Institute of Actuaries of Australia

Greenhouse Gas Issues Within Australia's Electricity Industry

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The Commonwealth government is developing a strategic plan for Australia's long term energy policy. This paper was written as background for an IAA submission to the government. It discusses:

- How Australia’s demand for electricity is met now (83% from coal)
- Capital and running costs of power generation
- Greenhouse gas emission intensities
- Current emission levels (96% from coal)
- Commonwealth and state emission abatement measures
- Expected increases in electricity demand (75% from 2000 to 2020)
- Projected emission increases if increases are met by black coal (65% to 2020)
- Emission increases using best current technology (28% to 2020)
- The emissions trading regime recommended by the recent COAG review of the national energy market.

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1. Summary

The Commonwealth government is developing a strategic plan for Australia's long term energy policy. Input from government and private sources includes the recently completed energy market review for the Council of Australian Governments (COAG).

Coal provides about 83% of the electricity generated in Australia, and about 96% of the greenhouse gas emissions from electricity generation. Electricity demand is projected to increase by about 75% from 2000 to 2020.

If all the extra demand is met by current technology, black coal-fired plant, emissions from electricity generation may rise by about 65%. If all the extra demand could be met by lower emission plant such as combined cycle gas or similar, emissions may only rise about 28%. Emissions charges of $20 to $30 per tonne of CO_2e would help align electricity production costs between low intensity emitters and high intensity emitters.

The Commonwealth's Mandatory Renewable Energy Target (MRET) is a requirement for an additional 9500 GWh of electricity to be purchased from renewable sources by 2010. Non-compliance penalties of $40 per MWh are equivalent to about $43 per tonne of CO_2e from black coal.

The energy market review has recommended an economy wide emissions trading system to replace 5 existing greenhouse gas abatement schemes, including MRET. Incomplete analyses by ACIL Tasman suggest that an annual permit price of $3.75 per tonne of CO_2e would give the same emission reductions as the 5 schemes.

Allen Consulting favour the sale of emission permits by the Government, rather than administrative allocation. The resulting revenue of up to $15 billion could be used for a variety of purposes, including adjustment assistance to present greenhouse gas emitters.

It is essential that there be a long-term national energy plan, implemented by targeted penalties and subsidies. Much greater reductions in greenhouse gas emissions may be needed than those analysed by ACIL Tasman, and much higher emissions charges may be required to make them economically viable.

2. Introduction

"There is a legitimate role for Government to lead economic and environmental outcomes. This leadership must be at the Federal government level; acting as the focal point for State Government and industry input."[1]

On 20/11/02, in an address to the Committee for Economic Development for Australia, the Prime Minister said

> "We are developing a strategic plan for Australia's long term energy policy, bringing together and enhancing many other areas of policy work already being done… A critical task, to be carried out with the support of our own advisers as well as with appropriate private sector advice, will be to work on energy market reform now underway, including the findings of the recently released Parer report which aims to aid the building of a truly national and efficient energy market."

On 20/12/02, the COAG Energy Market Review published its final report, titled "Towards a truly national and efficient energy market." The review received submissions from many different sources, and made wide-ranging recommendations for Australia's energy markets.

One of these recommendations was that an economy-wide emissions trading system replace five existing greenhouse gas abatement schemes. This recommendation focussed on creating a unified, national scheme, with specific focus on lower emission levels. Recommendations for emissions targets or incentive levels for emission reduction were not part of the review.

This document is intended as a background paper to help the Institute of Actuaries of Australia make a submission to the Ministerial Oversight Committee, comprising the Prime Minister, Deputy Prime Minister, Treasurer and the Ministers for Environment, Heritage, Industry, Tourism and Resources.

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The views expressed are however our own.

[1] Tarong Energy submission to the COAG panel, 2002

3. Electricity generation in Australia

3.1. Electricity generation plant installed 30/6/01

In terms of capacity installed, coal is the predominant resource for electricity generation in Australia:[2]

Area	Hydro MW	Coal MW	Oil products MW	Gas MW	Combined cycle gas MW	Other re-newables MW	Total MW
NSW/ACT	447	11681	100	192	162	86	12668
Victoria	541	6395	0	1273	0	156	8365
Qld	653	6875	910	332	598	340	9708
SA	0	760	0	1906	658	26	3350
WA	34	1739	167	2962	196	44	5142
Tasmania	2262	12	250	0	0	1	2525
NT	0	0	304	234	123	7	668
Snowy	3756	0	0	0	0	0	3756
Total	7693	27462	1731	6899	1737	660	46182

Hydro includes 1490 MW of pump storage. Multi-fuel plants in WA have been treated as 50% coal, 50% gas. Renewable energy sources other than hydro are bagasse, biomass, waste, wind and solar (see glossary at end).

3.2. Electricity generated 00-01

Using production as a measure, coal is an even more dominant fuel source:[3]

Area	Hydro GWh	Coal GWh	Oil Products GWh	Gas GWh	Combined cycle gas GWh	Other re-newables GWh	Total GWh
NSW/ACT	309	63358	2	0	1019	n/a	64688
Victoria	625	48465	0	881	0	n/a	49971
Qld	689	42208	44	173	1955	n/a	45069
SA	0	4479	5	3550	2554	n/a	10588
WA (WPC)	2	8443	320	3402	0	n/a	12167
Tasmania	10027	0	86	0	0	n/a	10113
NT	0	0	66	772	813	n/a	1651
Snowy	4533	0	0	0	0	n/a	4533
Total	16185	166953	523	8778	6341	n/a	198780

[2] Electricity Supply Association of Australia (2002, tables 2.1 to 2.4).
[3] Electricity Supply Association of Australia (2002, tables 2.5 and 2.6).

Figures for WA are for the Western Power Corporation only. Output from the Snowy is about 4% of the other power generated in NSW and Victoria. Coal provides nearly all of the electricity in NSW, Victoria and Queensland, and about 83% of all electricity in Australia. No data were available on electricity generated in 00-01 from renewable sources other than hydro. Eligible renewable generation under the MRET scheme is understood to be over 600GWh in the 1 April to 31 December 2001 period, and well over 1000 GWh for calendar year 2002, according to ORER media releases http://www.orer.gov.au/about/mr25sept02.html. and http://www.orer.gov.au/about/mr10jan02.html

3.3. Capacity factors in 00-01

Capacity factors are the energy produced in a period, as a proportion of the total energy produced if the generators had operated at maximum output throughout the period. By fuel type and state, electricity generation capacity factors have been:

Area	Hydro	Coal	Oil products	Gas	Combined Cycle gas	Total
NSW	8%	62%	0%	0%	72%	59%
Victoria	13%	87%		8%		69%
Qld	12%	70%		6%	37%	55%
SA		67%		21%	44%	36%
WA (WPC)	1%	55%	22%	13%		27%
Tasmania	51%	0%	4%			46%
NT			2%	38%	75%	29%
Snowy	14%					14%
Total	24%	69%	3%	15%	42%	50%

The above figures were estimated from 3.1 and 3.2. For example, the capacity factor for combined cycle gas in Queensland was estimated as:

electricity generated in 00-01 (GWh)	1955
plant capacity (MW)	598
times hours in a year	8760
potential power generated in a year (GWh)	5238
average capacity factor	37%

Capacity factors reflect a number of different things:

- The nature of the electricity demand being met;
- The mix of generation types, and in turn, available fuel types; and importantly
- The cost structure of different types of generator.

Low fuel cost plant tend to run most often and have high capacity factors. For capital intensive plant such as coal generators, this can give rise to capacity factors well over 70% and even over 90%.

Higher fuel cost plant tends to run at demand peaks rather than at all times, eg natural gas and oil fired generators. These generators also tend to be less capital intensive per MW installed, and can be built cost effectively, knowing they will only run a small percentage of the time.

Hydro plant capacity factors can vary widely depending on circumstance. Peaking generators or water restricted plant will usually have lower capacity factors, while plant installed where there is no economically viable alternative, such as in Tasmania, may also operate in base load roles, and will tend to have a higher capacity factor overall.

3.4. Ages of existing plant

Australia's generation stocks are ageing, and uptake of newer technologies such as combined cycle gas and wind is recent:

Type	Number of known Age	Minimum Year built	Maximum year built	Average age in 2003
Bagasse	9	1956	1997	24
Black coal	27	1965	2003	20
Brown coal	11	1958	1996	23
Combined cycle gas	7	1986	2002	4
Gas thermal	33	1967	2001	19
Gas turbine	35	1972	2002	9
Hydro	60	1926	2002	33
Methane	2	1997	1997	6
Oil product	12	1971	1998	19
Waste gas	3	1928	1992	45
Wind	10	1997	2002	2
Total	209	1926	2003	21

Some plant remain in operation even though they are well beyond the end of their planned economic lives, typically 20 to 30 years.

The above ages have been estimated from the completion dates in appendix A. Appendix A lists 237 power stations, largely taken from appendix 1 of ESAA (2002). For these 237, completion dates were known for 209. Where two dates were given, the average was used. For example, Hazelwood power station in Victoria has completion dates 1964 and 1971, and was taken as 1968. Average ages for each type of plant were estimated by weighting the age of each plant by its output.

