Supply side options for WA stationary energy

An assessment of alternative technologies and development support mechanisms

Final report to WA Greenhouse and Energy Taskforce by Next Energy

26 September 2006

Executive summary

The WA Greenhouse and Energy Taskforce was asked to identify practical and economically feasible policies to manage emissions from stationary energy. This report was commissioned to inform the deliberations of the Taskforce in considering the supply side of the WA stationary energy sector.

> ***Reducing emissions and continuing current economic prosperity appears feasible if anticipated economic and technological trends are realised***

Stationary energy emissions have been growing rapidly in conjunction with strong economic growth from the current resources boom and have already increased some 70% from 26.4 Mt in the 1990 Kyoto Protocol base year to 39.7 Mt in 2004-05. ABARE is projecting further increases to 71.4Mt in 2030 under a scenario in which limited priority is given to managing greenhouse gas emissions.

Despite these emission increases, there is reason for optimism. Reducing emissions –while continuing current economic prosperity - appears feasible if anticipated economic and technological trends are realised. An intense and accelerating global effort is resulting in rapid development of low emission generation technologies, which, if successfully developed, would provide significant abatement potential at low cost. These include advanced coal, carbon capture and storage (CCS) and a range of renewable energy technologies.

Furthermore, the small number of major projects involved in the stationary energy sector means that Government can have significant influence on investment decisions in this sector.

Fostering the development and deployment of these emerging low emission technologies and factoring in likely future carbon constraints would allow WA to minimise its exposure to potential future carbon liabilities, while continuing to provide low cost energy to power the resources and mining sectors that currently underpin the WA economy.

Investment in new electricity generation infrastructure and other energy supplies typically have long term implications, measured in decades. Deferring long-lived investments in assets with high greenhouse exposures could therefore pay dividends for WA. One approach may be through greater demand management. Although demand management has not been considered in this report, the work of the National Framework for Energy Efficiency indicates significant cost-effective efficiency opportunities with the potential to delay the need for new generation and network augmentation.

> ***Natural gas fired generation, renewable energy and advanced coal with carbon capture and storage appear to be the most attractive prospective sources of large-scale abatement over the medium-term***

In the meantime, where investment in new generation capacity cannot be avoided, the use of highly efficient gas cogeneration and combined cycle plants reduce the long term carbon exposure at low or no cost. Minimising WA's greenhouse exposure will require ensuring adequate supplies of natural gas from the North West, both in terms of production and in pipeline capacity.

Advanced renewable energy technologies including geothermal and wave power appear to be prospective sources of large-scale dispatchable power supply and significant abatement over the medium-term.

Subject to favourable developments with respect to carbon capture and storage, the use of advanced coal generation with geosequestration could also be an important risk management strategy to allow for future carbon emission reductions.

Abatement potential

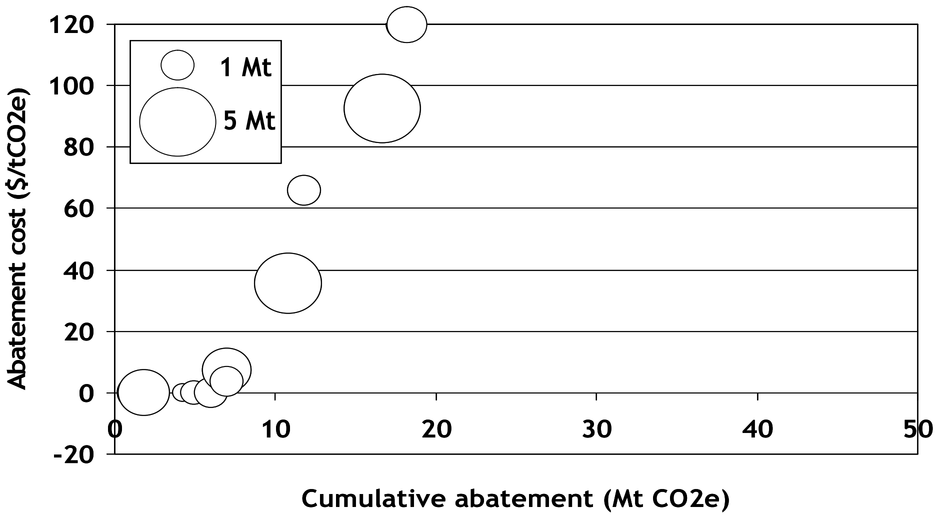
This report includes an assessment of the abatement potential and associated costs of currently available low emission technologies and emerging technologies that are anticipated to be ready for deployment by 2020 if anticipated economic and technological trends are realised. These include electricity generation technologies (excluding nuclear energy) and technologies that directly produce electricity, heat, or mechanical power at major industrial facilities.

Executive summary

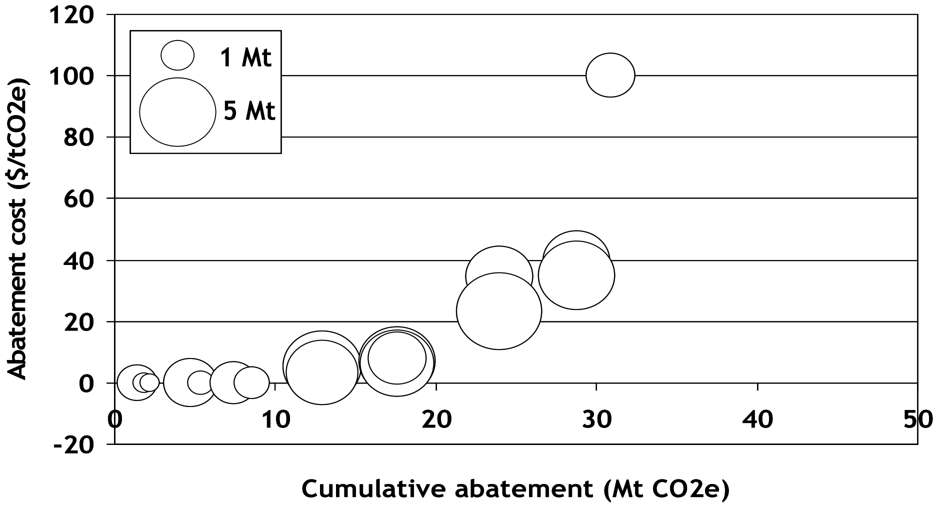
The following indicative abatement cost curves summarise the abatement potential identified with anticipated costs between now and 2010, 2020 and 2030 relative to the ABARE business-as-usual emission projections. Each circle in the following charts represents a different abatement opportunity and annotated cost curves are included on pages 100 to 103. It should be noted that the cost curves, while representing only one possible scenario, provide an indication of the types of abatement measures, costs and magnitudes that could eventuate. The clear trend however, is for more abatement over time at lower cost.

Indicative abatement curves for supply side stationary energy technologies

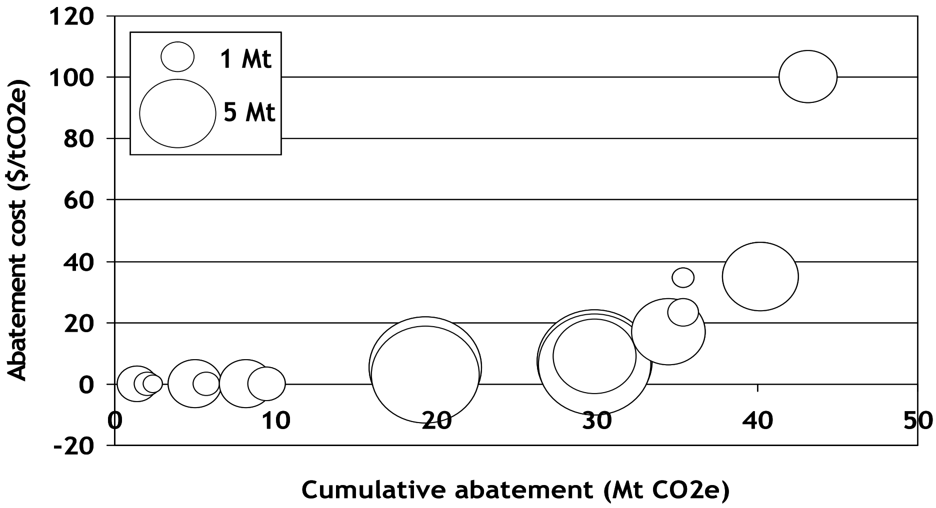
2010



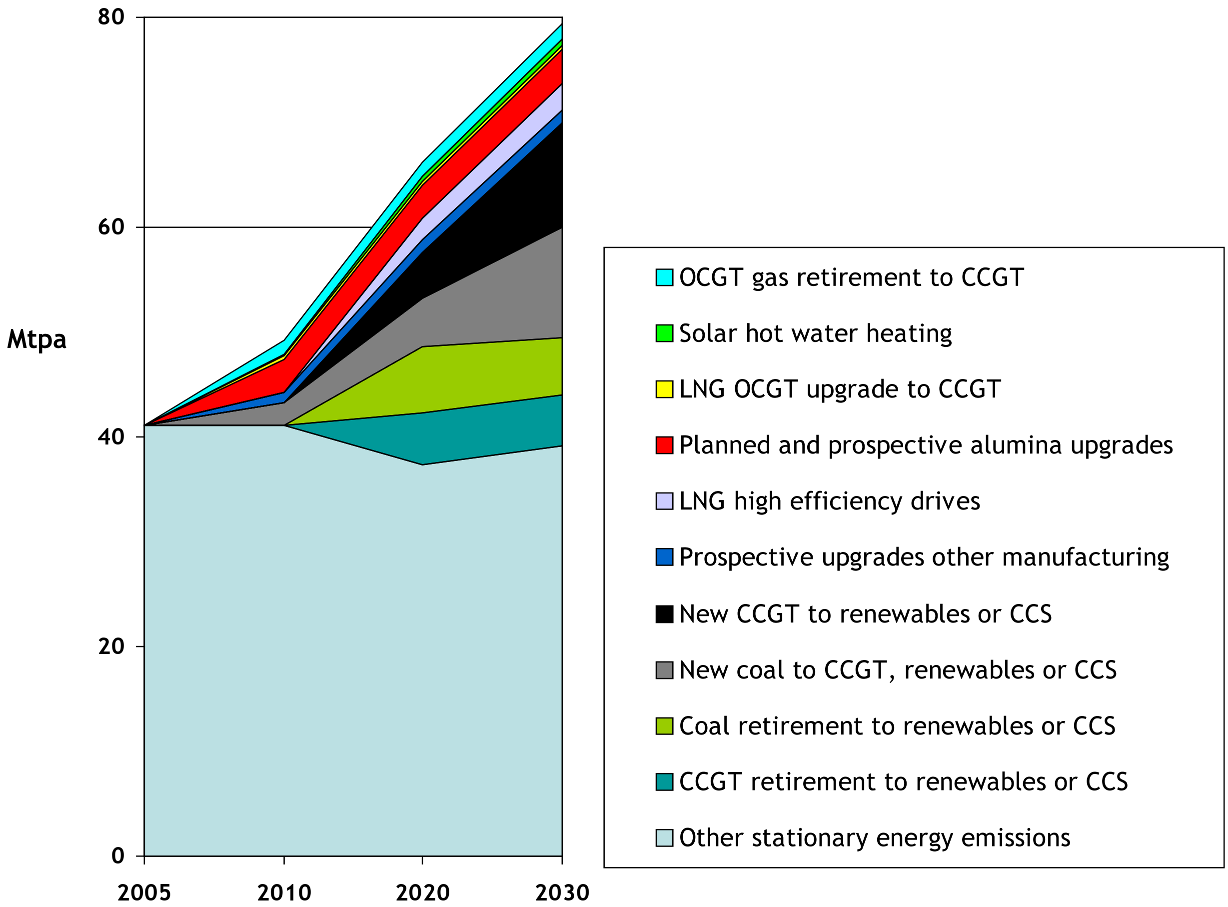
2020



2030



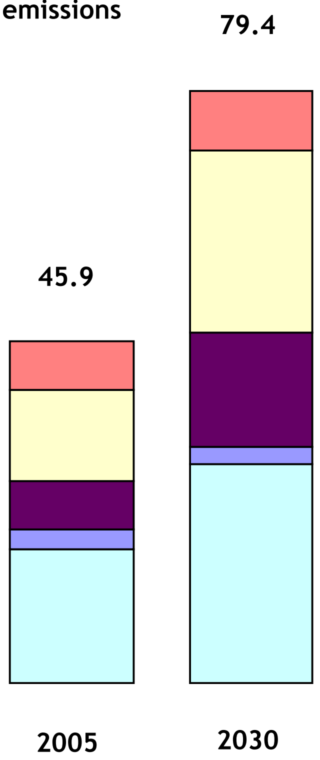
Indicative 'wedges' diagram of abatement opportunities to 2030 with cost below $40/t



Summary of abatement potential

	Abatement potential		
Carbon price	**2010**	**2020**	**2030**
< $5	7.0	13.0	19.0
< $20	7.0	17.6	34.5
< $50	10.8	28.8	40.3
< $100	16.7	30.9	43.2

The following table summarises the major supply side abatement opportunities between now and 2030 against each major fuel type in the stationary energy sector.

2030 summary of representative abatement potential		**Mt**	**$**
WA stationary energy emissions 	Fugitive		
	Geosequestration		
	Gas		
	Replace LNG OCGT with CCGT	0.3	<$5
	Alumina upgrades - planned	2.6	<$5
	Alumina upgrades - prospective	0.7	<$5
	LNG high efficiency drives	2.5	<$5
	Manufacturing upgrades	1.3	<$5
	Petroleum		
	Biodiesel	2.9	<$100
	Coal		
	non-electric		
	Electricity		
	Replace OCGT with CCGT	1.4	< $5
	Replace new CCGT with geothermal or wave	9.4	<$5
	Replace new coal with advanced coal and CCS (or geothermal/wind/ solar thermal)	10.6	<$20
	Replace coal refurbishment with geothermal/wind/ solar thermal	4.6	<$20
	Retire coal early and replace with geothermal or wind	0.9	<$50
	Retire CCGT early and replace with geothermal/wind/ solar thermal (or advanced coal and CCS)	4.9	<$50

Risks and uncertainties

The anticipated technology performance and costs trends documented in this report are neither unduly pessimistic nor optimistic and are consistent with current trends. However, a number of factors could significantly impact on the capacity to achieve the levels of abatement set out above. These risks and uncertainties must be considered in developing policies to encourage the deployment of low emission technologies and other abatement options.

These include the risks that:

1. ***Anticipated technology developments are not realised*** - A range of technologies are anticipated to deliver attractive cost and performance gains over the intermediate horizon. However, the pace and extent of achievement are inherently uncertain. Among the most notable examples is the emergence of economic carbon capture and storage. While individual elements are demonstrated, effective and economic integration suitable to power generation remains to be demonstrated and commercially deployed. Cost estimates based on current state of technology are relatively high. However, leading and large scale technology development efforts, such as the US FutureGen program, target significant improvements in this immature but rapidly emerging area. A wide array of emerging renewable energy technologies provides other examples. While building on demonstrated technologies, foreshadowed cost and performance improvements over the intermediate horizon are significant. An array of WA, Australian, and international market and policy considerations are set to drive rapid technology development across the technology spectrum, but the ultimate success in achieving target outcomes within the planned schedule remains a question. Failure or delays would necessarily result in higher costs and/or higher emissions than indicated.
2. ***Major increases in natural gas prices*** - In the nearer term, significant opportunity to manage greenhouse emissions depends on the continued availability of adequate and economic domestic natural gas supplies. While domestic gas prices can be strongly influenced by international LNG market conditions, they are also strongly influenced by domestic policy settings. This report assumes that domestic gas policy settings will be successful in delivering adequate and economic domestic natural gas. In particular, it assumes that domestic policy is effective in limiting gas prices to within the cost region as assessed in 2005. This is necessarily a significant and critical assumption, and subject to a variety of state policy objectives, as currently being considered within the domestic gas reserves policy setting process.
3. ***Carbon storage is not feasible for geologic reasons*** - Even if anticipated CCS technology emerges globally, deployment in WA will require that suitable geologic depositories are confirmed. While there are prospective sites in suitable areas (e.g., in the Perth basin, for coal generation within the region), there is some risk that detailed geologic investigations may prove the areas infeasible or uneconomic.
4. ***Underlying economic developments higher or lower than projected -*** The rate of economic growth, and the relative contribution of different sectors to growth, may strongly impact both actual future emissions and prospects for abatement. In the WA context, in which resource exports and associated major projects play a leading role, this depends heavily on international market conditions. Accelerated or deferred development of major LNG, iron, or nonferrous metals projects will necessarily affect the outlook for emissions.
5. ***Lack of policies now lead to investment in high emission long lived technologies*** - Finally, there is a risk that policy development and implementation is delayed, resulting in the near-term deployment of long-lived, high emissions projects. For example, once a new coal generator is committed without CCS capability (or economic CCS retrofit capability), it will most likely continue operating, with relatively high emissions, for several decades.

Executive summary

Barriers and constraints

This report identifies a number of barriers to the development and deployment of low emission technologies, including:

(i) Lack of clear policy intent – Although business operates in a highly uncertain environment, the emergence of climate change as an issue to be addressed has resulted in significant additional uncertainty for investors in long-lived energy assets.

(ii) Higher cost of current low emission technologies - In the absence of pricing structures that include environmental externalities, the higher costs of low emission technologies mean they simply cannot compete in a market dominated by low-cost high-emission energy supply.

(iii) Time required for new technological development - although there are a number of very promising trends in the development of low emission technologies, these all require some time to be commercially proven and ready for widespread deployment – generally anticipated in the next decade.

(iv) Physical barriers - The physical nature of some resources mean that they are either located at distance from end users (as in the case of gas and tidal resources in the North West) or face other physical constraints such as the intermittency of some renewable resources (such as wind) or limited availability (for example the limited daylight hours of solar resources).

(v) Institutional barriers – Government and market institutions have developed to support an energy system dominated by large (and inexpensive) centralised power stations and as a result, some implicit and explicit barriers exist to more decentralised and intermittent technologies. In addition, the institutional capacity and expertise of both government and industry to assess, consider, encourage and deploy new technologies is often seriously limited.

(vi) Lack of information / data gaps - Three types of information/data gaps appear significant. First, information about rapidly emerging technologies is inherently uncertain and sometime inaccurate. Second, some information is necessarily commercial-in-confidence or reflects differing commercial perspectives (for example, regarding the commercial risk of alternative technologies), and not available to government. Third, some information (such as basic site emissions data) remains to be collected through an emissions reporting scheme.

Recommendations for action

To overcome the barriers identified and to effectively manage supply side greenhouse gas emissions from the stationary energy sector, a number of recommendations have been made for consideration by the Taskforce.

Overall, there is no single, simple 'silver bullet' solution, and the recommendations below should be viewed as measures which, while reasonable, would almost certainly require ongoing revision and adjustment as experience is gained, as technologies and prospective major projects emerge (or don't), and as market conditions evolve (e.g., for the domestic and international prices of natural gas and greenhouse gases).

Several of the measures recommended below are mutually interactive. While each of these elements would facilitate the selection of CCGT in the near term over coal, none would likely be fully adequate in isolation.

Given the small number of major projects in this sector, Government policies can have significant impacts with relatively small changes in policy.

Discourage new investment in high emission technologies

Because of the intense global investment in rapidly emerging low emission technologies (both renewable and fossil fuel), it would be prudent to seek to avoid new investment in the short term in high emission long lived technologies.

It is recommended that the WA Government:

- Make a clear statement of policy intent,
- Formalise the WA EPA best practice expectation with minimum performance standards for all classes of stationary energy usage, possibly allowing inclusion of offsets to achieve greater economy and flexibility. Coal plant standards should require explicit provision for CCS retrofit capability.
- Extend the minimum performance standard above to major industrial cogeneration developments,
- Establish an aggressive energy efficiency program to ensure cost effective measures are implemented, and
- Defer development of high CO2 content LNG fields (e.g., with CO2 content higher than currently operating facilities) until geosequestration proves feasible.

Facilitate adequate and economic gas supply

Gas will play a critical role in delivering emission reductions and ensuring adequate and economic gas supply will be essential.

It is recommended that the WA Government:

- Continue the domestic gas set aside as additional LNG fields develop, and
- Continue to facilitate the development of adequate pipeline capacity.

Accelerate and facilitate technology development in WA context

As new technologies become commercially feasible, it will be important to fully understand the potential for WA application and facilitate its widespread deployment.

It is recommended that the WA Government:

- Work with industry to facilitate research and development efforts across the full range of prospective technologies identified in this report,
- Facilitate the identification and assessment of appropriate sites for geological sequestration, and
- Facilitate the identification and assessment of geothermal potential in the Perth Basin and wave and wind potential along the WA coastline.

Provide economic incentives and prepare for a carbon price

Without a carbon price signal, it is unlikely that any of the emerging low emission technologies will be adopted at any meaningful scale. There is already an international market for emission reductions under the framework of the Kyoto Protocol and it is likely that there will be future costs placed on carbon either through direct measures (such as taxes or emissions trading) or indirectly though emission constraints.

In order to prepare for future with carbon pricing, it is recommended that the WA Government:

- Make a clear statement that project proponents will be liable for future carbon compliance costs,
- Foreshadow a future carbon price, develop a carbon risk analysis framework and consider an EPA requirement for project proponents to undertake a carbon price sensitivity analysis,
- Continue to work with the National Emissions Trading Taskforce,
- Implement the Government’s commitment to emissions reporting, and
- Continue the subsidy for gas boosted solar hot water systems.

Build industry and institutional capacity to reduce emissions

In order to build institutional capacity, it is recommended that the WA Government:

- Address the institutional barriers to more intermittent generation in the South West Interconnected System (SWIS),

- Establish a cogeneration program to build capacity in the commercial and industrial sectors
- Provide detailed information about the level and availability of renewable energy resources.

Contents

Introduction

The WA Greenhouse and Energy Taskforce

The Western Australian (WA) Government established the Greenhouse and Energy Taskforce ('the Taskforce') on 30 May 2005 to advise the WA Cabinet on policy options available to manage greenhouse gas emissions in the short and long term, including the feasibility of reducing emissions by 50% by 2050.

The Taskforce was asked to advise WA Cabinet on:

- Practical and economically feasible policies to manage GHG emissions from the stationary energy sector in the short term,
- Longer term policies, actions and strategies that the State should consider to assist its efforts to reduce GHG emissions,
- The feasibility and implications of reducing GHG emissions by 50% by 2050,
- Policy options that would be complementary to a National Emissions Trading Scheme that could be adopted in Western Australia in the short term,
- Measures to prepare the State for such a National Emissions Trading Scheme and future integration with international emissions trading markets,
- Proposals for energy conservation initiatives focused on encouraging businesses and householders to make significant reductions in energy consumption, and
- Policy proposals for Government consideration on greenhouse offsets that would provide clear ground rules for proponents of projects that will have significant greenhouse emissions.

In addition, it was established that:

- Nuclear energy is not to be considered in its deliberations,
- 1990 stationary energy emissions is the 'baseline' for reductions, and
- The definition of stationary energy is that used by the Australian Government in its National Greenhouse Gas Inventory.

This report

This report was commissioned by the Taskforce to assess and report on currently available and emerging energy supply technologies expected to be available by 2020.

This report provides:

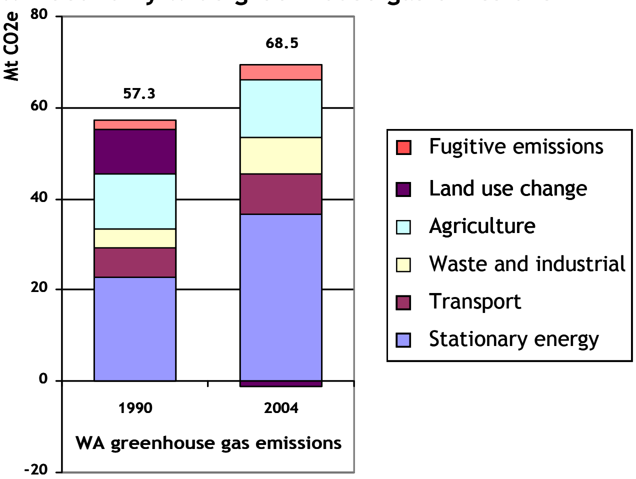
- An outline of the drivers for stationary energy supply in each sector of the economy, including ABARE's scenario of future emissions,
- An assessment of the cost and potential of technologies for each sector that are currently available for commercial deployment or close to ready and anticipated to be available by 2020,
- A summary of abatement opportunities for the WA stationary energy sector for 2010, 2020 and 2030, relative to the ABARE scenario,
- An overview of barriers to the use of these technologies and existing measures designed to overcome them, and
- Recommendations for policies and measures to help overcome barriers to the deployment of these technologies.

WA stationary energy sector emissions

In 1990, WA accounted for a total of 57.3 Mt of greenhouse gas emissions or over 10% of the national total. According to the most recent national greenhouse inventory, actual emissions had increased to 68.5 Mt by 2004 and WA had increased its share of national emissions to over 12%.

Most emissions have shown significant rates of growth but this is somewhat offset when looking at economy wide emissions from the reduction in emissions from land clearing over the same period.

WA economy wide greenhouse gas emissions



Source: Australian Greenhouse Office (2006)

Stationary energy emissions are generated in the use of energy across the economy, but in WA are dominated by energy use in the mining and minerals processing sectors. In 2004-05, stationary energy accounted for some 39 Mt of WA emissions (around half), with 58% of these from the LNG, alumina and mining sectors.

What is stationary energy?

Stationary energy is defined by the Australian Greenhouse Office in the *Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2003: Energy (Stationary Sources)*. It includes all greenhouse gas emissions resulting from the purposeful combustion of fuels in stationary equipment to provide useful energy. It also includes fuels used in on-site mobile equipment, e.g., in the mining industry.

Fuels covered include:

- Coal and fuels derived from coal (coke, coal briquettes and coke oven gas),
- Petroleum products, and
- Natural gas and town gas.

The significant majority of emissions are from CO2 resulting from the oxidation of carbon contained in the fuel. Other gases are produced by incomplete combustion of the fuel and/or side reactions in the combustion process.

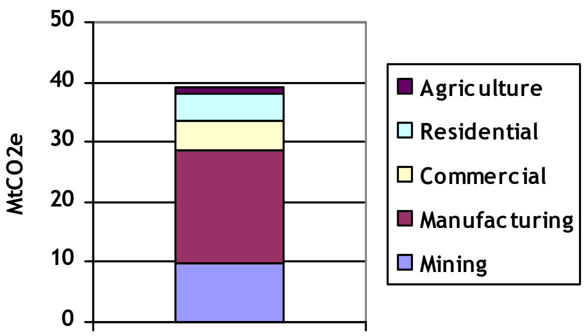
Emissions from transport, fugitive fuel emissions and industrial processes as defined by the Australian methodology are not included in this analysis, with the exception of emissions from venting and flaring in the production of LNG.

These fugitive emissions have been included due to the significant implications of stationary energy policy for these emissions, but they have been clearly identified in the analysis.

WA has the highest per capita emissions of any Australian state and its emissions profile is different from most other developed economies. This is due to a significant proportion of emissions generated in the production of energy and raw materials for use in other countries.

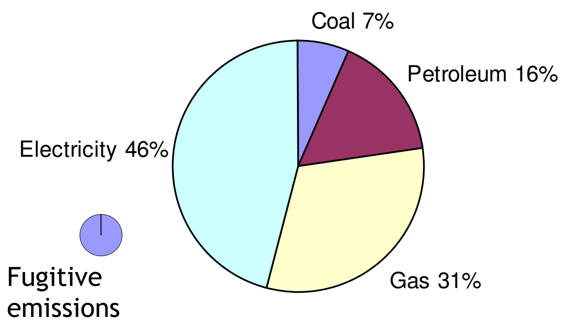
2005 WA stationary energy emissions

By sector



Source: ABARE (2006)

By fuel source (40 Mt)



Source: ABARE (2006)

ABARE's scenario of future stationary energy emissions

To perform a meaningful assessment of technologies and support mechanisms, it is essential to consider a plausible scenario of WA energy demand and infrastructure investment requirements in stationary energy to 2010, 2020 and 2030.

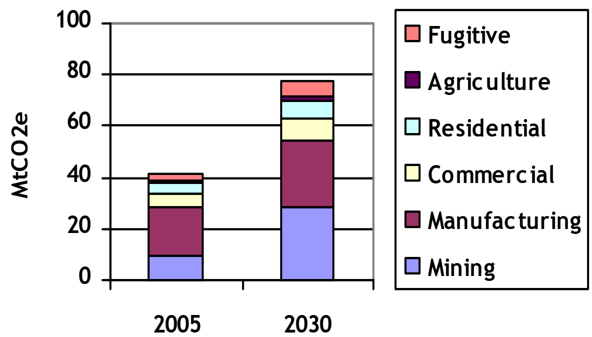
ABARE has projected energy use and emissions for WA to 2010, 2020 and 2030. ABARE's work is often characterised as 'business as usual' and assumes existing government policies continue, but no additional measures are put in place to manage greenhouse emissions. It therefore represents a scenario in which relatively low priority placed on actions to reduce greenhouse gas emissions.

This analysis uses the ABARE projections as a starting point for its analysis.

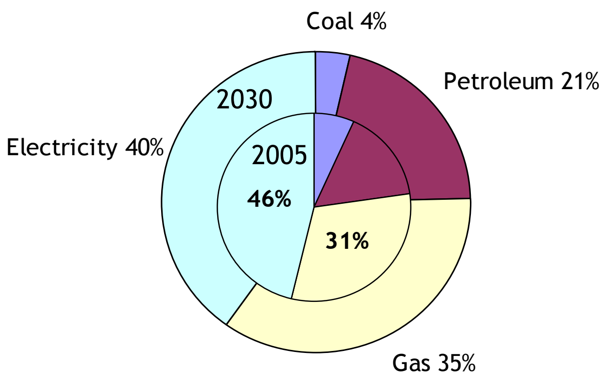
Under the ABARE scenario, stationary energy emissions are anticipated to increase 80% from 40 Mt in 2005 to 71 Mt in 2030. Fugitive emissions are projected to grow more than threefold from 1.8Mt in 2010 to 6.6Mt in 2030. All sectors show growth, with the most significant emissions growth in mining, alumina and LNG sectors.

Although electricity is currently the dominant fuel source, by 2030, its contribution as a share of stationary energy emissions is expected to decrease from 46% to 40% by 2030, with the contribution of gas increasing from 31% to 35%. This is due to the predominant growth in mining, alumina and LNG sectors (those sectors not dominated by electricity use).

ABARE scenario of WA stationary energy emissions
Total emissions by sector

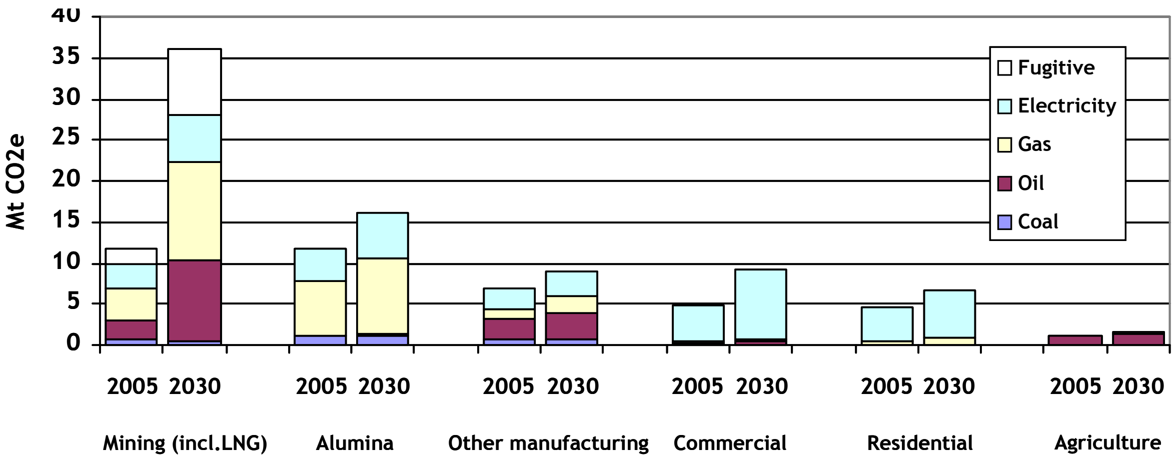


Total emissions by fuel source



Source: ABARE (2006)

ABARE scenario of WA stationary energy emissions by sector and fuel source



Source: Adapted from ABARE (2006)

Although the ABARE projections are used as a starting point for this analysis, it should be noted that a relatively small number of major industrial projects such as new LNG plants, minerals processing facilities, chemical plants and major mine site projects will have significant implications for future emissions and abatement opportunities, yet there is significant uncertainty in timing and ultimate development of many of these.

