modularity of dish/engine systems allows them to be deployed for remote and distributed applications, as well as in larger arrays. As with the other solar thermal technologies, dish/engine systems can also be hybridised with a fossil fuel to provide power that can be dispatched. However, solar thermal storage is not an option.

Technology Development Status

The maturity level, output ranges and important advantages and disadvantages of the four technologies described above are summarised in Table 6-6. The trough system is the most mature technology currently available for large-scale utility electricity generation, whereas the other technologies are in various phases of development and/or demonstration.

Table 6-6
Summary of Solar Technology maturities, output ranges, and important advantages and disadvantages

CSP Technology	Maturity Level 1 (Testing) To 5 (Utility)	Typical Capacity Range	Sun Tracking	Storage Option & Type	Major Advantages/Concerns
Parabolic Trough	5	50 to 300 MW	Single-axis	Oil-to-salt/salt-back-to-oil heat exchanger for Thermal Energy Storage (TES)	• Commercially viable, reliable, and proven solar technology • Working fluid is synthetic oil (molten salt and direct steam are in development). • Maximum steam temperature is approximately 370 °C based on currently employed HTFs. • Integration with combined-cycle plants and other fossil fuel fired plants offers potential to improve the overall solar-to-electric efficiency beyond stand-alone solar plants (highly dependent on integration method). • One possible concern is the potential environmental impact (if spilled) and safety hazards associated with synthetic oil HTF. • Thermal storage option is available, but is less effective then tower due to lower operating temperature. It requires a third working fluid, is a significant capital cost expense and is an added risk due to high freezing temperature of molten salts used today. • Extensive fluid piping system is required.
Power Tower / Central Receiver	3	10 to 20 MW (new conceptual range 100 to 300 MW)	Two-axis	Molten Salt TES	• Steam temperatures of 540 °C+ can be achieved allowing potential for most efficient integration with fossil fueld power plants (although not proven yet). • HTF can be molten salt or water/steam. • Molten salt can be used both as heat transfer fluid (HTF) and a storage medium, eliminating the use of additional heat exchangers. Higher operating temperatures offer better integration with thermal storage then parabolic trough/synthetic oil systems. • Significant heat tracing is required for the high freezing point of molten salt, approximately 220 °C. • Potassium and sodium nitrate salts are corrosive. • There is a relatively higher land requirement compared to trough and CLFR. • Piping is minimised by having a central energy receiver vs. vast in-field piping network required of trough and CLFR. • Two-axis heliostat tracking offers better solar resource usage at high incident angles but has higher O&M cost. • Currently no operating experience with utility-scale plants.
Compact Linear Fresnel Reflector	2	5 to 20 MW (new conceptual range 175 to 300 MW, although Ausra has announced scale –back from these larger sizes)	Single-axis	Hot water storage	• Land use requirement is less than a typical trough or tower plant. • Operation of the entire array system is simple due to its modular arrangement, no flexible/ball joints required which is O&M concern on trough plants. • Optical efficiency significantly lower than trough • Lower capital cost/m^2 due to relatively flat mirrors, lower profile, less advanced Fresnel receiver (no vacuum tube) than trough. • Water/steam is typical working and heat transfer fluid. • Storage concept is pressurised hot water which is significantly limited by high vapour pressure of water. • This technology is still in the demonstration/prototype stage, proven steam temperatures are lower than trough.
Parabolic Dish/Engine		10-25 kW per unit	Two-axis	Thermal storage not available	• Modularity allows for small, remote single unit installations or large utility-scale plants • Anticipated to be capable of higher efficiency, greater modularity, and more autonomous operation than other CSP technologies • High uncertainty surrounding capital and O&M costs • Long-term performance testing needed • Power purchase agreements signed between Solar Energy Systems and both Southern California Edison and San Diego Gas and Electric for 500-800 MW and 300-900 MW plants, respectively

Parabolic trough systems are the most commercially available CSP technology. The trough design was first commissioned in southern California in 1985 and known as the Solar Electric Generating Station (SEGS) I, delivering 13.8 MWe to the electric grid. The US currently receives electric power from ten parabolic trough power plants equalling over 400 MWe of installed solar trough power, all located in the southwestern states.

As mentioned above, direct steam generation (DSG) in the trough technology has its difficulties, mostly due to the high vapour pressure of the water. Altogether, parabolic trough DSG is a new and unproven technology. Ceimat and DLR (German Aerospace Center) are currently testing DSG at the Plataforma Solar de Almeria in Spain aiming to solve these various technical issues.

For the power tower technology, some system developers such as Abengoa and BrightSource Energy are opting for direct steam generation. The objective is to reduce cost (and risk) by eliminating the salt systems at the expense of significant (over ~30 minutes) TES, and still obtain 538ºC+ steam temperatures. Molten salt offers the valuable option of storing energy for later use (up to 15 hours) and thus the ability to more readily follow utility dispatch needs.

There are currently no utility-scale power tower plants in operation in the United States. However, the US Department of Energy had a 10 MW pilot power tower project in Barstow, California from 1982 to 1986, namely Solar One and later Solar Two. Solar One used DSG and was decommissioned in 1984 due to market trends; later in 1994 it was recommissioned as Solar Two using molten salt HTF and finally shut-down in 1999. Overseas, Spain has an operating 11 MW solar power tower in Seville named PS10 utilising DSG with 250-290ºC steam turbine inlet temperature. Some anticipated and under-construction power tower projects include: PS20-Abengoa (20MW, Spain, DSG, similar to PS10), Solar Tres-Sener (17MW, Spain, 565°C molten salt, 15 hrs TES), Ivanpah-BrightSource Energy (400MW, California, DSG, 550°C steam), and Antelope Valley-eSolar (245MW, California, DSG).

Currently, there are no operating commercial CLFR power plants in the United States. However, the 177MW CLFR Carrizo Energy Solar Farm project in San Luis Obispo County, California is under review by the California Energy Commission and is scheduled to be online in the first quarter of 2012. In addition, Ausra has an 18MWth (~3MWe) demo CLFR plant in operation in Bakersfield, California that exports steam to power the nearby Clean Energy Systems power plant and Spain has announced Gotasol, a 10MW CLFR plant in Gotarrendura.

Parabolic dish/engine technology is still in the demonstration stage. Currently, no commercial-scale projects exist. However, in the United States, a major demonstration, planned to lead ultimately to a 500- to 850-MW generating plant, was announced as part of a PPA between Stirling Energy Systems (SES) and Southern California Edison (SCE) in early August 2005. A month later, SES and San Diego Gas & Electric announced a similar agreement, this time for 300 to 900 MW. SES is working with Sandia National Laboratory on a six-dish 150-kW demonstration near Albuquerque NM in preparation for building a 40-dish 1-MW pilot facility in California as the first phase of the SCE PPA plant. If these proceed as planned, they promise to significantly accelerate dish/engine technology development.

For this evaluation, the solar technology considered for further examination is the parabolic trough system and the power tower system, both with six hour molten salt energy storage. A 200 MWe plant is used with a Rankine cycle, with steam turbine inlet steam conditions of 100 bar and 377ºC.

Major Technical Issues and Future Development Directions/Trends

One technical issue associated with the solar power technology is the need to increase the annual capacity factor. One advantage of parabolic trough solar power plants is their potential for storing solar thermal energy to use during non-solar periods and to dispatch when it is needed most. As a result, thermal energy storage (TES) allows parabolic trough power plants to achieve higher annual capacity factors-from 25% without thermal storage and up to 70% or more with it. As shown in the Figure 6-28 the solar field is sized to allow for both direct power generation and storage of energy during daytime hours. The stored energy is used in the evening to continue power generation after the sun goes down.

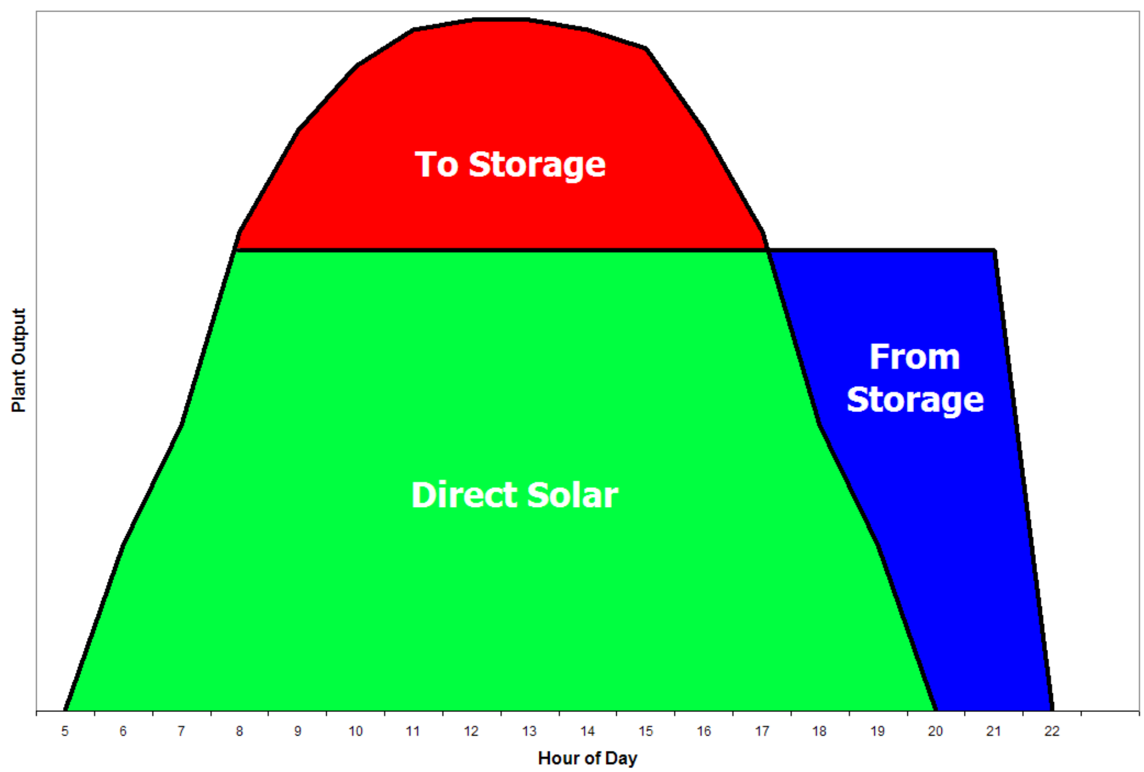


Figure 6-28
Power Output Variation vs. Time

In addition to solar radiation issues, land and water use are also key factors.

Solar thermal plants without storage require 2-4 hectares/MW of peak capacity in good solar-resource locales (over 2200 kWh/m^2/yr). However, plants that incorporate some storage may require three to ten times more land per peak megawatt, and their generating units will typically not be designed to use the entire peak thermal output of the collector field. Therefore, a more meaningful metric of land use would be the area required per annual MWh of output, which would range between about 0.2 and 1.6 x 10^{-3} hectare/MWh/yr. (Note that, although conceptually distinct, these two quantities have the same fundamental units of area/power).

Water requirements of trough and tower solar thermal generating plants are similar to those of other steam plants of equal nameplate capacity using wet cooling towers. Dry cooling is a viable water conserving alternative, but at a cost of up to 10% lower operating efficiency. Thus, for optimum efficiency, some 2 to 4 m^3 of water is needed for cooling for every MWh generated. In all cases, a minor amount of water may be needed for mirror cleaning.

Solar thermal power plants that are not hybridised with fossil fuel generate no direct emissions of CO_2, methane or other greenhouse gases. Even when hybridised, the solar-generated portion of the plant's output is emissions free. Consequently, all solar-thermal power plants provide greenhouse gas emissions reductions. In addition, should a CO_2 emissions-reduction mandate be enacted in the future, solar thermal power could become an important component of a CO_2 emissions-reduction strategy and could participate in CO_2 emissions trading.

The CO_2 emissions-reduction potential of a renewable energy power plant is a function of the generation mix of the existing generation system, while the effective CO_2 emissions-reduction cost is a function of the CO_2 emission rate and of the average generation costs of the base system and the renewable energy power plant.

Integrating concentrating solar thermal energy into existing combined cycle power plants may be achieved with several objectives in view. Integration options basically fall into two categories: the ability to create more MWe to the grid; or to replace existing fossil generated MWs with solar generated MWs. For the most part, retrofit applications fall into the later category, which means the plant's heat rate will be lowered when solar heat is added into the Rankine cycle. As important as heat rate is, one of the most critical assessment parameters used to compare all integration options is solar use efficiency.

It is very important when arriving at solar use efficiency to properly establish a base case from which to compare the effect of solar thermal input. For reference, stand-alone trough plants using synthetic oil can achieve sent-out cycle efficiencies of around 33% (sent-out MWe to grid divided by solar thermal input to Rankine cycle), which can be directly compared to solar use efficiency. If the solar use efficiency is less then 33% for trough ISCC applications, one should weigh the economics of a stand-alone plant.

Admittedly, the capital costs ($/kW) of ISCC retrofit projects will most likely be less than stand-alone projects, so slightly lower solar use efficiencies should still work out economically. Thermodynamically, solar heat input should ideally be used to replace latent heat input from the HRSG at the highest possible temperature level. However, not all solar plant technologies and/or HTFs can achieve the best solar use efficiency.

Integrated solar steam can be used in both high and low temperature applications. For integrations requiring high temperature steam, the heat transfer fluid must be able to properly perform under such conditions. The currently available high temperature (>300ºC) heat transfer fluids capable of producing superheated steam are limited to those listed in Table 6-7. The drawback is that these fluids (with the exception of molten salt) are considered hazardous materials for transport, handling, and disposal.

In the case where low temperature steam is all that is required, a low temperature (≤300ºC) heat transfer fluid may be utilised. This lower temperature requirement broadens the selection pool of available heat transfer fluids including petroleum-based mineral oils. Mineral oils have the advantage of being more economic and more environmentally friendly than the HTFs used in high temperature applications. Mineral oils are non-hazardous, not regulated for transport, and can be recycled with other lubricant oils.

Table 6-7 (high temperature HTF) and Table 6-8 (low temperature HTF) below list important properties for evaluating potential HTFs best suited for the application. Maximum operating temperature is the primary HTF selection factor—this property ultimately defines the limits of integration strategy, unless DSG is selected. Selecting an HTF with the right freeze point can save a project millions of dollars. For instance, a project location with low night-time temperatures requires a freeze protection system, most commonly consuming natural gas. Using a low freezing point HTF, such as Therminol XP, which freezes at -20ºC, can eliminate or significantly reduce size and operational hours of the freeze protection system.

In cases where the combined cycle plant will usually operate at night, steam turbine exhaust can be used for freeze protection (and also reduce cooling duty). The HTF freezing point becomes less significant in this case. In addition, heat transfer fluids with higher specific heats require less flow for a given duty, thus decreasing the size and parasitic load on the HTF pumping system. Higher specific heats also reduce the required system HTF volume, significantly reducing capital and operating costs for initial fill and replacement HTF.

Another important variable in HTF selection is vapour pressure. This property partially dictates the design pressure of all HTF system components. Less importantly it determines the size of the nitrogen blanketing system used to protect and pressurise the HTF expansion system. A higher vapour pressure requires a higher nitrogen pressure in the expansion vessels in order to maintain the HTF in the liquid state. Although this higher nitrogen pressure benefits the HTF pumping system by adding to the suction head (when pumps are located downstream of the expansion system), the nitrogen itself is expensive to purchase, transport and store—in most cases it's stored as a liquid. Therefore, a lower HTF vapour pressure is always desired. Finally, viscosity plays a significant role in the pump size, parasitic load, and HTF piping diameters. More viscous fluids have a lower Reynolds Number (higher friction factor) for a given flow rate and pipe size resulting in higher friction losses. This will result in either larger HTF pumps and system design pressure or larger pipe sizes (to reduce pump power and system design pressure). Therefore an HTF with a lower viscosity will allow for smaller HTF pipe diameters which adds up to significant cost savings for solar fields with several thousand meters of pipe.

Table 6-7
Selected High-Temperature (>315 °C) Heat Transfer Fluid Properties Used for HTF Selection in Integrated Solar Applications

Heat Transfer Fluid	Manufacturer	Composition	Max Operating Temp	Freeze Point	Density (24ºC)	Specific Heat (205ºC)	Specific Heat (390ºC)	Liquid Viscosity (205ºC)	Liquid Viscosity (390ºC)	Vapour Pressure (205ºC)	Vapour Pressure (390ºC)
			ºC	ºC	kg/m^3	cal/gºC	cal/gºC	cP	cP	kPa	kPa
Therminol VP-1	Solutia	Biphenyl and Diphenyl Oxide	400	12	1060	0.492	0.622	0.383	0.150	27.2	999.7
Therminol 72	Solutia	Synthetic aromatic mix	380	-9	1075	0.487	0.604 (380ºC)	0.490	0.140 (380ºC)	31.9	574.6 (380ºC)
Slytherm 800	Dow	Dimethyl Polysiloxane	400	-60	934	0.460	0.537	1.035	0.258	112.1	1307.9
Dowtherm A	Dow	Biphenyl and Diphenyl Oxide	400	12	1054	0.500	0.638	0.380	0.130	27.3	977.0
Xceltherm MK1	Radco	Biphenyl and Diphenyl Oxide	400	12	1058	0.492	0.622	0.383	0.149	27.2	1003.2
Molten Salt	NA	60% NaNO3 and 40% KNO3	565	220	1905 (290ºC)	0.36 (290ºC)	0.37 (565ºC)	3.562 (290ºC)	1.14 (565ºC)	100 (290ºC)	100 (565ºC)

Table 6-8
Selected Low-Temperature (≤315 °C) Heat Transfer Fluid Properties Used for HTF Selection in Integrated Solar Applications

Heat Transfer Fluid	Manufacturer	Composition	Max Operating Temp	Freeze Point	Density (24ºC)	Specific Heat (205ºC)	Specific Heat (390ºC)	Liquid Viscosity (205ºC)	Liquid Viscosity (390ºC)	Vapour Pressure (205ºC)	Vapour Pressure (390ºC)
			ºC	ºC	kg/m^3	cal/gºC	cal/gºC	cP	cP	kPa	kPa
Therminol XP	Solutia	Hydrogenated white mineral oil	315	-20	875	0.625	0.718	0.805	0.337	2.0	42.5
Therminol 55	Solutia	Synthetic hydrocarbon mix	290	-26	869	0.612	0.682 (290ºC)	0.718	0.366 (290ºC)	2.5	25.8 (290ºC)
Therminol 59	Solutia	Alkyl substituted aromatic	315	-45	970	0.547	0.640	0.461	0.231	14.8	162.7
Xceltherm 600	Radco	Hydrogenated white mineral oil	315	-20	849	0.627	0.717	0.590	0.252	1.2	24.5
Paratherm NF	Paratherm	Hydrogenated white mineral oil	315	-43	869	0.670	0.810	0.650	0.150	3.0	13.8
Paratherm HE	Paratherm	Paraffinic Hydrocarbon	315	-15	861	0.612	0.708	1.130	0.472	0.1	6.0

Anticipated Improvements by 2030

As concentrating solar power plants gain footing in the utility market and their installed capacity expands, the cost of the plants is expected to continue to decrease due to the higher production volume of key equipment and increased experience gained by manufacturers and engineers who are planning and building plants. In addition, it is expected that cheaper heat transfer fluids will become available or that fluids that can handle higher temperatures, and therefore increase efficiency, will be used. The cost of storage systems is also expected to be reduced. Furthermore, improvements are expected in receiver tube absorption and steam turbine efficiencies that would increase the capacity factor for these plants. The combination of a decrease in capital cost and an increase in plant output will lead to a lower cost of electricity. An overview of the anticipated capital cost improvements by technology is presented in the table below.

Table 6-9
Anticipated Improvements in Solar Thermal Capital Costs by 2030

	Parabolic Trough		Central Receiver	
	With 6 hours of Thermal Storage	Without Storage	With 6 hours of Thermal Storage	Without Storage
Capital Cost (relative to 2015 technology)	0.7	0.65	0.65	0.60

Development and Commercialisation Timeline

High temperatures and solar concentrating systems are necessary for the solar thermal technologies to achieve reasonable electric generating efficiencies. In the US the DOE established the Solar Energy Technologies Program, a cooperative effort with private industry to conduct R&D to advance the development of solar thermal technology. The goal of the DOE program is to reduce the cost of electricity from concentrating solar power technologies to \$0.08 - \$0.10/kWh by 2012, via continued research and deployment.

Each of the solar thermal technologies is at a different stage of development. Currently, the most mature technology is the parabolic trough, which is at the commercial phase. Power towers have been demonstrated and are ready for scale up and commercialisation. Power towers have been demonstrated at the large megawatt scale and Fresnel reflectors are in development or demonstration phase.

Utilising molten salt HTF, as opposed to synthetic oil, has the potential of obtaining 565°C+ steam, without the cost/performance issues associated with using water as the HTF described above. However, significant engineering and O&M issues arise due to the high freezing temperature of molten salts. R&D using molten salts in parabolic trough systems is ongoing and has the potential of reducing LCOE over synthetic oil HTF trough plants.

Development and/or further refining of these systems for power generation will continue well into the 2025-2030 timeline.

Relevant Business Issues

The economic viability of a site for a concentrating solar plant is dependent on many factors including the amount of direct normal solar radiation, the topography, land availability, and access to transmission lines. Based on these factors in the US the southwestern states offer the best opportunity for developing solar thermal technologies. Typical direct-normal insolation throughout the United States is most abundant in the south-west, and the largest regions of highest-quality resource are in Nevada, Arizona, California, and New Mexico.

Other locations outside of the US that are well suited for concentrated solar thermal technologies include Southern Africa, the Mediterranean countries (i.e., North Africa, Middle East, and Southern Europe), India, parts of South America, northern Mexico, and Australia.

A resource that can impact cost is water availability and the type of cooling systems used. Water can be a significant issue in arid climates impacting cost of cooling system. Other key business and market indicators are an increase in renewable portfolio standards; commercial applications of solar technologies; and advances in thermal storage.

Solar Photovoltaic

Brief Description of the Technology

Solar photovoltaic (PV) technologies convert sunlight directly into electricity using semiconductor materials that produce electric currents when exposed to light. Semiconductor materials used for PV cells are typically silicon doped with other elements that have either one more or one less valence electrons to alter the conductivity of the silicon. For example, if the silicon is doped with an element having one more valence electron, such as phosphorus, then the resulting material will have an extra electron available for conduction. This material is called an n-type semiconductor. Conversely, when the silicon is doped with an element having one less valence electron, such as boron, then the p-type semiconductor that is produced has an electron vacancy, or hole. When adjacent layers of n-type and p-type materials are illuminated, a voltage develops between them, which can cause a DC electric current to flow in an external circuit.

A typical silicon solar cell today is about 100 cm^2 in area and produces about three amps at 0.5 volts. Individual cells are combined into modules and connected in series and parallel to provide higher voltage and current levels. The active areas of the modules range from 0.1 to 2 m^2, and the modules are typically connected together in flat arrays. Three array configurations are used for PV systems: fixed-tilt arrays that are stationary and oriented to tilt towards the equator for maximum sun exposure, single-axis tracking that tracks the sun's movement from east to west, and two-axis tracking that tracks the sun to remain perpendicularly oriented to the sun's rays. The DC power generated is converted to AC by a power-conditioning unit, if necessary.

It is important to understand the different sorts of "watts" that are used in describing PV systems to correctly anticipate the field performance of such systems versus the module-label rating in "DC watts at STC" (Standard Test Conditions, which are 1,000 W/m^2 illumination and 25°C module temperature). The STC are "laboratory" conditions that seldom occur in the field and the actual module output varies as illumination and temperature change. Typically, modules operate 20 to 40°C hotter than STC on very sunny days and, as a result, power output is10% to 20% less at 1,000 W/m^2 illumination than their labels say. Other derating factors include imperfect use of the available land area for the array (packing-factor loss), electrical losses due to field wiring resistance and module-mismatch (no two modules have precisely the same current-voltage characteristics), and less than 100% inverter DC-AC conversion efficiency. These losses altogether amount to about 33% derating of plant AC output versus the sum of the modules' DC ratings.

There are three main types of PV technology: flat plate crystalline silicon, thin film, and concentrated PV. Flat plate crystalline silicon is the most common PV technology available today and also the most mature. To date, crystalline silicon cells have achieved the greatest efficiency of non-concentrating PV technologies, but the manufacturing process remains relatively slow and difficult to automate. Nevertheless, because crystalline silicon cells have the most highly-developed manufacturing processes, they remain at the low end of the PV cost spectrum.

Thin film PV cells are a developing technology that is beginning to capture a share of the PV market. Very thin films of amorphous silicon, copper indium diselenide (CIS), cadmium telluride (CdTe), or other novel semiconductors are deposited on a low-cost substrate, such as plastic, glass, or metal foil. These thin film cells use considerably less raw material than crystalline cells and their manufacturing techniques are well suited for mass production. To date, thin film cells have not achieved the efficiencies of crystalline cells, but they show potential for doing so. Meanwhile, their greater application flexibility promises to accelerate their marketplace acceptance.

In concentrated photovoltaic (CPV) systems, lenses or mirrors gather sunlight and concentrate its intensity onto small PV cells. The goal of these concentrator systems is to minimise the amount of PV material and energy required to produce the cell while maximising sunlight collection. CPV systems can provide higher conversion efficiencies than conventional flat-plate systems – more than 30% for multi-junction devices, but it has been slow to gain a commercial foothold until just recently in central station applications. CPV systems require two-axis tracking to maintain direct normal (perpendicular) illumination for optimum concentration.

PV systems have been used both for small-scale residential, commercial, and industrial applications and for larger-scale utility applications. This report provides detailed cost and performance estimates for flat-plate utility-scale crystalline PV systems. It also provides discussion of CPV systems and residential-scale systems.

Technology Development Status

PV technology is still evolving and has not yet reached mature commercial status. Without subsidies, it is currently best suited economically to small installations (several watts to a few kilowatts) in special applications, including electrical switching and lighting at remote locations, billboard lighting and emergency telephones along highways, and other special applications where, in fact, PV often can provide a service at the lowest cost. Other important present markets for PV, driven by significant subsidies, include those derived from growing public interest in "green power," such as residential and commercial rooftop retrofit installations of 1 to 500 kW each. This market force will also help to stimulate the growth of Building Integrated PV (BIPV) throughout the second decade of this century. BIPV includes roofing materials and building facades, generally installed only during new construction.

Large-scale bulk-power PV facilities at the present time are not competitive with other intermediate and peaking supply technologies and it may be unlikely that many large centralised PV facilities will be built in the near future outside of markets where they are specifically motivated by policy-driven subsidies, such as in Germany, Spain, Portugal, and several other European Union countries. Also, Renewable Portfolio Standard (RPS) requirements in several states within the US appear to be fuelling central-station PV facilities due to solar carve outs requiring that a portion of the RPS be met with solar technologies. Two multi-megawatt PV systems were commissioned in the US in the first half of

2008 and hundreds-of-megawatt PV agreements have already been announced in the state of California.

Major Technical Issues and Future Development Directions/Trends

One of the major issues with solar photovoltaic systems can be the intermittency associated with the variability of the solar resource. Unlike solar thermal plants, PV systems have no inherent thermal storage within a heat transfer fluid. Storage technologies are necessary to produce power capable of dispatched or “firm” solar power, but they add cost to the system. For non-utility-scale systems where net metering policies are in place, grid-tied systems often forego storage because they can transfer excess energy to the grid, essentially using it as a 100%-efficient storage system.

Utility distribution companies also have concerns about the safety and power-quality effect of connecting PV to distribution feeders. These interconnection questions involve such issues as islanding protection, fault contributions, and voltage regulation. For most small PV systems, recent Institute of Electrical and Electronics Engineers (IEEE) and state utility commission standards within the US have made interconnection more straightforward.

Because PV devices generate DC power, electronic interfacing devices (inverters) are used to convert the power into AC for connection to the grid. Inverter reliability has been an issue for grid-connected PV systems, making inverter replacement or repair a leading O&M cost component. This situation has been improving, but careful selection of the specific inverter for any large installation is warranted.

The lack of transmission infrastructure to deliver power from remote solar resources continues to be a barrier to new solar development in Australia where the best solar resources are inland and the major population centres are on the coasts. Both the cost of new transmission and the inherent siting issues can delay or prevent new project development.

Anticipated Improvements by 2030

The cost of electricity from photovoltaic plants is expected to decrease rapidly in the future. This is due both to expected reduction in solar panel costs and increased efficiency. As more solar PV plants are built, the cost of solar modules continues to decrease due to mass production. The balance of system and inverter costs is also expected to decrease over time. In laboratories, researchers have continued to develop new PV configurations, such as multi-junction concentrators, that promise to increase cell and module efficiency. While the efficiencies seen in a commercial solar field typically lag the record efficiencies seen in laboratories by 15 to 20 years, these improvements can be expected to be seen by 2030. Higher efficiencies can also contribute to lower capital costs and lower operation and maintenance costs as less surface area is needed to produce a given amount of power. Figure 6-29 shows the anticipated cost reduction curve for photovoltaic modules based on the amount of future deployment. Table 6-10 summarises the impact of the anticipated improvements on photovoltaic capital costs and collection efficiency. It can be seen that the biggest improvements in collection efficiency are expected from the multi-junction cells that are currently receiving a significant R&D focus.

