Australian Government
National Water Commission

Water and the electricity generation industry

Implications of use

Alan Smart and Adam Aspinall

Waterlines Report Series No. 18, August 2009

Waterlines

A SERIES OF WORKS COMMISSIONED BY THE NATIONAL WATER COMMISSION ON KEY WATER ISSUES

Waterlines

This paper is part of a series of works commissioned by the National Water Commission on key water issues. This work has been undertaken by ACIL Tasman and Evans & Peck on behalf of the National Water Commission and the Department of Resources, Energy and Tourism.

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Contents

Figures and tables

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Foreword by the Chair and Chief Executive Officer

The electricity and gas sector accounts for around 1.4 per cent of total water consumption in Australia. Around 65 per cent of the generating capacity in the National Electricity Market (NEM) currently depends on fresh water for hydro-electricity generation or cooling in coal or gas fired thermal generation. Emerging electricity generation technologies, such as solar thermal generation, will also consume water.

Adequate water supply is an important issue for all existing and new thermal and hydro-electric generators. Already, the current drought affecting much of southern Australia has had impacts on security and reliability of power generation due to decreased water supplies. Many electricity generators, including hydro-electric generators, are experiencing constraints on the availability of water due to competing demand for this resource for other purposes. Power stations are coming under increasing pressure to reduce their use of fresh water by drawing on other supply options such as sea water, lesser quality water or treated waste water, or by introducing alternative cooling options.

Recognising the linkages between water supply and energy security, the National Water Commission and Australian Government Department of Resources Energy and Tourism commissioned this report to investigate the impact of changed water availability for electricity generation in Australia and identify future management options for the sector. In doing so, the consultants considered the implications of the National Water Initiative for the electricity generation sector, in particular the agreement by state and territory governments to introduce:

- water access entitlement and planning frameworks that enhance the security and commercial certainty of water access for all users, and provide adequate opportunity for productive, environmental and public benefit considerations to be identified and considered in an open and transparent way
- water market arrangements that facilitate the efficient trade of water, thereby giving water-using businesses access to flexible opportunities to trade water and choose how they utilise their water access entitlements
- water pricing arrangements, such as full cost recovery for water services, that promote economically efficient and sustainable use of water resources and water infrastructure assets.

The information presented in this Waterlines paper will assist the electricity industry to incorporate future water supply risks and management options in its planning and investment decisions.

With many catchments in Australia facing increased pressure, it is more important than ever that water policy and management decisions encourage efficient sharing of regional water resources. All water users should face the full economic costs of their consumption decisions, so that they have appropriate incentives to invest in more efficient technologies. To facilitate this, the National Water Commission maintains that all consumptive water users, including electricity generators, should:

- be covered by water access entitlement and water planning frameworks, with
  - their use included in the consumptive pool and based on clearly specified NWI-compliant water access entitlements
  - settled entitlement arrangements for new sources of water such as coal seam gas by-product
  - access to participatory and transparent water planning processes that allow for consideration of supply reliability requirements

- pay a price for supplied water that reflects the full costs of supply and management
- have unrestricted and equitable access to water markets in order to manage risk associated with water access entitlements and contracts for supply
- take water availability and reliability into account when planning the location of major developments that require access to water.

The Commission also supports the general principle that contractual arrangements for water supply to generators should reflect the same access provisions as other water users, and not mandate take-or-pay contracts or exclude participation in water trading.

These are preconditions to the emergence of more sophisticated market instruments to enable the electricity generation industry, along with other water users, to manage supply risks and to face the full economic cost of their water consumption.

Ken Matthews AO
Chair and Chief Executive Officer
National Water Commission

Executive Summary

This report examines the potential impacts of changed water availability on the Australian electricity industry with the aim of facilitating informed consideration of future options for managing water. This report also looks at the role of current and planned reforms in water, electricity and carbon markets in determining the most suitable and effective water management options.

Ongoing drought conditions and lower water inflows in some parts of Australia may reduce the water available to electricity generators, and increase the risk that there will not be enough electricity generation capacity to meet demand in some regions. In the longer term, continued growth in electricity demand will require additional investment in thermal power stations, such as coal-fired, gas-fired, geothermal and solar thermal generators, which are reliant on water for cooling purposes.

Water use in generation

Water is used for electricity generation in two distinct ways. Firstly, in hydro-electricity generation water is used as a source of potential energy to drive water turbines providing energy for generators. This water is returned to the environment and not consumed.

Secondly, in thermal power stations water is used for generating steam to drive steam turbines, for cooling the exhaust steam and for other operations including ash disposal, emissions control and potable use. This water is consumed, recycled or disposed to the environment.

To guarantee a secure and reliable water supply, the electricity industry requires adequate water access arrangements. The value of water used in electricity generation is high, with estimates of the marginal value of water in electricity generation ranging from $14 000 per ML to $18 000 per ML (ACIL Tasman, 2007). Water is currently trading at around $1500 per ML.

In most areas of Australia electricity generators sell electricity into wholesale electricity markets. All costs must be recovered from the sale of electricity in a market where price is determined by supply and demand. These costs incorporate retrofitting water use efficiency measures for existing power stations, or deciding on water use technologies for new power stations.

This report focuses primarily on the use of water in thermal power stations - the largest user of water in the electricity generation industry. Thermal power plants, primarily coal-fired power stations, are responsible for around 1.4 per cent of total water consumption in Australia (ABS, 2005).

Future water constraints

While the situation varies from region to region, the electricity generation industry faces a water constrained future both in the short and long term. The National Electricity Market Management Company (NEMMCO) drought simulation modelling raises some concerns for power supplies in some states in the short term.

The electricity generation industry has already implemented many water use efficiency options with some coal-fired power stations realising up to 15 per cent reduction in water use per MWh generated. Uncertainty over the availability of future water supplies is an important concern for the industry as it has an impact on financing as well as planning for new investments.

In concert with governments, the electricity generation industry has developed policy statements on water use and recycling and has participated in regional planning for use of treated recycled water.

Technical options to reduce constraints on water availability

The electricity industry has a number of short and longer term technical options for reducing water requirements. These include increasing water use efficiency, dry or hybrid cooling, saline water (such as seawater) cooling, recycled waste water, purified recycled water, coal seam gas water, and desalination.

Options to dramatically reduce the fresh water requirements of thermal power plants are most applicable to new power plants. There are significant cost and logistical issues associated with retrofitting dry cooling to existing power plants. Issues for consideration with saline water cooling are the cost implications of transporting fuel to power plants and planning constraints that apply in coastal areas.

Dry cooling can reduce water consumption of thermal power stations by more than 90 per cent and is most applicable to power plants located in inland areas. However, dry cooling reduces the sent-out efficiency (the ratio of fuel consumed to energy sent out from a power station) of power plants by around two to three per cent and increases carbon dioxide emissions of coal-fired power plants by up to six per cent.

Issues related to water availability and carbon dioxide emissions present long term challenges for electricity generators. This is because water-cooled, low-emission, thermal power plants are likely to be significantly more water intensive than current coal-fired power plants. For example, coal-fired power plants incorporating carbon capture and storage (CCS) could be one-quarter to one-third more water intensive. Furthermore, as solar thermal and geothermal power plants are likely to operate at lower thermal efficiencies than conventional coal-fired steam turbines, they are also likely to have a higher water intensity.

While there is considerable research underway around the world into reducing carbon emissions from power stations, few countries face Australia's limited water supplies. Research priorities in Australia therefore need to include development of low water-use technologies.

Market options to address constraints on water availability

In addition to addressing water availability through technical options, the National Water Initiative (NWI) also provides an opportunity to secure additional water through trading and to manage supply risks through participation in water markets.

Current access arrangements

Current water access arrangements for the electricity industry involve licences and contracts specifically tailored for the adequate supply of water in electricity generation. These licence arrangements provide a highly secure supply of water to large power stations. While aspects of these are consistent with the water access framework set out by the NWI, there are examples of where they do not meet the requirements include:

- limited tenure rather than perpetual;
- limitations or conditions on trading;
- imposing conditions such as water use efficiency and discharge rules, and
- take or pay conditions.

Intersecting markets

The key issue arising out of the consultations and economic analysis undertaken for this study is the interaction between the markets for wholesale electricity, emissions permits, fuel and water supply. These markets are important drivers of investment decisions in water use efficiency measures and for selection of cooling technologies for new generators. They also influence risk management which is ultimately reflected in energy security.

It is important that these markets operate efficiently in order to allow sound business decisions to be made by those investing in new technologies, emissions reduction and water use efficiency measures. Of the four markets, the water market is likely to require the longest time to evolve and for as long as this is the case there remains a risk of inefficient investments in water use efficiency measures.

There is strong evidence that the electricity generation industry is actively investing in improvements in water use efficiency, partly due to the impact of lower water inflows in most areas as a result of the ongoing drought. Regional water planning has also emerged as an important development that affects particular generators— notably in south east Queensland, the Latrobe Valley and in the Upper Collie catchment in Western Australia. However in some areas, the electricity generation industry may not always be included in public consultations as part of planning processes.

While a fundamental revision of existing water licencing arrangements for generators is not likely to be practical or desirable, it will be important that future arrangements are as consistent as possible with the framework principles for access and pricing under the NWI.

Recommendations

Recommendation 1

Governments should ensure that future licence arrangements are made as consistent as possible with the pricing and access frameworks of the National Water Initiative particularly with respect to supply security; security of tenure; trading entitlements; and pricing.

Recommendation 2

To facilitate improved water use efficiency by the electricity generation industry, water supply access arrangements should not mandate take or pay arrangements, nor exclude participation in water trading unless agreed by electricity generators.

Recommendation 3

In line with the National Water Initiative, the full opportunity cost of all supply and savings options should be reflected in the price of all supply options when considering these in regional water planning processes. This should form the basis of pricing for the selected options for generators.

Recommendation 4

Policy makers should ensure that the electricity generation industry is included in consultations between water planners, the community and other users as part of the longer term development of planning and policy options for future water resource management.

Recommendation 5

The legislation and regulations for use and disposal of water produced from coal seam gas should be reviewed to ensure that there are no unnecessary regulatory or legislative constraints on the use of that water.

Recommendation 6

In light of the need to reduce carbon emissions and the impact on water demand for cooling in power stations, priority should be given to focusing research and development in Australia on water management and efficiency in electricity generation.

1. Introduction

1.1 Background

This report examines the impact of changed water availability on the electricity generation industry, to facilitate informed consideration of future water management options and needs for planning and investment decisions in the electricity industry. It was commissioned by the National Water Commission (NWC) and the Department of Resources, Energy and Tourism (RET).
The Terms of Reference are included at Attachment B.

This report is based on evidence from consultation with electricity generators, industry associations and institutions and government policy agencies in energy and water, as well as analysis undertaken by ACIL Tasman Pty Ltd and Evans & Peck Pty Ltd using, in part, models developed to analyse and research the electricity and water markets.

1.2 Context

The electricity and gas sector comprises around 1.4 per cent of Australia's total water consumption. Total water use in electricity generation in 2004–05 was 60,292 GL, which was 10 per cent higher than in 2000–01 (ABS, 2005). The majority of this water use (99.6 per cent) was used instream for hydro-electricity. Water consumption in 2004–05 by non-hydroelectric electricity generators was 271 GL, most of which was used for cooling at coal and gas-fired power stations.

Table 1 shows the water use per GWh by generation type for 2004-05. Hydro-electricity is high at 3743.81 ML per GWh, which reflects its instream use. By comparison, coal-fired generation consumed an average of 1.51 ML per GWh and gas 0.56 ML per GWh.

Table 1 **Water use and generation in 2004-05**

	Water use	Electricity generated	Water use per GWh (a)
	GL	GWh	ML/GWh
Hydro-electricity	59 867 227	15 991	3743.81
Black Coal	153 021	102 180	1.50
Brown Coal	81 887	54 041	1.52
Gas	11 606	20 786	0.56
Other	810	1473	0.55
Total	60 114 551	194 471	

a includes in stream use

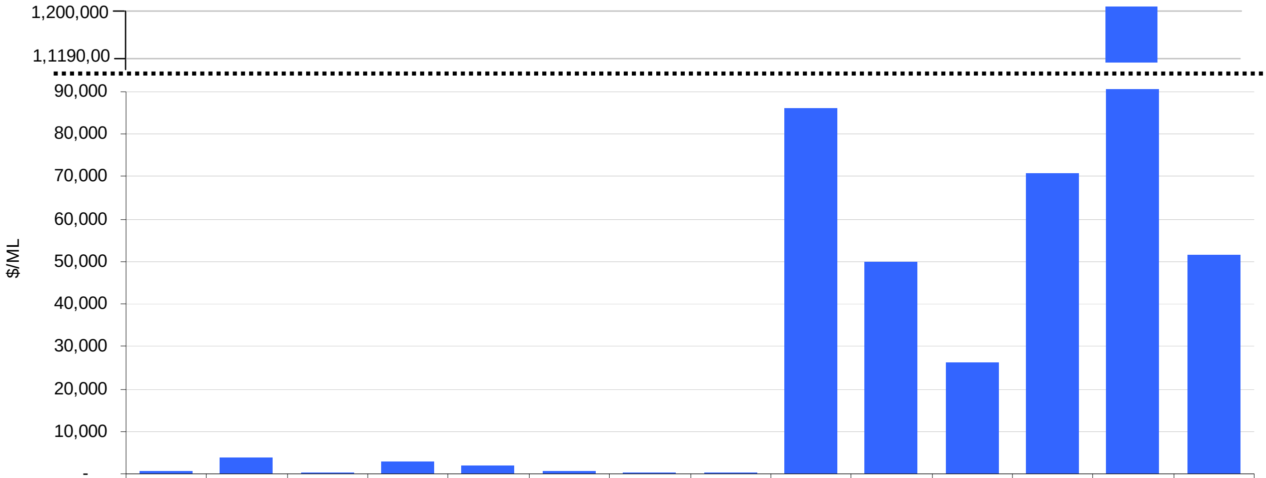
Note: Total does not match total water use – the difference being between regulated discharge and in stream use.

Data source: (ABS, 2005)

Approximately 65 per cent of the generating capacity in Australia's National Electricity Market (NEM) currently depends on freshwater for cooling in coal or gas-fired thermal generation. In the future solar and geo-thermal generation plants located inland will also require water for generation and cooling.

The value added per ML of water used in the electricity and gas sector is high. Australian Bureau of Statistics (ABS) industry definitions and the ABS Water Account 2004–05 show that in 2004–05 the value added in the electricity and gas sector was just over $50 000 per ML. (see Figure 2).

Figure 1 **Value added per ML of water used by industry, 2004-05**



	Dairy farming	Vegetables	Sugar	Fruit	Grapes	Cotton	Rice	Livestock, pasture and grains	Coal mining	Metal ore mining	Other mining	Wood and paper	Oil and gas extraction	Electricity and gas supply
Gross value added/ML	717	3,867	376	2,744	1,833	498	162	255	86,127	49,906	26,175	70,759	1,200,151	51,552

Data source: (ACIL Tasman, 2007)

In a report released in 2007, ACIL Tasman estimated the value of water used in electricity generation ranged between $14 000 per ML for combined cycle gas turbine (CCGT) to between $16 000 per ML and $18 000 per ML for coal-fired generation (ACIL Tasman, 2007). It is clear that water used in electricity generation is one of Australia's higher value water uses.

Recent drought conditions have led to increased volatility in wholesale electricity prices as well as government intervention in arrangements for supplying water to generators. While electricity price volatility is an immediate concern, changed water availability resulting from climate change and drought presents new challenges for the electricity industry. Energy and water security, sustainable use of water resources and the introduction of the Carbon Pollution Reduction Scheme (CPRS) will be key challenges for investors, operators and planners in the electricity industry and for Australian policy makers in the coming years.

Policy reform in the electricity and water markets has been in progress since the early 1990s. The NEM was established in 1998 following eight years of coordinated reform between the Australian and eastern state governments. The South West Interconnected System (SWIS) in Western Australia was established in 2007 after an extensive consultation and policy review process. Under wholesale market systems, investment, in the main, is based on an expectation of future price paths created by supply and demand, moderated by some regulation of price and renewable energy targets. Electricity markets have become, on the whole, efficient and sophisticated.

In February 1994, the Council of Australian Governments (COAG) agreed to a Water Reform Framework. Ten years later, in 2004, COAG agreed to the National Water Initiative (NWI), which sets out the objectives, principles, outcomes and actions for a 10 year program of co-ordinated water reform (COAG, 2004). In 2007 the Australian Government also released the National Plan for Water Security (Australian Government, 2007) and in 2008 COAG released the Intergovernmental Agreement on the Murray Darling Basin Reform

(COAG, 2008). This reform program is as relevant to the electricity generation industry as it is to other sectors of the economy and the community.

The NWI remains the key policy framework for water resource management in Australia. It calls for state and territory governments to:

- establish well defined, secure water entitlements for consumptive users
- introduce improved and well structured water planning that gives rise to entitlements
- establish efficient water markets and water trading
- clarify and protect environmental and public good outcomes
- improve knowledge systems and water accounting, and
- jointly manage surface and groundwater (Sinclair, Knight, Mertz, 2008).

Returning over-allocated and over-used catchments to a sustainable level of extraction is an important over-arching NWI objective.

Considerable progress has been made in the areas of water planning and allocation and in the development of tradable water access entitlements. However, the National Water Commission's first Biennial Assessment of Progress in Implementation revealed that much still remains to be done (NWC, 2008).

The challenges of improving water markets, achieving joint management of surface and ground water and recovering water for the environment differ in important ways to those that arose when wholesale electricity markets were established. The issues associated with moving water from one geographic area to another also mean that water markets will probably face more constraints than electricity markets. However, electricity markets can also be constrained by transmission and interconnector capacity and losses.

The Australian Government's proposed introduction of emissions trading under the CPRS from 2011 would also introduce a market for carbon dioxide equivalent (CO2-e) emissions. In the near future, investment in new electricity generation capacity will be subject to the intersection of four markets—fuel, electricity, water and CO_2-e. Linkages between these markets will have implications for finding the most efficient ways to respond to the need to reduce both water use and carbon emissions. These matters are discussed in more depth in the body of this report.

1.3 Approach to this report

This report is evidence-based. To gather information ACIL Tasman and Evans & Peck consulted with electricity generation companies and organisations, the National Electricity Market Management Company (NEMMCO), the National Generators Forum (NGF) and state and Australian Government departments responsible for water and energy policy. The list of consulted organisations is provided at Attachment C. Interviews with each organisation were based on a questionnaire (included at Attachment D). Chapters 2 and 3 outline how water is used in electricity generation, drawing on the results of the questionnaires and interviews. Readers with less interest in the technical aspects of water use in power stations may wish to skim these chapters and return to them after reading subsequent chapters.

Chapter 4 examines how generators currently use and acquire water. Chapter 5 reviews the availability of water for generation and the water supply outlook for major catchments and chapter 6 examines the options for addressing limited water supplies.

In chapter 7, ACIL Tasman draws on its new entrant economic model to analyse the impact of water use efficiency technologies for generators on decisions on new power station technologies. Chapters 8 and 9 address the implications for energy and water reform respectively. Chapter 10 also outlines recommendations that arise from the findings of this report.

The Australian Energy Market Operator (AEMO) will officially commence operations on 1 July 2009. AEMO will incorporate all functions currently carried out by NEMMCO. AEMO will also include functions currently carried out by VENCorp (Victoria), Gas Market Company (NSW) and REMCo (SA), and new gas functions - including a gas bulletin board and short-term trading market. References to NEMMCO remain in this report as the aforementioned transition is due to occur after drafting has been completed.

2. Water use in thermal electricity generation

2.1 Introduction

Water has many different uses in thermal electricity generation and its value can be very high (refer to Figure 2).

Power stations need access to secure and reliable water supplies so that they can provide security of supply to electricity consumers and meet requirements for system reliability. Energy security is therefore dependent on the availability of secure water supplies to power stations.

This chapter describes how water is used in thermal electricity generation and provides an indication of the factors that drive choices about means of cooling and the various technologies available to address water scarcity. Readers who do not wish to examine the technical issues in the first instance, may initially skip this chapter and return to it after reading subsequent chapters.

2.2 Thermal electricity generation

In thermal electricity generation water is used in:

- the boiler for steam raising;
- the cooling system;
- managing and disposing of ash; and
- services and potable water supplies.

Thermal coal, combined cycle gas turbine, solar thermal and geothermal plants require water for boiler make-up and cooling where dry cooling is not installed.

Water use varies between the different types of thermal power stations. Typical water consumption for a coal-fired power station with re-circulated cooling is shown in Table 3.

Table 2 **Typical water use in a base load coal-fired power station with recirculated cooling**

Process	Typical use	Approximate annual consumption for 1000 MW base load coal-fired power station with recirculated cooling
	ML/GWh	GL/year
Boiler make up water	0.01-0.03	~0.5 GL/year
Water evaporated in cooling process	1.6-1.8	~13 GL/year
Water for cooling tower blowdown	0.2-0.3	~2 GL/year
Ash disposal	0-0.1	~0.5 GL/year
Other potable uses	Not generation dependent	~0.5 GL/year

Note: Amounts are approximate. Capacity factor is assumed to be around 85%. Nature of each use and terms are discussed in Section 2

Data source: Evans and Peck

A conventional wet cooled coal-fired power station consumes around 2.2 ML of water per GWh— this is equivalent to 17 GL of water per year for a 1000 MW base load power station. Over 90 per cent of this water is consumed in the cooling system. A combined cycle gas turbine consumes around one third of the water consumed by a conventional coal-fired plant of equivalent generation capacity.

2.2.1 The Electricity Generation Cycle

The process used for generating electricity at most intermediate and base load thermal power stations in Australia is based on the thermodynamic principles of the Rankine Cycle. This is where water is heated in a boiler to produce high pressure/high temperature steam that is used to drive a turbine and generator.

When brought back to basics the steam cycle at a power station has four basic process steps.

- Process 1: The water pressure in the boiler is increased using a high pressure pump.
- Process 2: The high pressure water is heated to become steam.
- Process 3: The steam expands through a turbine and generates electricity, resulting in a decrease in the energy of the steam.
- Process 4: The steam then enters a condenser to become a saturated liquid and returns to its original temperature and pressure as water before starting the cycle again.

An essential part of the power station cycle is the cooling of the low energy steam after it exits the turbine so that it can be pumped back up to a high pressure to start the cycle again.