For example ABARE's 2004 long term scenarios assumed rapid development of a three large hot briquetted iron projects in WA. However, these projects are no longer under consideration, and the one previously operating was shut down in 2004. Removing these four plants reduced the projected gas requirements for 2020 by about 120 PJ, or about 60% of the current projected gas consumption in manufacturing.

Fluctuating world oil and LNG prices will also have significant bearing on stationary energy abatement costs and opportunities as well as the extent and effectiveness of government efforts to develop energy efficiency opportunities. The Taskforce has commissioned a separate consultancy to identify opportunities for demand side reductions and policies to ensure their deployment, so consideration of energy efficiency and demand side measures are not included in this report.

To the extent possible, these inherent uncertainties have been considered in the development of policies and measures to encourage the deployment of abatement opportunities.

Greenhouse priority scenario and the general technology outlook

The ABARE scenario is based on a relatively low priority placed on actions to reduce greenhouse gas emissions, with few if any additional energy efficiency measures. However, under a scenario with greater policy priority placed on reducing carbon liability risks, it can be assumed that greater efforts would be made to implement not only supply-side abatement opportunities, but a full range of cost-effective energy efficiency and other emission reduction measures as well.

There are a number of international research and development programs undertaking work on low emission technologies for the stationary energy sector. These include:

- The Asia Pacific Partnership - In 2005, Australia, China, India, Japan, Republic of Korea and the United States formed the Asia-Pacific Partnership on Clean Development and Climate to foster technology development and transfer. The partnership establishes working groups with government and private sector representation to develop action plans for 'cleaner' fossil energy, renewable energy and distributed generation, power generation and transmission, steel, aluminium, cement, coal mining and buildings and appliances.
- The G8 Plan of Action on 'climate change, clean energy, and sustainable development' includes commitments to a dialogue to 'address the strategic challenge of transforming our energy systems to create a more secure and sustainable future' and 'share best practice between participating governments'.
- IEA activities http://www.ieagreen.org.uk/ – significant energy programs across a range of renewable and fossil fuel technologies.
- The US Climate technology program (www.climatetechnology.gov) – was established in 2001 to coordinate multi-agency research and development and provide recommendations to the President on climate change science and technology. It sets research and development targets across a range of technology areas.
- The Carbon Sequestration Leadership Forum - an international initiative to develop improved cost-effective technologies for the separation and capture of carbon dioxide for its transport and long-term safe storage and make these technologies broadly available internationally.
- US Coal Technology Program – The US government currently spends about $400 million pa on an array of technologies to deliver economic, near-zero emissions coal power plants. Efforts include development of advanced combustion systems and turbines, fuel cells, gasifiers, and carbon capture and storage. The program is facilitating the development of FutureGen, a $1.3 billion public-private partnership to design, build and operate a near zero-emissions commercial scale coal plant producing 275 MW of electricity and hydrogen. Plant start-up is scheduled for 2011.

The FutureGen Industrial Alliance includes BHP Billiton and Rio Tinto, among other leading coal producers and users.

There are three main technology development themes emerging from the international work currently underway. These are:

- Low cost renewable technologies – developments in geothermal, solar thermal, wave and tidal and wind technologies are all on track to deliver extremely low cost renewable energy that can provide base load dispatchable power at costs that are competitive with current fossil fuel technologies.
- Advanced coal – coal combustion, gasification, fuel cell and post-combustion CO2 capture technologies are emerging, with an outlook for higher efficiency and the collection of carbon for subsequent geosequestration. Achieving the US coal program's targets would see near-zero emissions plants with modest cost increases of relative to current plants.
- Carbon capture and storage or 'geosequestration' – capturing CO2 emissions and re-injecting into natural sub-surface reservoirs is looking promising as an option for low emission fossil fuel use. Significant investment is being made to use both existing and emerging technologies. Current technological trends anticipate relatively low cost premiums above current fossil fuel technologies.

Electricity generation

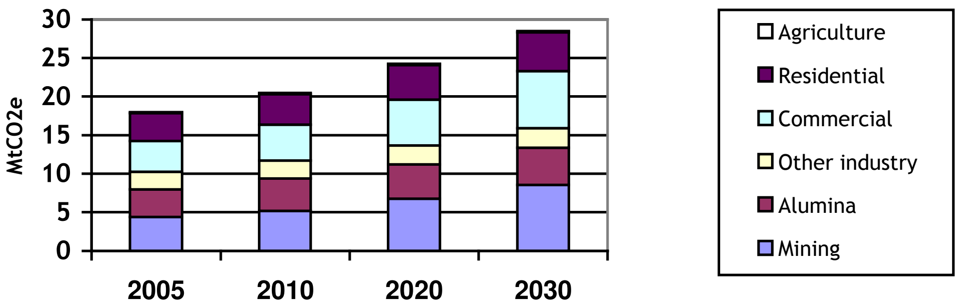
Sector overview

Around 25% of WA's total greenhouse gas emissions are emitted in the generation of electricity consumed by various end users – including households, commercial buildings, mining, alumina production and other industry. This is lower than the national average of 35%, but is still very significant and accounts for 46% of WA stationary energy emissions.

More than half of total electricity generation in the state is used in the South West Interconnected System (SWIS) region. In the SWIS, coal is the largest fuel source, followed by gas. Generation in the rest of the state is predominantly off grid and gas – driven by the needs of the mining sector.

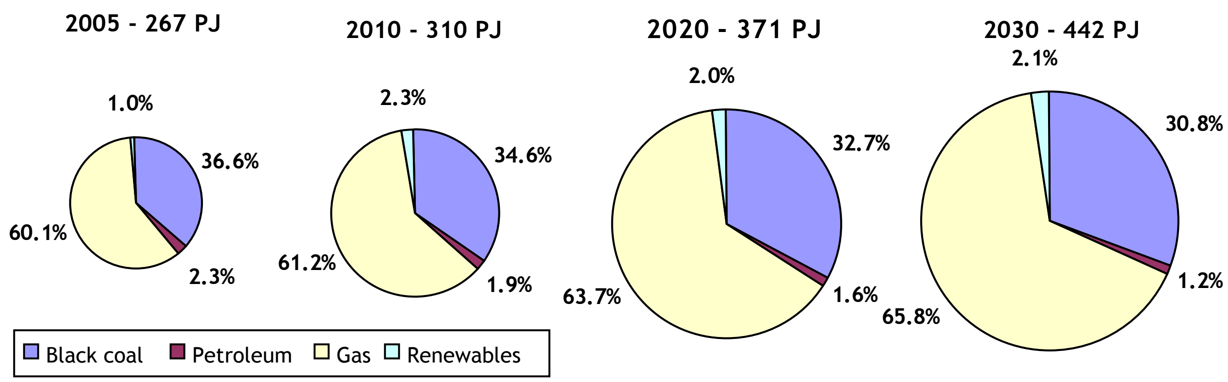
Total emissions from electricity generation in the ABARE scenario are expected to grow rapidly as increasing energy needs – predominantly in the mining, alumina, commercial and residential sectors. This increasing demand is likely to be met through construction of new coal and gas plants, with some modest efficiency improvements. The share of generation supplied by high efficiency gas plants is projected to increase, leading to a reduction in emissions intensity.

ABARE scenario of WA electricity emissions by sector



Source: ABARE (2006)

ABARE scenario of electricity generation by fuel mix to 2030



Source: ABARE (2006); Note, however, that the Office of Energy estimates that renewable energy currently contributes more than three times more generation than indicated by ABARE (2006).

ABARE emissions intensity of electricity generation to 2030

	2005	2010	2020	2030
WA emissions intensity (tCo2e/MWh)	0.71	0.66	0.61	0.56

Gas generation

Gas fired generation currently dominates electricity generation in WA, accounting for 60% of the current fuel mix. To meet upcoming base load capacity needs on the SWIS, WA has committed to high efficiency, low emission gas plants[1], although private developers are developing new coal generation projects as well.[2] This is reflected in the ABARE scenario to an extent, with an increasing share of lower emissions gas generation indicated. New gas generation on the SWIS includes both cogeneration (notably related to the alumina industry) and dedicated generators. The growth in gas generation also relates to rapidly growing mining industry use off-grid, including for the expected rapid increase in LNG production.

The ABARE scenario indicates an increase in gas generation of about 130% by 2030, and a gradual increase in gas generation efficiency from 34% to 43%. This is generally consistent with a gradual increase in the use of high efficiency units rather than the open cycle units used both for peak SWIS loads and in parts of the mining industry for baseload.

Coal generation

Coal currently contributes around 37% of generation, and ABARE projects that output will increase by about 60% to 2030. Retirement plans have been announced for two existing coal plants comprising over 20% of coal capacity[3,4]Construction has started on one new coal plant[5], but increasing coal output would require not just increasing the capacity factor of remaining units, but also construction of new coal plants, at least two of which have been proposed.[6, 7] The ABARE scenario implies that the efficiency of the overall coal plant fleet would be relatively low, and emissions would be commensurately high.

While ABARE projects total coal generation to increase, the rate of increase of gas generation to be substantially higher, resulting in a declining share of total electricity.

Renewable generation

Renewable energy currently contributes around 3.2% of WA electricity generated – including substantial amounts in remote off-grid applications.[8] The SWIS region has an estimated 4.2% of electricity generation from renewable sources.

The WA Government has committed to increase the share of renewable generation in the SWIS to 6% by 2009-10, which will increase the renewable contribution to electricity generation in WA to 2.3% by the end of this decade. However, there is currently no policy mechanism in place to deliver on this target and it is unclear at this stage how this will be achieved.

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[1] WA Government Media Statement, *New gas power station brings more power, cheaper and cleaner*, 16 August 2005

[2] Griffin Group, "Bluewaters Power Station" April 2006. www.thegriffingroup.com.au/pdf/bluewaters-2006-brochure-april.pdf

[3] Muja A&B and Kwinana A, totalling over 400 MW; Western Power '*2004 Generation Status Review*.'

[4] Independent Market Operator '*Statement of Opportunities South West Interconnected System'* July 2005.

[5] 204 MW Bluewaters Stage 1 power station scheduled to begin service in December 2008; Independent Market Operator "Statement of Opportunities" July 2006.

[6] Griffin Energy "Bluewaters Power Station Public Environmental Review" May 2004; and "Bluewaters Power Station Phase II Public Environmental Review" January 2005 and PER May 2004.

[7] Strategen for the Collie Power Consortium, "Public Environmental Review" January 2005 and "Response to Public Submissions Collie Power Station Expansion" May 2005.

[8] WA Office of Energy communication, July 2006.

Energy efficiency and demand management

The need for additional new base load can be delayed through extensive opportunities for energy efficiency that provide financial benefits to the whole economy and have the potential to substantially reduce demand in 2030[9]. These opportunities are neither explicitly included in the ABARE scenario, nor for the most part do they appear to be implicitly included.

The following sections set out electricity generation technologies, including both fossil fuels and renewable energy.

[9] NFEE estimates of significant energy efficiency opportunities are the subject of other Taskforce consultancies.

Fossil fuel technologies

(a) Combined cycle gas turbines

Combined cycle gas turbines (CCGT) are conventional power generation technology in widespread global use that integrates a gas combustion turbine with a steam turbine to capture the exhaust heat from the gas turbine and achieve higher efficiencies.

Under the ABARE scenario, about 75% of new generation to 2030 is gas-fired with efficiencies consistent with that of CCGTs. Several CCGTs are already in operation or proposed in WA, as summarised below.

In addition, carbon capture and storage technologies are emerging and could be applied to CCGTs either in retrofit applications or in novel turbines. While not demonstrated and speculative, they hold promise for substantial emissions reductions in the intermediate future if successfully developed.

CCGTs in WA[10]

Owner	Location	Capacity (MW)
Robe River Iron Associates	Cape Lambert	105
Goldfields Power (Transalta)	Parkeston	105
Western Power Corporation	Mungarra	112
Alinta Ltd	Port Hedland	180
Perth Power Partnership	Kwinana	120
Western Power Corporation	Cockburn 1	240
Total		1,472

Technology cost and performance

Under its Generator Efficiency Standards program, the Australian Government assessed world's best practice for a large new CCGT plant in 1999 to have efficiency of 52%, compared to about 36% for a gas turbine alone.[11] Smaller CCGTs achieve lower efficiencies than large units, as indicated by a Generator Efficiency Standard of 46.7%.

Capital cost depends on a number of factors, including site conditions and unit size. Estimates for the National Electricity Market Management Company (NEMMCO) indicated CCGT capital costs of $1000/kW for 385 MW greenfield plant, and 240MW units such as NewGen Kwinana at about $1140/kW.[12] The combination of a cost premium and reduced efficiency for smaller units suggests that consideration be given to facilitating larger unit sizes in the future. Larger plant sizes do, however, also increase the cost of managing reserve requirements.

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[10] Geoscience Australia (2005) *Energy markets - Fossil Fuel Power Stations* http://www.agso.gov.au/fossil_fuel/

[11] Australian Greenhouse Office "Generator Efficiency Standards" January 2001, p. 26.

[12] Derived from ACIL Tasman, 2005.

While commercially mature, CCGT technology continues to advance, with declining plant costs[13] and higher efficiencies. For example, large CCGTs now achieve net thermal efficiency of up to 54%[14,15], and the smaller NewGen Kwinana CCGT is estimated to achieve efficiency of 48%, higher than established in the Generator Efficiency Standards.[16]

Actual efficiency is inevitably lower than idealised plant design due to factors such as operating at part load, or supplementing the steam generation by burning gas in the ducts, rather than sourcing all heat from the combustion turbine exhaust. For example, the NewGen CCGT under construction at Kwinana is expected to use duct firing for about 1000 hours annually to supplement the heat recover steam generation and increase output to about 320 MW during peak periods. The resulting efficiency is likely to be about 6% lower than in full combined cycle mode, although still far higher than a combustion turbine which might otherwise be used for peak periods.

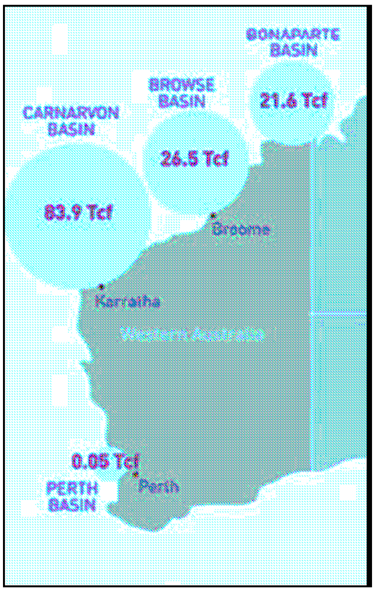
The emissions intensity of the NewGen Kwinana CCGT will be about 0.424 t CO2e/MWh when operated in full combined cycle mode, including fuel cycle emissions associated with supply and transport of fuel.[17] In contrast, the current average emissions intensity in the SWIS is about double that amount.[18]

Price and adequacy of gas supply

Western Australia has vast natural gas resources, with 80% of the nation's total reserves, producing 65% of the nation's natural gas. However, the vast majority of reserves are located off the remote northwest coast.

The adequacy and price of gas supplies are critical considerations for deployment of additional CCGT –particularly in the SWIS, which is currently gas-supply constrained. Most of the gas used for electricity generation in the SWIS is supplied from the North West Shelf (NWS) through the Dampier Bunbury Natural Gas Pipeline (DBNGP), with a small amount supplied through the Goldfields Gas Pipeline for generation in the Kalgoorlie region. Additional CCGT generation in the SWIS beyond current plans would be dependent on additional supplies emerging.

2004 WA gas reserves



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[13] World Bank, p. 21 estimates 6% to 10% reduction between 2004 and 2015.

[14] General Electric Press Release "GE Energy to Provide 209FB Combined-Cycle System for Power Plant in Castellon Spain" May 30 2006.

[15] General Electric Technical Brochure, 2006. GE reports 60% efficiency, which is based on the lower heating value of the fuel (i.e., not including heat lost in vaporising water in the combustion products). For appropriate comparison to Generator Efficiency Standards, a 10% adjustment to higher heating value.

[16] "Proposed NewGen Power Station Kwinana Industrial Area Referral to EPA" Appendix E Greenhouse Gas Assessment," Prepared by Energy Strategies, May 2005.

[17] "Proposed NewGen Power Station Kwinana Industrial Area Referral to EPA" Appendix E Greenhouse Gas Assessment," Prepared by Energy Strategies, May 2005.

[18] AGO Workbook 2005.

WA Gas pipelines

Source: DOIR

The DBNGP's current capacity of 600 TJ / day is constrained, but additional planned compressor stations will increase that by 130 TJ / day in 2007.[19,20] A further expansion of about 310 TJ / day has been proposed[21], with a first stage under consideration in 2006 which would could supply an additional 110 TJ/day by 2008.[22] For perspective, the 330 MW NewGen Kwinana CCGT, which represents about 2 years projected load growth, will use about 40 TJ/day.

Adequacy of supply from WA's large offshore reserves will depend on ongoing development of the NWS reserves, and eventually from the Gorgon, Browse and/or Pilbara Basins. While the global LNG market is the major driver for developing the reserves, the NWS currently supplies up to 600TJ/day to the domestic market. Indeed, the legislation governing the proposed Gorgon development requires that the proponents reserve 2000 PJ for domestic use, with a minimum of 300 TJ / day.[23] The State Government is currently developing a policy position on domestic gas reservations in the context of future LNG proposals.[24] While a draft position is scheduled for later in 2006, the Premier has indicated support for a continued reservation requirement.[25]

In addition to gas from the northwest, the Perth Basin and coal seam methane hold prospect for additional gas supplies. These prospects, however, are more speculative. A 2005 assessment of the prospective price and availability of gas to the South West Coast estimated an additional 600 TJ / day may become available, as summarised in the following graph. While the 2005 assessment is consistent with historical conditions and cost outlook at the time it was produced, there is a significant prospect for future gas prices to be considerably higher due to changing conditions in the global LNG market as well as domestic costs. Depending on market and policy developments, including in domestic gas reservation policy, it is possible that the price range could be considerably larger than shown, with prices possibly in excess of $6/GJ in the future. Notably, this would place natural gas prices in WA at levels far higher than found in the Eastern states, despite the relatively limited resource base there.

While such a price outcome may eventuate, this report assumes that WA domestic gas policy is effective in achieving an adequate supply of natural gas at no higher than the top of the price range assessed in 2005, of about $3.50 / GJ.

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[19] Dampier Bunbury Pipeline "DBP update on Stage 5 expansion plans" 3 February 2006. www.dbp.net.au/about/documents/DBPStage4AExpansionCompleted030206Final.pdf

[20] Economic Regulation Authority, "Draft Decision: Dampier to Bunbury Natural Gas Pipeline…Stage 5 Expansion" http://www.era.wa.gov.au/library/DraftDecisionFinal.pdf , p. 4.

[21] Economic Regulation Authority, "Draft Decision: Dampier to Bunbury Natural Gas Pipeline…Stage 5 Expansion" http://www.era.wa.gov.au/library/DraftDecisionFinal.pdf , p. 2.

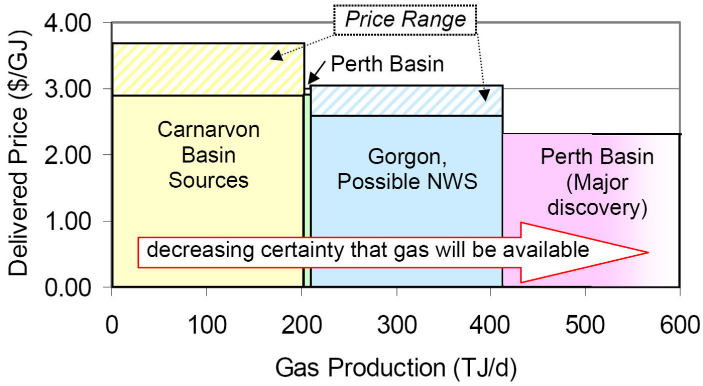
[22] Dampier Bunbury Pipeline "DBP update on Stage 5 expansion plans" 23 May 2006. www.dbp.net.au/about/documents/Stage5May23Final1.pdf

[23] Barrow Island Act 2003, Schedule 1. (17).

[24] Department of Industry and Resources "WA Government Policy on Securing Domestic Gas Supplies Consultation Paper" February 2006.

[25] Government of Western Australia Media Statement "Domestic gas reserves to expire in just 10 years" 28 July 2006.

Potential additional gas supplies available for the south west coast region, as assessed in 2005



Source: Energy for Minerals Development in the South West Coast Region of WA (2005).

Note that conditions in global LNG and domestic markets since 2005 suggest that the price range may be considerably wider, with future delivered prices potentially in excess of $6/GJ.

CCGT with post-combustion carbon capture and storage

Because the atmosphere is mostly nitrogen, the concentration of CO2 in the exhaust gases from a CCGT is relatively low (below 15%). To achieve reasonable costs for carbon transport and storage infrastructure, it would be necessary to concentrate the CO2 to a nearly pure stream. CO2 separation is well demonstrated in industrial plants and is a core element in gas cleaning for LNG production.

While the technology has not been commercially deployed, there is a positive emerging outlook for the capture of CO2 emissions from CCGTs in commercial applications.[26] In a gas CCGT, this would typically use a liquid solvent, as is used in LNG production. Carbon capture and compression would require energy to run the process, estimated at between 11% and 22% using current technology, adding to the total cost of generation.[27] In addition, there would be an increase in plant capital costs of perhaps 75% based on current technology for the capture and compression systems. Transport and storage of the capture CO2 would further add to costs, depending on the availability and location of a suitable storage site.

The availability of a geologic reservoir is essential to carbon capture and storage. The GEODISC program screened about 300 prospective sites in Australia. Following on from that work, the Cooperative Research Centre for Greenhouse Gas Technologies, CO2CRC, is investigating the Perth Basin as a potential site for power plant sequestration in WA. Assuming favourable geologic conditions are found within the Perth Basin, geosequestration of CCGTs in the SWIS may be feasible.

Current pipeline costs are estimated at US$1 to $8 / t CO2 per 250 km depending on volume, and storage including monitoring and verification are estimated at between US$0.6 to $8 / t CO2 using current technology.[28]

Therefore based on current technology discussed above, post-combustion carbon capture and storage from a CCGT could increase the cost of delivered energy by 40% to 60%. This cost increase would be expected to deliver emission intensity reductions of about 85%. Due to the relatively low emissions intensity of the CCGT, the average cost of abatement would be relatively high.

Emerging technology may deliver significant cost reductions in the intermediate horizon. For example, the technology roadmap and program plan of the US Department of Energy's carbon sequestration program has targets of significant cost reductions from current levels. In particular, the overarching program goal by 2012 is to demonstrate 90% CO2 capture, 99% storage permanence, and a cost increase of under 10%.

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[26] IPCC Special Report on Carbon Dioxide Capture and Storage.

[27] IPCC, CCSD.

[28] IPCC p. TS-33.

Two areas of development applicable to CCS for CCGTs are advanced post-combustion capture technologies and oxyfuel combustion. Extensive development work is ongoing for post-combustion capture, which would be suitable either to new or retrofit CCGT applications, as well as to coal power plants.[29] Also under development and of relevance only to new special purpose CCGTs is the use of oxygen, rather than air, in the combustion process. Oxyfuel combustion would involve developing new turbines as well as low cost processes for producing oxygen.

Overall cost and performance

Even without consideration of greenhouse emissions, CCGTs can be economically attractive in circumstances such as WA, assuming that its large gas reserves continue to translate into a relatively inexpensive fuel supply, as has prevailed historically. Notably, the recent WA request for proposals for new generation attracted both CCGT and coal generation proposals, with the decision made in favour of the CCGT. However, changing global market conditions with increasing LNG prices, and domestic policy settings regarding domestic reserves may result in less favourable future prospects.

Summary of CCGT cost and performance characteristics

Capital cost, no CCS	About \$1000/kW, subject to site-specific conditions. Higher costs for smaller unit sizes. With capacity factor of 80% and a pretax nominal cost of capital of 11.5% (6.31% real after tax), capital costs average \$12/MWh.
Capital cost, with CCS (\$/MWh)	\$20/MWh currently, declining sharply if technology anticipated by the US CCS program emerges
Fuel cost, *no CCS* (\$/MWh)	Under \$27 / MWh, assuming gas of under \$3.5 / GJ
Fuel cost, *with CCS* (\$/MWh)	Under \$30/MWh initially, declining if anticipated technology emerges, assuming gas of under \$3.5 / GJ
O&M cost (\$/MWh)	\$5 / MWh
CCS transport, storage, monitoring & verification (\$/MWh)	\$1 to \$7/MWh
Total cost (\$/MWh)	Under \$43/MWh with no CCS; ~\$63/MWh declining to \$47 with effective CCS technology development and gas under \$3.5 / GJ
Reliability and other risks	No unusual reliability risks. Risk of increasing gas prices due to international conditions and domestic gas policies. Failure to achieve timely and predictable development of gas supplies and delivery would significantly impede CCGT development. Uncertainty regarding the cost, timing and extent of post-combustion capture technology development for CCS
Other relevant performance attributes	No unusual or unmanageable environmental problems.
Greenhouse emissions intensity no CCS (t-CO2e/MWh)	0.38 to 0.42 t CO2e / MWh depending on size, and declining over time with technology improvements

[29] See, for example, "Investigating Viable CO2 Capture and Separation Options" www.co2crc.com.au/PUBFILES/CAP0304/PUBFT-0209.pdf

Greenhouse emissions intensity, *with CCS* (t-CO2e/MWh)	0.06 to 0.04 t CO2/MWh, not including gas fuel cycle emissions.
Potential barriers to deployment	Lack of economic incentives for emissions abatement. Timely development of fuel supply and transport capacity. Preference for smaller unit sizes, and the cost resulting from higher reserve requirements when larger units are used, may restrict achieving additional emissions reduction opportunities. Technology risk of early adoption of CCS technology
Uncertainties and information gaps	Rate and extent of cost and performance improvements for CCGT Rate and extent improved CCS technology emerges Project costs are inherently somewhat uncertain from government perspective. Gas prices are uncertain, and depend both on government policy and global market conditions. Cost and reliability implications for SWIS operations of larger unit sizes. Availability of suitable geologic repository, for CCS

Key references

Australian Greenhouse Office “Generator Efficiency Standards” January 2001, p. 26.

Barrow Island Act 2003, Schedule 1. (17).

Dampier Bunbury Pipeline “DBP update on Stage 5 expansion plans” 23 May 2006. www.dbp.net.au/about/documents/Stage5May23Final1.pdf

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Intergovernmental Panel on Climate Change “Special Report on Carbon Dioxide Capture and Storage” October 2005.

US Department of Energy “Carbon Sequestration Technology Roadmap and Program Plan 2005” Ministerial Council on Mineral and Petroleum Resources “Carbon Dioxide Capture and Geological Storage – Australian Regulatory Guiding Principles” 2005.

Various publications of the Cooperative Research Centre for Greenhouse Gas Technologies, CO2CRC.

(b) Advanced coal combustion

Coal power plants in WA use subcritical pulverised coal combustion technology with an average efficiency of about 34%. Higher efficiency supercritical technology is available that delivers substantially higher efficiency, and further cost and performance improvements are anticipated.

Without carbon capture and storage, emissions intensity for advanced coal combustion will remain considerably higher than for CCGT plants, even with continued technology advances under development. As with CCGTs, post-combustion carbon capture and storage technologies are emerging that would be applicable to advanced coal combustion in retrofit applications. While not demonstrated and still speculative, they hold promise for substantial emissions reductions in the intermediate future if successfully developed.

The ABARE scenario indicates that coal generation will increase by about 60% by 2030, with efficiency only gradually improving relative to current plants, and significantly lower than that offered by supercritical or other advanced coal power units.

Supercritical coal plants use advanced materials that allow higher operating pressures and temperatures than subcritical plants to deliver higher efficiency. For example, the Australian Generator Efficiency Standards assessed world's best practice for a super-critical coal plant to have efficiency of 41.7%, compared to about 38% for a smaller subcritical plant.[30] Several supercritical plants in Europe reportedly achieve significantly higher efficiency than established in the Generator Efficiency Standards at up to 46%.[31]

Capital costs depend on a number of factors, including site conditions, coal quality and unit size. Estimates for the National Electricity Market Management Company indicate capital costs of about $1500 / MW for a 500 MW greenfield plant utilising high quality coal.[32] Smaller plants have lower economies of scale and higher costs. Use of the lower quality coal typical of WA could add perhaps 10% to plant costs.[33] Supercritical coal power plants are commercially mature, with more than 600 operating worldwide.[34] Three supercritical plants operate in Australia currently, with a fourth under construction, all in Queensland.

Australian supercritical coal plants

Plant	Year commissioned	Size (MW)	Efficiency
Callide Power Station	2001	420 MW	39%
Millmerran	2001	2 x 430 MW	37%
Tarong North	2002	443 MW	39%
Kogan Creek	Planned 2007	750 MW	37%

Source: CCSD 2006, Appendix A p. 6.

Improvements in supercritical coal plant technology are foreshadowed, with ongoing improvements being deployed in commercial projects. These are expected to continuing both reducing costs and

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30 Australian Greenhouse Office "Generator Efficiency Standards" January 2001, p. 26.

31 CCSD Appendix A p, 7. CCSD adjusted the European results to reflect warmer Australian conditions, which result in lower efficiency.

32 Derived from ACIL Tasman, 2005.

33 "Cost Comparison IGCC and Advanced Coal" Electric Power Research Institute, Roundtable on Deploying Advanced Clean Coal Plants, July 29, 2004.

34 World Bank "Technical and Economic Assessment: Off Grid, Mini-Grid and Grid Electrification Technologies" November 2005, p. 50.

improving efficiency over the coming decade. With the emergence of ultra supercritical plants, the US government and industry Clean Coal Technology Program is targeting significantly higher efficiencies in the intermediate horizon, reaching 45% to 50% in commercial applications by 2010 and 50% to 60% by 2020.[35] The Australian CRC for Coal in Sustainable Development presents a more conservative view, anticipating 50% efficiency by 2015.[36]

A challenge for the application of supercritical plants in Western Australia is the relatively large scale required. Currently, the minimum commercially available plant is about 350 MW, and most technology development work involves considerably larger units.[37] Accordingly, deploying relatively smaller units would considerably more costly, and may not achieve similar efficiency. Large unit sizes present operational and outage risk management challenges for a relatively small grid such as the SWIS, where the largest current plant is about 300 MW. The combination of a cost premium and reduced efficiency for smaller units suggests that consideration be given to facilitating larger unit sizes in the future to enable more competitive proposals.

Notably, the Bluewaters Stage I coal plant, currently under construction, and proposed Bluewaters Stage II coal plants are about 200 MW each, and accordingly, based on subcritical technology. With a proposed efficiency of about 36.5%, emissions intensity would be about 0.86 t CO2e / MWh[38], or more than double the emissions intensity of a CCGT.

Price and adequacy of coal supply

Substantial coal reserves are available for power generation in WA in the Collie Basin, with additional reserves in the Perth Basin. Currently, only the Collie Basin is being developed, with production for electricity generation and industrial use. Collie coal is of moderate quality, with energy content of about 20 MJ/kg.[39] In contrast, NSW and Queensland coals have typical energy content 20% to 40% higher.