4. Generator costs and emissions

4.1. Estimated emissions in 00-01

Emissions by State and generation type for the 00-01 financial year are estimated as:

Area	Hydro	Black coal	Brown coal	Oil Products	Gas	Combined cycle gas	Total
	$MtCO_2e$	$MtCO_2e$	$MtCO_2e$	$MtCO_2e$	$MtCO_2e$	$MtCO_2e$	$MtCO_2e$
NSW	0.0	57.3	0.0	0.0	0.0	0.4	57.8
Victoria	0.0	0	64.8	0.0	0.5	0.0	65.3
Qld	0.0	38.0	0.0	0.0	0.1	0.8	38.9
SA	0.0	0	6.0	0.0	2.1	1.0	9.1
WA (WPC)	0.0	7.6	0.0	0.2	2.0	0.0	9.9
Tasmania	0.0	0.0	0.0	0.1	0.0	0.0	0.1
NT	0.0	0.0	0.0	0.0	0.5	0.3	0.8
Snowy	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	103.0	70.9	0.3	5.3	2.5	181.9

These figures were calculated from the electricity generation in 00-01, using the following assumed average emission intensities (tonnes per MWh)

black coal in NSW & WA	0.91
black coal in Qld	0.90
brown coal in Vic & SA	1.34
oil products & gas	0.60
combined cycle gas	0.40

These assumptions are based on the averages in 4.4. About one-fifth of Queensland's coal generation capacity is supercritical, and the assumed intensity for black coal in Queensland allows for this proportion.

Black coal stations in NSW, Queensland and WA accounted for 57% of emissions from electricity generation in 00-01, and brown coal stations in Victoria and SA accounted for another 39%.

4.2. AGO estimates of generation emissions in 2000

Source	CO2 In 2000 Mtonnes	CH4 in 2000 Mtonnes	N2O in 2000 Mtonnes	CO2e in 2000 Mtonnes	Our estimates Mtonnes
Black coal	100.915	0.001	0.001	101.2	100.9
Brown coal	61.255	0.000	0.001	61.6	69.4
Petroleum	1.487	0.000	0.000	1.5	0.3
Gas	10.695	0.003	0.000	10.8	7.6
Wood, wood waste	na	0.000	0.000	0.0	
Biogas	na	0.002	0.000	0.0	
Total	174.352	0.006	0.002	175.1	178.2

The above estimates are from the Australian Greenhouse Office (2002a, B-78). A tonne of methane has been taken as equivalent to 21 tonnes of carbon dioxide, and a tonne of nitrogen dioxide as equivalent to 310 tonnes (AGO 2002a page 3 of "General notes").

Our estimates have been obtained from 4.1, dividing by 1.021 to allow for half a year of growth in demand (see 6.1). Overall, our estimates are within 2% of the AGO estimates, although the differences for some sources are large.

4.3. Marginal costs and emissions of selected power stations

Station	State	Type	Marginal costs $/MWh	Including $30/tCO2 $/MWh	Emissions tCO2/ MWh
Loy Yang A	Vic	Brown coal	3	42	1.30
Yallourn W	Vic	Brown coal	4	45	1.37
Hazelwood	Vic	Brown coal	4	48	1.47
Loy Yang B	Vic	Brown coal	5	42	1.23
Morwell	Vic	Brown coal	8	52	1.47
Millmerran	Qld	Black coal, supercritical	10	37	0.90
Callide C	Qld	Black coal, supercritical	10	34	0.80
Tarong North	Qld	Black coal, supercritical	11	35	0.80
Callide B	Qld	Black coal	11	39	0.93
Stanwell	Qld	Black coal	11	38	0.90
Tarong	Qld	Black coal	12	40	0.93
Bayswater	NSW	Black coal	12	39	0.90
Mount Piper	NSW	Black coal	13	38	0.83
Eraring	NSW	Black coal	13	40	0.90
Vales Point	NSW	Black coal	14	40	0.87
Liddell	NSW	Black coal	14	42	0.93
Gladstone	Qld	Black coal	14	41	0.90
Callide A	Qld	Black coal	14	46	1.07
Wallerawang	NSW	Black coal	15	42	0.90
Munmorah	NSW	Black coal	15	43	0.93
Northern SA	SA	Brown coal	16	50	1.13
Anglesea	Vic	Brown coal	16	57	1.37
Collinsville	Qld	Black coal	17	51	1.13
Newport	Vic	Gas	31	49	0.60
Thomas Playford	SA	Brown coal	33	78	1.50
Smithfield	NSW	Combined cycle gas	34	48	0.47

The above marginal costs are estimates from a bar chart in ACIL Consulting (2002). It is not clear if the marginal costs are just for fuel, or they include some operations and maintenance costs. Marginal costs with a \$30/tCO_2e emission charge were also given, and we have derived emission levels by comparing the two sets of marginal costs. For example, emissions for Yallourn W were estimated as

Marginal costs with \$30/t CO_2e charge	45
Less marginal costs without charge	-4
CO_2e charge per MWh	41
Divided by charge/tCO2	30
CO_2e emissions per MWh	1.37

These emission estimates have helped us to estimate average emission intensities from different types of generator and total emissions from all generators (4.1). Low marginal cost brown coal plant also happen to be high emission plant. While not shown in the above table, new combined cycle gas plant are understood to emit at less than 0.4 t CO_2e/MWh (Swanbank E, Qld; Pelican Point, SA). The wide differences between generators of the same type suggest that differing levels of emission charges may make some uneconomic while allowing others of the same type to continue operating.

4.4. Marginal costs and emissions of different types of station

Type	Number	Average marginal costs $/MWh	Range marginal costs $/MWh	Average emissions t/MWh	Range emissions t/MWh
Black coal	13	13.0	10-17	0.91	0.83-1.13
Black coal, supercritical	3	10.3	10-11	0.85	0.8-0.9
Brown coal	8	5.8	3-33	1.34	1.13-1.5
Combined cycle gas	2	28.0	22-34	0.40	0.33-0.47
Gas, other	1	31.0		0.60	
Total	27	11.4	3-34	1.01	0.33-1.5

The above statistics were obtained from 4.3. Average marginal costs and average emission intensities are weighted averages, taking into account the rated output of each generator.

4.5. Emissions and capital costs of new types of plant

Type	Emissions CO_2e/MWh	Efficiency	Cost in $m/MW
Supercritical black coal	0.83	40%	1.20
Frame 9H combined cycle gas	0.35	60%	1+
Ultrasupercritical black coal	0.75	44%	1.35
High pressure fluidised coal beds		45%-50%	
Integrated coal gasification	<0.35	>50%	2?
Solar tower	0		4

New plant offer lower emissions (on the whole) than existing plant.

Supercritical and ultrasupercritical technology have been in wide scale use for 15 and 10 years respectively around the world. H class frame 9 combined cycle plants are now being installed, with the first operational unit understood to have been completed in Wales in 2002. First generation fluidised bed coal plant are also known to be in operation (including at Redbank power station in NSW). High pressure fluidised coal beds and integrated coal gasification are not beyond the medium scale demonstration stage, and may not be commercially viable at large scale for 20 years.

The above information, except that for solar tower, has been obtained from presentations given by IHI, a supplier of major power station components. The Frame 9H combined cycle gas cost is a budget estimate[4].

The solar tower cost of $4m/MW has been obtained from EnviroMission (2003), which has announced plans for a $800m solar thermal electricity generator in the south west of NSW. This is intended to generate 200 MW by 2005, and four similar plants are planned to be operating by 2010. Each plant will use a 8000 hectare greenhouse to trap and heat air, which will generate electricity as it rises through a 1000 metre high chimney.

4.6. Estimated electricity generation costs

Type	Capital $/MWh	Fixed $/MWh	Fuel $/MWh	Total $/MWh
High capacity factor plant:				
Black coal	19	5	10	34
Brown coal	25	11	7	43
Natural gas combined cycle	13	7	21	41
Lower capacity factor plant:				
Natural gas open cycle	23	5	22	50
Wind	64	14	0	78
Solar photovoltaic	332	16	0	348
Solar thermal	175	22	8	205

The above costs are from figure 8.3 in the final report of the COAG Energy Market Review (2002, page 226). Total costs were marked on figure 8.3, but the capital, fixed and fuel components have been estimated from the graph, and may not be accurate. While it isn’t known whether these figures were intended to represent new or existing plant, or what capacity factor was used to measure these costs, the figures seem consistent with new plant, being black coal in NSW, brown coal in Victoria, and combined cycle gas in Queensland or Victoria. Costs for lower capacity plant are highly situation specific.

[4] Gas Turbine World, 2001

Allen Consulting Group & McLennan Magasanik Associates Pty Ltd (1999, page 86) assume a lifetime of 30 years and a real rate of return on capital of 10% pa (12.5% nominal equivalent is assumed for this purpose). Assuming a capacity factor of 90%, the charge per MWh needed to cover capital costs of $1.20m/MW is

capital cost per MW	$1,200,000
divided by hours in a year	8760
divided by capacity factor	0.9
divided by value of $1 pa for 30 years at 12.5% pa	7.77
capital charge needed per MWh	$19.60

This is in line with the $19 quoted by COAG for black coal. Combined cycle natural gas at $1m/MW is similarly estimated at $16. This is above the COAG estimate of $13, although this estimate may be based on less capital intensive (but slightly less efficient) F class Frame 9 technology. Note that the two recently constructed combined cycle plant at Pelican Point and Swanbank are both F class machines.