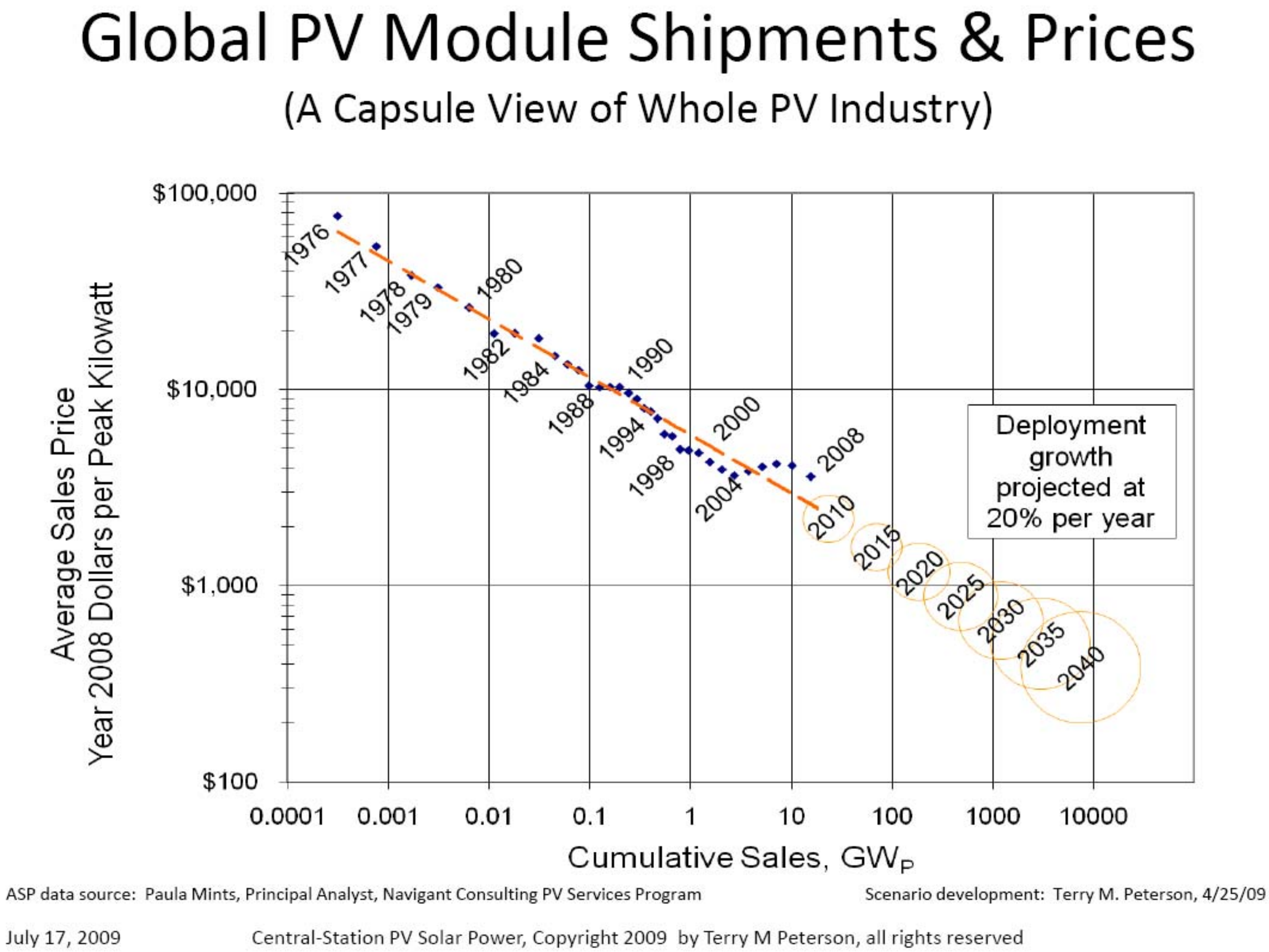


Figure 6-29
Anticipated Cost Improvement in Photovoltaic Technology with Deployment

Table 6-10
Anticipated Improvement in Photovoltaic Technology by 2030

	Fixed Flat Plate	Single Axis Tracking Flat Plate	2-Axis Tracking Concentrating Arrays with Multi-Junction Cells
Capital Cost (relative to 2015 technology)	0.65	0.65	0.65
Collection Efficiency (relative to 2015)	+2.9 pts	+2.9 pts	+10.0 pts

Development and Commercialisation Timeline

New materials and manufacturing techniques have been sought throughout the history of PV to increase efficiency and lower costs. Overall, these efforts have been very successful, and new materials and techniques continue to promise significant further improvements. The key to reducing the cost of crystalline silicon cells has been improved manufacturing techniques to speed mass production while also reducing material consumption and improving efficiency. Research and development in thin-film PV cells is also showing promising improvements in performance laboratory testing and strong interest from venture capitalists. Again, the ability to manufacture large quantities in a cost effective manner along with improved efficiency will help bring down the costs for thin-film PV and help its entrance into the market. Research in concentrating solar PV systems is focusing on reliability of both the optical concentrators and the controls and sensors required for dual-axis tracking systems.

Relevant Business Issues

The countries that have the highest deployment of solar energy tend to also have public policies that mandate deployment levels and offer various types of financial incentives to offset the costs. In Germany, the massive deployment of solar PV is economically feasible due to the Feed-in Tariff system. Similarly, the Spanish Feed-in Tariff supports the development of solar thermal technologies.

PV projects would also be more competitive with higher natural gas prices or limits on fossil fuel use and greenhouse gas emissions.

Wind

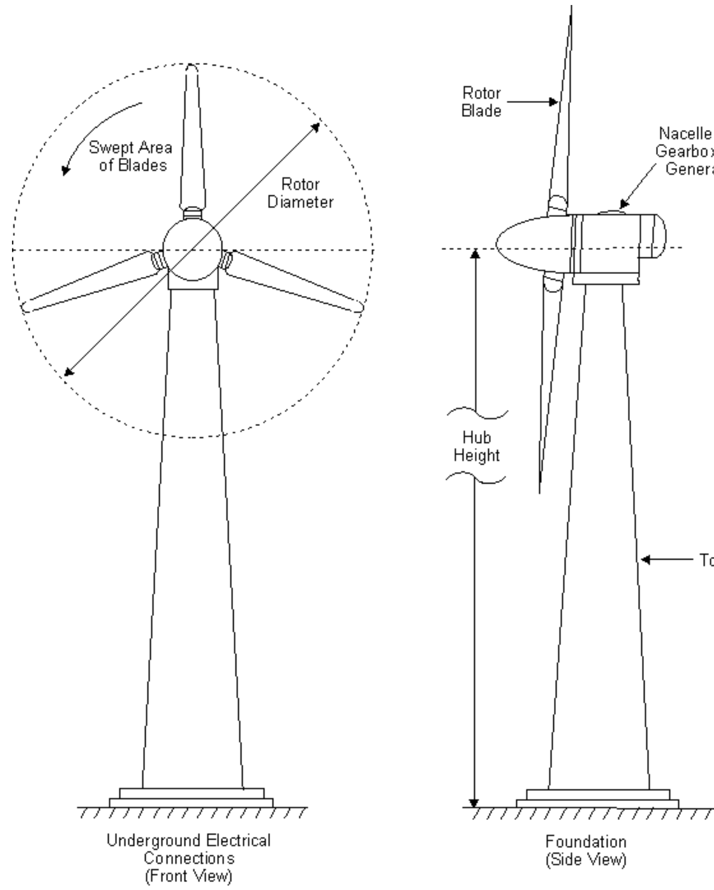
Brief Description of the Technology

In recent years, wind has been the fastest growing form of electricity generation in the world. The World Wind Energy Association reports that installed wind capacity worldwide at the end of 2008 was over 121,000 MW with forecasts of continued large-scale installation. Almost all wind power capacity installed to date is on-shore wind. However, the superior wind resources available off-shore along coastlines has led to considerable research and development of larger off-shore wind turbines and the construction of a few off-shore wind farms.

On-Shore Wind

During the past 20 years of development, numerous wind turbine design configurations have been proposed and tested, including vertical and horizontal axes, upwind and downwind rotors, two or three blades, direct and gearbox-drive train, and fixed-speed, two-speed, and variable-speed generators. Today, the most common wind turbine configuration is the three-blade, upwind, horizontal-axis design with a three-speed gearbox, variable-speed generator and power electronics to generate 50 or 60 Hz power.

The primary components of an on-shore wind turbine include the tower and foundation, the rotor, the nacelle and drive train, and the electrical controls, all of which are described in more detail below. Figure 6-30 shows a typical wind turbine.



(Source: US Department of Energy. Energy Information Administration. "Forces Behind Wind Power". Renewable Energy 2000: Issues and Trends. DOE/EIA-0628. February 2001.)

Figure 6-30
Wind Turbine Front and Side View

The tower is the base that holds the nacelle and the rotor. Typically, turbine towers are constructed from steel. To support the tower, the rotor, and the nacelle, as well as the dynamic structural loads created by the rotating turbine, a large steel-reinforced concrete foundation is typically required, with the exact amount of materials needed depending on the site and soil conditions.

For large-scale electricity production, multiple wind turbines are typically arranged in single or multiple rows, which are oriented to maximise generation when the wind is from the prevailing direction. The wind turbines must be arranged to minimise the impact of wake turbulence on other downwind turbines. To do this, they are often separated by five to 15 rotor diameters downwind and three to five rotor diameters in the direction perpendicular to the wind. Because individual wind turbines require a minimal area for the foundation, only 5-10% of the total land covered by the wind farm is used for the turbines and the remaining land area is available for crop production, grazing land for livestock, or other uses.

At the top of the tower, the rotor blades capture the wind and transfer its power to the rotor hub, which is attached to the low-speed drive shaft. In modern wind turbines, the pitch of the rotor blades is controlled by individual mechanisms that rotate the blade about its long axis to control the wind load on the turbine in high winds. The rotor also helps to maintain a constant power output and limit drivetrain overload.

The rotor blades are conventionally fabricated from fiberglass composites. However, the wind industry seems to be moving towards carbon composite blades, which have a much higher length to weight ratio, allowing longer blades to be used as rated capacity increases without making the dynamic loads at the top of the tower proportionately bigger. The rotor blades are attached to the hub, which is typically made from cast iron or steel.

As the rotor blades capture the wind, they rotate the hub and the low-speed shaft of the turbine. Some turbine designs use direct-drive multiple-pole generators, and most use a three-stage gearbox to increase the rotation speed and drive the generator to produce electricity. Contrary to typical electrical generators, the rotor, gearbox, and generator are designed to efficiently capture wind energy at both low and high wind speeds. Efficiency is less important at higher wind speeds above the rated wind speed, where the blade pitch is adjusted to spill some of the wind in order to maintain the rated power. The nacelle serves as the housing for the gearbox and the electrical generator and is typically fabricated using fiberglass composites.

The electronic controller monitors the wind turbine’s condition. It controls the yaw mechanism, which uses an electric motor to rotate the hub and rotor blades so that the turbine is optimally facing into the wind. It also starts and stops the turbine based on wind speed and shuts down the turbine if there is a malfunction.

Wind turbines are designed to operate within a wind speed window, which is bound by a “cut-in” speed and a “cut-out” speed. When the wind is below the cut-in speed, the energy in the wind is too low to utilise. When the wind reaches the turbine’s cut-in speed, the turbine begins to operate and produce electricity. As the wind gets stronger, the power output of the turbine increases until it reaches its rated power. After this, the blade pitch is controlled to maintain the rated power output, even as the wind speed increases, until the wind reaches its cut-out speed. At the cut-out speed, the turbine is shut down to prevent mechanical damage.

Wind plants typically are operated unattended and are monitored and controlled by a supervisory control and data acquisition (SCADA) system. Using onboard computers, wind turbines start up when the wind reaches its cut-in speed and shut down when the wind exceeds its cut-out speed or drops back below the cut-in speed. The system is also designed to shut down the turbine if there are any mechanical or electrical failures detected, and maintenance crews will be notified.

Off-Shore Wind

The primary difference between offshore and onshore wind turbines is the size and foundation requirements. Due to the high cost of offshore wind turbine foundations and undersea electric cables, offshore wind turbines are typically larger than their onshore counterparts in order to take advantage of economies of scale. In addition to the difference in size, offshore wind turbines have been modified in a number of ways to withstand the corrosive marine environment, such as implementation of a fully-sealed or positive-pressure nacelle to prevent corrosive saline air from coming in contact with critical electrical components, structural upgrades to the tower to withstand wave loading, and enhanced condition monitoring and controls to minimise service trips.

Currently, commercial offshore wind farms are installed in water depths of up to 30 m with foundations fixed to the seabed. The most common foundation type for shallow depths is the steel monopole foundation, which is drilled or driven 25 to 30 m into the seabed. Other types of fixed foundations include steel or concrete gravity bases, which rest on top of the seabed and rely on the weight of the structure to provide stability. Bucket foundations are large-diameter hollow steel structures that are partially driven into the subsea structure by suction and filled with soil and rock to stabilise the foundation. Future developments in offshore wind turbine foundation technology include fixed turbine foundations for transitional depths of 30 m to 60 m and floating turbine foundations for deepwater sites of 60 m to 200 m.

Currently, offshore wind farms are installed at distances from shore ranging from 0.8 km to 20 km. Undersea cables connect the wind turbines within a project to an offshore substation and from the substation to the mainland. Most offshore wind farms utilise high voltage AC transmission lines to transmit power from the offshore substation to the mainland. High voltage DC (HVDC) transmission is a new technology that experiences lower electrical line losses than high voltage AC. However, rectifier and inverter losses are introduced when converting from AC to DC at the offshore substation and from DC back to AC at the onshore grid connection point. The lower line losses are expected to outweigh the additional electrical conversion losses and cost differential only for projects located a significant distance from shore.

Technology Development Status

On-shore wind technologies are a generally mature technology. However, the size and generating capacity of on-shore wind turbines continue to grow. With these increases in size come new challenges for structural foundations and supporting towers. Off-shore wind has just begun commercial installation.

Major Technical Issues and Future Development Directions/Trends

As with many other renewable technologies, intermittency can be an issue for wind development. As the amount of wind integration with the electricity grid increases, the intermittency of wind can become more of a problem. Forecasting systems have been improving over the years to allow system operators to schedule a wind plant’s capacity and energy with some accuracy, effectively avoiding some capacity and fuel costs while maintaining reliability standards.

The lack of transmission infrastructure to deliver power from remote wind resources also continues to be a barrier to new wind development. Both the cost of new transmission and the inherent siting issues can delay or prevent new project development.

Anticipated Improvements by 2030

Developments in the operation and efficiency of wind turbine technology are expected to be the main driver in the decrease in wind power costs in the future. As larger turbines with larger rotors and higher hub heights are used, the power output of a single turbine will increase. Improvements in the power electronics and drive systems will also increase the performance of the turbines. In addition, wind sensing equipment continues to improve, allowing for more optimised use and operation of the wind turbine farms, resulting in increased power production for the same sized wind farm. The cumulative impact of these anticipated improvements is estimated to decrease the capital cost of wind turbine installations by 35% in 2030 relative to 2015 technology.

Development and Commercialisation Timeline

On-shore and off-shore wind farms are continuing to be installed worldwide. On-shore wind turbines are expected to continue to increase in size for the near future, though it is expected that there will ultimately be a limit due to rotor diameter, likely at a generating capacity of 3 to 5 MW. As off-shore wind farms become more prolific, their size will also likely increase and improvements will be made to their design and maintenance as operational experience is gained.

Relevant Business Issues

Public resistance to wind development is common due to the noise associated with wind turbines, the visual impacts, the addition of transmission lines, and other environmental issues. A proactive approach is required to assess environmental impacts and address community concerns.

The noise produced by operating wind generation facilities is much different in both level and character from the noise generated by large power plants and other industrial facilities. It is generally considered to be low-level noise and consists of both mechanical and aerodynamic components. In August 2002, the National Wind Coordinating Committee issued an update to their report, *Permitting of Wind Generation Facilities*[4], which addresses noise characteristics, impacts on receptors, prediction and measurement, and mitigation strategies. In general, the more the noise from a new source exceeds the background level or generates a different tonal characteristic than background noise, the more it will be unacceptable to the local community. Turbine noise studies should be conducted when siting wind facilities to predict noise level profiles in the areas surrounding the wind facility.

Although many wind projects are located in rural and remote areas, a project's impact on the natural terrain and landscape can raise public acceptance issues. In general, deploying fewer and wider-spaced turbines of uniform type, colour, tower design, and rotational direction enhances a project's visual appearance and makes it more likely to gain public acceptance.

Avian interaction with wind facilities became a central issue for the wind industry in the late 1980s, when bird carcasses were first reported in a wind resource area in northern California. Although birds are killed each year by man-made structures such as buildings, communication towers, bridges, and transportation vehicles, the presence of endangered species near wind facilities can draw added attention to the issue. A number of studies have investigated the factors that lead to bird deaths (i.e. turbine designs, placement, geography, vegetation, and prey availability at the site; habitat encroachment in surrounding areas; and interaction behaviours such as flying, perching, hunting, etc.). In 1999, the National Wind Coordinating Committee published a definitive report, *Studying Wind Energy/Bird Interactions: A Guidance Document* [5] . The report stresses that each site must be evaluated on the basis of its unique set of parameters. The current wind industry trend toward larger wind turbines with higher turbine heights and slower rotor speeds may reduce avian mortality risk at wind facilities.

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[4] National Wind Coordinating Committee. " Permitting of Wind Energy Facilities: A Handbook." August 2002 (http://www.nationalwind.org/assets/publications/permitting2002.pdf).
[5] Studying Wind Energy/Bird Interactions: A Guidance Document, National Wind Coordinating Committee, Washington, D.C. December, 1999.

Another key business issue is public policy. The countries that have the highest deployment of wind energy tend to also have public policies that mandate deployment levels and offer various types of financial incentives to offset the costs. In the US market, the deployment of wind is closely tied to the Federal Production Tax Credit. There has been a significant reduction in wind deployment in the years when the credit expired followed by booming development in the years when the credit was reinstated.

Ocean Energy Technologies

Brief Description of the Technology

Wave Energy Conversion Technology

Wave energy is the capacity of the waves for doing work. Ocean waves are generated by the influence of the wind on the ocean surface first causing ripples. As the wind continues to blow, the ripples become chop, fully developed seas and finally swells. In deep water, the energy in waves can travel for thousands of miles until that energy is finally dissipated on distant shores.

Wave power research programs in industry, government, and at universities have established an important foundation for the emerging wave power industry over the last decade. In the late 1970s and early 1980s, the UK regarded wave power as an alternative to nuclear generation and had the most aggressive R&D program in the world. Although the program contributed to important basic research on optimal control and tuning of wave power conversion devices, it ultimately stalled as oil prices dropped and government funding ceased. In the past decade, continuing research in wave-powered generation has resulted in advances in remote control capabilities, while advances in the offshore industry have led to economically-viable designs— some of which have been tested as single full-scale prototypes in natural waters over the last three years.

Wave energy extraction is complex and many Wave Energy Conversion (WEC) device designs have been proposed. Four of the best known device concepts and their principle of operation are listed below and shown in schematics in Figure 6-31.

- *Point absorber* - A bottom-mounted or floating structure that absorbs energy in all directions. The power take-off system may take a number of forms, depending on the configuration of displacers/reactors. The illustration shows a floating buoy, however, it could be a bottom-standing device with an upper floater.
- *Oscillating Water Column (OWC)* - At the shoreline, this could be a cave with a blow-hole and an air turbine/generator in the blow hole. Near shore or offshore, this is a partially submerged chamber with air trapped above a column of water. As waves enter and exit the chamber, the water column moves up and down and acts like a piston on the air, pushing it back and forth. A column of air, contained above the water level, is compressed and decompressed by this movement to generate an alternating stream of high-velocity air in an exit blowhole. The air is channelled through an air turbine/generator to produce electricity.
- *Attenuator or Linear Absorber* - An example of the attenuator principle is a long floating structure that is orientated parallel to the direction of the waves. The structure is composed of multiple sections that rotate in pitch and yaw relative to each other. The four sections move relative to each other and this motion is converted at each hinge point to electricity by a hydraulic power converter system.

- *Overtopping terminator* - A floating reservoir structure with reflecting arms and a ramp so that as waves arrive, they overtop the ramp and are restrained in the reservoir. The collected water turns the turbines as it flows back out to sea and the turbines are coupled to generators.

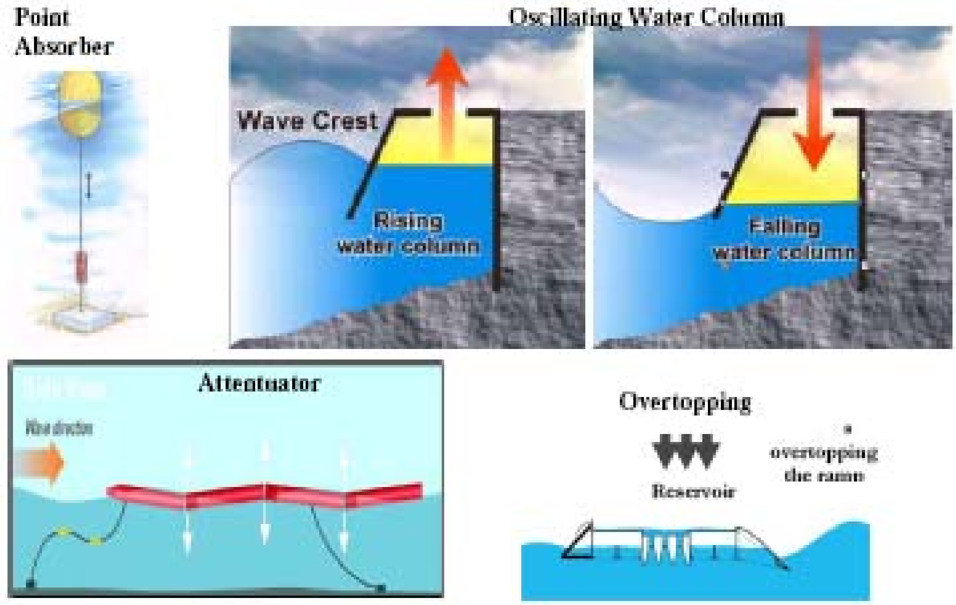


Figure 6-31
WEC Configurations

Example machines using each of the four types summarised above are shown in Figure 6-32.

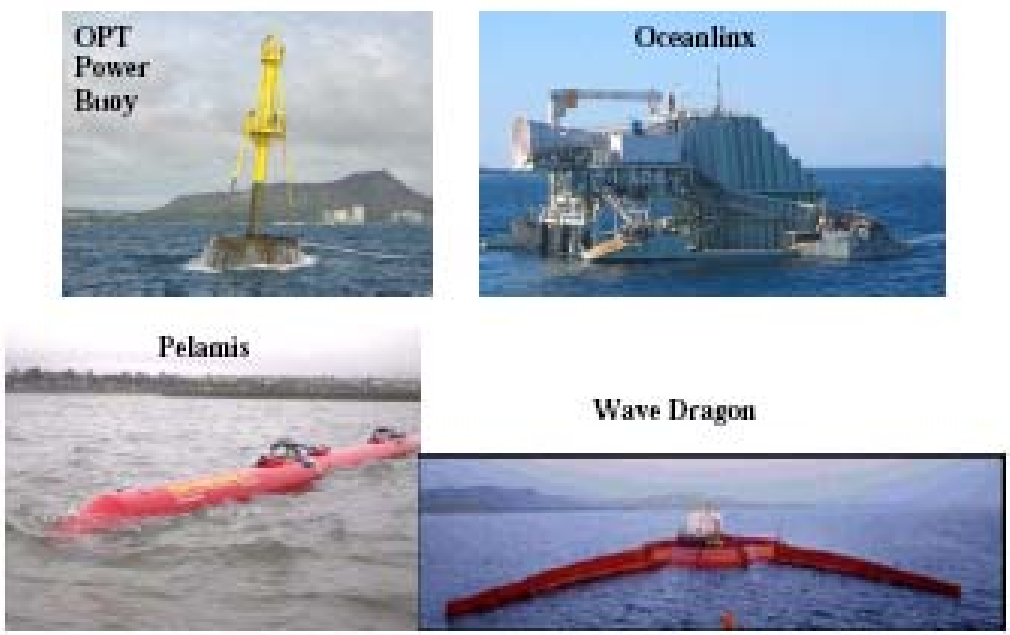


Figure 6-32
WEC Example Machines

Tidal In-Stream Energy Conversion Technology

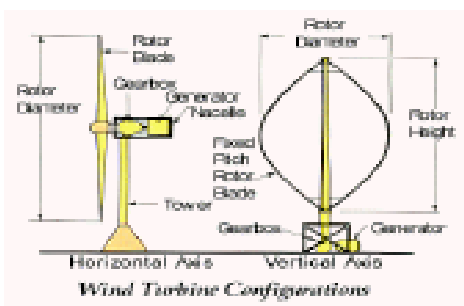
Tidal in stream energy occurs due to the moving mass of water with speed and direction caused by the gravitational forces of the sun and the moon, and centrifugal and inertial forces on the earth's waters. Due to its proximity to the earth, the moon exerts roughly twice the tide raising force of the sun. The gravitational forces of the sun and moon and the centrifugal/inertial forces caused by the rotation of the earth around the centre of mass of the earth-moon system create two "bulges" in the earth's oceans: one closest to the moon, and the other on the opposite side of the globe.

Tidal energy extraction is complex and many device designs have been proposed. Water turbines, like wind turbines, are generally grouped into two types:

- vertical-axis turbines, in which the axis of rotation is vertical with respect to the ground and perpendicular to the water stream; and
- horizontal-axis turbines, in which the axis of rotation is horizontal with respect to the ground and parallel to the water stream.

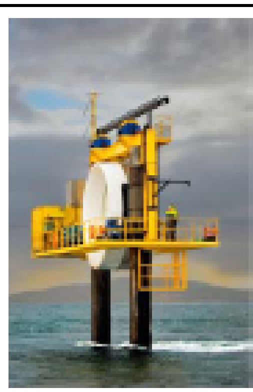
Figure 6-33 illustrates the two types of turbines and shows three examples of horizontal axis turbines that have been tested in natural waters.

Horizontal-and Vertical-Axis Turbines



Marine Current Turbines Horizontal Axis Turbine (Courtesy Marine Current Turbines)

Open Hydro Horizontal Axis Turbine (Courtesy Open Hydro)



Verdant Horizontal Axis Turbine (Courtesy Verdant Power)

Figure 6-33
Tidal In-Stream Energy Conversion (TISEC) Configurations and Example Machines

Subsystems typically include a blade or rotor, which converts the energy in the water to rotational shaft energy; a drive train, which usually comprises a gearbox and a generator; a tower that supports the rotor and drive train; and other equipment, including controls, electrical cables, and interconnection equipment. These devices may be grouped in other ways.

- *Fixing* - Devices may be either gravity foundation based, attached to a mono pile foundation, or anchored and moored and allowed to “fly” in the stream as a result of buoyancy and/or dynamic pressure forces. They may also be hung from a floating platform with the platform anchored and moored to maintain its location.
- *Open vs. Ducted* - Turbine rotors may be either open, much like wind turbines, or have ducting. Since the energy is a function of the cross-sectional area of the influenced water, using a duct of a given cross sectional area is the equivalent of using an open rotor whose cross-sectional area is the same. The wind energy industry has found that adding length to a rotor blade is more economical then adding a duct to increase the area and power of a wind machine. However, water turbine ducts may provide a different economical answer than in the wind turbine case.
- *Fixed vs. Variable pitch blades* - Pitch control is used to limit power, maximise the efficiency of the turbine, and enable bi-directional operation. There are other ways to accomplish these three functions with fixed blade turbines and many different design concepts for implementing them.
- *Closed centre (hub-type) vs. Open centre* - Instead of a fixed hub and rotating blades, a design variation uses an outer fixed rim and an inner rotating bladed disc. The potential benefit in an open centre design is the elimination of the need for a gearbox by encapsulating the stator of a generator on the rim of the machine.
- *Savonius vs. Darrieus Vertical Axis Turbines* - Invented in Finland, the Savonius turbine is S-shaped if viewed from above. This drag-type vertical axis turbine turns relatively slowly, but yields a high torque. The Darrieus turbine was invented in France in the 1920s. Likened to an eggbeater, this vertical axis turbine has vertical blades that rotate into and out of the wind. Using aerodynamic lift, these turbines can capture more energy than drag devices.
- *Helical vs. Cycloidal aerodynamic lift type vertical axis turbine blade configuration* - A helix is a three-dimensional curve that lies on a cylinder or cone, so that its angle to a plane perpendicular to the axis is constant. A cycloid is the curve traced by a point on the circumference of a circle that rolls on a straight line.

There are other types being investigated (e.g. hydro venturi and oscillating). However, they are not of sufficient practical importance at this time to be described in this chapter.

Ocean Current Technology

Open ocean currents are relatively steady flows of ocean water moving in a constant direction, driven by wind and the rotation of the earth[6]. Ocean current technology is in the very early stages of development and, therefore, there are few detailed specifics regarding design types of the technology. The general concept is to use submerged turbines, much like wind turbines, to harness the hydrokinetic energy of ocean currents. Though the speed of ocean currents is much lower than typical wind speeds required for wind farms, the density of the water makes up for this, resulting in far less velocity

6 http://oceanservice.noaa.gov/education/kits/currents/05currents1.html

required to exert the same force on the turbine. While the turbine itself would be near the surface of the ocean, it would likely be mounted to the ocean floor far below.

Technology Development Status

Wave Energy Conversion Technology

WEC is an emerging technology. Worldwide installed capacity of WEC devices is about 5 MW, though less than 3 MW is currently grid-connected and the devices are commercial prototypes. The first shore-based grid-connected wave power unit was deployed in Scotland in July 2000 and has since operated successfully. The first offshore grid-connected wave power unit was deployed at the European Marine Energy Centre (EMEC) in the Orkneys in July 2004. Based on the successful testing of that Pelamis device at EMEC, Pelamis WavePower announced the first commercial sale of an offshore wave power in May 2005 to Enersis of Portugal. The first phase of this project (three Pelamis units at 0.75 MW each totals 2.25 MW), which will eventually be 30 MW, first transmitted electricity to the grid in mid-2008. A half dozen full-scale prototype WEC devices have been demonstrated at sea over the past five years while another dozen sub-scale prototypes have also been demonstrated and are now ready for full-scale demonstration.

Numerous project and device developers have initiated wave power plant projects off the shores of many countries. Today, a number of small companies are leading the commercialisation of technologies to generate electricity from ocean waves. As of July 2008, there were more than 40 known developers of WEC devices at different stages of development.

Tidal In-Stream Energy Conversion Technology

TISEC is an emerging energy technology. Worldwide installed capacity of TISEC devices is about 2 MW. All of these devices are prototypes and no commercial power plants have yet been announced. However, as of June 2008 there were more than 30 known developers of TISEC devices. While most are at laboratory testing, experimental, or technology demonstration (testing of function and performance) development status, a few are at commercial demonstration (testing of commercial viability) or early commercial status.

In 2007, Marine Current Turbine (UK), Open Hydro (Ireland), Ponte de Archimede (Italy), Verdant (US), Ocean Renewable Power Corp (US), and Clean Current (Canada) prototype TISEC devices were demonstrated. In 2008, Marine Current Turbines deployed the world's largest grid connected pre-commercial prototype, the 1.2 MW SeaGen in Strangfold Narrows, Northern Ireland. Verdant reengineered its turbine blades, tested them at the National Renewable Energy Laboratory (NREL) Blade Test Facility, and reinstalled new blades on two turbines in New York's East River. Ocean Renewable Power Corp. completed barge testing of a subscale cross flow axis machine in the Western Passage, Maine.

Ocean Current Technology

Ocean current technology is in the early stages of development with no commercial installations. Florida Atlantic University's (FAU) Center for Ocean Energy Technology (COET) is working to establish a National Open-ocean Energy Laboratory (NOEL) to serve as a test bed for ocean current technologies, as well as ocean thermal energy, research and development. COET's hope is that NOEL will be available to all technology developers for small-scale to commercial-scale device testing. In April 2009, COET deployed four acoustic doppler current profilers in the Gulf Coast to gather baseline data for NOEL.[7]

Major Technical Issues and Future Development Directions/Trends

Wave Energy Conversion Technology

Given proper care in site planning, offshore wave power promises to be one of the most environmentally benign electricity generation technologies and should not cause any permanent damage. Early demonstration and commercial offshore wave power plant projects should include rigorous monitoring of the environmental effects of the plant and similar rigorous monitoring of a nearby undeveloped site in its natural state so that natural effects can be separated from induced effects in long-term trends.

Tidal In-Stream Energy Conversion Technology

Extraction of kinetic power from tidal streams alters the tidal regime in an estuary by reducing flow volumes, constricting the tidal range, and altering the timing of tidal events. However, the magnitude of these impacts depends strongly on the level of power extraction, estuary geometry, non linear dynamics of in-stream turbines, and the natural tidal regime. An understanding of the various fluidic effects of large-scale kinetic power extraction is an essential first step in a more detailed investigation of ecosystem impacts.

Given proper care in site planning, tidal in-stream power promises to be one of the most environmentally benign electrical generation technologies and should not cause any permanent damage to the environment. Early demonstration and commercial tidal in-stream power plants should include rigorous monitoring to record both environmental impacts as well as natural impacts at nearby undeveloped sites.

To date, no definitive “in-situ” monitoring studies have been conducted due to the newness of the technology and lack of deployed systems. However, anecdotal information from numerous temporary testing activities in the US, Canada, UK, and other countries has not observed any harm to aquatic life. The blades of TISEC devices rotate very slowly (around 10 rpm for an 18 meter diameter rotor) and the speed at the tip of the blade is about 10-12 m/s (22-27 mph). The devices are self limiting in that any faster speeds result in cavitation.