Under the principles of thermodynamics, the efficiency of this power station cycle is directly related to the difference between the highest energy state and the lowest energy state. Greater efficiency is achieved by lowering the energy state of the steam exhausted from the turbine. The cooling process determines the energy state of the steam exhausted from the turbine and is therefore one of the most important considerations when designing a new thermal power station.

2.3 Water use in boilers

The boiler component of a power station consumes only small amounts of water, but this must be high quality. A typical boiler can require 0.15 ML of water to fill, but consumption is associated with losses through valve glands, boiler tube leaks, steam ejectors, soot blowing and cycling of load.

2.4 Water use in cooling

The major use for water in Rankine Cycle based thermal power stations is for cooling. There are several different cooling technologies employed in existing Australian power stations. Wet cooling uses high volumes of water to remove the thermal load from the source, or uses the 'latent heat of evaporation' of the water to do so. Dry cooling transfers the thermal load to the air. Hybrid cooling is a combination of both dry cooling and wet cooling. These technologies are discussed below.

2.4.1 Wet cooling

Wet cooling uses water to cool steam that is discharged from a turbine. The amount of water extracted for this is different to the amount of water consumed. Water consumed is evaporated in the course of cooling or otherwise disposed of to reduce build up of salts in cooling water. Water that is not consumed in this way is returned to the environment. Hence the amount of water consumed is often less than the amount of water initially extracted.

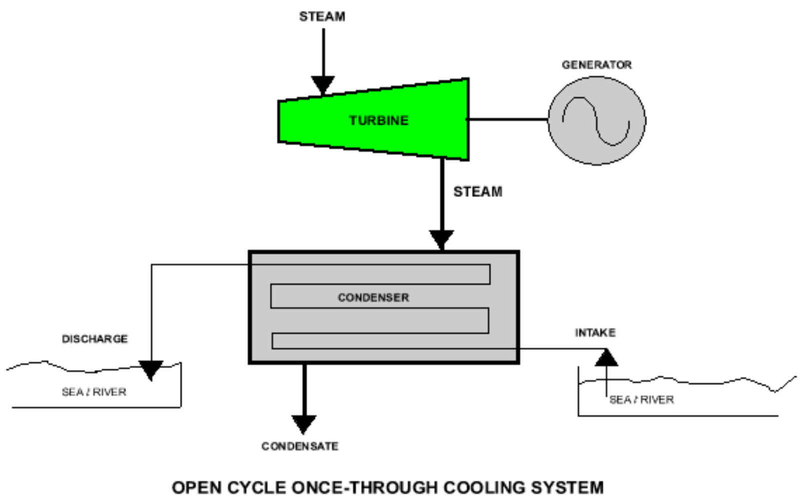
Once-through cooling

Conceptually, the simplest method of cooling steam that is exhausted from the turbine is referred to as an open cycle or once-through cooling system. Water is drawn from a natural source such as a lake, sea or river, passed through the power station's steam condenser and then returned to the water source at an elevated temperature.

Once-through systems typically have high flow rates and relatively low discharge temperatures to limit the increase in temperature in the receiving waters. A typical 350 MW unit would have a flow rate of around 18 000 litres per second. The actual flow rate tends to be determined by the allowable temperature of discharge.

Very little water is 'consumed' by the power station as it is returned to the source. The higher temperature of discharge water does result in a slightly higher evaporation rate in the water source but this is estimated at less than one per cent of total throughput (EPRI, 2002). Thus, for example, a 1000 MW base load plant extracting 1300 GL of water per year would consume approximately 13 GL per year from evaporation. Of course this increased evaporation has little impact on freshwater requirements if the water source is the sea.

Figure 2 Open cycle once through cooling



Source: http://www.energymanagertraining.com/power_plants/condenser&cooling_sys.htm

Historically once-through cooling was the preferred method of cooling for a significant number of Australian power stations. Some of the Australian power stations using this method of cooling include:

- Eraring Power Station 2640 MW (cooled from Lake Macquarie)
- Vales Point Power Station 1320 MW (cooled from Lake Macquarie)
- Munmorah Power Station 600 MW (cooled from Lake Munmorah)
- Liddell Power Station 2000 MW (cooled from Lake Liddell)
- Gladstone Power Station 1680 MW (cooled by seawater)
- Torrens Island Power Station 880 MW (cooled by seawater)
- Hazelwood Power Station 1600 MW (cooled from Hazelwood Cooling Pond).

A number of newer power stations are also once-through cooled including:

- Tallawarra Power Station 400 MW CCGT (cooling from Lake Illawarra); and
- Pelican Point Power Station 487 MW CCGT (cooling from the sea through the Port River)
- Newport Power Station 500 MW gas-fired boiler (cooling from the Yarra River and Hobsons Bay).

Power stations that are cooled using water from freshwater lakes such as Hazelwood or Liddell consume about one per cent of the water put through the cooling condensers as a result of higher evaporation caused by a rise in the temperature of the water source or lake.

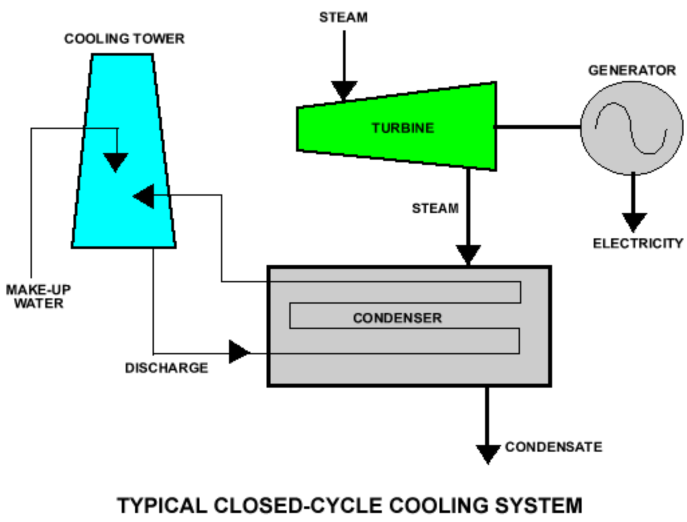
Power stations cooled by saline water from the sea or estuaries do not consume freshwater for cooling, but do use a small amount of freshwater for boiler make up, ash disposal and potable use. They are required to meet water quality and temperature criteria for water returned to the marine environment.

Closed cycle—wet cooling systems

In a closed cycle wet cooling system, energy rejected by the turbine is transferred to the cooling water system through a condenser. The heat in the cooling water is then discharged to the atmosphere using a cooling tower.

In the cooling tower, heat is removed from the falling water and transferred to the rising air by the evaporative cooling process (taking advantage of the 'latent heat of evaporation'). The falling water is broken up into droplets or films by the extended surfaces of packing in the cooling tower heat exchangers (sometimes referred to as 'fill').

Figure 3 Closed cycle wet cooling systems

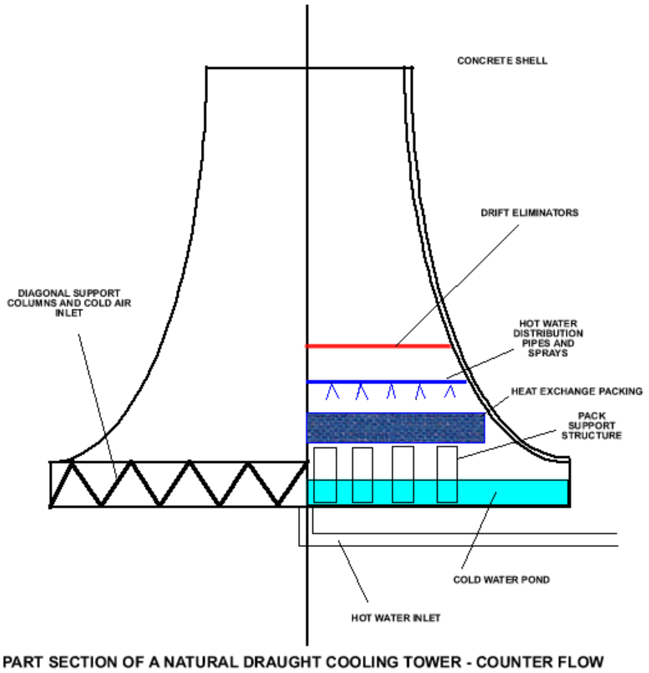


Source:http://www.energymanagertraining.com/power_plants/condenser&cooling_sys.htm

The moisture laden air is often visible in the plume of water vapour above the cooling towers in times of high humidity. The evaporation rate of a typical 350 MW cooling system is typically 1.8 ML of water per GWh of power generated. For a base loaded 1000 MW plant generating 7400 GWh per year this equates to some 13 GL of water used in evaporation per year.

There are two typical cooling tower designs that enhance the evaporation process. They are known as natural draft and forced (or mechanical) draft cooling towers. Natural draft towers have a large concrete shell as shown in Figure 4. The heat exchanger packing is in a layer above the cold air inlet at the base of the shell as shown in the tower sectional view. The warm air rises up through the shell as a result of the 'chimney effect', creating the natural draft to provide airflow and operate the tower. These towers therefore do not require fans and have low operating costs.

Figure 4 Natural draft cooling towers



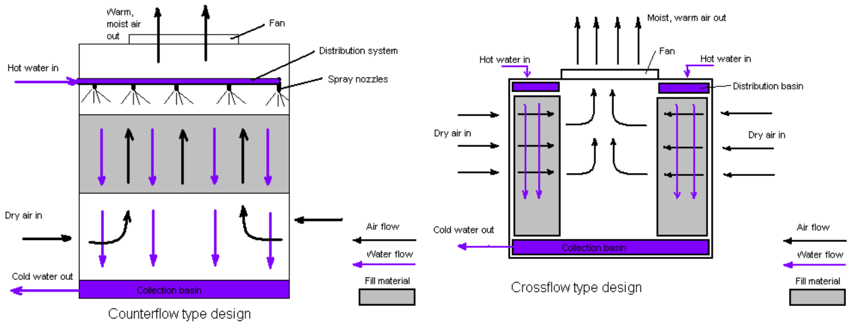
Source:http://www.energymanagertraining.com/power_plants/condenser&cooling_sys.htm

Australian power stations with natural draft closed cooling include:

- Bayswater Power Station (2640 MW)
- Stanwell Power Station (1400 MW)
- Tarong Power Station (1400 MW)
- Mt Piper Power Station (1320 MW)
- Loy Yang A&B (2000 MW & 1000 MW)
- Yallourn Power Station (1480 MW)

Forced draft cooling towers employ axial flow fans to create airflow. While fans require auxiliary power, typically 1.5 to 2.0 MW for a 420 MW unit, fans have the advantage of being able to provide lower water temperatures than natural draft towers, particularly in hot humid conditions, thereby increasing the thermal efficiency and electricity generation capacity of the power plant. Forced draft cooling towers therefore suit Australia's hotter tropical areas, such as in Queensland.

Figure 5 Mechanical draft cooling towers



Source: http://en.wikipedia.org/wiki/Image:Crossflow_diagram.PNG, http://en.wikipedia.org/wiki/Image:Counterflow_diagram.PNG

Australian power stations with forced draft closed cooling include:

- Tarong North Power Station (450 MW)
- Swanbank B and E Power Station (500 MW & 385 MW)
- Callide C Power Station (900 MW)

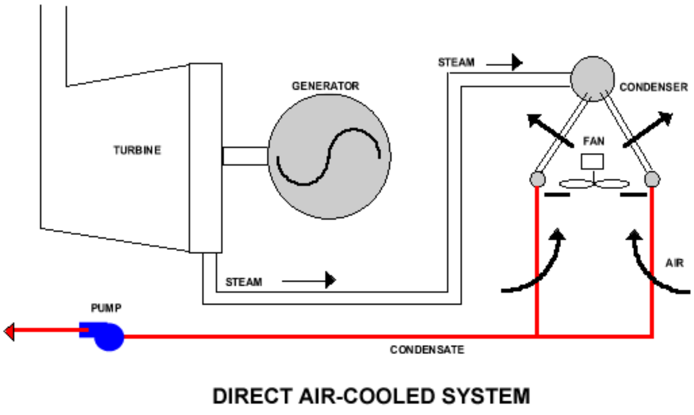
2.4.2 Dry Cooling

Dry cooling is a cooling option for thermal power stations where water availability is constrained. There are two dry cooled options—direct dry cooling and indirect dry cooling.

Direct dry cooling

In a direct dry cooling system (sometimes referred to as air-cooled condensers), turbine exhaust steam is piped directly to an air-cooled, finned tube, condenser. The finned tubes are usually arranged in the form of an 'A' frame over a forced draft fan to reduce the footprint.

Figure 6 Direct dry cooled IGCC



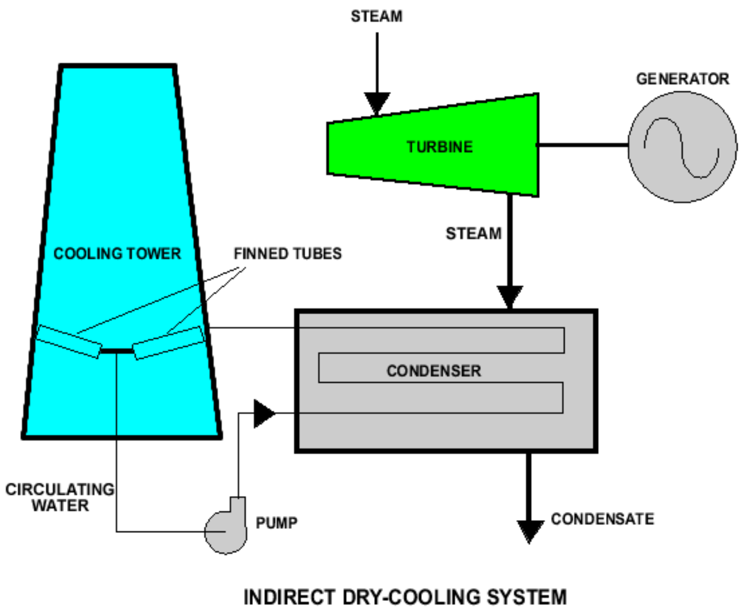
Source:http://www.energymanagertraining.com/power_plants/condenser&cooling_sys.htm

Two recent Australian power stations have been built with direct dry cooling systems. These are Kogan Creek (780 MW) and Millmerran Power Stations (850 MW).

Indirect dry cooling

Indirect dry cooling systems comprise a condenser and turbine exhaust system as for wet systems, but the circulating water is passed through finned tubes in a cooling tower. This allows the towers to be sited further away from the turbine.

Figure 7 Indirect dry cooling



• Source :http://www.energymanagertraining.com/power_plants/condenser&cooling_sys.htm

Hybrid dry cooling

The performance of dry cooling towers reduces in hot weather. Air cooled condensers can be modified with water sprays for evaporative cooling of the finned tubes for short periods of extreme temperature. Such systems can use large amounts of water for short periods on hot days. Hybrid systems consume more water than full dry cooling systems, but do not lose as much efficiency as full dry cooling systems.

Water consumption

Except for hybrid dry cooling, dry cooling eliminates water consumption for cooling. However dry-cooled power stations still require water for boiler water replacement, ash disposal, fire fighting and other services. A 1000 MW dry cooled coal-fired power station would typically require around 2.5 GL of water per year.

2.4.3 Saline water cooling

Saline water cooling in power stations involves the use of water from the sea, lakes, groundwater and, in some cases, run of river water. Saline water cooling is generally based on the once-through cooling process discussed in Section 2.4.1. There are several examples of once-through saline water cooling systems in Australia. These include:

- Eraring Power Station (2640 MW)
- Vales Point Power Station (1320 MW)
- Munmorah Power Station (600 MW)

- Gladstone Power Station (1680 MW)
- Torrens Island Power Station (880 MW)
- Pelican Point Power Station (487 MW)

It is also possible to use recirculated saline water cooling tower system. This requires less water from the water source. However the potential for scaling limits the number of times the saline water can be cycled through the towers. An example of a re-circulated saline water cooled power stations in Australia is the Osborne Power Station in South Australia (62 MW).

In addition to the efficiency benefits, the advantages of saline water cooling from the sea include:

- significantly reduced use of freshwater;
- lower capital cost of providing cooling infrastructure compared with the construction of cooling towers;
- lower and more stable temperature of the water enabling very high levels of sent-out efficiency to be achieved (lower emissions of CO_2-e compared with dry cooling); and
- the relatively minor impact on the environment of water discharges if appropriate measures are taken.

Issues with transporting fuel stocks is a key driver that works against once-through cooling using saline water. The transportation of fuel can be costly as most sources are not near the coast. Additionally there may be an adverse public reaction to large volumes of fuel being railed or trucked through built up areas. It should be noted that this is not always an insurmountable obstacle. A good example of this is Gladstone Power Station in Queensland where, because of the presence of a large coal export industry, these issues were already mitigated.

A further driver working against the increased uptake of once-through cooling using saline water is that there is often adverse public reaction to licensing coastal sites for electricity generation. However, this has not been a major issue at Kwinana where both coal and gas-fired power stations are salt water cooled.

In a country where the value of freshwater to large and growing communities has recently become a major issue, saline water cooling has some advantages as an alternative cooling technology for future power stations. However the environmental impacts associated with the temperature of water released and its impact on the marine environment need to be managed. This has not raised serious concerns in the open marine environment where temperature discharge standards and standards on quality, including chlorine limits, are set. Discharge of water into saline estuaries and lakes can be more constrained because of the effects of temperature as is the case with the Tallawarra power station on Lake Illawarra.

2.4.4 Water quality

Coal and gas-fired power stations have technical requirements for water quality. Boiler water must be high quality to prevent scaling and most power stations have demineralisers to produce water with very low mineral and salt content. Water for cooling does not need such high quality specifications, but there are limitations on the amount of total dissolved solids (TDS) that can be cycled through cooling tower systems. The higher the TDS in make-up water the lower the number of cycles that the cooling water system can tolerate. In general terms TDS levels above 2500 parts per million (ppm) cause scaling problems and most cooling water is limited to 2000 ppm.

Some coal-fired power stations employ reverse osmosis (RO) and micro filtration plants to treat water recycled within the plant or to bring lower quality water, such as water provided from treated effluent or saline sources, up to the quality required for the cooling water system.

Evaporative desalination can also be used to treat saline water used in cooling. Commercially available distillation processes can be integrated into power stations to produce fresh water. Distillation processes require more energy than RO systems and reduce sent-out efficiency. There are no examples of distillation processes being used in Australian coal-fired power stations.

2.4.5 Supply security

Electricity demand varies throughout the year but market operating rules impose standards for maintaining a secure supply of electricity at all times. As a result, electricity plants that are reliant on water for generation require a high proportion of their water supply to be high security to meet supply reliability criteria.

Large coal-fired power stations in Australia sometimes augment very high security water supplies with lower security supplies. They manage supply risks according to the supply security levels in their water supply agreements or contracts.

2.5 Typical water requirements of thermal power stations

The following section provides a general indication of the thermodynamic properties of each of the key electricity generation alternatives and discusses the specific requirements for cooling and water use of the various systems. Comparisons of thermal load, water usage and cycle efficiency are made at a high level to provide a context for discussing issues faced by investors when selecting cooling systems for electricity generation.

2.5.1 Coal-fired power stations

There are primarily two types of coal-fired plant—the more traditional sub-critical and the newer super-critical plants. The difference between the two is their operating pressure, with the higher pressures and temperatures in super-critical plants being more efficient (over 40 per cent sent-out efficiency against around 36 per cent sent-out efficiency for sub-critical plant). The efficiency of state-of-the-art super critical coal-fired power stations can exceed 45 per cent, depending on cooling conditions.

Australian power stations

Most of the coal-fired power stations in Australia are sub-critical power plants. All the cooling types are represented including Eraring and Liddell (once-through cooling), Bayswater, Stanwell, Mount Piper and Loy Yang A and B power stations (natural draft closed cooling) and Swanbank (forced draft closed cooling). More recently a number of super-critical coal plants have been constructed in Queensland, Tarong North, Millmerran, Kogan Creek and Callide C power stations. Millmerran and Kogan Creek are dry cooled. Typical cooling water use for these technologies is shown in Table 3 along with comparisons for efficiency, heat rate and emissions.

Table 3 Typical cooling water use, efficiency and carbon dioxide intensity for coal-fired power stations

Plant Type	Sub-critical once-through saline water cooling freshwater lake	Sub-critical recirculating cooling	Super-critical once-through cooling from freshwater lake	Super-critical recirculating cooling	Sub-critical dry cooled	Super-critical dry cooled
Cooling Water Use	Withdrawn from source 150–200 ML/GWh Around 1.5 to 2.0 ML/GWh from additional evaporation from the lake. Fresh water consumed 0.2 ML/GWh in other uses	1.9ML/GWh (cooling) 0.2ML/GWh (blowdown) 0.1 ML/GWh other uses	Withdrawn from source 130–175ML/GWh Around 1.3 to 1.8 ML/GWh from additional evaporation from the lake. Fresh water consumed 0.2ML/GWh in other uses	1.7ML/GWh (cooling) 0.2ML/GWh (blowdown) 0.1 ML/GWh other	0.2ML/GWh (blowdown) 0.1 ML/GWh other	0.2ML/GWh (blowdown) 0.1 ML/GWh other
Typical annual fresh water consumption for a 1000MW plant	13 to 17GL/year	17 GL/year	11 to 15 GL/year	15 GL/year	2 GL/year	2 GL/year
Sent-out efficiency Heat rate (HHV)	36% 10 GJ/MWh	36% 10 GJ/MWh	42% 8.6 GJ/MWh	42% 8.6 GJ/MWh	34% 10.6 GJ/MWh	40% 9.0 GJ/MWh
CO_2 Intensity as generated	884 tonne/GWh	884 tonne/GWh	750 tonne/GWh	758 tonne/GWh	936 tonne/GWh	796 tonne/GWh

Note: Sent-out efficiency is the ratio of fuel consumed to energy sent-out from the power station. Heat rate is the fuel required in GJ for each MWh of energy sent-out. HHV is high heating value and includes energy involved in evaporating water in the fuel. Calculations based on 1000 MW at 85% capacity factor.

Table 4 shows that freshwater consumption for wet cooling and replacement of boiler blow down for a 1000 MW plant varies between two GL per year for a once-through sea water cooled plant to 17 GL per year for recirculating freshwater cooling.

Table 4 also shows that a move to dry cooling reduces water consumption to around two GL per year but increases fuel use and carbon emissions by around five per cent.