Current coal costs have been estimated at $2.25/GJ, with potential to achieve significant cost reductions through expanded production and economies of scale.[40] However, even with the estimated economies of scale, costs would be significantly higher than in the Eastern states, as shown in the following graph. This contrasts with natural gas costs, which have historically been considerably higher in the eastern states than estimated for WA based on historical conditions.

[35] US Department of Energy, Electric Power Research Institute and Coal Utilization Research Council “Clean Coal Technology Roadmap”

[36] CCSD 2006, Appendix A.

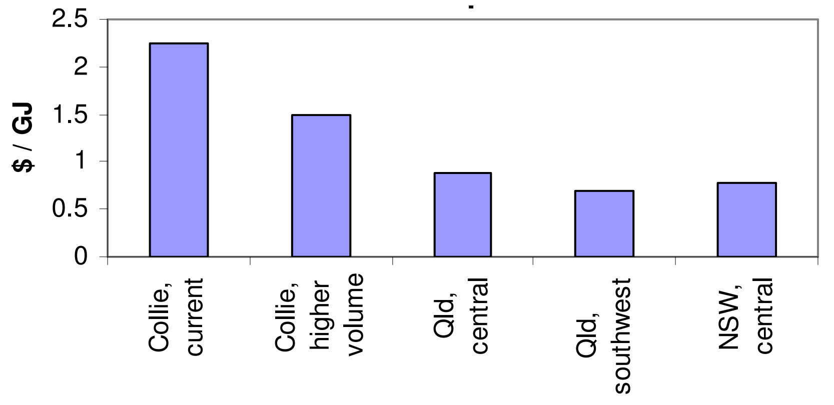
[37] Griffin Energy “Bluewaters II Public Environmental Review” January 2005.

[38] Griffin Energy “Bluewaters Power Station Public Environmental Review” May 2004; and “Bluewaters Power Station Phase II Public Environmental Review” January 2005 and PER May 2004.

[39] Strategen for Collie Power Consortium “Response to Public Submissions Collie Power Station Expansion” May 2005, p. 6.

[40] “Energy for Minerals Develoment in the South West Coast Region of WA” p. 114

Cost comparison for different coal plant



Source: Derived from ACIL 2005; Energy for SW Minerals, 2005.

Carbon capture and storage for advanced coal combustion

Generally, CCS issues are similar for advanced combustion technologies as for CCGTs (see above). The main indicated distinctions are the representative increases in capital costs and capture process energy requirements. Relative to CCS for a CCGT, a representative increase in coal plant capital costs as estimated by the IPCC is slightly lower, at 63% (76% for CCGT), and the increase in energy requirement is greater, at 24% to 40% (11% to 22% for CCGT).[41]

Based on current technology as discussed above, carbon capture and storage for a coal combustion plant could increase the cost of delivered energy by 50% to 80%, which is a larger representative increase than for CCGTs. This cost increase would be expected to deliver reduction in emissions intensity of perhaps 85% as for CCGTs, but from a substantially higher initial intensity. Therefore, the unit cost of abatement would be significantly lower.

As with CCS for CCGTs, emerging technology may deliver significant cost reductions in the intermediate horizon. The overarching program goal of the US$2 billion US Clean Coal Technology Program by 2012 is to demonstrate 90% CO2 capture, 99% storage permanence, and a cost increase relative to typical technology of less than 10%. The CRC for Coal in Sustainable Development holds a more conservative view regarding the prospects for CCS for supercritical plant, anticipating a capital cost premium for post combustion capture of about 70% by 2015, with no reduction due to learning from current costs.[42] In its review of emerging technology studies for advanced coal combustion, the IPCC found estimated increases in average energy cost relative to typical technology of about 60%.[43]

Further, specifically regarding retrofitting existing plants with post-combustion carbon capture, the emerging technology studies reviewed by the IPCC found that would increase average energy cost by over 100%. This suggests that any consideration of new coal advanced coal combustion power plants for development prior to the commercial availability of carbon capture should be designed to facilitate subsequent retrofitting of post-combustion systems.[44]

Overall cost and performance

If natural gas prices rise substantially from historical levels, advanced coal combustion technologies including CCS may present attractive cost and performance for achieving greenhouse emissions reductions.

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[41] IPCC, p. TS-15.

[42] CCSD 2006, Appendix A.

[43] IPCC, p.3-99.

[44] CCSD p.3

However, while there is an intensive international effort to develop advanced coal technology with higher efficiency and lower costs, the emphasis is on plant sizes significantly larger than currently used in WA. It is unclear whether, to what extent, and when the improved performance emerging for larger unit sizes might become available at smaller scale. This uncertainty is in addition to that inherent in the general development of advanced coal technology including CCS.

Assuming successful development of advanced fossil generation including CCS, coal technology would remain closely competitive with CCGT at gas prices consistent with historical levels, and become increasingly so if gas prices rise.

While the overall cost prospects for advanced coal including CCS hold promise for WA, they are not as strong as in the eastern states, where larger coal plant unit sizes, higher coal quality, lower coal fuel costs, and higher gas prices combine to make a more attractive case.

Advanced coal combustion cost and performance characteristics

Capital cost No CCS	About \$1700/MW for 200 MW plant, subject to site-specific conditions.[45] (Potentially significantly lower cost for larger unit sizes.) Target cost reduction of 10%-20% by 2010, and further 10% by 2020.[46] Potentially lower cost reductions over time for small unit sizes, due to lack of international development focus. With capacity factor of 80% and a pretax nominal cost of capital of 11.5%, average capital costs of about \$14/MWh currently, and about \$11 / MWh by 2020.
Capital cost With CCS	\$30/MWh currently, declining sharply if US Clean Coal Technology Program goals achieved
Fuel cost No CCS (\$/MWh)	About \$14 / MWh assuming coal at \$1.5/GJ and 40% efficiency, declining to \$11/MWh by 2020. Potentially lower cost reduction for smaller unit sizes.
Fuel cost *with CCS* (\$/MWh)	\$19/MWh currently, declining sharply if US Clean Coal Technology Program goals achieved
O&M cost (\$/MWh)	\$6/MWh
CCS transport, storage, monitoring & verification (\$/MWh)	\$2 to \$14 /MWh
Total cost (\$/MWh)	\$39/MWh with no CCS; with CCS, \$56 to \$69/MWh declining to \$43 if US Clean Coal Technology Program goals achieved
Reliability and other risks	No unusual reliability risks identified for large supercritical units, with large numbers of units in operation, and with extensive international development focus. Additional cost and performance risk relative to smaller plant sizes due to lack of international development focus. Significant uncertainty regarding the cost, timing, performance, and extent of technology development for CCS

[45] Derived from ACIL 2005, with 15% cost increase due to smaller size and lower coal quality than assumed by ACIL.

[46] Derived from US DOE, EPRI, CURC “CCT Roadmap”

Other relevant performance attributes	No unusual or unmanageable environmental problems.
Greenhouse emissions intensity, no CCS (t-CO2e/MWh)	0.8 t CO2e/MWh, declining over time with technology improvements to 0.7 t CO2e/MWh
Greenhouse emissions intensity, with CCS (t-CO2e/MWh)	0.12 t CO2e/MWh, declining over time with technology improvements to 0.07 t CO2e/MWh
Potential barriers to deployment	Lack of economic incentives to achieve emissions abatement. Challenge of integrating large unit sizes may restrict achieving additional emissions reduction opportunities. Risk of early adoption of CCS
Uncertainties and information gaps	Timing and extent of cost and performance improvements anticipated for large supercritical plants. Extent to which improvements are achievable in smaller plants. Cost and reliability implications for SWIS operations of larger unit sizes. Rate and extent CCS technology emerges Availability of suitable geologic repository for CCS

Key references

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World Bank (2005) *“Technical and Economic Assessment: Off Grid, Mini-Grid and Grid Electrification Technologies”* November 2005.

Various publications of the Cooperative Research Centre for Greenhouse Gas Technologies, CO2CRC.

(c) Integrated gasification – combined cycle coal

Integrated gasification combined cycle (IGCC) coal power plants are an emerging technology with a prospect for very high efficiency, smaller unit sizes, and suitability for CCS. There are five operating coal IGCC power plants operating commercially and several more under construction internationally[47], none of which are in Australia.

As with advanced combustion coal power, the emissions intensity of IGCC would remain considerably higher than for CCGT. However IGCC holds significant promise for integration with carbon capture and storage, which could potentially deliver very low emissions at a more attractive cost than for coal combustion and post-combustion capture.

The ABARE scenario indicates that coal generation will increase by about 60% by 2030, with efficiency that appears similar to current subcritical plants, significantly lower than that offered by IGCC.

Technology overview

In IGCC plants, coal is gasified under high pressure and temperature, rather than combusted, to create a synthetic fuel gas of hydrogen and carbon monoxide. The gas is then converted to electricity in what is essentially a CCGT. In addition to achieving high thermal efficiency, the gasification process allows effective cleaning, resulting in very low emissions of NOx, SOx and particulates relative to coal combustion.

While experience with commercial IGCC power plants is limited to five operating plants, they are generally expected to deliver significantly higher efficiency than supercritical plants. For example, the Australian Generator Efficiency Standards indicate that best practice plant in 1999 had a thermal efficiency of 49.4%, or about 20% higher than the 41.7 for a supercritical plant.[48]

Rapid advances are foreshadowed for coal IGCC, some of which are being demonstrated in current early commercial projects.[49] Under the US Clean Coal Technology Program, IGCC units are targeted to reach 45% to 50% efficiency in commercial applications by 2010, with a cost reduction of 10% to 15% from current levels. By 2020, the targets are 50% to 60% efficiency and further cost reductions.[50]

While the prospects for IGCC are strong, the low rate of deployment to date (for example, 5 operating IGCC plants relative to the 600 supercritical units worldwide) means that a new plant requires more special purpose design and higher capital costs, and has higher cost and performance uncertainty. This in turn leads to few orders, and a continuing lack of experience. Further contributing to minimal commercial take-up, early IGCC demonstration plants had relatively low availability. IGCC is estimated to have a current capital cost premium of about 10%[51] to 30%[52] in the US, or perhaps 60% in Australia[53] relative to conventional coal plants, with somewhat lower availability and higher risk. The total average cost of energy for a new current-technology IGCC are estimated at about 20% above conventional coal plants.[54]

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[47] Public Service Commission of Wisconsin “IGCC Technology Draft Report” June 2006.

[48] Australian Greenhouse Office “Generator Efficiency Standards” January 2001, p. 26.

[49] World Bank, p. 72.

[50] US Department of Energy, Electric Power Research Institute and Coal Utilization Research Council “Clean Coal Technology Roadmap”

[51] Stu Dalton, EPRI “Cost Comparison IGCC and Advanced Coal” 2004.

[52] World Bank, p. 70.

[53] CCSD, Appendix A and Appendix D.

[54] Public Service Commission of Wisconsin “IGCC Technology Draft Report” June 2006.

Several US utilities and independent power producers have recently announced IGCC development plans. Dozens of projects have also been proposed in Europe and Asia. Most are pursuing larger unit sizes than early units, as shown in the following table, which would raise questions of scale for WA similar to those applying to supercritical plants, as discussed above. However, several involve plant sizes similar to WA's largest current units. A notable element of the proposals is that they rely heavily on either government funding or regulatory approvals for cost recovery, rather than on market electricity prices.

One challenge for IGCC in WA is the relatively moderate energy content of Collie coal, as discussed above. Lower energy content imposes a higher cost premium on IGCC plant capital cost and reduced thermal efficiency than on advanced coal plants.[55]

Current US IGCC development projects

Plant	Size (MW)	Status
American Electric Power / Ohio	629 MW	First operation expected 2010. Regulatory approval for pre-construction costs granted in April 2006.
American Electric Power / West Virginia	600 MW	First operation expected 2010. Regulatory cost approval granted.
American Electric Power / Kentucky	629 MW	Planning stage
Cinergy/Indiana	500 to 600 MW	Seeking regulatory cost approval for feasibility studies.
Excelsior Energy Mesaba Energy/ Minnesota	600 MW	Anticipated operation in 2010. Supported by US DOE funding.
BP and Edison Mission / California	500 MW	Will include carbon sequestration; funded partly by US government
Erora Group	770 MW	Independent power producer; first operation expected 2010
Southern Company / Florida	285 MW	US DOE contributing 40% of funding. Commercial operation in 2010
Illinois Steelhead Energy / Illinois	545 MW	Partial state government funding
Xcel Energy	300 MW	Includes some carbon capture; Seeking federal co-funding and state approval for full cost recovery; target operation by 2013
FutureGen	275 MW	IGCC with carbon capture and storage; public private partnership with substantial government cofunding. Initial operations by 2012

Source: Wisconsin Public Service Commission 2006

[55] Stu Dalton, EPRI "Cost Comparison IGCC and Advanced Coal" 2004.

Price and adequacy of coal supply

See discussion under advanced coal combustion.

Coal IGCC with carbon capture and storage

Many CCS issues for IGCC are similar to those for advanced combustion technologies, as discussed above. However, the currently estimated representative cost and performance is significantly better for IGCC. Relative to CCS for advanced coal combustion, the representative increase in plant capital costs is far lower, at 37% (63% for advanced coal), as is the increase in energy requirement, at 14% to 25% (24% to 40% for advanced coal).[56]

Based on current technology as discussed above, carbon capture and storage for an IGCC plant could increase the cost of delivered energy by 30% to 60%. This is a larger representative increase than for CCGTs, but less than for advanced coal combustion. This cost increase would be expected to deliver reduction in emissions intensity of about 85% as for CCGTs and advanced coal combustion. As with advanced coal combustion CCS, the higher initial emissions intensity results in a significantly lower unit cost of abatement relative to CCGT.

As with CCS for CCGTs and advanced coal, emerging technology may deliver significant cost reductions in the intermediate horizon. Again, overarching program goals of the US$2 billion US Clean Coal Technology Program by 2012 are to demonstrate 90% CO2 capture, 99% storage permanence, and a cost increase of less than 10%. Notably, an advanced IGCC hybrid is a centrepiece of the US$1 billion FutureGen project being developed by private parties in concert with significant US government co-funding. It is also notable that the several IGCCs being developed by private parties in concert with US federal and state government support with the express intention of delivering on what are viewed as prospective emissions abatement characteristics. As with the outlook for supercritical plants with CCS, the Australian CRC for Coal in Sustainable Development presents a more conservative view than emerging in the US, anticipating very limited capital cost reductions achieved by 2015.[57]

Overall cost and performance

As with supercritical technology, it appears that both the economics and emissions intensity of IGCC without CCS present little or no advantage to natural gas CCGTs. In contrast with supercritical technology, however, it appears that there is substantial development work oriented to relatively small IGCC unit sizes that may be suitable in the SWIS. Furthermore, if the gasification approach to achieving high CO2 capture economics proves more effective than post combustion or oxy-fuel approaches, as in development for CCGT and advanced coal combustion, IGCC-CCS could present an attractive abatement technology. Again, it is notable that an advanced IGCC hybrid forms the centrepiece of the US Government/industry FutureGen project, and that several other IGCCs are currently being developed internationally, with an eye to CCS as well as demonstrating general cost and performance improvements. While the ability to achieve the US program goals is uncertain, there is clearly extensive funding and effort to that end.

IGCC cost and performance characteristics

Capital cost - no CCS	About $1800 / MW, subject to site-specific conditions. Target cost reduction of 10%-20% by 2010, and further 10% by 2020.[58] With capacity factor of 80% and a pretax nominal cost of capital of 11.5%, average capital costs of about $15/MWh currently, and about $12 / MWh by 2020.

[56] IPCC, p. TS-15.

[57] CCSD 2006, Appendix A.

[58] Derived from US DOE, EPRI, CURC “CCT Roadmap”

Capital cost – with CCS	\$32/MWh currently, declining sharply if anticipated FutureGen technology emerges
Fuel cost (\$/MWh)	About \$11 / MWh assuming coal at \$1.5/GJ and 45% efficiency.
Fuel cost, *with CCS* (\$/MWh)	\$13/MWh currently, declining if anticipated technology emerges
O&M cost (\$/MWh)	\$6 / MWh
CCS transport, storage, monitoring & verification (\$/MWh)	\$2 to \$13 / MWh
Total cost (\$/MWh)	\$40/MWh with no CCS; with CCS, \$52 to \$64/MWh declining to \$44 if FutureGen technology emerges
Reliability and other risks	Limited experience globally produces high cost and performance risk. Significant uncertainty regarding the cost, timing, performance, and extent of technology development for CCS
Other relevant performance attributes	Substantial reductions in water consumption, SOX, particulates and NOx relative to conventional coal generation.
Greenhouse emissions intensity, t-CO2e/MWh	0.7 t CO2e/MWh, declining over time with technology improvements to 0.6 t CO2e/MWh
Potential barriers to deployment	Lack of economic incentives to achieve emissions abatement. Risk of early adoption of IGCC technology Risk of early adoption of CCS
Uncertainties and information gaps	Timing and extent of cost and performance improvements. Availability of suitable geologic repository for CCS

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World Bank “Technical and Economic Assessment: Off Grid, Mini-Grid and Grid Electrification Technologies” November 2005.

Various publications of the Cooperative Research Centre for Greenhouse Gas Technologies, CO2CRC.

(d) Fuel cells

While currently high cost and only in prototype applications, they are an emerging power generation technology that will be competitive with combustion turbines. For stationary applications, fuel cell technology holds promise relative to combustion turbines in three areas.

- First, in large sizes, they are expected to deliver comparable efficiency to CCGTs high efficiency comparable to CCGTs, but potentially somewhat lower capital cost.
- Second, fuel cells are expected to become available at much smaller unit sizes than CCGTs, allowing applications in distributed generation such as small to medium cogeneration and distributed generation embedded within networks. For example, Ceramic Fuel Cells Ltd has developed a fuel cell unit producing 1 kW of electricity and 1 kW of domestic hot water.[59] This small size is suitable for residential and small commercial use.
- Third, as they use ultimately use hydrogen fuel, they may prove to be more attractive than development of advanced turbines for use in IGCC.

In addition to offering high efficiency in diverse size and fuels at competitive costs, the chemical process used in fuel cells, which involves initially separating hydrogen from carbon in the fuel, facilitates effective capture of CO2, a key step in carbon capture and storage. Large scale fuel cells are being actively developed in the FutureGen IGCC program to play a central role in near zero-emissions coal power plants.

Technology cost and performance

Fuel cells are electromechanical devices that convert a fuel such as natural gas or hydrogen directly into electricity without combustion. Fuel cells are attracting extensive research and development and demonstration activities not only for stationary energy applications but for transportation as well. There are several hundred fuel cell units operating worldwide[60], most of about 200 kW, primarily as demonstration projects.

Fuel cell cost is currently very high relative to other fossil fuel generation technologies, but is declining rapidly based on intensive research activities. For example, the US Department of Energy estimated the cost of large natural gas fuel cells (classified as 50 kW to 250 kW) at about US$2500/kW in 2004, dropping to US$1500/kW in 2005, with efficiency of about 30%.[61]

The US development program has a target of US$400 to US$750 / kW by 2010,[62] with efficiency of 36%. Goals for 2015 include achieving costs below US$400/MW and 50% to 60% efficiency in large-scale applications, possibly in hybrid systems of fuel cells and turbines. A further goal is to demonstrate fuel cells using coal gas with 90% CO2 capture in integrated systems with efficiency of about 60%.[63]

Achieving cost and performance targets requires identifying less expensive materials and fabrication methods. If achieved, the fuel cell or fuel cell/turbine hybrid systems would deliver efficiencies comparable to those expected for CCGTs, but at a perhaps 10% lower cost. Furthermore, fuel cell systems would deliver similar cost and performance even at far smaller sizes, for example, under 1 MW, facilitating their use in distributed generation applications.

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[59] Ceramic Fuel Cells Limited “The Future of Power Generation – Distributed micro-CHP” www.cfcl.com.au/Links/CFCL_MicroCHP_0305.pdf

[60] US Climate Change Technology Program (2005) *Technology options for the near and long term*, September 2005, p. 2.1-8.

[61] US Department of Energy DOE Hydrogen Program – VII Fuel Cells FY 2005 Progress Report, p. 720.

[62] US Department of Energy “Multi-Year Research, Development and Demonstration Plan” current, p. 3-80.

[63] US DOE FE Distributed Generation Fuel Cells Program, April 18, 2005.

Price and adequacy of fuel supply

Emerging fuel cell technology would be able to use fuels from a variety of potential sources, including coal (for example, in an IGCC), natural gas, and methanol produced from biomass. Accordingly, the price and adequacy issues for fuel cells are similar to those discussed elsewhere in this report under those topics.

Overall cost and performance

As the technology emerges over the next decade, overall cost and performance of fuel cells would be attractive. Emissions abatement opportunities in large scale applications would be generally similar to that anticipated for CCGTs and IGCC. Ultimately, the choice of whether to use fuel cells, turbines, or hybrid systems will depend on the cost and performance of the technology as it emerges.

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US Department of Energy Fossil Energy Distributed Generation Fuel Cells Program, April 18, 2005.

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World Bank “Technical and Economic Assessment: Off Grid, Mini-Grid and Grid Electrification Technologies” November 2005.

Renewable energy technologies

Governments around the world are providing increasing support for renewable energy technologies, with many countries, states and regions setting renewable energy targets. These include:

- A UK target of 10.4% by 2010
- An EU Directive to increase from 14% in 1997 to 22.1% in 2010
- China's commitment to a 10% increase by 2010 and 12% by 2020 (excluding traditional biomass and large scale hydropower)
- India's commitment to 10% increase by 2012.

In Australia, the Mandatory Renewable Energy Target (MRET), targets a 9500GWh increase in the contribution of renewable energy sources by 2010. The introduction of this target led to significant investment in renewable generation, but the industry has since stalled with the Federal Government announcing its intention not to extend the target.

WA currently has less than 200MW of renewable energy capacity compared to 5300MW of fossil fuel technologies. Although renewable power plants account for 3.4% of capacity, they contribute only 1% of energy use. The WA Government has recently introduced a target of 6% renewable energy electricity generation in the SWIS by 2010.

(e) Bio-mass

Biomass electricity generation can use a range of well understood and commercially mature technologies, and can utilises a diverse array of waste and dedicated fuel supplies. When growing, biomass absorbs CO_2, offsetting the CO_2 emissions that are subsequently released in energy production. There can be non-energy benefits associated with biomass production, such as salinity management, and co-production of other valuable materials, benefiting the rural economy. Critical questions for biomass electricity generation relate to the extent, sustainability, transport and cost of potential fuel supply more than to generation technology.

The ABARE scenario assumes negligible biomass electricity generation in WA over the forecast horizon, of under 0.25% of total generation throughout the forecast horizon.

The type of technology used in biomass electricity generation depends on fuel type. Given the relatively low energy density of biomass and the high cost of transport, plant sizes tends to be dictated by biomass fuel availability within relatively limited areas.

There are several types of potential biomass supply for use in electricity generation. The main potential sources are:

- Landfill and sewage gas
- Solid biomass wastes, including forestry residues, agricultural waste, municipal solid waste
- Dedicated energy/multi-purpose crops

Landfill and sewage gas. The most common biomass electricity generation operating in WA uses methane recovered from landfills or sewage, with 10 plants producing a total of about 23 MW.[64] These plants use conventional internal combustion engines, using technology that is well demonstrated in WA, Australia, and internationally. Due to the high greenhouse potential of the methane captured and used for fuel, landfill gas projects provide a significant additional greenhouse benefit. However, the extent of potential generation relying on landfill gas or sewage gas is limited and will become increasingly so over time with ongoing efforts to reduce municipal waste. The landfill and sewage gas plants appear to be reflected in the ABARE scenario.

[64] Geosciences Australia

Solid biomass wastes. Solid biomass wastes can be readily converted to electricity using conventional steam boiler technology. By far the largest current amount of biomass electricity in Australia uses bagasse for cogeneration in the sugar industry. The technology is mature and in widespread use in Australia and internationally. There is one 6 MW bagasse generation plant in Western Australia, at Ord River. Expansion of bagasse generation in WA would depend on developments in the sugar industry.

The next leading source relies on wood waste. In a low cost but effective technology approach, wood wastes are currently cofired in the existing Muja coal power plant.[65] Ultimately, waste from a co-located sawmill and pallet-making facility should supply the equivalent of about 5 MW of baseload generation. This approach is well demonstrated, and used at several power plants in Australia.

Forestry wastes hold promise for at least a moderate amount of additional renewable generation in the near term. This can be seen in a series of three proposed commercial projects, one of which is at a relatively advanced state of pre-construction development[66] (see Table below). These projects would use dedicated conventional steam boiler technology. The developer of these projects indicates plant capital costs of $2M/MW, and a delivered electricity price of $75 to $100/ MWH.[67] These costs are consistent with the small unit sizes and the relatively high costs of collecting and transporting biomass.

Solid biomass electricity generation projects in WA

	Approach	Capacity	Status
Muja	Cofiring wood waste in coal power plant	2024 MWh in 2002, 1104 MWh in 2005[68], Up to 1% cofiring of 1040 MW power station.[69]	Full co-firing operation since 2005
Kemerton		20 MW	In principal power purchase and fuel supply agreements - operational in 2007+
Dardanup/ Alcoa	waste	20 MW	Proposed
Albany		20 MW	Proposed
Ord	Bagasse	6 MW	Operating
Narrogin	Oil Mallee coppicing	1 MW	Demonstration plant operating; due for decommissioning
Various	Oil Mallee coppicing	10 x 5 MW	Proposed

[65] www.verveenergy.com.au/mainContent/sustainableEnergy/futureProjects/BiomassMujaPowerStation.html

[66] The project proponent has been suspended from trading on the ASX pending resolution of ASIC concerns regarding solvency. Green Pacific Energy *Suspension from Official Quotation* 15 May 2006.

[67] Green Pacific Energy “Investor Briefing MD on Agreement to Build New Green Energy Projects”“Green Pacific Energy Limited on track to commence construction of green energy power plants” 25 February 2005.

[68] Energy generated using wood wastes and achieving accreditation under the Mandatory Renewable Energy Target, as reported at www.rec-registry.gov.au

[69] Office of Energy “2006 Final Generation Table.pdf” 2006, http://www.energy.wa.gov.au/cproot/802/5379/2006%20Final%20Generation%20Table.pdf

The extent to which additional generation could be developed based on existing collected waste stream is unclear, and the total potential has not been estimated. Achieving the low end of the pricing indicated above would depend on low cost waste streams. Notably, the total plantation estate is expected to increase from 125,000 ha currently to 175,000 within ten years.

With regard to agricultural waste streams, there is a large amount of biomass material produced, although these wastes are generally not collected and delivered to central locations suitable for electricity generation. A significant increasing contribution from solid biomass waste would depend on collecting agricultural residues such as the harvestable stubble from wheat. These present a potentially large scale biomass resource. For example, one estimate places the available harvestable residues from wheat production at about 0.7 dry t / ha, with an energy content of about 20 GJ/t.[70] A 20 MW plant would require about 400 sq km for the waste biomass feedstock. With about 8 million ha of wheat and other crops in production in WA[71], harvesting wheat stubble could supply about 110 PJ of primary energy, or about 40% of the total fuel used in WA electricity production in 2005.

The costs of collecting and converting this material are high largely due to the small scale. Small plant size also results in relatively low efficiency. Further, removal of waste biomass, rather than recycling the nutrients in the field, may reduce future crop yields. Emerging technology may increase efficiency and reduce costs. In particular, biomass gasifiers may deliver significantly higher efficiencies with similar capital costs than achievable in relatively small steam generators as currently used. A study by the CRC for Coal in Sustainable Development has estimated a range of input costs[72], which have been adapted for this report as shown in the Table below. This would appear to encompass technology improvements in conversion as well as in collection. This opportunity merits further detailed investigation, given the large potential size of the resource. Notably, a significant fraction of the total cost, about 20% to 30%, is the estimated reduction in future crop yields. This area in particular merits further detailed investigation.

Multi-benefit biomass crops. Multi-benefit bioenergy crops present a significant prospect for electricity generation. In particular, oil mallee and other woody species suitable to coppicing may be able to deliver a supply of fuel of about 10 mtpa of dry wood, or about 200 PJ pa, at a delivered cost of $70/ton.[73] With an average yield of about 5 t/ha[74] pa, this implies about 2 million ha of coppiced biomass crops.

A key benefit envisioned for the use of coppiced oil mallee is its potential role in mitigating dryland salinity. The resprouting ability of mallee allows the deep roots to soak up ground water and mitigate rising salt, while producing a regular supply of biomass. With several million hectares of agricultural land at risk of dryland salinity, the potential for short rotation coppiced biomass as a new large volume agricultural product are substantial. The 200 PJ pa potential biomass supply is large, representing about 75% of 2005 fuel use for electricity generation in WA. However, it should be noted that such a large new bioenergy crop may be applied not to electricity generation, but rather to competing uses in producing liquid fuel.

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[70] Clean Energy Future, p. 81.

[71] Australian Bureau of Statistics Agricultural State Profile Western Australia, 7123.5.55.001 26/10/2005.

[72] Cooperative Research Centre for Coal in Sustainable Development "Techno-Economic Assessment of Power Generation Options for Australia" April 2006.

[73] Bartle et al, *"Scale of biomass production from new woody crops for salinity control in dryland agriculture in Australia"* International Journal of Global Energy Issues, 2006, cited by Wu & Ewing *"Inquiry into Australia's future oil supply and alternative transport fuels"* Submission to Senate Rural and Regional Affairs and Transport Committee.

[74] Wildy et al "Silviculture and water use of short-rotation mallee eucalypts" report for Joint Venture Agroforestry Program, August 2003.

Electricity generation using agricultural waste

$/MWh	Current $80 to $113/MWh depending on delivered fuel cost, declining with emerging technology to $73 to $85/MWh
Capital cost	$2700 k/MW[75] for steam boiler system currently. Similar cost in 2015, but for higher efficiency gasifer systems. With capacity factor of 80% and a pretax nominal cost of capital of 11.5% (6.31 real after tax), average capital costs of about $27/MWh.
Fuel, delivered including transport	$1.1 -$2.5/GJ[76]; ($22 to $50/dry ton) or $9 to $23/MWh at efficiency of 40%. By 2015, low end of cost range achieved through special purpose collection technology.[77]
Efficiency	25% currently, rising to 40% by 2015 using gasification
Capacity factor	60% to 80%
O&M	$8[78] to $19/MWh[79]
Loss of future crop yield with stubble retention	$22/MWh[80]
Greenhouse emissions intensity, t CO2e/MWh	Near zero
Potential barriers to deployment	Lack of economic incentives to achieve emissions abatement. Uncertain impact of biomass removal on future agricultural productivity
Uncertainties and information gaps	Impact of biomass removal on future agricultural productivity at different removal rates Costs of biomass collection and delivery with emerging whole-crop harvesting technology

Applied to 0.6 million ha, this would potentially produce about 1500 GWh pa, or about 200 MW of baseload generation. The cost has been estimated at about $94/ha for a dedicated crop without co-benefits. After accounting for the cost of electricity would depend heavily on the value of the eucalyptus oil and activated carbon, and on the value attributed to salinity management, all of which are uncertain.

Verve Energy's 1 MW Narrogin integrated wood processing demonstration plant at Narrogin is a leading example of a potential multi-benefit bioenergy crop that includes electricity production. Having operated successfully as a demonstration plant for a brief period, it is due for closure in June 2006. As originally conceived, full operating integrated wood processing plants would have a

[75] Consistent with US Department of Agriculture Forest Products Laboratory "Wood Biomass for Energy" 2004; CCSD 2006 Appendix J; and World Bank 2006.

[76] Derived from CCSD 2006, Appendix J.

[77] US Climate Change Technology Program Technology Options, September 2005.

[78] World Bank 2006.

[79] CCSD 2006 Appendix J.

[80] CCSD Appendix J.

capacity of about 5 MW each. Notably, electricity is a relatively minor element of the economics of the proposed commercial IWP plants as initially conceived, constituting about 20% of revenues.[81] The majority of revenue would be from the sale of on producing activated carbon (60%)and eucalyptus oil (20%). Thus, the cost would be highly dependent on these commodity markets.