Ocean Current Technology

Because of its very early developmental status, a lot of research must take place to develop ocean current technology. Technical research must be conducted to investigate appropriate materials for ocean conditions, life cycle analysis, and installation and maintenance. Some of this development may be able to use developments in other ocean energy technologies as a baseline. The impact of ocean current technologies on ocean life, current flow, and other environmental concerns must also be

7 http://www.laboratoryequipment.com/news-FAU-ocean-current-energy-monitor-040809.aspx?xmlmenuid=51

investigated through long term testing. Furthermore, the effect of future farms on shipping routes and other recreational uses of the water must be considered.[8]

Development and Commercialisation Timeline

EPRI's Ocean Energy program is conducting preliminary studies, designs, and permitting exercises in the hope of building and testing Ocean Energy projects in the US in the near future. Figure 6-34 (below) shows the current development on these projects, followed by some of the key questions that these demonstrations hope to answer.

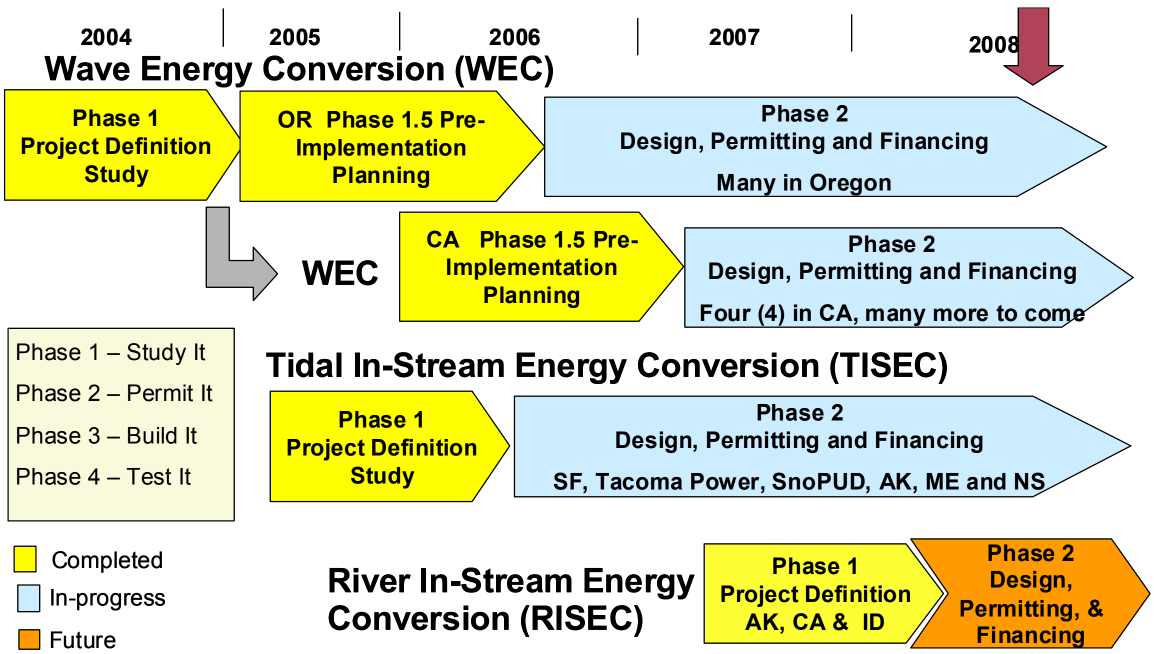


Figure 6-34
EPRI's Ocean Energy Project Development

Wave Energy Conversion Technology

Although technologically ready for demonstration, many important questions about the application of wave energy to electricity generation remain, including:

- what type/size will yield optimal economics?
- will the installed cost of wave energy conversion devices realise its potential of being less expensive than solar or wind?
- will the one- to two-day forecast-ability of wave power earn a capacity credit for its ability to be dispatched?

[8] http://ocsenergy.anl.gov/guide/current/index.cfm

- will the performance, cost, and reliability projections be realised in practice once wave energy devices are deployed and operated?

Longer term testing of WEC devices will provide insight into the susceptibility of materials to corrosion and biofouling in a search for low-cost but robust mooring and sea bed attachments. An understanding of lifecycle maintenance can also be developed with long term testing. It will be important to research the effects of TISEC devices on the surrounding ecosystems to develop streamlined permitting systems and industry-wide standards. Modelling of the wave resources around the world would help developers assess WEC's potential in different locations.

Tidal In-Stream Energy Conversion Technology

As with WEC devices, important questions about the application of in-stream tidal energy to electricity generation remain, including:

- what type/size will yield optimal economics?
- will the predictability of tidal power earn a capacity credit for its ability to be dispatched?
- will the performance, cost, and reliability projections be realised in practice once tidal energy devices are deployed and operated?

Longer term testing of TISEC devices will provide insight into the susceptibility of materials to corrosion and biofouling in a search for low-cost but robust mooring and sea bed attachments. An understanding of lifecycle maintenance can also be developed with long term testing. It will be important to research the effects of TISEC devices on the surrounding ecosystems to develop streamlined permitting systems and industry-wide standards. Modelling of the tidal resources around the world would help developers assess TISEC's potential in different locations.

Relevant Business Issues

Wave Energy Conversion Technology

While WEC devices are anticipated to be generally benign technologies, some concerns do exist. These concerns, as well as potential mitigation strategies, are listed below.

Withdrawal of Wave Energy – changes to sediment transport patterns: Lowering of wave energy levels reaching the coast may reduce longshore sediment transport, possibly reduce erosion in the vicinity of the site, and increase erosion "down coast". If down coast erosion takes place, wave farm dispersion may be required.

Interactions with Marine Life, Seabirds and Benthic Ecosystems: The presence of WEC devices may provide artificial "haul-out" space for pinnepeds, enabling larger populations to exist than would otherwise be possible. Submerged components such as anchors and cables may provide substrates for colonisation by algae and invertebrates creating "artificial reefs." WEC devices should be designed to minimise haul out space for pinnepeds and birds (for example, a conical "hat" on point absorbing buoys).

Atmospheric and Oceanic Emissions: Working fluids of devices with closed circuit hydraulic systems may leak or spill during transfers. Seawater-based systems should not be employed and only biodegradable fluids should be used.

Visual Appearance and Underwater Noise: Coastal and near shore systems could have a negative aesthetic effect of visually affecting the pristine coast. Significant underwater noise levels could have adverse effects on marine mammals. Locating plants a good distance off shore will reduce the visual effect.

Conflicts with other uses of Sea Space: WEC devices could potentially conflict with recreational uses (e.g. surfing), commercial shipping, commercial fishing, oyster, lobster and abalone harvesting and kelp farming, dredge solid disposal and other activities. Any underwater cables can lead to fishing gear snags and gear loss. Holding siting, design and installation, operation, and procedure discussions with all local stakeholders prior to making final plant detail design decisions can mitigate these conflicts.

Interfering with the migration marine mammals such as gray whales: Large offshore wave energy conversion device arrays have the potential to interfere with the migratory patterns of marine mammals. For example, in California, grey whales use the sea space off the California coast for their annual migration from Alaska to the Baja. A web of cables could pose a hazard to migrating marine mammals. Installation activities should be planned for the summer months when the seas are the calmest and when the whales are not migrating. Cables should be minimised and buried or rock bolted to the seabed.

Tidal In-Stream Energy Conversion Technology

While TISEC devices are anticipated to be generally benign technologies, some concerns do exist, many of which are similar to those of WEC devices. These concerns, as well as potential mitigation strategies, are listed below.

- *Withdrawal of Tidal Energy* - Installation of TISEC devices results in the retardation of tidal discharge rates and lowering of tidal range levels, which could affect natural ecosystem processes in fragile estuaries. Limiting the withdrawal of tidal energy to a level which does not result in any noticeable ecological effects will help to reduce this concern.
- *Interactions with Marine Life, Seabirds and Benthic Ecosystems* - Fish mortality seems to be the most significant issue. Effects on the benthic ecosystems, primarily during installation, and effects on sediment transport processes are also of concern. The rotation speed of the blades should be limited to a level that precludes fish mortality.
- *Atmospheric and Oceanic Emissions* - This applies to devices with closed-circuit hydraulic systems where working fluid may leak or spill during transfers and use of fluids for installation (i.e. drilling sockets in hard rock seabed). Biodegradable working fluids are available and should be used for TISEC devices.
- *Visual Appearance and Noise* - The aesthetic effect of visually impacting the pristine coast is unacceptable to many stakeholders. Significant underwater noise levels could have adverse effects on marine mammals. Fully submerging the energy conversion devices, landing the cable under the shore, and muffle underwater noise can help reduce these nuisances.
- *Conflicts with Other Uses of Sea Space* - The installation of TISEC devices could result in conflicts with recreational uses, commercial shipping, commercial fishing, crabbing and kelp farming, dredge solid disposal, and other activities. Holding site location, design and installation, operation, and procedure discussions with all local stakeholders prior to making final plant detail design decisions can mitigate these conflicts.

Geothermal

Geothermal energy is literally energy in the form of heat contained within the Earth. It arises from the heat of the Earth's molten interior and occurs mainly in geologically active areas where the planet's continental plates meet.

Geothermal power plants are able to be dispatched and range in size from 0.5 MWe to 180 MWe, with 30 to 60 MW considered standard for steam or flashed-steam plants. For binary cycle plants, smaller sizes are more common, in the range of 15 to 45 MW. Ramp rates of 5 MW per hour are typical for all geothermal power plants. Energy production is not affected by daily or seasonal resource supply fluctuations. Atmospheric emissions are low or non-existent and solid wastes are readily managed by conventional techniques. In addition to use for electric power generation technologies, which are the subject of this report, hot geothermal fluids can be used directly in aquaculture, greenhouses, space heating, wood drying, and vegetable drying.

As a general rule, geothermal resources are classified in three categories: hydrothermal-convection, geopressured, and hot rock (HR) resources. Hydrothermal-convection resources are subdivided further into vapour- and liquid-dominated resources, which produce mostly steam and hot water, respectively. They occur as a result of heat transfer from geologically active high-temperature belts to aquifers in close proximity. Geopressured resources are hot water containing dissolved methane under a high subsurface pressure about twice that of normal hydrostatic pressure. HR resources are hot rock masses that lack fluid content but are close enough to the surface to have potential for commercial heat extraction. Figure 6-35 shows the developmental status of the range of geothermal technologies.

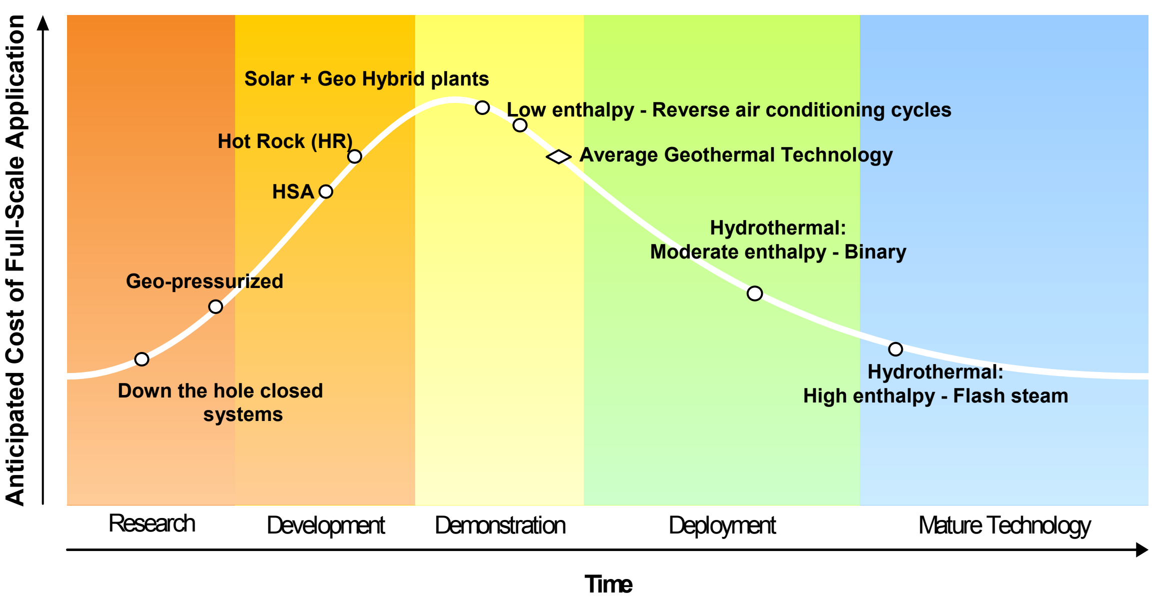


Figure 6-35
Geothermal Grubb Curve

Brief Description of the Technology

A brief description of each of the technologies shown on the Grubb curve is given above. Hydrothermal flash, hot rock (HR) geothermal and hot sedimentary aquifers (HSA) are discussed in further detail in the remainder of this section.

Hydrothermal high enthalpy – Flash Steam

Flashed steam hydrothermal plants are suited for high enthalpy geothermal resources. Hot water is removed from the production well and flashed in a separator, where the drop in pressure causes part of the water to flash to steam. The steam is then routed through a steam turbine generator while the separated water is re-injected into the hydrothermal reservoir. After the steam passes through the steam turbine, it is condensed and also returned to the reservoir to be reheated.

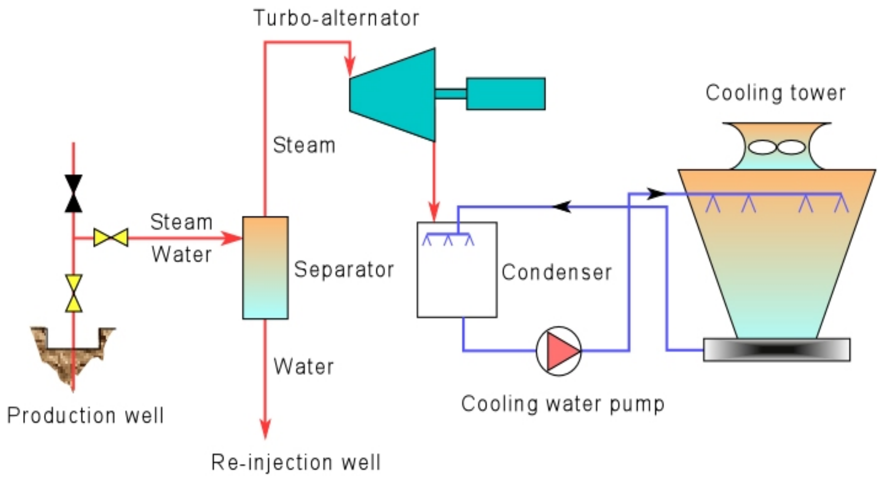


Figure 6-36
Flash Steam Hydrothermal Plant

Hydrothermal moderate enthalpy – Binary

Binary hydrothermal plants are best suited to moderate enthalpy geothermal resources. Geothermal water is removed from the production well and passed through a heat exchanger, where it transfers heat to a second (binary) liquid, the working fluid. The working fluid then boils to vapour and expands through a turbine, generating electricity. The working fluid is then condensed to a liquid to being the cycle again, which the geothermal water is returned to the reservoir via a re-injection well to be reheated.

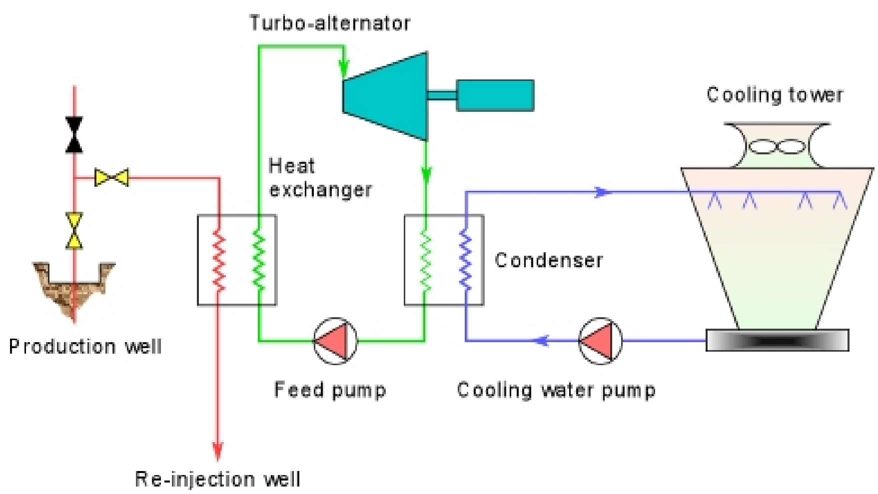


Figure 6-37
Binary Hydrothermal Plant

Low enthalpy - Reverse air conditioning cycles

Reverse air conditioning cycles can be used for low enthalpy geothermal resources. The cycle is based on mass produced air conditioning components: a single stage centrifugal compressor, heat exchangers designed for large chiller applications, and low cost R-134a fluid. For geothermal power output applications, the centrifugal compressor is run in reverse as a radial inflow turbine and the heat exchangers work to transfer heat from the geothermal resource to the working fluid. A reverse air conditioning cycle has been in operation in Alaska since 2006, producing electricity with high availability (98%) from a 75°C (165°F) geothermal resource and a 5°C (40°F) river water heat sink Fully manufactured modules can be added to expand the power of geothermal plants with low temperature resources. This low cost technology expand the minimum temperature range for producing power from lower temperature, shallow geothermal hot springs systems

Solar + Geo Hybrid plants

Solar-geothermal hybrid plants combine a concentrating solar field with a geothermal plant. It can be used for either binary or flash steam plants. In either design, heat is collected in the solar field and transferred to a heat transfer fluid (HTF). In a flash steam plant, this hot HTF then passes through a heat exchanger with geothermally heated water coming from the production well. The HTF further heats the geothermal water before it enters the separator, where it is flashed and then expanded through the turbine. In a binary system, the working fluid is first heated by the geothermal water before it is further heated in a HTF heat exchanger and then expanded through the turbine. Solar-geothermal hybrids offer improved performance over a pure geothermal system due to the additional hat from the solar field. They can also be more cost-effective than stand-alone solar facilities. In addition, they off-set the risk of premature resource depletion, provide operating flexibility, and can take advantage of peak summer high electricity prices by generating additional electricity during hot summer days when the solar resource is strongest.

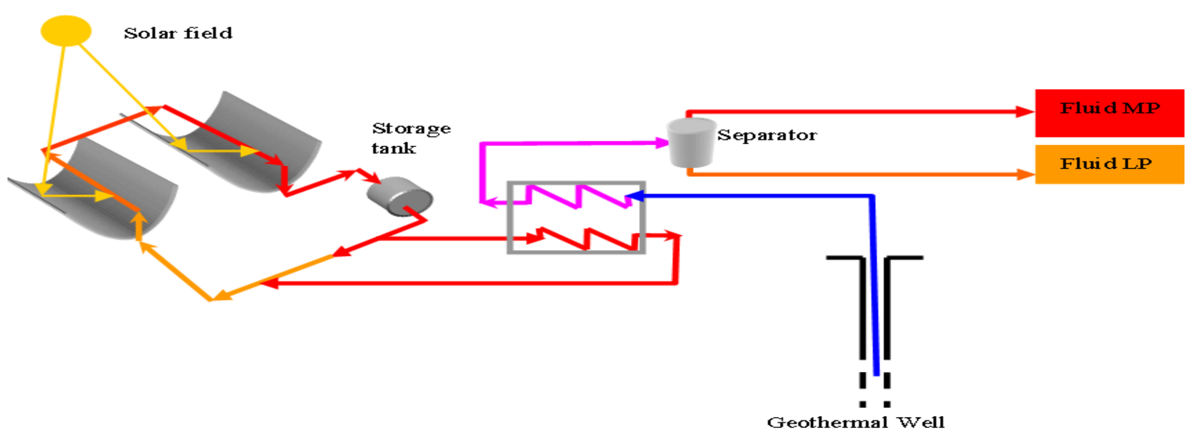


Figure 6-38
Flash Steam Solar-Geothermal Hybrid Plant

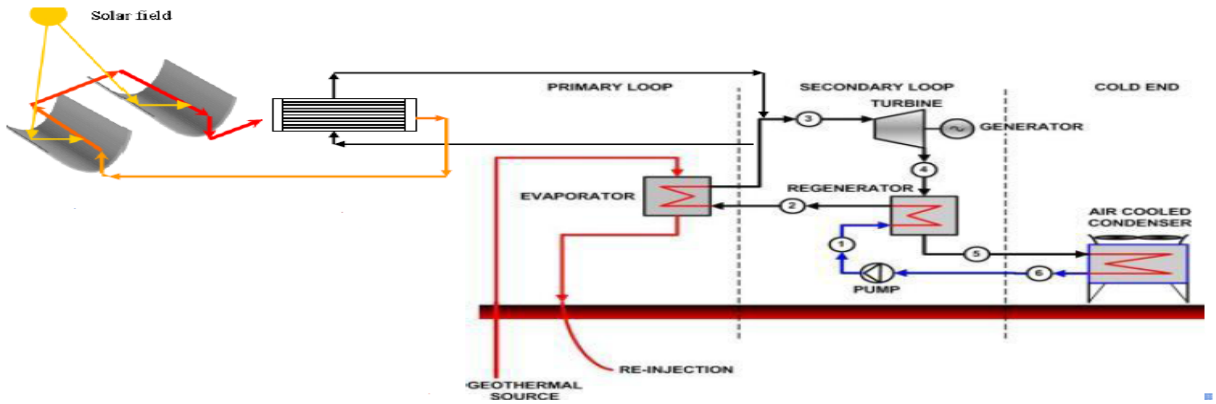


Figure 6-39
Binary Solar-Geothermal Hybrid Plant

Hot Rock (HR)

Hot rock (HR) geothermal systems are systems that utilise geothermal resources by creating reservoirs by fracturing geothermally-heated hot rock formations at depths of 2,000 to 10,000 meters to extract the geothermal heat. Surface water is then pumped into the hot fractures and most of that water is recovered through production wells, as in a natural hydrothermal power system. The superheated water transfers its heat to a secondary fluid or working fluid and is then recirculated and pumped back down the injection well.

Hot Sedimentary Aquifers (HSA)

Hot sedimentary aquifers are reservoirs in which rain water that has been absorbed into the ground is heated at temperatures that increase with depth or by contact with hot rocks. The water collects in porous rocks between two impermeable sedimentary layers, creating an aquifer from which hot fluid can be extracted, usually by drilling. HSA typically requires a binary cycle for electricity production due to the temperature of the brine. The focus of HSA research is to find shallow systems that reduce the development costs and allow the use of proven hydrothermal systems and supporting technology. Secondary reservoir stimulation techniques, known as Secondary Enhancement of Sedimentary Aquifer Play (SESAP) is also being researched as a way to increase permeability and production rates of HSA.

Geo-pressurised

Natural gas production and electricity generation from geo-pressured-geothermal aquifers is an unconventional hydrocarbon source that has long been unproductive due to its economic constraints and lack of technical certainty. New technologies may allow more efficient extraction of methane and thermal energy from the geo-pressure brine. Use of binary-cycles may improve thermal recovery efficiencies to economic sustainable levels. The injection of paraffinic hydrocarbons into the produced fluid could improve methane recovery efficiencies while reducing the amount of surface equipment necessary for handling geo-pressured brines.

Economic feasibility depends of natural gas and electricity prices, capital cost and operating expenses. Commercial potential of geo-pressurised aquifers could increase with a reduction in dry-hole risks, well replacement costs and optimised binary cycles.

Down the hole closed systems

Down the hole closed geothermal systems place a heat exchanger deep in the earth within the geothermal resource. The working fluid cycles through the heat exchanger in the ground and then returns to the surface for use in the power block. Because this system is closed loop, it removes the risk of contaminating the aquifer and uses limited water and space. It could potentially be used in existing oil and gas wells.

Technology Development Status

Hydrothermal technologies are generally considered commercial technologies. They can now be cheaper than new coal plants for identified resources in high potential areas. Off-the-shelf power generation equipment is readily available for hydrothermal plants and the drilling technology required for tapping the resource is now well established with lower risk than in the past. Advancements in scale inhibitor chemical technology has helped to reduce problems with wellbore and equipment scale and, in turn, reduced O&M. Better understanding also exists now of proper reservoir management to increase project life and reduce long term resource risk.

However, risks do still exist with hydrothermal power plants. Exploration and drilling costs can be expensive. Occasionally drilling results in dry holes, which do not produce hot liquids or steam. There is also risk associated with reservoir cooling. In the past 20 years, no real improvements have been made in the exploration process. Risk also lies in reservoir management to maintain the reservoir output. Reservoir life depends on the success of re-injection into the geothermal reservoir, and supplemental injection may be needed to extend the reservoir life.

Hot Rock (HR) is not yet a commercial technology, though it is believed to be proven as technically feasible, with technology readiness projected for 2015. Like hydrothermal plants, HR is a baseload renewable technology that is low cost to operate and has low cost volatility due to a lack of fuel costs. The same plant and drilling technologies can be used as hydrothermal plants, but with a less site-specific restriction on plant location compared to a hydrothermal resource. The resource risk is also lower than that for a hydrothermal plant.

However, HR has a high up front cost, up to 70-80% of total costs, in developing the well field. Resource exploration and assessment methods need to be improved to reduce costs and stimulation technologies for generating the cracks within the rock also need improved development. Furthermore, the question of the risk of inducing seismic hazards through stimulation must be addressed.

HSA is also not yet commercially proven. However, it is often considered the “low-hanging fruit” of near term geothermal development. Because it uses a conventional binary cycle, involves shallower drilling, and does not require resource stimulation, it is considered less risky than HR. Several potential sedimentary basins have been identified in Australia, which may further reduce exploration, drilling, and reservoir risks.

Major Technical Issues and Future Development Directions/Trends

Australia does not have the wet, high-temperature geothermal environments found in volcanically active countries. Consequently, Australia’s hydrothermal systems are neither hot enough nor under enough pressure to produce large amounts of steam. Therefore most Australian geothermal resources will be exploited using binary power generation systems and HR resources.

Hot rock is still largely experimental as it has yet to be developed commercially. Well costs increase exponentially with depth and because HR resources are much deeper than hydrothermal resources, they are much more expensive to develop. Also, although the technical feasibility of creating HR reservoirs has been demonstrated at experimental sites in the US, Europe, and Japan, operational uncertainties regarding the resistance of the reservoir to flow, thermal drawdown over time, and water loss have so far made commercial development unacceptably risky. Lower-cost resource assessment and drilling technologies will help bring these HR systems into commercial use

Development and Commercialisation Timeline

The industry consensus is that characterising the commercial potential of identified geothermal reservoirs is a high priority. Techniques such as fracture mapping, more accurate thermal-gradient wells, and other, untested methods should be evaluated and refined, if appropriate. The objective is to be able to measure the temperature, fluid characteristics, and permeability of the resource prior to committing to expensive production wells and generation equipment.

Hot rock systems are still widely experimental. Evaluation and testing must be conducted to confirm the economic viability of these systems.

- *Demonstration of commercial-scale reservoir* - Stimulation and maintenance of a large volume of rock is required in order to minimise temperature decline in the reservoir. Actual stimulated volumes have not been reliably quantified in previous work.
- *Sustained reservoir production* - Recent studies conclude that 200°C fluid flowing at 80 kg/sec (equivalent to about 5 MWe) is needed for economic viability. No HR project to date has attained flow rates in excess of ~25 kg/sec.
- *Replication of hot rock system reservoir performance* - Hot Rock technology has not been proven to work at commercial scales over a range of sites with different geologic characteristics.

These assumptions can be tested with multiple HR reservoir demonstrations using current technologies. In the long-term, significant reduction in drilling costs will be necessary to access deeper resources, and the cost of conversion of the energy into electricity must be reduced. These improvements will move HR technology forward as an economically viable means of tapping the geothermal resources.

Relevant Business Issues

Because Australia's geothermal resources do not appear to support the more commercial hydrothermal technologies, advancement of geothermal power outside of HSA in Australia will depend upon the development of rock fracturing technologies to allow for high production rates from the abundant HR resource. Most of the necessary drilling and well testing equipment is adapted from the oil and gas industry. However, some of this equipment has been specifically refined for the hotter and more corrosive environments of geothermal drilling. R&D success in fracture detection and fracture permeability studies could give the industry important new tools to improve geothermal exploration and reservoir engineering effectiveness, and also drive down project costs. These fracture and permeability enhancements of natural hydrothermal hot water reservoirs could be the start of commercial activity in HR.

Biomass

Brief Description of the Technology

Biomass fuels are produced by living plant and animal matter. The use of these fuels, which are typically considered renewable fuels, provides electricity generators with, non-intermittent renewable power that is able to be dispatched due to the fact that, for the most part, biomass fuels can be produced, concentrated, and stored for use when it is economic to do so.

Biomass fuels exhibit certain fundamental differences from other fossil fuels. Typically, biomass fuels are either gathered up or harvested from diffuse sources and concentrated at a given location. Consequently, there are practical limitations on the quantities that can be obtained at any location without experiencing significant cost pressures. This is in distinct contrast to the fossil fuels that are produced in centralised locations—e.g. coal—and are distributed to users such as power plants.

Fuels currently used as biomass fuels are, almost exclusively, residues from other processes. They may be wood processing residues such as pig fuel, bark, sawdust, or spent pulping liquor. They may be agricultural and agribusiness residues such as bagasse. They may be wastewater treatment gas or landfill gas. These are commodities that are presently outside the commercial mainstream. In many cases these commodities have both material and energy value. Wood waste markets, for example, can include mulch for urban areas, bedding for livestock and poultry, feedstocks for materials such as particleboard, and feedstocks for niche chemical and related products. As a result, fuel pricing is highly sensitive to locale and the competitive pressures of local and regional economies.

Currently the technologies that are commercially available, or commercially offered, include various forms of co-firing along with stand-alone (100% biomass-fired) Rankine cycle generating systems. Co-firing refers to the practice of firing one or more biomass fuels as a supplement to coal (or very rarely, gas). Stand-alone biomass plants may either supply superheated steam to condensing turbines where the only product is electricity; or they may supply steam to backpressure or automatic extraction turbines in cogeneration (also known as combined-heat-and- power or CHP) applications. Six different biomass combustion technologies are described in this report: 100% biomass direct combustion in a circulating fluidised bed plant, a 100% biomass CHP cogeneration plant, 5% biomass co-fired in a pulverised coal (PC) boiler, 10% biomass co-fired in a circulating fluidised bed coal boiler, 20% torrefaction and pelletisation (ToP) pellet biomass co-fired in a PC boiler, and municipal solid waste (MSW)/landfill gas reciprocating engines.

100% Biomass Circulating Fluidised Bed Combustion

Fluid bed combustion is a commercial technology for burning biomass, coal, and other fuels. There are two basic commercial types: bubbling bed and circulating bed. Biomass enters the boiler and enough combustion air is added to fluidise the biomass during combustion. Fluid bed combustors are known to be very fuel flexible and have been widely deployed in biomass service, firing wood, grasses, and most other common types of biomass. Fluid bed boilers are more common in larger biomass applications (greater than 50 MW) and can be larger than 250 MW in biomass service. Because of the fluidisation aspects, the size of the material should be carefully controlled.

Air pollution equipment for solid biomass-fired systems includes either fabric filters (FFs) or electrostatic precipitators (ESPs) and either selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR) systems. Acid gas scrubbers are not required due to the composition of typical solid biomass fuels.

100% Biomass Combined Heat and Power Cogeneration

CHP cogeneration plants supply process steam for applications other than power production. While the general arrangement of a CHP plant is similar to that of a electricity only plant, the steam turbine is designed with automatic extractors for process steam or backpressure turbines to exhaust process steam under specific conditions, depending upon the plant requirements. This is as opposed to exhausting steam at low condensing pressures, as is done if power is the exclusive product.