4.7. Comments on different electricity sources

Type	Capital costs as % of black coal	Fixed costs as % of black coal	Fuel costs as % of Black coal	Total Costs as % of Black coal	Emis-Sions as % of black coal
High capacity factor plant:					
Black coal	100%	100%	100%	100%	100%
Brown coal	132%	220%	70%	126%	145%
Natural gas combined cycle	68%	140%	210%	121%	43%
Lower capacity factor plant:					
Natural gas open cycle	121%	100%	220%	147%	65%
Wind	337%	280%	0%	229%	
Solar photovoltaic	1747%	320%	0%	1024%	
Solar thermal	921%	440%	80%	603%	

Electricity from brown coal is about 26% more costly than from black coal, and produces about 46% more CO_2e emissions per MWh. The last brown coal capacity added was in 1996 (Edison Mission's Loy Yang B station in Victoria). There appears to be little possibility of any new brown coal plant being built, particularly if the cost of CO_2e emissions is allowed for. Growing demand in Victoria may be met by new gas generators in Victoria, or by black coal generators in NSW and Queensland (assuming sufficient transmission facilities become available). Electricity from natural gas combined cycle is about 21% more costly than from black coal, but produces about 57% less CO_2e emissions per MWh.

Electricity generated from low capital cost, fast starting gas plant is a good way to meet peak demands. Some gas plant has recently been built for this purpose (for example, 300 MW of gas turbines in the Latrobe Valley and 150 MW of gas turbines at Somerton, both completed in 2002). Wind power is more than double the cost of that from coal or gas, and needs assistance to be viable. From the cost estimates in 4.6, a subsidy of about $44/MWh above the cost of black coal may be needed to make wind generation viable, close to the $40 provided by MRET.

4.8. New power stations of 100 MW or more

New stations of 100MW or more built in 1999 or later have been:

State	Description	Output MW	Station	Year built
WA	Gas/cogeneration	120	Worsley	1999
Qld	Jet A1, Open Cycle*	159	Yabulu	1999
SA	Combined cycle gas	478	Pelican Pt CC	2000
Qld	Natural gas/liquids, open cycle	282	Oakey	2000
Qld	Black coal, supercritical	840	Callide C	2001
NSW	Black coal, fluidised bed	150	Redbank	2001
Vic	Natural gas, open cycle	300	Valley Power	2002
Vic	Natural gas, open cycle	150	Somerton	2002
Qld	Black coal, supercritical	852	Millmerran	2002
SA	Natural gas/liquids, open cycle	220	Hallett	2002
Qld	Combined cycle gas	385	Swanbank E	2002
Qld	Black coal, supercritical	450	Tarong North	2003
Black coal		2292		52%
Combined cycle gas		863		20%
Other gas and liquids		1231		28%
Total		4386		100%

*Converting to combined cycle gas, 2005.

2292 of 4368MW of new plant have been constructed in Queensland. The only new station in NSW is coal fired, and all the new stations in Victoria, SA and WA (where gas is readily available) are gas fired.

New plant is not being constructed to replace ageing plant. The cost of construction is considerable – over $1 billion for a new 1000MW coal fired station (more in Victoria due to the higher capital cost of brown coal plant). Maintenance of existing stations for as long as possible may be more financially appealing than the major capital outlay for a new station.

Note also that new stations in new locations will also require transmission investment to connect to the high voltage grid, and this can add tens of millions of dollars to up front costs.

5. Emission levels, abatement measures, and the need to act

5.1. The Kyoto target, progress to date, the electricity generation sector

Australia's target for the first commitment period (2008 to 2012) under the Kyoto protocol would be national emissions of 543.6 Mt CO_2e pa, 108% of our 1990 baseline of 503.3Mt CO_2e. The stationary energy sector made up 208.5 Mt of the baseline. The AGO National Greenhouse inventory showed that the stationary energy industry emitted 264 Mt CO_2e in the 2000 year, a 26.6% increase over the 1990 level.

Clearly, this stationary energy increase will make any effort to meet the overall target more difficult, and action needs to be taken to reduce emissions.

A number of measures have already been taken, with schemes in place or with implementation well underway. There are 5 major schemes that relate to the electricity sector.

5.2. The five major schemes

One of the recommendations of the COAG review was that an economy-wide emissions trading system replace five existing greenhouse gas abatement schemes. The five schemes recommended for replacement were:

- The Federal MRET scheme, described at http://www.orer.gov.au/;
- The NSW Greenhouse Efficiency Benchmarks Scheme (the NGAC Scheme) described in various papers on the NSW ministry of Energy and Utilities website http://www.energy.nsw.gov.au/whats_new/index.htm
- The Qld Gas fired electricity scheme (the GEC Scheme), described in various papers on the Queensland Office of Energy website, http://www.energy.qld.gov.au/pubs.htm
- The Federal GGAP program, described at http://www.greenhouse.gov.au/
- The Federal GES (Generator Efficiency Standards) program, also described at http://www.greenhouse.gov.au/

The first three schemes are certificate based schemes, where the requirement to purchase certificates rests with energy users, and a penalty for non compliance is levied. A comparison of the features of these three schemes:

	MRET	NGAC	GEC
Aim of scheme	Increase generation from renewable sources	Reduce GHG emissions related to electricity generation	Reduce GHG emissions by encouraging gas fired generation
Geographic Application	National	NSW based	Qld based
Commenced	1/4/2001	1/1/2003	1/1/2005 (planned)
Ends	2020		2019
Mechanism to achieve aim	Generation from specified fuel sources	Many are postulated, both supply and demand side	Generation from specified fuel sources
Target	Incremental 9,500GWh of renewable electricity pa by 2010 over 1997 baseline. Ramps up from 300GWh pa in 2001	CO_2e levels per capita to be reduced to 7.27 t CO_2e by 2007 (first target of 8.65t in 2003)	13% of purchases from eligible electricity to be purchased from gas fired sources from 2005
Applies to	Electricity retailers and direct purchasers	Electricity retailers and direct purchasers	Electricity retailers and direct purchasers
Non-compliance penalty	$40/MWh	$10.50 per tonne	$11 per GEC
Key Advantages	Not intended to be tax deductible Targets sustainable generation	Not intended to be tax deductible Directly targets emission reduction	Not intended to be tax deductible Simple concept
		Demand side actions included	Will result in lower emissions/MWh
Key Disadvantages	Targets a mechanism, not a GHG solution Supply side only, no reward for energy efficiency	Potentially very complex to administer Only applies to NSW	Targets a mechanism, not a GHG solution Only Applies to Qld Supply side only, no reward for energy efficiency

The GGAP (Greenhouse Gas Abatement Program) program is a major Commonwealth funding program targeting major greenhouse gas abatement measures or carbon sink enhancements that would not take place in the absence of GGAP. The program targets projects with potential abatement levels above 250,000 t CO_2e per annum.

The GES - Generator Efficiency Standards - program is a voluntary mechanism designed to encourage electricity generators to operate at benchmark thermal efficiency levels.

5.3. Progress and achievements so far

MRET

The $40/MWh penalty for not acquitting sufficient REC's has fostered a secondary market in these certificates, and a number of generators have been constructed in response. Projects have included wind generation, landfill gas, hydroelectric, solar thermal and solar photovoltaic generation among others.

As at September 2002, over 1 million REC's had been registered with ORER, implying over 1,000 GWh of eligible electricity had been generated.

At the 2010 target level of 9,500 GWh pa, replacing black coal output with zero emission renewable output could save 8.8Mt pa CO_2e, assuming black coal intensity of 0.93t CO_2e/MWh. If the emission intensity of the renewable energy were not emission free but half that of black coal, 4.4Mt pa CO_2e would still be saved.

For energy and REC's purchased from a MRET eligible generator where REC's are valued at $40/MWh, this premium above an energy only price is equivalent to buying power from a black coal generator with emissions of 0.93 tCO_2e /MWh, who passes on an emission cost of $43/t CO_2e ($40/MWh/0.93t CO_2e /MWh).

NGAC

The NGAC Scheme has just been brought to legislation in NSW, commencing 1 January 2003, and as such no measures attributable to the NGAC scheme have yet been identified. Note that projects planned under other schemes, such as GGAP, may be eligible under the NGAC scheme.

If the targeted emission level of 7.27t CO_2e per capita is reached, the scheme could result in reduction in emissions of over 9Mt pa CO_2e from 2007 onwards.

GEC

The major supply of GEC's, and hence lower emissions in Queensland will probably be the recently constructed Swanbank E power station, and the Yabulu station once it is converted from open cycle mode running on Jet A1 to Combined cycle running on natural gas.

If the GEC target is met at an average emission level of 0.4t CO_2e per MWh, total emission reduction expected is approximately 3Mt CO_2e pa in 2010.