Electricity generation using dedicated mallee or similar biomass crops

$/MWh	Current $96, declining with success of emerging technology to $70
Cost Elements	
Capital Cost	$2700 k/MW[82] for steam boiler system currently. Similar cost in 2015, but for higher efficiency gasifer systems. With capacity factor of 80% and a pretax nominal cost of capital of 11.5% (6.31 real after tax), average capital costs of about $29/MWh.
Fuel, delivered including transport	$3.5/GJ[83]; ($22 to $50/dry ton) or $50/MWh at current 25% efficiency, declining to $32/MWh by 2015 with higher efficiency gasification
Efficiency	25% currently, rising to 40% by 2015 using gasification
Capacity Factor	60% t0 80%
O&M	$8/MWh[84]
Co-production benefits	Key area of uncertainty
Greenhouse emissions intensity, t CO2e/MWh	Near 0
Potential barriers to deployment	Lack of economic incentives to achieve emissions abatement. Ability to achieve commercial benefits from coproducts Need for land-holders to enter novel area of production Uncertain impact of biomass removal on future agricultural productivity
Uncertainties and information gaps	Actual harvestable biomass growth rates and delivered fuel cost in large volume production Whether other uses of the biomass are more economic, for example, in producing liquid fuels Benefits for salinity management

[81] Enecon 2001.

[82] Consistent with US Department of Agriculture Forest Products Laboratory "Wood Biomass for Energy" 2004; CCSD 2006 Appendix J; and World Bank 2006..

[83] Bartle 2006 as reported in Wu & Ewing.

[84] CCSD 2006 Appendix J.

(f) Wind

Wind energy is an abundant resource which has been harnessed for centuries and is easily accessible in most parts of the world. Modern wind turbines convert wind energy into electricity and as one of the most cost effective renewable energy sources; large scale wind farms have experienced significant growth in Australia and overseas.

The European Wind Energy Association Wind Force 12 report makes a case that there are no technical, economic or resource barriers to supplying 12% of the world's electricity needs with wind power alone by 2020 at the same time as a projected two thirds increase of electricity demand by that date.

According to Geoscience Australia, WA currently has more than 120MW of wind generation capacity and another almost 500MW proposed[85]. Currently the largest wind farm in WA is the 90 MW Walkaway wind farm owned by Renewable Power Ventures and Alinta, followed by Western Power's Albany wind farm which consists of twelve 1.8 MW turbines, each with a 65m tower and three 35m long blades. New developments underway include Energy Visions 100MW at Coronation Beach and Griffin Energy and Stanwell Power 80MW at Emu Downs.

In 2004-05, wind energy contributed 42% of renewable energy generation in WA and ABARE anticipates that wind will provide the vast majority (85%) of new generation to 2010 and more than half new generation to 2020. The Australian Wind Energy Association has an industry target to install 5000 MW by 2010 (or around 6% of Australia's electricity needs)[86].

Cost and performance characteristics

Large wind farms are currently the most cost effective of renewable technologies and over a 20-year lifespan have levelised generation costs of around \$75-\$90/MWh[87]. However, the capital costs of wind projects are relatively high, with costs in the order of \$2100/kW of installed capacity.

Although wind power technology is relatively mature, the technology is continuing to improve in both economic cost and technical performance. Between 1981-98, production costs of wind turbines reduced by a factor of four[88] and further significant improvements are anticipated. Turbines are becoming increasingly larger and more efficient for both land and sea-based wind farms. From 25kW machines 25 years ago, the larger machines being developed currently have capacities as high as 2.5 MW. Further developments are anticipated as the costs of power electronics – and variable speed drives fall.[89]

The US Climate Technology program is anticipating a further 25% reduction in cost at the best sites to A\$40/MWh by 2012.[90] The European Wind Energy Association expects the reduction to be in the order of 36% by 2020.[91]

The World Bank has estimated wind energy costs as set out in the following table.

Levelised costs ($/MWh) [92]	2004	2010	2015
10 MW wind farm	88	80	73
100MW	75	68	63

According to the Australian Wind Energy Association, wind turbines are more than 99% reliable in terms of operation and maintenance, compared to about 97% for the steam turbines used by coal plants[93]. Newer larger systems also have lower operating and maintenance costs. Capacity factors vary between 20-40% for wind generation and are highly dependent on wind speeds at a given location. [94]

Intermittency of wind power generation is often cited as a barrier to its widespread deployment. However, a recent report commissioned by the Office of Energy[95] concluded that the South West Interconnected System (SWIS) has the scope to accommodate significant renewable generation capacity beyond that currently installed and under development 'providing adequate policy and systems are put in place to avoid the difficulties, uncertainties, disruptions and additional costs of renewable energy development'.

The report further concludes that for levels of levels of 10% of intermittent generation there is no significant impact on frequency control requirements. For levels of up to 20% additional controls are required and in countries where intermittent generation has reached 30%, the cost on market participants is around 2% of the retail price of electricity.[96] This conclusion is supported by

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[85] Geoscience Australia (2005) *Map of operating renewable energy generators in Australia* http://www.agso.gov.au/renewable/

[86] AusWEA website *Fact sheet 2 - Wind farming and the Australian Electricity System* http://www.auswind.org/auswea/index.html

[87] See for example World Bank discussion paper (2005) Technical and Economic Assessment: Off Grid, Mini-Grid and Grid Electrification Technologies, US Climate Technology Program (2005) Technology Options for the Near and Long Term, Sleeman (2004) Energy for minerals development in the south west coast region of Western Australia

[88] IEA(2005) Renewable Energy – RD&D Priorities- Insights from IEA Technology Programmes

[89] World Bank discussion paper (2005) *Technical and Economic Assessment: Off Grid, Mini-Grid and Grid Electrification Technologies* http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTENERGY/0,,contentMDK:20796696~pagePK:210082~piPK:210098~theSitePK:336806,00.html

[90] US Climate Technology Program (2005) *Technology Options for the Near and Long Term*, p.2.3.2

[91] European Wind Energy Association (2004) *Wind Force 12* http://www.ewea.org/index.php?id=30

[92] World Bank discussion paper (2005) *Technical and Economic Assessment: Off Grid, Mini-Grid and Grid Electrification Technologies* and using a $US exchange rate of 0.75

[93] AusWEA website *Fact sheet 2 - Wind farming and the Australian Electricity System* http://www.auswind.org/auswea/index.html

[94] World Bank discussion paper (2005) *Technical and Economic Assessment: Off Grid, Mini-Grid and Grid Electrification Technologies* http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTENERGY/0,,contentMDK:20796696~pagePK:210082~piPK:210098~theSitePK:336806,00.html

[95] Econnect (2006) *Maximising the Penetration of Intermittent Generation in the SWIS* - Econnect Project No: 1465 for the WA Office of Energy

[96] Econnect (2006) *Maximising the Penetration of Intermittent Generation in the SWIS* - Econnect Project No: 1465 for the WA Office of Energy

Unisearch (2003) that estimated that the WA system could readily accept up to 500MW, from a national total of 8000MW[97].

In theory, therefore, the take up of wind will be constrained by the proportion of its contribution to the network (to accommodate issues of intermittency), however, due to the additional cost of wind, these constraints are unlikely to be an issue in the foreseeable future.

For remote power generation, Western Power and Powercorp have developed a new advanced high-penetration wind-diesel power system that uses a low load diesel system to increase the supply of electricity from wind energy.

The technology has been installed in Denham with strong, consistent winds (about 850km north of Perth), which previously relied on diesel fuel for electricity. The Denham system has a 1.7MW diesel power station and 3x 220kW wind turbines capable of supplying up to 70% of energy and operating at 100% wind penetration at low load.[98]

Other relevant performance attributes

Wind turbines can have associated bird fatalities and can affect populations of endangered species, particularly if sited in an endangered bird's migratory path.[99] This was recently recognised in a contentious decision of the Federal environment Minister to oppose a wind farm development in Victoria. Wind projects can also attract significant opposition based on visual and other amenity issues.

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[97] Unisearch (2003) National Wind Power Study - An estimate of readily accepted wind energy in the National Electricity Market A report for the AGO prepared by Hugh Outhred

[98] Unisearch (2003) National Wind Power Study - An estimate of readily accepted wind energy in the National Electricity Market A report for the AGO prepared by Hugh Outhred

[99] Department of the Environment and Heritage "Wind farm collision risk for birds" March 2006.

(g) Tidal barrage systems

Tidal systems capture energy from incoming and outgoing tides through turbines in dams built across an estuary inlet (a tidal 'barrage system'). Power output is predictable but not constant in time and other environmental impacts can be significant.

In Australia, the main potential site for tidal technology is in the north-west of WA - very remote from the main centres of electricity demand. The Derby region has considerable estimated tidal resources, although a recent Derby Hydro Power proposal to construct a 50 MW tidal plant was shelved when compared unfavourably with an alternative gas plant.

The technology

Tidal barrage technology is relatively mature and is essentially the same as technology used in hydropower developments – with the construction of a dam across the estuary and use of turbines. Over the past 40 years, numerous tidal energy schemes have been investigated but very few have actually been built due to the very high capital costs and local environmental impact (similar to large dams)[100].

There are few sites with sufficiently high tides and low potential environmental impact. A 240 MW tidal power station has been operating since 1967 at La Rance, France and several other tidal power stations are being considered, including the Severn project in England.

Cost and performance characteristics

In a detailed assessment of a number of options to replace diesel generation at Derby[101], SEDO found that preliminary cost estimates per kW ranged from $6,770 to $12,800 for the Derby tidal project, with capital costs ranging from $12.8 million to $33.9 million for 1 MW and 5 MW options respectively.

While noting that the analysis was relied on limited information, SEDO found that the most cost effective option was a 5 MW tidal plant with an estimated capital cost of $33.9 million and annual generation of 16.7 GWh (including a surplus generation of 2.3 GWh). The tidal plant would meet 50% of the annual demand, with existing diesel generators meeting the rest. The cost of unsubsidized tidal energy was estimated at $410/MWh.

Tidal power is predictable but cyclical, which means that back up generation is required that can supply 100% of power at any time. This has considerable implications for cost, as capital costs are incurred with the back up system.

Tidal project have similar environmental impacts to the construction of large dams. SEDO identified the following specific impacts from the proposed tidal project at Derby (and noted that all of these could be managed at additional cost):

- Disturbance of water courses and water quality,
- Excessive sedimentation requiring ongoing dredging,
- Significant impacts on mangrove habitats, and
- Potential acid sulphate soils with associated corrosion.

The most likely application of tidal barrage systems in WA is at Derby to offset the use of diesel generation. However, given the recent decision to proceed with a gas system, this is unlikely in the timeframe of this analysis and would require a significant increase in the price of gas.

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[100] SEDO(2001) Study of Tidal Energy Technologies for Derby, prepared by Hydro Tasmania, http://www1.sedo.energy.wa.gov.au/uploads/Derby%20Tidal%20Energy%20Study%20-%20Executive%20Summary_21.pdf

[101] SEDO(2001) Study of Tidal Energy Technologies for Derby, prepared by Hydro Tasmania

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SEDO(2001) Study of Tidal Energy Technologies for Derby, prepared by Hydro Tasmania, http://www1.sedo.energy.wa.gov.au/uploads/Derby%20Tidal%20Energy%20Study%20-%20Executive%20Summary_21.pdf

(h) Wave, tidal and ocean currents

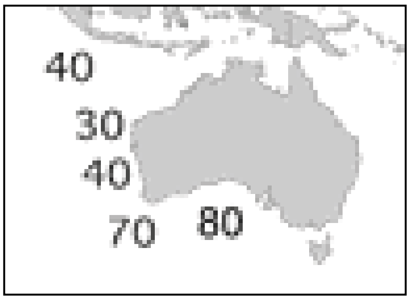
Technology overview

Wave, tidal and ocean current systems are still in the research and development stage and involve immersing turbines under water in powerful currents that may or may not be tidal. The energy conversion system has more in common with wind power than conventional tidal barrage systems and its environmental impact is low.

Although wave and tidal resources are intermittent, they are more consistent and reliable than wind energy and according to Oregon State University, waves are a lot more efficient than wind energy because water is orders of magnitude more dense than air, which means you can extract more power from a smaller volume, which in turn means lower cost[102].

The World Energy Council has estimated that approximately 2 terrawatts, about double world current electricity production, could be produced from the oceans via wave power[103].

Wave energy levels (kW/m)



This map shows wave energy levels in kilowatts per metre of wave front. To put into context, Ocean Power Technologies PowerBuoy systems are optimized to work in sites with 20 kW/m or greater. WA therefore has high wave power resources, particularly in the south west, close to high population densities.

Wave and ocean systems can be used for remote or utility power generation, desalination and resource processing.

Source: Ocean Power Technologies

Cost and performance characteristics

Wave energy development began in the 1970s and the market is currently moving from research, development and testing into pre commercial trials, with full-scale commercial production in sight[104]. Wave systems can be floating or fixed to the seabed and different technologies are being developed. Projects are already in operation in Scotland, Portugal and Hawaii, with seven companies installing systems to date.

Following successful demonstration trials off Freemantle, WA company Seapower Pacific is building a commercial prototype of the CETO renewable wave energy converter[105]. CETO is the first wave power converter to sit on the seabed. Unlike other wave energy technologies that require undersea grids and costly marine qualified plant, CETO requires only a small diameter pipe to carry high pressure seawater ashore to either a turbine to produce electricity, or to a reverse osmosis filter to produce fresh water.

According to its developers, the CETO technology has the potential for economic payback periods competitive with coal or gas-fired base load power plants[106]. Detailed costings for capital and operational costs are not yet established. However, if the current trials are successful, proponents anticipate that this technology will overcome the usual cost barriers of renewable technologies. As

[102] As reported on http://www.waveberg.com/wavenergy/resource.htm

[103] As reported on http://www.oceanpowertechnologies.com/

[104] Seapower Pacific (2006) http://www.seapowerpacific.com/BACKGROUND.htm

[105] Seapower Pacific (2006) http://www.seapowerpacific.com/BACKGROUND.htm

[106] Seapower Pacific (2006) http://www.seapowerpacific.com/BACKGROUND.htm

with any new technology, the initial commercial applications are likely to be higher cost until economies of scale are achieved and sufficient industry capacity is developed.

Ocean Power Technologies has developed the Powerbuoy system which captures mechanical energy as the buoy moved up and down with the rising and falling of the waves (pictured below). This technology has been installed in Hawaii (1MW) and New Jersey (40kW) with a 1.25MW system under development in Spain. A 10-Megawatt OPT power station would occupy around 30 acres of ocean space.

Ocean Power Technologies estimate the costs of their Powerbuoy technology at $40-$53/MWh for utility scale power generation, which is already cost competitive with fossil fuel generation.

Levelised costs of wave energy ($/MWh) [107]

	2006
Utility scale	40-53
Remote	93-133

Source: Ocean Power Technologies

These costs are slightly more optimistic than Sleeman consulting estimates of between $70-120/MWh[108].

According to the IEA, ocean energy technologies still need to overcome a very high technical risk from the harsh environment of strong waves or currents and fulfil basic economic and environmental requirements including low cost, safety, reliability, simplicity, and low environmental impact.[109]

Ocean based systems may not raise the same visual and other amenity issues or impact on wildlife as land based wind systems. For example, because of the higher density of water relatively to air, the turbines move more slowly, thus reducing the potential wildlife impact. However, until large scale projects are proposed and developed, public acceptance will remain somewhat speculative, particularly where projects are perceived as affecting recreational and commercial activities.

Publicly available detailed information on wave, tidal and ocean current resources in WA to identify the most prospective generation sites. If the current trials are successful, this work would be invaluable in assisting the new fledgling technology.

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http://www.iea.org/Textbase/publications/free_new_Desc.asp?PUBS_ID=1592

Ocean Power Technologies http://www.oceanpowertechnologies.com/

Seapower Pacific (2006) http://www.seapowerpacific.com/BACKGROUND.htm

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[107] http://www.oceanpowertechnologies.com/

[108] Sleeman Consulting (2004) Energy for minerals development in the south west coast region of Western Australia Report to WA Department of Industry and Resources

[109] International Energy Agency (2006) Renewable Energy – RD&D Priorities: Insights from IEA Technology Programmes
http://www.iea.org/Textbase/publications/free_new_Desc.asp?PUBS_ID=1592

(i) Geothermal– hot dry rock technology

The technology

Geothermal technology harnesses energy from the friction of tectonic movement or radiated as radioactive elements in the rocks naturally decay over time. According to Geodynamics, one cubic kilometre of hot granite at 240°C has the stored energy equivalent of 40 million barrels of oil when the heat is extracted to a temperature of 140°C[110].

Conventional geothermal systems harness naturally occurring hydrothermal resources (hot water and steam) at relatively shallow depths and which are relatively inexpensive to exploit.

In Australia however, these resources are limited and it is the engineered geothermal systems – or hot dry rocks - which show more potential. Rocks are cracked hydraulically and heat is extracted by pumping water through an engineered heat exchanger, which is then used directly for heating or if hot enough, to create electricity. Hot dry rocks are a particularly attractive renewable energy source as they do not have the intermittency issues of wind and solar systems and is therefore dispatchable.

Commercial maturity / availability

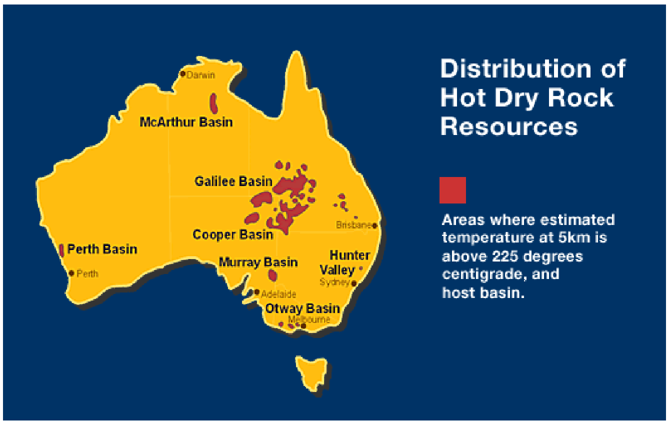
Conventional geothermal energy is already used in many places throughout the world, such as Greenland and New Zealand – primarily for heating. However the use of hot dry rock technology to create electricity is less developed, and a fully commercial Hot Rock power plant is yet to be built. IEA has set a commercialisation horizon of 2015 for hot dry rock technology.

In 2004, the world geothermal electricity production reached 57 000 GWh while direct use of geothermal heat amounted to 261 420 TJ.[111]

Hot dry rock projects in Australia include the Birdsville geothermal power station in Queensland and a test project in the Cooper Basin, South Australia.

Research undertaken in 1994 by the Energy Research and Development Corporation estimated the potential geothermal resource in Australia at 23 million PJ – 80% of which is in the Eromanga Basin in SW Queensland and NE South Australia[112] and 49,000 PJ in the Perth Basin.

More recent work by ANU created thermal images of geothermal potential, showing WA with some prospect for hot dry rock technology in the Canning and Perth Basins[113].



Source: www.geodynamic.com.au

A 1982 report by the Geological Survey of WA concluded that prospects for geothermal energy development were 'similar to those being exploited in other continental areas overseas ... exist and that further more detailed studies are warranted.'[114]

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[110] www.geodynamics.com.au

[111] IEA (2005) *Energy technologies at the cutting edge*

[112] ANU hot rock energy website http://hotrock.anu.edu.au/resource.htm

[113] ANU hot rock energy website http://hotrock.anu.edu.au/ , Sleeman Consulting (2004) *Energy for minerals development in the south west coast region of Western Australia* Report to WA Department of Industry and Resources

Performance and cost characteristics

ANU anticipates that the demonstration plant in the Cooper Basin will derive energy from 240–270 degrees Celsius granite at a break even electricity price of around $60/MWh, and around $40/MWh at full scale production.[115] However, this is yet untested as a fully commercial hot rock energy power plant has not yet been built. Sleeman Consulting estimates costs of around $50-70/MWh.[116]

World Bank estimates of levelised energy costs for conventional hydrothermal power plants are already less than $60/MWh[117], with a typical life span of a plant around 20-30 years. It is uncertain whether these levels of costs could be achieved in hot dry rock technology.

In terms of resource exploration, hot rock energy offers a lower level of uncertainty and risk when compared with exploration for conventional geothermal energy, oil and gas. Large areas of continental crust have relatively uniform geothermal gradients, so once a favourable gradient has been determined in an area, the presence, size and depth of a hot rock energy resource can be predicted with a fair degree of confidence. [118]

Barriers to commercial deployment

The main barriers to the uptake of hot dry rock systems are likely to be the higher cost of new technologies, lack of suitably skilled companies to exploit the resources, lack of WA specific geological data and more prospective sites in other states.

To further explore the potential for hot dry rocks in WA, additional geological surveying is required – particularly in the Perth Basin which is located close to high demand.

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http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTENERGY/0,,contentMDK:20796696~pagePK:210082~piPK:210098~theSitePK:336806,00.html

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114 Geological Survey of WA (1982) Record 1982/6 - The potential for geothermal-energy development in Western Australia

115 See Geothermal Energy on WA Department of Industry and Resources website at www.doir.wa.gov.au

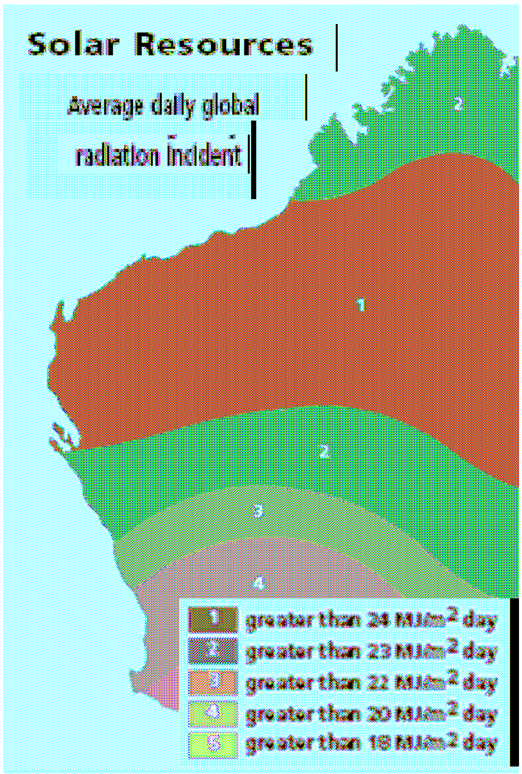
116 Sleeman Consulting (2004) Energy for minerals development in the south west coast region of Western Australia Report to WA Department of Industry and Resources

117 World Bank discussion paper (2005) Technical and Economic Assessment: Off Grid, Mini-Grid and Grid Electrification Technologies
http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTENERGY/0,,contentMDK:20796696~pagePK:210082~piPK:210098~theSitePK:336806,00.html

118 ANU hot rock energy website http://hotrock.anu.edu.au/

(j) Solar thermal or concentrating solar power

WA has extremely high levels of solar resources - as illustrated in this solar map – higher than any other Australian state with the exception of the Northern Territory. While costs are high, solar thermal has the attraction of virtually unlimited technical potential. For example, with average solar insolation of about 7.3 GJ/m2 pa[119], an area of under 300 km2 with 20% efficiency could supply all of WA's projected 2030 electricity needs, assuming it was coupled with effective storage.



Source: WA Office of Energy (2003)

Solar technologies that convert sunlight to electricity generally fall into two broad categories:

- concentrating solar power (or solar thermal) systems and
- flat plate photovoltaic (PV) systems.

Solar thermal power plants concentrate solar energy 50 to 5,000 times to produce temperatures of 400°C to 800°C in a receiving fluid.

The heat is then used to power conventional heat engines (steam, gas turbines or Stirling engines) to produce electricity with no greenhouse gas emissions.

These systems typically use one of three different types of technology:

Parabolic troughs uses parabolic trough arrays to focus solar energy on a linear oil filled receiver. The heat is then used to generate superheated steam to power a conventional steam turbine. These systems range from 1-100 MW and can be supplemented with natural gas to provide dispatchable power when solar energy is not available. Nine systems built in Southern California in the 1980's account for almost the entire current worldwide capacity – which is less than 360MW[120],

Solar power towers uses a circular array of reflectors to focus sunlight onto a power tower that collects solar energy at high temperatures and generates steam for a conventional steam turbine. Tower power technology however is in the development stage, with no commercial projects in operation. The first tower system, Solar One, was constructed in Southern California and has since been retrofitted with 3 hours of thermal storage. The first commercial plant is now being planned in Spain[121].

Parabolic dish/heat engines - parabolic dish concentrators provide high temperature thermal energy to drive small scale engines located in the focal point of the dish which points directly at the sun. Prototypes are in operation in Nevada, Arizona, Colorado and Spain, but this technology is still at the pre-commercial stage. The capacity to supplement solar thermal with gas provides an attractive dispatchable low emission hybrid system. Solar-thermal technologies could also be well

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[119] Morrison, GL and Litvak, A, (1999) *Condensed solar radiation data base for Australia* Report No 1/1999 Solar Thermal Energy Laboratory, University of New South Wales

[120] California Energy Commission (2005) *Developing Cost-Effective Solar Resources with Electricity System Benefits* http://www.energy.ca.gov/2005publications/CEC-500-2005-104/CEC-500-2005-104.PDF

[121] US Climate Technology (2005) *Technologies for the Near and Long Term*, p.2.3-9 – 2.3-10.

placed for direct conversion of natural gas or water into hydrogen (rather than indirect conversion through electrochemical reactions) for future hydrogen-based economies[122].

Australian company Solar Heat and Power uses the Australian Compact Linear Fresnel (CLFR) Design which directs steam at 350°C and can be used to supplement existing rankine cycle plants, increasing efficiencies by up to 10%.[123] Macquarie Generation has commissioned a 40MW CLFR concentrator adjacent to its Liddell Power Station in NSW. Solar Heat Power is currently developing a stand alone 240MW design for a power station that utilises underground thermal storage capable of producing low cost baseload power competitive with current fossil fuel technologies.

The US Department of Energy is working with the Western Governors to map a strategy to deliver 1-5GW of solar concentrating power in the southwest USA by 2015.

Performance and cost trends

Sleeman Consulting reports Queensland Department of Natural Resources estimates of levelised costs of solar thermal at $180-250/MWh.[124]

The US National Renewable Energy Laboratory (NREL) anticipates significant further advancements to solar trough technologies without breakthroughs in technology. These include significant increases in capacity factors with the addition of up to 12 hours thermal storage and an eight-fold increase in plant capacity up to 400 MW by 2020. Hybridisation with gas also allows for dispatchable power supply. NREL has projected significant cost reductions assuming reasonable deployment, which see prices falling from current values of around $193/MWh to $76/MWh by 2020, which is competitive with the wholesale electricity market. According to the California Energy Commission[125], these trends correlate well with estimates by Navigant Consulting, the Electric Power Research Institute and Solargenix Energy.

The US Climate Technology program interim goal is to reduce the costs of large scale plants to between $120-$147/MWh by 2010, which is slightly higher than the California Energy Commission expectations.

Parabolic trough cost and performance characteristics[126]

	1989	2004	2010	2020
Capital costs ($/MW)	3.4	4.2	3.3	2.6
O&M costs ($/MWh)	33	23	19	13
Capacity factor (%)	22%	33%	56%	56%
Levelised costs ($/MWh)	241	193	100	76

Source: California Energy Commission (2004)

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[122] US Climate Technology (2005) *Technologies for the Near and Long Term*, p.2.3-9 – 2.3-10. http://www.climatetechnology.gov/library/2005/tech-options/tor2005-232.pdf

[123] Solar Heat and Power website www.solarheatpower.com

[124] Sleeman Consulting (2004) Energy for minerals development in the south west coast region of Western Australia Report to WA Department of Industry and Resources

[125] California Energy Commission (2005) Developing Cost-Effective Solar Resources with Electricity System Benefits, p.4. http://www.energy.ca.gov/2005publications/CEC-500-2005-104/CEC-500-2005-104.PDF

[126] California Energy Commission (2005) Developing Cost-Effective Solar Resources with Electricity System Benefits, p.6.

Although tower power technology is still in the development stage, projections of cost reductions are optimistic, with NREL anticipating that towers will become cost competitive by 2010 assuming a significant level of deployment achieved.

Solar power tower cost and performance characteristics[127]

	2004	2008	2018
Capital costs ($/MW)	9.6	4.2	3.1
O&M costs ($/MWh)	44	11	8
Capacity factor (%)	78%	73%	73%
Levelised costs ($/MWh)	213	83	67

Source: California Energy Commission (2004)

Parabolic dish systems are still at pre-commercial stage and there is limited performance and cost trend information available. However, US Department of Energy estimates suggest that this technology is unlikely to be cost competitive for another two decades.

Parabolic dish cost and performance characteristics[128]

	2003	2007	2025
Capacity factor (%)	24%	24%	50%
Levelised costs ($/MWh)	533	200	60

Source: California Energy Commission (2005)

An early production costing by Solar Heat and Power design anticipates competitive costs both with and without underground storage systems. Significantly lower estimated cost relative to the CEC analyses result from a number of design features, but remain to be demonstrated. If these cost estimates prove achievable, such a plant would be cost competitive with fossil generation even without a value placed on greenhouse emissions.

Financial analysis of the Solar Heat and Power 240MW CLFR stand alone plant[129]

	240MW with buffer storage only	240MW with cavern storage
Capital cost - no margin ($million)	$160	$450
Peak output – thermal / electrical (MW)	800 / 240	2660 / 240
Thermal to electrical efficiency	30%	30%
Annual capacity Factor (%) / Annual output (MWh_e)	17% / 350	56% / 1170
Levelised cost ($/MWh)	$52.5	$41.7

Source: Solar Heat and Power (2004)

[127] California Energy Commission (2005) Developing Cost-Effective Solar Resources with Electricity System Benefits, p.10-11.

[128] California Energy Commission (2005) Developing Cost-Effective Solar Resources with Electricity System Benefits, p.10-11.

[129] Solar Heat and Power (2004) *Competitive Solar Electricity* Paper presented to ANZSES 2004.

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Solar Heat and Power website www.solarheatpower.com

(k) Solar photovoltaic power stations

A photovoltaic (PV) system contains solar cells that convert light into electricity.

As discussed in the previous section on solar thermal technologies, WA has relatively high levels of solar resources and Perth has the highest solar resources of any state capital city in Australia. In contrast to other solar technologies, PV systems can use direct, scattered and reflected sunlight to generate electricity and consequently they can be used over a broader geographical range.

PV can operate either stand alone or connected to the grid, but is by far the most expensive of currently available electricity generating options, particularly if requiring battery storage to overcome the limited hours of power output. However, despite its high costs, PV enjoys very high levels of community support. Furthermore, as with solar thermal, the technical potential is virtually unlimited, with an area of under 300 km2 able to supply all of WA's projected 2030 electricity needs, assuming 20% efficiency and integration with effective storage.

The technology

PV technology is commercially mature and growing rapidly. The global market is dominated by Germany, USA and Japan.

The modular systems provide for easy transportation and rapid installation, with easy expansion if demand increases. PV systems are used for:

- rooftop installation where they compete with retail electricity prices (discussed in more detail in the commercial and residential sections),
- small grid-connected power stations equivalent to any other generator supplying power to the electricity grid.
- stand-alone systems with battery storage or diesel/petrol back-up. Usually used for homes and farms in more remote areas (discussed in the agricultural section). These are the most economic PV application and are already widespread, accounting for around 90% of current PV application in Australia.

According to the IEA, current Australian installed capacity at the end of 2004 was more than 52MW[130], of which almost 90% were off-grid applications. The majority of these are small scale and according to Geosciences Australia, there is less than half a megawatt of capacity from systems over 3kW in WA, although there is an additional 12.5 MW proposed[131]. The largest PV system installed in WA is 151 kW capacity PV system[132] owned by Hammersley Iron.

In 2000 the US solar industry contributed 75MW of peak generation capacity from a national total of 825 GW. Although this represents less than 0.01%, the US PV roadmap anticipates ongoing growth at 25% per year - approaching 10% of peak generation by 2030.