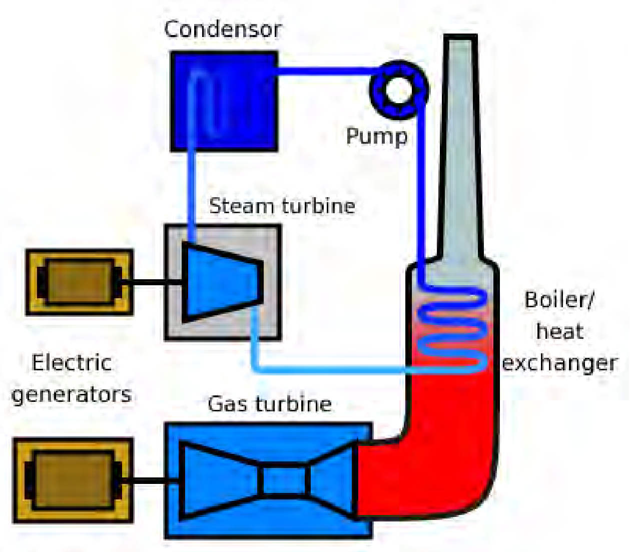
2.5.2 Gas-fired Power Stations

General

Combined-cycle gas turbine (CCGT) power plants have both gas and steam turbines. Hot exhaust gas from the gas turbine is passed through a heat recovery steam generator (HRSG) to produce steam for the steam turbine. The output temperature of the gas turbine exhaust has a temperature of 450–650°C and the steam produced by the HRSG is in the range of 450–580°C. Steam that is ejected from the steam turbine is condensed in the cooling system and recycled to the HRSG.

The steam cycle may be more or less complex with single or multi-pressure HRSG operation. Additionally, where cogeneration is involved, steam may be extracted from various points in the cycle for use in a partner facility. Condensate may or may not be returned to the power cycle. These characteristics of the steam cycle depend on the project objectives and economics.

Figure 8 CCGT steam cycle



Source:http://upload.wikimedia.org/wikipedia/commons/8/84/COGAS-diagram.png

Approximately two-thirds of the plant output is obtained from the gas turbine side. Nominal overall plant efficiency is about 55 per cent, compared to 36 per cent for newer open cycle gas turbines.

The configuration of the generating plant can also vary depending on the type of plant being used, the final gas firing temperature and the process steam being extracted (if any).

Australian plants

In the last 10 years a number of combined cycle power stations have been built in Australia. Examples of such power stations include:

- Pelican point power station (SA)– direct cooling – from sea
- Swanbank E power station (QLD) – closed forced wet cooling towers
- Townsville gas turbine (QLD) – closed forced wet cooling towers
- Osborne power station (SA) – recirculated sea water direct cooling
- Newport power station – (VIC) – combined cycle, direct sea water cooling

Table 7 highlights the lower water consumption of gas-fired generation. Open cycle gas turbine plants (OCGT) use very little water. CCGTplants use water in the steam cycle but overall consume a little over one third of the water used in a comparable wet cooled coal-fired power station. The table also shows that the impact of dry cooling on sent-out efficiency, heat rate and emissions is less for a CCGT plant compared with a coal-fired plant.

Table 4 Typical cooling water use, efficiency and carbon dioxide intensity for gas turbine power stations

Plant Type	OCGT (300 MW)	CCGT Once-through Cooling from freshwater lake (100 0MW)	CCGT Recirculating Cooling (100 0MW)	CCGT Dry cooling (100 0MW)
Cooling Water Use	Very small (only water might be for NOx control fogging or evaporative cooling to improve capacity)	Withdrawn from source 50 to 60ML/GWh. Water consumed around 0.5 to 0.6 ML/GWh if cooled from lake. Makeup & potable 0.08ML/GWh	0.68ML/GWh (cooling) 0.2 ML/GWh (blowdown, makeup & potable)	0.08ML/GWh (makeup & potable)
Annual cooling water use	0.3 GL/year	5 GL/year	6.6 GL/year	0.8 GL/year
Sent- out efficiency Heat rate(HHV)	36% 10.0GJ/MWh	52% 7.0GJ/MWh	52% 7.0GJ/MWh	50% 7.1GJ/MWh
CO_2-e intensity as generated	513 tonne/GWh	355 tonne/GWh	355 tonne/GWh	363 tonne/GWh

2.5.3 Integrated Gasification and Combined Cycle

The electricity generation process referred to as integrated gasification and combined cycle (IGCC) has, quite recently, become of interest as a likely key to ‘clean coal’ technology. Essentially the IGCC process involves production of synthetic gas (syngas) that can then be cleaned and used to power a gas turbine as part of a CCGT.

The major benefit is in improved sent-out efficiency, which approaches the sent-out efficiencies of a CCGT. Even allowing for energy lost in the gasification process, efficiencies in the order of 50 per cent have been suggested. A secondary benefit is the reduced water consumption for cooling as the steam cycle still only represents one-third of the generated output and therefore requires proportionally less water for cooling.

However, a number of issues remain. IGCC is still in the development phase and there are few IGCC plants operating around the world. The capital cost of the gasification process is considerable. Additionally, although the overall IGCC process improves efficiency and reduces water consumption, compared with conventional coal-fired alternatives, the gasification process itself is also somewhat water intensive and CO_2-e intensity remains only slightly below the conventional coal-fired equivalent. Water consumption is about 50 per cent of a conventional coal-fired plant.

Whilst a number of the key overseas suppliers have taken up the development challenge, it is estimated that commercialisation of the technology is likely to be at least 10 years into the future. Table 5 sets out typical parameters quoted for IGCC technologies for comparison.

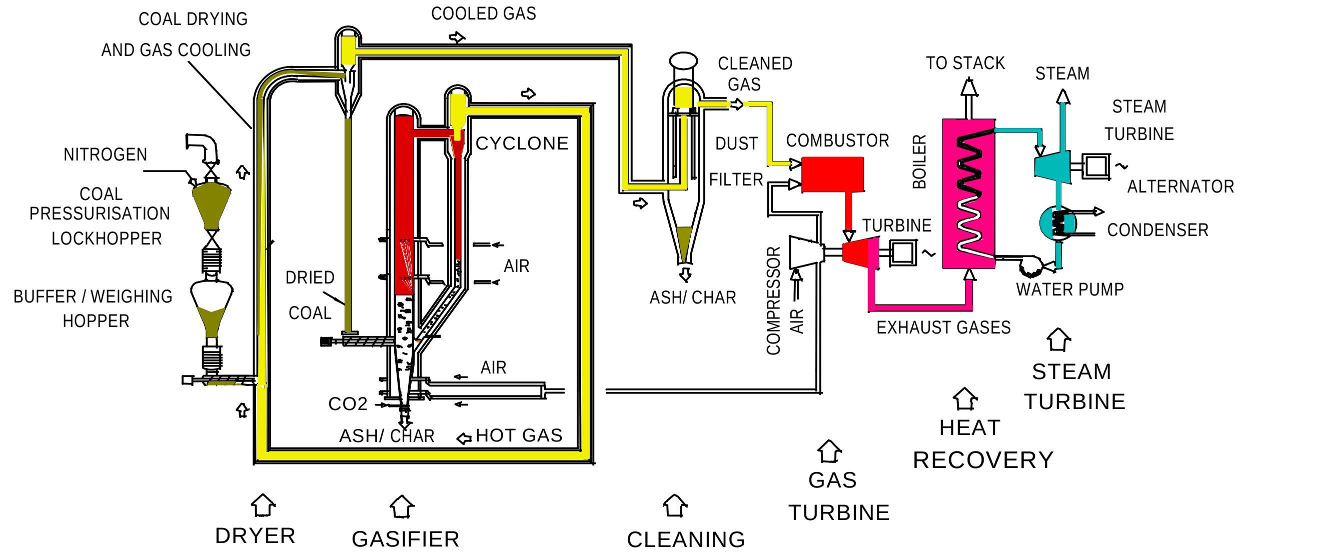
Table 5 Water use in IGCC plants

Plant Type	IGCC
Cooling water use	1.2 ML/GWh Including cooling, blowdown & process water
Annual cooling water consumption for a 1000 MW plant operating at base load	9 GL/year
Sent-out efficiency Heat rate (HHV)	40– 45% 8-9 GJ/MWh
CO_2-e Intensity without CCS as generated	700-800 tonne/GWh

HRL Limited, with assistance from the Australian and Victorian Governments, is developing a 400 MW integrated drying gasification combined cycle power station (IDGCC) at the Morwell power station site in the Latrobe Valley in Victoria. This is a demonstration project building on earlier work that successfully tested a 10 MW scale wet coal gasification and electricity generation plant.

The IDGCC process involves drying coal with hot gas, converting the dried coal to syngas and using the cooled syngas to drive a combined cycle gas turbine and steam turbine. The structure of the process is shown in Figure 9.

Figure 9 **IDGCC process**



Data source: HRL Limited

From the 10 MW project, HRL Limited estimates that the process has 30 per cent lower emissions of CO_2 and 50 per cent less water use than conventional brown coal power plants. Capital costs are estimated to be around 30 per cent lower than a new brown coal power plant.

2.5.4 Other forms of thermal generation – solar thermal, geothermal

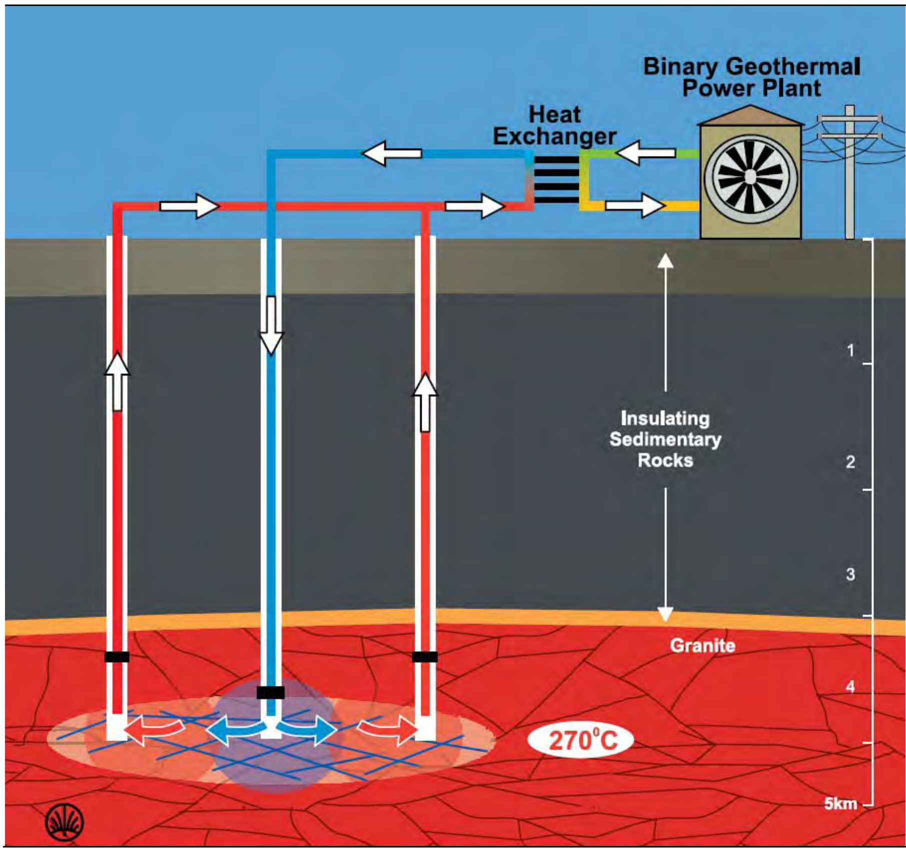
The imperative to reduce emissions of carbon dioxide and other greenhouse gases has brought focus on renewable technologies. Two technologies of emerging interest in Australia over the next 10 years will be solar thermal energy and geothermal energy.

ACIL Tasman has also been advised that solar thermal applications in western Queensland are under consideration. Additionally, there is interest in solar thermal in inland New South Wales and in South Australia (Wizard Power, 2009).

Origin Energy, Geodynamics and Petratherm, among others, are in the early stages of assessing and/or developing geothermal electricity generation in the Cooper Basin in South Australia.

Thermodynamically, both these technologies are similar to coal and gas-fired steam turbine plants. They employ the Rankine Cycle to convert energy supplied by the sun or from hot rocks deep underground, into electric energy using a steam turbine. As with a conventional coal-fired steam turbine, these technologies still produce a heat load that must be rejected to condense the steam that is ejected from the turbine. However, as solar thermal and geothermal power plants are likely to operate at lower thermal efficiencies than conventional coal-fired steam turbines, they are also likely to have a higher water intensity (i.e. a higher volume of water used per unit of electricity output). The rejection of the heat load is achieved either by wet or dry cooling. An illustration of a geothermal generation plant is shown in Figure 10.

Figure 10 **Geothermal energy**



Data source: Geodynamics (2009)

An important difference between these technologies and conventional coal and gas power arises from their location. In Australia it appears likely that many solar thermal and the most prospective geothermal technologies will be located towards central Australia where it is drier and hotter.

Dry cooling performs less effectively in hotter conditions since the lowest temperature the cooling plant can bring the steam down to is limited by the ambient dry bulb temperature. With dry cooling there is a significant reduction in both sent-out efficiency and generator capacity. If dry cooling is to be used in solar thermal and geothermal plants it is likely to require hybrid cooling where additional water cooling can be used during peak temperatures.

Wet cooled geothermal and solar thermal power plants are more likely to be suitable to hot inland areas in Australia. Wet cooled systems deliver higher capacity at lower capital cost.

2.6 Factors affecting choice of cooling system

A number of factors influence the choice of cooling system for new thermal generators. These include capital and operating costs, location of the generating unit, water quality, cooling water cycle efficiency, water recycling and the impact on sent-out efficiency.

Dry cooling involves additional capital cost and lower sent-out efficiency. Lower sent-out efficiency increases fuel requirements and emissions of carbon dioxide and other greenhouse gases.

These considerations must be taken into account along with expected wholesale electricity prices, fuel availability and costs and the price of CO_2-e emissions.

Once-Through Cooling

The clearest benefit of a once-through cooling system is the relatively lower capital cost of the system compared with recirculating cooling systems. Typical capital costs are those associated with high capacity pumps (usually screened to prevent intake of foreign materials) and pipelines to the condenser, and return pipelines to discharge the water back to the sea, river or lake.

The efficiency of the typical steam cycle is directly related to the temperature difference between the highest steam temperature and the lowest temperature just prior to exhaust from the turbine. This in turn is dependent on the temperature of the cooling water entering the condenser. For these reasons, the performance of open cycle cooling is ultimately dependent upon the temperature of the water entering the condenser. The advantage of using water from a large water source in once-through cooling is that it provides a very stable and often cool (compared to the ambient air temperature) source of water. This is therefore often the most efficient of the cooling options.

The disadvantages include the environmental impact on the adjacent waterway through the slight temperature increase, or potential residual chlorine if dosing with chemicals is needed to remove biological deposits in the condenser. Typically these are easy to manage in compliance with licence arrangements.

Although there have been exceptions in the past, once-through cooling is normally not an option for inland power stations in Australia because of the lack of large inland water sources.

Natural Draft Cooling Towers

Natural draft cooling towers represent the highest capital cost option for cooling with water. This is due to the very large and structurally complex concrete structures that comprise the main shell of the cooling tower. This high capital cost is partially off-set by the low operating costs since there are reduced power requirements compared to forced draft cooling.

Natural draft cooling towers achieve quite good efficiencies in cool or humid areas, butare less efficient in dry, hot locations. In such an environment natural draft towers may not be able to reduce the cooling water down to the wet bulb temperature (temperature at which water is evaporating). Natural draft towers are therefore normally the least efficient of the water cooling options. However, natural draft towers typically have lower auxiliary power consumption compared to their forced draft counterparts.

Forced draft Cooling Towers

Forced draft cooling towers are an intermediate capital cost option because the cooling tower structures are more compact and simpler to construct than the natural draft towers. The biggest pitfall is however the relatively high operating costs and particularly the high power requirement to drive the cooling fans at the top of the towers.

Forced draft cooling towers provide very good performance and are able to reduce the cooling water temperature to the wet bulb condition in nearly all conditions. Because of their higher power consumption they represent an intermediate option in terms of efficiency.

Dry cooling

As discussed above, dry cooling significantly reduces water consumption. A dry cooled thermal power plant's water requirements are around 10 per cent of wet cooled plants. The capital cost of dry cooling is slightly higher and dry cooling reduces sent-out efficiency. This leads to increased fuel requirements and higher emissions of carbon dioxide and other greenhouse gases.

There is little information in the public domain on the additional cost of dry cooling in a new power station. Information from manufacturers and anecdotal evidence from power station owners suggest that the capital cost can be up to five per cent higher for a new power station. Operating costs are similar to a forced draft cooling tower system.

Retrofitting is a different consideration. Retrofitting dry cooling requires an amount of space which is not necessarily available in all power stations. One respondent consulted indicated that the cost of retrofitting a 1000 MW coal station with air cooled condensers or a hybrid dry cooling system could be around $400 million. ACIL Tasman estimated that this would result in the cost of water saved exceeding $3000/ML. Others consulted indicated costs could be as low as $1500/ML. There is no information in the public domain to confirm these costs.

Retrofitting also requires the power station to be taken out of service while the cooling system is converted. This could create concerns about the system's reliability and mean that additional generation may need to be installed elsewhere before such a step could be taken without risking supply disruptions.

Impact on sent-out efficiency

Dry cooling lowers sent-out efficiency. A detailed discussion of the reasons for this is set out in Appendix E. Performance of dry cooled condensers is limited to the ambient dry bulb temperature. This is of particular concern on hot days in Australia where the dry bulb temperature can rise above 30 degrees. Both open cycle and closed cycle wet cooling systems are able to achieve the ambient wet bulb temperature. This means power stations with dry cooling systems will always be less efficient than the open cycle and closed cycle wet cooling systems.

Another disadvantage of dry condensers is the auxiliary power consumption. The power required to operate the fans of this system can be several times that required for natural draft wet cooling towers, and is typically four to five MW for a 420 MW unit.

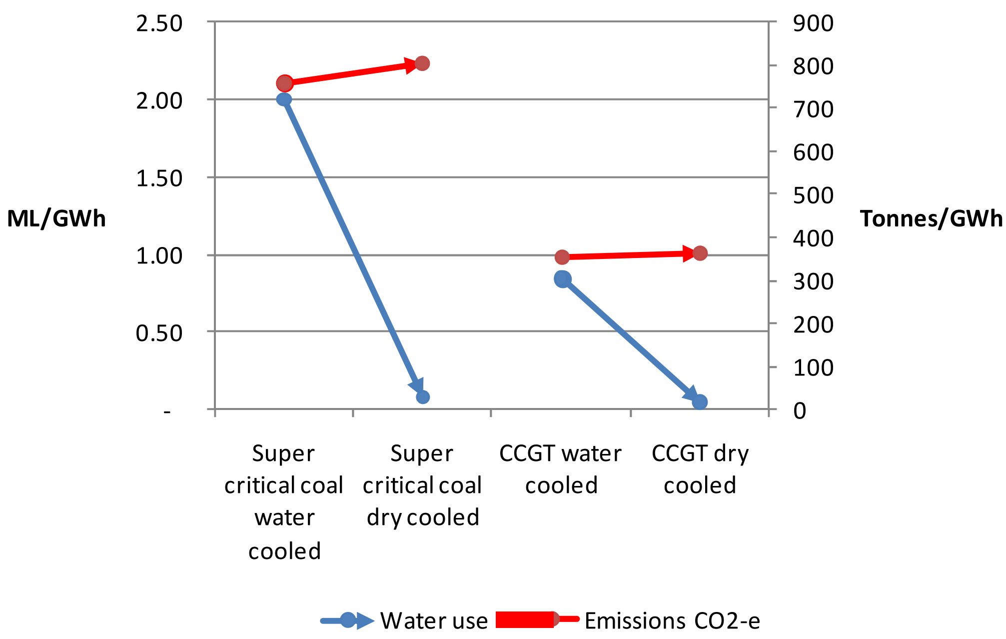
Industry consultations indicated that dry cooling has an efficiency penalty of between one and two per cent for new power stations. For retrofitting the efficiency penalty can be as high as seven per cent. The reason for this is the impact of dry cooling on turbine back pressures.

Impact of dry cooling on water use and emissions

Dry cooling can reduce water consumption in new and existing thermal power stations by more than 90 per cent, however, additional capital and operating costs would be incurred. The additional capital costs are around five per cent in a new power station although they can be more significant for retrofitting existing wet cooled power stations.

The reduced sent-out efficiency associated with dry cooling leads to an increase in emissions of carbon dioxide and other greenhouse gases as well as increased fuel requirements (Figure 11).

Figure 11 **Water and emissions intensity**



Data source: ACIL Tasman Chart

Table 6 lists the data behind this figure. The table shows that dry cooling increases emissions of carbon dioxide and other greenhouse gasses from a super critical coal power station by five per cent and by four per cent from a CCGT plant.

Table 6 **Comparison of wet and dry cooling on water use and emissions**

	Water use	CO_2-e
	ML/GWh	Tonne/GWh
Super critical coal wet cooled	2.00	758
Super critical coal dry cooled	0.08	806
Percentage difference	-96%	6%
CCGT wet cooled	0.85	355
CCGT dry cooled	0.05	363
Percentage difference	-94%	5%

Data source: ACIL Tasman

Retrofitting an existing power station could result in a higher reduction in sent-out efficiency and a larger percentage increase in carbon emissions.

Investment decisions will be further complicated by the need to consider the cost and availability of water. Further, the additional costs of dry cooling and those associated with carbon emissions will become important considerations in future decision making by investors in new generation capacity and in retrofitting existing power stations. These matters are discussed further in chapter 7.

2.7 Carbon capture and storage

Carbon capture and storage (CCS) for thermal power stations is in the research and demonstration stage. There are a number of projects around Australia that currently aim to add to existing research and develop the necessary technologies. Two projects in Queensland that will be important to Australia's contribution to this research effort are:

- ZeroGen: a proposal to build an integrated gasification and combined cycle plant (initially open cycle) that will include a CCS facility in an attempt to reduce the carbon dioxide intensity of the overall plant to 350 kg/MWh CO_2-e (ZeroGen, 2006);
- CS Energy's Oxyfuel Project: a project designed to utilise an oxygen rich firing process to facilitate the carbon capture process by increasing the concentration of the CO_2-e.