GGAP

The AGO website lists the projects approved under GGAP round 1 at http://www.greenhouse.gov.au/ggap/successfulprojects/index.html,. The stationary energy projects among these are estimated to reduce emissions by over 26Mt in the first Kyoto commitment period from 2008 to 2012 inclusive. Stationary energy projects already approved to date account for 10.6 Mt of this – an average of 2.1Mt pa of abatement.

GES

The third national communication on climate change, http://www.greenhouse.gov.au/international/third-comm, estimates that the Generator Efficiency Standards program will reduce emissions by 4Mt CO_2e pa once best practice is reached by all participating generators. This would achieved by generators achieving an agreed best practice thermal efficiency level, taking into account their age, fuel source and technology type.

5.4. GHG reductions expected from these programs

The total level of emission reduction achieved by adding the reductions in 5.2 is 22.5 to 26.9 Mt CO_2e for the 2010 year. It should be noted there is some overlap between these schemes, eg REC's can be surrendered to acquit both MRET and NGAC liability, and emission reductions from programs funded by GGAP can be used to acquit NGAC liability.

Overall emission reductions from the 5 schemes may, then, be less than 22.5 Mt CO_2e pa in 2010.

In fact, ACIL Tasman (2002) estimate these 5 schemes will save only 13.9 to 18.3 Mt CO_2e in the year 2010. A comparison of estimates:

Scheme	Emission reductions As per 5.2	Emission reductions from ACIL Tasman	Comment
MRET	4.4 to 8.8	7.4	
NGAC	9	4.3	ACIL may have allowed for possible double up with MRET
GEC	3	0.2	Hard to explain this difference. Our 3Mt figure is not unreasonable
GGAP	2.1	2.0	
GES	4.0	0.0 to 4.0	
Total	22.5 to 26.9	13.9 - 18.3	

The NGAC and GGAP differences are plausible, but the GEC difference is puzzling.

5.5. A single scheme with the same effect

ACIL Tasman estimated that a single, emissions trading scheme with a permit price of $3.75 per tonne will have the same emission reduction effect as the five current schemes, ie 18 Mt in 2010, and then 17 Mt in 2020. This may well be the case, but whether this is the most appropriate target remains debatable.

With stationary energy emissions already 55.4Mt above 1990 levels in 2000, (Australian Greenhouse Office, 2002c) abating 18 Mt may not be an adequate response.

6. Meeting future electricity demand, and emissions outcomes

6.1. Electricity demand forecasts

Electricity demand is forecast to grow significantly in the next 20 years:

Year	Business as usual GWh	High GWh	Low GWh
2000	167636		
2001	174795		
2002	177540	179529	176877
2003	183255	186241	180434
2004	188386	193117	184106
2005	195130	201850	188696
2006	201480	210165	191870
2007	207312	217515	195563
2008	212380	224396	198518
2009	216992	233064	201005
2010	224577	242904	204384
2011	232719	254179	208703
2012	240001	264187	212255
2013	246245	272763	215825
2014	251678	280867	218906
2015	257088	288401	221794
2016	264382	298443	225415
2017	272019	309091	229260
2018	279290	319496	233448
2019	286016	329298	237097
2020	292852	339536	240902
Increase 2000 to 2020	74.7%	102.5%	43.7%
Growth rate pa	2.8%	3.6%	1.8%

The above forecasts are from National Institute of Economic and Industry Research (2002), and are based on three economic growth cases, with differing GSP, GDP, $A/$US, crude oil prices and population growth levels. Economic growth and energy usage are widely understood to be linked, although there is some debate over the direction in which the causality runs. The average of the 2000 and 2001 demands is about 14% lower than ESAA figures on generation in 00-01 (see 3.2). The difference represents auxiliary consumption in power stations and transmission losses between generators and customers.

Interestingly, Foran and Poldy (2002, page 165) show a primary energy growth in the electricity generation sector of 37% in the period 2000 to 2020. Foran and

Poldy's assumptions about technology advances and thermal efficiency gains are understood to be aggressive.

6.2. Meeting the 2020 demand with supercritical black coal

If current plant continue to operate in the same way as in the year 2000, meeting incremental demand with black coal gives these emissions outcomes:

Source	2000 GWh	2020 GWh	2000 $MtCO_2e$	2020 $MtCO_2e$	Increase $MtCO_2e$
Hydro	15852	15852	0.0	0.0	0%
Black coal	111664	249553	99.1	213.5	115%
Brown coal	51855	51855	68.2	68.2	0%
Oil products	512	512	0.3	0.3	0%
Gas	8598	8598	5.1	5.1	0%
Combined cycle gas	6211	6211	2.4	2.4	0%
Other renewables	1947	10947	0.0	0.0	
Total	196639	343528	175.1	289.5	65%

Note that these emissions do not allow for the abatement measures discussed in section 5.4 other than MRET. It is, however, clear that abatement from these measures would not significantly mitigate the increase of over 114 Mt shown here.

Power generated in 2000 is from the 00-01 estimates in 3.2, divided by 1.021. Power from other renewables in 2000 is assumed to be 1% of power from all other sources. Emissions in 2000 are from the 00-01 estimates in 4.1, divided by 1.039 to balance with the AGO total in 4.2.

Total power generated in 2020 is assumed to be 74.7% higher, based on the business as usual forecast in 6.1. 9000 GWh are assumed to come from new renewables (based on the MRET 9500 GWh from 1/1/97 to 2010). All the increase is assumed to come from supercritical black coal plants, with emissions of 0.83 t/MWh. Emissions from all black coal plants in 2020 are estimated as

Additional generation from black coal in 2020 (GWh)	137889
Times 0.83t/MWh	0.83
Additional emissions from black coal in 2020 ($MtCO_2e$)	114.4
Plus emissions from black coal in 2000	99.1
Total emissions from black coal in 2020 ($MtCO_2e$)	213.5

The COAG energy market review noted that

> "Australia has approximately 800 years supply of easily accessible brown coal and 290 years supply of black coal." (page 7)

6.3. Meeting the 2020 demand with combined cycle gas

Alternatively, incremental demand could be met with lower emission generation. The most readily available and economic at the present time is combined cycle gas turbines (CCGT). If CCGT were used, resulting emissions would be:

Source	2000 GWh	2020 GWh	2000 $MtCO_2e$	2020 $MtCO_2e$	Increase $MtCO_2e$
Hydro	15852	15852	0.0	0	0%
Black coal	111664	111664	99.1	99.1	0%
Brown coal	51855	51855	68.2	68.2	0%
Oil products	512	512	0.3	0.3	0%
Gas	8598	8598	5.1	5.1	0%
Combined cycle gas	6211	144100	2.4	50.7	1977%
Other renewables	1947	10947	0.0	0.0	
Total	196639	343528	175.1	223.4	28%

Once again, abatement other than due to MRET are not allowed for in these figures. The above increases of 47.4 Mt represents a significantly lower emission outcome than in 6.2 above. This is a clear simple demonstration of the value (in a greenhouse gas sense) of incentivising low emission fuels and/or technologies. Note that combined cycle gas is just one way of achieving this: this is discussed further in section 6.6.

All the extra demand has been assumed to be met by combined cycle gas stations with emissions of 0.35 tonnes/MWh. The availability of sufficient economic gas reserves to sustainably fuel 144100 GWh pa of gas fired generation has been questioned, particularly for eastern Australia (Foran and Poldy 2002, p166).

6.4. Permit price to equate black coal and gas generation

Black coal and gas generation could be brought to level cost terms by way of emission penalties in one of two ways.

Method 1: equate long run average costs

costs per MWh of combined cycle (4.6)	41
less costs per MWh of black coal (4.6)	-34
difference in total costs	7
divided by difference in CO_2e/MWh (4.5)	0.48
permit price per tonne to equalise costs	15

The list of new stations in 4.8 shows that a mixture of gas and black coal plants are being built in different locations, and the local prices of gas and coal varies. The above rough analysis suggests that emissions charges of $10 to $20 per tonne of CO_2e would help ensure that new power stations fired by gas and coal compete on a cost basis over the long term.

Method 2: equate short run marginal costs

The disadvantage of the long run average cost equalisation method is that on a short run marginal cost basis, new black coal ($10+$15=$25) remains cheaper than gas (21+15=$36). This would mean that if bids in the market reflect marginal costs of operation, black coal will bid lower than gas, and be dispatched more frequently, partially negating the incentive for gas generation at the $15 price level.

From the marginal costs of electricity from black coal and combined cycle gas in 4.6, the permit price needed to approximately equalise total costs may be about

costs per MWh of combined cycle (4.6)	21
less costs per MWh of black coal (4.6)	-10
difference in total costs	11
divided by difference in CO_2e/MWh (4.5)	0.48
permit price per tonne to equalise costs	25

On this basis, $20 to $30 per tonne of CO_2e would help equalise marginal costs of coal and gas, allowing gas to compete with coal for dispatch. If black coal and gas can compete for dispatch on level terms, gas plant may become favoured, all other things being equal, due to their lower capital costs.