5% Biomass Co-Firing with Pulverised Coal Boiler

Co-firing systems are most readily adapted to electric generating stations. Biomass can be integrated with the fuel supply to existing boilers designed to utility standards. The biomass can be used in large reheat boilers where steam is used most efficiently. Such systems are less expensive than stand-alone power plants on a $/kW supported by biomass basis. If the biomass is unavailable temporarily, the operation of the unit is not compromised. Co-firing with biomass also typically has a positive effect on overall plant emissions. However, integrating biomass fuel into the coal stream still involves complex issues of materials handling and control. Further, co-firing does not contribute additional capacity; instead it displaces coal fuel at the unit.

Co-firing in PC boilers can be accomplished either by blending biomass with coal on the main belt feeding the coal bunkers or by separately injecting biomass directly into the furnace equipped with either burner modifications or specially designed biomass burners. Blending on the belt is limited to woody biomass. Herbaceous biomass such as switchgrass causes significant problems in this application. Milling of the biomass for blending on the belt limits the amount of biomass that can be used to about 3-5% to minimise problems with the mills. Most demonstrations of PC co-firing—both tangentially fired boilers and wall-fired boilers—have focused upon separately preparing and injecting biomass into the primary furnace.

10% Biomass Co-Firing with Circulating Fluidised Bed Coal Boiler

Biomass co-firing in CFB coal boilers is similar to PC co-firing in that the systems are less expensive than stand-alone biomass plants on a $/kW from biomass basis. Operation is not compromised by intermittent biomass supply, and co-firing with biomass has beneficial effects on emissions.

As mentioned above for 100% biomass use in a CFB boiler, fluid bed combustors are known to be very fuel flexible. For this reason, CFB coal boilers can typically handle a higher percentage of biomass co-firing than PC boilers.

20% ToP Biomass Co-Firing with Pulverised Coal Boiler

Torrefaction and pelletisation (ToP) removes most of the moisture present in biomass and creates uniform biomass pellets for combustion. ToP biomass has a lower moisture content and higher energy density than wood pellets and other types of biomass. In addition to improving combustion characteristics, this improved energy density also better justifies transporting ToP biomass beyond the typical limited range.

Municipal Solid Waste/Landfill Gas Reciprocating Engine

Gases released from the decomposition of municipal solid waste in landfills are also considered a form of biomass. Solid waste landfills are the largest source of human-related methane emissions in the United States. Landfill gas composition is typically 50% methane, 50% carbon dioxide, and small amounts of other organic compounds. Landfill gas is extracted from landfills using a series of wells and a blower/flare (or vacuum) system. This system directs the collected gas to a central point where it can be processed and treated depending upon the ultimate use for the gas. From this point, the gas can be simply flared or used to generate electricity, replace fossil fuels in industrial and manufacturing operations, fuel greenhouse operations, or be upgraded to pipeline quality gas.

Technology Development Status

The use of biomass for electric power generation is not a new concept, but due the perception that it is a carbon neutral source, the importance of the family of biomass technologies is rising. Both stand-alone and co-fired biomass generating units are installed throughout the world, though most co-firing plants use only a small fraction of heat input into the boiler derived from biomass (2% or less).

ToP biomass is still in the development phase with some completed proofs of principle and concept. First-of-a-kind pilot plants are anticipated to be operational in Europe and the US by late 2010.

Major Technical Issues and Future Development Directions/Trends

Efficiency penalties due to co-firing biomass can vary depending upon system design and operation. Typically, biomass is introduced with ambient air. This reduces the combustion air passing through the air heater and raises the temperature of the gaseous combustion products exiting the air heater. Further, moisture in the fuel along with hydrogen in the fuel exerts a minor penalty on boiler efficiency.

While coal is produced at a central location such as a mine and distributed to users, wood waste is produced as a diffuse resource and collected or gathered into a user location. This fundamental distinction highlights one capacity limitation impacting biomass systems. The second limitation results from the typical fuel characteristics: 240 to 320 kg/m^3 bulk density; 40% to 50% moisture; and 8 to 10 GJ/tonne as-received.

These factors combine to limit boiler and generating capacity. Given typical transportation distances for wood fuel of up to 80 km, wood-fired boilers have been limited to a nominal 100 to 125 tonne/hr firing rate (nominally 300 m^3/hr of fuel), or 50 to 70 MWe depending on system design and operation. This capacity limitation carries with it significant implications:

- it is difficult to economically justify more than three turbine extractions for feed-water heaters; the three extractions are typically for a low-pressure heater, the de-aerator, and a high pressure heater. In some cases only one extraction (de-aerator) is justified;
- reheat cycles that significantly improve cycle efficiencies are not economic at the size plants available for wood firing; and
- depending on staffing philosophies, such units will achieve ratios of 0.5 to 2.0 MWe per worker, depending upon unit capacity and staffing approach. This contrasts with conventional coal-fired staffing ratios of 3 to 6 MWe per worker.

- many of the wood wastes can contain trace minerals and chemicals drawn up by the plant – eg Chlorine. These tend to concentrate in the leaves and twigs and can cause material corrosion issues under high firing temperatures. Australian eucalypts are a case in point.

Development of ToP processes, which will improve the energy density of biomass and, therefore, justify the expansion of biomass use outside current limits could expand the use of biomass.

Development and Commercialisation Timeline

The continued development of ToP biomass is the main focus of biomass R&D at this time. Some first-of-a-kind plants are being built in the United States and Europe for ToP combustion and are anticipated to begin operation as early as late 2010. Large-scale testing of co-firing with ToP will commence when enough pellets are available for continuous testing.

Relevant Business Issues

Emissions impacts are clear and significant. SO_2 emissions decline as a function of biomass kJ substitution in the boiler. Similarly, Hg emissions decrease as a function of kJ substitution. CO and opacity emissions are generally not impacted by cofiring. NO_X emissions decrease, particularly as a function of targeting the location of the biomass injection. Research is ongoing to address the impact of biomass cofiring on the life of deNO_X catalysts and on fireside corrosion. In both cases, the alkali/alkaline earth constituents prevalent in the biomass may adversely impact catalyst poisoning or corrosion reactions.

As emissions regulations continue to become more stringent, co-firing with biomass may become more favourable as an aid to reducing emissions. Biomass is generally considered to be “carbon-neutral”, making it attractive as a co-firing fuel for coal heavy utilities trying to reduce their CO_2 emissions.

Hydroelectric

Brief Description of the Technology

Hydropower is electricity created from the force of running water. This force can be the natural flow of rivers or waterfalls, or the flow of water released from dams. The kinetic energy of the water is converted to electric energy as the water flows through turbines that are attached to generators.

Hydroelectricity provides about 8% of the electricity generated in Australia. Built between 1949 and 1974, the Snowy Mountain Hydroelectric Scheme diverts water from the Snowy and other rivers, sending the bulk of it west to the Murray and Murrumbidgee River system. Hydroelectricity is produced through infrastructure that includes sixteen major dams, seven power stations, 145 km of interconnect tunnels and 80 km of aqueducts before the water is used for irrigation. Each year the Snowy Scheme produces an average of 4,500 gigawatt-hours of energy and is the largest contributor to renewable energy in the National Electricity Market (NEMMCO) The second largest hydro-scheme, run by the Tasmanian Hydroelectric Corporation, generates about 30% of all Australia hydro power.

Technology Development Status

Large hydroelectric stations are a very mature technology, as evidenced by its position far to the right on the Grubb curve shown in Figure 6-2. However, concerns have been raised in more recent years about the effect of hydroelectric dams on fish, other animals, and plant life due to changes in water flow patterns, land use and water quality. The large area of land that dams require also raises concerns. As a result, large hydroelectric dams are rarely built now, and existing hydro generation assets are on average 45 years old. Any new hydro power will likely come from much smaller new plants, such as micro (less than 500 kW) and mini hydro (less than 5 MW), and the addition of generators to existing dams and structures.

Major Technical Issues and Future Development Directions/Trends

Hydroelectricity has many advantages: it is renewable, able to be dispatched and is more reliable than solar and wind power because it can be stored in dams, it produces no gas emissions or waste, and hydroelectric plants are relatively inexpensive to operate. However, as mentioned above, concerns about fish, other animals, and plant life has led to less acceptance of hydroelectric power. Furthermore, the argument has been made that even though hydroelectric plants produce no greenhouse gases, they can have greenhouse gas emissions impacts due to the methane released by decomposing plants on the land flooded to create a dam. The amount of the carbon contained in the biological material that is converted to methane increases with the size of the lake. However, this decreases as the output of the hydro-scheme and its life time increases.

Due to strong and consistent public opposition it is unlikely that any more large dams will ever be built. Nevertheless there is potential for increasing the TWh contribution from hydroelectricity by maintaining and refurbishing existing assets and through the construction of smaller, less controversial micro and mini hydro plants.

Development and Commercialisation Timeline

It is estimated that hydroelectric capacity could increase by 8% to 10% above its current level in Australia, primarily due to installation of small hydro plants and upgrades and refurbishments of existing plants.

Relevant Business Issues

Though new large hydroelectric dams may never be built in Australia, there are still ways to stimulate the Australian hydro power industry. These include changing water storage management practices so that output is increased, improving the efficiency of the way stored water is used to increase output and also plant capacities, upgrading and refurbishing turbine generators and other plant equipment to increase output and constructing new micro and mini hydro plants and adding generators to existing dams and structures.

6.3 Nuclear Technologies

Figure 6-40 shows the development timeline for nuclear power technologies. The following section focuses on Generation III and III+ technologies.

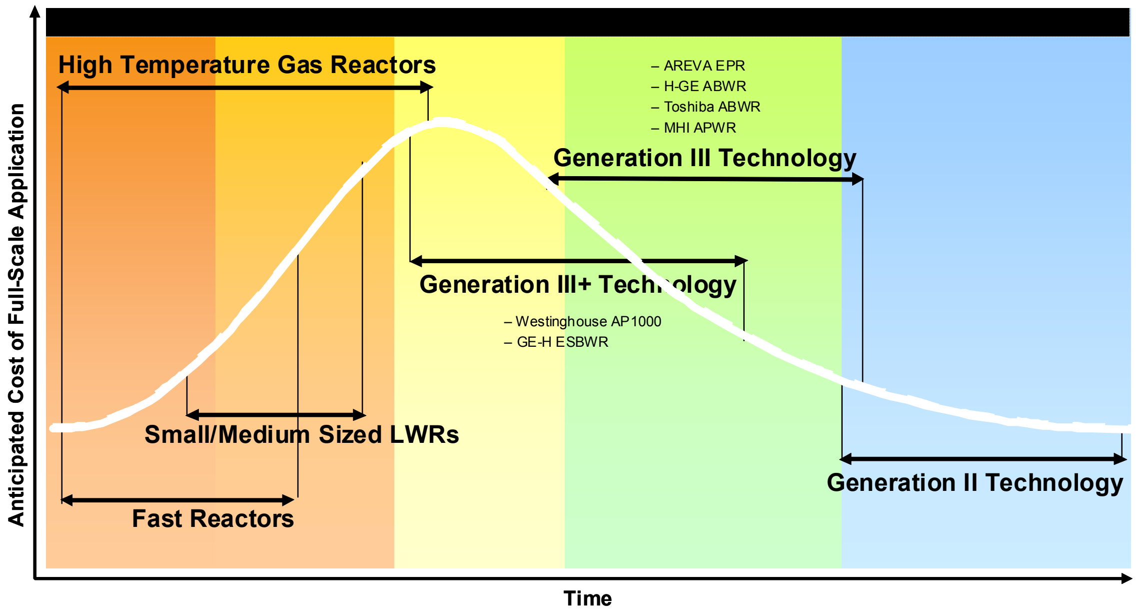


Figure 6-40
Grubb Curve for Nuclear Technologies

Nuclear

Brief Description of the Technology

Nuclear power is a fairly mature technology representing approximately 20% of the electricity generated in the US and over 16% of the electricity generated in the world. It is well suited for large scale stationary applications as well as maritime vessels such as submarines and ships. It is especially attractive to countries with limited access to fossil fuels. The major factors driving interest in nuclear power include projected growth in electricity demand, a desire to reduce greenhouse emissions and move away from reliance on fossil fuels, increasing fossil fuel prices, and energy security.

Compared to other large scale central stations, nuclear plants are typically more expensive to construct, but less expensive to operate. High construction costs are mostly due to safety and security requirements, including both design/construction requirements and the lengthy licensing process. Low operating costs are a result of low fuel costs (on a per kWh basis). Therefore, they can be cost effective when construction costs are kept in check and when the plant is to be operated at high capacity for many years. Due to the low operating costs of nuclear reactors, the electricity generation costs are expected to be more stable than for coal or natural gas-fired plants. They produce no gaseous emissions, although they do generate nuclear waste that poses its own problems. Therefore, CO_2 emissions regulations would also tend to make nuclear power economically favourable.

Nuclear power is generated through a fission chain reaction. The heat produced during fission is transferred via gas or liquid to produce steam. Light water reactors (LWR) use standard water as the heat transfer medium and moderator. The moderator turns fast neutrons into thermal neutrons by reducing the neutron’s velocity. The thermal neutrons are then capable of sustaining the fission chain reaction in neighbouring uranium atoms. Less commonly used moderators are heavy water and graphite. Fast neutron reactors do not require a moderator, and they utilise a variety of coolants.

Nuclear fuel typically consists of uranium dioxide enriched to 3-5% (by weight) using the uranium-235 isotope. Natural uranium, mixed oxide (MOX) consisting of both plutonium and enriched uranium oxides, thorium, and actinides are also used as nuclear fuel. Uranium prices have been increasing over the last several years due mostly to renewed interest in construction of nuclear power plants and recent mining production problems associated primarily with flooding of mines. However, compared to other power plant fuel sources, nuclear fuel cost is quite low and has much less volatility.

Generation I nuclear reactors include plants that were developed in the 1950s and 1960s. These reactors typically used unenriched uranium as the fuel, and graphite as the moderator. There are only two still in commercial operation in the United Kingdom; both are scheduled for closure within the next few years.

Generation II nuclear reactors include light water reactors of two primary types – pressurised water reactors (PWR) and boiling water reactors (BWR). PWRs utilise pressurised water as the coolant, with another cooling loop for driving the steam turbine. This design contains the radioactivity within the reactor and the primary cooling loop. BWRs allow the water in the cooling loop to boil, and this steam is then used to drive the steam turbine. These Generation II reactors began to be installed in the 1970s, and comprise the vast majority of reactors in operation today. They generally utilise enriched uranium fuel. The advanced gas-cooled reactor (AGR) utilises graphite as the moderator and natural uranium for fuel. The CANDU reactor also utilises natural uranium fuel and uses heavy water as its moderator. These reactors include active safety features.

Generation III and III+ nuclear reactors are being constructed and continue to undergo some development. The first was constructed in Japan and has been operating since 1996. They are known as the advanced reactors, and are similar to the Generation II reactors with notable economic and safety advancements. Most of them employ passive safety features rather than active ones, with controls using gravity or natural convection. These reactors are expected to also have reduced nuclear waste and fuel consumption due to higher fuel burn-up. Anticipated lifetime for these reactors is approximately 60 years. The specific types of Generation III and III+ reactors are the:

- *advanced boiling water reactor (ABWR)* by General Electric-Hitachi and Toshiba are currently licensed in the US, Japan, and Taiwan. Four units are operating in Japan, with another three under construction in Japan and Taiwan. ABWR was the first Generation III reactor to operate commercially in 1996 at 1350 MW. The construction phase has been characterised as 39 months from first concrete to first fuel load. ABWRs utilise internal recirculation pumps, resulting in improved reliability and efficiency, reduced radiation dose, and no external piping.
- *advanced pressurised water reactor (APWR)* by Mitsubishi Heavy Industries has a US version known as the US-APWR. Although similar to the original APWR, the US-APWR is specifically designed to comply with US regulations. This design is under review for licensure in the US while the original APWR design is under review in Japan. A steel neutron reflector surrounds the core, and this increases the reactivity, allowing for a slightly lower ^{235}U enrichment level.
- *AP1000 Westinghouse reactor* is a scaled up version of the earlier AP600. It was the first Generation III+ reactor to be licensed in the US, and an amended version is currently under review. One design feature of this plant is that long-term accident mitigation is maintained without operator action or reliance on off-site or on-site AC power. The first US contract agreement since Three Mile Island was signed in April 2008 by Georgia Power Company for two AP1000 reactors. It is estimated that the construction period will last approximately 36 months.

- *economic simplified boiling water reactor (ESBWR)* is a 1535 MW reactor from General Electric-Hitachi that is currently under review for licence in the US It is considered a Generation III+ reactor. Its design builds on that of the ABWR, with improvements including natural circulation through increased vessel height and decreased active fuel height, further design simplification, and a passive containment cooling system. Due to the simple design and reduced building materials, it is estimated that the construction phase for this reactor type would last 36 to 42 months. Also, an operating ESBWR should require less maintenance, thereby reducing the operating costs.
- *evolutionary pressurised reactor (EPR)* by Areva is based on the PWR design. The first reactor of this type is currently under construction in Finland, with another underway in France. In addition, there are two EPRs planned for Taishan, China in the Guangdong province. There is a US version of this design known as the US-EPR that is 1600 MW, which is under review by the Nuclear Regulatory Commission for licensing. This reactor contains a large steel “heavy reflector” surrounding the core to reduce fast neutron leakage.

Additionally, several Generation IV nuclear reactor designs are under various stages of development and are expected to become commercially available in the 2030 timeframe. In addition to higher thermal efficiency, the major feature for these reactors will be their ability to integrate into closed fuel cycles. That is, the long-lived actinides that are currently being treated as nuclear waste could be used as a fuel in many of these reactors. This may help to reduce waste and cost, while ensuring the fuel associated with these reactors is more resistant to nuclear proliferation. It is also expected that these reactors will be capable of supporting high temperature hydrogen production, high temperature water desalination, and other high temperature process heat applications

Technology Development Status

Generation III and III+ reactors are being constructed and continue to undergo development. As reactor designs become more standardised, the hope is that the permitting and licensing period before construction can be reduced to help control capital costs. Research is underway for Generation IV reactors. This generation of reactor is expected to have increased burn up rates to reduce nuclear waste and increased plant efficiency. The table below summarises the current development status of nuclear technologies and anticipated developments in the future.

Table 6-11
Nuclear Technology Development Status

	Commercial Power Reactors (LWR/CANDU/AGR)	Gen III/III+ Advanced Reactors (ABWR/EPR/ESBWR/ AP1000/etc.)	Gen IV Fast and/or Thermal Reactors (GFR, LFR, MSR, SFR, SCWR, VHTR)
Leading Vendors	**N/A**	**GE–Hitachi, MHI, Toshiba/Westinghouse, Areva (Framatome), AECL**	
Major Trends	Uprating of existing plants, increases in capacity factors by reducing the length of refueling outages, extension and renewal of operating licenses.	Move to Generation III/III+ designs with passive safety features, standardisation of designs.	Collaboration between and within industry and governments, standardisation of designs.
Changes To Watch For	N/A	Development of smaller and medium sized reactors (SMRs) ranging from 10MWe-125MWe.	Additional fuel cycle development – increasing burn up rates to reduce waste volumes and developing new fast reactor fuels to reduce waste toxicity.
Capital Cost (mid-2009 AUD/kW)	N/A	5,742 (2015 timeframe) 4,876 (2030 timeframe)	Unknown
Heat Rate, HHV (kJ/kWh)	10,900	10,900	GFR = 7,500; SCWR = 8,000; MSR = 8,200; VHTR = 8,000
Resource Requirements That Impact Technology	Uranium prices have increased dramatically over the last few years, high fossil fuel prices favour nuclear.	Uranium prices have increased dramatically over the last few years, high fossil fuel prices favour nuclear, availability of unique materials (especially ultra large reactor forgings).	Uranium prices have increased dramatically over the last few years, high fossil fuel prices favour nuclear, global governance of fuel cycle is not yet decided.
Market Restructuring & Deregulation	Numerous consolidations of plant ownership by nuclear plant fleet operators have occurred in deregulated areas.	OEMs and utilities are partnering to get approval and licensure.	
Key Issues/Concerns	Active safety features, safety and nuclear waste concerns led to poor public opinion.	Lengthy review/approval/construction processes, high capital costs, global competition, potential shortage of workers with nuclear experience	Engineering, materials, and fuel issues require further R&D to ensure reliable performance in a commercial setting. Lengthy review, approval and construction processes, high capital costs.
Key Market Indicators	Operating plants are applying for and receiving license extensions – cash positive assets for utilities	Global warming and energy security concerns have positively changed public opinion of nuclear power, any CO_2 emissions regulations would favour nuclear.	
Key Business Indicators	Licenses are being extended.	18 COLAs filed for 28 units; currently, interest expressed for a total of 32 new reactors in US. Many new reactors under construction outside US	U.S DOE increasing funding in NGNP Program for FY 2010.

GFR = Gas-Cooled Fast Reactor, LFR = Lead-Cooled Fast Reactor, MSR = Molten Salt Reactor, SFR = Sodium-Cooled Fast Reactor, SCWR = Supercritical Water-Cooled Fast Reactor, VHTR = Very High Temperature Reactor.

N/A – Not available

Major Technical Issues and Future Development Directions/Trends

While nuclear power plants do not release harmful emissions, they do produce nuclear waste. Reprocessing nuclear waste creates concerns about weapons proliferation, while disposing of nuclear waste raises issues about the safety and longevity; and where to store it. The unresolved issue of nuclear waste remains a contentious issue within Australia and globally. Development of Generation

IV reactors that have a higher burn up rate and, therefore, reduce the amount of nuclear waste produced can help relieve this problem.

Without the ability to utilise dry cooling, nuclear power plants also face water issues. Large amounts of water must be used for the cooling cycle in nuclear power plants. Water use issues due to droughts and concerns about affecting water temperature for animals and plants inhabiting the rivers or oceans used for cooling are environmental concerns that must be addressed. The water shortage in Australia could pose a barrier for building nuclear plants due to their large water requirement and current inability to utilise dry cooling methods.

Nuclear plants are a very capital intensive technology. While they remain less expensive to operate than typical fossil fuel plants, the high upfront cost and financing risk remain a barrier for many utilities that plan to build new nuclear power plants. The extensive licensing process that is required before beginning construction on a nuclear plant also poses a challenge among utilities.

Anticipated Improvements by 2030

Generation IV designs may provide thermal efficiency improvements over Generation III/III+ designs, while fuel costs for nuclear plants are expected to remain low compared to fossil fuels. Some cost reductions in nuclear power technology are expected by 2030 due to the natural learning that will occur by deploying multiple copies of the Generation III+ and IV designs. Overall EPRI anticipates the capital cost of a nuclear power plant deployed in 2030 will be 15% less than one built in 2015.

Development and Commercialisation Timeline

As mentioned above, Generation III and III+ reactors, while under construction in some parts of the world, are continuing to be developed and improved. They are considered current nuclear technologies. Generation IV technologies are expected to be made commercially available in the 2030 timeframe.

Relevant Business Issues

Nuclear reactors are carbon free, baseload power generation options, attributes which look favourable to many as carbon regulations loom. Keeping capital construction costs in check will be an important factor in making nuclear power plants cost competitive. In addition, the price and variability of natural gas, which is the major portion of the cost of electricity for natural gas combined cycle plants (another lower CO_2 generation option compared to coal-fired plants) will have a strong influence on how attractive the economics of nuclear power are.

7
FOSSIL TECHNOLOGIES PERFORMANCE & COST

Each of the selected fossil technologies has been evaluated at the ambient conditions defined in Section 3 and repeated below:

- Dry bulb temperature 25°C
- Wet bulb temperature 19.45°C
- Relative humidity 60%
- Atmospheric pressure 1.00 bar
- Equivalent altitude 111 m

In addition to the conditions above, since water supply is limited throughout Australia, all cases are based on the use of dry cooling equipment such as air cooled condensers and fin-fan coolers for auxiliary equipment.

The technologies were evaluated based on the use of currently available equipment, systems and materials. Heat and material balances were developed for each case, thereby providing data and information needed for cost estimation. The performance evaluation software used to evaluate each of the technologies was:

- Integrated Gasification Combined Cycle – Gatecycle
- Pulverised Coal – Gatecycle
- Combined Cycle Gas Turbine – GT Pro
- Open Cycle Gas Turbine – GT Pro

General descriptions of each of the technologies are included in Section 6. Specific performance and cost information on each case is provided in the following subsections.

7.1 INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

A general description of the IGCC process and systems is included in Section 6 of this report and provides a source of information regarding the systems included.

Four IGCC cases were evaluated, two with brown coal firing and two with black coal firing. For each fuel the IGCC was evaluated with and without CO_2 capture. For all IGCC cases a 2+1 combined cycle power generation arrangement was used based on GE 9FA gas turbines. The IGCC technology selected was the Shell gasification system which uses dry coal feed. For all cases coal drying was performed prior to feed to the gasifier. A simple block cycle diagram is provided below in Figure 7-1 for the cases without CCS and Figure 7-2 for the cases with CCS.

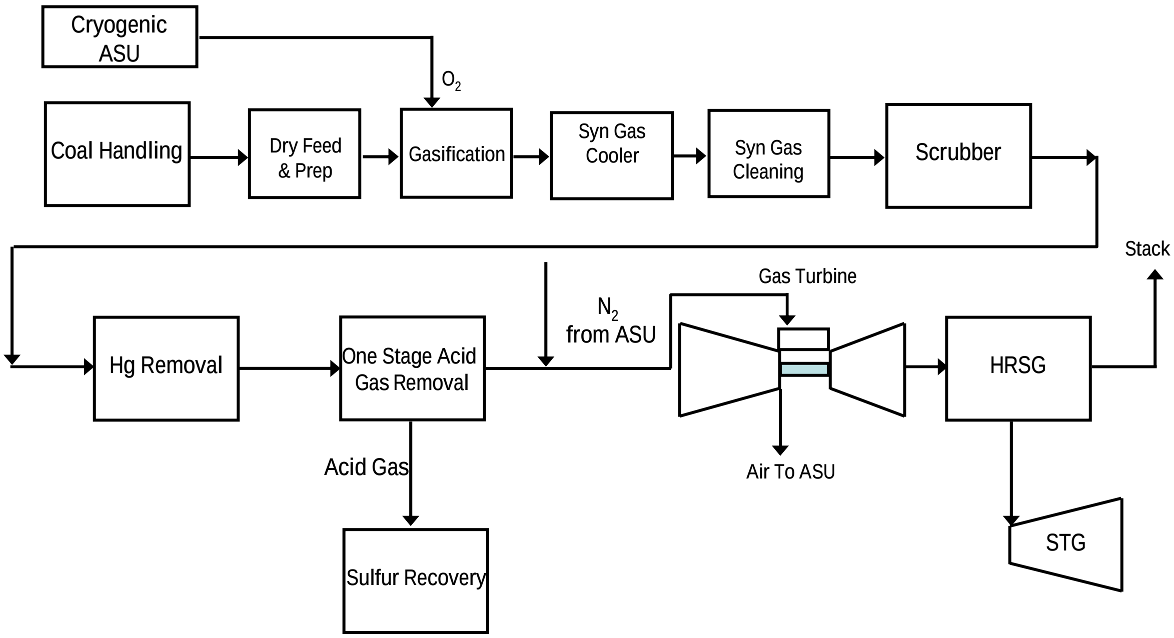


Figure 7-1
IGCC System without CCS

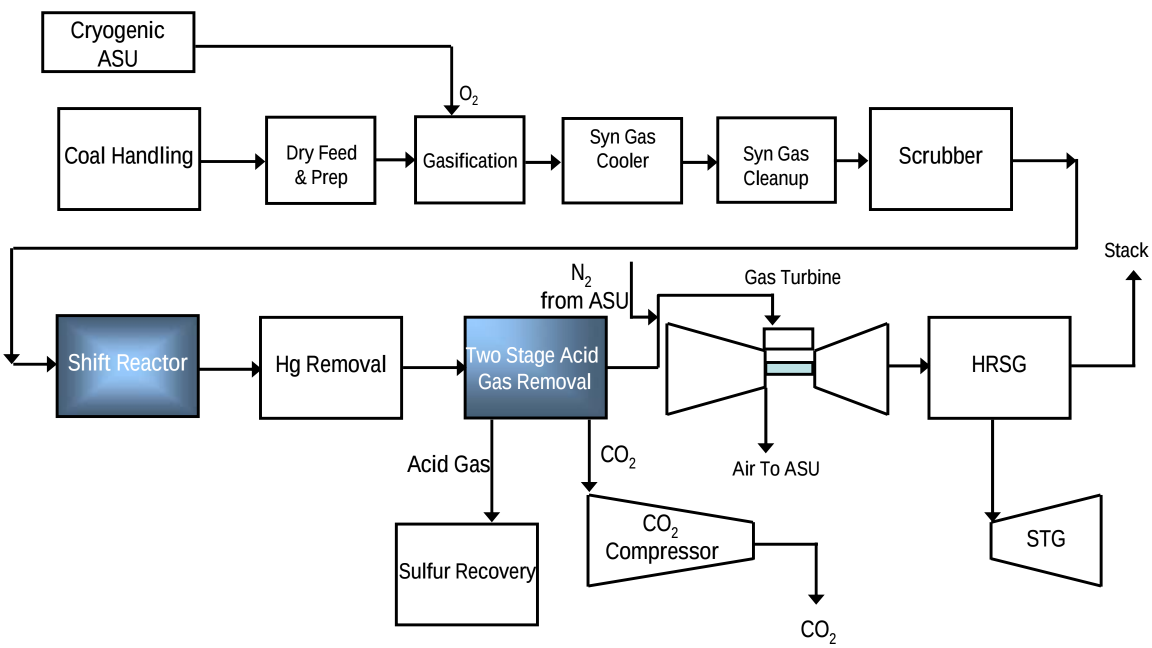


Figure 7-2
IGCC System with CCS

Since each of the IGCC cases is configured with the same GE 9FA gas turbine in a 2+1 combined cycle configuration there is a difference in the sent-out power produced between the cases due to significant differences in the auxiliary power loads associated with the air separation units, fuel handling and drying and the CCS system including the CO_2 compression to 158.6 bar (2300 psi).

The IGCC systems for the evaluated cases are configured as two parallel trains. Note the diagrams included above in Figure 7-1 and in Figure 7-2 each show a single train arrangement.

Since water supply in Australia is limited the steam condenser and process auxiliary systems requiring cooling have been configured with air cooled systems. The steam turbine condensing load is cooled with an air cooled condenser and the other systems incorporate fin-fan coolers. The IGCC process, especially the shift reactor used in the cases with CCS, requires water feed, therefore the water consumption for the IGCC cases is higher than for the other technologies evaluated.

IGCC Performance Results

The plant performance for each case evaluated was determined via process heat and material balance calculations using information within the EPRI subcontractor's technical databases. Some of the process information is considered proprietary by the process developer and therefore such additional data has not been included within the data summaries provided in this report. Sufficient information is provided to be able to evaluate the relative performance and cost of each technology against the others. A summary of the overall plant performance for the IGCC Cases is provided in Table 7-1.

Table 7-1
IGCC Overall Plant Performance (Near Term)

Fuel	BLACK COAL WITHOUT CCS	BLACK COAL WITH CCS (88.5% Capture)
Generated Plant Output (kW)		
Gas Turbine	286,000	286,000
Steam Turbine	311,791	277,504
Total Generated Output	883,791	849,504
Aux Loads and Losses (kW)		
Process Plant	140,851	259,761
Power Plant	12,009	11,024
Tranformer Losses	2,651	2,549
Total Aux Loads & Losses	**155,512**	**273,333**
Fuel Consumption, GJ/Hr - HHV	6,659	7,183
Coal Flowrate, kg/hr	268,346	289,460
Sent Out Output		
Sent Out Plant Power Output (kW)	**728,279**	**576,171**
Sent Out Plant Efficiency (% - HHV)	39.4	28.9
Sent Out Plant Efficiency (% - LHV)	41.0	30.1
Sent Out Plant Heat Rate (kJ/kWhr - HHV)	9,144	12,467
Sent Out Plant Heat Rate (kJ/kWhr - LHV)	8,782	11,974

IGCC Emissions and Water Use

The emissions of CO_2, SO_X and NO_X plus water consumption for each IGCC case are shown below in Table 7-2. Compared to the pulverised coal cases, the IGCC has lower emissions of SO_X and NO_X due to the process emissions reduction systems included, however, the CO_2 emissions and water consumption rates are higher for the IGCC cases versus the pulverised coal cases.