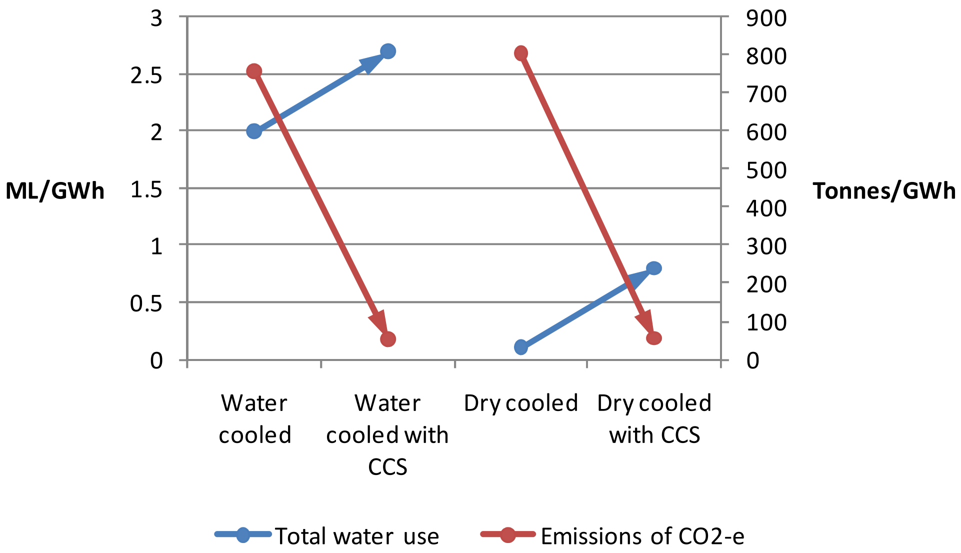
Discussions with suppliers also reveal that there is significant research and development effort into CCS particularly in Europe where it is being driven by a maturing carbon trading environment.

One of the key comments from all proponents of such research is that it is still in the very early stages and that commercial technologies are 10 years off at best.

The implications of CCS technologies for water use are worth considering. Comments from researchers and potential suppliers of CCS technologies indicate that there is a capacity penalty of approximately twenty five per cent for a power station using CCS technologies. While this is a very approximate figure and highly dependent on the actual design of the plant, the implications for existing and future coal and gas plants are significant.

For a modern CCGT producing 500MW, the actual sent-out power might be reduced to 375MW if CCS technologies are fitted. If water cooling is employed on such a plant this has the effect of increasing the water intensity (ML/GWh) by one-third. For example a CCGT producing 2000GWh per year using 1500 ML (total water intensity = 0.85ML/GWh) of water for cooling will now only send out 1500GWh but use the same volume of water to do it (i.e. a water intensity of 1.0 ML/GWh). The impact of CCS on water and emissions intensity for a super critical coal-fired power station is illustrated in Figure 12.

Figure 12 **Water and emissions intensity for super critical coal-fired power station with and without CCS**



Data source: ACIL Tasman Chart

The numbers behind this figure are shown in Table 7 together with a comparison for a CCGT.

Table 7 Impact of CCS on water use and emissions of carbon dioxide and other greenhouse gases

Plant technology	Total water use	Emissions of CO_2-e
	ML/GWh	Tonne/GWh
Super critical coal power station - wet cooled	2.0	758
Super critical coal power station - wet cooled with CCS	2.7	51
Super critical coal power station - dry cooled	0.1	806
Super critical coal power station - dry cooled with CCS	0.8	55
CCGT - wet cooled	0.85	349
CCGT - wet cooled with CCS	1.0	23
CCGT - dry cooled	0.1	373
CCGT -dry cooled with CCS	0.25	25

Data source: ACIL Tasman

2.8 Increasing water use efficiency in electricity generation

There are a number of options available for power stations to increase water use efficiency. Options include recycling, cycling up cooling towers (increasing the number of times water is passed through the cooling towers), recycling waste water and installing hybrid or dry cooling. These are only the onsite options. Power stations can also reduce their need to draw surface water supplies by drawing on treated effluent supplies and groundwater. Consideration of options involves a trade off between the costs of each option and impact on other variables such as emissions, security of supply and the additional treatment costs to treat lower quality water.

Options available to power stations to address limited water access are discussed in Chapter 6.

2.9 Conclusions

Wet cooling systems require large quantities of water, most of it at high security levels. As around 90 per cent of the water is consumed in the cooling process, saline water cooling and dry cooling systems are important options for reducing fresh water requirements of thermal power stations.

Dry cooling comes at the cost of sent-out efficiency. This efficiency penalty and the associated increase in CO_2-e emissions are factors that further complicate the decision to install dry cooling. There is a larger sent-out efficiency penalty with CCS. Should CCS be implemented in future, it will increase the water needed for cooling per MWh.

This chapter also provided a high level discussion of the complex interaction between costs, technologies and sent-out efficiency that determine the economics of different cooling and emissions reduction technologies.

3. Hydro-electricity generation

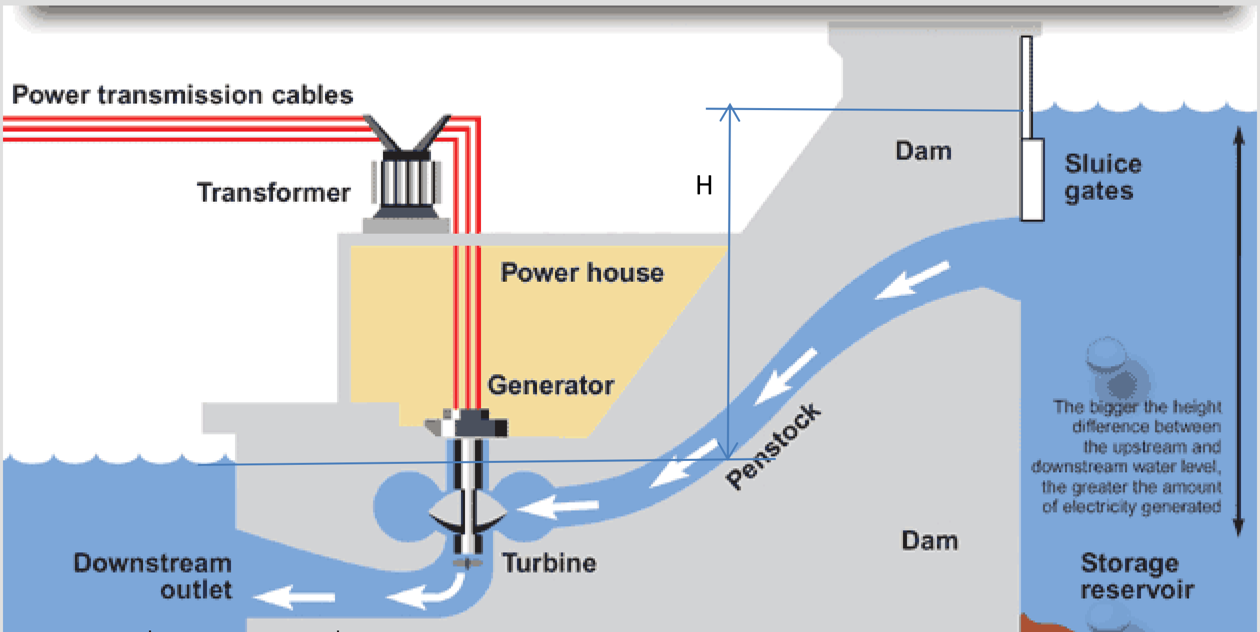
Hydro-electricity power stations are the largest users of water of all power stations in Australia. In 2004-05 hydro-electric power stations used a total of 509 867 GL of water— 99.6 per cent of total water use in the electricity industry. However, water is not consumed in hydroelectric generation, unlike for cooling in coal and gas-fired power stations. The water that passes through the turbines is discharged and is available to downstream users.

Hydro-electricity is an important contributor to Australia's electricity supply. In 2006-07 hydro-electricity generated 13,726 GWh or around seven per cent of Australia's total electricity supply in that year (Energy Supply Association of Australia, 2008). More than 90 per cent of electricity generated in Tasmania is from hydro-electricity. The Snowy Mountains Hydro-electricity Scheme in New South Wales generates more than 70 per cent of the renewable energy supply to the National Electricity Market (NEM).

3.1 Water use in hydro-electricity

Hydro-electricity is derived from the gravitational potential energy of water held in reservoirs. Electricity is generated as water turbines convert this potential energy into kinetic energy to drive a generator. The power from hydro-electricity is proportional to the height through which the water falls when released (head) and the flow rate. The amount of power typically ranges from between 0.25 MW per ML to 8 MW per ML.

Box 1 **Hydro-electricity**



Source: Environment Canada

Australia's major hydro-electricity schemes are in the New South Wales Snowy Mountains, (3756 MW installed capacity) and throughout Tasmania (1180 MW long term average power output). There are many smaller schemes such as the Kiewa Scheme (435MW), the Ord River Hydro plant (30 MW installed capacity) and schemes associated with water storages and dams such as Wivenhoe Dam in south east Queensland, Dartmouth Dam in Victoria and the Kangaroo Valley and Bendeela schemes in New South Wales.

Hydro-electric power stations can also be associated with pumped storage. The Snowy and Tasmanian schemes both incorporate pumped storage capability. Wivenhoe Power Station in Queensland is a purpose built 500 MW pumped storage plant on the Wivenhoe Dam. Other examples include the Fitzroy Falls power station in the Shoalhaven scheme in New South Wales. Pumped storage systems generally draw energy for pumping at off-peak periods to be stored and used for generation during periods of higher demand.

Release of water in hydro-electric schemes is in many cases determined by factors other than electricity generation, such as in the Snowy Scheme where water for irrigation is the main determinant of release. In other cases, such as in Tasmania and in smaller schemes such as the Warragamba and Fitzroy Falls, the generation of power is the prime criteria for release.

Increasing demand for water for environmental flows has had an impact on water use arrangements for some hydro-electricity power stations. The most notable case was the decision by the Victorian and New South Wales Governments in 2000 to return up to 212 GL per year as environmental flows to the Snowy River.

Electricity generated from hydro power interacts with that generated from thermal generation. Low rainfall events and low inflows to reservoirs can result in concurrent constraints on supplies. Earlier modelling undertaken by ACIL Tasman revealed that limited availability of water for hydro-electricity generation can be exacerbated by constraints on generation from lack of water available for conventional thermal generation. This creates a threat to the stability of pricing in the NEM (ACIL Consulting, 2000). The wider regional impact of low rainfall on energy availability and price has been confirmed in recent modelling undertaken by the National Electricity Market Management Company (NEMMCO, 2009).

3.2 Conclusions

Increased competition for water for consumptive use and increasing environmental flows to return catchments to sustainable levels of extraction is beginning to have an impact on some hydro-electricity generators. In December 2000, the New South Wales, Victorian and Australian Governments made a commitment to return up to 28 per cent of average natural flows to the Snowy River commencing with an initial 21 per cent (equivalent to around 212 GL per year) in the Snowy River and an added 70 GL per year additional dedicated environmental flows to the Murray River. Increasing demand for environmental flows and irrigation is emerging in Tasmania and in some cases is factored into water release planning. While such developments have not seriously affected generator output there may be increased requirements to schedule releases from hydro schemes to meet environmental flow requirements.

Periods of low rainfall and low inflows have the potential to affect water available for both hydro-electric and thermal generation. As a result, periods of low water availability are likely to exacerbate price volatility.

4. Existing water use and access arrangements

4.1 Framework

Under the National Water Initiative (NWI), the Council of Australian Governments (COAG) acknowledged that better management of water resources is a national issue. The Initiative points out that the framework within which water is allocated attaches rights and responsibilities to water users. The right is to a share of water made available for extraction at any particular time. The responsibility is to use the water in accordance with usage conditions set by government.

Key elements of the NWI framework for access to water resources include the following:

- clear and nationally-compatible characteristics for secure water access entitlements
- enhanced security and commercial certainty of water access entitlements by statutory specification of the nature of those entitlements
- clear assignment of risk from future changes in the availability of water for the consumptive pool
- compatibility across jurisdictions, and
- access entitlements will be
  - exclusive
  - tradable
  - able to be subdivided or amalgamated
  - enforceable
  - consistent with water plans
  - able to be modified
  - subject to provisions applying during emergencies as specified in legislation.

4.2 Overview of current arrangements

The current arrangements for access to and supply of water to the electricity generation industry differ widely across Australia. Most reflect historical developments when the electricity and water sectors were vertically integrated and largely government owned. The sources of water for electricity generation are shown in Table 8.

In 2004-05, the largest source of water was self extraction (by power stations) at 60 172 GL (90.9 per cent). Most, but not all, of this would have been for instream use in hydro-electricity generation. Distributed supplies amounted to 115 GL and re-use to six GL respectively in 2004–05. Sea water provided around 5928 GL (nine per cent of total water use).

Table 8 **Electricity - sources of water 2004-05**

Source of water	Annual volume	Proportion
	ML	%
Self-extracted	60 171 834	90.87
Distributed	114 535	0.17
Re-use	6002	0.01
Total	60 292 371	91.05
Sea water	5 927 760	8.95
Total including sea water	66 220 131	100.00

Note: includes in stream use

Data source: (ABS, 2005)

The largest users of freshwater in Australia's thermal electricity industry are the large coal-fired generators in Queensland, New South Wales, Victoria and Western Australia. Freshwater supply is generally provided to inland generators under agreements or licence arrangements between government-owned water authorities and government-owned generators. The mechanisms for accessing water include:

- special purpose licences such as the major utilities licences in New South Wales
- access entitlements providing a share of the available capacity in the water system
- specific purpose agreements such as the Snowy Water Agreement
- contracts with water authorities.

Some of these arrangements were established under previous electricity and water sector regimes. In some cases the generators now pay for water sourced from infrastructure that they originally owned.

Some generators located in coastal areas draw saline water from the sea or estuaries for once through cooling. Saline water supply arrangements are established under licence arrangements for regulation of use and disposal of saline water from the marine or estuarine environment.

Water arrangements for hydro-electricity also vary, mainly with respect to provisions for the release of water. Some release arrangements give priority to irrigation requirements (i.e. Snowy Water Licence, Ord River Water Licence), while others are determined by generation priorities (Tasmania, Dartmouth Power Station). The licence arrangements can also include requirements for maintenance of environmental flows.

Gas-fired generators in most states were constructed in the late 1990s and generally acquired water through supply contracts from local water utilities or water corporations. Older gas-fired generators in South Australia, the Northern Territory and Tasmania draw saline water for cooling under licence from the relevant government authority.

4.3 Queensland

Around 65 per cent of Queensland's electricity generation capacity is coal-fired. Of the 10 coal-fired power stations located in Queensland, two are dry-cooled, one is seawater cooled and the remainder are conventional circulating water-cooled. Gas-fired combined cycle gas turbine (CCGT) power stations such as Swanbank E and Yabulu use water cooling for the steam cycle component of the power station.

Water use and access arrangements for selected Queensland electricity generators are summarised in Table 9.

Table 9 **Water access arrangements for Queensland thermal generators**

Generator	Category	Water use	Source	Contractual arrangement
Millmerran (852 MW)	Super critical thermal coal -air cooled condenser	0.7 – 0.8 GL/year for boiler and auxiliaries	Recycled sewage treated with ultra filtration and reverse osmosis.	Take or pay contract with Toowoomba City Council
Callide B (700 MW)	Thermal coal –natural draft wet cooling towers	Water for natural draft cooling tower and auxiliaries 14 -17 GL/year	Awoonga Dam (14.9 GL/year) and Sunwater's Callide Dam (3 GL/year)	Contract with Gladstone Area Water Board for water from Awoonga Dam and with SunWater for transport to Callide Dam and for water from Callide Dam
Callide (900 MW)	Super critical thermal coal – forced draft cooling towers	Water for forced draft cooling towers Approx 12.6 GL/year	Awoonga Dam (12.6 GL/year)	Contract with Gladstone Area Water Board for water at Awoonga Dam and with SunWater for transport to Callide Dam
Kogan Creek (781 MW)	Super critical thermal coal – air cooled condenser	1.2 GL/year for boiler and auxiliaries	Local ground water	Licensed arrangement with QLD Department of Natural Resources and Water
Gladstone (1680 MW)	Thermal coal – once through saline water cooling	0.9GL/year for boiler and auxiliaries 0.7 GL/year treated recycled sewage for ash disposal	Saline water from Auckland Creek Supplied by Gladstone City Council under water access entitlement to Awoonga Dam Gladstone City Council	Environmental licence for removal and discharge of saline water. Domestic supply arrangements with Water Access Entitlement of 5 ML/day
Stanwell (1,400 MW)	Thermal coal – water cooled natural draft cooling tower	15 GL/year	Fitzroy River	Long term contract with SunWater.
Tarong (1,400 MW)	Thermal coal – natural draft wet cooling tower	20 GL/year	Boondooma Dam 29.3 GL/year allocation SEQ Water Grid (See note 1) 8.5 GL/year allocation	Contract with SunWater Contract with SEQ Water Grid Manager Licensed to discharge 17GL/year to Meandu Creek Dam
Tarong North (450 MW)	Thermal coal – wet cooled forced draft cooling tower	9 GL/year	SEQ Water Grid	Contract with SEQ Water Grid Manager
Swanbank B (500 MW)	Thermal coal– wet cooled forced draft wet cooling tower	14 GL/year	Recycled Water Wivenhoe and Moogerah Dam	SEQ Water Grid Manager
Swanbank E (485 MW)	CCGT – forced draft wet cooling tower	4.7 GL/year	Recycled Water Wivenhoe	SEQ Water Grid Manager

Note 1 The Tarong Energy Water Grid Contracts allow the Water Grid Manager to determine the source priority for water supplied via the grid. In Tarong's case the source priority is firstly, Purified Recycled Water (PRW) and secondly, raw water from Wivenhoe Dam.

Data source: Consultations with generators

The 852 MW dry cooled Millmerran Power Station is an example of a low water consumption plant. It draws its water from treated sewage from Toowoomba City Council under a contract and takes no water from surface or groundwater resources. The contract for treated sewage is take or pay with no rights to on-sell water that is surplus to requirements. Millmerran has on-site retention of all run-off water based on a network of drainage channels and dams. The run-off water is used for dust suppression and for watering vegetation. The power station releases no water to the environment.

The 1680 MW Gladstone Power Station is the only saline water cooled power station in Queensland. Gladstone obtains saline water from nearby Auckland Creek under a licence from the local council. Freshwater for makeup water and for auxiliaries is obtained from a number of sources. The main source is a water access entitlement issued by SunWater for water supplied from Awoonga Dam on the Boyne River. The entitlement is for five GL per year but the generator only takes half of that. The surplus cannot be traded. Gladstone Power Station also takes treated effluent from Gladstone City Council for use in treatment and stabilising fly ash.

Stanwell Power Station is wet cooled by a natural draft cooling tower for which water is acquired from the Fitzroy River under a long term contract with SunWater.

Water supplies for Callide B Power Station are drawn from the Callide Dam (which was constructed for the original Callide A power station) and via pipeline and creek from Awoonga Dam under a take or pay arrangement with Gladstone Area Water Board (water) and Sunwater (pipeline and pumping). Callide C (a joint venture between CS Energy and OzGen) is also supplied under similar arrangements from Awoonga Dam.

Swanbank power stations have access to water from Wivenhoe Dam, Moogerah Dam and the Bundamba recycling plant. Under arrangements recently established by the Queensland Government, supply from these three sources is controlled by the South East Queensland Water Grid (SEQWG) under a contract with a price path that will ultimately result in a 94 per cent take or pay requirement. The arrangement does not allow the generator to sell water that is surplus to its requirements. CS Energy estimates that the new arrangements for Swanbank will result in water costs rising to 25 per cent of its operating costs.

In 2004, CS Energy decommissioned the 400 MW Swanbank A power station and effectively replaced it with the 380 MW CCGT Swanbank E power station. While the power stations are not on the same site, this change reduced water consumption by around two thirds of the original water consumption of Swanbank A.

Tarong Energy holds a high priority water allocation from the Boyne Tarong Water Supply Scheme for use by Tarong Power Station. This water is supplied via a pipeline from Boondooma Dam under a water supply contract with SunWater. Boondooma Dam is covered by the Burnett Water Resource Plan (Burnett WRP). The Burnett Basin Resource Operations Plan (Burnett ROP) sets out the operating rules for the Boyne-Tarong Water Supply Scheme. Wivenhoe Dam is part of the Moreton Water Resource Plan (Moreton WRP) and was a source of supply to Tarong Power Station. However the plan limits additional water available from Wivenhoe Dam to town water supply purposes.

Tarong Energy also has a contract with the SEQWG for access to water for Tarong Power Station. Tarong North Power Station is supplied under a separate contract.

During the 2007 drought, the Queensland Government directed that Tarong and Swanbank power stations to restrict the intake of water from the Wivenhoe Dam in response to extremely low levels of water in Boondooma Dam. As a result, Tarong Power Station was forced to curtail generation during the 2007 drought. Swanbank also operated on partial restrictions. The Tarong and Swanbank power stations are now supplied under contracts with the SEQWG following the implementation of the Western Corridor Recycled Water Project. Currently, the SEQWG contracts preclude reselling of surplus water.

4.4 New South Wales

Around 95 per cent of electricity generation capacity in New South Wales is coal-fired. There are no dry-cooled coal-fired power stations in the state. Three coal-fired power stations located in the Lake Macquarie region are saline water cooled— Munmorah, Vales Point and Eraring.

Two coal-fired power stations, Liddell and Bayswater in the Hunter Valley, are freshwater cooled. Redbank Power Station, also located in the Hunter region, is wet cooled and is fuelled primarily with coal tailings. There are a number of smaller gas-fired generators in New South Wales and a major CCGT plant is being constructed at Tallawarra. The latter will be saline water cooled from Lake Illawarra.

Details of the main generators' water usage and access arrangements are summarised in Table 10.