6.5. Effect of emissions charges on electricity demand

Allen Consulting Group & McLennan Magasanik Associates Pty Ltd (1999) said

> "there is considerable uncertainty over the price elasticity of demand, with estimates ranging from -0.2 to -0.5" (page 95)

From 6.2, the CO_2e emissions content of electricity generated in 2000 was approximately

CO_2e emissions (Mtonnes)	175.1
Divided by electricity generated (GWh)	196639
CO_2e emissions (tonnes/MWh)	0.89

The price rise resulting from a $10 per tonne permit price in 2002 may have been about

permit price per MWh	8.9
divided by average NEM price in 2002 per MWh (B.4)	44
% increase in NEM price from $10 per tonne emissions charge	20%

Based on the revenues of generators, transmission networks and distributors shown by ESAA (2002), generation costs may only represent about 40% of retail electricity costs. A 20% increase in NEM prices may thus result in about an 8% increase in retail prices.

These figures suggest that a $10/tonne permit price would reduce long-term demand by somewhere between 2% and 4%. Such demand reductions would be helpful in meeting Australia's greenhouse gas targets.

6.6. The effect of new technologies

Combined cycle gas turbines are currently the most emission - efficient available large scale generation technology. As discussed in section 4.5, new, clean coal technologies may emerge over time. Should this be the case, coal may once again become the generation fuel of choice, in fluidised bed or integrated gasification arrangements. Given the abundant supply of coal in Australia and concerns over natural gas reserves being sufficient to support large scale long term electricity generation, this might represent a longer term solution to Australia’s ever growing demand for energy.

7. COAG energy market review

7.1. COAG national energy policy objectives

At its meeting on 8/6/01, COAG agreed the following national energy policy objectives

- encouraging efficient provision of reliable, competitively-priced energy services to Australians, underpinning wealth and job creation and improved quality of life, taking into account the needs of regional, rural and remote areas
- encouraging responsible development of Australia's energy resources, technology and expertise, their efficient use by industries and households and their exploitation in export markets
- mitigating local and global environmental impacts, notably greenhouse impacts, of energy production, transformation, supply and use.

7.2. COAG energy market review

At the same meeting, COAG agreed on an independent energy market review, intended to be a forward-looking, strategic study to facilitate decision-making by governments. One of the six priority issues for the review was

> "assessing the relative efficiency and cost effectiveness of options within the energy market to reduce greenhouse gas emissions from the electricity and gas sectors, including the feasibility of a phased introduction of a national system of greenhouse emission reduction benchmarks"

Members of the review panel were:

- The Hon Warwick Parer (former Senator for Queensland and former Federal Minister for Resources and Energy)
- David Agostini (Senior Consultant, petroleum industry and Adjunct Professor, Oil and Gas Engineering, University of Western Australia)
- Paul Breslin (Director, ACIL Consulting)
- Rod Sims (Director, Port Jackson Partners Limited).

The review sought submissions by April 2002, published a draft report on 15/11/02, invited submissions by 6/12/02 and published its final report on 20/12/02. An ACIL Tasman report on the impacts of the recommendations was released together with the final report.

7.3. Recommendations in relation to greenhouse gas emissions

Recommendations made by the review in relation to greenhouse gas emissions were

"8.1 A cross sectoral greenhouse gas emissions trading system should be introduced to reduce greenhouse gas emissions in the electricity and gas sectors. Once an announcement has been made on an agreement to implement an emissions trading system the following measures should

immediately cease to operate:

(a) *Commonwealth stationary energy measures:*

Mandatory Renewable Energy Target
Generator Efficiency Standards
Greenhouse Gas Abatement program; stationary energy projects.

(b) *State based stationary energy measures:*

NSW Electricity Retailer Greenhouse Benchmarks
Queensland 13 per cent Gas Scheme.

8.2 *Energy intensive users in the traded goods sector are to be excluded from the scheme referred to in recommendation 8.1 until Australia's international competitors introduce similar schemes. Excluded entities are required to meet world's best practice in relation to their energy use.*

8.3 *Investments entered into in response to existing schemes, identified in Recommendation 8.1, will continue to receive an equivalent subsidy. The Final details of such a payment will need to be developed in parallel with the development of the emissions trading system so as to minimise Overlap.*

8.4 *The introduction of interval meters should be mandated in order to Increase opportunities for demand-side participation in the electricity sector."*

7.4. Form of emissions trading scheme

The review is not specific about the form of the proposed emissions trading scheme

> "There are a number of alternative options available to allocate permits including auctioning, performance based allocation arrangements and/or a free once-and-for-all allocation." (page 238)

The review quotes from an Australian Greenhouse Office (2002b) submission

> "Given the diversity of interest and attributes within the economy, it is likely that a 'tailored' approach to permit allocation, possibly including a process of intensive analysis and negotiation, could only be adopted for large Individual players with a high greenhouse exposure and few opportunities to absorb or pass on costs. For less affected entities within the economy more generic allocation procedures could be considered, including the possibility of a permit auctioning system with revenue recycled through adjustment assistance or tax relief packages."

Both of these comments refer to an emissions trading scheme where some emissions permits are allocated free of charge. Neither seem to consider the option to auction permits. Allen Consulting, in their report to the AGO (Allen Consulting 2000) consider this option. This is discussed in section 7.9.

7.5. ACIL Tasman report on emissions trading scheme

Together with its final report, the energy market review published a commissioned report by ACIL Tasman (2002). One of its 9 chapters analyses an economy wide emissions trading scheme, intended to reduce emissions in the electricity sector by up to 18.3 million tonnes of carbon dioxide in 2010. The 18.3 million tonnes is an upper estimate of the reductions in emissions likely to be achieved by the five present schemes to be replaced by the emissions trading scheme.

ACIL Tasman estimated a permit price of $3.75 per tonne of carbon dioxide

> "The estimated annual permit price for an economy-wide emissions trading scheme is $3.75 per tonne of carbon dioxide in 2002 dollars. This has been estimated by setting an emissions reduction target of 18.3 million tonnes … in 2010 and allowing Tasman Global to determine the permit price. Tasman Global has within it a specification of the carbon dioxide emissions throughout the economy, and this is the amount of an implied change on all fuels across all sectors of the economy that would be needed to change behaviour in a way that would cause this reduction."
>
> "At the price of $3.75 a tonne there are some renewable energy schemes which would be cheaper than the price of the permit (in addition to cost-effective energy measures). ACIL Tasman modelling suggests that the most likely would be biogas (sewage and landfill) schemes." (page 67)

ACIL Tasman's estimates apparently do not depend on the form of permit allocation

> "The assessment is undertaken assuming that the emissions trading Allocation, whether by auction or by administrative allocation, makes no difference to market behaviour. ACIL Tasman believes this is a reasonable approach given the ample literature to show that appropriately designed initial allocation should make no difference to economic efficiency, although it does have significant wealth redistribution Implications." (page 69)

ACIL Tasman do not favour annual permits

> "Annual permits will result in less economically efficient outcomes than permits that allow lowest cost risk management, including through the development of mature secondary markets." (page 69)

7.6. Limitations of ACIL Tasman analyses

The analyses only went to 2010, and sought only to provide a reduction of 18.3 $MtCO_2e$. Our estimates, however, show an increase of 114 Mt CO_2e by 2020, assuming all new demand is met by supercritical black coal (see 6.2). Much higher permit prices would presumably be needed to keep emissions anywhere near present levels.

The Tasman-Global model used by ACIL Tasman may have overestimated the flexibility of electricity generators

> "…models such as Tasman-Global … tend to overestimate the ability of the sector to alter the fuel mix and reduce emissions over certain ranges of carbon dioxide prices." (page 73)

ACIL Tasman did not have time to reconcile their models

> "In the time available.. It was not possible to investigate the causes and effects of the discrepancies between ACIL Tasman's tops-down model (Tasman-Global) and the bottom-up model (PowerMark)." (page 73)

ACIL Tasman only modelled an emissions trading scheme. They did not model the phased introduction of a national system of greenhouse emission reduction benchmarks, as mentioned in the review's terms of reference. Nor did they model any form of emissions charge.

ACIL Tasman assumed that initial permits would be free

> "emission permits were grandfathered (that is, allocated to the States and Territories of Australia) based on 2005 emissions." (page 72)

Is it intended that changes to emissions quotas be determined and administered by the States and Territories?

7.7. Disadvantages of present greenhouse schemes

The review criticized existing schemes, which target particular technologies

> "The rationale for a scheme which focuses only on renewable rather than on greenhouse benefits is the perception of the need for the conservation of non-renewable resources. This is, however, not an issue for Australia. Consequently, any arbitrary diversion of investment away from more efficient carbon reducing options and towards renewables will burden the economy with unnecessary costs."
>
> "Clearly, the solutions that represent least cost to the community will be those focussed on greenhouse abatement, and that apply to the broadest part of the economy."
>
> "…Governments, should not, however, be picking technologies, as they are doing now. They will inevitably get the choice wrong, to the cost of the wider community." (pages 39-40)

The review mentioned the problems created by competing greenhouse schemes of the Commonwealth, states and territories

> "This has created the potential for gaming and the distortion of economic behaviour. In some jurisdictions for some measures, companies can claim under both Commonwealth and jurisdictional schemes, whereas in others this is disallowed. Some measures are greenhouse friendly in one state, but not another." (page 40)

The review noted that an overwhelming theme in submissions was the need for greater regulatory certainty

> "The third problem is the cost imposed on the energy industry because of the uncertainty. Industry can see the public concern over this issue and they recognize that the current responses are not the final ones. Industry responds to this uncertainty by factoring in higher project discount rates which are then reflected in a requirement for higher wholesale electricity prices than should be necessary to justify new investment." (page 40)

7.8. Problems with emissions trading in energy sector

In theory, emissions trading should provide the most cost-effective solution to any required emissions target. In practice, a badly designed emissions scheme may be a major obstacle to long-term progress. Some of the issues to be faced under such a scheme are:

- Equity considerations, particularly between existing generators (with sunk capital, and relatively high emissions) and potential new entrants (with high capital requirements, despite potentially lower emissions);
- cost disadvantages directly attributable to low emission technologies – the cost of being clean;
- locational signals. Cleaner energy depends heavily on fuel availability, and some parts of Australia have limited access to clean fuels;
- transmission lines to move clean power from source to demand centre can prove very expensive;
- uncertainty created by the dependence of emission prices on national emissions targets.