Table 7-2
IGCC Emissions and Water Consumption

Fuel	BLACK COAL WITHOUT CCS	BLACK COAL WITH CCS (88.5% Capture)
Emissions		
CO2 Emissions, kg/MWhr-sent out	812	127
SOx Emissions, g/MWhr-sent out	200	209
NOx Emissions, g/MWhr-sent out	12	12
Water Consumption, m3/day	4,489.4	18,035.3
Total Annual Water Consumption, m3	1,310,898	5,266,293

IGCC Capital Cost Estimates

The total plant costs for each of the IGCC cases were estimated per the procedures described in Section 4 of this report. The resulting estimates are summarised in Table 7-3. All costs are shown in mid-2009 Australian dollars.

Table 7-3
Total Plant Cost for IGCC Cases (Near Term)

Description	INTEGRATED GASIFICATION COMBINED CYCLE	
Fuel	**BLACK COAL WITHOUT CCS**	**BLACK COAL WITH CCS (88.5% Capture)**
Plant Capital Cost (AUDx1000)		
Coal & Fluxant/Sorbent Handling	84,751	88,442
Coal & Fluxan/Sorbentt Prep & Feed	353,569	371,692
Feedwater & Misc. BOP Systems	38,646	44,676
Gasifier (inc ASU)/PC Boiler & Accessories	1,123,439	1,219,726
Gas Cleanup & Piping/ Flue Gas Cleanup	161,482	365,573
CO2 Removal & Compression	0	117,855
Combustion Turbine & Accessories	189,748	197,157
HRSG, Ducting & Stack	96,527	96,527
Steam Turbine Generator (inc ACC)	227,301	212,648
Cooling Water System	41,517	87,013
Ash/Spent Sorbent Handling	109,317	114,566
Accessory Electric Plant	130,253	154,019
Instrumentation & Controls	38,770	41,987
Improvements to Site	38,594	39,769
Buildings & Structures	38,432	39,208
Total Bare Erected Cost	**2,672,345**	**3,190,858**
Engineering & Constr. Mgmt.	240,511	287,177
Contingencies	541,329	657,025
Project Specific Costs	259,064	310,130
Total Plant Cost (AUDx1000)	**3,713,249**	**4,445,190**
Total Plant Cost (AUD/kW sent out)	**5,099**	**7,715**

IGCC Operating and Maintenance Cost Estimates

The O&M costs for each of the IGCC cases evaluated were estimated per the procedures described in Section 4 of this report. The results of these estimates, in mid-2009 Australian dollars, are shown in Table 7-4.

Table 7-4
IGCC O&M Cost Estimates for IGCC

Fuel	BLACK COAL WITHOUT CCS	BLACK COAL WITH CCS (88.5% Capture)
Operating and Maintenance Costs		
Fixed O&M (AUD/kW-yr)	72.7	103.7
Variable O&M (AUD/MWh)	12.8	20.0

7.2 PULVERISED COAL-FIRED POWER PLANTS

Power generation with pulverised coal combustion systems has been used by power utility companies around the world for over 75 years and is considered a very mature technology. Advances continue to be made to improve efficiency, reduce emissions and to reduce costs. The pulverised coal cases evaluated in this study include supercritical steam cycles which are proven and represent a modern level of the technology. Additionally, a case using pulverised coal with oxy combustion has been included. This is a new technology advancement that is being offered by major boiler suppliers but is not yet in commercial operation. Both the conventional and the oxy combustion pulverised coal technologies are described in more detail in Section 6 of this report.

All of the pulverised coal cases were evaluated using a single reheat supercritical pressure Rankine steam cycle. The steam conditions are 267 bar/596ºC/596ºC. The configuration of the steam cycle for each case is depicted in Figures 7-3 through 7-5.

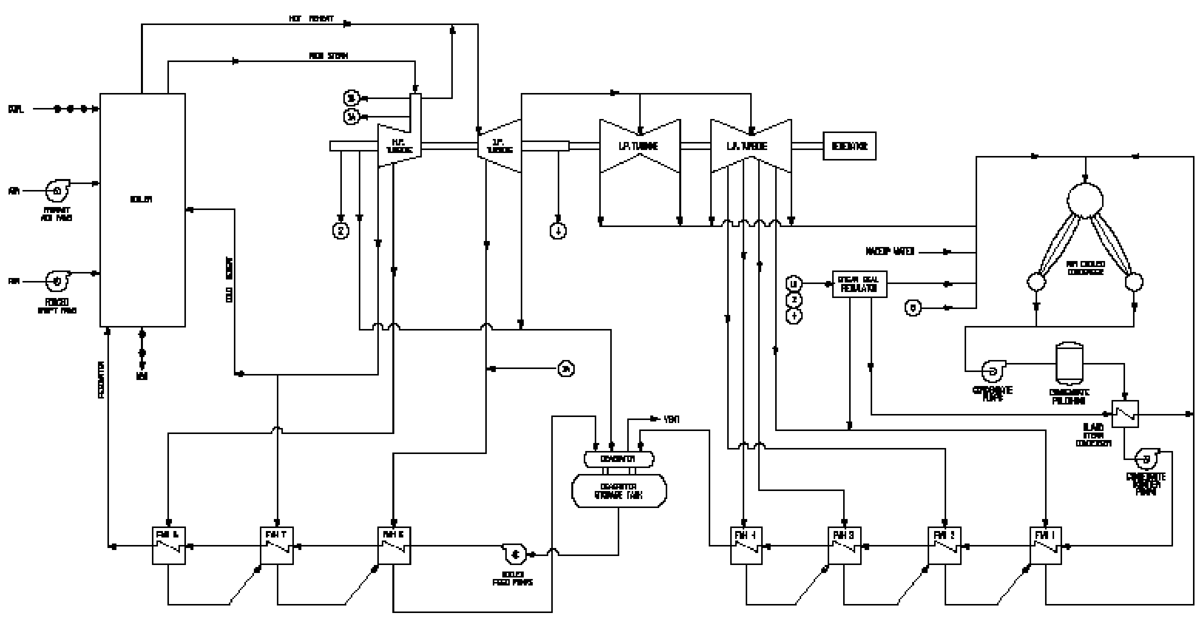


Figure 7-3
Pulverised Coal Steam Cycle without CCS

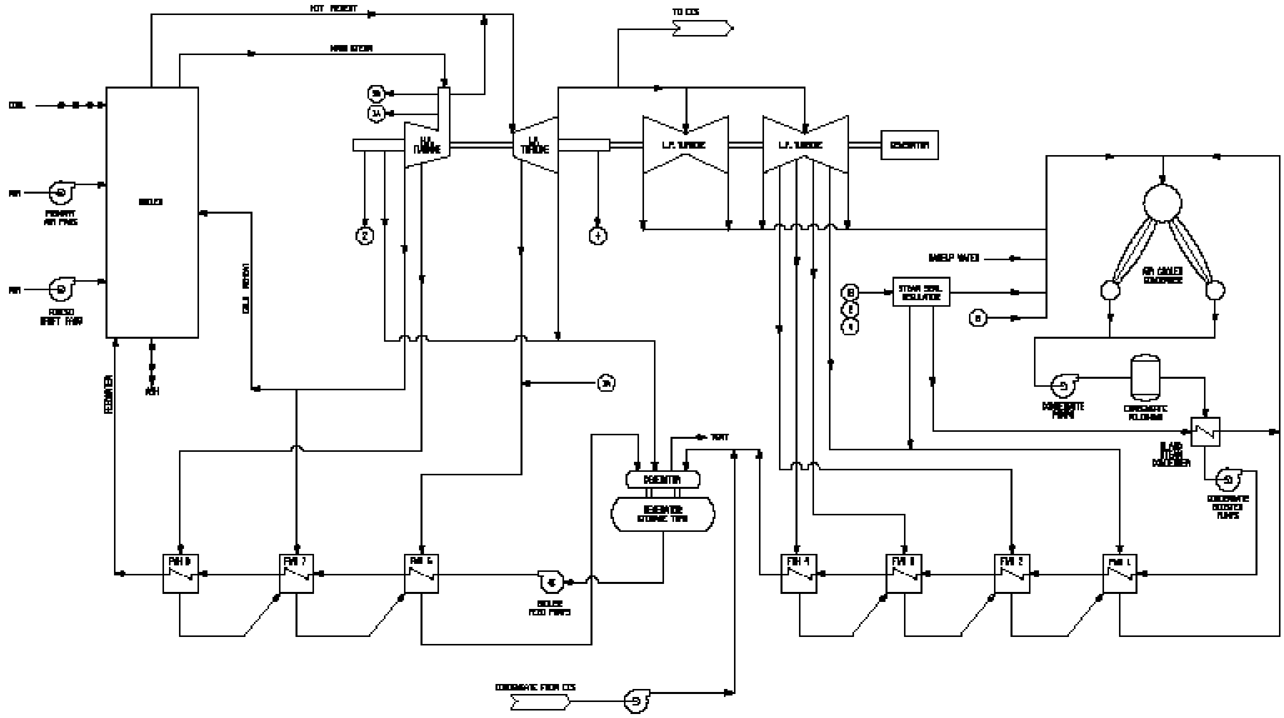


Figure 7-4
Pulverised Coal Steam Cycle with CCS

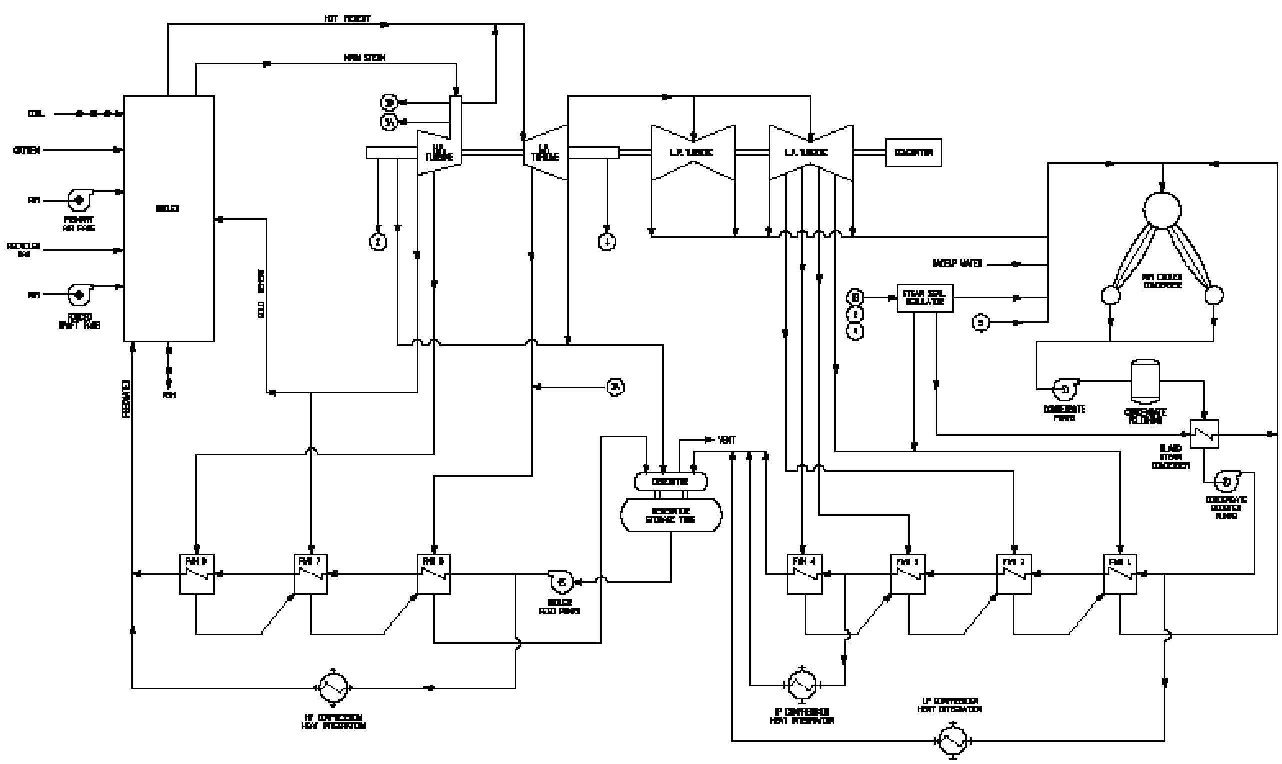


Figure 7-5
Pulverised Coal Cycle with Oxy Combustion

Pulverised Coal Performance Results

The plant performance for each case evaluated was determined via process and heat and material balance calculations using information within the EPRI's subcontractor's technical databases. The calculated plant performance results for each case are shown in Table 7-5 below.

Table 7-5
Supercritical Pulverised Coal Overall Plant Performance (Near Term)

Fuel	BROWN COAL, NO Nox/SO2 CONTROLS	BROWN COAL WITH CCS	BLACK COAL, NO Nox/SO2 CONTROLS	BLACK COAL WITH CCS	BLACK COAL OXY-COMBUSTION
Generated Plant Output (kW)					
Gas Turbine	NA	NA	NA	NA	NA
Steam Turbine	835,726	986,091	831,512	977,511	1,093,760
Total Generated Output	835,726	986,091	831,512	977,511	1,093,760
Aux Loads and Losses (kW)					
Process Plant	NA	124,840	NA	123,754	240,773
Power Plant	83,219	108,292	79,017	100,824	101,698
Tranformer Losses	2,507	2,958	2,495	2,933	3,281
Total Aux Loads & Losses	**85,727**	**236,091**	**81,512**	**227,511**	**345,752**
Fuel Consumption, GJ/Hr - HHV	7,751	10,604	7,110	9,505	8,953
Coal Flowrate, kg/hr	781,297	1,068,890	286,503	383,024	360,776
Sent Out Output					
Sent Out Plant Power Output (kW)	**750,000**	**750,000**	**750,000**	**750,000**	**748,008**
Sent Out Plant Efficiency (% - HHV)	34.9	25.5	38.0	28.4	30.1
Sent Out Plant Efficiency (% - LHV)	42.9	31.4	39.6	29.6	31.3
Sent Out Plant Heat Rate (kJ/kWhr - HHV)	10,334	14,138	9,480	12,673	11,969
Sent Out Plant Heat Rate (kJ/kWhr - LHV)	8,390	11,479	9,105	12,173	11,496
CO2 Captured, kg/hr	-	786,704	-	680,907	626,193

Emissions and Water Use

The emissions of CO_2, SO_X and NO_X plus water consumption for each pulverised coal case are shown below in Table 7-6.

Table 7-6
Pulverised Coal Plant Emissions and Water Consumption

Fuel	BROWN COAL, NO Nox/SO2 CONTROLS	BROWN COAL WITH CCS	BLACK COAL, NO Nox/SO2 CONTROLS	BLACK COAL WITH CCS	BLACK COAL OXY-COMBUSTION
Emissions					
CO2 Emissions, kg/MWhr-sent out	833	117	738	101	93
SOx Emissions, g/MWhr-sent out	312,239	14,737	328,228	13,164	0.00
NOx Emissions, g/MWhr-sent out	889	1,216	815	1,090	0.00
Water Consumption, m3/day	599.6	820.3	572.4	765.2	899.4
Total Annual Water Consumption, m3	186,029	254,505	177,573	237,396	279,043

Pulverised Coal Capital Cost Estimates

The total plant costs for each of the pulverised coal cases were estimated per the procedures described in Section 4 of this report. The resulting estimates are summarised below in Table 7-7. All costs are shown in mid-2009 Australian dollars.

Table 7-7
Total Plant Cost for Pulverised Coal Cases (Near Term)

Fuel	BROWN COAL, NO Nox/SO2 CONTROLS	BROWN COAL WITH CCS	BLACK COAL, NO Nox/SO2 CONTROLS	BLACK COAL WITH CCS	BLACK COAL OXY-COMBUSTION
Plant Capital Cost (AUDx1000)					
Coal & Fluxant/Sorbent Handling	152,347	182,854	85,866	101,173	97,797
Coal & Fluxan/Sorbentt Prep & Feed	352,567	438,660	28,958	35,075	33,717
Feedwater & Misc. BOP Systems	137,493	171,545	126,847	155,614	149,221
Gasifier (inc ASU)/PC Boiler & Accessories	743,227	939,481	559,936	696,161	1,423,167
Gas Cleanup & Piping/ Flue Gas Cleanup	69,578	166,768	60,759	151,116	24,162
CO2 Removal & Compression	0	970,635	0	888,179	581,883
Combustion Turbine & Accessories	0	0	0	0	0
HRSG, Ducting & Stack	91,475	122,109	84,892	111,457	37,884
Steam Turbine Generator (inc ACC)	355,552	369,622	358,846	378,080	445,926
Cooling Water System	12,801	166,594	13,577	150,813	107,342
Ash/Spent Sorbent Handling	13,955	19,308	40,810	49,753	43,428
Accessory Electric Plant	130,038	190,047	127,762	187,176	223,196
Instrumentation & Controls	42,389	49,200	42,868	49,865	45,438
Improvements to Site	32,065	36,421	31,988	36,270	36,437
Buildings & Structures	130,996	144,015	130,632	143,325	151,622
Total Bare Erected Cost	**2,264,483**	**3,967,259**	**1,693,741**	**3,134,057**	**3,401,218**
Engineering & Constr. Mgmt.	203,804	357,053	152,437	282,065	306,110
Contingencies	308,058	812,686	223,690	668,557	666,923
Project Specific Costs	208,226	385,275	155,240	306,351	328,069
Total Plant Cost (AUDx1000)	**2,984,571**	**5,522,273**	**2,225,108**	**4,391,030**	**4,702,320**
Total Plant Cost (AUD/kW sent out)	**3,979**	**7,363**	**2,967**	**5,855**	**6,286**

Pulverised Coal Operating and Maintenance Cost Estimates

The O&M costs for each of the pulverised coal cases evaluated were estimated per the procedures described in Section 4 of this report. The results of these estimates, in mid-2009 Australian dollars, are shown in Table 7-8.

Table 7-8
Pulverised Coal operating and Maintenance Costs

Fuel	BROWN COAL, NO Nox/SO2 CONTROLS	BROWN COAL WITH CCS	BLACK COAL, NO Nox/SO2 CONTROLS	BLACK COAL WITH CCS	BLACK COAL OXY-COMBUSTION
Operating and Maintenance Costs					
Fixed O&M (AUD/kW-yr)	41.4	67.4	33.1	55.3	60.1
Variable O&M (AUD/MWh)	5.1	16.4	4.6	15.7	9.1

7.3 COMBINED CYCLE GAS TURBINE EVALUATIONS

The combined cycle gas turbine selected for this evaluation is a 2 on 1 configuration incorporating GE 9F gas turbine generators. This is a conventional combined cycle plant with substantial commercial application, hence, the technical risk in its application is very low. This option is based on natural gas fuel only. The combined cycle gas turbine plant represents the lowest capital cost on an installed basis compared to the other technologies with the exception of the open cycle case. For the combined cycle system the fuel cost is generally the largest portion of the total cost of generated electricity.

The combined cycle system uses a conventional, sub-critical steam cycle with a three pressure heat recovery steam generator located after the gas turbine exhaust to recover energy as steam for feed to the steam turbine. For the combined cycle case with CCS a portion of the steam prior to the low pressure steam turbine is extracted as needed for the CO_2 capture process, hence the megawatts generated in the steam turbine are lower for this case. The cycle diagrams for the combined cycle cases are shown in Figure 7-6 and Figure 7-7.

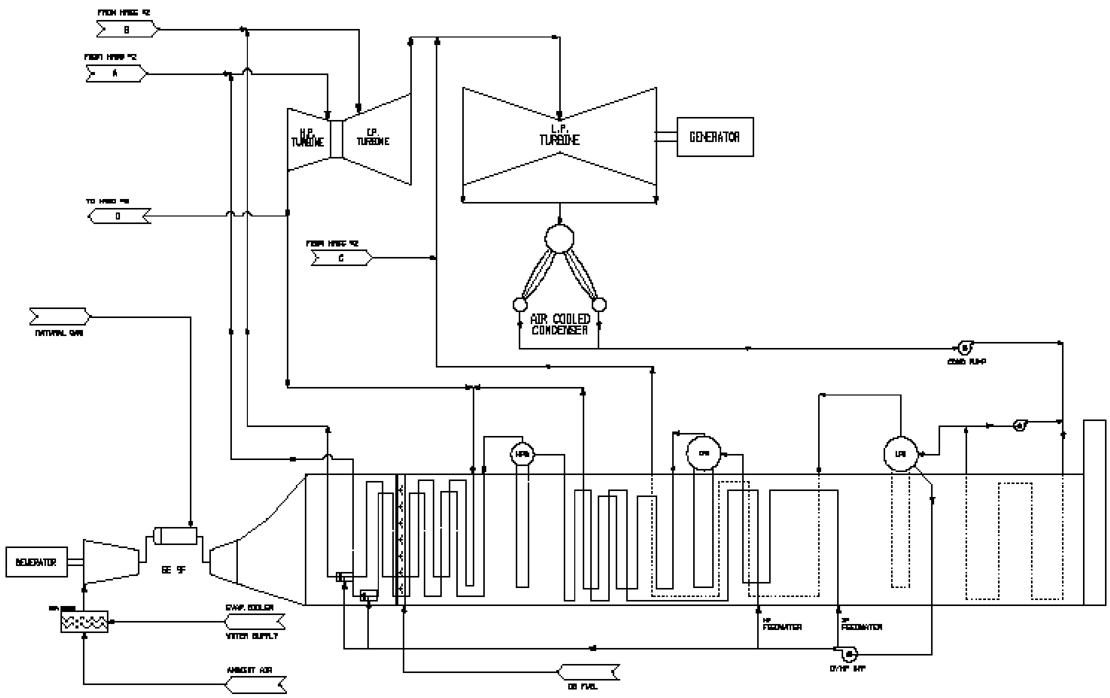


Figure 7-6
Natural Gas-Fired Combined Cycle Gas Turbine without CCS

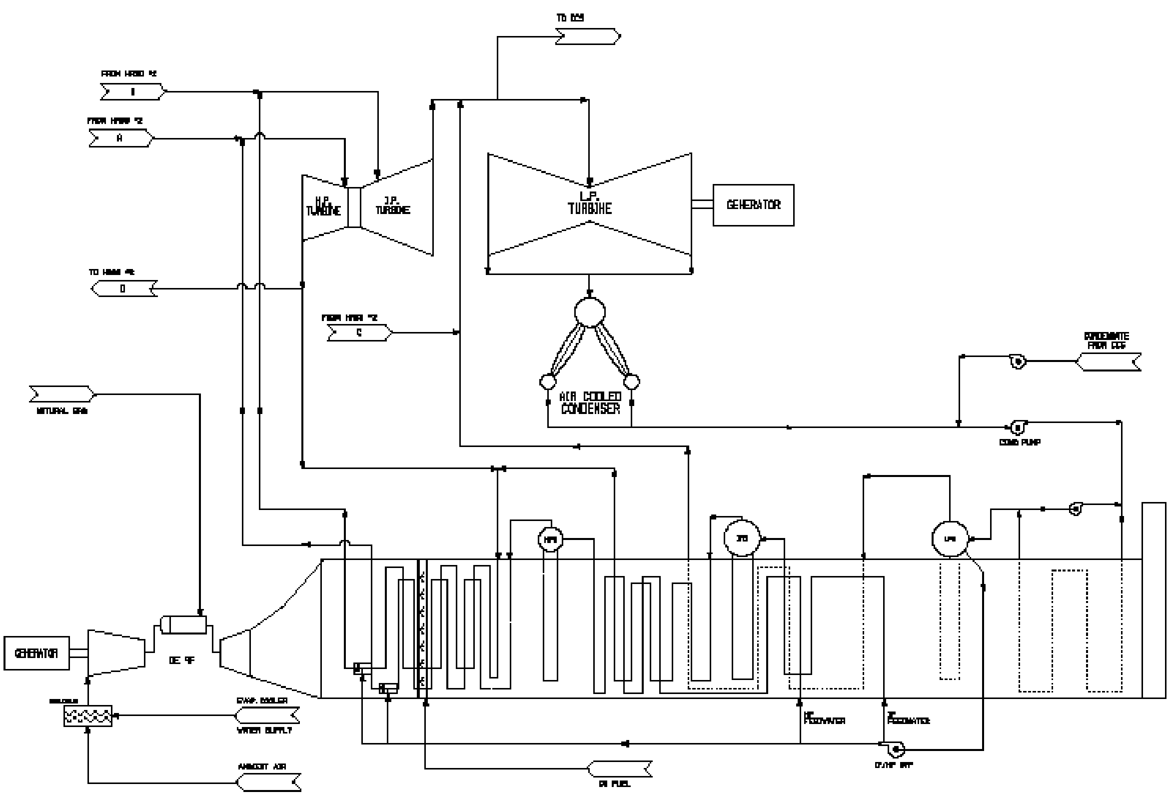


Figure 7-7
Natural Gas-Fired Combined Cycle Gas Turbine with CCS

Combined Cycle Gas Turbine Performance Results

The plant performance for each case evaluated was determined via process and heat and material balance calculations using GT Pro software and information within the EPRI subcontractor's technical databases. Since both the combined cycle cases, with and without CCS, use the same GE 9F gas turbines the sent-out power is lower for the case with CCS as a result of the CO_2 capture process auxiliary power and steam consumption. Additionally, due to the nature of the natural gas fuel, less CO_2 is produced which is why the CO_2 capture indicated is considerably lower than for the coal fired cases. The calculated plant performance results for each combined cycle case are shown in Table 7-9.

Table 7-9
Combined Cycle Gas Turbine Plant Performance (Near Term)

	WITHOUT CCS	WITH CCS
Generated Plant Output (kW)		
Gas Turbine	235,842	235,842
Steam Turbine	260,713	227,042
Total Generated Output	732,397	698,726
Aux Loads and Losses (kW)		
Process Plant	NA	88,460
Power Plant	18,866	17,122
Tranformer Losses	2,197	2,096
Total Aux Loads & Losses	**21,063**	**107,678**
Fuel Consumption, GJ/Hr - HHV	5,171	5,171
Coal Flowrate, kg/hr	NA	NA
Sent Out Output		
Sent Out Plant Power Output (kW)	**711,334**	**591,048**
Sent Out Plant Efficiency (% - HHV)	49.6	41.2
Sent Out Plant Efficiency (% - LHV)	54.9	45.6
Sent Out Plant Heat Rate (kJ/kWhr - HHV)	7,269	8,749
Sent Out Plant Heat Rate (kJ/kWhr - LHV)	6,565	7,901

Combined Cycle Gas Turbine Emissions and Water Use

Due to the use of natural gas fuel in the gas turbines, very little emissions control is needed to maintain low stack emissions levels. For these cases, the natural gas sulphur content is assumed to be 18.31 mg/100 scm. The gas turbines are equipped with dry low NO_X combustors. No SO_X or particulate controls are needed to clean up the flue gases. The emissions values and water consumption values are shown in Table 7-10.

Table 7-10
Combined Cycle Gas Turbine Emissions and Water Use

	WITHOUT CCS	WITH CCS
Emissions		
CO2 Emissions, kg/MWhr-sent out	376	45
SOx Emissions, g/MWhr-sent out	0.74	0.89
NOx Emissions, g/MWhr-sent out	285	342
Water Consumption, m3/day	218.0	272.5
Total Annual Water Consumption, m3	51,730	64,662

Combined Cycle Gas Turbine Capital Cost Estimates

The design, equipment and labour costs for each of the combined cycle gas turbine cases were estimated per the procedures described in Section 4 of this report. The resulting estimates are summarised below in Table 7-11. All costs are shown in mid-2009 Australian dollars.

Table 7-11
Combined Cycle Gas Turbine Total Plant Cost (Near Term)

Fuel	NATURAL GAS WITHOUT CCS	NATURAL GAS WITH CCS
Plant Capital Cost (AUDx1000)		
Feedwater & Misc. BOP Systems	28,264	28,540
CO2 Removal & Compression	0	367,910
Combustion Turbine & Accessories	189,749	189,749
HRSG, Ducting & Stack	96,527	96,527
Steam Turbine Generator (inc ACC)	195,417	167,472
Cooling Water System	6,736	60,037
Ash/Spent Sorbent Handling	0	0
Accessory Electric Plant	66,037	90,093
Instrumentation & Controls	24,663	27,147
Improvements to Site	22,143	22,736
Buildings & Structures	23,386	22,510
Total Bare Erected Cost	**652,922**	**1,072,720**
Engineering & Constr. Mgmt.	44,399	72,945
Contingencies	79,079	239,032
Project Specific Costs	58,230	103,852
Total Plant Cost (AUDx1000)	**834,630**	**1,488,550**
Total Plant Cost (AUD/kW sent out)	**1,173**	**2,518**

O&M Cost Estimates for Combined Cycle Gas Turbine

The O&M costs for each of the combined cycle gas turbine cases evaluated were estimated per the procedures described in Section 4 of this report. The results of these estimates, in mid-2009 Australian dollars, are shown in Table 7-12.

Table 7-12
O&M Cost Estimate for Combined Cycle without CCS

Fuel	NATURAL GAS WITHOUT CCS	NATURAL GAS WITH CCS
Operating and Maintenance Costs		
Fixed O&M (AUD/kW-yr)	13.6	24.8
Variable O&M (AUD/MWh)	2.0	4.2

7.4 OPEN CYCLE GAS TURBINE EVALUATION

A single open cycle case was evaluated based on the use of a frame type gas turbine. A nominal 100 to 150 MWe capacity plant was defined and for this a GE 9E gas turbine was selected which generates approximately 115 MWe (sent-out). The defined open cycle case does not include CCS. Additionally, since the gas turbine firing natural gas produces very low emissions, no emissions control systems have been included except for the use of dry low NO_X combustors on the gas turbine. The gas turbine cycle is shown below in Figure 7-8.

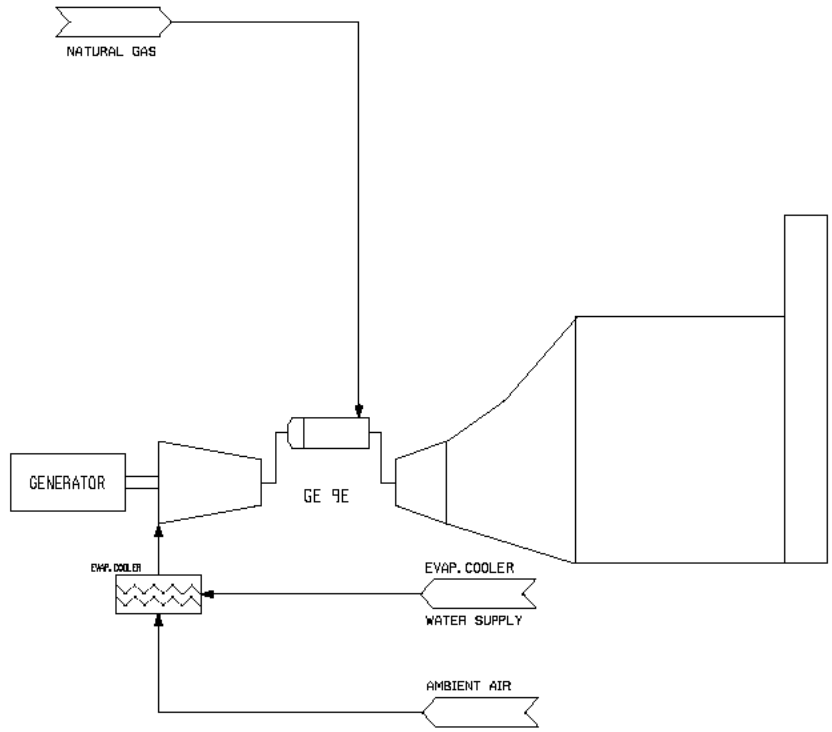


Figure 7-8
Open Cycle Gas Turbine

Open Cycle Gas Turbine Performance

The plant performance for the open cycle case was determined via process and heat and material balance calculations using GT Pro software and information within the EPRI's subcontractor's technical databases. Since turbines operating in open cycle configurations have higher heat rates than combined cycle plants they are typically used to support electric power peaking load conditions. This results in low operating capacity factors and for this case a capacity factor of 10% was defined. The performance results for this case are shown in Table 7-13.