4.4.1 Current use and access arrangements

Table 10 Water access arrangements for New South Wales generators

Generator	Category	Water use	Source	Contractual arrangement
Bayswater Power Station (2640 MW)	Coal-fired – natural draft cooling tower	32GL/year for cooling, blow down ash disposal and auxiliaries	Liddell and Plashett Dams Regulated source on Barnard River.	Macquarie Generation is entitled to take water under a Major Utility Water Access Licence under the *Water Act 1912 (NSW)*
Liddell Power Station (2000 MW)	Coal-fired– once through direct cooled.	Around 30GL/year for cooling , ash plant, blowdown and auxiliaries	Liddell and Plashett Dams Regulated source on Barnard River.	Macquarie Generation is entitled to take water under a Major Utility Water Access Licence under the *Water Act 1912 (NSW)*
Eraring Power Station (2640 MW)	Coal-fired– once through direct cooled by saline water.	Seawater for cooling Around 1.5 GL/year for boiler make up, ash disposal plant and auxiliary cooling.	Seawater from Bonnell's Bay Lake Macquarie 0.19 GL per year potable water from Hunter Water Corp 1.28 GL per year of treated effluent from Hunter Water Corp.	Reticulated water supply from Hunter Water Corp
Mt Piper Power Station (1320 MW)	Coal-fired– water cooled natural draft cooling tower	15.6 GL/year for cooling, ash plant, makeup water and auxiliaries	Water is extracted from Delta's three dams on the Coxs River and Fish River supplied from State Water. Corporation. Total entitlement is 23GL/year shared with Wallerawang.	Major Utility licence under Part 9 of the *Water Act 1912*
Wallerawang 'C' Power Station (1000 MW)	Coal-fired– water cooled - natural draft cooling tower (U8) + Forced draft cooling tower (U7)	10 GL/year Mount Piper for cooling, make up water and ash plant.	Water is extracted from Delta's three dams on the Coxs River and Fish River supplied from State Water Corporation. Mine dewatering can be delivered to the cooling tower.	Major Utility licence under Part 9 of the *Water Act 1912*
Munmorah Power Station (600 MW)	Coal-fired – saline cooling water- once through direct cooling.	Water from estuarine lakes for condensate cooling ~1.5 GL/year sourced from town water	Lake Munmorah	Boiler makeup water supplied from Gosford Wyong reticulated town water supply
Vales Point "B" Power Station (1320 MW)	Coal-fired – once through direct cooling – saline water.	Water from estuarine lakes for condensate cooling ~2 GL/year sourced from town water	Chain Valley Bay on Lake Macquarie (saline)	Boiler makeup water supplied from Gosford Wyong reticulated town water supply
Tallawarra (450 MW)	CCGT – building on an old coal plant site. Direct cooling – from Lake Illawarra	0.06 GL/year	Will draw cooling water from Lake Illawarra.	Need planning agreement to use lake water – a permitting authority from the Lake Illawarra Authority.

Note: Estimates of water use are approximate

Data source: Consultations with generators, NSW Department of Water and Energy Major Utilities Licences.

Water for the major coal-fired power stations is supplied under major utility licences. These licences provide for supply of very high security water and establish the access, duration and other conditions that must be met by generators.

The main water supply for the Wallerawang and Mount Piper power stations is supplied under a licence issued to Delta Electricity (Department of Natural Resources, 2005). The licence, which expires in 2025, sets out arrangements for supplies from the Coxs River and related storages. Water for Wallerawang is supplied from two dams on the Coxs River— Lake Lyell and Lake Wallace, and also from Thompsons Creek Dam—an off-river storage. The storages are owned by Delta Electricity. Additional supplies are sourced from the Fish River under the Fish River Water Agreement and from the nearby Springvale Mine under an agreement with the mine operators.

The licence specifies water use efficiency standards—1.65 ML per GWh for Mt Piper and 1.75 ML per GWh for Wallerawang—and release and water quality/river health monitoring.

Thompson's Creek Dam has been topped up with water pumped from Lake Lyell and from water from mine dewatering (removing water produced during mining). The mine dewatering water has salinity levels three times that of water from Coxs River. During the worst of the 2007 drought, generation at Wallerawang was partly curtailed because of the high salt content of the water and the unavailability of suitable quantities of water from the Fish River for dilution.

Delta Electricity's Munmorah and Vales Point power stations are saline water cooled. Water for other operations is supplied from the town water system. The company has also implemented a treated recycled water scheme.

Macquarie Generation obtains its water through a major utilities licence for extraction of water from the regulated and unregulated water sources of the Hunter Catchment. The licence permits Macquarie Generation to on-sell water to other water users. There are however some restrictions and reporting requirements associated with selling arrangements (Department of Water and Energy, 2008). Macquarie also buys and sells high security and general security water to augment water supplied under the major utility licence.

Eraring Power Station is saline water cooled. Eraring obtains around 1.5 GL per year of freshwater from the Hunter Water Corporation. Of this 1.3 GL per year is provided as secondary treated effluent.

The proposed Tallawarra CCGT power station being developed by TRUenergy will draw on saline water from Lake Illawarra. The plant will be built on an abandoned coal-fired power station site and water supplies will be limited to the water supply arrangements of the former power station.

Water for the Snowy Mountains hydro-electric scheme is supplied under the Snowy Water Licence that determines the release schedule for the Murray, Murrumbidgee and Snowy and Montane Rivers. There are also small hydro-electricity generators such as at the Burrendong, Copeton and Glenbawn Dams which are all operated by AGL. These schemes also access water through specific water licences.

Macquarie Generation has small hydro-electricity associated with pumping for Liddell and Bayswater power stations and Eraring Energy operates a hydro pumped storage facility in the Shoalhaven catchment based at Fitzroy Falls, as well as at Burrinjuck in the Snowy Mountains.

4.5 Victoria

Around 91 per cent of Victoria's electricity generation is based on five brown coal-fired plants located in the Latrobe Valley. These are the largest water users in the Victorian electricity industry. Other generation includes gas-fired power stations such as at Somerton and Laverton and hydro stations such as those at Dartmouth Dam and Eildon Weir.

The principal area of interest for this report is water use and developments associated with the five coal-fired power stations in the Latrobe Valley. These base load stations were developed to use the high quality brown coal resources of the Latrobe Valley and the water resources of the Latrobe River.

Water use and access arrangements for selected generators in Victoria are discussed in section 5.3.4 and summarised in Table 11.

Table 11 Water access arrangements for Latrobe Valley generators

Generator	Category	Water use	Source	Contractual arrangement
Yallourn Power Station (1450 MW)	Coal - natural draft cooling tower	Low quality water - 36.5 GL/year with around 15 GL/year returned to the river system – a net consumption of 21.5 GL/year.	Blue Rock Dam, Lake Naracan plus Latrobe River passing flows.	Bulk water entitlement
Loy Yang Power Station (2200 MW)	Coal-fired – natural draft cooling tower	High quality water around 1 GL/year Low quality water – around 25 GL/year Ground water – around 10 GL/year.	High quality water from Moondarah reservoir Low quality water from Blue Rock Dam, Lake Naracan and Latrobe River passing flows – 40 GL/year bulk water entitlement. Groundwater from mine dewatering.	High quality water supplied under contract from Gippsland Water on a volumetric basis. Low quality water supplied under a bulk water entitlement.
Loy Yang B Power Station (1000 MW)	Coal-fired – natural draft cooling tower	1 GL/year high quality water 17 GL/year low quality water.	High quality water for domestic Services Water ex Moondarra Reservoir. Low quality water from Blue Rock Dam, Lake Naracan & Latrobe River under a 20 GL/year entitlement.	High quality water supplied under contract (Water Services Agreement) from Gippsland Water. Low quality water supplied under licence from Southern Rural Water.
Hazelwood Power Station (1600 MW)	Coal-fired – cooling pond	Total water use around 27 GL/year	Around 13 GL/year supplied from Moondarra Reservoir. Around 12 GL/year supplied from mine dewatering plus another 2 GL/year from other sources.	Supplied under contract from Gippsland Water – total entitlement of 22 GL/year. Supplied under a licence limited to use in electricity generation.
Morwell Co-generation Power Station (170 MW)	Coal-fired – natural draft cooling tower Co-generation	7.1 GL/year	Supplied from Moondarra reservoir.	Contract with Gippsland Water.

Data source: Consultations with generators and Department Infrastructure, Energy and Resources

Water supply to the Latrobe power stations is drawn from the Latrobe River, the Moondarra Reservoir on the Tyers River and artesian water supplied from mine dewatering. The supplies are provided under different arrangements from Gippsland Water and the Southern Rural Water Authority. There are two bulk water entitlements, one diversion licence and one bulk unallocated entitlement available for electricity generators. Yallourn Energy and Loy Yang Power hold bulk water entitlements to Blue Rock Dam and flow from the Latrobe River of 36.5GL/year and 40GL/year respectively. Southern Rural Water provides an entitlement for Loy Yang B of 20GL/year.

The bulk water entitlements are full water access entitlements and allow trading of the entitlements. Low quality water taken directly from the Latrobe River is primarily used for cooling. The power stations have access to a share of water stored in Blue Rock Dam. High quality water supplied from Moondarah reservoir is used for boiler feed water by the power stations. This water is supplied on a volumetric basis from Gippsland Water as opposed to the resource share arrangements for bulk water. Artesian water supplied from coal mining operations at Morwell, Yallourn and Loy Yang is mainly used for cooling.

A complex network of infrastructure supplies water to the Loy Yang Power Station (Loy Yang Power and International Power Mitsui Pty Ltd Loy Yang B) from multiple sources. High quality water for generating steam is pumped from Moondarra Reservoir, via pipeline and two intermediate storage reservoirs, before being gravity fed to the Loy Yang Power treatment plants. This is supplied under a long term contract with Gippsland Water (to both Loy Yang Power and Loy Yang B). The contracts are in volumetric terms.

Low quality water supplied from the Latrobe River from Lake Naracan and Blue Rock Dam augments run-of-river flows. From there it is pumped 25 kilometres to a storage reservoir and is then gravity fed into the Loy Yang Complex low quality water systems. This supply is supplemented with Latrobe River run-of-river flows and is the preferential draw over Blue Rock when water is available from the Latrobe River. For Loy Yang Power the maximum draw from Blue Rock is 9.17GL annually with the balance of required flows (up to 20GL) taken from run-of-river flows.

Gippsland Water owns the high quality water supply infrastructure to Loy Yang A treatment plants. Loy Yang Power owns the low quality water supply infrastructure. The Blue Rock Dam was purpose built by the former State Electricity Commission of Victoria to supply low quality water to the Loy Yang Power complex and Yallourn power stations (and potential future Latrobe Valley power stations) and is now owned by Southern Rural Water.

Loy Yang Power currently holds a 40 GL per annum bulk entitlement to low quality water with Southern Rural Water for water supplied from Blue Rock Dam. Groundwater pumped from the Loy Yang mine also supplies water to Loy Yang A. Loy Yang B does not gain an accounting benefit from this artesian supplement, but uses around a 30 per cent mix of artesian and Latrobe / Blue Rock sourced water under contractual arrangements.

Loy Yang B purchases water from Southern Rural Water under a Diversion Licence. Loy Yang Power transfers this water under an infrastructure services agreement with Loy Yang B. In 2006–07, Loy Yang B had to purchase five GL water from the auction of the government’s unallocated share of water from Blue Rock Dam. This water was purchased at a cost from $80/ML to $280/ML through WaterMoves—a water trading scheme operating in Victoria and Southern New South Wales.

Hazelwood Power Station, also operated by International Power Mitsui, has a contract with Gippsland Water for supply of up to 14 GL per year of water from Moondarra Dam. This is supplemented by mine dewatering from Morwell acquired under licence. The power station also has access to the Hazelwood cooling pond.

Yallourn Power Station also has a bulk water entitlement from Blue Rock Dam and Lake Naracan. In addition the station can take passing flows from the Latrobe River. During the drought of 2006 Yallourn also purchased water from the auction of unallocated entitlement from Blue Rock Dam.

The Morwell Power Station draws around seven GL per year from Moondarah Reservoir also under a contract with Gippsland Water. Morwell has implemented improved water management measures. This includes recycling around 0.5 GL per year from settling ponds and wash-down water from its briquette plant.

There is a limited market for water in the Latrobe Valley. The Victorian Government established a price of $1500 per ML for water from its currently unallocated share in Blue Rock Dam which is regarded as the cost of water for maintenance and supply by Southern Rural Water.

There are also small hydro-electricity generators such as at Dartmouth and Eildon Dams which are operated by AGL. These schemes also access water through specific water licences.

4.6 South Australia

Around 54 per cent of generation capacity available to South Australia is gas-fired and 15 per cent coal-fired. Of the remainder, 15 per cent is wind, 13 per cent is imported through the interconnector and three per cent is diesel. Most of the gas-fired power stations are located in coastal areas and are saline water cooled.

Water use and access arrangements for selected generators in South Australia are discussed in section 5.3.5 and summarised in Table 12.

Table 12 **Water access arrangements for South Australian generators**

Generator	Category	Water use	Source	Contractual arrangement
Hallett Power Station (180 MW)	Gas Turbine –no cooling	Small quantities for fogging and emissions control less than 0.5 GL/year.	Local water supplies	Local water authority
Northern Power Station (530 MW)	Thermal –coal – once through direct cooled	Saline water cooled. Less than 0.5 GL /year of fresh water	Local water supplies for small quantities	Local water authority
Osborne Power Station (118 MW)	Gas Turbine – gas (CC) – cogeneration	Minimal water consumption.	Local water supplies for small quantities	Local water authority
Pelican Point Power Station (487 MW)	Gas Turbine –Gas (CC)– direct cooled from sea	Saline water cooled. Less than 0.3 GL /year	Ocean Local water supplies	Contract with water authority
Ladbroke Grove (80 MW)	Gas Turbine	Evaporative cooling and fogging – less than 0.05GL/year.	Local water supplies	Contract with water authority
Quarantine Power Station (92 MW)	Gas Turbine	Evaporative cooling and fogging – less than 0.05 GL/year	Local water supplies	Contract with water authority
Playford B Power Station (240 MW)	Coal- fired – once through direct cooled.	Saline water cooled –Less than 0.05 GL/year	Ocean Local water supplies	Local water authority
Torrens Island Power Station 'A' (480 MW)	Gas-fired steam turbine – once through direct cooled.	Saline water cooled Small quantities of freshwater to control NOx and SOx Around 0.5 GL/year.	Ocean Local water supplies	Local water authorities
Torrens Island Power Station "B" (800 MW)	Gas- fired steam turbine – once through direct cooled.	Saline water cooled Small quantities of freshwater to control NOx and SOx Around 1 GL/year.	Ocean Local water supplies	Local water authorities

Data source: Consultations

Open cycle gas turbines such as at Hallett Power Station and Ladbroke Grove and Quarantine power stations do not use significant amounts of water. The main use is for evaporative cooling of intake air, sometimes fogging and for control of emissions of oxides of nitrogen (NO_x) and sulphur (SO_x). The small quantities are in all cases met by contract with local water authorities. In most cases the annual consumption is less than 0.5GL per year

The combined cycle power stations such as Pelican Point are saline water cooled. Some water is acquired from local water authorities for fogging and emissions control on the gas turbine component. The Torrens Island gas-fired plant and the coal-fired plants are once through saline water cooled. Water consumption ranges between 0.5 GL per year to one GL per year.

Water access for power stations is agreed via arrangements with local water authorities. Supply and disposal of saline water for cooling are arranged under environmental licences.

4.7 Western Australia

In discussing water supply to power stations in Western Australia, electricity generation can be divided into the major generators in the Collie coal fields, the coastal generators at Kwinana and inland gas-fired generation. There is also hydro-electricity generation on the Ord River.

The Collie generators are primarily supplied by water from mine dewatering from the coalfields. The coastal generators use saline water cooling and the inland gas-fired generators are mainly open cycle gas turbine and do not use significant quantities of water.

Water use and access arrangements for selected generators in Western Australia are discussed in section 5.5.6 and summarised in Table 13.

Table 13 **Water access arrangements for selected Western Australian generators**

Generator	Category	Water use	Source	Contractual arrangement
Muja Power Station (954 MW)	Coal-fired forced draft cooling tower	11 GL/year –water for cooling, blowdown make up and auxiliaries	Mine dewatering water Bore water	State agreement for water with Griffin Coal and with Wesfarmers. Bore water provided under licence.
Collie Power Station (340 MW)	Coal-fired forced draft cooling tower	4 GL/year – water for cooling, blowdown and auxiliaries	Mine dewatering water plus bore water	State agreement for water with Griffin Coal and with Wesfarmers. Bore water provided under licence.
Bluewaters Power Station (200 MW)	Coal-fired forced draft cooling tower	3.25 GL/year	Mine dewatering	Contract with mine extracting under a water allocation licence
Cockburn CCGT 240 MW	Gas combined cycle with direct cooling from the sea	Saline water cooling Less than 0.2 GL per year	Freshwater from Water Corporation	Contract with Water Corporation
Kwinana Coal 854 MW	Coal-fired–direct cooling from the sea	Saline water cooling Less than 0.6 GL/year	Freshwater from Water Corporation	Contract with Water Corporation
Kwinana CCGT 180 MW	Gas combined cycle – saline water cooling towers	Saline water cooling Fresh and recycled water for other purposes such as emissions control Less than 0.3 GL/year	Freshwater from Water Corporation plus recycled water.	Contract with water corporation and potentially recycled water from the BP oil refinery.

Data source: Consultations

The coastal saline water cooled generators at Kwinana are not large users of freshwater. They require relatively small amounts of water for power station functions including boiler make-up and ash disposal in the case of the coal-fired power station, and water for services and emissions control in the case of gas-fired power stations. Consideration is being given to increasing the use of recycled water and desalination to replace freshwater supplies to these generators.

The Verve coal-fired power stations at Muja and Collie use water produced from dewatering Collie coal mines. Water for the power stations is provided through two state agreements—one with Griffin Coal and one with Wesfarmers.

Muja Power Station uses around 11 GL per year, Collie Power Station around four GL per year. Griffin Energy is constructing a new 400 MW coal-fired plant close to its coal mine near Coolangatta in the south west. The plant will use around 7.5 GL per year. However water availability is limited in the Upper Collie catchment. Groundwater resources are fully allocated and there is only a small amount of surface water available for new allocation. While all freshwater is effectively fully allocated, water of marginal quality (~ 1000 ppm TDS) is available from Wellington Reservoir.

Griffin energy has commissioned the first stage of its Bluewaters coal-fired power station. By the end of 2009 a total of 200 MW will have been commissioned. The water supply will be dewatered mine water from the local coal mine extracted under a water allocation abstraction licence. The licence does not allow water to be traded. Griffin needs to obtain a further licence to supply cooling water to the next stages of the power station which will involve a further 200 MW to be commissioned. Griffin has not yet received approval for this water supply.

The Western Australian Government is reviewing water management arrangements in the upper Collie catchment. It is likely that the higher quality water from coal mine dewatering will be incorporated into a broader water management arrangement in the catchment. The Western Australian Government released a discussion paper on management of upper Collie water in December 2007 (Department of Water, 2007). The challenges facing water managers in the Collie catchment include the management of salinity in the Wellington Reservoir, the potential for a desalination plant to supply some needs, the use of high quality dewatered mine water and supplies to a range of industrial, agricultural and urban uses. No decisions have been made at this stage.

A possible outcome for Griffin Energy will be a separate supply agreement being established to supply water to the power station as opposed to using higher quality water from mine dewatering. This could involve drawing on saline water from Wellington Dam. Desalination would be required if this were the option selected.

Water supply arrangements for power stations in the Collie catchment involve agreements specifically drafted for supply to power stations. They are quarantined from the normal operations of water markets, limit trading opportunities and assign security and water quality conditions appropriate to the specific conditions. These arrangements are framed in the context of catchment water management planning, but they are isolated from the broader water market.

4.8 Tasmania

Electricity generation in Tasmania is dominated by the six hydro-electricity schemes owned and operated by Hydro Tasmania that provide around 98.5 per cent of total installed capacity. Further security is provided through the 240 MW gas-fired thermal plant at Bell Bay. An additional three turbines were installed in 2005 for added security against low water inflows into the dams.

Access to water for hydro-electricity generation is provided through a water licence that provides Hydro Tasmania with access to all the water in the catchments. Use of this water is determined by demand for electricity generation. However there can be releases to meet environmental flows which can result in forced generation.

In some circumstances irrigation requirements are taken into account. This can involve sale of a temporary allocation to irrigators at a revenue neutral price. Up to this point this has not created conflicts although with expansion of irrigation it might become an issue in the future.

4.9 Northern Territory

Electricity supply in the Northern Territory is made up of stand-alone systems that are not connected to the National Electricity Market. Electricity generation across the Northern Territory is a mixture of gas, diesel and renewable technologies. Total generation capacity in the Northern Territory is 380MW of which the Channel Island 254 MW CCGT Power Station is the largest. This power station draws on around one GL per year supplied by pipeline from the Darwin River Dam. The water access arrangement for Channel Island Power Station is via an internal agreement under which the power station pays an internal service charge. The water is used for water cooled condensers and for fogging and NOx control.

The Power and Water Corporation advised that new CCGT power stations in the Northern Territory would most likely consider dry cooling for future inland power stations.

4.10 Australian Capital Territory

There are no power stations presently operating in the Australian Capital Territory. ACTEW-AGL is planning a 28 MW gas-fired co-generation plant but plans for the proposed power station are not settled. It is unlikely that the plant would have significant water requirements as it would most likely be a gas turbine with waste heat being used for air conditioning in the associated document storage centre.

4.11 Conclusions

Water access arrangements for the large water using power stations vary around Australia. They range from general bulk water entitlements, to specific purpose utility licences and contracts with bulk water supply organisations. The reforms to access arrangements under the NWI have not affected these licences. Smaller quantities of water are acquired from local water authorities and town water supplies under retail arrangements.

Specific licences and contracts that provide for supplies to the coal-fired power stations generally are not consistent with the access principles set out in the NWI. They are usually for a defined time and often include conditions such as restraints on trading surplus water, or water use efficiency targets. The coal-fired power stations also augment supplies from these contracts with additional purchases of water from the market or through water access entitlements with the largest example being the brown coal-fired power stations in the Latrobe Valley.

Increasingly the electricity industry is considering use of treated effluent and lower quality water to meet future water needs. This may be done in isolation as in the case of Gladstone Power Station, or as part of government sponsored regional water supply schemes designed to deliver treated effluent or treated saline water as in the case of Tarong and Swanbank. To date only the Queensland Government has implemented a regionally coordinated supply of treated effluent to wet cooled power stations.

5. Outlook for water supplies for electricity generation

This chapter discusses the outlook for water supplies for electricity generation in Australia using some possible scenarios for new demand profiles. The chapter then examines the availability of water supplies to meet short and long term electricity generation needs.