7.9. Sale or administrative allocation of emission permits?

An emissions trading scheme may involve permits being either administratively allocated at no cost, or alternatively, auctioned by Government. Each method is likely to have its proponents, and advantages and disadvantages accrue to both. A scheme that is both equitable and efficient will no doubt be challenging to design.

Allen Consulting (2000, page 8) discuss the advantages of sale by the Government of emission permits.

> "In imperfect markets, auctioning can have important advantages over administrative allocation on efficiency grounds. If Capital Gains Tax were

applied to emission permits, it is difficult to see any circumstances under which administrative allocation could be favoured, It can further be argued than an announcement of that permits will be auctioned can create incentives for early abatement action, which do not exist under administrative allocation options."

"Much of the resistance towards auctioning is based on equity grounds. The main equity argument is that it represents the appropriation of a right, that is the right to emit or pollute, from a private entity to the government…"

"Some proponents of the auctioning approach, however, argue that equity objectives can be *better* achieved under auctions. Auctioning permits would give governments an effective, flexible and substantial instrument in pursuit of their particular equity goals … For example, if the Government sold 500 million permits a year at $30 each, the resulting revenue of $15 billion could be used to:

- Abolish payroll tax in all States and Territories;
- Subject to WTO rules, provide support to trade-exposed, energy-intensive industries that would otherwise move offshore;
- Support a major R&D program in new fuel technologies;
- Provide adjustment assistance to GHG-intense emitters, such as brown coal generators…"

Allen Consulting favour the sale of permits (page 10)

"Any administrative allocation system will be deficient both in efficiency and equity terms … The sale of permits with revenue recycling, on the other hand, has the potential to satisfy both efficiency and equity objectives."
"We propose that the second approach, based on the sale of permits, be adopted."

8. National energy strategy

8.1. Action is clearly required

The coal fired generation scenario shown in section 6.2 leads to a rapid increase in emissions from electricity production which is unlikely to be offset by schemes currently in place, in their current form. The resulting levels of emissions are highly unlikely to be acceptable in any arena, either national or international, and this “business as usual” scenario is not a genuine option for the future. A coordinated, reasoned approach to greenhouse gas abatement is required, which includes the generation sector as a key participant within the wider economy.

It seems difficult for this to be achieved without Commonwealth leadership.

8.2. The need for a national energy strategy

There is a strong need for a national energy strategy, rather than a state-based or purely market-based approach:

- only the Commonwealth government can determine Australia's international greenhouse gas commitments;
- greenhouse gas emissions occur in many different sectors of the economy, and an overall approach is essential;
- some innovative, low operating cost energy projects involve large amounts of capital, and can need initial tax concessions or other subsidies to become viable and provide long-term benefits to Australia;
- only the Commonwealth has the taxing powers needed for emissions charges;
- uncoordinated actions by different states may not be in Australia's best interest – witness the commentary in the COAG review on electricity transmission and the need for a national coordinator;
- energy projects often involve very long-term investments, for periods of 30 to 50 years, and potential investors want stability and minimal regulatory risk during these periods.

8.3. Need for a robust strategy

Any national energy strategy needs to be robust enough to deal with large uncertainties, including:

- Australia's international commitments to emissions control over the long term
- A wide range of future population scenarios
- Future energy consumption levels and patterns per capita
- Consequent uncertainty in the capital and ongoing costs of meeting energy demand
- Emission outcomes from other sources, such as transport.

The International Panel on Climate Change believes that stabilising greenhouse gas concentrations at double pre-industrial levels will require deep cuts in global emissions, eventually by 60% or more. Ways to achieve such reductions for Australia have been proposed by Turton, Ma, Saddler & Hamilton (2002).

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10. Glossary

AGO	Australian Greenhouse Office
Bagasse	Residue after extraction of juice from sugar-cane or sugar-beet
Biomass	Vegetation used for the generation of electricity or fuel
Capacity factor	The power produced by a generator in a period, as a proportion of the total power it could have produced if operated at maximum output throughout the period
COAG	Council of Australian Governments
CO_2e	Carbon Dioxide Equivalent: having the equivalent greenhouse gas effect as 1 tonne of CO2
Coal Gasification	A process where methane, carbon dioxide and other gases are extracted from coal prior to combustion
Combined cycle	In reference to gas turbines, a process where waste heat from a combustion turbine is used to produce steam which powers a steam turbine
Emissions	Greenhouse gas emissions
ESAA	Electricity Supply Association of Australia
Fluidised Bed	Combustion technology involving extraction of combustibles from mixtures by bubbling them to the surface of a fluid bed and then combusting.
Frame 9, Frame 9F, Frame 9H	In relation to gas turbines. Frame 9 refers to physical size (Frame 9 is the largest, Frame 6 and 7 are the smaller versions), F and H refer to operating temperatures and pressures.
GEC	Gas Electricity Certificates
GES	Generator Efficiency Standards
GGAP	Greenhouse Gas Abatement Program
GHG	Greenhouse Gas
GWh	A gigawatt hour is a unit of energy, equivalent to a billion watts for an hour
MRET	Mandated Renewable Energy Target (see 5.3)

Mt CO_2e	One Million tonnes of CO_2e
MWh	A megawatt hour is a unit of energy, equivalent to a million watts for an hour
NGAC	NSW Gas Abatement Certificate. The instrument used to acquit liability under the NSW Electricity Benchmark scheme
NEC	National Electricity Code (see Appendix B)
NECA	National Electricity Code Administrator (see Appendix B)
NEM	National Electricity Market (see Appendix B)
NEMMCO	National Electricity Market Management Company Limited
ORER	Office of the Renewable Energy Regulator. ORER administers the MRET scheme
Pump storage	Lifting water by electro-mechanical means so that it can be used for hydroelectric generation
REC	Renewable Energy Certificate. The instrument used to acquit liability under the MRET scheme
Snowy	The Snowy Mountains Hydro-Electric Authority is jointly owned by the federal government and the state governments of NSW and Victoria
Stationary energy	Electricity or heat generation
Supercritical	Referring to coal generation. Operating at higher steam temperatures and pressures than conventional (subcritical) plant.
Ultrasupercritical	Referring to coal generation. Operating at higher steam temperatures and pressures than supercritical plant.

Appendix A : Electricity generators in Australia in 2002

State	Description	Output MW	Location	First year built	Last year built
NSW	Black coal	2640	Eraring	1982	1984
NSW	Black coal	2640	Bayswater	1982	1984
NSW	Black coal	2000	Liddell	1971	1973
NSW	Black coal	1320	Vales Point B	1978	
NSW	Black coal	1320	Mount Piper	1992	1993
NSW	Black coal	1000	Wallerawang C	1976	1980
NSW	Black coal	600	Munmorah	1969	
NSW	Hydro/pump	240	Shoalhaven Bendeela	1977	
NSW	Combined cycle gas	177.5	Smithfield	1997	
NSW	Black coal, fluidised bed	150	Redbank	2001	
NSW	Gas turbine/oil	50	Broken Hill	1989	
NSW	Gas turbine/oil	50	Hunter Valley	1988	
NSW	Hydro	50	Hume	1957	
NSW	Waste gas/cogeneration	61.25	BHP RBPD	1928	1992
NSW	Methane	54	Appin	1997	
NSW	Waste gas/cogeneration	22	Appin		
NSW	Hydro	50	Warragamba	1959	
NSW	Methane	40	Tower	1997	
NSW	Hydro	18	Wyangla		
NSW	Hydro	14.5	Burrendong	1996	
NSW	Hydro	24	Copeton	1996	
NSW	Wind	10.6	Blayney	2000	
NSW	Wind	4.8	Crookwell	1999	
NSW	Hydro	9	Yarrawanga	1997	
NSW	Hydro	27	Burrinjuck	1938	2002
NSW	Hydro	6	Keepit	1938	
NSW	Hydro	5.8	Glenbawn	1995	
NSW	Hydro	4	Brown Mountain	1938	
NSW	Hydro	9.8	Nymboida	1928	
NSW	Hydro	5	Oakey		
NSW	Wind	0.6	Kooragang Island	1997	
NSW	Wind	1.3	Hampton	2001	
Vic	Brown coal	2000	Loy Yang A	1984	1987
Vic	Brown coal	1600	Hazelwood	1964	1971
Vic	Brown coal	700	Yallourn W	1973	1975
Vic	Brown coal	750	Yallourn W	1981	1982
Vic	Brown coal	1000	Loy Yang B	1993	1996
Vic	Gas	500	Newport D	1980	
Vic	Open cycle gas	226	Jeeralang	1979	
Vic	Open cycle gas	240	Jeeralang	1980	
Vic	Gas turbine/gas	300	La Trobe Valley	2002	
Vic	Brown coal	20	Morwell	1958	
Vic	Brown coal	90	Morwell	1958	1959