Table 7-13
Open Cycle Gas Turbine Performance Results

	WITHOUT CCS
Generated Plant Output (kW)	
Gas Turbine	115,868
Steam Turbine	NA
Total Generated Output	115,868
Aux Loads and Losses (kW)	
Process Plant	NA
Power Plant	791
Tranformer Losses	348
Total Aux Loads & Losses	**1,139**
Fuel Consumption, GJ/Hr - HHV	1,240
Coal Flowrate, kg/hr	NA
Sent Out Output	
Sent Out Plant Power Output (kW)	**114,729**
Sent Out Plant Efficiency (% - HHV)	33.2
Sent Out Plant Efficiency (% - LHV)	36.8
Sent Out Plant Heat Rate (kJ/kWhr - HHV)	10,841
Sent Out Plant Heat Rate (kJ/kWhr - LHV)	9,790
CO2 Captured, kg/hr	-

Open Cycle Gas Turbine Emissions and Water Use

Due to the use of natural gas fuel in the gas turbine, very little emissions control is needed to maintain low stack emissions levels. For this case, the natural gas sulphur content is assumed to be 18.31 mg/100 scm. The gas turbine is equipped with dry low NO_X combustors. No SO_X or particulate controls are needed to clean up the flue gases. The emissions values and water consumption values are shown in Table 7-14

Table 7-14
Open Cycle Gas Turbine Emissions and Water Use

	WITHOUT CCS
Emissions	
CO2 Emissions, kg/MWhr-sent out	622
SOx Emissions, g/MWhr-sent out	1.10
NOx Emissions, g/MWhr-sent out	282
Water Consumption, m3/day	54.5
Total Annual Water Consumption, m3	1,990

Open Cycle Gas Turbine Capital Cost Estimate

The design, equipment and labour costs for the open cycle case were estimated per the procedures described in Section 4 of this report. The resulting estimate is summarised below in Table 7-15. All costs are shown in mid-2009 Australian dollars.

Table 7-15
Open Cycle Gas Turbine Capital Cost Estimate

Fuel	NATURAL GAS WITHOUT CCS
Plant Capital Cost (AUDx1000)	
Feedwater & Misc. BOP Systems	2,376
CO2 Removal & Compression	0
Combustion Turbine & Accessories	52,888
HRSG, Ducting & Stack	0
Steam Turbine Generator (inc ACC)	0
Cooling Water System	488
Ash/Spent Sorbent Handling	0
Accessory Electric Plant	5,959
Instrumentation & Controls	4,988
Improvements to Site	3,689
Buildings & Structures	1,501
Total Bare Erected Cost	**71,890**
Engineering & Constr. Mgmt.	4,889
Contingencies	8,706
Project Specific Costs	6,411
Total Plant Cost (AUDx1000)	**91,896**
Total Plant Cost (AUD/kW sent out)	**801**

O&M Cost Estimate for Open Cycle Gas Turbine

The O&M costs for the open cycle gas turbine case evaluated were estimated per the procedures described in Section 4 of this report. The results of these estimates, in Australian dollars, are shown in Table 7-16

Table 7-16
O&M Cost Estimate for Simple Cycle

Fuel	NATURAL GAS WITHOUT CCS
Operating and Maintenance Costs	
Fixed O&M (AUD/kW-yr)	9.3
Variable O&M (AUD/MWh)	2.5

8 RENEWABLE TECHNOLOGIES PERFORMANCE EVALUATIONS

8.1 PARABOLIC TROUGH CONCENTRATING SOLAR PLANT

The parabolic trough technology selected for this case is described in Section 6. The plant evaluated was sized at 200 MWe sent-out capacity and was evaluated both with and without storage. Including thermal energy storage allows the plant to provide power generation during times when sunlight is not available. A two-tank molten salt system with six hours of storage was assumed for the plant with thermal storage. Both plants assumed dry cooling for the power block steam cycle.

Due to the relatively low density of energy from the sun a large amount of space is required for generation of solar electric power. Additionally, the capacity factor of solar energy plants is low since they can only produce power when sunlight is available. A key benefit of solar produced electricity is the lack of SO_2, NO_X and particulate emissions and the use of 'free' renewable energy. The downside of the solar power plant is its very large capital cost per megawatt-hour produced.

Since the temperatures in the thermal solar system are moderate, a relatively low pressure and temperature sub-critical steam cycle is used. Therefore, the equipment used to generate the power is fully commercialised and technical risks for this part of the plant are very low. Parabolic trough energy recovery equipment is relatively new but is considered to be commercially available. The largest area of technical risk for this type of system is with the molten salt energy storage system. Application of this on a large scale and for extended operating periods has not been applied yet in the field. Careful engineering of the first large systems employing thermal energy storage will be essential.

Parabolic Trough Plant Performance

Because the performance of a parabolic trough plant strongly depends on the solar resource available at the plant site, the performance for the parabolic trough cases was evaluated for a range of direct normal insolation (DNI): 5, 6, and 7 kWh/m^2/day. For reference, some Australia specific DNIs are as follows: Canberra = 4.9 kWh/m^2/day; Mildura = 5.8 kWh/m^2/day; Alice Springs = 7.2 kWh/m^2/day.

Assuming a solar-to-electric efficiency of 13.6%, the following table shows the capacity factors for parabolic trough systems, both with and without storage, for the different levels of solar resource. Stronger solar resources result in higher capacity factors because the plant can produce more electricity for a given solar field size. The addition of thermal storage also increases the capacity factor because the solar field is sized to collect more heat, some of which can be used immediately and some of which is stored for later use, allowing the plant to run for more hours of the day.

Table 8-1
Parabolic Trough Plant Performance Results

	Parabolic Trough with 6 Hours of Thermal Storage			Parabolic Trough without Storage		
DNI (kWh/m^2/day)	5	6	7	5	6	7
Capacity Factor (%)	26.2	31.5	37.0	16.2	19.4	22.6

Parabolic Trough Emissions and Water Use

Since there is no fuel burned in the generation of solar electric power, parabolic trough plants do not produce any of the harmful emissions typically associated with conventional fossil power plants. The use of dry cooling greatly reduces the water requirements of the plant as well. Water is used for makeup to the steam cycle and for mirror washing which is very important to maintain the capacity of the solar plant. The amount of mirror washing water consumption is based on a use rate of 52 litres per hour per m^2 of mirror area. Approximately 45% of the water used in the solar plant is for mirror washing.

Parabolic Trough Plant Capital Cost Estimate

The table below shows the total plant cost for a parabolic trough plant both with and without storage. While the plant is more expensive with storage included, this can often be superseded by the fact that the plant can then produce more electricity, lowering the cost of electricity. All costs are shown in mid-2009 Australian dollars.

Table 8-2
Parabolic Trough Plant Capital Cost Estimate

	Parabolic Trough with 6 Hours of Thermal Storage	Parabolic Trough without Storage
Total Plant Cost (AUD/kW sent-out)	8,751	5,677

O&M Cost Estimate for Parabolic Trough Plant

The table below shows the O&M costs for the parabolic trough plants. All costs are shown in mid-2009 Australian dollars.

Table 8-3
O&M Cost Estimate for Parabolic Trough Plant

	Parabolic Trough with 6 Hours of Thermal Storage	Parabolic Trough without Storage
Fixed O&M (AUD/kW-yr)	73	55
Variable O&M (AUD/MWh)	0	0

8.2 CENTRAL RECEIVER CONCENTRATING SOLAR PLANT

The central receiver technology selected for this case is described in Section 6. The plant evaluated was sized at 200 MWe sent-out capacity and was evaluated both with and without storage. Including thermal energy storage allows the plant to provide power generation during times when sunlight is not available. A two-tank molten salt system with six hours of storage was assumed for the plant with thermal storage. Both plants assumed dry cooling for the power block steam cycle.

As with the parabolic trough, due to the relatively low density of energy from the sun a large amount of space is required for generation of solar electric power. Additionally, the capacity factor of solar energy plants is low since they can only produce power when sunlight is available. A key benefit of solar produced electricity is the lack of SO_2, NO_X and particulate emissions and the use of free renewable energy. The downside of the solar power plant is its very large capital cost per megawatt-hour produced.

Temperatures of the central receiver thermal solar system are higher than those of the parabolic trough. However, the equipment used to generate the power is still fully commercialised and technical risks for this part of the plant are very low. Central receiver energy recovery equipment is less developed than that of the parabolic trough and is considered to be still in the demonstration phase. The largest area of technical risk for this type of system is with the molten salt energy storage system. Application of this on a large scale and for extended operating periods has not been applied yet in the field. Careful engineering of the first large systems employing thermal energy storage will be essential.

Central Receiver Plant Performance

As with the parabolic trough plants, because the performance of a central receiver strongly depends on the solar resource available at the plant site, the performance for the central receiver cases was evaluated for a range of direct normal insolation (DNI): 5, 6, and 7 $kWh/m^2/day$. For reference, some Australia specific DNIs are as follows: Canberra = 4.9 $kWh/m^2/day$; Mildura = 5.8 $kWh/m^2/day$; Alice Springs = 7.2 $kWh/m^2/day$.

Assuming a solar-to-electric efficiency of 15.5%, the following table shows the capacity factors for central receiver systems, both with and without storage, for the different levels of solar resource. Stronger solar resources result in higher capacity factors because the plant can produce more electricity for a given solar field size. The addition of thermal storage also increases the capacity factor because the solar field is sized to collect more heat, some of which can be used immediately and some of which is stored for later use, allowing the plant to run for more hours of the day.

Table 8-4
Central Receiver Plant Performance Results

	Central Receiver with 6 Hours of Thermal Storage			Central Receiver without Storage		
DNI ($kWh/m^2/day$)	5	6	7	5	6	7
Capacity Factor (%)	26.4	31.6	36.9	16.2	19.5	22.7

Central Receiver Plant Emissions and Water Use

Since there is no fuel burned in the generation of solar electric power, central receiver plants, like parabolic trough plants, do not produce any of the harmful emissions typically associated with conventional fossil power plants. The use of dry cooling greatly reduces the water requirements of the plant as well. Water is used for makeup to the steam cycle and for washing the heliostat field to maintain the mirror reflectivity.

Central Receiver Plant Capital Cost Estimate

The table below shows the total plant cost for a central receiver plant both with and without storage. While the plant is more expensive with storage included, the ability to produce electricity for more hours of the day can often result in a reduced cost of electricity compared to a plant without storage.

All costs are shown in mid-2009 Australian dollars.

Table 8-5
Central Receiver Plant Capital Cost Estimate

	Central Receiver with 6 Hours of Thermal Storage	Central Receiver without Storage
Total Plant Cost (AUD/kW sent-out)	6,475	4,559

O&M Cost Estimate for Central Receiver Plant

The table below shows the O&M costs for the central receiver plants. All costs are shown in mid-2009 Australian dollars.

Table 8-6 O&M
Cost Estimate for Central Receiver Plant

	Central Receiver with 6 Hours of Thermal Storage	Central Receiver without Storage
Fixed O&M (AUD/kW-yr)	73	55
Variable O&M (AUD/MWh)	0	0

8.3 PHOTOVOLTAIC PLANTS

The solar photovoltaic (PV) technologies selected for this case is described in Section 6. The PV systems analysed in this report were evaluated at both 5 MW and 50 MW. Three different photovoltaic systems are included in this analysis: fixed flat plate crystalline silicon PVs, single-axis tracking flat plate crystalline silicon PVs, and two-axis tracking concentrating solar PVs.

As with the concentrating solar plant technologies, due to the relatively low density of energy from the sun a large amount of space is required for generation of solar electric power. Additionally, the capacity factor of solar energy plants is low since they can only produce power when sunlight is available. A key benefit of solar produced electricity is the lack of SO_2, NO_X and particulate emissions and the use of free renewable energy. The downside of the solar power plant is its very large capital cost per megawatt-hour produced.

Photovoltaic Plant Performance

The performance of the photovoltaic systems was calculated for a location with a direct normal insolation of 6.7 kWh/m^2/yr. The table below shows the module collection efficiency and the capacity factor for the three PV technologies analysed. The collection efficiency for the concentrating PV is higher than that for the flat plate PV and the capacity factor of the tracking systems increases due to the increased exposure to the sun.

Table 8-7
Photovoltaic Plant Performance Results

	Fixed Flat Plate PV	Single Axis Tracking Flat Plate PV	Two-Axis Tracking Concentrating PV
Module Efficiency (%)	12.4	12.4	20.2
Capacity Factor (%)	21	26	31

Photovoltaic Plant Emissions and Water Use

As with the concentrating solar technologies, photovoltaic systems do not produce any of the harmful emissions typically associated with conventional fossil power plants. The only water requirement is occasionally washing the modules to prevent reduced collection efficiency.

Photovoltaic Plant Capital Cost Estimate

The table below shows the capital costs of the three PV technologies evaluated in this study for both a 5 MW and a 50 MW plant. All costs are shown in mid-2009 Australian dollars.

Table 8-8
Photovoltaic Plant Capital Cost Estimate

	Fixed Flat Plate PV		Single Axis Tracking Flat Plate PV		Two-Axis Tracking Concentrating PV	
Size (MW)	5	50	5	50	5	50
Total Plant Cost (AUD/kW sent-out)	9.121	8.459	11.219	10.276	13.992	11.544

O&M Cost Estimate for Photovoltaic Plants

The table below shows the O&M costs for the photovoltaic plants. All costs are shown in mid-2009 Australian dollars.

Table 8-9
O&M Cost Estimate for Photovoltaic Plant

	Fixed Flat Plate PV		Single Axis Tracking Flat Plate PV		Two-Axis Tracking Concentrating PV	
Size (MW)	5	50	5	50	5	50
Fixed O&M (AUD/kW-yr)	55	38	66	47	105	76
Variable O&M (AUD/MWh)	0	0	0	0	0	0

8.4 WIND TURBINE PLANTS

The wind technology selected for this case is described in Section 6. Wind plants were analysed at three different sizes: 25 x 2 MW, 100 x 2 MW, and 250 x 2 MW. In recent years, wind has been the fastest growing form of electricity generation in the world and is the most highly deployed renewable technology, not counting large-scale hydro. Wind turbines are considered a mature, commercial technology, though research continues into making the turbines larger and developing advanced controls. Installing wind turbines off-shore to capture the stronger and steadier wind resources available along many coastlines is also an ongoing area of research. As with the solar technologies discussed in this section, a key benefit of wind produced electricity is the lack of SO_2, NO_X and particulate emissions and the use of free renewable energy.

Wind Plant Performance

The performance of the wind plants was calculated for a range of wind speeds. These include wind classes 3, 4, 5, and 6 which have average wind speeds at 50 meter tower height of 6.7 m/s, 7.3 m/s, 7.8 m/s, and 8.4 m/s, respectively. The table below shows the capacity factor of wind farms for these different wind classes.

Table 8-10
Wind Plant Performance Results

	Wind Class 3 (Average 6.7 m/s)*	Wind Class 4 (Average 7.3 m/s)*	Wind Class 5 (Average 7.8 m/s)*	Wind Class 6 (Average 8.4 m/s)*
Capacity Factor (%)	29.1	33.2	36.6	40.6

***Average at 50 m**

Wind Plant Emissions and Water Use

Wind plants do not produce any of the harmful emissions typically associated with conventional fossil power plants. They also have no water requirement.

Wind Plant Capital Cost Estimate

The table below shows the capital costs of the three wind farm sizes evaluated in this study. All costs are shown in mid-2009 Australian dollars.

Table 8-11
Wind Plant Capital Cost Estimate

	25 x 2 MW	100 x 2 MW	250 x 2 MW
Total Plant Cost (AUD/kW sent-out)	4,142	3,763	3,577

O&M Cost Estimate for Wind Plants

The table below shows the O&M costs for the wind plants. All costs are shown in mid-2009 Australian dollars.

Table 8-12
O&M Cost Estimate for Wind Plant

	25 x 2 MW	100 x 2 MW	250 x 2 MW
Fixed O&M (AUD/kW-yr)	42	39	37
Variable O&M (AUD/MWh)	0	0	0

8.5 GEOTHERMAL PLANTS

The geothermal technologies selected for this case, hot rock (HR) geothermal and hot sedimentary aquifers (HSA), are described in Section 6. The geothermal systems analysed in this report were evaluated at 50 MW. An advantage of geothermal plants is that they can serve as baseload power generators with high capacity factors, while being very low in emissions. However, they are very resource dependent, and the cost of resource exploration and characterisation can be a very large portion of the plant's overall cost.

Geothermal Plant Performance

Geothermal plants typically operate as baseload units and, therefore, have high capacity factors year round. The table below shows the capacity factor for the geothermal technologies analysed.

Table 8-13
Geothermal Plant Performance Results

	Hot Rock Geothermal	Hot Sedimentary Aquifer
Capacity Factor (%)	85	85

Geothermal Plant Emissions and Water Use

Geothermal plants are relatively benign when it comes to emissions. Some hydrothermal fluids contain hydrogen sulphide and/or high levels of dissolved solids such as sodium chloride (salt). Hydrogen sulphide emissions are abated, when necessary, with environmental control technology. Another hazardous element found in a few geothermal plants is mercury. Although mercury is not present in every geothermal resource, where it is present, mercury capture equipment typically reduces emissions by 90 percent or more.

Generally, there is less likelihood of adverse environmental impacts from binary-cycle generation, like HSA, than from flash steam generation because the hotter geothermal fluids (steam and water) used in flash plants tend to contain greater concentrations of chemical contaminants than do the cooler geothermal fluids (water) typically used in binary plants. In general, hotter water will dissolve more mineral from a rock formation than will cooler water. Also, in binary plants that employ dry, rather than wet, cooling systems, the geothermal fluid remains in a closed system and is never exposed to the atmosphere before it is injected back into the reservoir. The potential environmental impact of a HR binary system is likely to be even lower. This is because the water used in such a system originates from a shallow groundwater well or other source with low levels of dissolved solids and no hydrogen sulphide to begin with, and because the limited contact time of the injected surface water with the hot rock will in most cases limit the level of dissolved mineral (including dissolved gas) to below that of chemical equilibrium.

Geothermal systems can operate with dry cooling to greatly minimise the use of water in the plant.

Geothermal Plant Capital Cost Estimate

Geothermal power systems combine fuel supply and power conversion systems into one system. The geothermal fluid serves as the equivalent of fuel. Unlike fuel-fired power systems, in a geothermal plant, the fuel supply (the geothermal resource) and electricity generation (the power plant) are integrated and physically connected. As a result, the power plant cost is even more site-specific than for other power generation technologies. The cost is affected not only by the size and design of the power plant, but also the geothermal resource temperature and pressure, steam, impurity and salt content, and well depth. The table below shows the range of capital costs of the geothermal technologies evaluated in this study. All costs are shown in mid-2009 Australian dollars.

Table 8-14
Geothermal Plant Capital Cost Estimate

	Hot Rock Geothermal	Hot Sedimentary Aquifer
Total Plant Cost (AUD/kW sent-out)	5,480 – 10,750	4,110 -7,310

O&M Cost Estimate for Geothermal Plants

The table below shows the O&M cost ranges for the geothermal technologies. All costs are shown in mid-2009 Australian dollars.

Table 8-15
O&M Cost Estimate for Geothermal Plant

	Hot Rock Geothermal	Hot Sedimentary Aquifer
Fixed O&M (AUD/kW-yr)	150-225	100-150
Variable O&M (AUD/MWh)	0	0

9
NUCLEAR TECHNOLOGY

A general description of the Generation III and III+ nuclear reactor technologies is included in Section 6 of this report and provides a source of information regarding the technology status and systems included.

Since water supply in Australia is limited the steam condenser and process auxiliary systems requiring cooling have been configured with direct seawater cooling based on the plant being at a costal location.

9.1 Nuclear Performance Results

The plant performance for the Generation III and III+ nuclear reactor technologies was determined using information from EPRI's technical databases. A summary of the overall plant performance for the nuclear case is provided in Table 9-1.

Table 9-1
Nuclear Overall Plant Performance (Near Term)

Net Power Output, MW	**1,117**
Net Plant Efficiency (% - HHV)	**33.0**
Net Plant Heat Rate (kJ/kWhr - HHV)	**10,900**

9.2 Nuclear Emissions and Water Use

There are no carbon dioxide emissions from the nuclear power plant and water consumption is essentially limited to boiler feedwater make-up.

9.3 Nuclear Capital Cost Estimates

The total plant cost for the nuclear case was estimated per the procedures described in Section 4 of this report. The resulting estimates are summarised in Table 9-2. All costs are shown in mid-2009 Australian dollars.

Table 9-2
Total Plant Cost for Nuclear (Near Term)

Total Plant Cost (AUDx1000)	**6,413**
Total Plant Cost (AUD/kW sent out)	**5,742**

9.4 Nuclear Operating and Maintenance Cost Estimates

The O&M costs for the nuclear case were estimated per the procedures described in Section 4 of this report. The results of these estimates, in mid-2009 Australian dollars, are shown in Table 9-3.

Table 9-3
O&M Cost Estimates for Nuclear

Operating and Maintenance Costs	
Fixed O&M (AUD/kW-yr)	146.9
Variable O&M (AUD/MWh)	6.1

10
COST OF ELECTRICITY ANALYSIS AND SENSITIVITIES

10.1 Cost of Electricity Analysis

The levelised cost of electricity was calculated for all of the technologies included in this study. Economic assumptions used for these calculations were presented in Section 5 and are summarised below in Table 10-1. The total plant cost for the technologies are presented in Section 7, 8, and 9. Total capital required was calculated from these total plant cost results by adding AFUDC and owner costs and were used for calculating cost of electricity. All of the levelised costs of electricity presented in this section are in constant Australian dollars for mid-2009. Assumed fuel prices are shown in Table 10-2. Levelised costs of electricity are summarised in Table 10-3 to Table 10-13. It should be noted that the costs of electricity for renewable technologies do not include production or investment tax credits, which are often included in reported costs in the United States, since such credits are not currently available in Australia.

Table 10-1
Economic Assumptions Summary

		– Current Dollars –		– Constant Dollars –	
Type of Security	**% of Total**	**Cost (%)**	**Return (%)**	**Cost (%)**	**Return (%)**
Debt	70	9.0	6.3	6.3	4.4
Preferred Stock	N/A	N/A	0.0	N/A	0.0
Common Stock	30	16.0	4.8	13.2	4.0
Total Annual Return			11.1		8.4
Inflation Rate	2.5				
Federal and State Income Tax Rate	30				
Discount Rate					
After Tax			9.2		7.1
Before Tax (Used for this study)			11.1		8.4
Book Life, Fossil Fuel/Nuclear/Solar Plants, years	30				
Book Life, Wind Plants, years	20				
Tax Life, Fossil Fuel/Nuclear/Solar Plants, years	30				
Tax Life, Wind Plants, years	20				
Tax Depreciation Schedule	Straight line tax life depreciation				
Levelising Years, Fossil Fuel/Nuclear/Solar Plants	30				
Levelising Years, Wind Plants	20				

Table 10-2
Fuel Assumptions

Fuel Type	Cost (AUD/GJ)
Black Coal (1)	1.0 – 2.0
Brown Coal (2)	0.5 - 1.0
Natural Gas (3)	5 - 12
Uranium	0.94

Notes:

1. **Black Coal prices are for higher ash coal that is generally not considered export parity coal. AUD1.5/GJ was used for the base case analysis.**
2. **Brown coal price of AUD1.0/GJ is representative of a new mine, cost from existing mines is closer to AUD0.5/GJ. AUD0.75/GJ was used for the base case analysis.**
3. **There are two distinct natural gas markets in Australia. The range of natural gas prices for Eastern Australia is AUD5-9/GJ, and for Western Australia is AUD9-12/GJ. An average natural gas price for all of Australia is not meaningful. AUD9/GJ was used for the base case analysis.**

Table 10-3
IGCC Levelised Cost of Electricity

Technology Description	IGCC WITH BLACK COAL WITHOUT CCS	IGCC WITH BLACK COAL WITH CCS (88.5% Capture)
Capital	93	141
O&M	23	34
Fuel	14	19
CO_2 T&S	0	20
LCOE (Constant 2009 AUD/MWh)	**130**	**213**

Table 10-4
Pulverised Coal Levelised Cost of Electricity

Technology Description	PULVERISED COAL WITH BROWN COAL, NO NO_X/SO_2 CONTROLS	PULVERISED COAL WITH BROWN COAL WITH CCS	PULVERISED COAL WITH BLACK COAL, NO NO_X/SO_2 CONTROLS	PULVERISED COAL WITH BLACK COAL WITH CCS	PULVERISED COAL WITH BLACK COAL OXY-COMBUSTION
Capital	73	134	54	107	115
O&M	11	25	9	23	17
Fuel	8	11	14	19	18
CO_2 T&S	0	21	0	18	17
LCOE (Constant 2009 AUD/MWh)	**91**	**191**	**78**	**167**	**166**

Table 10-5
Open and Combined Cycle Levelised Cost of Electricity

Technology Description	CCGT WITHOUT CCS	CCGT WITH CCS	OCGT WITHOUT CCS
Capital	27	58	117
O&M	4	9	13
Fuel	65	79	98
CO_2 T&S	0	8	0
LCOE (Constant 2009 AUD/MWh)	**97**	**153**	**227**

Table 10-6
Parabolic Trough Levelised Cost of Electricity

Technology Description	PARABOLIC TROUGH W/ 6 HRS STORAGE	PARABOLIC TROUGH W/ 6 HRS STORAGE	PARABOLIC TROUGH W/ 6 HRS STORAGE	PARABOLIC TROUGH W/OUT STORAGE	PARABOLIC TROUGH W/OUT STORAGE	PARABOLIC TROUGH W/OUT STORAGE
DNI ($kWh/m^2/day$)	5	6	7	5	6	7
Capital	495	412	353	519	434	372
O&M	32	26	23	39	32	28
Fuel	0	0	0	0	0	0
LCOE (Constant 2009 AUD/MWh)	**527**	**438**	**376**	**558**	**466**	**400**

Table 10-7
Central Receiver Levelised Cost of Electricity

Technology Description	CENTRAL RECEIVER W 6HRS STORAGE	CENTRAL RECEIVER W 6HRS STORAGE	CENTRAL RECEIVER W 6HRS STORAGE	CENTRAL RECEIVER W/OUT STORAGE	CENTRAL RECEIVER W/OUT STORAGE	CENTRAL RECEIVER W/OUT STORAGE
DNI (kWh/m^2/day)	5	6	7	5	6	7
Capital	363	304	260	417	346	298
O&M	32	26	23	39	32	28
Fuel	0	0	0	0	0	0
LCOE (Constant 2009 AUD/MWh)	**395**	**330**	**283**	**456**	**379**	**325**

Table 10-8
Photovoltaic Levelised Cost of Electricity

Technology Description	PV FIXED FLAT PLATE	PV FIXED FLAT PLATE	PV SINGLE-AXIS TRACKING	PV SINGLE-AXIS TRACKING	PV TWO-AXIS TRACKING	PV TWO-AXIS TRACKING
Size (MW)	5	50	5	50	5	50
Capital	439	407	401	367	369	304
O&M	34	24	35	25	32	23
Fuel	0	0	0	0	0	0
LCOE (Constant 2009 AUD/MWh)	**473**	**431**	**436**	**392**	**400**	**327**

Table 10-9
25 x 2 MW Wind Levelised Cost of Electricity

Technology Description	WIND (25 X 2MW)	WIND (25 X 2MW)	WIND (25 X 2MW)	WIND (25 X 2MW)
Wind Class	3	4	5	6
Capital	195	171	155	140
O&M	20	17	16	14
Fuel	0	0	0	0
LCOE (Constant 2009 AUD/MWh)	**214**	**188**	**171**	**154**

Table 10-10
100 x 2 MW Wind Levelised Cost of Electricity

Technology Description	WIND (100 x 2 MW)	WIND (100 x 2 MW)	WIND (100 x 2 MW)	WIND (100 x 2 MW)
Wind Class	3	4	5	6
Capital	177	155	141	127
O&M	18	15	14	13
Fuel	0	0	0	0
LCOE (Constant 2009 AUD/MWh)	**195**	**171**	**155**	**140**

Table 10-11
250 x 2 MW Wind Levelised Cost of Electricity

Technology Description	WIND (250 X 2MW)	WIND (250 X 2MW)	WIND (250 X 2MW)	WIND (250 X 2MW)
Wind Class	3	4	5	6
Capital	175	154	139	126
O&M	16	14	13	12
Fuel	0	0	0	0
LCOE (Constant 2009 AUD/MWh)	**192**	**168**	**152**	**137**

Table 10-12
Geothermal Levelised Cost of Electricity

Technology Description	Hot Rock Geothermal	Hot Sedimentary Aquifer
Capital	96-188	72-128
O&M	20-30	13-20
Fuel	0	0
LCOE (Constant 2009 AUD/MWh)	**116-218**	**85-148**

Table 10-13
Nuclear Levelised Cost of Electricity

Technology Description	NUCLEAR GENERATION III/III+
Capital	137
O&M	26
Fuel	10
LCOE (Constant 2009 AUD/MWh)	**173**

10.2 CAPITAL COST SENSITIVITY

For all of the technologies, a capital cost range was applied based on the maturity of the plant and the uncertainty surrounding the cost estimate. Table 10-14 shows the uncertainty ranges used for the different technologies. The levelised cost of electricity in Figures 10-1 through to 10-4 below show an I-bar representing the range of cost of electricity that results from this capital cost sensitivity.