5.1 Demand for new electricity generation capacity

Projections of growth in energy requirements and maximum demand by region to 2020 are shown in Table 14 and Table 15. These were developed by ACIL Tasman based on the 2007 National Electricity Market Management Company (NEMMCO) Statement of Opportunities and ACIL Tasman projections for the South West Interconnected System (SWIS) (NEMMCO, 2007 and ACIL Tasman, 2008). They assume a 10 per cent emissions reduction target by 2020. The 2007 Statement of Opportunities (NEMMCO 2007) reveals slightly higher projections for Victoria and slightly lower projections for the other National Electricity Market (NEM) states.

Table 14 **Energy requirements in the NEM and the SWIS**

	NEM	SWIS	Total
	GWh	GWh	GWh
2008	210 874	15 878	226 752
2020	235 261	18 944	254 205
Additional energy requirement	24 387	3066	27 453
Aggregate growth	12%	19%	12%
Annual average growth rate	1%	1%	1%

Note: Based on a 10 per reduction in CO_2-e by 2020
Data source: (ACIL Tasman, 2008)

Table 15 **Maximum demand by region**

	NSW	QLD	SA	TAS	VIC	SWIS
	MW	MW	MW	MW	MW	MW
2008	14 070	9461	2990	1781	9198	3521
2020	16 074	12 440	3329	1878	9949	4378
Maximum demand increase	2004	2979	339	97	751	857
Aggregate growth	14%	31%	11%	5%	8%	24%
Annual average growth rate	1%	2%	1%	0%	1%	1%

Note: Based on a 10 per reduction in CO_2-e by 2020
Data source: (ACIL Tasman, 2008)

Table 14 shows that energy requirements are likely to increase by 12 per cent in the NEM and 19 per cent in the SWIS. This will require additional generation capacity to maintain adequate reserve margins. Table 15 shows that additional capacity of around 2000 MW in New South Wales and around 3000 MW in Queensland will be required by 2020. An additional 850 MW is projected to be required for the SWIS by 2020.

The types of investment in new generation capacity that will supply this demand growth will depend on a number of considerations. An important factor will be the ultimate price of emission permits. Other issues relate to progress in meeting renewable energy targets and the load patterns that emerge across the electricity supply grids.

In a study completed for the Electricity Supply Association of Australia in 2007, ACIL Tasman modelled different scenarios for a 10 per cent and 20 per cent emissions reduction target by 2020 (ACIL Tasman, 2008). The scenario based on a 10 per cent emissions reduction by 2020 is summarised in Table 18. The modelling was undertaken before the announcement of the arrangements for the Carbon Pollution Reduction Scheme (CPRS) and assumed that compensation was not provided to the coal-fired generators. Since that time the Australian Government has announced compensation arrangements under the scheme that would alter some of the modelling outcomes for projected closures of some coal-fired plant. Despite this, the modelling is useful in identifying broadly where the additional generation investment will be required in Australia.

Table 16 **Additional capacity required in the NEM and SWIS based on 10% emissions reduction by 2020**

State	Coal/gas-fired steam turbine	CCGT	OCGT	Geothermal	Hydro	Other renewables
	MW	MW	MW	MW	MW	MW
Queensland	375	2790	770	750	-	314
New South Wales	-	-	1,570	-	-	2209
Victoria	-	3250	1,340	-	150	2628
South Australia	-	-	270	750	-	744
Tasmania	-	240	-	-	-	-
Western Australia	929	240	442	-	-	900
Total	1304	6520	4392	1500	150	6795

Note: Based on a 10% emissions reduction scenario which includes some plant retirements notably coal

Data source: (ACIL Tasman, 2008)

While these results are indicative only, they show that an additional 1304 MW of coal or gas-fired steam turbine generation, 6520 MW of combined cycle gas turbine (CCGT) and 1500 MW of geothermal capacity is scheduled under the 10 per cent scenario. These technologies require cooling, either wet or dry. Of the coal/gas-fired steam turbine technologies, 208 MW are projected to be in the Upper Collie catchment in Western Australia and 375 MW in south east Queensland.

For new CCGT, 2790 MW is projected to be in Queensland and 3250 MW in Victoria over the next ten years. The additional need for CCGT in these states assumes that some of the existing coal-fired plants are retired. If this were to occur it is likely that the new capacity would be installed in the same location as the retired coal-fired plant to take advantage of the existing transmission infrastructure and water supplies. However, it is not possible to predict retirement patterns for coal-fired plant with any certainty at this stage.

The geothermal plants are likely to be located in south east Queensland and the north east of South Australia. They are likely to draw on groundwater for water supplies.

These projections do not include inland solar thermal plants. Such plants would also need to consider dry or wet cooling. Water for wet cooling would most likely come from groundwater resources for inland locations.

Much of the new generation capacity is likely to be in water constrained regions or subject to periodic drought conditions.

5.2 The short term outlook

Given the reliance of the electricity industry on adequate water supplies, the Ministerial Council on Energy Standing Committee of Officials asked the NEMMCO to investigate the impact of the ongoing drought on electricity generation to provide market participants with guidance on the short term outlook for energy generation in December 2006. The first report was released in May 2007. Given the sharp deterioration of rainfall levels after the release of the report, the Ministerial Council on Energy requested that NEMMCO provide an update. NEMMCO now releases updates on a quarterly basis using up-to-date rainfall data, any water use efficiency measures generators employ and jurisdictional water allocations.

Generators were asked to report on three rainfall scenarios:

- Low rainfall—based on rainfall between 1 July 2006 and 30 June 2007.
- Short term average rainfall—based on the average rainfall recorded over the past 10 years.
- Long term average rainfall—based on the average rainfall recorded over the past 50 years, or the longest period for which rainfall data is available should this be less than 50 years.

NEMMCO uses the data received to simulate medium-term supply projections. In particular the report projects levels of un-served energy (USE) for each scenario. The Australian Energy Market NEMMCO Reliability Panel has set a standard of unserved energy of 0.002 per cent of annual energy demand for each region.

In its March 2009 update of the drought scenarios investigation, NEMMCO found the following:

In the low rainfall scenario, the overall forecast for expected USE due to the drought is higher than the Reliability Panel Standard of 0.002 per cent for the first year of the study period in the South Australian and Victoria regions. This is primarily due to assumed reductions in water availability to two Victorian generators in the summer of 2009-10. Similar to the December 2008 report, this report forecasts that USE in all other NEM regions will be below 0.002 per cent in the low rainfall scenario (NEMMCO, 2009).

The potential constraints in South Australia under the low water scenario are not caused by lack of water in South Australia but by limited generation in Victoria, which is projected to constrain supplies imported into South Australia through the interconnector.

Hydro Tasmania reported in early December 2008 that despite the long term drought, it will be able to maintain security of supply through the summer and autumn dry months following near average spring rains. Security of supply is reinforced in Tasmania through a combination of supply from hydropower and Basslink imports from Victoria, augmented by the Bell Bay Power Station.

5.3 The long term outlook

5.3.1 Overview of water availability

Australia's water resources are highly variable ranging from heavily utilised rivers and groundwater resources to rivers and aquifers that are relatively untouched. Recent droughts have raised concerns about the availability of water for consumptive use in areas where water supplies for urban, agricultural, environmental and industrial uses are close to fully allocated, or in some cases over-allocated.

Following the signing of the National Water Initiative (NWI) Intergovernmental Agreement, governments in Australia began assessing sustainable yield from surface and groundwater across Australia. Caps on diversions and extraction were set as findings from the assessments emerged.

A summary of the status of surface and groundwater caps is provided in Table 17.

Table 17 **Surface and groundwater caps as at 2005**

State	Surface water cap	Groundwater cap
Queensland	Surface water caps in 60 per cent of water resource plan areas. Of the caps that are in place 40 per cent have an absolute limit on diversions —the remainder are conditional while plans are being completed	There are 16 groundwater management units with caps and no caps on a further 18 unincorporated units.
NSW	All areas covered by a water sharing plan have a surface water cap in place —45 management areas.	There are 88 groundwater management units with caps on usage and extraction.
Victoria	All Victorian water management areas are capped.	There are 62 caps on groundwater management units but no caps on unincorporated groundwater management units.
Western Australia	There are currently no caps on surface water use — there are six water management areas in Western Australia that will potentially need a cap.	Caps on all 44 groundwater management units and provisional caps on all unincorporated areas.
South Australia	Four surface water areas have caps. Another 13 have provisional caps set at sustainable yield.	There are 28 groundwater caps with no caps on a further 31 unincorporated groundwater management units.
Northern Territory	Provisional surface water resources caps were implemented in the Northern Territory in 2000.	There are 52 groundwater caps and no caps on a further 3 unincorporated groundwater management units.
Tasmania	Provisional caps have been placed on 38 of Tasmania's 48 surface water areas.	No groundwater caps in Tasmania

Note: This data is as at 2005

Data source: (National Water Commission, 2005; National Water Commission, 2007; National Generators Forum, November 2006)

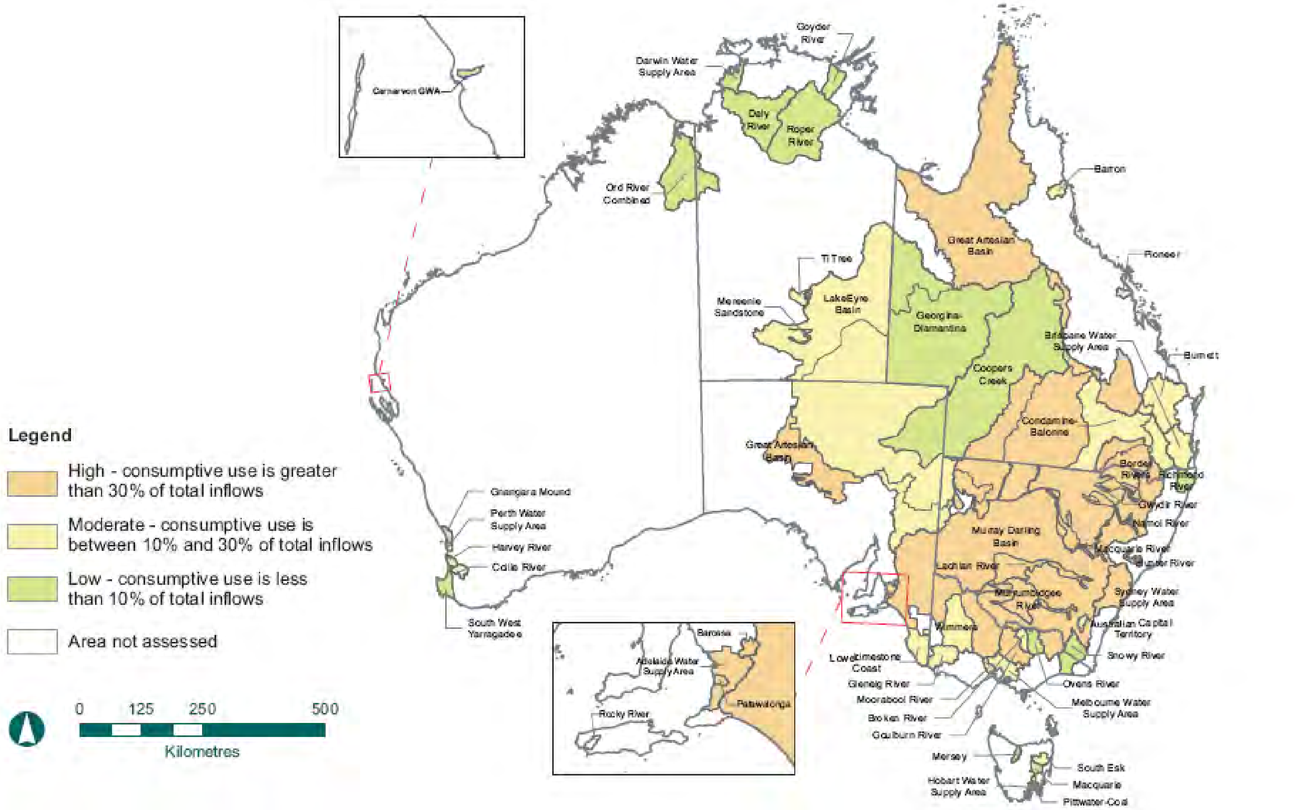
According to the National Water Commission survey, about half of the surface water management areas in Australia had a surface water cap in place in 2005 (195 out of 340 water management areas) (National Water Commission, 2005). The Commission also found that the status of groundwater caps was not consistent across Australia. Tasmania, for example, has no caps (the resource is not currently licensed and only slightly developed). In contrast, Western Australia has caps on all its groundwater management units. The other states and territories have a combination of capped and uncapped groundwater management units or unincorporated areas.

Capping of diversions and extraction has affected the electricity industry regardless of the status of water resources in each region. In regions where water resources are constrained, existing power stations are coming under increasing pressure to reduce their water use or draw on other options such as substituting treated recycled water for various uses. However even in under-allocated catchments, growing demand for water for urban and industrial use has had an impact on power stations.

Current use levels in water management areas

The level of development of water resources in water resource management areas provides some indication of the availability of water for future use. In 2005 the National Water Commission undertook an assessment of the level of water resource development in Australia. The criteria and detailed assessments by water management area are summarised in Figure 13.

Figure 13 **Levels of consumptive use compared to inflows across Australia in 2004-05**



Note: The Gnangara Mound groundwater management area underlies the Perth Water supply Area, but is illustrated in this map due to it high consumptive use category. The Perth Water Supply Area has moderate water use. The Great Artesian Basin (GAB) underlies large areas of the Lake Eyre Basin, Georgina-Diamantina, Cooper Creek and the Murray-Darling Basin surface management areas and therefore is not clearly shown, except for in its northern and south-western portions. The GAB rates high in the consumptive use category

Data source: (NWC, 2005)

This is a general comparison and does not account for drought circumstances, or for specific areas of constraint. However it illustrates an important point for future power station water access. Most of the water resource management areas in Queensland, New South Wales, Victoria and South Australia where coal or gas-fired power stations are likely to be located are classified as highly developed. On top of this, inland groundwater resources of the Great Artesian Basin and the Lake Eyre are overused.

The relatively high usage levels in water management areas where electricity generation facilities are located provides background to the increasing concern about water supplies for electricity generation. However it does not capture the shorter to medium term concerns over the impact of drought on electricity generation.

5.3.2 Queensland

The availability of water in Queensland varies by region with moderate to high levels of use across most of the water management areas of the state (Table 18)

Table 18 **Levels of water use in water management areas in Queensland**

Water Management Area	Level of use	Consumptive use as a proportion of inflows	Consumptive use as a proportion of water resource
Burnett	moderate	moderate	moderate
Pioneer	moderate	moderate	moderate
Condamine-Balonne	n/a	moderate	moderate
Barron	moderate	moderate	low
Georgina-Diamantina	n/a	high	low
Brisbane water supply area	moderate	moderate	moderate
Coopers Creek	n/a	low	low
Great Artesian Basin	overused	high	high
Border Rivers	moderate	high	high
Ord River	low	low	low

Data source: (NWC, 2005)

Water resources in catchments in central and northern Queensland are not fully allocated and new allocations from the consumptive pool are possible in some regions. However the same cannot be said for water supplies in the south eastern corner of the state where sustainable yield from surface and groundwater resources is less than current demand. Further, the Great Artesian Basin is classified as overused.

The outlook for water supplies in south east Queensland has been the focus of considerable attention in the light of low inflows and growing demand. The South East Queensland Water Strategy reports that the existing yield from surface and groundwater supplies of 416 000 ML per year is around 20 per cent less than the urban allocation as at 2007. The Queensland Government is implementing a regional water strategy to increase the level of system yield to 631 000 ML per annum by 2012. The strategy includes development of the Western Corridor Recycled Water Project, investment in new storages, development of a south east Queensland water grid and investigation into six potential desalination plants and a range of conservation measures.

Water for the Swanbank, Tarong and Tarong North power stations represents six per cent of total consumption in the area and is an important consideration in water resource planning in the south east. As noted earlier in this report, the Queensland Water Commission directed Tarong and Swanbank power stations to restrict water taken from Wivenhoe Dam during the 2007 drought to protect the water supply to Brisbane. The aim of the strategy is to provide climate resilient supplies to meet water supply targets.

The power stations in the south east are now supplied from the Queensland Water Grid Manager on a take or pay basis. The supply is based on use of purified recycled water. The Grid Manager decides on the proportion and makeup of supply sources.

The strategy has secured supplies for the power stations. However this has been at a significant increase in costs of water, which now make up around 25 per cent of operating costs.

Regardless of the status of supplies in specific catchments, localised growth in demand for industrial and urban use is creating competition, causing some power stations to review the adequacy of their supply arrangements.

The Callide and Gladstone power stations have adequate water supplies. However growing industrial demand in the Gladstone region is creating a need to augment water supply infrastructure which will have consequences for the cost of water to generators. As a result further water use efficiency and recycling possibilities are being examined including retrofitting dry cooling in one instance. Despite the fact that Gladstone is saline water cooled it will continue to consider options to reduce its draw of freshwater from Awoonga Dam.

Callide B and C power stations continue to examine opportunities to reduce water use and to source alternative viable water supplies, such as the use of water from the local mine to supplement supplies. The owners of Callide B and Callide C are investigating phased conversion of the plant to hybrid cooling in order to free up water as an alternative to augmenting Gladstone supply.

Stanwell Power Station has sufficient water supply for the future although investment in water use efficiency measures is still being pursued.

The CPRS will have an important impact on future decision making by coal and gas-fired generators. The final expected price of CO_2-e emissions and the level of compensation to power stations will determine the cost of additional carbon emissions that in turn will affect the operating costs of dry and hybrid cooling.

Beyond 2020, the potential introduction of solar thermal and geothermal generation in western Queensland could present further challenges for supply of groundwater for cooling and other operations. As stated earlier, water in the Great Artesian Basin is highly committed. That said, there may be options available to secure water without exacerbating unsustainable water management practices in the Basin. For example the operators of the Olympic Dam mine secured water for their operations through water use efficiency measures such as capping unused water bores and piping open drains on pastoral properties.

Dewatering from coal seam gas (CSG) projects is a possible source of water supply for gas-fired power stations and for solar thermal power stations in parts of Queensland. Origin Energy's proposed Darling Downs CCGT plant could utilise water from Origin's Spring Gully CSG production facility. Legislation in Queensland is still somewhat unclear on how the dewatered mine water from CSG production can be traded in some circumstances.

In situ coal gasification also requires water. However in this case the water is sourced from the coal seam and consumed in the gasification process. Any future in situ coal gasification would draw on this water and would not require additional supplies.

In summary, access to water is likely to remain a challenging issue for future electricity generation investment in Queensland. The principle areas of concern are the south east of the state and over the longer term in western Queensland, should solar thermal and geothermal generation be developed. However for existing and future investment, the pressure to increase water use efficiency and optimise supply arrangements will continue to be a high priority.

5.3.3 New South Wales

Water management areas in New South Wales are characterised by moderate to high levels of use and high consumptive use as a proportion of inflows in catchments where electricity generation is likely to be located (Table 19). Areas falling under the Murray Darling Basin Cap are also subject to constraints. This cap is a long term average allocation target which combines with shorter term annual target assessments that take annual climatic variations into account.

Table 19 **Levels of water use in water management areas in New South Wales**

Water Management Area	Level of use	Consumptive use as a proportion of inflows	Consumptive use as a proportion of water resource
Gwydir River – regulated	moderate	high	moderate
Richmond River	low	low	low
Namoi River - regulated	high	high	moderate
Macquarie River – regulated	low	high	moderate
Hunter River – regulated	moderate	high	moderate
Lachlan River - regulated	moderate	high	high
Murrumbidgee River - regulated	high	high	high
Sydney water supply area	n/a	high	high
Murray Darling Basin	high	high	high
Australian Capital Territory	moderate	moderate	moderate

Data source: (NWC, 2005)

In New South Wales catchments, water supplies for new power stations are likely to be sourced from existing water access entitlements where new allocations are not possible. The pressure on existing power stations to reduce their water use is unlikely to diminish. Mt Piper and Wallerawang power stations are located in drought prone areas and the Bayswater and Liddell power stations are located in the Hunter catchment where supplies are constrained by drought and growing local demand for urban and rural consumption. An embargo on issuing new commercial water licences has been in place for the Hunter Regulated River since 1982. Any expansion of gas or coal-fired electricity generation would require acquisition of existing entitlements or further water use efficiency measures—Delta Electricity has also indicated this to be a reality now.

As discussed earlier, the expansion in generation capacity over the period to 2020 is expected to come from a range of sources including coal and gas-fired electricity generation and geothermal. Where possible and practical, saline water cooling offers significant advantages for cooling water. The TRUenergy Tallawarra CCGT project is one example of such a solution. In this case the project benefited from the fact that the plant is to be built on the site of a former power station with access to saline water in Lake Illawarra.

Beyond 2020, the prospects for conventional coal and gas-fired generation may depend on the successful commercialisation of carbon capture and storage (CCS) technologies. This technology is still at an early stage of development, but dry cooling of power plants incorporating CCS is likely to be a serious option in situations where saline water cooling or purchasing of water from other users is not feasible.

5.3.4 Victoria

Water catchments in Victoria are generally in the moderate to high category of use and many are subject to the Murray Darling Basin Cap.