Vic	Brown coal	60	Morwell	1962	
Vic	Gas turbine	150	Somerton	2002	
Vic	Brown coal	150	Anglesea	1969	
Vic	Hydro	150	Dartmouth	1980	
Vic	Hydro	120	Eildon	1956	1957
Vic	Hydro	96	McKay Creek	1960	
Vic	Open cycle gas	86	Bairnsdale	2001	
Vic	Hydro	61.6	West Kiewa	1955	1956
Vic	Hydro	26	Clover	1944	1945
Vic	Hydro	13.55	Rubicon	1928	
Vic	Hydro	2.7	Lower Rubicon	1928	
Vic	Hydro	2	Cairn Curran	1960	
Vic	Hydro	0.8	Royston	1928	
Vic	Hydro	0.3	Rubicon Falls	1926	
Vic	Waste gas/cogeneration	44.4	Corio	1968	1992
Vic	Waste gas	32	Petroleum/Esso-LIP		
Vic	Gas/cogeneration	54.5	Maryvale	1976	1989
Vic	Hydro	4.5	Eildon		
Vic	Wind	18	Codrington	2001	
Vic	Wind	21	Toora	2002	
Qld	Black coal	1680	Gladstone	1976	1982
Qld	Gas turbine/oil	15	Gladstone GT	1976	
Qld	Black coal	1400	Tarong	1984	1986
Qld	Gas turbine/oil	15	Tarong GT	1983	
Qld	Black coal	1400	Stanwell	1993	1996
Qld	Black coal	408	Swanbank A	1966	1969
Qld	Black coal	500	Swanbank B	1970	1973
Qld	Black coal, supercritical	852	Millmerran	2002	
Qld	Black coal	700	Callide B	1988	1989
Qld	Hydro/pump	500	Wivenhoe	1984	
Qld	Open cycle gas/liquids	282	Oakey	2000	
Qld	Kerosene	288	Mt Stuart	1998	
Qld	Black coal, supercritical	420	Callide C	2001	
Qld	Black coal	180	Collinsville	1998	
Qld	Open cycle liquids	159	Yabulu	1999	
Qld	Black coal	120	Callide A	1998	
Qld	Open cycle gas	76	Roma GT	1999	
Qld	Hydro	72	Kareeya	1957	1959
Qld	Hydro	60	Barron Gorge	1963	
Qld	Combined cycle gas	53	Barcaldine	1996	
Qld	Open cycle liquids	34	Mackay	1976	
Qld	Open cycle liquids	37	Swanbank D GT	1999	
Qld	Black coal, supercritical	450	Tarong North	2003	
Qld	Combined cycle gas	385	Swanbank E	*2002*	
Qld	Gas	132	Mica Creek A	1998	
Qld	Gas turbine	100	Mica Creek A	*1998*	
Qld	Gas turbine	90	Mica Creek B & C	1997	
Qld	Bagasse	50.5	CSR (Invicta)	1976	1996
Qld	Bagasse	49	Burdekin River		
Qld	Gas	44.5	Mt Isa		

Qld	Black coal/cogen	37.5	Queensland Nickel	1974		
Qld	Combined cycle gas	32	Bulwer Island	2000		
Qld	Bagasse	21.3	Tully	1956	1997	
Qld	Bagasse	23	CSR (Plane Creek)	1970	1997	
Qld	Reciprocal/distillate	24.4	Cannington	1997		
Qld	Black coal/cogeneration	25	Gladstone	1973		
Qld	Bagasse	19.3	South Johnstone	1970	1997	
Qld	Bagasse	18	Marian Mill	1967	1978	
Qld	Bagasse	13.8	Racecouse Mill	1968	1982	
Qld	Bagasse	13	Farleigh	1956	1983	
Qld	Bagasse	10.5	Mulgrave	1970		
Qld	Bagasse	10.1	Pleystowe	1966	1975	
Qld	Wind	12	Windy Hill	2000		
Qld	Hydro	7	Koomboolomba	2000		
Qld	Bagasse	30	Rocky Pt Bagasse			
SA	Gas	480	Torrens Island A	1967		
SA	Gas	800	Torrens Island B	1977		
SA	Brown coal	520	Northern SA	1985		
SA	Combined cycle gas	478	Pelican Pt CC	2000		
SA	Gas turbine/gas	220	Hallett	2002		
SA	Brown coal	180	Thomas Playford	1960		
SA	Open cycle gas cogeneration	180	Osborne	1998		
SA	Open cycle gas	156	Dry Creek	1973		
SA	Open cycle gas	90	Mintaro	1984		
SA	Gas turbine	78	Snuggery	1978		
SA	Gas turbine/diesel	25	Snuggery	1997		
SA	Open cycle gas	80	Ladbroke Grove	2000		
SA	Gas turbine/distillate	50	Port Lincoln	1998	2000	
SA	Waste gas	60	Whyalla	1941		
SA	Waste gas	37.5	BHPLPD			
SA	Under 20MW	60				
WA	Black coal, oil	400	Muja	1985	1986	
WA	Black coal, oil	400	Muja	1981		
WA	Black coal, oil	240	Muja	1965		
WA	Black coal, gas, oil	400	Kwinana	1976		
WA	Gas turbine/distillate	21	Kwinana	1972		
WA	Black coal, gas, oil	480	Kwinana	1970		
WA	Gas turbine/distillate	466	Pinjar	1990	1992	
WA	Gas turbine	120	Pinjar	1996		
WA	Black coal	330	Collie	1990		
WA	Gas/cogeneration	120	Worsley	1999		
WA	Gas/cogeneration	116	Kwinana(Mission)		1998	
WA	Gas turbine	112	Mungarra	1990	1991	
WA	Gas turbine	105	Parkeston	1996		
WA	Gas/cogeneration	98	Wagerup Alcoa		1981	1996
WA	Gas/cogeneration	95	Pinjara Alcoa		1972	1985
WA	Black coal/cogeneration	82.5	Worsley			
WA	Gas/cogeneration	34	Worsley Alumina		2000	
WA	Gas turbine/distillate	62	Kalgoorlie	1984	1990	
WA	Gas/cogeneration	74.5	Kwinana Alcoa		1994	

WA	Gas turbine	42	Kalgoorlie Nickel	1996	
WA	Gas turbine	42	Kambalda Nickel	1996	
WA	Gas turbine	36	Tiwest	1999	
WA	Gas turbine/distillate	21	Geraldton	1973	
WA	Hydro	2	Wellington Dam	1992	
WA	Gas turbine	180	Port Hedland	1996	1998
WA	Gas	120	Dampier C		
WA	Gas turbine	120	Dampier		
WA	Gas turbine	108	Mt Newman	1996	
WA	Gas turbine	105	Cape Lambert		
WA	Gas/cogeneration	76	Murrin Murrin		1998
WA	Gas turbine	42	Leinster	1996	
WA	Gas turbine	42	Mt Keith		
WA	Hydro	30	Argyle		
WA	Gas turbine/distillate	23.45	Pilbara	1979	
WA	Wind	22	Albany	2001	
WA	Diesel	20	Argyle		
WA	Gas turbine	20	Paraburdoo		
WA	Wind	19	Esperance	1999	
WA	Gas/cogeneration	14	Orabanda	1998	
WA	Distillate/oil/wind	106.256	Various under 20 MW		
Tas	Hydro	432	Gordon River	1978	
Tas	Hydro	300	Central Plateau Area	1964	
Tas	Oil, converting to gas	240	Bell Bay	1971	
Tas	Hydro	231.2	Pieman River	1986	
Tas	Hydro	144	King River	1992	
Tas	Hydro	125	Central Plateau Area	1953	
Tas	Hydro	90	Central Plateau Area	1938	
Tas	Hydro	85	Forth River	1971	
Tas	Hydro	83.7	Central Plateau Area	1960	
Tas	Hydro	82.8	Anthony River	1994	
Tas	Hydro	80	Launceston	1955	
Tas	Hydro	79.9	Pieman River	1983	
Tas	Hydro	79.9	Murchison River	1982	
Tas	Hydro	60	Forth River	1969	
Tas	Hydro	51	Forth River	1969	
Tas	Hydro	48	Central Plateau Area	1962	
Tas	Hydro	43.2	Fisher River	1973	
Tas	Hydro	40	Lower Derwent	1967	
Tas	Hydro	38.3	Central Plateau Area	1957	
Tas	Hydro	32.4	Central Plateau Area	1956	
Tas	Hydro	30.6	Forth River	1971	
Tas	Hydro	28	Lower Derwent	1968	
Tas	Hydro	28	Forth River	1972	
Tas	Hydro	17	Lower Derwent	1968	
Tas	Hydro	12.2	Central Plateau Area	1951	
Tas	Hydro	10.4	Mersey River	1968	
Tas	Hydro	8.4	Lake Margaret	1995	
Tas	Diesel	4.4	King Island		
Tas	Hydro	1.6	Tods Corner		