Table 10-14
Capital Cost Uncertainty Ranges

	Low (-%)	High (+%)
Black Coal IGCC w/o CCS	18	18
Black Coal IGCC w/CCS	26	26
Brown Coal SCPC w/o CCS	18	15
Brown Coal SCPC w/CCS	26	23
Black Coal SCPC w/o CCS	15	15
Black Coal SCPC w/CCS	23	23
CCGT w/o CCS	15	15
CCGT w/CCS	23	23
OGCT w/o CCS	15	15
Parabolic Trough	15	30
Central Receiver	15	30
Photovoltaics	30	30
Wind	15	15

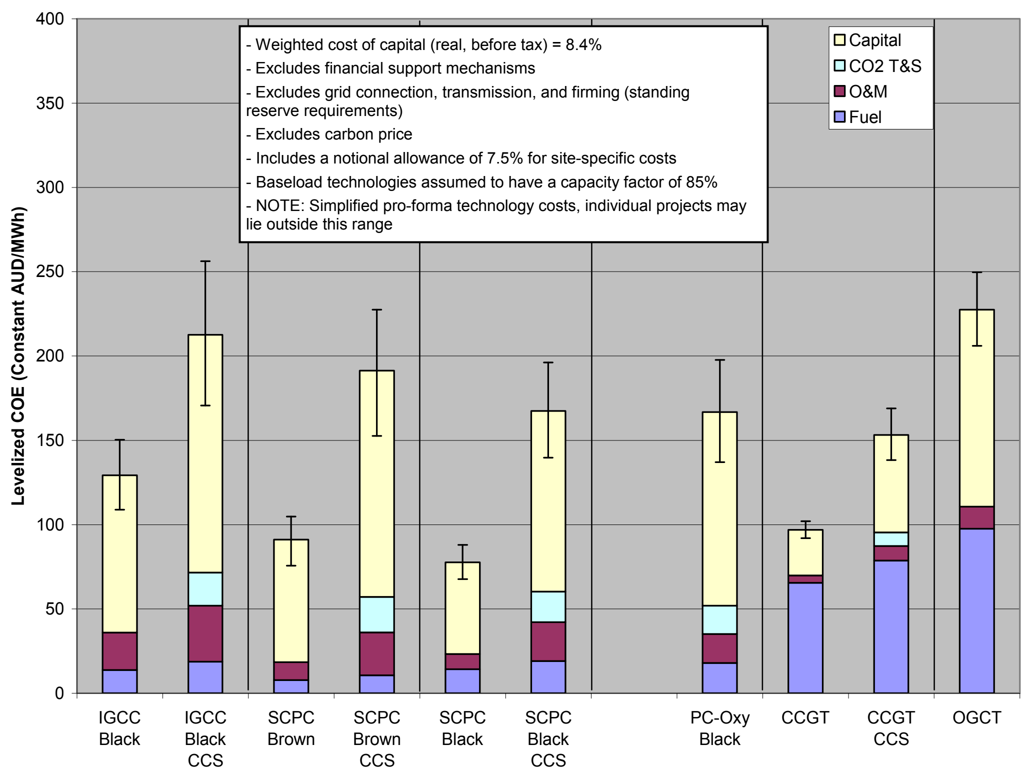


Figure 10-1
Fossil Fuel Capital Cost Sensitivity

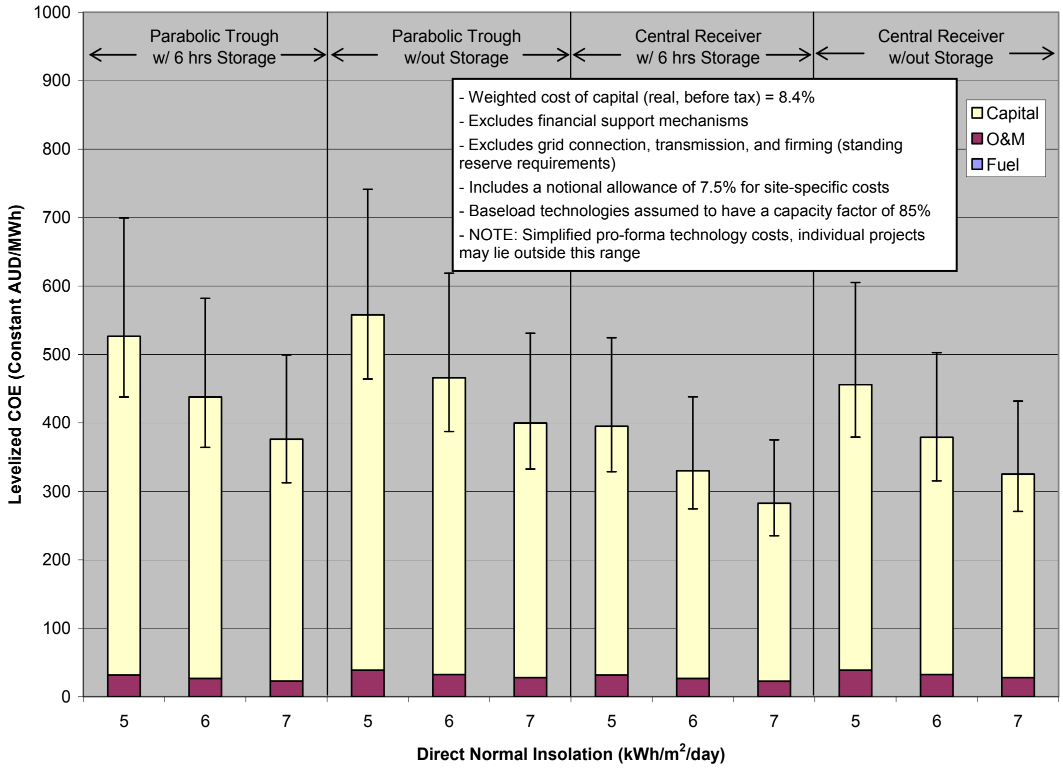


Figure 10-2
Concentrating Solar Plant Capital Cost Sensitivity

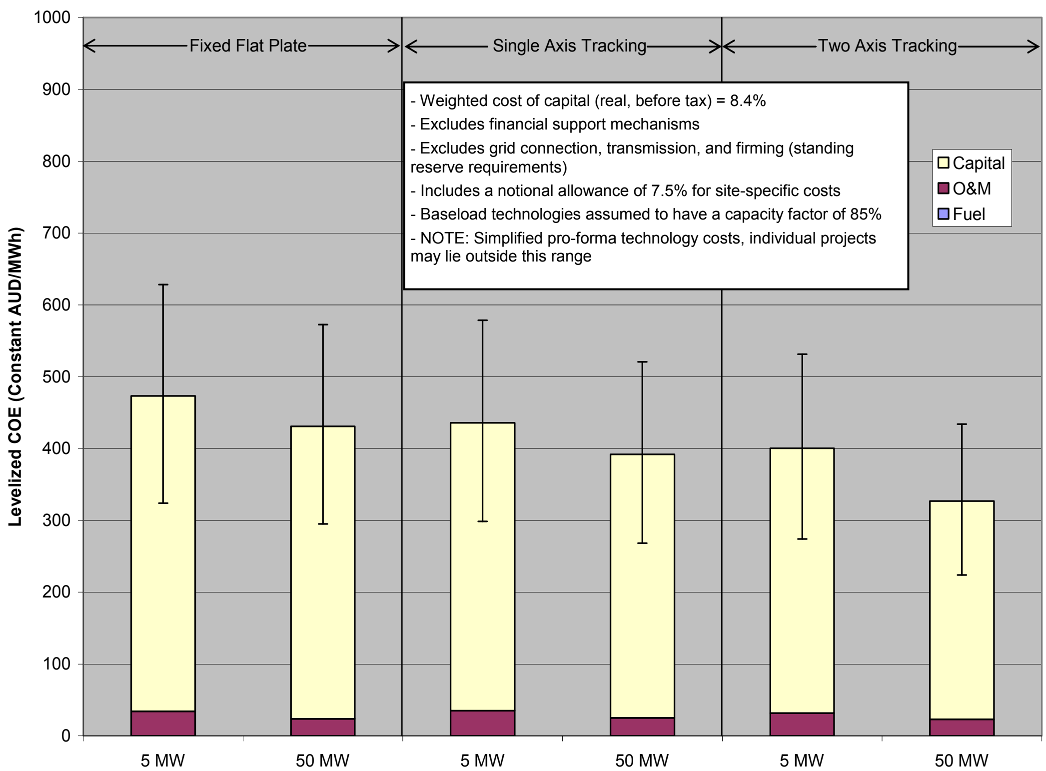


Figure 10-3
Photovoltaic Plant Capital Cost Sensitivity

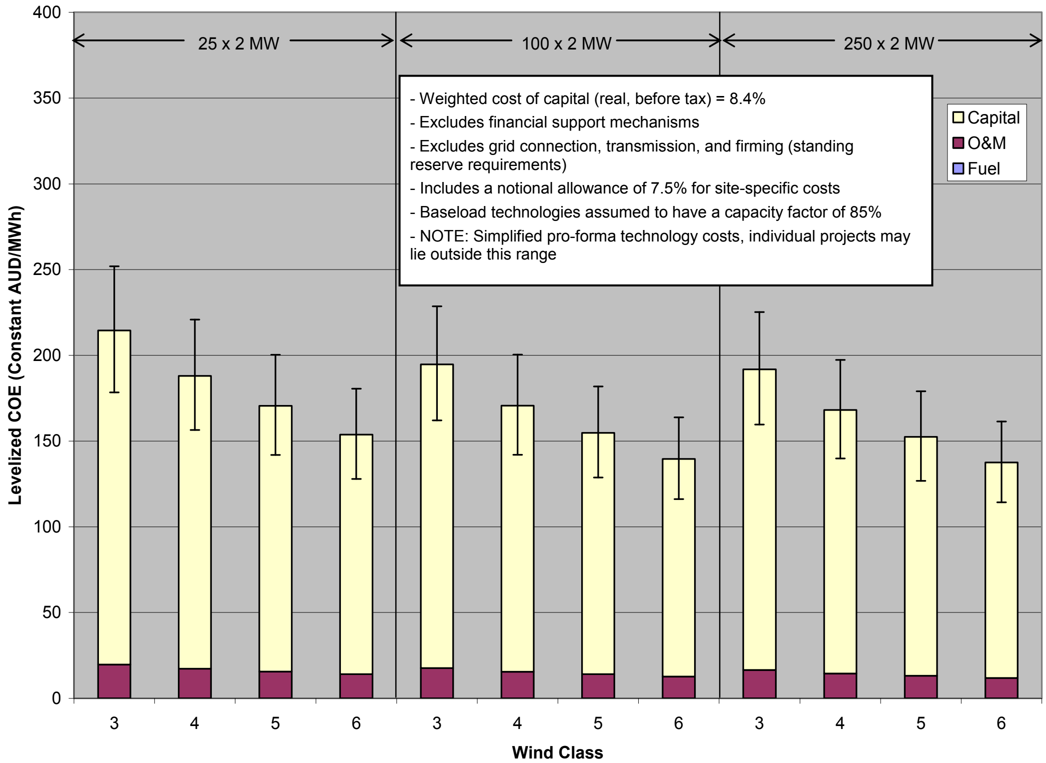


Figure 10-4
Wind Capital Cost Sensitivity

10.3 FUEL COST SENSITIVITY

The cost of fuel can have a significant effect on the levelised cost of electricity of fossil fuel technologies. A sensitivity analysis was conducted for the fossil fuel cases to look at the effect of fuel cost on their levelised cost of electricity. The ranges shown in Table 10-2 were used for this analysis.

Table 10-15
IGCC Fuel Cost Sensitivity

Technology Description	IGCC WITH BLACK COAL WITHOUT CCS	IGCC WITH BLACK COAL WITH CCS (88.5% Capture)
Low Fuel Cost (AUD/GJ)	1.00	1.00
Capital	93	141
O&M	23	34
Fuel	9	12
CO_2 T&S	0	20
LCOE (Constant 2009 AUD/MWh)	**125**	**207**
High Fuel Cost (AUD/GJ)	2.00	2.00
Capital	93	141
O&M	23	34
Fuel	18	25
CO_2 T&S	0	20
LCOE (Constant 2009 AUD/MWh)	**134**	**220**

Table 10-16
Pulverised Coal Fuel Cost Sensitivity

Technology Description	PULVERISED COAL WITH BROWN COAL, NO NO_X/SO_2 CONTROLS	PULVERISED COAL WITH BROWN COAL WITH CCS	PULVERISED COAL WITH BLACK COAL, NO NO_X/SO_2 CONTROLS	PULVERISED COAL WITH BLACK COAL WITH CCS	PULVERISED COAL WITH BLACK COAL OXY-COMBUSTION
Low Fuel Cost (AUD/GJ)	0.50	0.50	1.00	1.00	1.00
Capital	73	134	54	107	115
O&M	11	25	9	23	17
Fuel	5	7	9	13	12
CO_2 T&S	0	21	0	18	17
LCOE (Constant 2009 AUD/MWh)	**88**	**188**	**73**	**161**	**161**
High Fuel Cost (AUD/GJ)	1.00	1.00	2.00	2.00	2.00
Capital	73	134	55	107	115
O&M	11	25	9	23	17
Fuel	10	14	19	25	24
CO_2 T&S	0	21	0	18	17
LCOE (Constant 2009 AUD/MWh)	**94**	**195**	**83**	**174**	**173**

Table 10-17
Open and Combined Cycle Fuel Cost Sensitivity

Technology Description	CCGT WITHOUT CCS	CCGT WITH CCS	OCGT WITHOUT CCS
Low Fuel Cost (AUD/GJ)	5.00	5.00	5.00
Capital	27	58	116
O&M	4	9	13
Fuel	36	44	54
CO_2 T&S	0	8	0
LCOE (Constant 2009 AUD/MWh)	**68**	**118**	**183**
High Fuel Cost (AUD/GJ)	12.00	12.00	12.00
Capital	27	58	118
O&M	4	9	13
Fuel	87	105	130
CO_2 T&S	0	8	0
LCOE (Constant 2009 AUD/MWh)	**119**	**180**	**261**

10.4 2030 COST AND PERFORMANCE SENSITIVITY

As discussed in Section 6, there is potential for cost and performance improvements for all of the technologies discussed in this report in the 2030 time frame. It is assumed that all fossil fuel technologies in 2030 will have to have CCS. The charts below show the levelised cost of electricity of these technologies with cost and performance improvements in 2030 compared to the costs predicted above.

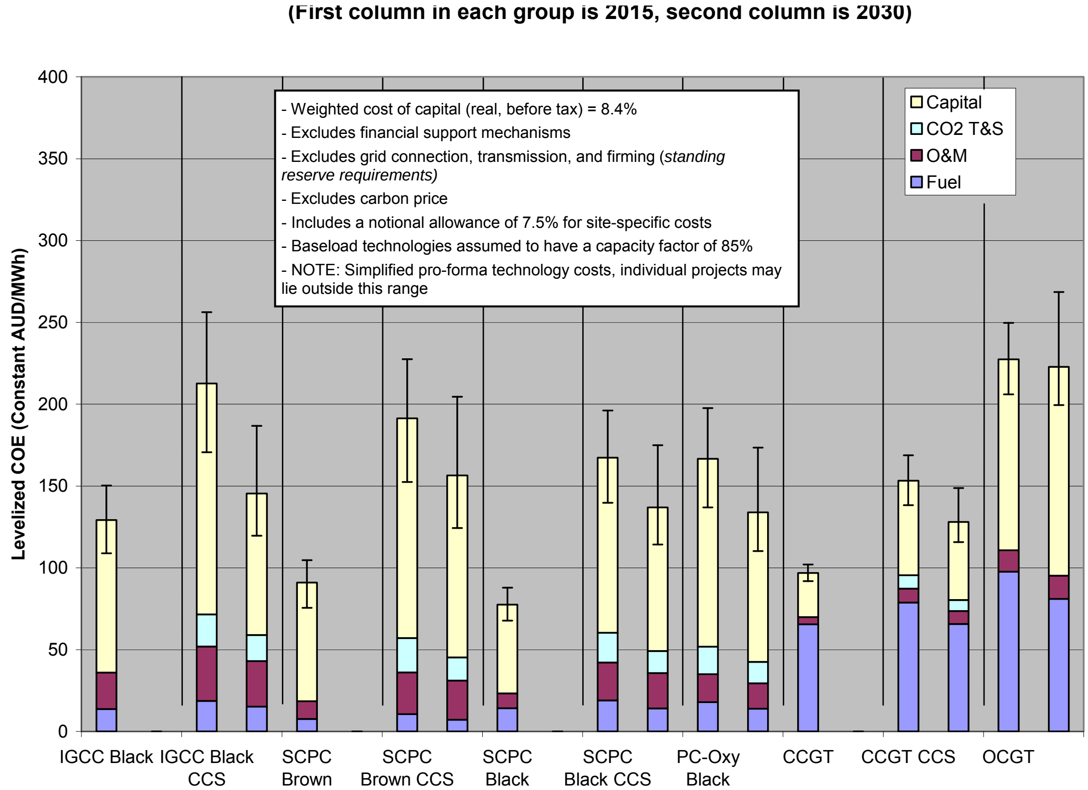


Figure 10-5
Fossil Fuel Comparison of 2015 vs. 2030 Cost of Electricity

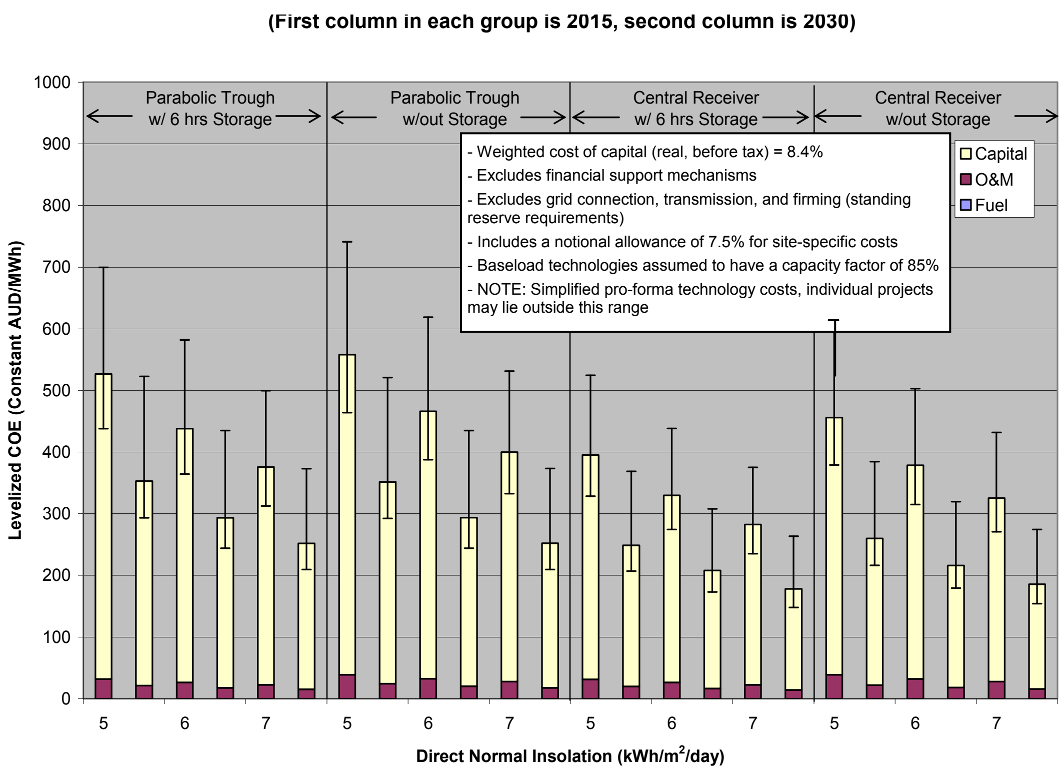


Figure 10-6
Concentrating Solar Power Comparison of 2015 vs. 2030 Cost of Electricity

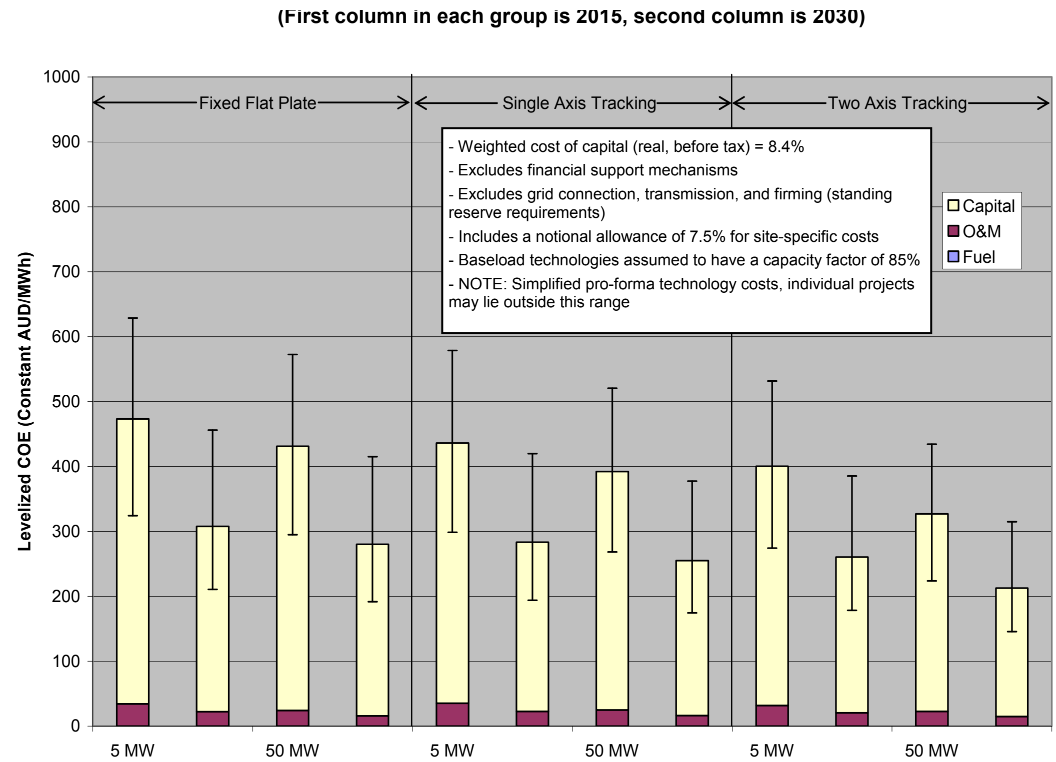


Figure 10-7
Photovoltaic Comparison of 2015 vs. 2030 Cost of Electricity

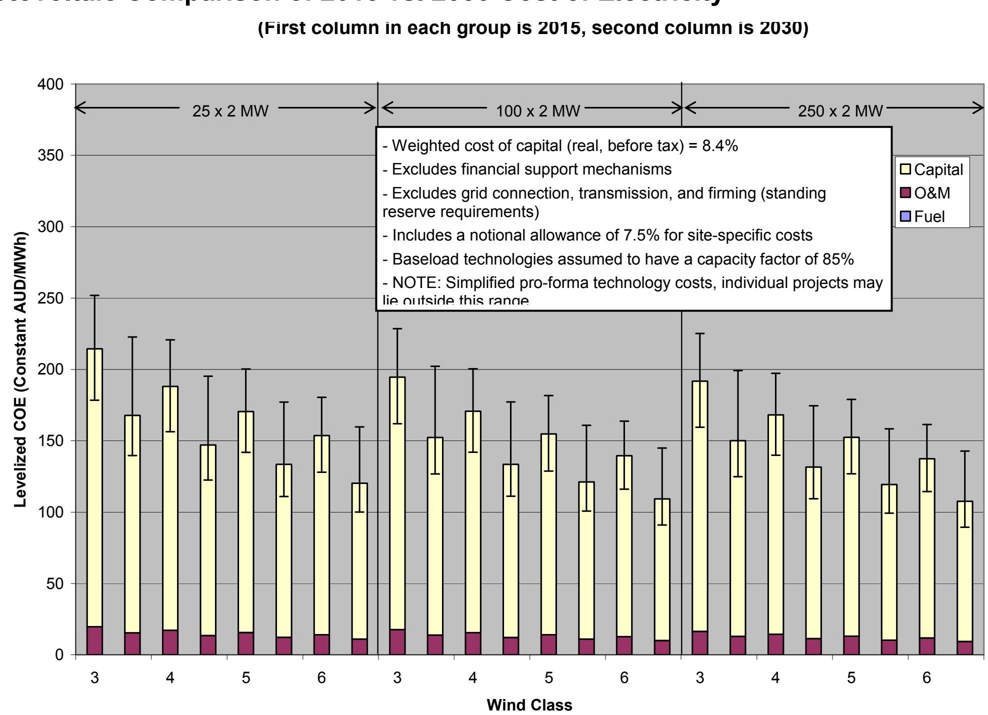


Figure 10-8
Wind Power of 2015 vs 2030 Cost of Electricity

10.5 OVERALL COST OF ELECTRICITY RANGES AND RANKINGS

There are a number of factors leading to uncertainty in the estimates and variability in results of this study. All of the cost estimates included in this report have an inherent uncertainty due to the level of detail included in the cost estimate. In addition, high volatility has been seen in the price of power plant equipment in the past two years, with extremely high costs due to market demands followed by a quick drop due to global economic conditions and fall in anticipated capacity expansion, with a large uncertainty about if and where these prices will "plateau". Other areas of uncertainty lie in the site specific development and owner costs that are difficult to capture in a general economic study, the site specific and uncertain nature of CO_2 transportation and storage costs, fluctuations in fuel costs, and the dependence of renewable technologies on the quality of a wind or solar resource.

The following charts show the combined impact of uncertainty ranges in plant capital cost, fuel cost, project and site specific costs, and CO_2 transportation and storage costs. While they still may not capture the absolute extremes of cost estimates, they provide a broader range of estimates due to the uncertainties described above.

The low end estimates of the charts assume a best case scenario: capital cost estimates and fuel prices are at the low end of the sensitivity ranges investigated above, project and site specific costs are assumed to add only 5% to the TPC (baseline is 7.5%), CO_2 transportation and storage cost is assumed to be only AUD10/tonne (baseline is AUD20/tonne), and, for renewable technologies, the best available resource was assumed (DNI = 7 kWh/m^2/day for parabolic trough and central receiver; wind class 6 for wind turbines).

The high end estimates of the charts assume the higher side of the uncertainties: capital cost estimates and fuel prices are at the high end of the sensitivity ranges investigated above, project and site specific costs are assumed to add 10% to the TPC, CO_2 transportation and storage cost is assumed to be AUD30/tonne, and, for renewable technologies, the worst available resource was assumed (DNI = 5 kWh/m^2/day for parabolic trough and central receiver; wind class 3 for wind turbines).

Figure 10-9 and Figure 10-10 show the ranges for the fossil technologies, both near term in 2015 and with anticipated improvements in 2030. Figure 10-11 and Figure 10-12 show these same ranges for the renewable technologies investigated. Finally, Figure 10-13 and Figure 10-14 show a comparison of all technologies, both fossil and renewable, in 2015 and 2030. They also show the anticipated CO_2 emissions associated with the different technologies. Costs for technologies without CO_2 capture are not presented for 2030 due to the assumption that plants in 2030 will not be permitted without being low emission technologies, other than perhaps peaking units such as the OCGT.

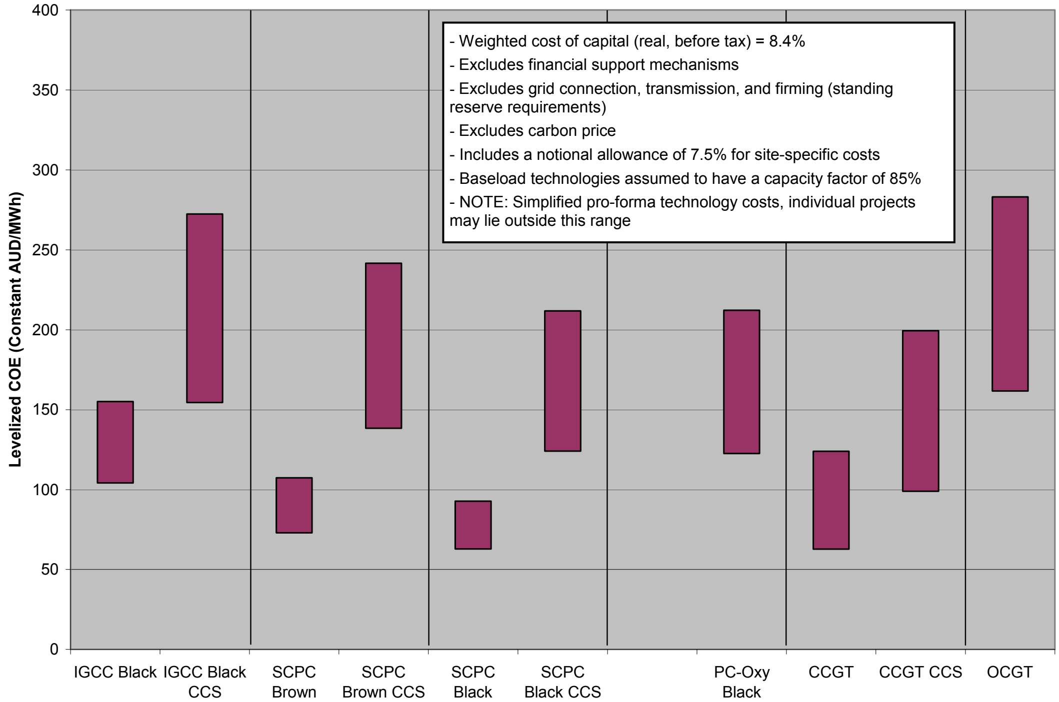


Figure 10-9
Maximum Range for Fossil Techs (2015)

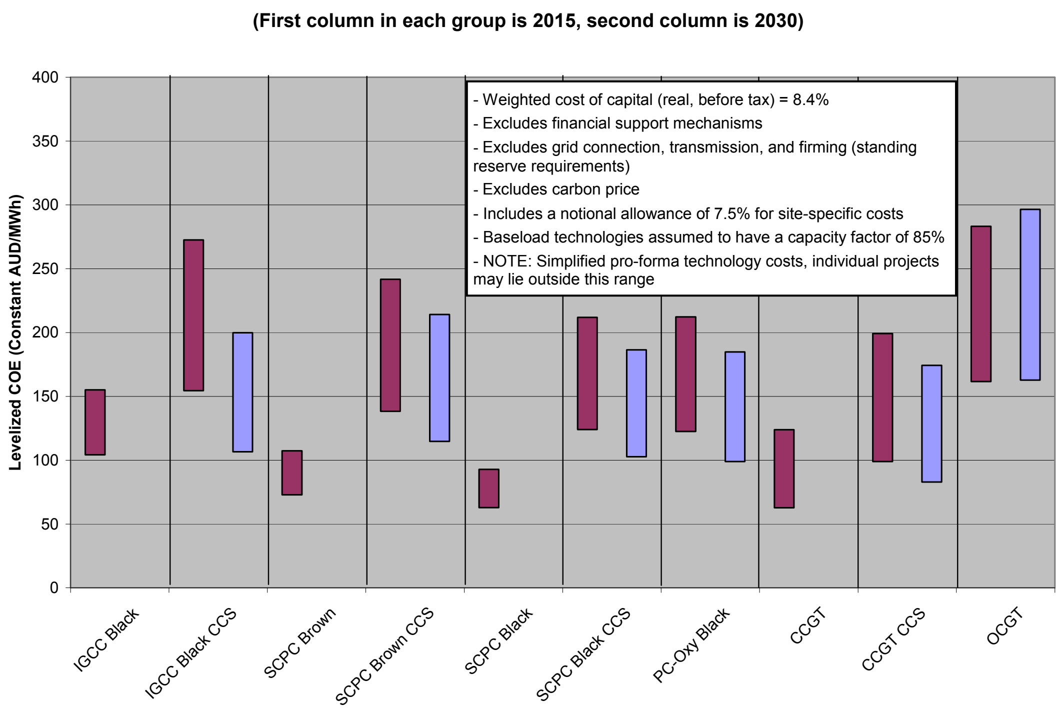


Figure 10-10
Maximum Range for Fossil Techs (2015 vs 2030)