The Australian PV Industry roadmap sets out an industry development strategy to deliver a cost-competitive Australian PV industry by 2020. It anticipates that the strategy could deliver 3% of Australia's power needs by 2020, and around 6740 MW of installed capacity by 2030 with 31,000 jobs. However, on current trends and with existing policies the industry is unlikely to meet that target.[133]

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[130] IEA Photovoltaic power systems programme (2005) *Trends in photovoltaic applications in selected IEA countries between 1992 and 2004* http://www.oja-services.nl/iea-pvps/isr/22.htm

[131] Geoscience Australia (2005) *Map of operating renewable energy generators in Australia* http://www.agso.gov.au/renewable/

[132] IEA Photovoltaic power systems programme (2005) *Trends in photovoltaic applications in selected IEA countries between 1992 and 2004* http://www.oja-services.nl/iea-pvps/isr/22.htm

[133] BSCE (2004) Australian Photovoltaic industry roadmap

Cost and performance characteristics

Significant progress has been made over the past two decades in research and development, improving manufacturing processes, reducing costs and establishing small but rapidly growing niche markets.

Grid connected PV systems currently cost as little as $10/W to install, which equates to around $400/MWh. Most current systems are based on crystalline silicon with conversion efficiencies of around 12-20%, and the PV modules account for around 50-60% of the overall system costs[134]. PV systems require very little maintenance, apart from occasional cleaning and replacement of the inverter once in their lifetimes. Research and development programs have focussed on reducing costs, extending the system life and improving the efficiency of the solar modules.

Increasing economies of scale and international research and development achievements look promising. The Californian Energy Commission has estimated possible future costs for utility scale PV as set out in the following tables (all A$).

PV costs for utility scale systems [135]

	2003	2007	2020
Capital costs ($/MW)	8.3-12.7	6.9	3.1-3.7
O&M costs ($/MWh)	107	27	7
Capacity factor (%)	11.5%	14%	16%
Levelised costs ($/MWh)	320	200	80

Source: California Energy Commission (2005)

The US Climate Technology program also targets long-term costs for residential PV applications of A$80/MWh, compared to costs ranging from $180-230/MWh in 2004. By 2010, they anticipate costs of $180-250/MWh[136] which is consistent with the California Energy Commission work. The World Bank estimates are even more optimistic again.

Although PV is very expensive relative to other current generation technologies, the economies of scale afforded by a grid connected power station make it relatively more attractive when compared to the much smaller rooftop applications.

Other issues

PV systems pose few environmental problems. The generating component produces electricity silently and does not emit any harmful gases during operation. The basic photovoltaic material for most common modules made out of silicon is entirely benign, and is available in abundance.

Some early PV modules were criticised for consuming more energy during production than they generated during their lifetime. With modern production methods and improved operational efficiencies this is no longer true and typically energy payback will be realised within 3-4 years.

The overwhelming barrier to deployment of PV is in grid-connected applications is the unit energy cost in comparison to conventional generating technologies.

In addition, the limit of power generation to hours of sunlight further limit its widespread application without some form of battery storage or back up system.

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[134] World Bank discussion paper (2005) *Technical and Economic Assessment: Off Grid, Mini-Grid and Grid Electrification Technologies* http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTENERGY/0,,contentMDK:20796696~pagePK:210082~piPK:210098~theSitePK:336806,00.html

[135] California Energy Commission (2005), p.21-22

[136] US climate technology program (2005) Technology Options for the Near and Long Term

The CEEM research on the coincidence of PV output and peak loads was undertaken in NSW, Victoria and SA. An analysis of PV output in a Perth context in relation to peak demand would be particularly useful.

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Barriers to renewable energy technologies

WA has taken important steps to facilitate the uptake of renewable energy technologies in the electricity system. For example, access by renewable generation was a key design objective of the new electricity market, and several notable projects have been successfully developed. As in any system, however, including best practice systems, there remain a variety of barriers to deployment which merit further consideration.

Intermittency of power generation

Intermittency of solar, wind and other renewable power generation is often cited as a barrier to its widespread deployment. However, a recent report commissioned by the Office of Energy[137] concluded that the South West Interconnected System (SWIS) has the scope to accommodate significant renewable generation capacity beyond that currently installed and under development 'providing adequate policy and systems are put in place to avoid the difficulties, uncertainties, disruptions and additional costs of renewable energy development'.

The report further concludes that for levels of levels of 10% of intermittent generation does not have a significant impact on frequency control requirements, for levels of up to 20% additional controls are required and in countries where intermittent generation has reached 30%, the cost on market participants is around 2% of the retail price of electricity.

A number of recommendations were made by Econnect in its recent report to the WA Office of Energy on intermittent loads in the SWIS[138], including recommendations relating to network stability, network frequency stability, additional analysis, forecasting, frequency control ancillary service (FCAS), geographical diversity, energy balancing, load following and planning controls.

It is recommended that the Taskforce consider the implementation of the Econnect recommendations to ensure that any barriers are removed in time for WA to meet its 2009-10 renewable energy target, and to facilitate ongoing deployment of renewable and other intermittent energy sources as they become economic.

Lack of data and access to information

SEDO has published a renewable energy handbook providing information relevant to renewable project development.[139] As identified in the Econnect report[140], difficultly in accessing relevant information required during the feasibility stage can delay or limit development. There are currently deficiencies in a range of information, including those related to:

- the extent and availability of renewable resources,
- land use that might affect or limit access to and use of those renewable resources,
- information on renewable penetration and consequent generator outages, output swings and estimates of contribution to network losses,
- standard information to guide connections, and
- potential scenarios for the high penetration of renewable energy to guide development planning and change to networks, regulatory or commercial frameworks.

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137 WA Office of Energy (2006) *Maximising the Penetration of Intermittent Generation in the SWIS* - Econnect Project No: 1465 for the WA Office of Energy

138 WA Office of Energy (2006) *Maximising the Penetration of Intermittent Generation in the SWIS* – A report by Econnect to the WA Office of Energy

139 Sustainable Energy Development Office "Renewable Energy Handbook for Western Australia" December 2005.

140 WA Office of Energy (2006) *Maximising the Penetration of Intermittent Generation in the SWIS* – A report by Econnect to the WA Office of Energy

It is recommended that these information deficiencies be addressed as a matter of priority.

Higher cost and lack of clear economic incentives

Despite significant cost reductions over the last decade, the overwhelming barrier to the widespread deployment of renewable energy technologies is their higher cost compared to current high emission fossil fuel technologies.

A carbon price that places a cost on greenhouse gas emitters – either directly through a carbon tax or indirectly through emission trading - will go some way to reducing this cost differential. However, a carbon price in the order of $40 is needed to make the currently least cost renewable technologies economically competitive with fossil fuels.

Location of renewable sources at distance from demand

Some renewable resources such as tidal and geothermal are located at some distances from the demand for electricity, which means transport costs add to the high costs of these generation technologies. This barrier is a physical one that cannot be immediately overcome and transport of energy must be incorporated into economic evaluation of projects.

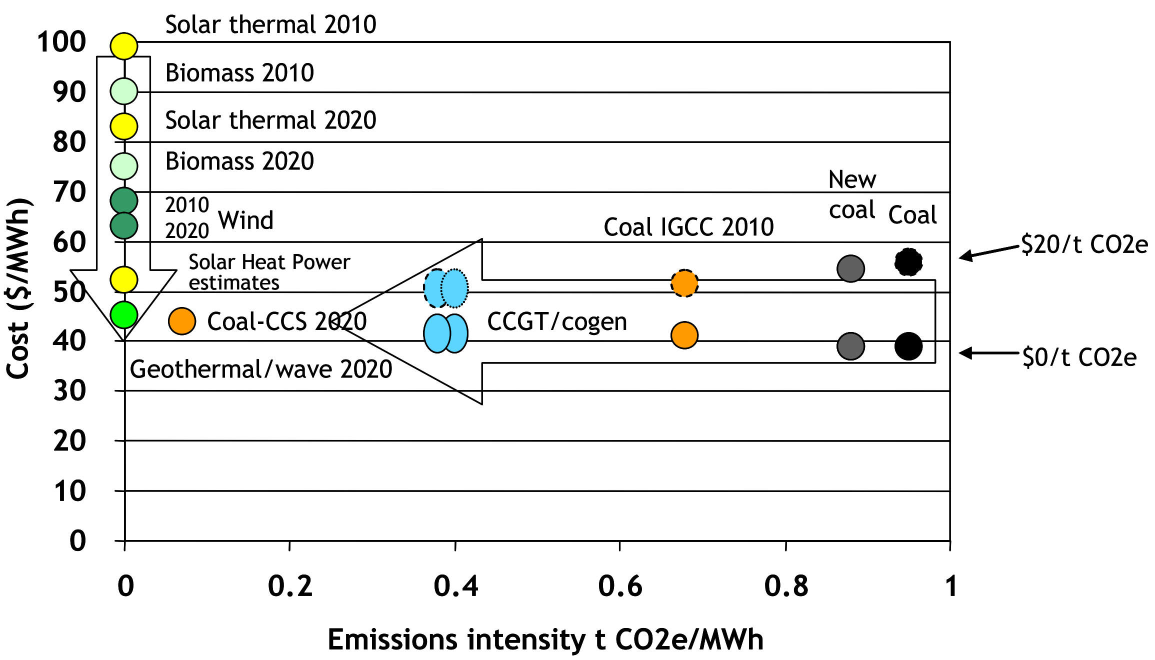
Summary of electricity abatement opportunities

The electricity sector has the most promising abatement potential of all the WA stationary energy sectors. Significant international commitment to research and development has resulted in a number of rapidly emerging low emission technologies which are increasingly cost effective.

The following graph of electricity costs and emissions clearly shows:

- the anticipated trends in diminishing costs of renewable energy technologies, and
- the decreasing emission intensities of fossil fuel technologies.

Costs and emissions of electricity in WA



The ABARE projections assume that the currently anticipated technological and economic trends are not likely to be delivered as the implied greenhouse intensity of electricity supply continues to be high under through 2030, reflecting current technology.

By 2020 extremely low emission technologies such as IGCC with CCS and advanced renewable energy technologies such as geothermal and wave power will be competitive with current high intensity coal and OCGT fossil fuel technologies, providing significant opportunities for emission abatement.

Even at relatively low levels, a carbon price signal will provide a clear advantage for investment in lower emission technologies in 2010 including:

- closed cycle gas over new coal generation,
- the early retirement of existing inefficient open cycle gas and replacement with closed cycle technology, and
- new gas technology instead of refurbishment of existing coal generators.

If additional demand can be constrained sufficiently, then it will be possible to postpone additional network capacity until these low emission technologies are available.

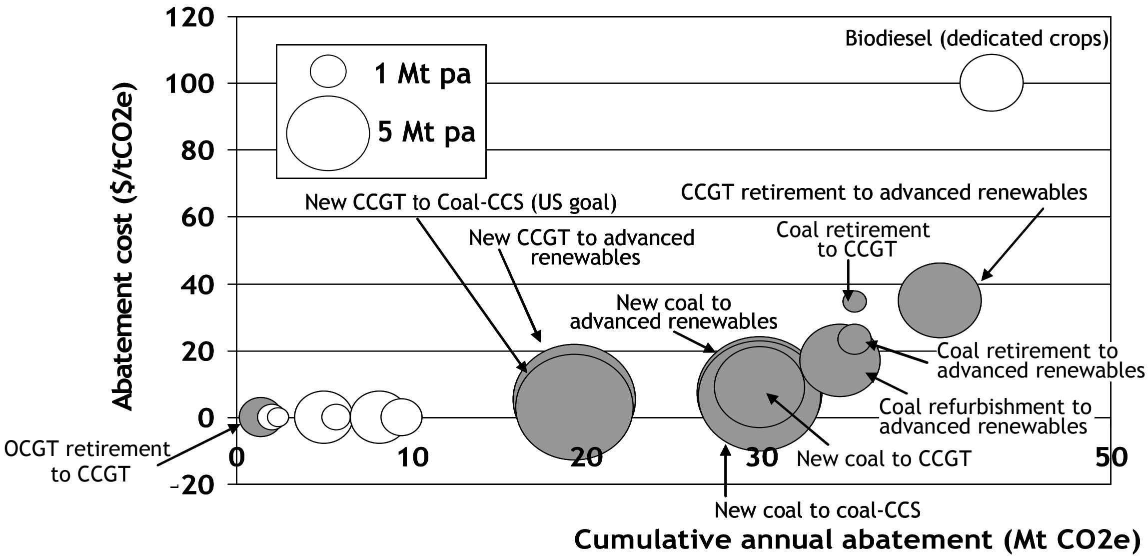
The key abatement opportunities in the electricity generation sector are:

- Replacing existing open cycle gas electricity generation with combined cycle gas technology
- Replacing new coal under the ABARE scenario with coal with retrofit capacity or renewable

energy such as geothermal, wind or solar thermal.

- Replacing new combined cycle gas electricity generation with geothermal or wave technology (or alternatively with advanced coal with carbon capture and storage)
- Retiring existing coal electricity generation early and replacing with combined cycle gas technology
- Retiring existing combined cycle gas electricity generation early and replacing with geothermal or wave technology (or alternatively with advanced coal with carbon capture and storage).

2030 abatement curve with highlighted electricity generation options



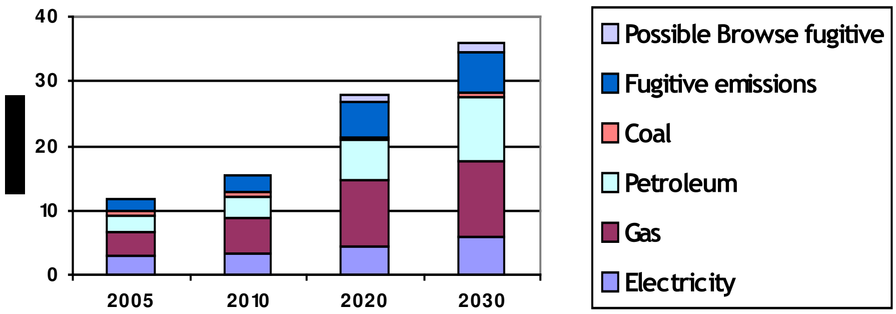
Mining

Western Australia's mining sector accounts for around 10 mtpa of combustion emissions, or around a quarter total stationary energy emissions. Stationary energy use in mining includes such diverse activities as producing, processing and liquefying LNG; operating trucks, loaders and other mobile equipment at surface and underground mines; and processing ore, using electricity generated on-site or remotely.

Western Australia's mining sector is growing rapidly, driven by a host of major development projects in LNG, iron ore, alumina, and other resources. Under the ABARE scenario, energy use and emissions would rise faster in mining than in the state overall, increasing about three-fold by 2030. The rate of increase is much faster than for the state overall, and the mining sector's share of state-wide stationary emissions would increase to about 40%.

The figure below shows the projected increase in stationary energy emissions in the mining sector. Also shown are fugitive emissions associated with production of natural gas, a central consideration in the expansion of the LNG sub-sector, as discussed below.

ABARE scenario of WA mining sector emissions by fuel source



Source: ABARE (2006)

Liquefied Natural Gas (LNG)

The rapid growth of LNG plays a significant role in the mining sector's anticipated emissions increase. Given the small number of very large projects (both in terms of value and emissions), a focus on the LNG sub-sector appears warranted.

WA plays a leading role in the rapidly expanding global LNG trade. LNG delivers lower cost energy than petroleum, and lower emissions intensity than either coal or petroleum. While long term LNG supply is potentially very large, rapidly increasing demand could to lead to tight or short supplies in the medium term from 2008.[141,142]

Contributing to global demand growth which has largely been driven by Asia, US LNG imports are expected to increase from about 11 mtpa in 2003 to some 65 mtpa by 2015 and 90 mtpa by 2030.[143] The estimated 2004 value of LNG exports was about $280 / t[144], and has increased subsequently

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141 ABARE "Asia Pacific LNG Market" in Australian Commodities, vol 12 no 2, June quarter 2005.

142 Woodside Petroleum "Investing in Growth" 8 August 2005.

143 US Department of Energy Energy Information Administration "Annual Energy Outlook 2006," p. 86. and US DOE/EIA"The Global LNG Market: Status and Outlook" December 2003, pp. 25, 29.

144 Dept of Industry, Tourism and Resources "Australian LNG-Clean Energy for a Secure Future" 2005, p. 8, 11.

with rising petroleum prices. LNG prices are above historical levels, consistent with the increases in oil market prices upon which they are often based.

Stationary energy emissions from LNG production primarily arise from the combustion of natural gas in turbines supplying mechanical and electrical power for producing, processing, refrigerating and compressing the LNG. The natural gas used in production is substantial, for example, representing about 15% of the LNG produced in 2005. In addition to stationary energy emissions, LNG production also releases fugitive emissions from venting of CO2 contained within the field gas, and from flaring.[145]

The North West Shelf project is the largest single source of stationary energy emissions in Western Australia. It comprises four operating LNG trains, and was the only Australian LNG facility operating in 2005.[146] A fifth NWS train is under construction, which will add about 4.2 mtpa bringing total production to nearly 16 mtpa when completed in 2008. In total, the five NWS trains will emit about 5 mtpa from gas combustion, or about 10% of Western Australia's total stationary energy emissions.

Two LNG projects, Gorgon and Pluto, are currently seeking environmental approvals. Pluto, with a gas field discovered in 2005, would produce 5 to 7 mtpa when fully operational by 2012. Gorgon would produce some 10 mtpa of LNG when fully operational by 2015. The Gorgon field has relatively high carbon dioxide content, comprising about 14% of the gas[147], or about 6 times higher than found in the NWS. If this field CO2 were vented, the emissions intensity of Gorgon would be significantly higher than that of the NWS project. The Gorgon project proposes to explore geosequestration through capture and reinjection of about 80% of the CO2, however, rather than venting. While the technology outlook is positive, it is not assured and no commitment has been made. If Gorgon was developed without geosequestration, Gorgon's total emissions intensity (including stationary energy and fugitive) would increase from about 0.35 to about 0.55 t CO2/t LNG. Browse field also has high CO2 content.

As with other resource sector projects, the timing of new LNG projects is necessarily uncertain, and subject to global market conditions. LNG prices have attained levels higher than the historic average, and higher than generally predicted. Accordingly, commercial development opportunities are likely to be greater than previously anticipated, with an opportunity to accelerate development projects. For example, it is notable that the Pluto project is based on a field that was discovered only in 2005.

[145] While beyond the specific brief of this report, fugitive emissions management is essential to LNG sector policies, so fugitive emissions are also estimated here for context.

[146] The Darwin LNG project in the Northern Territory was commissioned in early 2006.

[147] Gorgon DEIS p. Chapter 1, p. 11.

LNG projects under consideration (including Browse and Pilbara)

Project	**Start date**	**Capacity (mtpa)**
NWS Trains I to III, pre-expansion & process upgrades[148]	from 1989	7.5
NWS after process upgrades and Train IV[149]	2004	11.7
NWS after process upgrades and Trains IV and V[150]	2008	15.9
Pluto[151, 152]	by 2012; Environmental approval for land-based facilities; Environmental approval to be sought by end of 2006 for overall project	5-7
Gorgon[153, 154]	by 2015, proposed	10
Browse	by 2015, proposed	7- 14[155]
Pilbara[156, 157]	by 2020, pre-feasibility study ongoing. DOIR indicates production start by early 2011.	6
Unspecified other at Gorgon, NWS, Browse	by 2030	10
Total		53[158]

148 EPA 1999, p28. Estimates assume all emissions attributable to LNG processing (i.e., not the associated propane and butane production). Does not include emissions and energy use associated with gas production (as opposed to LNG processing and liquefaction), which may be about 3% of gas produced, (GWA, p. 18).

149 EPA 1999, p28.

150 EPA 1999, p28.

151 Woodside Petroleum "Investing in Growth" 8 August 2005.

152 DOIR "Prospect" March-May 2006, p. 39.

153 Gorgon DEIS, p. 609.

154 Department of Environment and Heritage Australian Greenhouse Office, "Greenfields Site Gorgon Australian LNG" 9 March 2005. www.greenhouse.gov.au/challenge/members/success-stories/chevron.html - Note that this indicates emissions of .81 t co2/t LNG, and assumes no geoseq.

155 DOIR "Prospect" March-May 2006, p. 39; could be up to 14 mtpa.

156 BHPBilliton "Pilbara LNG Newsletter" Issue 5 March 2006.

157 DOIR "Prospect" March-May 2006, p. 39.

158 ABARE WA 2030

Emissions reduction opportunities relative to the ABARE scenario

Emissions from the LNG industry are likely to increase substantially under any plausible scenario, given large anticipated increases in production of this valuable commodity. However, there are likely to be significant opportunities for reducing emissions intensity, and reducing the rate of growth. While the actual opportunities are site specific and subject to the detailed analyses of project owners/proponents, some prospective areas appear as follows:

- Ensuring the general uptake of current and emerging state of the art technologies
- Using combined cycle gas turbines and cogeneration for electricity and drives
- Geosequestration of CO2 field gas
- Deferring development of high CO2 content fields if no geosequestered.

It should be noted that LNG-related energy and stationary emissions are not separately modelled or reported by ABARE in developing its scenario. Rather, the modelling approach aggregates LNG with all other mining activities. Accordingly, the implied technology attributes and further emissions abatement opportunities are not readily discernible. ABARE indicates that the initial technology productivity is broadly consistent with current LNG development plans (for example, consistent with the recent upgrades of NWS I-III, and the development of NWS IV and V and the proposed Gorgon development). Some of these may be partly included in the ABARE scenario, including opportunities which are not assured

Cost and abatement characteristics

	2010		2020		2030	
	Mtpa	**$/t**	**Mtpa**	**$/t**	**Mtpa**	**$/t**
Ensuring uptake of the current and emerging state of the art, generally			partly included below		partly included below	
Use high efficiency combined cycle gas turbines (partly included in ABARE scenario)	0	0	4 to 5	$<0	5	<$0
Geosequestration of CO2 field gas (partly included in ABARE scenario)	0	<$10	2 to 4[159]	$4 to $20	2.4 to 5	<$4 to $20
Defer development of high CO2 content fields	0	$0 to >$100	3 to 4	$0 to >$100	3 to 4	>$100

Ensuring uptake of the current and emerging state of the art

The emissions intensity (as measured in t CO2e / t LNG) appears set to decline significantly under likely conditions. Overall, the LNG supply technology has improved significantly since first introduced in the 1960s, delivering rapid efficiency and productivity. According to the Gas Technology Institute, liquefaction costs have decreased by nearly 50 percent over the past decade, an average of about 7% per year.[160,161] Technological improvements delivering productivity and efficiency gains include:[162,163]

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159 These include the 2 mtpa initial target for reinjection at the Gorgon project that has already been accounted for in the base scenario. I.e., the additional reduction opportunity is 0.4 to 2 mtpa in 2020 and 0.4 to 3 mtpa in 2030.

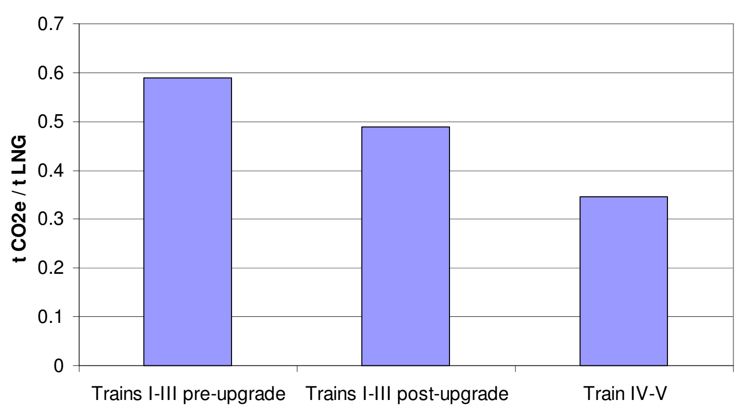
160 US Department of Energy Energy Information Administration “The Global Liquefied Natural Gas

- increased plant sizes, delivering economies of scale,
- improved refrigerants,
- improved processes with more thermodynamically efficient chaining of refrigerants,
- higher efficiency gas turbines and compressors,
- effective process heat recovery and cogeneration, and
- geosequestration through CO2 capture and re-injection.

While the industry focus has been on overall productivity and commerciality, a key driver has been improved energy efficiency, and some projects have been focused specifically on greenhouse emissions reductions even when not clearly commercially required. Technology improvements in each of the areas listed above continue to emerge.[164]

Technological advances in the international LNG industry are being applied in both existing and new LNG projects in WA. For example, de-bottlenecking and process improvements of the NWS LNG trains I – III reduced greenhouse emissions intensity from about 0.59 to 0.49 t CO2e per t of LNG, an improvement of about 20%. Despite the substantial improvements at those trains, trains IV (commissioned in 2004) and V (under construction) were expected to deliver an additional 30% reduction in emissions intensity.[165]

Improvements in NWS emission intensity



Market: Status and Outlook" December 2003.

161 Gas Technology Institute "The Globalization of LNG Supplies and Markets" Colleen Taylor Sen.

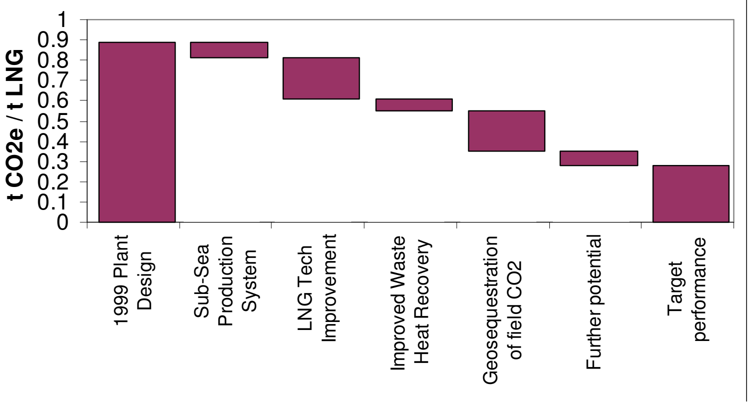
162 US Department of Energy Energy Information Administration "The Global Liquefied Natural Gas Market: Status and Outlook" December 2003.

163 ConocoPhilips, "Benefits of Integrating NGL Extraction and LNG Liquefaction Technology" 2005

164 See, for example, ConocoPhilips & Bechtel "Lowering LNG unit costs through large and efficient LNG liquefaction trains – What is the optimal train size?" April 2005.

165 Gorgon DEIS 2005. Includes stationary and fugitive LNG processing emissions, but not emissions from gas production.

Gorgon emission intensity improvement relative to 1999 design



Similarly, the proposed Gorgon development demonstrates the trend of improved greenhouse and energy efficiency in LNG production. In the few years between concept proposal in 1999 and submittal of environmental approvals, a number of significant technology enhancements become viewed as sufficiently demonstrated and commercially sound to warrant investment.

In total, these are estimated to deliver improved greenhouse efficiency of at least 60%. Slightly over half of this improvement results from energy efficiency gains, with the remainder from planned capture and geosequestration of the field's CO2. Additional targeted improvements are prospective that would further reduce emissions intensity by a further 20%.[166]

In general, technology improvements delivering energy and greenhouse intensity reductions of about 5% to 10% per annum have emerged over the past decades. While this pace of improvement may not be sustainable, substantial ongoing gains would appear likely. For example, the Snohvit LNG project appears to have a greenhouse intensity target of about 7% below the target performance for Gorgon, even after accounting for Snohvit's more favourable ambient conditions.[167] By far the largest use of stationary energy in LNG production, and an area which appears to present the most significant reduction opportunities, is in the turbines used to provide process power and electricity.

Substantial advances have been made in turbine performance, with net turbine efficiencies of about 50% in commercial applications when deployed in combined cycle systems. NWS uses a simple cycle turbine systems for power generation, with efficiencies between 23 and 33%. The Gorgon joint venturers have commissioned a power generation optimisation study that is investigating more efficient turbines and heat recovery relative to the currently assumed approach, which is viewed as a 'high emissions case' scenario.[168] In particular, the power generation assumed in the Gorgon DEIS would deliver efficiency of about 28%[169], far below the nearly 50% efficiency achievable in combined cycle gas turbines. In part this is due to the assumed use of exhaust heat in the CO2 separation process. Whether a more thermally efficient design is possible is under investigation.

[166] Gorgon DEIS, p. 604.

[167] Gorgon DEIS, p. 619.

[168] Gorgon DEIS p. 611, 612.

[169] Gorgon DEIS, p. 612 indicates electrical load of 270 MW with fuel use of 3433 GJ/h.

(a) Using CCGT and cogeneration for electricity and drives

The large majority of stationary energy emissions in LNG production are generated in the fuelling of turbines supplying mechanical and electrical power.

Advanced power systems using aeroderivative turbines and combined cycle steam turbines are increasingly being adopted in electricity generation sector as standard commercial technology. These currently have net efficiency of around 50%, about double that found in the turbines used at NWS and initially considered for the proposed Gorgon development.

Advanced combined cycle gas turbine systems are commercially mature and available, with a continuing trend of improving performance in power generation. However, they are not the norm in LNG production.

CCGT systems have perhaps 60% higher capital cost than simple cycle turbines. However, the much higher fuel efficiency should offset the higher capital cost in LNG production unless the value attributed to the fuel used is very low.

Each LNG development is comprised of a complex array of processes, systems and devices, the selection of which is made on the basis of site conditions, field characteristics, engineering, commercial, economic, and market factors. CCGTs offer potentially superior performance, but some increased risk, both to timing and performance. Technology choice is a complex commercial issue made by project developers that considers risks, cost, performance, market factors, timing, regulatory issues, and other factors.

There is potential for emission reductions of about 0.1 t CO_2 / t LNG produced using current technology, growing slightly as anticipated efficiency continues to increase over the coming decade.

If CCGT systems are suitable based on site specific conditions, the cost of abatement may be negative (ie. an economic benefit), unless fuel costs are substantially lower than for domestic gas pricing. With respect to retrofit to existing trains, economic deployment would involve deployment at a point consistent with the depreciation of existing generation assets.

The potential for deployment by 2010, 2020, 2030 depends upon detailed site and analyses and any estimate will require the actual costs and performance characteristics of commercial-in-confidence technology options. Notably, the original plans for expansion of NWS trains IV and V involved use of combined cycle gas turbines. The proposed Gorgon project is currently investigating more efficient thermodynamic operations than proposed in the current project plan.

If adopted at NWS, Gorgon and subsequent projects, could provide abatement of about 4 to 5 mtpa in 2020 and about 5 mtpa by 2030, depending on the rate of LNG project development.

Barriers to deployment include the relatively low commercial incentives, give the lack of greenhouse value and a possibly very low cost ascribed to fuel. Lack of precedent in LNG production. Unclear fit and flexibility with proposed project operations based on site-specific factors.

(b) Geosequestration of CO2 LNG field gas

There is a wide range of CO2 content in different gas fields. For example, NWS has about 2.5% CO2, whereas Gorgon has about 14% CO2. Field gas CO2 separated methane in LNG processing has typically been vented to the atmosphere. In contrast, geosequestration involves capture of the separated CO2, compression and transport to and injection into a suitable geologic storage site.

Geosequestration is planned as a central element of the Gorgon project, with an initial target of 80% of reservoir CO2 reinjected, rising to 95% under longer term targets. There is widespread interest in developing geosequestration, not just for LNG, but for any sites with high CO2 emissions, such as power plants.

Separating field gas CO_2 from methane is not only commercially mature, it is an essential step in LNG production. The technology involved in transporting and injecting CO_2 into geologic formations are also well understood and commercially available, including drilling and compression, and operating pipelines. CO_2 injection has been used in several locations globally, although typically to enhance the recovery in oil fields.

However, application of the technologies for long term, large-scale geosequestration has not been widely demonstrated. There are four sites globally where significant geosequestration volumes have been developed and two more under advanced planning including:

- Sleipner, Norway; since 1996; 3 ktpa.
- Weyburn, Canada; since 2000; 3-5 ktpa.
- In Salah, Algeria; since 1996; 3-4 ktpa.
- Snohvit, Norway; from 2006; 2 ktpa.
- Gorgon, Australia; from 2010; 10 ktpa.