Table 20 **Levels of water use in water management areas in Victoria**

Water Management Area	Level of use	Consumptive use as a proportion of inflows	Consumptive use as a proportion of water resource
Goulburn River	high	high	high
Broken River	high	moderate	low
Ovens River	low	low	low
Wimmera River	high	moderate	moderate
Glenelg River	low	moderate	moderate
Moorabool River	moderate	moderate	moderate
Melbourne water supply area	high	moderate	moderate
Murray Darling Basin	high	high	high

Data source: (NWC, 2005)

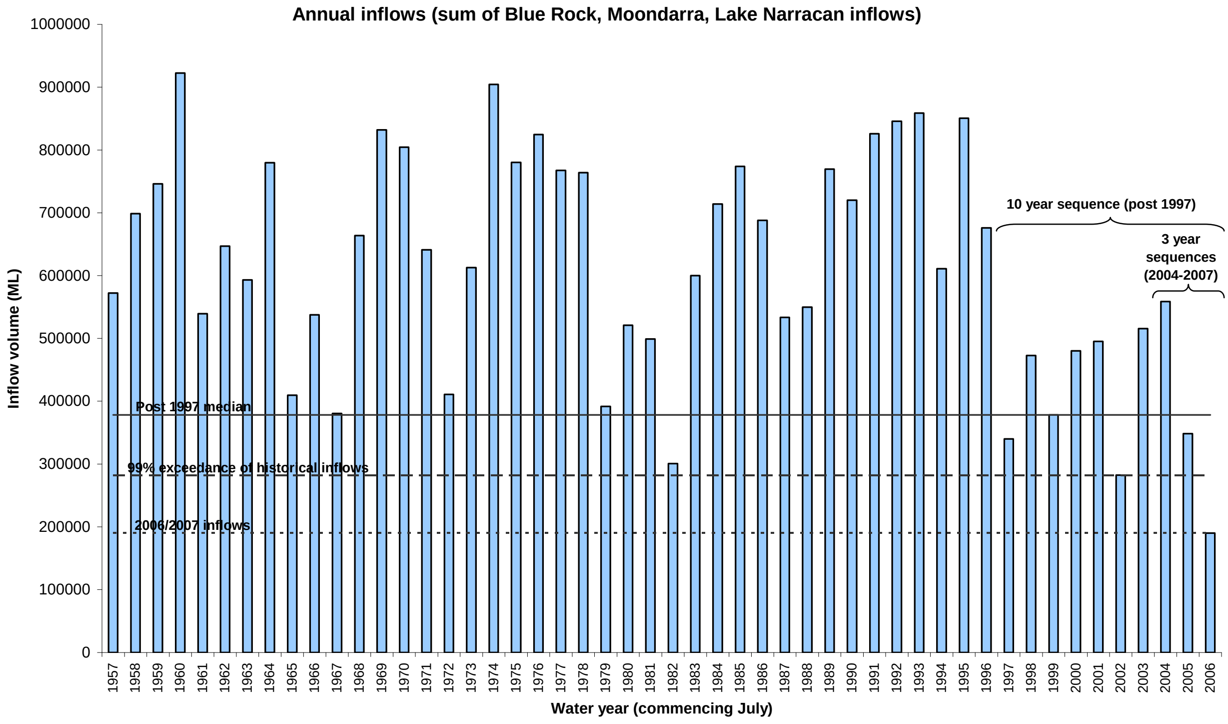
Electricity supplies in Victoria are dominated by the generation capacity in the Latrobe Valley. However Victoria will require an additional 3000 MW from CCGT plants in the event that coal-fired power stations in the Latrobe Valley are retired as a result of the CPRS. This is far from certain.

The CCGT plants will require wet or dry cooling and the decisions on which option to choose will depend on a range of factors including where they will be located, and the cost and availability of water particularly in drought periods. If coal-fired power stations are retired some water would be freed up in the Latrobe Valley for other uses, including for cooling new CCGT power stations if they were located there.

However there is likely to be ongoing pressure to improve water use efficiency, notwithstanding the potential to purchase additional water entitlements, because of wider concerns over the impact of lower rainfall patterns on existing water resources in the region.

Evidence that inflows are falling is a concern for water availability in Victoria. In recent years, low inflows into water storages have created concerns not only over short term supply arrangements, but longer term supply security for water users in south eastern Victoria (see Figure 14).

Figure 14 **Annual inflows into Latrobe storages**



Data source: (Center, 2008)

Water resources in the Latrobe Valley are not fully allocated. The Victorian Government has a capacity entitlement around 35 per cent of the water stored in Blue Rock Dam. This has been sold on a temporary basis to power stations in periods of low inflow. However, as the NEMMCO drought studies have shown, even this reserve may not be sufficient to totally protect the power stations from water supply constraints in future.

The regional study of supply options referred to in section 6.7 may result in further optimisation of water supplies in south eastern Victoria. The ultimate outcome will be important for the power stations and the investments they make in water use efficiency measures or dry cooling. After 2020, CCS technologies, if successful, could add to water requirements unless dry cooling is employed.

Water supplies for electricity generation will continue to be a constraint for electricity generators because of competing demands from urban and other industrial and agricultural uses, as well as from the need to increase environmental flows and from the lower inflows that may be more prevalent as a result of changing rainfall patterns.

5.3.5 South Australia

Levels of water use in South Australia regions range from moderate to overuse (Table 21).

Table 21 **Levels of water use in water management areas in South Australia**

Water Management Area	Level of use	Consumptive use as a proportion of inflows	Consumptive use as a proportion of water resource
Rocky River (Kangaroo Island)	n/a	n/a	n/a
Barossa Prescribed Water Resources area	moderate	high	high
Lower Limestone Coast Prescribed Well area	moderate	moderate	moderate
Patawalonga	n/a	high	high
Adelaide water supply area	overused	high	high
Lake Eyre Basin	overused	moderate	moderate
Coopers Creek	n/a	low	low
Great Artesian Basin	overused	high	high

Data source: (NWC, 2005)

The projections for new investment in generation in South Australia include 270 MW of open cycle gas turbine capacity that use very small amounts of water and 750 MW of geothermal which is likely to draw on groundwater. Beyond that, access to saline water cooling would be the most likely option for any additional CCGT capacity in the Adelaide and Port Pirie regions.

Significant expansion of the Olympic Dam project could also create the need for water supply and for electricity generation. While planning is in its early stages, consideration is being given to a desalination plant in the upper Spencer Gulf and renewable energy supply to support the plant. There is no public information available on plans for additional generation capacity for the mine itself. If an inland gas-fired plant were to be built it is highly likely that it would either be dry cooled or supplied by the desalination plant. Alternatively it might be supplied from a saline water cooled gas-fired power station on the coast.

Beyond 2020, it is difficult to predict where electricity supply will emerge until the potential for geothermal is fully assessed.

5.3.6 Western Australia

Levels of water use in water management areas in Western Australia vary from low to high (Table 22). However this masks localised high levels of use such as in the upper Collie catchment where three large wet cooled coal-fired generators are located.

Table 22 **Levels of water use in water management areas in Western Australia**

Water Management Area	Level of use	Consumptive use as a proportion of inflows	Consumptive use as a proportion of water resource
Harvey River	moderate	moderate	moderate
Collie River	moderate	moderate	moderate
Carnarvon	high	low	low
Gnangara Mound	overused	high	high
South West Yarragadee	low	low	low
Perth water supply area	high	moderate	moderate
Ord River	low	low	low

Data source: (NWC, 2005)

Most of the inland gas-fired generators have low water requirements as they are open cycle gas turbine plants. Water is likely to be sourced from groundwater, or possibly from augmentation from desalination in the medium term.

The coastal generators are saline water cooled and there are plans to add further generation capacity at Kwinana.

The key area of concern is for the water cooled generators in the Collie catchment area. Surface water supplies in the Upper Collie catchment are fully allocated. Competing demands for water for irrigation and urban and industrial use will create pressures for further water use efficiencies in the catchment and by the existing generators.

Water quality management in Wellington Dam and the related salinity problems also impact on water management in the area. Consideration is being given to desalination as one approach to meeting growth in regional demand for urban, industrial and irrigation use as well as for managing saline water in Wellington Dam.

Water supplied from dewatering mines is the current source of new water supplies for expansion of coal-fired power stations at Bluewater. However regional water planning may lead to this high quality water being used for other purposes and lower quality water being used in the new power stations.

While the geography, supply options and market structure in the Collie catchment differ to those that apply in south east Queensland and in the Latrobe Valley in Victoria, the economic and planning issues are similar. They involve optimising a range of external and internal investment options for the power stations as they balance the costs of water-using technologies with the price and cost of electricity, carbon and water provided by others. Regional water plans need to balance use of water resources between urban, agricultural, industrial and environmental use.

5.3.7 Northern Territory

Levels of water use in water management areas in the Northern Territory are low to moderate (Table 23). The Channel Island gas-fired power station is saline water cooled from the sea. Other electricity generation for mines and inland towns tends to be from diesel generators with minimal water requirements. These generators are likely to be converted to gas over the coming years as new gas supplies become available. Water requirements for gas generation in the Northern Territory are expected to be minimal.

Table 23 **Levels of water use in water management areas in Northern Territory**

Water Management Area	Level of use	Consumptive use as a proportion of inflows	Consumptive use as a proportion of water resource
Daly River	low	low	low
Goyder River	low	low	low
Roper River	low	low	low
Ti Tree	low	moderate	low
Mereenie Sandstone —Alice Water Control District	moderate	high	low
Darwin water supply area	moderate	low	low

Data source: *(NWC, 2005)*

5.3.8 Tasmania

Levels of water use in water management areas in Tasmania are low to moderate (Table 24).

Table 24 **Levels of water use in water management areas in Tasmania**

Water Management Area	Level of use	Consumptive use as a proportion of inflows	Consumptive use as a proportion of water resource
Macquarie	low	high	moderate
South Esk	low	moderate	moderate
Mersey	low	low	low
Pitt Water-Coal	low	moderate	moderate
Hobart water supply area	n/a	low	low

Data source: *(NWC, 2005)*

The largest use of water in electricity generation is in Hydro Tasmania's system. There is unlikely to be any significant expansion in this system in the coming years although smaller hydro-electric schemes are under consideration. There may be increased demands for water to be released for environmental flows and for some to be sold on an as-available basis for irrigated agriculture.

Water storages in Tasmania are at a 40 year low. Hydro Tasmania's storages were only 19 per cent filled in June 2007. The shortage of water has led to very little export of power to Victoria across Basslink. Demand has been met though imports of power from Victoria across Basslink and from gas-fired generation at Bell Bay (National Generators Forum, 2007).

The longer term outlook is uncertain. However supplies from Basslink, and augmented gas-fired generation capacity at Bell Bay are likely to remain important components of the Tasmanian supply portfolio.

5.4 Conclusions

Continued investment in new generation capacity will be required if current projections of growth in electricity demand are to be met. Over the next 10 years or so this will include additional gas or coal-fired power as well as geothermal and solar thermal generation. There is also likely to be small additions to hydro electricity capacity.

The projections for future increases in generation capacity in Queensland, New South Wales and Victoria also correspond to areas where water access is constrained, either through over allocation such as in the Murray Darling Basin, increasing demands on catchments such as in south east Queensland or because of low inflows.

If some coal-fired generation is retired it is possible that investment in additional CCGT capacity at the same site could occur. This would enable use of existing transmission infrastructure and water supply arrangements. This has occurred for example at Swanbank in Queensland and at Tallawarra in New South Wales.

Saline water cooling from the sea has advantages in lower freshwater use, lower costs, and lower emissions than dry cooling.

6. Options for generators in a water constrained future

The emerging constraints on water supplies have led the coal and gas-fired electricity generation industry to review its water use and implement measures to improve water use efficiency in existing and future power stations. These measures go beyond improvements in on-site efficiency to consideration of alternative sources of water including recycled water, treated effluent, groundwater (mainly supplied from mine dewatering) and desalination. Faced with water constraints, the industry has a range of options to consider.

6.1 Increasing water use efficiency

Increasing water use efficiency in plant operation has been an important short-term source of water savings in existing plants. All of the 15 coal-fired power stations surveyed for this report had implemented water use efficiency measures such as reclamation and recycling of water and in many cases drew on purified recycled water. Three of the wet-cooled power stations surveyed reported savings in the order of 15 per cent.

One of the largest water savings reported was from closer monitoring of cooling tower blowdown, which is used for managing the increased concentrations of salts in the recirculating water cooling towers. The resulting increased 'cycling up' of the cooling towers (increasing the number of times water is cycled through the towers) has helped produce savings. Increased cycling of cooling water creates risks of scaling which has to be monitored closely to maintain operational efficiency.

Improving plant efficiency and performance also reduces water consumption and some power stations have undertaken such measures. Such measures include:

- upgrading older turbines to increase energy conversion efficiency. This would reduce heat rejection and hence cooling water consumption; and
- improving condenser performance in cooling systems to lower back pressure on turbines to improve turbine performance and reduce cooling water consumption.

Improving the performance of water supply infrastructure is one approach being adopted. For example the owners of both Callide B and Callide C in Queensland paid for the construction of an additional length of pipeline to reduce evaporation and seepage losses along Stag Creek (3GL/yr).

Macquarie Generation has invested $50 million to upgrade water treatment facilities at the Bayswater Power Station in New South Wales. This will improve water use efficiency through increasing the water quality in Lake Liddell and will improve the reliability of the power station. Macquarie is also upgrading its Hunter River Pumping Station to increase security of operation and to take advantage of periodic opportunities offered from high river flow events.

Loy Yang Power in Victoria has undertaken a program of water use efficiency improvements over the last decade. Water consumption per unit of output has been reduced from 3.6 ML/GWh in 1991 to the current level of 2.2 ML/GWh. Net water consumption, taking account of water discharged, is somewhat less.

Water consumption at Loy Yang B has already been reduced by around 15 per cent through a range of plant improvement initiatives including harvesting storm water. Water treatment by reverse osmosis of cooling tower purge and dry cooling are considered by Loy Yang Power as too expensive at the present time.

International Power is currently undertaking a pilot project at Loy Yang B Power Station to retrofit a fluidised bed coal drying plant, improve boiler efficiency and retrofit a new higher efficiency turbine and a carbon capture facility. While a prime reason for this pilot project is to reduce emissions, improving plant sent-out efficiency also reduces water consumption.

6.2 Recycling plant waste water

A low cost option for power stations is to install capacity to recycle stormwater and operational water runoff. Water recycling requires investment in water treatment plant and employee training, plus a small increase in auxiliaries. On site water treatment consumes about 0.002 MWh per ML of water treated and does not significantly affect sent-out efficiency.

Recycled water is treated and used as a source of raw water for the power plant. Reverse osmosis and micro filtration is the main treatment technology to bring recycled water up to a standard for use in cooling. Water that cannot be treated is used to stabilise ash in the ash disposal process.

Stanwell Power Station in Queensland is an example of recycling measures being implemented. The service water system at the site has been re-engineered to replace raw water with water discharged from other parts of the station's process. This is reported to have reduced the use of raw water from the Fitzroy River by approximately 0.4 GL per year (Stanwell Corporation, 2008).

Tarong Energy has installed a reverse osmosis plant at Tarong Power Station in Queensland that has saved 0.5 GL per annum, improved stormwater collection, introduced reclamation of water from stormwater, effluent and water from the ash dam and utilised blowdown for on-site mine use.

Price and quality of water are important when considering water use efficiency. Lower quality water reduces the number of cooling cycles possible. Lack of flexibility with respect to price for quality and the take or pay arrangements restricts operational and risk management options.

Mt Piper Power Station in New South Wales was designed for zero discharge. All process waters from the site, including cooling tower blowdown, plant wash down and water treatment plant effluent are recycled and reused by the power station. Mt Piper has dry ash disposal and uses the salty water discharge for ash stabilization and disposal.

There is little public information on the cost of recycling. However estimates of representative costs by Evans & Peck suggest that recycling can cost between $2000 and $2500 per ML of water recycled (including micro filtration and reverse osmosis).

6.3 Hybrid or dry cooling

Retrofitting hybrid or dry cooling is being considered in several existing power stations among a range of options to address longer term concerns about water availability. The capital cost penalty of dry cooling in new plants is not large (perhaps around three to five per cent) but is likely to be higher for retrofitting options.

The impact on sent–out efficiency is reported to be up to seven per cent for retrofitting existing plants and around two per cent for new plants. This has implications for emissions of CO_2-e that can be up to six per cent higher with dry cooling on a new plant and higher for a retrofitted plant.

Physical space is a factor in retrofitting direct dry cooling as it requires space in the cooling tower area, which can be constrained in some circumstances. Indirect dry cooling and hybrid cooling can overcome this problem. Retrofitting also requires some down time for the power station, which must be sequenced with scheduled maintenance periods. The time required for retrofitting is longer than most maintenance periods and must be factored into planning for supply security if implemented.

Retrofitting dry cooling is not always feasible because of implications for plant operations. For example dry cooling would not be feasible at the Morwell Power Station in Victoria because of the impact on turbine back pressure.

Nevertheless dry cooling is now under serious consideration for existing as well as new power stations. CS Energy and Callide power management are examining the option of hybrid cooling for Callide B and Callide C. A decision on whether to proceed will depend on reaching agreement with Gladstone Area Water Board (GAWB) on a water buy-back arrangement.

Delta Electricity is considering a new 2000 MW coal plant at Mt Piper and two combined cycle gas turbine (CCGT) power stations at Bamarang and Marulan in New South Wales. The company is considering dry cooling for these developments among other options. Water for expansion at Mt Piper would be supplied from water use efficiency savings in the existing power stations.

6.4 Purified recycled water

The use of purified recycled water as an alternative source of water to supplement and offset existing freshwater consumption is becoming more prevalent in Australia's thermal power stations. The South East Queensland Water Reuse Project is the largest and most recent example.

The major advantage in using recycled water in this way is the substitution of freshwater with recycled water, which leaves the freshwater available for public consumption. There are also technical advantages in the use of recycled water for cooling at power stations primarily due to the high quality of the water, which enables more cycling of cooling water and therefore less blowdown and discharge of waste water offsite. Power stations can accept water of varying quality but must treat lower quality water on site to address risks associated with scaling.

The major disadvantage of the use of recycled water is the relatively high capital cost of developing the recycling facilities and the high ongoing operating costs of running the recycling plants and pumping water to the power stations. For example, the development of the south east Queensland facilities means that these costs are now fixed costs for the generators through take or pay contract arrangements. This will result in a higher cost of electricity generation from these stations and will likely limit the development of any alternative water use efficiency measures at these sites.

Macquarie Generation has also explored the possibility of using treated effluent from the Hunter Water Corporation's sewage treatment plants. However the costs to date have proven to be uneconomic.

6.5 Saline water cooling

The impact of dry and hybrid cooling on sent-out efficiency is not encountered with saline water cooling. There are therefore advantages both in terms of capital cost and emissions of cooling new coal and gas-fired power stations with saline water from the sea.

Issues for consideration are the transport of fuel to the power station and planning constraints applying in coastal areas. There appear to be strong competitive advantages for saline cooled CCGT plants in close proximity to gas pipeline infrastructure in the medium term. The proposed Tallawarra plant in New South Wales is one example that might be replicated in the future.

Saline water cooling is generally only economic near the coast. The cost of pipelines and pumping to inland sites generally makes it more expensive than other options such as use of recycled water and purified recycled water.

6.6 Desalination

Additional desalination plants provide the option of climate proofing part of a region's water supply. However it comes at a high cost if the desalination plants are not permanently in use. The capital cost of desalination plants must be recovered from production revenues and, as is also the case with electricity generators, the levelised capital cost is higher where usage rates are lower. Levelised costing calculates an annual equivalent cost per unit of energy or water produced from different options and allows comparison of costs on a consistent basis.

Another consideration is that desalinations plants consume around five MWh per ML of freshwater produced (Queensland Water Commission, 2008). As an example, if desalinated water was used to supply Tarong Power Station, around one per cent of the power generated would be used to provide energy for the desalination plant.

6.7 Regional water supply schemes

There are several examples of regional water planning currently underway that are relevant to electricity generators, namely:

- the South East Queensland Water Reuse Project
- the regional study of water supply and use for Latrobe Valley generators undertaken by the Victorian Government, and
- the Upper Collie catchment management plan undertaken by the Western Australian Government (Department of Water, 2007).

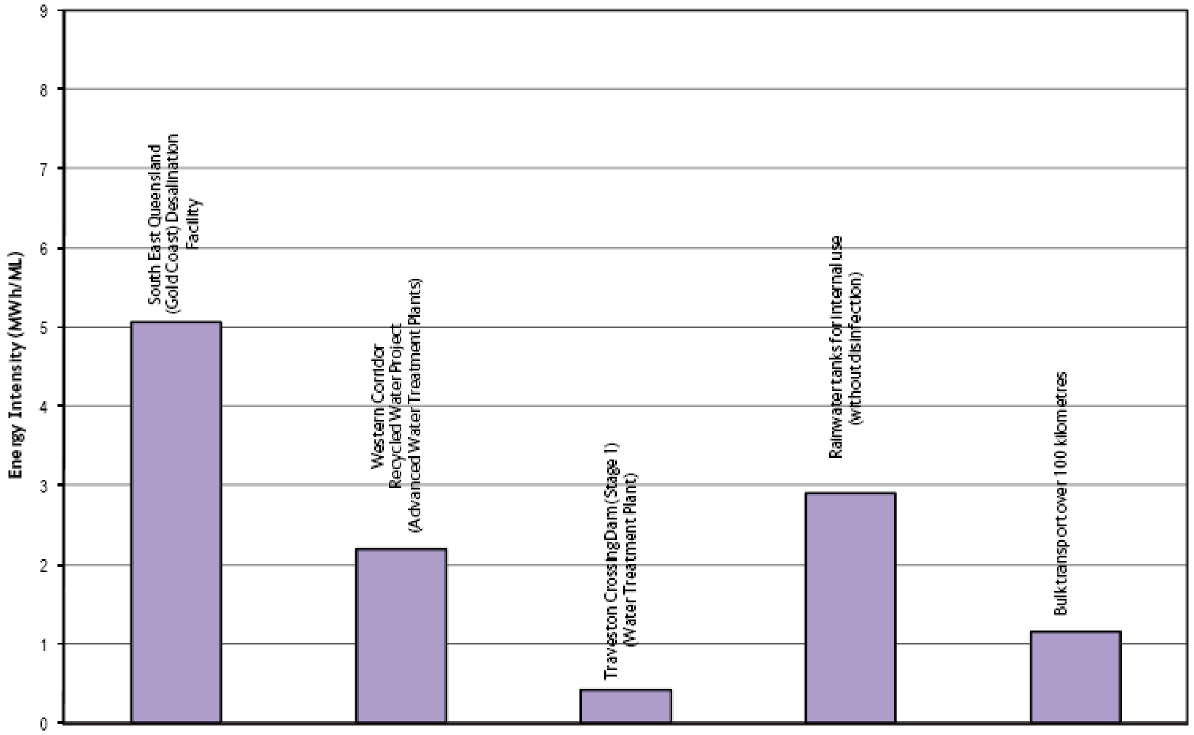
Regional water planning brings into consideration different supply portfolio options for generators, as for other large consumers. Regional water planning may involve inter-basin transfers and provide for better supply risk management across a range of supply sources. Each supply source is likely to involve different risk profiles that can, taken together, create a broader range of supply offerings at different levels of supply security.

These schemes are important for generators for whom the value of water at peak periods can be very high and where good supply risk management is important to energy security. It is therefore important that such planning is undertaken so it fully reflects the opportunity cost of water in different uses and the risk management profiles of all consumers, including electricity generators.

The Queensland Water Commission used levelised costing to compare the economics of different options (Queensland Water Commission, 2008). Such analytical techniques are critical in considering options for making up a portfolio of supplies.