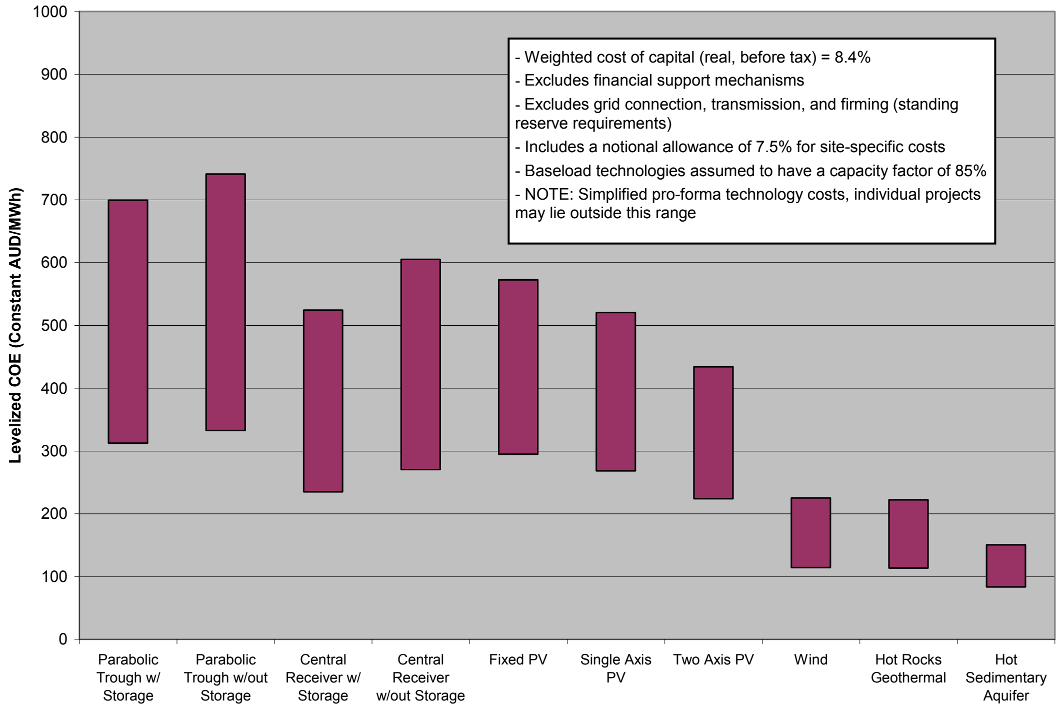


Figure 10-11
Maximum Range for Renewable Techs (2015)

(First column in each group is 2015, second column is 2030)

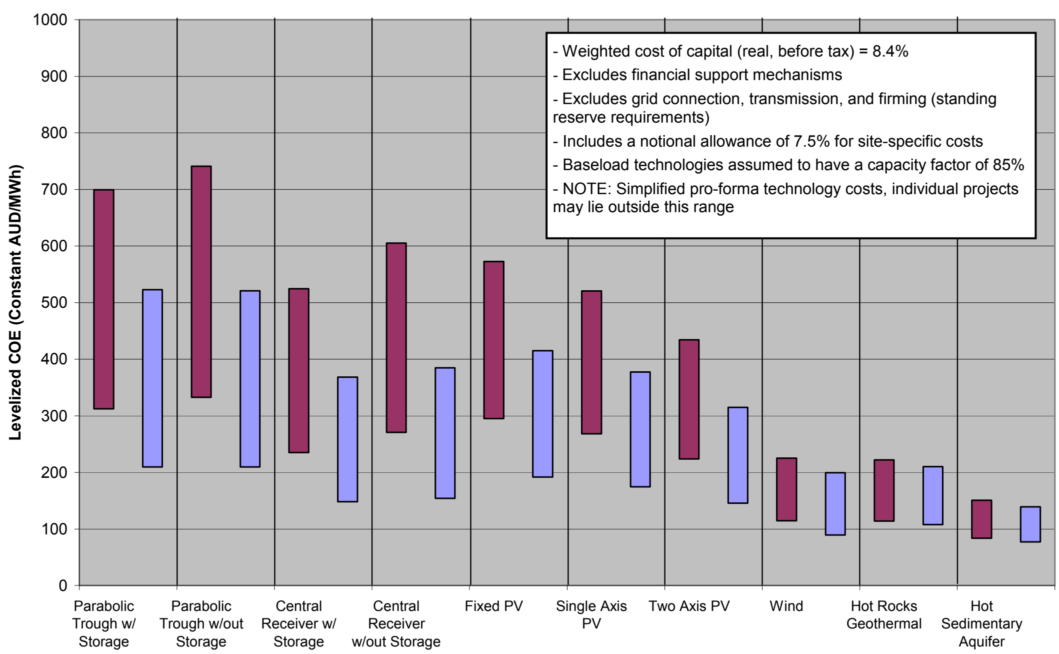


Figure 10-12
Maximum Range for Renewable Techs (2015 vs 2030)

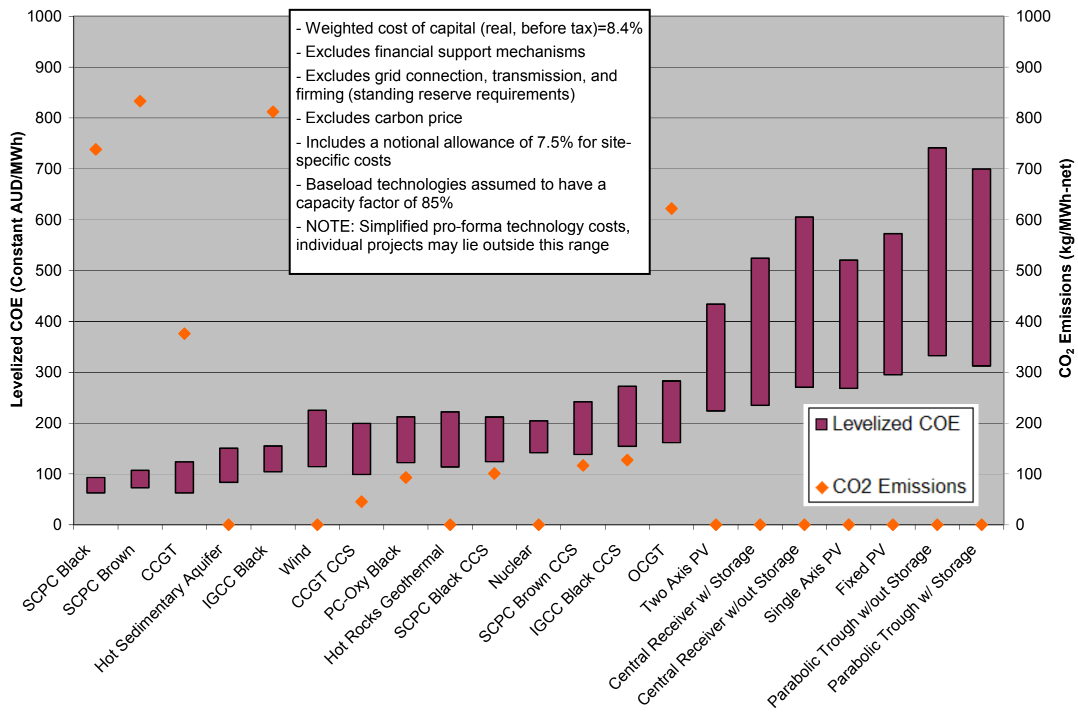


Figure 10-13
Sorted Technology Maximum Ranges (2015)

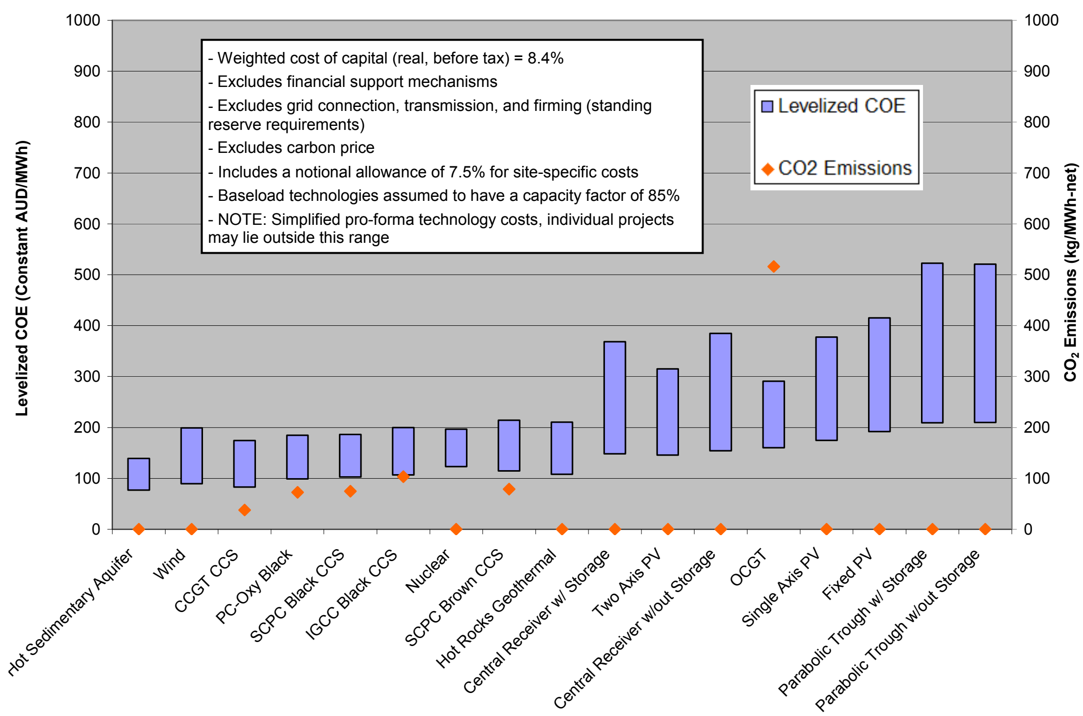


Figure 10-14
Sorted Technology Maximum Ranges (2030)

The tornado diagrams below show the effect of different assumptions on the levelised cost of electricity results. Capital costs were varied by +/-30% of the baseline cost results. For all technologies except for the wind turbine, the plant life was varied between 20 years and 40 years with a baseline lifetime of 30 years; for wind, the plant life was varied between 15 and 20 years with a baseline of 20 years. For fossil fuel technologies, fuel costs were varied based on the same fuel sensitivity ranges presented in Table 10-2. Uranium costs were varied by +/-30%. For renewable technologies, the resource was varied based on the resource ranges used throughout the report: 5-7 kWh/m^2/day for the concentrating solar technologies with a baseline of 6 kWh/m^2/day and wind class 3-6 for the wind turbines with a baseline of class 5. For photovoltaic technologies, the capacity factor was varied by +/-30%. CO_2 transportation and storage costs were varied between AUD10/tonne and AUD30/tonne, with AUD20/tonne as the baseline.

In all cases, it can be seen that extending the plant life (the "high" estimate) reduces the levelised cost of electricity by expanding the number of years over which capital costs are recovered. Improved renewable resources (the "high" estimate) also reduce the levelised cost of electricity by increasing the amount of electricity produced. For plants with high capital costs but low fuel costs, such as pulverized coal and IGCC plants, the effect of capital cost variation is much higher than the effect of the fuel cost. In contrast, for plants with lower capital costs and higher fuel costs, like the natural gas plants, the variation in fuel cost has a much larger effect on the levelised cost of electricity than variation in capital costs.

Another interesting result is that Total O&M appears to be a more significant variable than fuel cost for some of the more capital intensive technologies such as IGCC. That seems to be a result of the higher base O&M cost for IGCC, combined with the relatively low cost of coal in Australia.

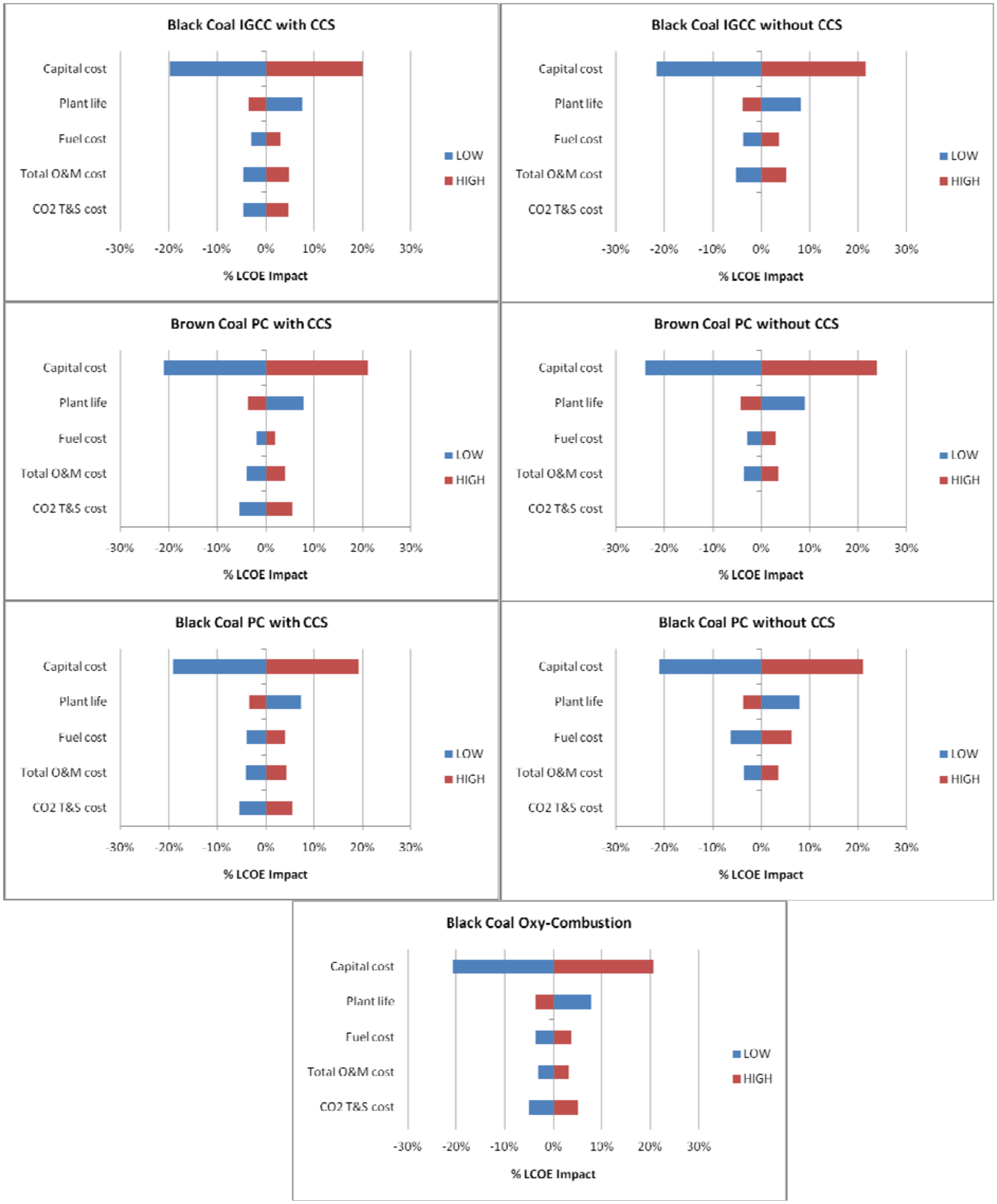


Figure 10-15
Coal Tornado Diagrams

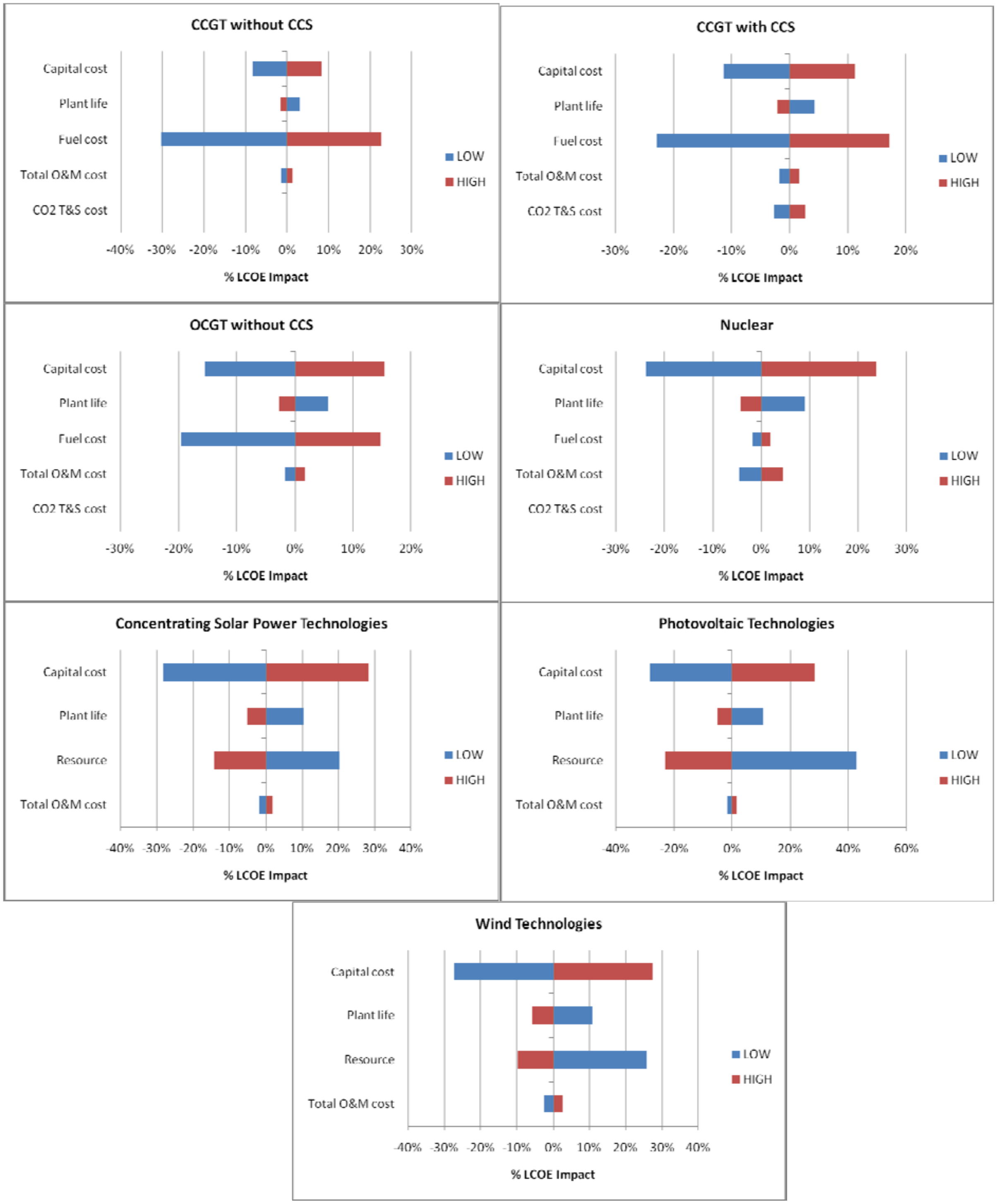


Figure 10-16
Natural Gas, Nuclear, and Renewables Tornado Diagrams

11
CONCLUSIONS

The key findings of this evaluation can be summarised as follows:

- there are many options available for low emission technologies at a various of stages of development;
- many low emission technologies are currently high cost compared to traditional generation technologies, but costs are expected to decline as more plants are deployed and as advanced R&D leads to more efficient, lower cost plants; and
- costs presented in this report are highly uncertain – sensitivity analyses and ranges are included in an attempt to better understand this range of uncertainty; general trends should represent relative technology costs at this time.

A comprehensive list of fossil, renewable, and nuclear technologies was selected for the overall evaluation. For all of the near term technologies selected, the cycle configurations, equipment included and materials used are currently available and used commercially in power plant systems. These near technologies do not represent projected potential advancements over currently available systems. Areas where each technology may be expected to improve through the application of efficiency and cost advancements were projected for the 2030 time frame.

Due to shortages of water availability throughout Australia, each of the technologies evaluated were configured with air cooling of the condensers and auxiliary equipment to minimise water consumption. Consistent with Australian practice on air emissions, each configuration evaluated included particulate emissions control (except the natural gas fired turbines). Control of NO_X and SO_2 emissions is not included except where required by the carbon capture technologies to prevent poisoning of the amines and chemicals used in those processes.

Cost estimates were developed based on US Gulf Coast costs and rates upon completion of heat and material balance performance evaluations which identified the required capacity of the key plant components and also defined the plant efficiencies, emissions and key flow rates. These estimates were then adjusted to Australian costs via the use of adjustment factors developed jointly between the EPRI's subcontractor's Australian and US offices.

The magnitude of the cost adjustments varied by technology, depending of the mix of major equipment, materials, and construction labour. Figures 11-1 through 11-3 show the relative overall capital cost adjustments for pulverised coal, wind, and open cycle gas turbines. The pulverised coal plant requires a much larger fraction of field labour and therefore has an overall US Gulf Coast to Australia adjustment factor of about 1.80, including currency conversion. By comparison, an open cycle gas turbine plant has a very low percentage of field labour due to its more modular nature, resulting in an overall adjustment factor of only 1.44.

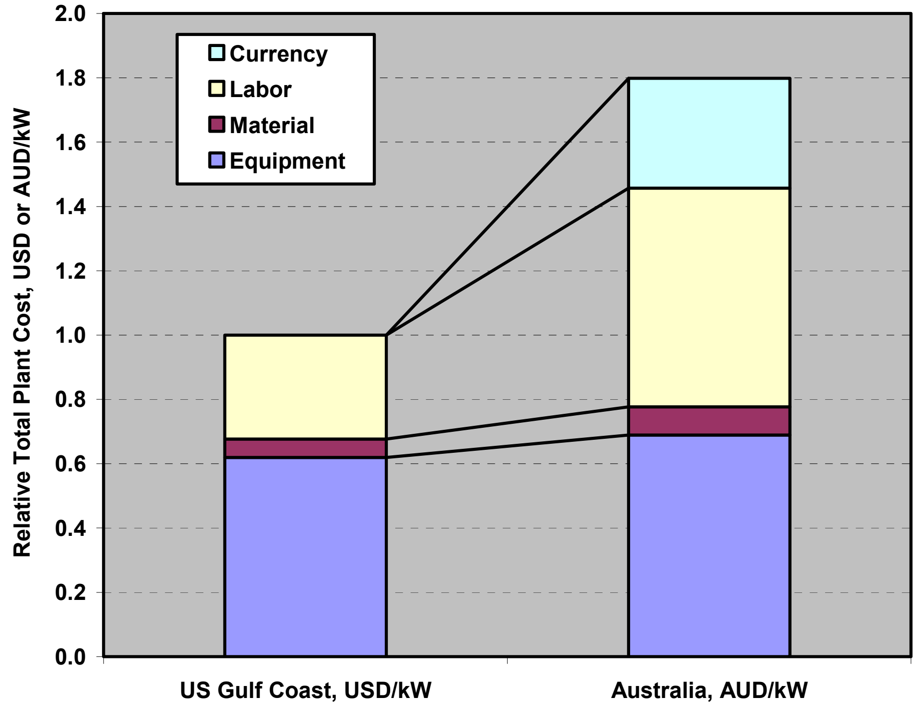


Figure 11-1
Pulverised Coal Plant Costs, US Gulf Coast vs Australia

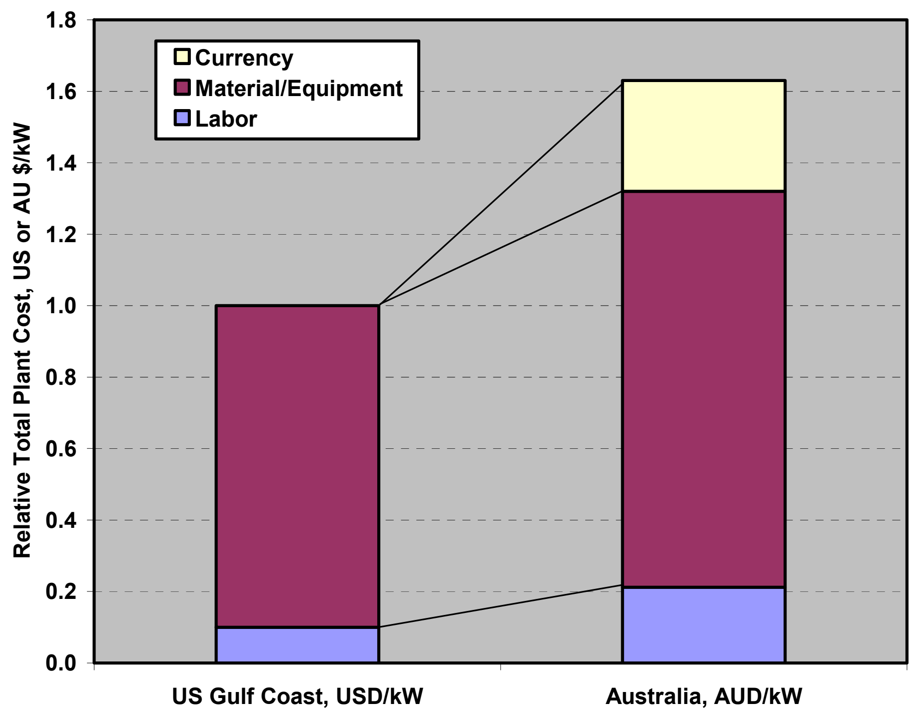


Figure 11-2
Wind Costs, US Gulf Coast vs Australia

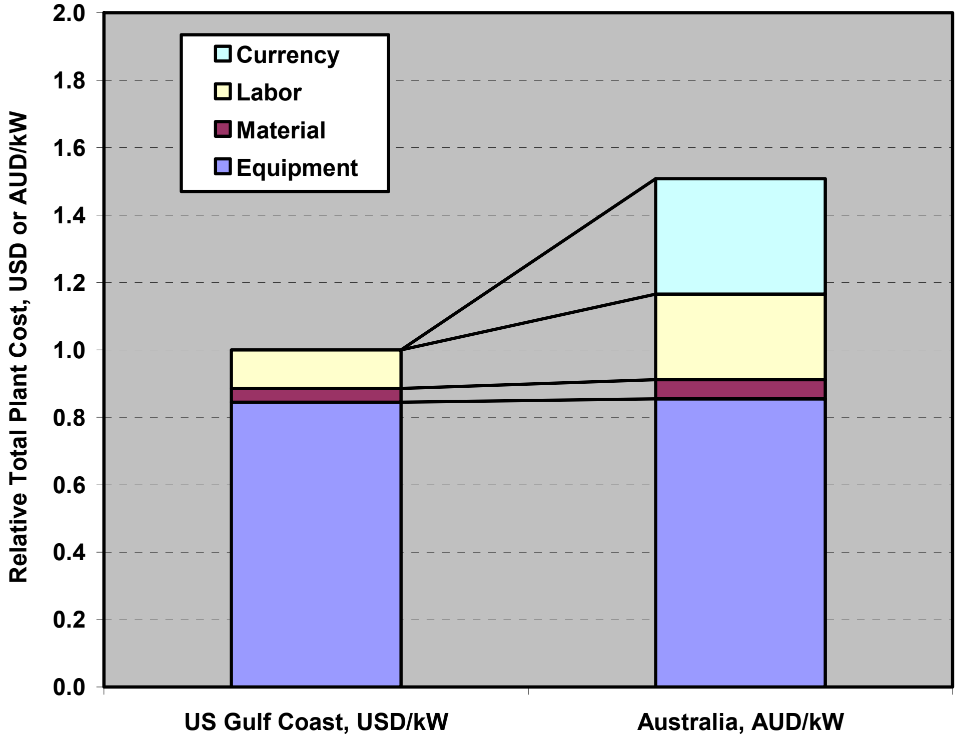


Figure 11-3
Open Cycle Gas Turbine Plant Costs, US Gulf Coast vs Australia

All cost estimates were based on June 2009 rates and performed on an "overnight" basis such that no escalation has been included to a future date or for cost escalation that could occur during a project execution. This provides a consistent basis for comparison between the technologies.

It is important to understand that this evaluation was not based on detailed plant designs or equipment and material quotations such as would be performed at the time a plant is to be built. Therefore, the absolute magnitude of the pricing developed is not as important as the *differences* between the performance and cost values for the different technologies.

There are a number of factors leading to uncertainty in the estimates and variability in results of this study. All of the cost estimates included in this report have an inherent uncertainty due to the level of detail included in the cost estimate. In addition, high volatility has been seen in the price of power plant equipment in the past two years with extremely high costs due to market demands followed by a quick drop due to global economic conditions and fall in anticipated capacity expansion, with a large uncertainty about if and where these prices will "plateau". Other areas of uncertainty lie in the site specific development and owner costs that are difficult to capture in a general economic study, the site specific and uncertain nature of CO2 transportation and storage costs, fluctuations in fuel costs, and the dependence of renewable technologies on the quality of a wind or solar resource.

These considerations underscore the fact that cost estimates are always snap-shots of a process in motion and depend on a variety of changing factors.

There are several R&D efforts underway to improve efficiency, lessen the impact of uncertainty, and reduce costs associated with low emission technologies for power generation. Increased deployment levels will also lower the cost over time. It is anticipated that these efforts will make these technologies attractive in the longer term (2030).

A
WAGE RATE COMPONENT DEFINITION

	USGC	Australia
Category	**Description**	**Description**
Fringe Benefits	Retirement Fund Holiday Sick Time Vacation Health / Dental Insurance Life Insurance	Superannuation Holidays Sick Leave Annual Leave Long Service Leave Redundancy / Severance
Payroll taxes and insurances	Includes employer portions of the following: Worker's Compensation Insurance Federal Insurance Contributions Act Federal Unemployment Insurance State Unemployment Insurance	Worker's Compensation Payroll Tax Income Protection Insurance
Contractor's General Liability insurance	Covers the premiums anticipated to be incurred	
Construction Supervision	Contractor's Supervision including: Contractor's Site Management Superintendents Project Controls Site Administrators Site Quality Assurance Inspectors Site Clerical Miscellaneous Supervision	Site Superintendent Leading Hand Allowance / Home Office Support *
Indirect Craft Labour	Non-Direct Craft Labour Items including: Tool Control Training Welder Certification Fire Watch Site Cleanup Dust Control Miscellaneous Indirect Work	Welding Allowance *

Wage Rate Component Definition

	USGC	Australia
Category	**Description**	**Description**
Scaffold Erection	Includes costs for rental, erection & removal of scaffolding.	Rigger, Dogman, Scaffolding Allowance * Multi-ticket Rigger/Scaffolder *
Temporary Facilities	Includes any temporary structures (other than field office) or utilities required at the job site. Items include (but are not necessarily limited to) : Temporary Warehouse Site Security Temporary Electric grid Power consumed during construction Water consumed during construction Trash Hauling fees Temporary sanitary connections Temporary Sanitary Facilities Change trailers	Temporary Facilities
Field Office	Field Office Trailer costs including: Trailer rental Furniture Office equipment Computers Site communication Office supplies	Site Office
Small Tools & Consumables	Small tools required for construction. Consumables such as welding gases and rods	Tool Allowance * Small Tools & Consumables
Material Handling	Labour costs to receive, unload & properly store materials and equipment delivered to the site. Includes materials management. Labour to retrieve materials and equipment from storage and deliver to the worksite.	
Safety / Incentives	Includes safety manager, personal protective equipment, drug testing kits including lab fees, jobsite orientation materials and materials required to maintain a safe jobsite.	Clothing / Footwear / Safety Glasses First Aid Allowance (Basic & Level 2)
Mobilisation / Demobilisation	Includes costs associated with mobilising to the jobsite and demobilising from the jobsite	
Other		Overtime Project Allowance Electrical License Allowance * Insulation Allowance *

	USGC	Australia
Category	**Description**	**Description**
		Travel Allowance Meals Allowance Construction Metal Trades Certificate Allowance * Living Away from Home Allowance
Construction Equipment	Includes costs for rental of all construction equipment necessary to construct the project. Equipment operators are included with direct labour costs.	Construction Equipment Own / Operate
Fuel, Oil & Maintenance for Construction equipment	Includes costs for the fuel, oil & maintenance of the construction equipment above.	Maintenance Equipment & Facilities
Contractor's Overhead and Profit (on labour and indirects)	Contractor's overhead and profit markup on all labour-related items as included above.	Company Overhead & Profit

*** Crew Dependent**

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