While the technologies generally required for geosequestration are well demonstrated, experience with geosequestration on a significant scale should be expected to deliver significant improvements on current costs and productivity. Monitoring and verification protocols need development.

Cost and performance characteristics

Relatively detailed cost estimates have been produced for geosequestration at sites in Europe, the US and Australia.[170] The Australian analyses indicate costs varying from under $5 / ton CO_2 to over $35 / ton, depending on such factors as flow rates, geologic conditions, whether the storage site is on- or off-shore, and presence of other gases.

The geologic conditions around the Burrup peninsula have been identified as among the most technically and economically prospective in Australia. Because the underlying technologies used in geosequestration of an existing CO_2 stream are well understood, there appears to be using current technology has been estimated.

While geosequestration appears highly prospective, several risk factors have been identified that may reduce the attractiveness of any specific site. These include: the actual detailed geologic conditions of a site, which will determine storage capacity, injectivity, and effective containment over a suitably long term.

No particular concerns appear to have been identified beyond those generally applicable at mining facilities and major resource development projects.[171]

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[170] Bradshaw et al Australian Petroleum Cooperative Research Centre “The Potential for Geological sequestration of CO2 in Australia: Preliminary findings and implications for new gas field development” APPEA Journal 2002.

[171] See, for example, “Carbon Dioxide Capture and Geological Storage Australian Regulatory Guiding Principles” 2005 with respect to OHS.

Abatement potential and barriers to deployment

Both the Gorgon and the Browse projects have relatively high CO_2 content fields[172], and both are assumed to become operational beyond 2010. The planned initial 80% re-injection target for Gorgon project CO_2 represents about 2 Mt per annum, and is included in the ABARE-based scenario. Achieving the longer term 95% re-injection would achieve a further 0.4 Mt per annum.

Geosequestration of smaller volumes of CO2, for example, from NWS and other fields with lower CO_2 content could potentially further reduce emissions as well, although the lower volumes and scale economies would be accompanied by higher unit costs.

The use of geosequestration will cost more than not using it – re-injection of field CO_2 has clear economic costs, including those of building and operating additional compression facilities, the return CO_2 pipeline, re-injection wells and ongoing monitoring and verification activities. The biggest barrier to its widespread deployment is the current lack of commercial incentives or any price on carbon emissions.

Some regulatory and legal uncertainty may also require further development, particularly for geosequestration beyond that already covered by the Barrow Island Act regarding the Gorgon project, for example, regarding long term liability for storage performance.

Other uncertainties include:

- The integrity of actual long-term storage and the likelihood of migration and leakage,
- Actual costs and performance data due to commercial-in-confidence technology options,
- Rate of productivity and cost improvement with greater experience, and
- Applicability of cost reductions to lower volume projects (for example, for the 2.5% CO2 field gas of NWS).

Key references

Intergovernmental Panel on Climate Change “Special Report on Carbon Dioxide Capture and Storage” October 2005.

Gorgon Joint Venturers “Draft Environmental Impact Statement and Environmental Review and Management Plan” 2005.

US Department of Energy “Carbon Sequestration Technology Roadmap and Program Plan 2005”
Ministerial Council on Mineral and Petroleum Resources “Carbon Dioxide Capture and Geological Storage – Australian Regulatory Guiding Principles” 2005.

Various publications of the Cooperative Research Centre for Greenhouse Gas Technologies, CO2CRC.

[172] Gorgon Joint Venturers “Draft Environmental Impact Statement and Environmental Review and Management Plan” 2005.

(c) Deferring high CO2 content fields until CCS feasible

If geosequestration proves technically or commercially infeasible, an approach to emissions reduction may be to defer development to high-CO2 gas fields.

Such an approach is foreshadowed with respect to the proposed Gorgon development in the Barrow Island Act 2003. Specifically, the governing legislation specifies that should the detailed proposal not include geosequestration, the Minister may in effect reject the proposal.[173] Notably, the Gorgon project would draw on the Jansz field as well as on the Gorgon field, with a substantially lower CO2 content of under 1%.[174] Deferral would not foreclose the option of future development, but rather allow further time for technology improvements to make geosequestration commercially feasible.

From a global life cycle perspective, such an approach, should it prove necessary due to the infeasibility of geosequestration, might have an unintended consequence of increasing emissions. In particular, even with venting of relatively high CO2 content fields, the lower emissions intensity of gas-fired generation relative to coal-fired generation in state of the art electricity generation combined cycle plants would mean that the net emissions could be lower even without geosequestration.

Emissions and cost of abatement

The ABARE-based scenario assumes successful implementation of Gorgon project sequestration. However, if geosequestration does not prove feasible at the Gorgon and Browse projects, the emissions intensity at those projects will increase by about 0.2 t CO2 / t LNG.

Foregone development would result in an opportunity cost commensurate with a prospective project's earnings. This could be very low, if geosequestration technology advances rapidly allowing the project to proceed with limited delay. In the worst case, the cost could be high if geosequestration remains infeasible. Assuming earnings of $20 /t LNG, or about 5% of current price, the unit cost of abatement would be $100 / t CO2.

Assuming that feasible geosequestration technology does emerge in a timely fashion subsequent to deferral, the uptake could be similar to that for the geosequestration case discussed previously.

[173] Barrow Island Act 2003, Schedule 1, 7(4).

[174] Gorgon Ch 1, p. 11.

Other mining

With respect to non-LNG mining, two areas of opportunity are considered. These are:

- Use of higher efficiency electricity generation, and
- Use of biodiesel, for example, for mobile mining equipment.

Several mine sites in WA are remote and operate with dedicated electricity generation. While some use highly efficient technologies such as combined cycle gas turbines and cogeneration, there are a few low efficiency open cycle gas turbines that appear to be operating as base-load units. As the ABARE electricity projections do not distinguish between SWIS and other electricity generation, opportunities for emissions reduction with respect to these are discussed in the section on electricity.

(d) Biodiesel from biomass crops

With respect to the use of petroleum for mobile mining equipment and other stationary energy uses, it is notable that the ABARE scenario projects energy consumption to increase by about a factor of four by 2030. Large scale use of biodiesel as a substitute for petrodiesel appears technically feasible over the medium-term horizon. Biodiesel substitutes are not included in the ABARE scenario, in large part because the cost of production is well in excess of projected petroleum costs.

Technology overview

In most circumstances, biodiesel can be substituted for petrodiesel in either blends or pure form. The energy content of biodiesel is about 10% lower than petrodiesel, depending on the source, but engine performance does not appear to suffer otherwise, and may actually benefit from superior lubricity compared to low sulphur petrodiesel. Use of biodiesel in engines also reduces emissions of various pollutants including particulates and carbon monoxide relative to petrodiesel, although NOx levels increase.

Biodiesel is produced through the transestrification of an organically derived oil. This relatively straightforward process mixes oil with an alcohol and a catalyst. The resulting products are biodiesel, glycerine and waste meal, all of which have commercial value.

A small amount of biodiesel is currently produced in Australia, with about 4 ML in 2004/05 or about 2 PJ. Total production capacity was estimated at about 15 ML.[175] Several new processing plants are under development that are forecast to increase capacity to some 520 ML per year, or about 20 PJ pa. This includes a 45 ML pa biodiesel in Picton WA, which is at advanced commissioning stage.[176] being developed by Australian Renewable Fuels. The plants under development are to use waste vegetable oils and animal fats. These waste products often have relatively low cost, although total feedstock is limited. For example, the Picton plant, using tallow, will use the equivalent of about 50% of WA's production. [177] . Waste cooking oil may present another relatively low cost feedstock, although there is not currently a significant market, and transportation costs may be high. The total volume of waste cooking oil in Australia is uncertain, but availability has been estimated as sufficient to about has been estimated as potentially capable to supply about 100 ML pa.[178]

For biodiesel to be used on a widespread basis, it appears that dedicated biomass crops would be required. For context, the total production from the Picton plant, 45 ML pa, represents about 2 PJ pa, or about 2% of current Western Australian diesel consumption.

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[175] Biomass Task Force, p. 41.

[176] Australian Renewable Fuels ASX Release 23 May 2006.

[177] Australian Renewable Fuels Prospectus, 2005.

[178] CSIRO, ABARE, BTRE "Appropriateness of a 350 million litre biofuels target" December 2003.

Capital and non-feedstock operating costs for a 45 ML pa plant are estimated at about between 9 and 15 c/L.[179] The large majority of biodiesel cost is in the feedstock. The table below summarises a range of estimated costs for potentially large scale biodiesel production using biomass crops.

Estimated cost of biodiesel

	Waste oil	**Tallow**	**Canola or other vegetable oil**
Potential volume	~10 mL pa	~80 mL pa	~1 kL/ha pa
Feedstock cost	20c/L, based on $170/t feedstock	50c/L, based on $450/t feedstock	104c/L, based on $910/t
Chemicals	9c/L		
Glycerol revenue[180]	0 – 6 c/L		
Plant capital costs	5c/L based on $25m, 40 mLpa plant		
Other operating cost	5 – 10c/L		
Total cost	39 – 44 c/L	69 – 74 c/L	123 c/L

The economic attractiveness of biodiesel depends on fossil fuel prices. (It also depends heavily on tax treatment and other financial policies. The cost comparison provided here is exclusive of tax or other treatments). Notably, current diesel oil prices, not including tax, are about 74c/L.[181] However, a decline in petrol prices to from the current values of about $70 to the low $30s as assumed in the ABARE scenario over the intermediate term, would see diesel costs dropping below 40c/L, well below biodiesel costs. In addition to competing against petrodiesel, biodiesel from Australian feedstocks may need to compete with foreign biomass, such as palm oil. Extensive efforts are ongoing in Malaysia and elsewhere to expand palm oil production, with costs that are likely to remain lower than those of domestically produced oil from oilseed.

There are extensive efforts, both within WA and internationally, to improve yields from biomass crops, and to identify crops that are suitable for lower value land.[182] These could reduce feedstock costs considerably, but total costs would likely remain well above current petro-diesel prices. Supplying the projected 144 PJ of mining industry petroleum use in 2030 with a 20% biodiesel blend would require about 600 mL pa, the large majority of which would have to come from new sources such as biomass crops. With current oilseed yields, that would require a substantial land area of perhaps 0.6 million ha, or 8% of current agricultural land.

WA has established a Biofuels Taskforce that will address a broad array of relevant issues. It is due to report in February 2007.

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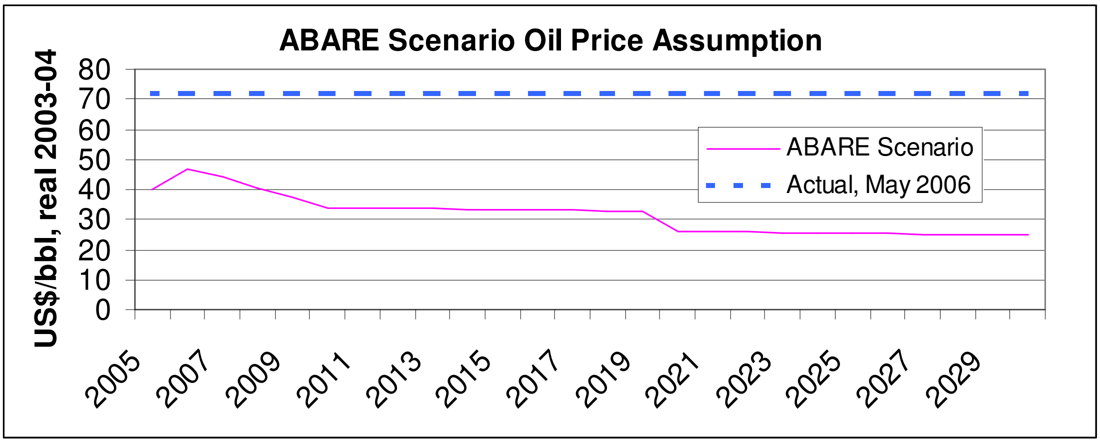
[179] CSIRO, ABARE, BTRE “Appropriateness of a 350 million litre biofuels target” December 2003.

[180] Estimated in the 2003 study at 6c/L, but dependent on developing new markets. Department of Agriculture and Food WA “Biodiesel Production and Economics” May 2006.

[181] Australian Institute of Petroleum “Diesel Prices Explained” http://www.aip.com.au/pricing/diesel.htm

[182] 2006 Oilseeds Updates Western Australia, papers presented 15-16 February 2006.



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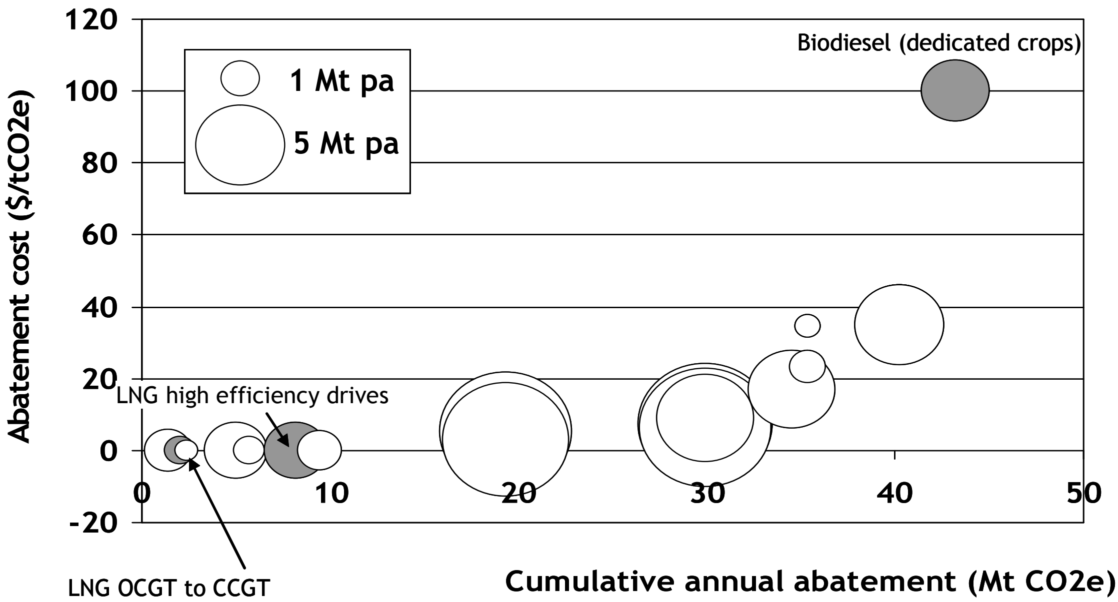
US Climate Technology Program (2005) *Technology Options for the Near and Long Term*, p.2.3.2 http://climatetechnology.gov/

Department of Agriculture and Food WA "Biodiesel Production and Economics" May 2006.

2030 abatement curve with highlight LNG and mining abatement options



Barriers to deployment in mining

Lack of clear economic incentives

While there are no clearly defined costs, such as would accompany an emissions trading regime or emissions charges, project proponents would be aware of the possibility of such costs emerging over the life of an LNG or other mining project. To the extent that such possibilities are viewed as plausible and likely, they present some form of economic incentive.

International project competitors without clear CO2 obligations

LNG and other resource development proposals in Australia must compete with international proposals in a global market. To the extent that these competing projects do not face CO2 obligations, adopting higher cost, lower emissions technologies to Australian proposals creates an element of competitive disadvantage. In a market environment of inadequate supply, as is anticipated over the medium term, this factor may be of relatively lesser significance.

Difficulty in benchmarking due to project-specific conditions

The cost and performance of resource projects globally can be relatively site specific, and vary due to conditions such as ambient temperature, ore quality, resource size and extraction rates, and for LNG. This variability complicates effective project benchmarking. For example, the benchmarking performed for the Gorgon project suggests that emissions could be about 25% lower for a project sourcing gas from a lower CO2 content gas field. Of the project's estimated 0.353 t CO2e / t LNG, about 0.03 t are due to the additional power required to remove the CO2 and compress it for reinjection, and 0.05 are due to residual CO2 venting.[183] Further, if sequestration is not successfully developed for Gorgon, venting of the CO2 would result in about a doubling of emissions intensity. coproduction such as domestic gas or LPG.

Economic deployment requires coordination with capital expenditure plans.

In general, delivering on mining sector opportunities involves major capital equipment and accordingly, would be most economic if implemented at the time of initial investment or major replacement or refurbishment. For mines with uncertain or short remaining lives, it may be difficult to justify capital costs for emissions abatement projects.

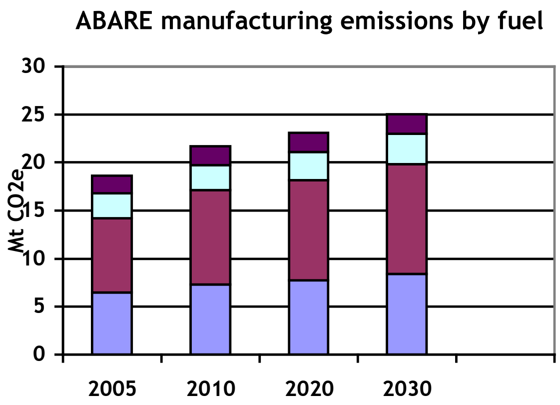
[183] Gorgon DEIS, p. 618.

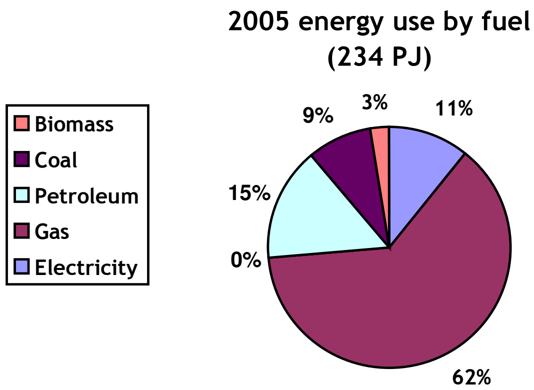
Manufacturing

Overview

Western Australia's manufacturing sector accounts for around 19 Mt each year, or 45%, of stationary energy emissions. The manufacturing sector is diverse, producing chemicals, food, wood and paper machinery and many other goods. Stationary energy is used in a range of applications, but the substantial majority is for electric motors, boilers and other thermal processes.

The manufacturing sector is growing, but far less rapidly than mining. Under the ABARE scenario, energy use and emissions increase by about one third, but the share of total emissions declines to 35%. The projected increase in stationary energy emissions under the current trajectory is et out in the following graph.





Opportunities for emissions reductions in the manufacturing sector appear to be substantial, primarily through improved energy efficiency in thermal and electrical processes, development of cogeneration to more efficiently supply the thermal requirements while generating electricity, and indirectly, as a result of reducing the emissions intensity of electricity supply.

The alumina industry presents an excellent example of the abatement opportunities for the manufacturing sector in electricity and thermal applications. If also merits particular focus due to its dominant position in WA's manufacturing energy use, accounting for about two thirds of the manufacturing sector's emissions. Furthermore, the industry is currently developing a series of plant upgrades that demonstrate the available opportunities.

Alumina

Western Australia is a world leader in alumina, with four refineries accounting for some 13% of world production in 2005. Consistent with their leading global role, Western Australia's four alumina refineries account for nearly 30% of total stationary energy emissions, or about 11 mtpa. Stationary energy use in alumina refining arises primarily from the use of coal or gas for thermal processes and electricity for pumps and motors.

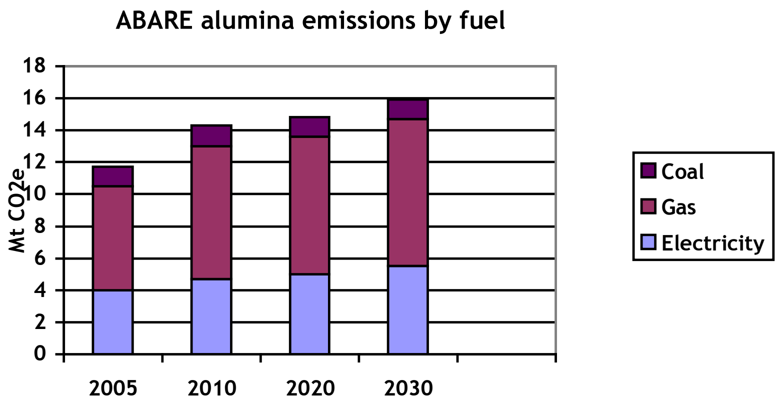
In brief, the alumina refining sector:

- accounts for nearly 30% of WA stationary energy emissions currently,
- accounts for about 65% of manufacturing sector emissions,
- has exceptionally good electricity cogeneration prospects due to high thermal needs, and
- is considering or undertaking several cogeneration and plant upgrade projects currently.

Energy accounts for about 23% of total Australian alumina production costs.[184] While the technology of alumina refining is mature, a long term trend of improvement in productivity generally, including energy productivity, is continuing. Major expansion projects under way or under consideration at three of the four refineries would increase production by about 43% to nearly 15 mtpa. Current capacity and expansion plans are shown in Box A-1. ABARE assumes a further 1 mtpa by 2030.[185] The three refinery upgrade projects would all deliver substantial productivity gains and reductions in energy intensity, as detailed below.

The three refinery upgrades simultaneously involve significant cogeneration projects as integral elements. Alumina refining requires extensive thermal energy and a relatively lesser amount of electricity, making it well suited to efficiently generate electricity for export to the power grid. All three refinery upgrade proposals would rely on gas rather than coal. Due to the low emissions intensity of gas relative to coal, this would deliver a reduction in emissions intensity. However, one proposal also includes a "worst case scenario" to use coal, should the gas option prove infeasible.186 The ultimate choice of fuel at that site would have an impact of 0.7 mtpa, due to the higher emissions intensity of coal relative to gas.[187]

The following graph summarises the emissions outlook based on the ABARE scenario. Overall, emissions intensity would increase by about 40%. Alumina refining would remain a large emissions source in WA, with 22% of total stationary energy emissions by 2030. The emissions scenario attributes state-wide average emissions intensity to the electricity used in alumina manufacture. ABARE's modelling and report do not indicate the extent to which high efficiency cogeneration is assumed to be developed in the alumina sector. Further, electricity sector emissions are not explicitly attributed to alumina production. Rather, the modelling approach includes cogeneration and other on-site generation with all other electricity generation.



Energy use under the ABARE scenario would increase by slightly less, based on very gradual energy productivity improvements of about 0.4% per annum.

Emissions reduction opportunities relative to the ABARE-based scenario

Emissions from the alumina industry are likely to increase, given the large increases in production to meet global demand. However, there are opportunities for reducing emissions intensity as measured in t CO_2 / t alumina, and reducing the rate of growth. These are not included in the ABARE scenario. Emissions reduction opportunities relative to the ABARE scenario are discussed here.

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[184] Australian Aluminium Council "Submission to the Productivity Commission Inquiry into Energy Efficiency" 2005, p 3.

[185] ABARE 2006, p. 5.

[186] "Worsley Alumina Pty Ltd Bauxite-Alumina Project Expansion Environmental Review and Management Programme" May 2005, p. 6, 7.

[187] Worlsey Alumina Bauxite-Alumina Project Expansion Environmental Review and Management Programme Executive Summary, p. 7.

These are:

- Cogeneration coupled with refinery productivity upgrades as currently proposed; and
- Improving the least efficient refinery's performance to match the current best performance.

Elements of the cogeneration and productivity opportunities to reduce emissions below the ABARE scenario are already underway. In particular, the first cogeneration unit associated with the Pinjarra refinery began operation in April 2006. The second cogeneration unit is under construction. Similarly, the Pinjarra refinery upgrades are currently under construction.

In summary, an indication of approximate costs and abatement characteristics is summarised in the following table. Also shown is an extrapolation of the abatement potential as estimated for the alumina sector to the remainder of the manufacturing industry, based on a broad assumption that opportunities would be similar.

	2010		**2020**		**2030**	
	Mtpa	**$/t**	**Mtpa**	**$/t**	**Mtpa**	**$/t**
Alumina plant performance upgrades coupled with gas-fuelled cogeneration, as currently proposed	2.4	<0	2.5	<0	2.6	<0
Improving the least efficient alumina refinery's performance to match the current best performance	0.7	<0	0.7	<0	0.7	<0
Extrapolating alumina refinery abatement to the rest of manufacturing sector	1	<$0	1.2	<$0	1.3	<$0

(a) Alumina cogeneration coupled with plant upgrades

Three of WA's four alumina refineries are undergoing or proposing significant cogeneration and plant productivity upgrades incorporating a range of enhancements, as summarized in the table below. Further enhancements, notably including a cogeneration project are under consideration for the fourth refinery as well.[188] The three refinery upgrades would result in substantially increased production, but with a decline in emissions intensity. The ABARE scenario does not incorporate these planned productivity improvements, and does not include a commensurate reduction in emissions intensity over the next few years.[189]

The plant upgrades and cogeneration projects rely on demonstrated technology and appear to pose no particular technical or other challenges. Each of the proposed refinery upgrade projects is anticipated to improve the commercial performance, while simultaneously reducing greenhouse emissions intensity. Accordingly, the net cost of abatement relative to historic emissions intensity can be viewed as negative, and a beneficial byproduct.

A number of OHSE attributes have been identified by the project proponents in the course of gaining governmental approvals. None were viewed by the proponents and by the Environmental

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[188] Kwinana Environmental Improvement Plan 2006-07.

[189] Personal communication with ABARE 2006 report author.

Protection Authority as raising undue challenges. Some elements of the upgrades were identified as delivering superior environmental outcomes other, for example, with respect to certain local air emissions.

In estimating abatement potential, Pinjarra, Wagerup and Worseley refineries are all assumed to successfully implement their proposed productivity and efficiency upgrades using natural gas, unless otherwise noted, and Kwinana is assumed to achieve similar performance improvement following its current review. While the upgrades have an additional benefit of reducing the emissions intensity of electricity generation, the estimates presented here are intended to represent only the abatement resulting from improved thermal energy supply to the refineries, and more efficient utilization. This assignment of emissions, and abatement, to steam and electricity is consistent with the basis of calculation used for the Pinjarra cogeneration plant.[190] In brief, this involves attributing the emissions intensity of a CCGT to the electricity portion of the cogeneration plant, with the remainder allocated to the thermal portion. This allows for consistent treatment of cogeneration and CCGTs with respect to estimating the emissions abatement opportunities in electricity generation, and avoids double counting of abatement.

Opportunities are project and site specific, and while the general direction appears clear, actual outcomes depend on detailed development by the affected companies.

Proposed cogeneration and productivity upgrades

Refinery	Pinjarra[191]	Worsley	Wagerup
Pre-upgrade production, mtpa	3.5[192]	3.25	2.4[193]
Proposed production, mtpa	4.2	4.4	4.7
Status	Efficiency upgrade under construction; 1st of 2 associated Alinta gas cogeneration units operational as of April 2006	In development	In development
Key productivity technologies expected to reduce energy and greenhouse intensity	Various 'best practice' energy efficient processes, including: - Higher efficiency steam generation from new cogeneration facility; - Higher alumina yield filtration facility - Reuse of steam from digestion - Upgraded heat exchange process[194]	Higher efficiency steam generation from new gas-fired cogeneration facility. Other opportunities are under consideration, but not planned, in similar areas currently being implemented at Pinjarra	Various 'best practice' energy efficient processes, including[195]: - High efficiency cogeneration of steam and electricity - Improvements in the seed filtration process; - Enhanced causticisation for efficiency of refinery liquor stream

Pre-upgrade emissions intensity, t CO2 / t alumina	0.656	=2.614[196] / 3.25 = 0.80	0.56
Pre-upgrade energy intensity, Gj / t alumina	10.6[197]	12.3[198]	9.2[199]
Planned improvement in energy or greenhouse productivity, %	14%[200]	~0% (coal cogen) 21% (gas cogen	15% (with cogen) 5% (with boilers)[201]
Planned emissions intensity, t CO2 / t alumina	0.56[202]	= 3.49 / 4.4 = .79 (coal cogen) = 2.79 / 4.4 = .63 (gas cogen)	0.48 (with cogen) 0.54 (with boilers
Planned energy intensity, Gj / t alumina	9.2	10.83[203] (coal cogen) 9.8 (gas cogen)	7.7 (with cogen) 8.8 (with boilers)

(b) Improving to match current best performance

The alumina industry, working with US and Australian governments to develop an industry roadmap, have identified and detailed prospective technology opportunities in a wide range of process management and control systems, in recovery of waste heat cogeneration, and a host of other

190 Pinjarra Cogeneration Plant Unit #1 Greenhouse Gas Emissions Management Plan Sept 2003.

191 « Environmental Protection Statement Pinjarra Refinery Efficiency Upgrade, December 2003 ; and Alcoa, Pinjarra Environmental Improvement Plan 2006-07, April 2006.

192 EPS, Table 13.

193 Capacity of 2.6 Mtpa, but limited by licensing to Mtpa. "ERMP Wagerup Refinery Unit Three" May 2005, p. xii.

194 Alcoa, Pinjarra Environmental Improvement Plan 2006-07, April 2006; p 18.

195 Wagerup ERMP, p. 80.

196 Proposed New Gas Cogeneration Facility Worsley Pty Ltd,

197 Based on full fuel cycle emission factor for gas of 61.6 t CO2 / GJ, as used in EPS. Note that natural gas constitutes 99.5% of Pinjarra emissions.

198 Estimated by Next Energy from Worsley Cogen applications.

199 Wagerup ERMP, p. 339.

200 EPS, p. 25.

201 Wagerup ERMP, p. 340.

202 EPS, Table 13. Includes savings from higher efficiency steam production of Alinta cogen Project

203 Worsley , Chapter 2.2.4, Table 2.10

areas.[204] Overall, the industry has identified an objective for the take-up of existing best practice and emerging technologies to deliver the following:

- 25% reduction in energy use per unit of production relative to current best practice (i.e., beyond the gains from simply moving from typical performance to best practice);
- improved productivity and product performance; reduced capital and operating costs; and
- improved overall environment, health and safety performance.[205]

Consistent with the differences in refinery histories, site specific attributes, and current plans, there appears to be a significant difference in anticipated emissions intensity amongst the alumina plants following the upgrades, with the lowest about 24% below the highest. Such differences may relate to a variety of site specific factors such as the quality of bauxite ore, but also depends on plant age, original design, and refurbishment steps taken.

This abatement measure assumes that over time and consistent with other refurbishment activities, the refinery with the highest apparent emissions intensity is upgraded to achieve an emissions intensity consistent with that of the lowest. That appears reasonable, particularly as that current plans include considering a variety of measures being implement at other refineries, as discussed above. It does not assume that the industry's aspirations for further performance improvement are achieved.

Actual opportunities may differ significantly from plant to plant. However, as an initial assumption, it appears reasonable to assume that efficiency opportunities are broadly similar between the four Australian refineries, and that similar performance should be achievable in a commercially sound fashion.

(c) Abatement in other manufacturing

Each industry, and indeed, each plant is distinct, with unique opportunities and constraints related to improving emissions performance. For the purposes of this assessment, it is assumed that other manufacturing sub-sectors are able to achieve similar outcomes to those assessed for alumina.

With respect to prospects for plant efficiency upgrades, and specifically with respect to cogeneration, a number of non-alumina projects have been developed to date. These are listed in the following table.

Current cogeneration projects in WA

Station	Owner	Fuel	Capacity (MW)
Cawse Nickel Mine	AGL (Cawse) Power	Gas	16.5
Kwinana	Perth Power Partnership	Gas	120
SWJV	South-West Joint Venture	Gas	120
Wagerup	Alcoa	Gas	98
Pinjarra	Alcoa	Gas	95
Kwinana	Alcoa	Gas	61
Kwinana Tiwest	Western Power	Gas	36

[204] See "Alumina Technology Roadmap", produced jointly by the aluminium industry, the US Department of Energy Office of Industrial Technologies, and the Australian Department of Industry, Science and Resources Energy Efficiency Best Practice Program.

[205] Alumina Technology Roadmap, p. 3.