Tas	Diesel	1.5	Flinders Island		
Tas	Gas turbine	10	TEMCO		
Tas	Oil	4	Wesley Vale		
Tas	Black coal	11.5	Burnie		
Tas	Wind	10.5	Woolnorth	2002	
Snowy	Hydro	750	Tumut 3	1973	
Snowy	Hydro/pump	750	Tumut 3	1973	
Snowy	Hydro	950	Murray 1	1966	
Snowy	Hydro	550	Murray 2	1968	
Snowy	Hydro	330	Tumut 1	1959	
Snowy	Hydro	286	Tumut 2	1961	
Snowy	Hydro	80	Blowering	1971	
Snowy	Hydro	60	Guthega	1955	
NT	Gas turbine	114	Channel Island	1986	
NT	Combined cycle gas	64	Channel Island		*1986*
NT	Gas	32	Channel Island	*1986*	
NT	Gas turbine	44.5	Channel Island	*1986*	
NT	Gas turbine	7.5	Cosmo Howley	1991	1994
NT	Diesel	3.8	Ron Goodin	1978	
NT	Diesel	16.5	Ron Goodin	1974	
NT	Diesel	12.6	Ron Goodin	1987	
NT	Gas turbine	11.7	Ron Goodin	1988	
NT	Diesel	6	Ron Goodin	*1988*	
NT	Gas turbine/jet fuel	30	Berrimah	1979	
NT	Gas turbine	21	Katherine	1987	
NT	Gas/diesel	1.8	Tennant Creek	1992	
NT	Gas/diesel	2	Tennant Creek	*1992*	
NT	Diesel	7.8	Tennant Creek	1975	
NT	Gas	4.79	Tennant Creek	1999	
NT	Gas/diesel	2.6	Yulara	1989	
NT	Diesel	1.6	Yulara	1986	
NT	Gas/diesel	2.6	Yulara	1982	
NT	Gas	3.94	Yulara	1999	
NT	Diesel	33.656	Various		
NT	Fuel oil	105	Gove	1971	
NT	Gas turbine	35	Mt Todd		
NT	Combined cycle gas	26	Pine Creek	1995	1996
NT	Gas	0.6	Pine Creek	*1995*	*1996*
NT	Gas turbine	7.5	Pine Creek	1998	
NT	Gas turbine	12	McArthur River	1995	
NT	Gas turbine	8.4	McArthur River	1995	1996
NT	Diesel	0.95	McArthur River	1995	
NT	Diesel	16	GEMCO		
NT	Diesel	8.51	Brewer Estate	1997	
Total		47359			

Nearly all data are from the Electricity Supply Association of Australia (2002, appendix 1). Coal plants in WA and Tasmania were assumed to be black coal. Approximate completion dates are shown in italics.

Appendix B : background on the National Electricity Market

B.1. Background on the National Electricity Market

The Victorian electricity market commenced in 1994, and regions have progressively been added to form the NEM, with Queensland finally achieving a major connection to NSW in 2001. Current estimates are for Tasmania to join in 2005 or 2006.

The NEM is currently made up of 5 regions, which align with States (with one exception). These are Queensland, NSW, Snowy, Victoria and SA. These 5 regions are connected by one interconnected Transmission network - understood to be the longest in the world from Cooktown to Port Augusta. Tasmania is expected to join within the next few years. Connecting NT and WA is impractical due to distances involved, and there is a separate grid centring on Mt Isa in Queensland, and a number of remote generators and small grids all around the country.

Participants in the NEM include Generators, Transmission Companies, Retailers, Distributors (who are most often also retailers as well) and regulators. There have in the past been pure trading houses - Enron and Edgecap - but both have subsequently withdrawn from the NEM. Participants are both state owned (most of Queensland and NSW) and privately owned (Victoria, SA and some participants in Queensland and NSW), and public/private partnerships exist.

Underpinning the NEM is an electricity spot market, into which generators bid and from which retailers and direct market customers purchase electricity. Electricity cannot be stored, and this market must clear.

The spot market is dispatched in each region every 5 minutes, and can be traded at half hourly intervals. Generators bid their capacity into the spot market, and are dispatched in price order until demand is met. Demand side bidding (to withdraw load) is catered for, but not common.

Generators and some loads provide other services to the market, primarily to maintain frequency and voltage at nominal levels.

Regulated transmission companies and distributors usually play no active role in the spot market, although their actions - transmission companies in particular - can have dramatic effect on price outcomes (there is a second kind of transmission entity - see below).

The market is administered by **NEMMCO, the National Electricity Market Management Company**. The national Electricity Code (NEC) is administered by **NECA, the national Electricity Code Administrator**. The ACCC maintains its usual Trade Practices Act role, and is the primary regulator for State based transmission companies, which are effectively regulated as monopolies. There is a second kind of transmission company, regulated a different way, which participates in the market by purchasing electricity from one region on the spot market, and selling it into an adjacent region in its spot market at times of their choice. This is different to the main kind of transmission where flow along a line is an outcome of generation and load patterns, not an actively controlled input.

Standing beside the NEM spot market is a derivatives market, used to reduce risk of exposure to a volatile spot. Most derivative deals are settled over the counter, and few of these have their details made public. There is currently little liquidity in these markets (except perhaps in Victoria), which is, in some instances exacerbated by the actions of the owners of some participants (particularly some publicly owned generators and retailers).

B.2. NEMMCO's description of the NEM

NEMMCO (2003) gives the following description of the national energy market

"The National Electricity Market (NEM) commenced operation on 13 December 1998, as part of the process of deregulation of the Australian power industry. Its key objective is to promote competition at each stage of the electricity production and supply chain."

"The National Electricity Market Management Company Limited (NEMMCO) operates a wholesale spot market for trading electricity between generators and electricity retailers in the NEM. This means that all the electricity output from generators is pooled, and then scheduled to meet electricity demand. This system has been adopted to reflect two particular aspects of electricity generation and use. Firstly, electricity cannot be stored for future use; therefore supply must always be responsive to variations in demand. Secondly, it is not possible to distinguish which generator produced the electricity consumed by a particular customer."

"The spot market is the whole process whereby prices for electricity are set and then settled. Generators are paid for the electricity they sell to the pool, and retailers and wholesale end-users pay for the electricity they use from the pool. In general, all electricity must be traded through the spot market. NEMMCO calculates the spot price using the price offers and bids for each half-hour period during the trading day. The spot price is the clearing price to match supply with demand."

The NEM currently covers most of NSW, Victoria, Queensland and SA.

Transmission of electricity between Victoria and Tasmania should be possible by January 2005 (ACIL Tasman 2002 page A.1-10). Tasmania has agreed to join the NEM.

B.3. Price instability in NEM

The price data in B.4 show that in times of high demand spot prices can rise very sharply. The COAG energy market review, discussing generator market power, said

> "With pool prices set by the highest bid unit required to meet demand, with generators able to rebid continually as they assess the level of demand and plant failure, and with pool prices set every five minutes, there are too many periods when one or two generators know they can effectively set the price at a level they choose." (COAG 2002 page 17)

High peak prices can reflect one or more of:

- high demand;
- the higher cost of peaking plant;
- lack of reserve margin;
- insufficient interconnection between NEM regions
- strategic bidding behaviour, and
- effective lack of competition in some states

B.4. NEM electricity demand and prices in 2002

Demand as % of capacity	Number of half hours	Average price $/MWh	Standard deviation of price	Standard error of price	Energy supplied GWh	Revenue $m
36%	4	6.45	1.10	0.17	28	0
38%	124	11.44	7.74	0.68	900	10
40%	478	13.43	2.96	0.22	3628	49
42%	891	14.68	2.17	0.15	7084	104
44%	881	16.67	2.65	0.16	7328	122
46%	896	19.33	3.74	0.19	7798	151
48%	1296	22.10	4.11	0.19	11781	260
50%	1386	27.78	37.72	1.36	13123	365
52%	1616	29.46	22.09	0.75	15893	469
54%	1354	33.52	34.14	1.02	13815	463
56%	1207	33.25	39.74	1.20	12798	425
58%	2039	31.44	23.06	0.73	22393	704
60%	1958	51.26	206.49	4.03	22181	1141
62%	1190	52.20	142.22	2.72	13932	729
64%	691	73.40	226.17	3.08	8348	613
66%	432	119.39	383.71	3.21	5385	644
68%	173	247.75	671.24	2.71	2221	552
70%	77	495.69	831.58	1.68	1015	504
72%	12	1052.09	1320.89	1.26	162	170
Total	16705	44.02	155.80	3.54	169814	7476

The above figures were obtained from half-hourly demand and price data for the National Energy Market from 1/1/02 to 14/12/02 (NEMMCO 2003), assuming a market capacity of 37825 MW.

Sharp price rises can occur at surprisingly low levels of demand, when compared with the total capacity. The highest price in 2002 was $8136/MWh, on 4/12/02.