Kalgoorlie Nickel Smelter	Southern Cross Energy	Gas	38
Kambalda Nickel Operations	Southern Cross Energy	Gas	38
Leonora, Murrin Murrin Nickel Mine	Minara Resources	Gas	76
Wagerup Bauxite Mine	Alcoa	Gas	98
Worsley	Worsley Alumina	Coal	120
Kununurra	CJ Ord River Sugar	Bagasse	6
Total			922.5

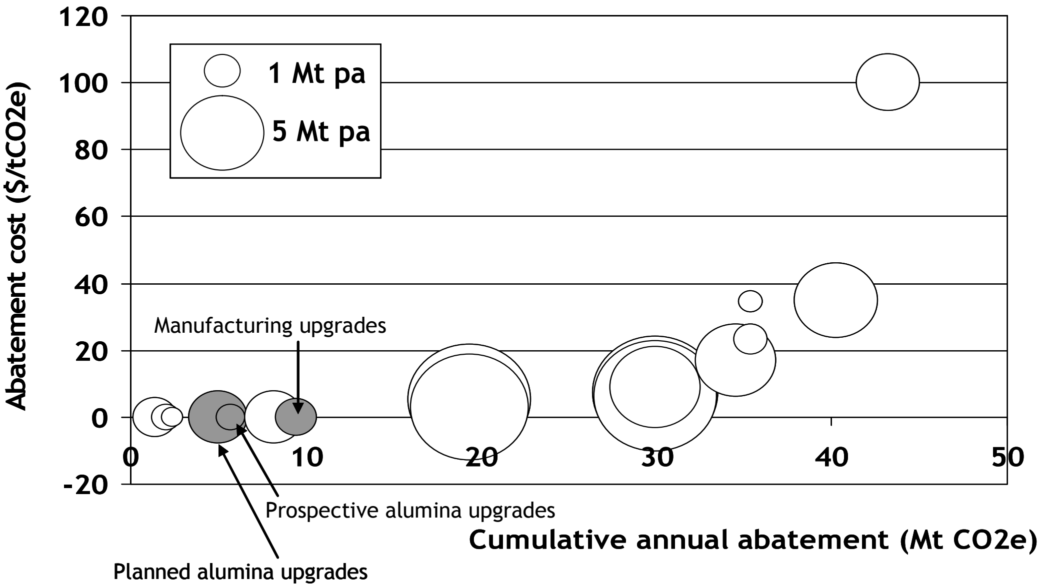
Source: Office of Energy

As with alumina, the potential abatement estimated here does not include the reduction in emissions intensity of electricity generation. Rather, that opportunity is incorporated into abatement estimates shown in the electricity sector.

The estimated abatement opportunity presented here is intended to reflect the improvement in supply and efficient use of thermal energy associated with the cogeneration and other plant upgrades. While the upgrades have an additional benefit of reducing the emissions intensity of electricity generation, the estimates presented here are intended to represent only the abatement resulting from improved thermal energy supply to the refineries, and more efficient utilization.

This assignment of emissions, and abatement, to steam and electricity is consistent with the basis of calculation used for the Pinjarra cogeneration plant.[206] In brief, this involves attributing the emissions intensity of a CCGT to the electricity portion of the cogeneration plant, with the remainder allocated to the thermal portion. This allows for consistent treatment of cogeneration and CCGTs with respect to estimating the emissions abatement opportunities in electricity generation, and avoids double counting of abatement.

2030 abatement curve with highlighted alumina and manufacturing options



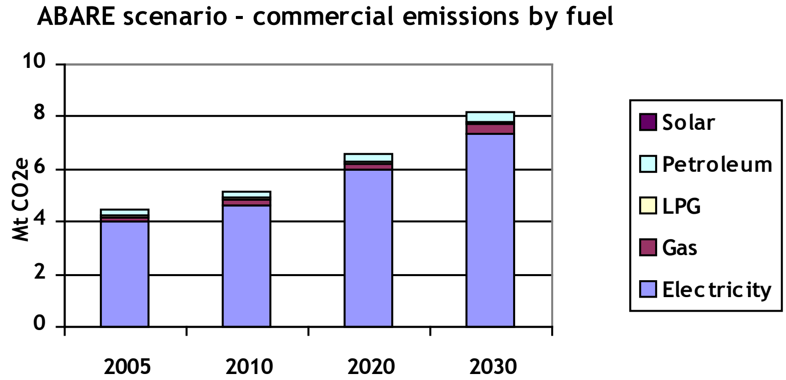
[206] Pinjarra Cogeneration Plant Unit #1 Greenhouse Gas Emissions Management Plan September 2003.

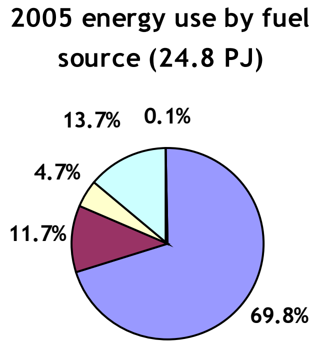
Commercial and institutional

Sector overview

The commercial and institutional sector includes office buildings, restaurants, sporting facilities, accommodation, hospitals, government and community services. Commercial applications, typically but not exclusively, are based on energy use in buildings – for lighting, water heating, space heating and cooling and appliances.

According to ABARE, in 2005 the WA commercial sector was responsible for 4.5 MT of stationary energy emissions, over 90% of which was from electricity use. Less greenhouse intensive use of gas, LPG and other petroleum account for fewer emissions (around 9%), but around 30% of energy use in the sector.





With such a high proportion of emissions from electricity, the most significant opportunities for reducing emissions in this sector will be from the deployment of lower emission technologies in electricity generation, as discussed earlier in this report. There is some opportunity for greater deployment of cogeneration and use of grid-integrated rooftop solar photovoltaic systems, however their economic potential will need to be assessed against the costs and performance of a range of electricity generation technologies.

With a contestable energy market, electricity tariffs range considerably. In WA, electricity prices are estimated to be between $15.16c/kWh and $17.47c/kWh for commercial and industrial customers on continuous load tariff, and as low as $5.29c/kW for off peak and as high as $58.31c/kW for demand charge.

(a) Cogeneration and fuel cells

The technology

Cogeneration (or combined heat and power - CHP) is the simultaneous production of heat (thermal energy) and power (electricity) in the one energy conversion process - reducing energy costs and providing heat or steam, which can be used for domestic, commercial or industrial use. Cogeneration increases overall energy conversion efficiencies up to 80% (if all usable heat is recovered) compared to the current WA average of 34% for coal fired power[207].

The most favourable conditions are a high and fairly constant thermal load with a high number of annual operating hours. Thermal energy use in the commercial sector accounted for around a quarter of commercial sector energy use and consists primarily of energy used for water heating,

[207] As calculated from ABARE (2006) data

space heating and cooling. According to research undertaken for the Australian Greenhouse Office, Currently this thermal demand is met through a mix of gas (around two thirds of energy requirements) and electricity use.

If a co-generation system is well matched to plant requirements for power and heat, then significant economic returns can be achieved.

There are a range of commercially available and established cogeneration technologies including: reciprocating gas or diesel engines, gas turbines, and steam turbines. Fuel cells on are on the verge of commercialisation and has the potential to expand the range of sites for which cogeneration is applicable.

Summary of typical cost and performance characteristics by CHP technology type[208]

Technology	Steam turbine	Diesel engine	Gas engine	Gas turbine	Micro-turbine	Fuel cell
Power efficiency	15-38%	27-45%	22-40%	22-36%	18-27%	30-63%
Overall efficiency	80%	70-80%	70-80%	70-75%	65-75%	65-80%
Typical capacity (MWe)	0.2-800	0.03-5	0.05-5	1-500	0.03-0.35	0.01-2
Installed costs (A$/kWe)	400-1200	1200-2000	1200-2000	1100-2400	1700-3300	3600-7100
O&M costs (A$/kWhe)	<5.3	7-20	9-27	4-13	13	7-50
Availability near	100%	90-95%	92-97%	90-98%	90-98%	>95%
Start-up time	1 hr - 1 day	10 sec	10 sec	10 min - 1 hr	60 sec	3 hrs - 2 days
Fuels	all	diesel, residual oil	gas, biogas, propane, landfill gas	gas, oil biogas, propane	gas, oil, biogas, propane	hydrogen, gas, propane, methanol
Noise	high	high	high	moderate	moderate	low
Uses for thermal output	LP-HP steam	hot water, LP steam	hot water, LP steam	heat, hot water, LP-HP steam	heat, hot water, LP steam	hot water, LP-HP steam
Power density (kW/m2)	>100	35-50	35-50	20-500	5-70	5-20

Typical cogeneration applications in the commercial and institutional sector include[209]: hospitals, large manufacturing facilities, and leisure centres. The primary fuel used in these facilities is natural gas, however there are also applications which use coal, process by-products, wastewater and landfill gas.

[208] Adapted from US EPA (2002) Catalogue of CHP technologies, US$ converted to A$ at exchange rate of 0.75 (all in 2000$).

[209] California Energy Commission (2005) *Assessment of California CHP market and options for increased penetration* Report prepared for California Energy Commissions by Electric Power Research Institute

The heating/cooling and power requirements of hospitals, hotels, institutions, commercial buildings, swimming complexes, computer centres, etc. can be provided economically by a cogeneration systems.

The existing market penetration of cogeneration in the commercial sector is low, and much lower than the industrial sector (a recent US study estimated that penetration in the industrial sector is nine times that in the commercial sector)[210]. Unlike the industrial sector which has large demand for thermal energy, the commercial sector capacity for use of cogeneration is limited by the thermal load – which is either inadequate or highly seasonal – and the hours of operation.

However, there is still significant technical potential for the application of cogeneration in the WA commercial sector as WA has cheaper gas and higher electricity costs than the eastern states, and fuel savings that accrue from cogeneration make it economic in many applications. A rise in gas prices would tend to reduce the economic prospects for commercial cogeneration, although this would be offset by any commensurate increases in electricity prices.

Capital costs vary considerably depending on the size and application and are extremely application specific.[211] Installed costs for typical gas turbines range from $1000 - $2400/kW while grid integrated systems are $1800-$3400/kw.Fuel cells are most expensive at $6000-$7000.[212]

There are very low reliability risks and no significant issues beyond the normal OHSE issues in a commercial building environment. But although the actual risks are low, studies have shown that there are more significant perceived risks in relation to the potential savings that discourage potential applications.

There is almost no information available about the current market penetration of cogeneration technologies in the WA commercial sector nor the potential opportunity. Any estimate of the abatement potential is therefore speculative.

Barriers, policies and measures

The low adoption of cogeneration technologies indicates that its economic benefits are not sufficient to ensure its use. Research indicates a number of reasons for this[213] including:

- Limited knowledge and understanding of the technology and its potential benefits,
- A high discount attributed to perceived technology risk, and
- Limited access to capital due to competing investments.

It is recommended that the Taskforce consider the following policy measures:

- Providing training and information to building designers, engineers and managers,
- Considering a Government revolving fund that provides access to capital and facilitating non-traditional financing options, including third party financing (under energy performance contracts) and build, own, operate schemes.
- Considering providing incentives program for cogeneration installations (for example the California Self Generation Incentive Program provides US $600 to US $1,000 per kW incentive).

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[210] US Department of Energy (2000) *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector* Prepared for U.S. Energy Information Administration by ONSITE SYCOM Energy Corporation

[211] US EPA (ND) Catalogue of CHP technologies

[212] California Energy Commission (2005) *Assessment of California CHP market and options for increased penetration* Report prepared for California Energy Commissions by Electric Power Research Institute

[213] California Energy Commission (2005) *Assessment of California CHP market and options for increased penetration* Report prepared for California Energy Commissions by Electric Power Research Institute

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US Department of Energy (2000) *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector* Prepared for U.S. Energy Information Administration by ONSITE SYCOM Energy Corporation

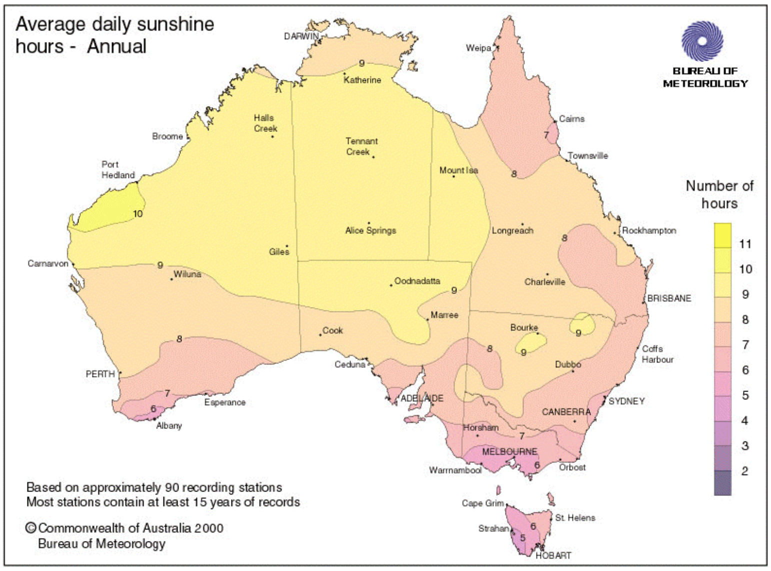
US EPA (2002) Catalogue of CHP technologies

(b) Rooftop solar photovoltaic

Electricity consumption accounts for almost 70% of stationary energy use in WA commercial sector with solar contributing less than 1%. Low emission electricity generation technologies (including grid-connected PV power station) are discussed in the electricity section. However the potential for PV for distributed electricity generation option in the commercial sector is included here.

WA has relatively high levels of solar resources and Perth has the highest solar resources of any state capital city in Australia. In contrast to other solar technologies, PV systems can use direct, scattered and reflected sunlight to generate electricity and consequently they can be used over a broader geographical range.

However PV is by far the most expensive of currently available electricity generating options, particularly when using battery storage to overcome the limited hours of power output. Yet despite its high costs, PV enjoys very high levels of community support.



Source: Bureau of Meteorology 2000

The technology

PV technology is commercially mature and growing rapidly. The modular systems provide for easy transportation and rapid installation, with easy expansion if demand increases. The global market is dominated by Germany, USA and Japan. PV systems are used for:

- rooftop installation where they compete with retail electricity prices,
- small grid-connected power stations equivalent to any other generator supplying power to the electricity grid (discussed in more detail in the electricity section).
- stand-alone systems with battery storage or diesel/petrol back-up. Usually used for homes and farms in more remote areas (discussed in the agricultural section). These are the most economic PV application and are already widespread, accounting for around 90% of current PV application in Australia.

According to the IEA, current Australian installed capacity at the end of 2004 was more than 52MW[214], of which almost 90% were off-grid applications. The majority of these are small scale and according to Geosciences Australia, there is less than half a megawatt of capacity from systems over 3kW in WA, although there is an additional 12.5 MW proposed[215]. The largest PV system installed in WA is 151 kW capacity PV system[216] owned by Hammersley Iron to power its rail network running 300km from mining town Tom Price to Dampier on the Pilbara Coast.

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214 IEA Photovoltaic power systems programme (2005) *Trends in photovoltaic applications in selected IEA countries between 1992 and 2004* http://www.oja-services.nl/iea-pvps/isr/22.htm

215 Geoscience Australia (2005) *Map of operating renewable energy generators in Australia* http://www.agso.gov.au/renewable/

216 IEA Photovoltaic power systems programme (2005) *Trends in photovoltaic applications in selected IEA countries between 1992 and 2004* http://www.oja-services.nl/iea-pvps/isr/22.htm

In 2000 the US solar industry contributed 75MW of peak generation capacity from a national total of 825 GW. Although this represents less than 0.01%, the US PV roadmap anticipates ongoing growth at 25% per year - approaching 10% of peak generation by 2030[217].

The Australian PV Industry roadmap sets out an industry development strategy to deliver a cost-competitive Australian PV industry by 2020. It anticipates that the strategy could deliver 3% of Australia's power needs by 2020, and around 6740 MW of installed capacity by 2030 with 31,000 jobs. However, on current trends and with existing policies the industry is unlikely to meet that target.[218]

Cost and performance characteristics

Significant progress has been made over the past two decades in research and development, improving manufacturing processes, reducing costs and establishing small but rapidly growing niche markets. However, PV is still very expensive relative to other current and rapidly emerging generation technologies and rarely pays for itself over its 25 year lifetime.

Grid connected PV systems currently cost as little as $10/W to install, which equates to around $400/MWh. Most current systems are based on crystalline silicon with conversion efficiencies of around 12-20%, and the PV modules account for around 50-60% of the overall system costs[219]. PV systems require very little maintenance, apart from occasional cleaning and replacement of the inverter once in their lifetimes. Research and development programs have focussed on reducing costs, extending the system life and improving the efficiency of the solar modules.

Increasing economies of scale and international research and development achievements look promising. The Californian Energy Commission has estimated possible future costs for residential scale PV systems as set out in the following table (all A$).

PV costs for residential PV systems (2-3kW)[220]	2003	2007	2020
Levelised costs ($/MWh)	435	295	120

The US Climate Technology program also targets long-term costs for residential PV applications of A$80/MWh, compared to costs ranging from $180-230/MWh in 2004. By 2010, they anticipate costs of $180-250/MWh[221] which is consistent with the California Energy Commission work. The World Bank estimates are even more optimistic again.

PV systems pose few environmental problems. The generating component produces electricity silently and does not emit any harmful gases during operation. The basic photovoltaic material for most common modules made out of silicon is entirely benign, and is available in abundance.

Some early PV modules were criticised for consuming more energy during production than they generated during their lifetime. With modern production methods and improved operational efficiencies this is no longer true and typically energy payback will be realised within 3-4 years.

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[217] Solar Electric Power (2003) *US photovoltaic industry roadmap* http://www.nrel.gov/ncpv/pdfs/30150.pdf

[218] BSCE (2004) *Australian Photovoltaic industry roadmap* http://www.bcse.org.au/docs/Publications_Reports/PV%20Roadmap-web.pdf

[219] World Bank discussion paper (2005) *Technical and Economic Assessment: Off Grid, Mini-Grid and Grid Electrification Technologies* http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTENERGY/0,,contentMDK:20796696~pagePK:210082~piPK:210098~theSitePK:336806,00.html

[220] California Energy Commission (2005) *Developing Cost-Effective Solar Resources with Electricity System Benefits*, p.21-22 http://www.energy.ca.gov/2005publications/CEC-500-2005-104/CEC-500-2005-104.PDF

[221] US climate technology program (2005) *Technology Options for the Near and Long Term*

In theory, there is unlimited technical capacity for PV as all commercial electricity needs could be met with PV. However, PV power generation is limited by its reliance on sunlight which in turn limits its application without some form of battery storage or back up system. Such battery storage is currently considerably expensive.

As there are more cost effective renewable electricity generation options available, the abatement potential for PV has not been calculated.

Barriers, policies and measures

Higher cost and lack of clear economic incentives

Currently the cost of PV for most commercial and institutional operations is prohibitive and despite energy savings, a system rarely pays for itself over the lifetime of the system on the basis of current economics. Current installation of PV tends to be limited to niche ‘green’ markets and show case applications in schools and some businesses.

Despite significant cost reductions over the last decade, the overwhelming barrier to the widespread deployment of renewable energy technologies is their higher cost compared to current high emission fossil fuel technologies.

A carbon price that places a cost on greenhouse gas emitters – either directly through a carbon tax or indirectly through emission trading - will go some way to reducing this cost differential. However, a carbon price in the order of $40 is needed to make the currently least cost renewable technologies such as wind economically competitive with fossil fuels, and would need to be much higher again (e.g., well over $100) for PV to be cost competitive.

Funding schemes and feed in tariffs to the local grid in many countries have played an important role in the PV industries development. In Germany, a guaranteed PV tariff means that Germany now has the highest PV capacity per capita – at 10W for every person in Germany. This compares to Australia at 2.6W per capita.

In California, the Million Solar Roofs Initiative is intended to provide incentives sufficient to deploy solar PV systems on fifty percent of new homes in thirteen years - nearly 500 MW of solar PV systems by 2010 and over 2000 MW by 2017. The program focuses efforts in areas of high housing growth to maximise the system benefits and economies of scale.

Lack of cost reflective pricing

Solar photovoltaic power output is clearly constrained by hours of daylight, however, many of the system benefits associated with a PV system do not accrue to the system owner.

According to research by the Centre for Energy and Environmental Markets at the University of NSW[222], PV output correlates well with commercial loads, indicating a stronger case for PV use in commercial buildings. However, peak demand on the electricity network is not as closely correlated with the maximum sunshine hours, and in any case, at current prices, PV will still be more expensive than other conventional fossil fuels).

Forecasts by the California Energy Commission the costs of PV exceed forecasted electricity rates for some time to come, the economics improves with the use of time sensitive tariffs and special financing mechanisms[223]. Cost reflective pricing may go some way towards addressing this issue

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[222] CEEM (2004) *Analyses of Photovoltaic System Output, Temperature, Electricity Loads and National Electricity Market Prices – Summer 2003-04* http://www.ceem.unsw.edu.au/documents/WattOliphantetalanzses04.pdf

CEEM (2005) *Tariff Implications for the Value of PV to Residential Customers* http://www.ceem.unsw.edu.au/documents/PopSolar2005Revised2.pdf

[223] California Energy Commission (2005) *Developing Cost-Effective Solar Resources with Electricity System Benefits*

although more analysis is required in the WA context. It is therefore recommended that the WA Government consider:

- Undertaking analysis of the correlation between PV power output and the commercial demand
- Introducing advanced, time varying or dynamic metering or
- Introducing some kind of guaranteed 'feed in' tariffs for PV that recognise the peak value of PV

PV systems can be more cost effective on the basis of tiered rates, TOU rates, dynamic pricing, or financing arrangements that are either longer term or capture non-energy benefits from grid connected PV systems. However, more near-term and widespread adoption of PV systems will likely continue to rely on public incentives.

Other opportunities

To facilitate the widespread deployment of PV systems in commercial buildings, the Taskforce could consider the option of promoting its use in prestige office buildings. Given the widespread use of high costs materials in prestige buildings, it would not be unreasonable to promote some proportion of the buildings energy needs to be met by a roof top PV array. This would help develop industry capacity in design and installation, build economies of scale and lead to adoption in other buildings.

However, this is a high cost abatement measure compared to other options.

Key references

California Energy Commission (2005) *Developing Cost-Effective Solar Resources with Electricity System Benefits*, p.21-22 http://www.energy.ca.gov/2005publications/CEC-500-2005-104/CEC-500-2005-104.PDFCEEM (2004) *Analyses of Photovoltaic System Output, Temperature, Electricity Loads and National Electricity Market Prices – Summer 2003-04* http://www.ceem.unsw.edu.au/documents/WattOliphantetalanzses04.pdf

CEEM (2005) *Tariff Implications for the Value of PV to Residential Customers* http://www.ceem.unsw.edu.au/documents/PopSolar2005Revised2.pdf

IEA Photovoltaic power systems programme (2005) *Trends in photovoltaic applications in selected IEA countries between 1992 and 2004* http://www.oja-services.nl/iea-pvps/isr/22.htm

Solar Electric Power (2003) *US photovoltaic industry roadmap* http://www.nrel.gov/ncpv/pdfs/30150.pdf

BSCE (2004) *Australian Photovoltaic industry roadmap* http://www.bcse.org.au/docs/Publications_Reports/PV%20Roadmap-web.pdf

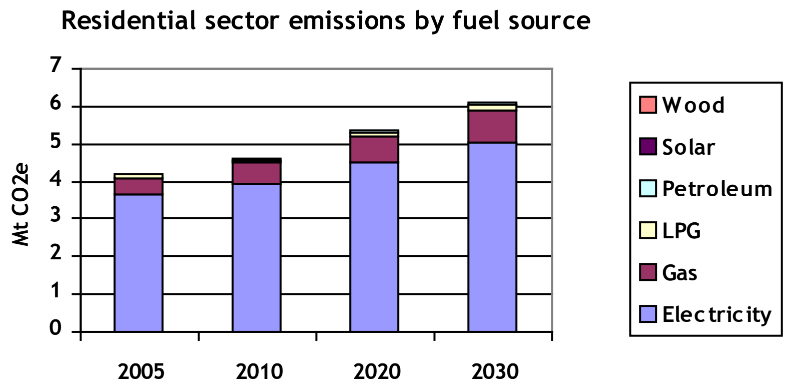
US climate technology program (2005) *Technology Options for the Near and Long Term*

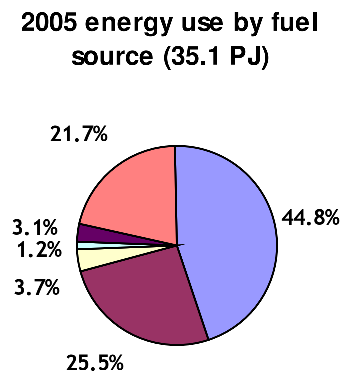
Residential

Sector overview

In 2005, WA's 790,000 homes were responsible for 4.2 Mt of stationary energy emissions, and under ABARE's scenario, these emissions are projected to grow 45% to 6.1 Mt by 2030.

Electricity use dominates residential sector emissions, accounting for 45% of energy use, but contributing 86% of emissions. Less greenhouse-intensive gas and petroleum contribute 30% of energy and only 15% of emissions, with biomass (wood) and solar energy contributing 25% of energy use, but no emissions.





It is widely recognised that there are significant energy efficiency opportunities in the residential sector, with estimates of cost effective energy efficiency savings that range anywhere between 20-70%[224]. The Taskforce has commissioned a separate consultancy to identify these and policy support measures to ensure widespread deployment.

With such a high proportion of emissions from electricity, the most significant supply side opportunities for reducing emissions in this sector will be from the deployment of lower emission technologies in electricity generation, as discussed earlier in this report. There is however, some limited additional opportunity for:

- Fuel switching in hot water systems - replacing electric and gas hot water systems with solar hot water heaters, particularly if gas-boosted.
- Grid-connected rooftop photovoltaic systems to generate electricity for domestic use.

The economic potential of these opportunities will need to be assessed against the costs and performance of options for electricity generation.

Although WA residential electricity prices at $13.94c/kWh[225] tend to be slightly higher than most other parts of Australia, in 2003-04, domestic energy bills in WA accounted for $22.48 per week – which is slightly less than the national average and around 2.6% of total household expenditure and 2% of gross household income[226]. Given the projected level of economic growth, fuel and power costs are likely to significantly decline as a proportion of household expenditure by 2030.

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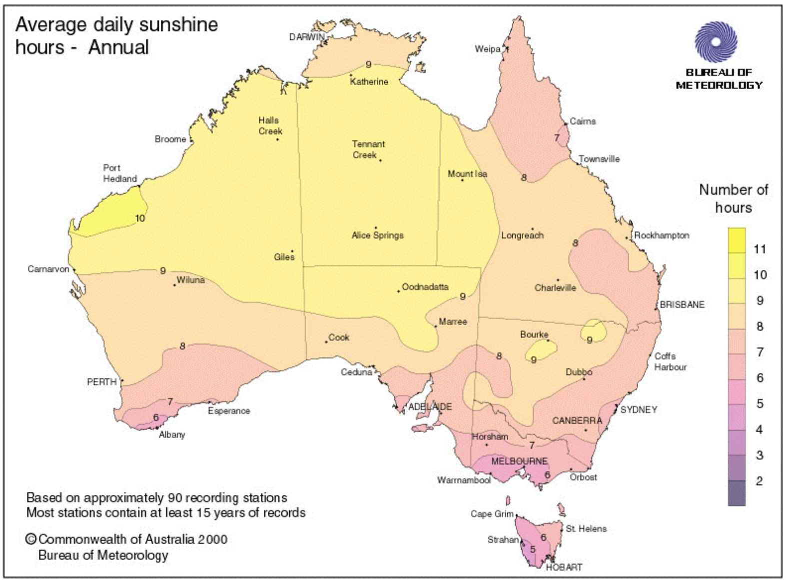
[224] See for example National Framework for Energy Efficiency.

[225] See prices and fee schedules at www.synergy.com.au and www.horizonpower.com.au

[226] ABS (2005) 6530.0 - Household Expenditure Survey, Australia: Summary of Results, 2003-04

(a) Fuel switching in hot water systems

According to the Australian Greenhouse Office and WA Sustainable Energy Development Office, the heating of water to low temperatures of less than 100°C currently accounts for up to 30% of an average Australian household's total greenhouse gas emissions and about the same proportion of total household energy use.



WA has extremely levels of solar resources, with more than eight hours of annual average daily sunshine in most areas of the state.[227]

Solar hot water systems manufactured in WA account for up to 80% of systems sold in Australia and 90% of systems sold in WA.

In 2002-03, the industry generated $80 million in sales and employed 250 people.[228]

In contrast to the rest of Australia, WA already has a high penetration of solar and gas hot water systems. Over 60% of existing WA systems are fuelled by gas (compared to less than 40% nationally) and over 15% by solar (compared to less than 5% nationally)[229]. New system sales have an even higher proportion of gas (83%), with only 2% electric.[230]

Although ABARE projects overall household emissions to increase by 45% to 2030, it is unlikely that the per capita use of hot water will significantly increase over that time. With the high use of gas for new systems, it is estimated that emissions from hot water are actually likely to fall from 1.26 Mt in 2005 to 1.14 Mt in 2020. Indeed, with the current focus on reducing water consumption, per capita use of water may well fall with an associated further reduction in emissions. And as electricity generation becomes less greenhouse-intensive, the greenhouse benefits of solar and gas hot water systems relative to electric or heat pump systems also decrease. This means that the abatement opportunity from solar hot water is relatively small.

Cost and performance characteristics[231]

Solar hot water systems, including gas, LPG and electric boosted are mature technologies, with negligible reliability risks and most systems guaranteed for at least 10 years. Efficiency improvements are therefore likely to be incremental, although greater economies of scale in solar hot water systems are likely to improve system economics.

[227] Bureau of Meteorology (2000)

[228] WA SEA (2006) The Western Australian Government solar water heater subsidy: Net benefits for consumers, the environment and the WA economy.

[229] ABS 4602.0 - Environmental Issues: People's Views and Practices, Mar 2005

[230] Taskforce briefing paper *Renewable energy in Western Australia* prepared by Department of Premier and Cabinet

[231] Adapted from WA SEA (2006) The Western Australian Government solar water heater subsidy: Net benefits for consumers, the environment and the WA economy.

Cost and performance characteristics

	Capital cost	NPV lifetime costs*	Lifetime emissions* (t)	$/t compared to electric
SHW gas	$4500	$5200	5	-$4.5
SHW electric	$3250	$5000	20	-$14
Gas instant	$1500	$6100	23	$14.5
Gas storage	$1100	$6300	25	$22.5
Electric heat pump**	$4500	$6500	30	$31
Electric storage**	$1250	$5600	80	-

* Assumes 18 year lifetime, ** Off-peak

If a homeowner funds the additional capital outlay through a home loan, the WA Sustainable Energy Association estimates that including interest payments, a home owner maintains a real annual positive cashflow for switching from gas storage or instantaneous to gas boosted solar and from electric storage to electric boosted solar – even without including the benefit of MRET or WA government subsidy. [232]

Barriers, policies and measures

The main barrier to the uptake of lower emission hot water systems is the higher up front costs associated with solar and gas systems, both for the system and its installation.

Emissions from electric systems are currently estimated to be some four times greater than gas and high running costs mean that it is already financially attractive to switch from electric to gas hot water systems. Although the returns are not as compelling to go to gas-boosted solar, electric-boosted solar or electric heat pump, the costs of each of these still compares favourably to gas systems over its guaranteed life with a positive rate of return[233].

The SA Government recently placed an 'effective ban on electric storage hot water systems from July 1, 2006' highlighting that savings in energy costs in the long-run will more than offset any additional costs for the alternative systems'. [234]

WA currently supports new gas boosted solar hot water systems with a $500 subsidy where natural gas is reticulated and $700 for LPG boosted systems where natural gas is unavailable. This is contributing to a higher take up of gas boosted solar, but the vast majority (83%) of new and replacement systems are gas, with only 2% of new systems being electric.

If all new and replacement units in WA were gas boosted solar hot water (with electric boosted solar where gas is unavailable or electric heat pump where solar access is also limited), it is possible to save up to 650,000 tonnes of greenhouse gas emissions from hot water heating each year in WA by 2030 (compared to the ABARE scenario). Any additional cost is offset by the fuel savings over the lifetime of the systems, with potentially even higher cost savings from efficiency improvements with greater economies of scale and lower relative input costs with future energy price increases. However, emission savings are likely to be much lower if electricity becomes less greenhouse-intensive and the deployment may be slower than anticipated.

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[232] WA SEA (2006) *The Western Australian Government solar water heater subsidy: Net benefits for consumers, the environment and the WA economy.* http://www.wasea.com.au/downloads/WASEAInc_SWH_consultancy.pdf

[233] This analysis includes the value of Renewable Energy Certificates under the Commonwealth Mandatory Renewable Energy Target

[234] SA Premier Rann (2005) www.thinkers.sa.gov.au/images/Schneider_mediarelease_1Jun05.pdf

Given that the economics are already favourable to the deployment of solar hot water heating, it is recommended that the Taskforce consider:

- A requirement that all new homes and major renovations install gas boosted solar hot water systems, with two exceptions - where gas is unavailable, electric boosted or LPG boosted solar, and where solar access is limited, electric heat pump, and
- Working with banks or utilities to provide innovative financing arrangements to assist in the finance higher up front costs for new or replacement solar hot water systems.

Key references

WA SEA (2006) The Western Australian Government solar water heater subsidy: Net benefits for consumers, the environment and the WA economy.

(b) Rooftop solar photovoltaic

Some 10,000 domestic residents in Australia currently have PV systems installed. However, the cost for most households is prohibitive and despite energy savings, a system rarely pays for itself over the lifetime of the system.

Electricity consumption accounts for almost 90% of stationary energy use in WA homes. The main opportunity for PV in the residential sector is in grid connected rooftop installations. In theory there is unlimited technical capacity for PV as all residential electricity needs could be met with PV together with expensive overnight battery storage.

The cost and performance characteristics of PV are discussed in detail in the commercial and electricity generation sections of this report.

Barriers, policies and measures

As discussed in the commercial sector section, the main barrier to the deployment of PV is its high capital and levelised costs and the current lack of cost reflective pricing. A number of programs are currently in place to support the use of PV including:

- The Commonwealth Government PV rebate program provides cash rebates to householders, owners of community use buildings, display home builders and housing estate developers who install grid-connected or stand-alone photovoltaic systems of $4 per peak watt, capped at $4,000 per residential system and $4,000 per School or Community Building system.
- The Commonwealth Government Renewable remote power generation program (RRPGP) that includes $18 million under the Remote Area Power Supply with rebates of up to 55% of the initial capital cost (50% from the Commonwealth and 5% from WA) and $4.8 million under the Renewable energy water pumping.

However, these subsidies are still not sufficient to enable PV to compete against existing fossil fuel or other renewable technologies. Even with the significant technological improvements that are anticipated over the coming decade, PV is likely to be out performed by geothermal, wave and tidal, solar thermal, wind and biomass technologies.

Other opportunities

To facilitate the deployment of rooftop PV systems, the Taskforce consider the option of mandating its use in high end residential properties, which could be linked to the value of the development. Given the significant overall costs of materials in high end residential developments, it would not be unreasonable to require some proportion of the buildings energy needs to be met by a roof top PV array. This would help develop industry capacity in design and installation, build economies of scale and lead to adoption more broadly.

However, this is a high cost abatement measure compared to other options. An obligation to purchase the equivalent in Green Power or RECs could provide a more cost effective approach to achieving a similar outcome.

If the Taskforce wishes to provide a ‘go solar’ message, it may be better served to focus on the opportunity for solar hot water heating, which although only a small opportunity, is a relatively straightforward one to implement and is cost effective now.

Abatement potential

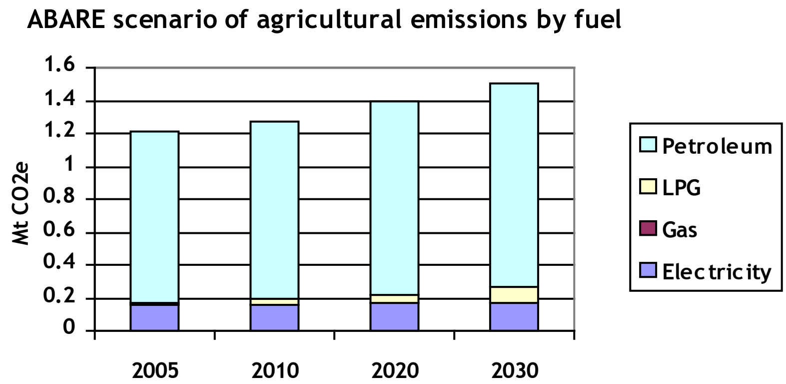
	2010		2020		2030	
	Mt	$/t	Mt	$/t	Mt	$/t
Solar hot water	0.15	0	0.46	0	0.65	0

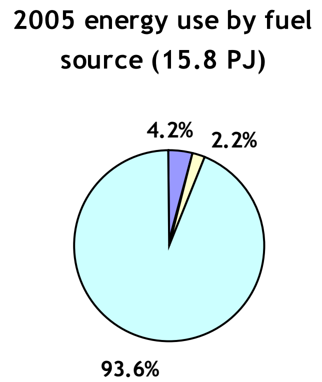
Agriculture

Sector overview

WA is a large producer and supplier of high-quality grains, beef, wool, live sheep and cattle, accounting for around 14% of Australia's agricultural production. Around 14,000 farms cover 106 million hectares or 42% of the total area of the state[235].

According to ABARE, in 2005 the WA agricultural sector was responsible for 1.2 Mt or 2% of stationary energy emissions which are projected to grow 24% to 1.5Mt by 2030. The use of petroleum in the form of diesel accounts for over almost 94% of energy use and 86% of emissions.





(a) Biofuels

Due to the overwhelming dominance of petroleum use in this sector, the most significant supply side technology option for reducing emissions is fuel switching to biodiesel use and wth the hike in international crude oil prices over the past few years, alternative fuels are attracting considerable interest in WA.

The production of biodiesel from oilseed crops and ethanol from grains are both established technology and can be done on a variety of scales – from individual growers up to large facilities involving thousands of tonnes. Opportunities to develop a range of industrial use oilseeds with good adaptation to dry seasons or environments exist.

A small amount of biodiesel is currently produced in Australia, with about 4 ML in 2004/05 or about 2 PJ. Total production capacity was estimated at about 15 ML.[236] Large scale use of biodiesel as a substitute for petrodiesel appears technically feasible over the medium-term horizon. Biodiesel substitutes are not included in the ABARE scenario, in large part because the cost of production is well in excess of projected petroleum costs.

Biodiesel technology is discussed in detail in the mining sector where diesel use accounts for a significant proportion of overall costs.

(b) Stand alone solar photovoltaic

Stand alone remote systems are the currently the most economic PV application and are already widespread, accounting for around 90% of current PV application in Australia. Although there is

[235] WA Department of Agriculture (2006) Agri-food, fibre and fisheries industries 2006

[236] Biomass Task Force, p. 41.

additional potential for remote systems, the scale is small and unlikely to make a significant impact on emission reductions.

An analysis of the technology is presented in the electricity generation section and rooftop PV applications are discussed in both the residential and commercial sectors.

PV is most cost effective for stand alone remote power generation, although cost – particularly upfront capital cost - is still a barrier to its adoption. The Federal Government’s Renewable remote power generation program (RRPGP) provides support for remote renewable systems including up to 55% rebate off the initial capital costs (50% from the Commonwealth with an additional 5% provided by the WA Government) under the Remote Area Power Supply program and funding towards renewable energy water pumping.

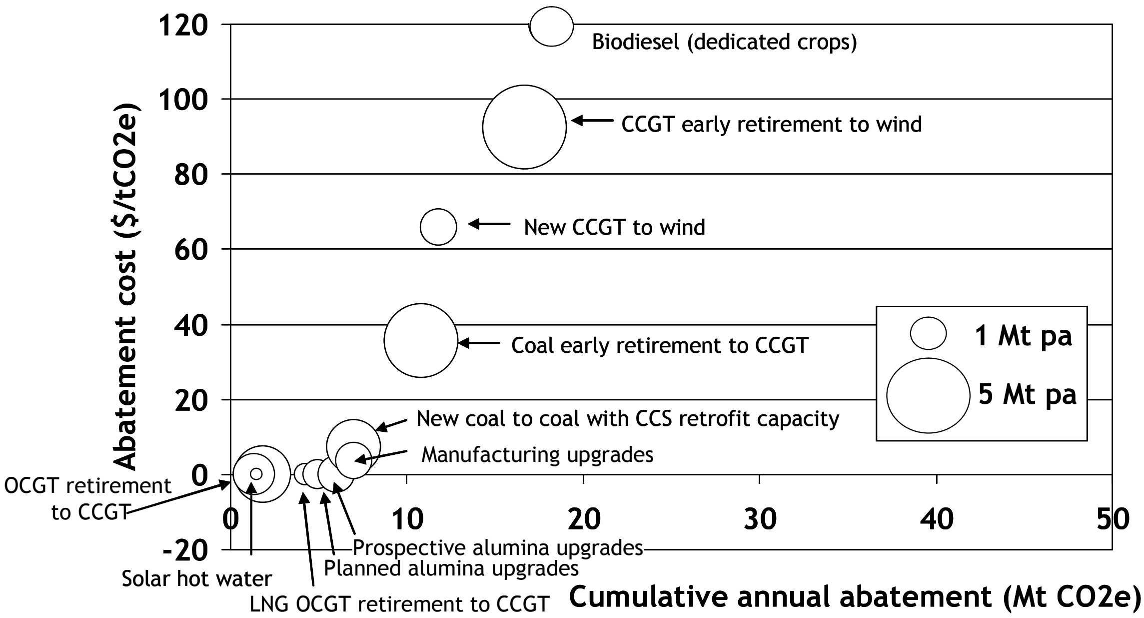
Abatement, barriers and measures

Abatement potential

This report has provided an overview of the abatement potential and associated costs of currently available low emission technologies and emerging technologies that are anticipated to be ready for deployment by 2020 if current economic and technological trends continue.

The most significant abatement potential is in the electricity generation sector, although significant opportunities were also identified in the mining sector. The following representative abatement cost curves summarise abatement costs and potential in 2010, 2002 and 2030 relative to the ABARE scenario. It should be noted that the cost curves, while representing only one possible scenario, provide an indication of the types of abatement measures, costs and magnitudes that could eventuate.

2010 Abatement curve for WA energy supply side technologies

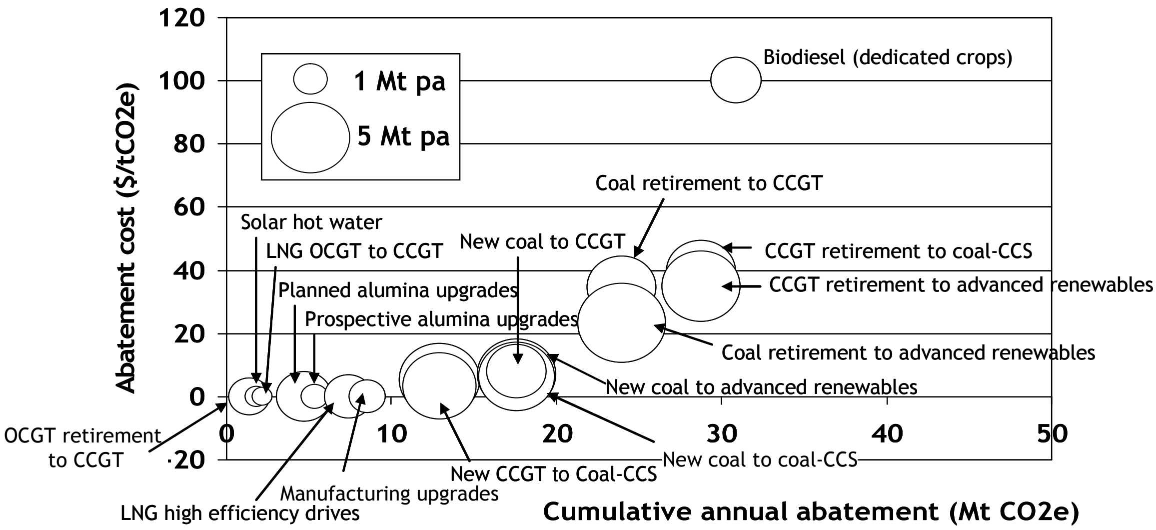


In 2010, total abatement potential of 14Mt pa was identified at an average abatement cost of $12.70/t CO2e (excluding the highest cost option of biodiesel from dedicated crops). Higher cost renewable energy technologies (such as solar PV) do not appear on the abatement curves as other less costly emissions abatement are deployed in preference.

Representative abatement options for 2010	**Cost ($/t)**	**Potential (Mt pa)**
Replace existing open cycle (OCGT) generation with CCGT	0	1.3
Solar hot water	0	0.2
Replace LNG open cycle (OCGT) with CCGT	0	0.3
Planned alumina upgrades	0	2.4

Prospective alumina upgrades	0	0.7
Prospective upgrades in other manufacturing	0	1.1
Ensure new coal electricity generation has CCS retrofit capacity	3.7	1.1
Retire existing coal generation early and replace with CCGT	35.6	3.8
Replace new CCGT electricity generation with wind	65.8	1.0
Retire existing CCGT generation early and replace with wind	92.5	4.9
Biodiesel	120.0	1.5

2020 Abatement curve for WA energy supply side technologies



In 2020, total abatement potential of 29.5 Mt pa was identified at an average abatement cost of \$16.25/t CO2e (excluding biodiesel from dedicated crops). The average cost of abatement is higher than in 2010, but this is due to the much larger abatement opportunities around \$20/tCO2e.

The considerably higher level of abatement reflects the anticipated arrival into the market of low emission fossil fuel technologies (advanced coal and carbon capture and storage) and low cost renewable technologies (geothermal, wave and tidal and solar thermal).

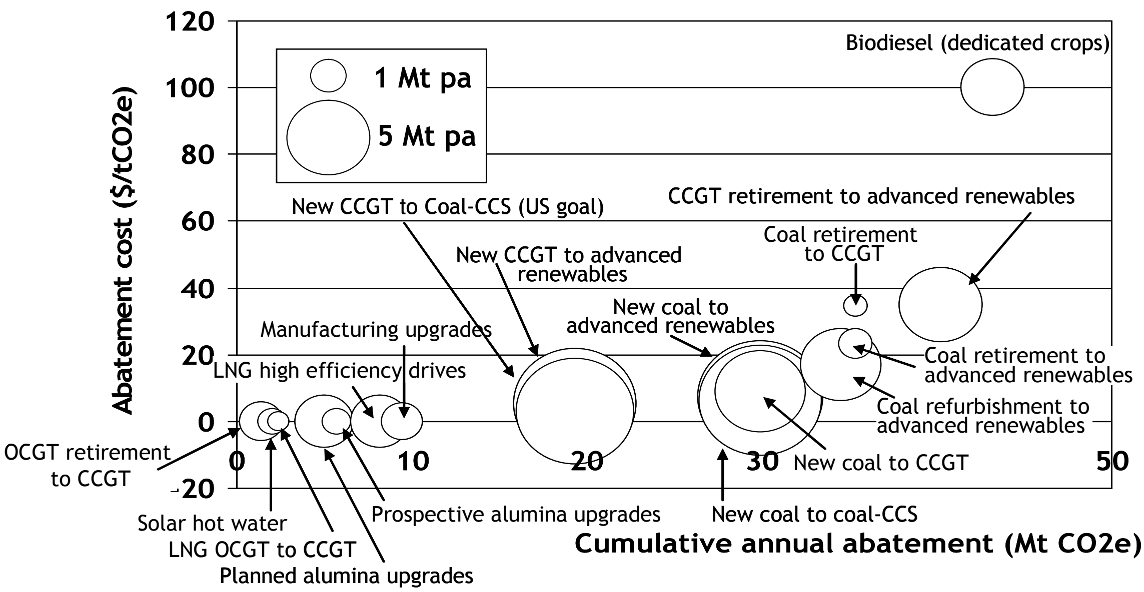
Coal-CCS and advanced renewable technologies such as geothermal and wave energy both appear highly prospective in this time horizon. If the US technology development goals for CCS are not achieved, however, there is the potential that abatement costs will be higher (as represented by the shaded circle on the curve above).

Note - if LNG projects proceed without sequestration, additional emissions of 4Mt pa will arise.

Representative abatement options for 2020	**Cost ($/t)**	**Potential (Mt pa)**
Replace existing open cycle (OCGT) generation with CCGT	< 0	1.4
Solar hot water	0	0.5

Replace LNG open cycle (OCGT) with CCGT	0	0.3
Planned alumina upgrades	0	2.5
Prospective alumina upgrades	0	0.7
LNG high efficiency drives	0	2.0
Prospective upgrades in other manufacturing	0	1.2
Replace new CCGT generation with coal CCS (or advanced renewables)	3.2 (5.6)	4.4 (5.4)
Replace new coal electricity generation with coal-CCS (or geothermal or wave energy) [or CCGT]	6.2 (6.8) [8.0]	4.6 (5.0) [2.9]
Retire existing coal electricity generation early and replace with advanced renewables (or CCGT)	23.2 (34.4)	6.4 (3.9)
Retire existing CCGT electricity generation early and replace with advanced renewables (or coal-CCS)	35.0 (39.4)	4.9 (4.0)
Biodiesel	100	2.1

2030 Abatement curve for WA energy supply side technologies



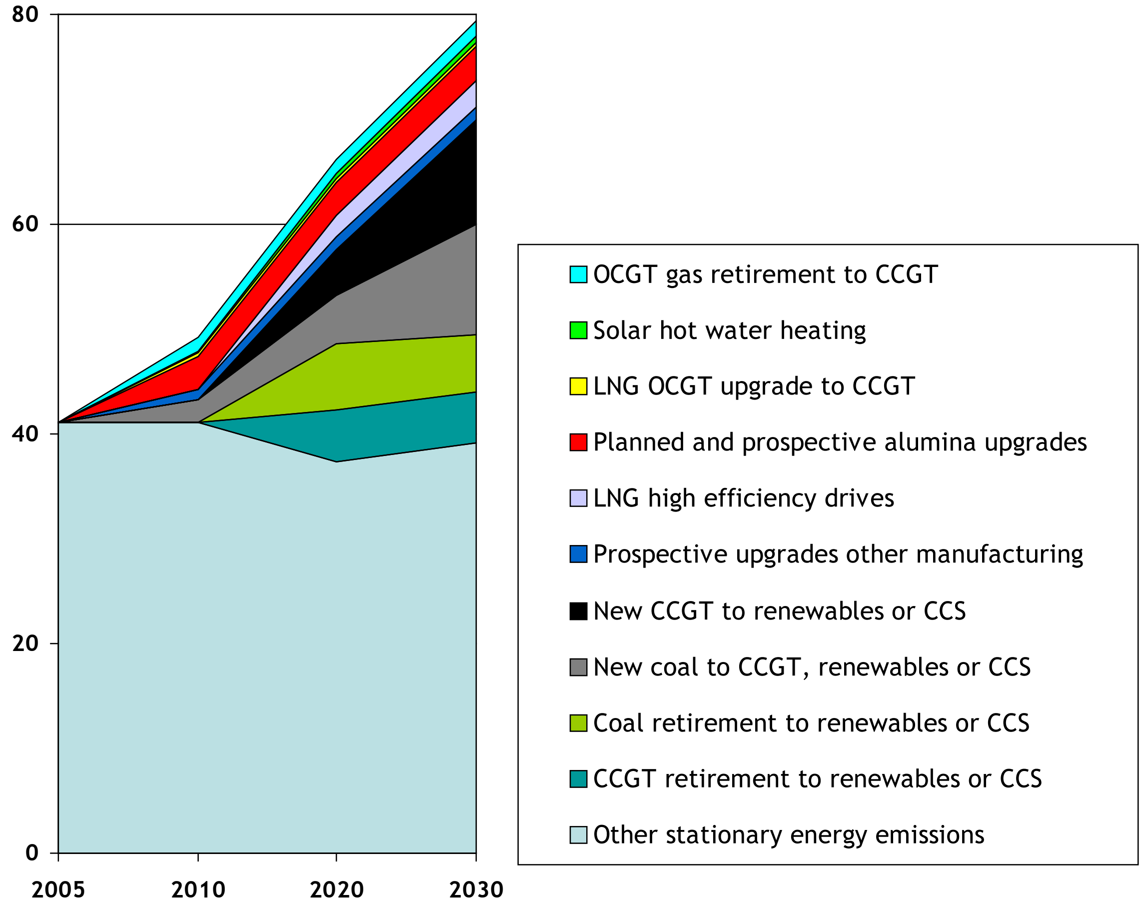
In 2030, total abatement potential of 41.9 Mt pa was identified at an average abatement cost of \$13.80/t CO2e (excluding biodiesel from dedicated crops). The average cost of abatement is lower than in 2020, due to the much larger abatement opportunities at lower costs.

As discussed with reference to 2020 abatement options, coal-CCS and advanced renewable technologies such as geothermal and wave energy both appear highly prospective in this time horizon. If the US technology development goals for CCS are not achieved, however, there is the potential that abatement costs will be higher (as represented by the shaded circle on the curve above).

Note - if LNG projects proceed without sequestration, additional emissions of 5Mt pa will arise.

Representative abatement options for 2030	Cost ($/t)	Potential (Mt pa)
Replace existing open cycle (OCGT) generation with CCGT	< 0	1.4
Solar hot water	0	0.7
Replace LNG open cycle (OCGT) with CCGT	0	0.3
Planned alumina upgrades	0	2.6
Prospective alumina upgrades	0	0.7
LNG high efficiency drives	0	2.5
Prospective upgrades in other manufacturing	0	1.3
Replace new CCGT with coal-CCS (or geothermal or wave energy)	2.9 (5.3)	9.9 (10.9)
Replace new coal with Coal-CCS (or geothermal or wave energy) [or CCGT]	6.3 (7.3) [8.9]	10.6 (11.0) [6.0]
Replace coal generation refurbishment with geothermal or wave energy	16.9	4.6
Retire existing coal electricity generation early and replace with advanced renewables (or CCGT)	23.3 (34.4)	0.9 (0.5)
Retire existing CCGT generation early and replace with advanced renewables (or coal-CCS)	35 (36.6)	4.9 (4.4)
Biodiesel	100	2.9

Representative 'wedges' diagram of abatement opportunities to 2030 with cost below $40/t



Abatement and measures

Barriers to low emission electricity technologies

This report identifies a number of barriers to the development and deployment of low emission technologies, including:

(i) Lack of clear policy intent – Although business operates in a highly uncertain environment, the emergence of climate change as an issue to be addressed has resulted in significant additional uncertainty for investors in long-lived energy assets.

(ii) Higher cost of current low emission technologies - In the absence of pricing structures that include environmental externalities, the higher costs of low emission technologies mean they simply cannot compete in a market dominated by low-cost high-emission energy supply.

(iii) Time required for new technological development - although there are a number of very promising trends in the development of low emission technologies, these all require some time to be commercially proven and ready for widespread deployment – generally anticipated in the next decade.

(iv) Physical barriers - The physical nature of some resources mean that they are either located at distance from end users (as in the case of gas and tidal resources in the North West) or face other physical constraints such as the intermittency of some renewable resources (such as wind) or limited availability (for example the limited daylight hours of solar resources).

(v) Institutional barriers – Government and market institutions have developed to support an energy system dominated by large (and inexpensive) centralised power stations and as a result, some implicit and explicit barriers exist to more decentralised and intermittent technologies. In addition, the institutional capacity and expertise of both government and industry to assess, consider, encourage and deploy new technologies is often seriously limited.

(vi) Lack of information / data gaps - Three types of information/data gaps appear significant. First, information about rapidly emerging technologies is inherently uncertain and sometime inaccurate. Second, some information is necessarily commercial-in-confidence or reflects differing commercial perspectives (for example, regarding the commercial risk of alternative technologies), and not available to government. Third, some information (such as basic site emissions data) remains to be collected through an emissions reporting scheme.

Abatement and measures

Recommendations

To overcome the barriers identified and to effectively manage supply side greenhouse gas emissions from the stationary energy sector, a number of recommendations have been made for consideration by the Taskforce.

These recommendations focus on the need to:

- Discourage new investment in long lived high emission technologies
- Facilitate adequate and economic gas supply
- Accelerate and facilitate technology development in the WA context
- Provide economic incentives and prepare for a carbon price
- Build industry and institutional capacity to reduce emissions

Overall, there is no single, simple 'silver bullet' solution, and the recommendations below should be viewed as measures which, while reasonable, would almost certainly require ongoing revision and adjustment as experience is gained, as technologies and prospective major projects emerge (or don't), and as market conditions evolve (e.g., for the domestic and international prices of natural gas and greenhouse gases).

Several of the measures recommended below are mutually interactive. For example, deployment of relatively low emissions CCGTs in preference to new coal plant until CCS is available would be supported by:

- formalising emissions intensity expectations for new plant;
- facilitating adequate and economic gas supply;
- working towards the National Emissions Trading scheme; and
- foreshadowing a future carbon price for explicit consideration by project proponents.

While each of these elements would facilitate the selection of CCGT in the near term over coal, and none would likely be fully adequate in isolation.

Discourage new investment in high emission technologies

Because of the number of rapidly emerging low emission technologies (both renewable and fossil fuel), it would be prudent to seek to avoid new investment in the short term in high emission long lived technologies. This can be achieved through both investment in low emission technologies now, or deferring the need for new investment through demand management.

Existing measures include:

- The Commonwealth Government's:
    - The voluntary Generator Efficiency Standards which sets best practice standards for all types of fossil fuel generators
    - Greenhouse Gas Abatement Program – funded projects expect to deliver abatement of 6.1 Mt in 2010 although no further rounds will be offered.
- The WA Government's
    - EPA Guidance for the Assessment of Environmental Factors No. 12 – Guidance Statement for Minimising Greenhouse Gas Emissions which sets best practice for emissions intensity equal to or better than closed cycle gas technology.
    - Renewable Energy Strategy currently under development, a 6% target for the SWIS and a commitment to purchase 5% of Government energy from cost-effective renewable energy
- A range of Commonwealth, National and State programs to encourage energy efficiency

It is recommended that the WA Government build on these measures and:

- Make a clear statement of policy intent recognising the long term challenge and need to reduce emissions in the order of 50% by 2050
- Formalise the WA EPA best practice expectation with a minimum performance standard for new base load electricity generation of an emissions intensity equal to or better than closed cycle gas technology and including a requirement for the capacity for future retrofitting of carbon capture and storage technology if and when it becomes available. To achieve greater economy and flexibility, consideration could be given to allowing inclusion of offsets
- Extend the minimum performance standard above to major industrial cogeneration developments to ensure investment in CCGT rather than coal cogeneration (eg the recent Wagerup proposal for a coal cogeneration plant would be excluded under this proposal)
- Consider a mandatory requirement to ensure the SWIS 6% renewable target is achieved (this could be with a requirement for wholesale purchasers to surrender Renewable Energy Certificates according to market share)
- Establish an aggressive energy efficiency program to ensure all cost effective measures are implemented. Although demand management opportunities were not considered as part of this analysis, it is generally recognised that considerable efficiency improvements are possible with net economic benefits. These should be harnessed as a matter of urgency and could involve more effective building standards and considering mandating industrial efficiency opportunities as is currently the case in Victoria
- Defer development of high content LNG fields (e.g., with CO_2 content higher than in currently operating facilities) until geosequestration proves feasible.

Facilitate adequate and economic gas supply

Additional gas generation in the SWIS beyond current plans depends on additional supplies of gas emerging and increased capacity in the pipeline system which is currently constrained.

Existing measures include:

- A WA Government requirement under the Barrow Island Act for Gorgon development proponents to set aside 2000PJ for domestic gas supply (with a daily minimum of 300TJ).

It is recommended that the WA Government build on these measures and:

- Continue the domestic reserve allocation requirement as additional LNG fields develop beyond the Gorgon development
- Continue to facilitate the development of adequate pipeline capacity from the north west to the South West.

Accelerate and facilitate technology development in WA context

Existing measures include:

- The Commonwealth Government's:
    - Low Emission Technology Development Fund for technologies that will be able to reduce Australia's greenhouse emissions by at least 2% at realistic rates of uptake ($500m to 2020)
    - Government's $29.6m Low Emission Technology and Abatement initiative that funds strategic abatement, renewable energy, fossil fuels and geosequestration
    - $75m Solar Cities program to trial solar applications integrated with energy efficiency and more effective energy market signals.
    - The Renewable Energy Development Initiative ($100m over 7 years) and $20m towards development of intermittent energy storage
- The WA Government's:

- Financial contribution towards CRC for Coal and sustainable development and the CRC for Plant-based management of dryland salinity.
- SEDO grants programs supporting research and development of innovative sustainable energy products, services, installations and practices, and the development of the Western Australian sustainable energy industry.

It is recommended that the WA Government build on these measures and:

- Work with industry to facilitate greater engagement in Commonwealth and other international research and development efforts, including the Asia Pacific Partnership and the Futuregen carbon capture and storage projects
- Facilitate the identification and assessment of appropriate sites for geological sequestration
- Facilitate the identification and assessment of geothermal potential in the Perth Basin and wave and wind potential along the WA coastline.
- Facilitate the development through financial and technical support of one or more high profile, large potential projects suitable for the Commonwealth governments Low Emissions Technology funds in the emerging areas of geothermal, solar thermal and/or wave/tidal energy.

Provide economic incentives and prepare for a carbon price

Existing measures include:

- National Emissions Trading Taskforce development of a model emissions trading scheme for State and Territory Government consideration.
- The Commonwealth Government's:
    - The voluntary Generator Efficiency Standards which sets best practice standards for all types The Commonwealth Mandatory Renewable Energy Target (MRET) requiring an additional 9500 GWh renewable energy generation by 2010.
    - Over $200m support for remote renewable power generation, contributing up to 55% of initial capital costs for renewable energy systems.
- The WA Government's:
    - Commitment to a 1c/kWh payment for renewable energy not eligible under the remote renewable program and not selected by WA retailers for to meet their MRETR liability.
    - $500 to $700 per system subsidy for gas boosted solar hot water systems.
    - The Solar Schools initiative to install 100 photovoltaic installations in metropolitan and regional schools, with rebates of up to 80% of the cost of systems up to $10,000.

It is recommended that the WA Government build on these measures and:

- Make a clear statement that project proponents are expected to incorporate carbon risk into commercial decision making and will be liable for any future carbon compliance costs.
- Consider adapting the Australian Greenhouse Office risk analysis framework to the Western Australian context
- Foreshadow a future carbon price, develop a carbon risk analysis framework to build capacity in industry and consider a requirement for project proponents to undertake a carbon price sensitivity analysis at a particular carbon price of say $20/t CO_2e
- Continue its work with the National Emissions Trading Taskforce and advocate for a price signal (while allowing for measures to address the trade exposed sectors of the economy)
- Implement the Government's commitment to emissions reporting as a critical step towards emission trading and consider emissions liability disclosure to the financial sector
- Require that all new homes and major renovations install gas boosted solar hot water systems, with two exceptions - where gas is unavailable, electric boosted or LPG boosted solar, and where solar access is limited, electric heat pump.

Abatement and measures

Build industry and institutional capacity to reduce emissions

Existing measures include:

- COAG distributed generation working group – identifying barriers in the National Electricity Market to the uptake of smaller scale and distributed generation.
- The Commonwealth Government's Greenhouse Challenge Plus
- The Commonwealth Government's Energy efficiency opportunities program

It is recommended that the WA Government build on these measures and:

- Address the institutional capacity to allow for more intermittent generation in the SWIS
- Establish a cogeneration program to build capacity in the commercial and industrial sectors and encourage adoption of technologies that are cost effective now
- Provide detailed public information about the level and availability of renewable energy resources and land use to facilitate new project identification.