Different supply options involve investments of widely varying capital and operating costs. The potential divergence of operating characteristics is illustrated in Figure 15. This shows that the energy intensity of different options varies from around 0.4 MWh per ML of water used for a water supply dam to five MWh per ML for a desalination plant. When the interaction between wholesale electricity prices and the price of water is taken into account such differences are important in selecting the optimum supply portfolio.

Figure 15 **Energy intensity of supply options in south east Queensland**



Data source: (Queensland Water Commission, 2008)

Following the implementation of the Western Corridor Recycled Water Project in south east Queensland the power stations at Tarong and Swanbank are now supplied by the South East Queensland Water Grid. Purified recycled water is the main source of supply for Tarong North Power Station and is a back up supply for Tarong Power Station.

Regional supply schemes for power stations have also been considered elsewhere. In 2007, the Victorian Government undertook a study of the options for supply of water to the Latrobe Valley generators in cooperation with the generators. The results of the study have not been released. ACIL Tasman was advised that water consumption improvement options included increasing cycling of cooling water, use of antiscalants to further increase cooling water cycling, efficiency improvements in cooling tower operation, passing cooling water blow down through a reverse osmosis plant and retrofitting hybrid dry-cooling systems. Decisions on these options are pending.

The cost analysis of each option considered in the study is not public. However on the basis of capital costs supplied in the course of consultations ACIL Tasman estimates that the costs of measures such as reverse osmosis and hybrid cooling could be somewhere between $2000 per ML and $3000 per ML of water saved.

The Victorian Government also examined other options including treated effluent from the Eastern Treatment Plant, water produced from the Gippsland Water Factory, seawater for power station cooling and additional water from coal dewatering and from coal processing.

The construction of a large desalination plant and a pipeline from the Goulburn River could relieve pressure for supply of Latrobe Valley water to Melbourne. Nevertheless ongoing concerns over low inflows into Latrobe Valley reservoirs remain and further water use efficiency measures are understood to be still under consideration.

Regional planning of water supplies has also been undertaken in the Upper Collie catchment in Western Australia. This is relevant to future water supplies for the new coal-fired power station development at Blue Waters in the south west of the state. The regional plan examines all supply options for surface and ground water and the needs of urban, industrial and agricultural users.

6.8 Conclusions

There are several water saving options available for power stations to consider in a water constrained future. The survey revealed that shorter term water use efficiency measures delivered savings of up to 15 per cent in existing coal-fired power stations.

Longer term options such as dry or hybrid cooling or use of purified recycled water have different cost impacts on power stations' operations and on emissions.

The increasing need to optimise regional and cross catchment water use brings power stations into the equation. Although their water use is small in comparison to other water use, changing water supply arrangements creates other costs for power station operators that must be taken into account in the economic calculations.

The challenge for the industry is to choose the most efficient options both from the point of view of the electricity market and of water supplies.

7. Economics

The National Electricity Market (NEM) and the South West Interconnected System (SWIS) are wholesale electricity markets. The NEM is a gross pool where all electricity is bid into a central point of dispatch. To some degree, generators in New South Wales also compete with their counterparts in Queensland, with the extent of the competition determined by the capacity of interconnectors between the NEM regions and transmission losses. The SWIS is a net pool where generators can sell through contracts or into the net pool.

These electricity markets are structured so that generators cannot influence the price in the market at any one time. Costs are the only item that the generators can control and are therefore critical to decision making on investment in either new generation capacity or improving performance of existing generators—such as improvements in water use efficiency.

The market is subject to policy mandates such as the expanded Renewable Energy Target (RET) and the Queensland Gas Scheme, which apply certain conditions that override the market.

Demand for electricity varies throughout the day, with changes in domestic and industrial activities, and throughout the year, as seasonal changes in temperature result in changes in use of appliances such as air conditioning and heating. This is accompanied by price movements over the day and during the year as demand grows and recedes.

Each generator technology has operating characteristics that suit different aspects of the load profile. For example coal-fired power stations are generally more suitable to base load generation, while open cycle gas turbines are more suitable for peak loads. Hydro-electricity can operate as peak or base load depending on its ability to call on pumped storage. Some renewable energy, such as wind or solar is intermittent and requires some additional capacity from generators that can be on call to maintain system stability when renewable generation falls away.

Regardless of the type of generation, or its location, the characteristics of capital and operating costs play a central role in decisions to invest either in new generation or in improvements in areas such as water use efficiency. Input costs that are not efficiently structured lead to inefficient investment.

7.1 Factors influencing investment decisions

The underlying investment criteria for investors in new power stations capacity is the long run marginal cost (LRMC). In electricity markets the timing of new investment will be determined when the wholesale price reaches the LRMC of a new investment. The LRMC includes all capital and operating costs that must be recovered over the life of a project.

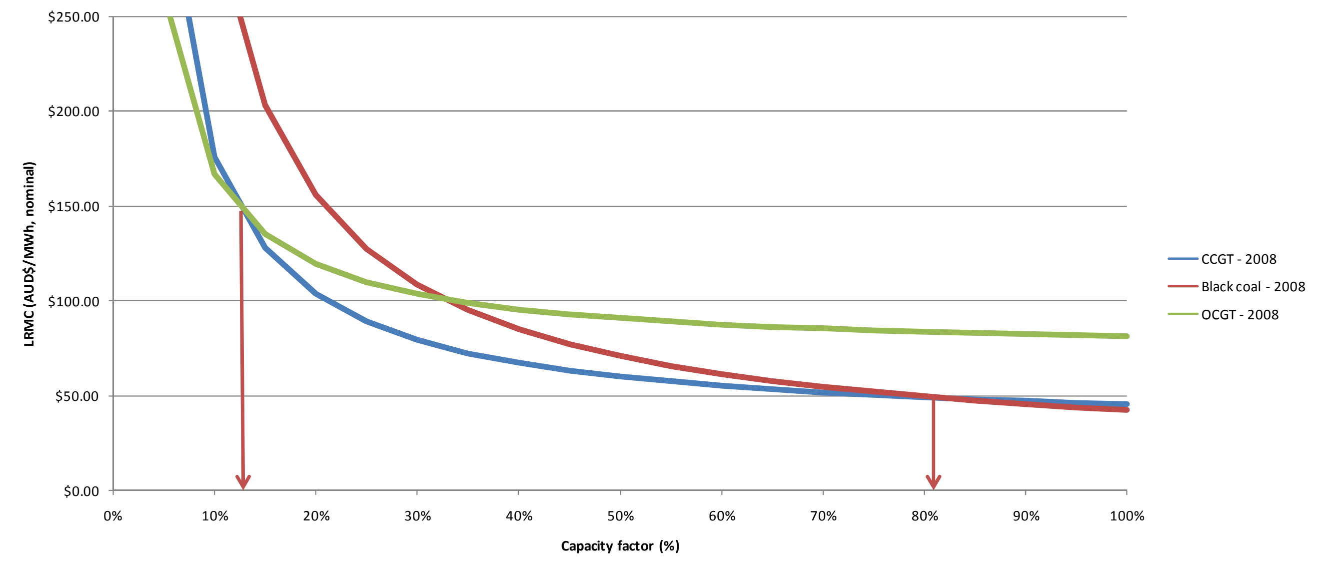
Components of the long run marginal cost include:

- levelised capital costs (the annual charge that recovers the capital cost over the economic life of the power station)
- fixed annual maintenance costs
- variable maintenance costs
- fuel and water costs
- income tax
- carbon charges – the costs associated with purchasing CO_2-e emissions permits, and

• local taxes and charges.

These components vary between different power station technologies. As a result the LRMC varies according to capacity factor (the proportion of the year that each generator dispatches into the power grid). This is illustrated in Figure 16 for a conventional coal-fired plant, a carbon capture and gas turbine (CCGT) plant and an open cycle gas turbine (OCGT) plant. These curves have been prepared assuming 2008 prices and no carbon price.

Figure 16 **Long run marginal cost of new entrant generators**



Note: Capacity factor is the percentage of the year that each generator is dispatched.

Data source: ACIL Tasman

The charts show how the LRMC changes for different capacity factors. For capacity factors below 13 per cent OCGT has the lowest LRMC in terms of $/MWh. Between capacity factors of 13 per cent and 81 per cent CCGT has the lowest LRMC and above 81 per cent coal-fired plant has the lowest LRMC. In recent years increasing capital costs have brought the LRMC of thermal coal and CCGT closer together at higher capacity factors.

The investment decision therefore requires an assessment of the nature of the load profile and price movements in the market for different types of load (base, intermediate and peak). The interaction between price movements and costs can be complex. Changes in costs associated with cooling, water treatment and alternative sources of water can affect the LRMC in different ways for different technologies.

7.1.1 Economic impact of dry cooling carbon capture and storage

For the purpose of illustration, the impact of the different cooling options and carbon capture and storage (CCS) on the LRMC has been calculated for a super critical coal-fired electricity generator and a CCGT. Dry cooling would have similar impacts on efficiency and capital costs for solar thermal and geothermal generation.

Dry cooling reduces sent-out efficiency by around two per cent and increases capital cost of new power stations by around three to five per cent. Carbon capture and storage is expected to reduce sent-out efficiency by around eight to ten per cent and involves significant additional capital costs.

CCS technologies are still in the development phase so costs associated with CCS are still uncertain. Despite the uncertainty, there is a large amount of experience with all stages of the process of generating electricity with carbon capture and storage. Current literature estimates that, with the ongoing research and development efforts around the world, CCS technologies will begin to enter a demonstration phase with construction of larger scale plants beginning around 2015 (McKinsey & Company, 2008) (IEA, 2007).

Emissions factors have been calculated based on data available from the Department of Climate Change and are summarised in Table 25 below.

Table 25 **Assumed emission factors for fuels consumed by electricity generators (kg CO_2-e/GJ)**

	CO_2	CH_4	N_2O	Total
Black coal	88.2	0.03	0.20	88.43
Brown coal	92.7	0.01	0.40	93.11
Natural gas	51.2	0.10	0.03	51.33

Data source: (Department of Climate Change, 2008)

The assumptions made for the purposes of modelling the LRMC of different generator cooling and carbon capture options are summarised in Table 26. These assumptions are generally in line with current expectations of costs for illustrative purposes but are subject to a range of uncertainties. These uncertainties are outlined in Box 2.

Table 26 **Cost assumptions, emission and water use factors**

Technology option	Fuel cost	Fixed O&M	Variable O&M	Capital cost	Efficiency	Auxiliaries	Capacity	Emission factors	Water use factors
	$/GJ	$/MW/yr	$/MWh	$/kW			MW	kg CO2/GJ	kL/MWh
CCGT — water cooled	4.65	12 800	4.85	1200	52%	2%	380	51.33	0.85
CCGT —dry cooled	4.65	12 800	4.85	1236	50%	2%	380	51.33	0.05
CCGT CCS—water cooled	4.65	32 800	4.85	2900	39%	22%	380	2.57	1.00
CCGT CCS —dry cooled	4.65	40 000	4.85	2486	37%	22%	380	2.57	0.05
Black coal supercritical — water cooled	1.00	40 000	1.20	2200	42%	8%	500	88.43	2.00
Black coal supercritical —dry cooled	1.00	40 000	1.20	2266	40%	8%	500	88.43	0.08
Black coal CCS — water cooled	1.00	60 000	1.20	3900	32%	28%	500	4.42	2.70
Black coal CCS -—dry cooled	1.00	70 000	1.20	3966	29%	28%	500	4.42	0.10

Data source: Based on ACIL Tasman and Evans & Peck, US DOE and IEA data

Box 1 **Assumptions and uncertainties**

Over the past two years capital costs have increased substantially, driven largely by steel prices and, to a lesser extent, labour costs.

A tightening in the demand/supply balance for turbines is also believed to have played a significant role in the step change (sudden change in cost of new technology) for certain technologies but does not yet appear to have resulted in Australian gas turbine prices being significantly increased.

While the current global financial crisis could temper demand for inputs to power station costs it is not certain to what extent this will reduce future costs. For the purposes of this report it was assumed that capital and operating costs will remain at 2008 levels in real terms. This could change in future.

Economic analysis requires a discount rate to discount the value of future revenues and costs to the present time. The discount rate used in the analysis was based on a weighted average cost of capital assuming 60 per cent debt.

The nominal cost of debt was assumed to be 8 per cent and the nominal required return on equity 16.5 per cent. Inflation was assumed to be 2.5 per cent over the life of the power station. The corporate tax rate was assumed to be 30 per cent

The weighted average cost of capital used for the analysis was based on the post tax real rate of 6.81 per cent. These assumptions are for illustrative purposes only.

The project life was assumed to be 30 years.

Source: ACIL Tasman

As the Australian Government is committed to progressively reducing Australia's greenhouse gas emissions, the carbon price is likely to increase over time. Treasury modelling suggests that under Australia's unconditional commitment to reduce emissions by five per cent below 2000 levels by 2020, the initial price of carbon will exceed $20 per tonne, increasing by four per cent per annum in real terms. It should be noted, however, that under the Australian Government’s proposed Carbon Pollution Reduction Scheme, the price of carbon pollution permits for the first year of the Scheme will be at a fixed price of $10.

For the purpose of calculation a $30 per tonne carbon charge and a water price of $500 per ML was assumed. Water charges vary significantly across regions. In some cases water charges paid by generators are as high as $1,500 per ML for small additional purchases of water. However this would not reflect the average price for water purchased by generators.

7.1.2 Water cooled compared with dry cooled gas and coal generation

The impact on water use, emissions and LRMC of dry cooling for a coal-fired power station is shown in Table 27.

Table 27 **Super critical coal with $30 per tonne carbon price**

Cooling option coal	Water use	CO2	LRMC at 80% CF
	ML/GWh	Tonne/GWh	$/MWh
Super critical coal water cooled	2.00	758	73.5
Super critical coal dry cooled	0.08	806	76.2
Percentage difference	-96%	6%	4%

Note: Includes a carbon price of $30 per tonne CO_2-e and a water price of $500 per ML

Data source: ACIL Tasman modelling, references cited in report.

The table shows:

- Dry cooling reduces water consumption for a supercritical coal-fired power plant from two ML per GWh to 0.08 ML per GWh sent-out electricity—a reduction of 96 per cent. However emissions of carbon dioxide increase by five per cent from 758 tonnes per GWh to 806 tonnes per GWh.
- For a 1000 MW super critical coal-fired power station at 80 per cent load factor, these changes would amount to a reduction in water consumption of 13.5 GL per year and an increase in CO_2-e emissions of around 336 000 tonnes per year of carbon dioxide.
- The LRMC increases from $74 per MWh to $76 per MWh at 80 per cent capacity factor —an increase of four per cent.

The impact on water use, emissions and LRMC of dry cooling for a CCGT power station is shown in Table 28.

Table 28 **CCGT with $30 per tonne carbon permit price**

Cooling option coal	Water use	CO2	LRMC at 50% CF	LRMC at 80% CF
	ML/GWh	Tonne/GWh	$/MWh	$/MWh
CCGT water cooled	0.85	349	80.4	68.3
CCGT dry cooled	0.05	373	83.0	70.6
Percentage difference	-94%	5%	3%	3%

Note: Includes a carbon price of $30 per tonne CO_2-e and a water price of $500 per ML

Data source: ACIL Tasman modelling, references cited in report.

The table shows:

- Dry cooling reduces water consumption for a CCGT power plant from 0.85 ML per GWh to 0.05 ML per GWh sent-out electricity—a reduction of 94 per cent. However emissions of carbon dioxide increase by five per cent from 349 tonnes per GWh to 373 tonnes per GWh.
- For a 380 MW CCGT at 50 per cent load factor, this results in a reduction in water use of 1.3 GL per year and an increase in emissions of CO_2-e of around 40 000 tonnes per year.
- The LRMC increases from $80 per MWh to $83 per MWh of sent-out electricity at 50 per capacity factor —an increase of three per cent.

7.1.3 Water cooled coal and gas-fired generation compared with water and dry cooled generation with CCS

As the carbon price rises, low emission technologies such as coal and gas thermal generation with CCS will become more commercially attractive. The impact on LRMC of water cooled super critical coal-fired compared with water cooled and dry cooled plant including CCS is summarised in Table 29.

Table 29 **Coal-fired with and without CCS**

Cooling and CCS coal	Water use	CO2	LRMC at 80% CF
	ML/GWh	Tonne/GWh	
Super critical coal water cooled	2.00	758	73.5
Super critical coal water cooled with CCS	2.70	51	107.1
Percentage difference between water cooled with and without CCS	35%	-93%	46%

Note: Includes a carbon price of $30 per tonne CO_2-e and a water price of $500 per ML

Data source: ACIL Tasman modelling and references cited in the report.

The table shows:

- Adding CCS to a water–cooled coal-fired power station increases water usage by 35 per cent from 2.0 ML per GWh to 2.7 ML per GWh of sent-out electricity.
- Emissions of CO_2-e are reduced by 93 per cent.
- For a 1000 MW coal-fired power station operating at 80 per cent load factor this is equivalent to an increase in water consumption of 4.9 GL per year and a decrease in emissions of CO_2-e of over five million tonnes per year.

The long run marginal cost at 80 per cent capacity factor increases by 46 per cent from $74 per MWh to $107 per MWh of sent-out electricity. Introduction of CCS results in a significant increase in the LRMC and in water use.

The impact of moving from water cooled CCGT to water cooled plant with CCS is summarised in Table 30.

Table 30 **CCGT with and without CCS**

Cooling and CCS gas	Water use	CO2	LRMC at 50% CF	LRMC at 80% CF
	ML/GWh	Tonne/GWh	$/MWh	
CCGT water cooled	0.85	349	80.40	68.30
CCGT water cooled with CCS	1.00	23	133.81	102.00
Percentage difference between water cooled without CCS and water cooled with CCS	18%	-93%	84%	49%

Note: Includes a carbon permit price of $30 per tonne CO2e and a water price of $500 per ML

Data source: ACIL Tasman modelling and references cited in the report.

The table shows:

- Adding CCS to a water cooled CCGT power station increases water usage by 18 per cent from 0.85 ML per GWh to 1.0 ML per GWh of sent-out electricity. However emissions of CO_2-e are reduced by 94 per cent.
- For a 380 MW CCGT operating at 50 per cent load factor, this is equivalent to an increase in water consumption of 0.25 GL per year and a decrease in emissions of around 540 000 tonnes per year of CO_2-e.
- The long run marginal cost at 80 per cent capacity factor increases by 49 per cent from $68 per MWh to $102 per MWh of sent-out electricity.

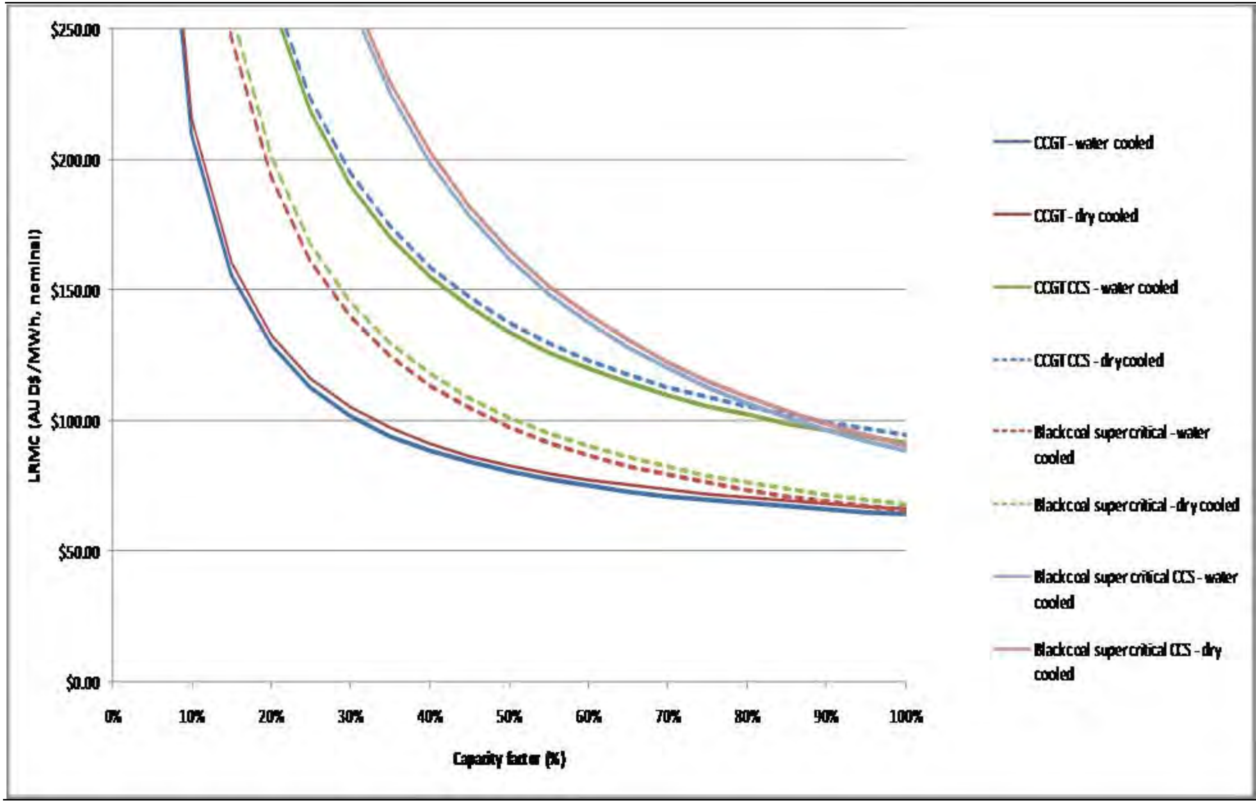
As with the coal example, introduction of CCS increases the LRMC and water use significantly.

We have not reported all of the combinations that might be considered. However this analysis supports the findings from interviews with the power industry that dry cooling is a reasonably competitive option for power stations, but with an associated increase in emissions of CO_2-e. As the price of emission permits increases, the cost of the additional CO_2-e emissions also increases.

7.1.4 Generator cost curves

The impact of these options on generator cost curves is shown in Figure 17 for super critical coal and CCGT respectively.

Figure 17 **Long run marginal cost curves for new entrant coal-fired and CCGT power stations**



Note: Includes a carbon permit price of $30 per tonne CO2e and a water price of $500 per ML
Data source: ACIL Tasman modelling

At high load factors the LRMCs of coal-fired and gas-fired generation are similar. The additional cost of dry cooling could alter relative competitiveness of the two technologies for base load applications.

It must be emphasised that this analysis is only illustrative of the impact of different options on the cost curves. If the fuel or water assumptions were changed, or capital costs fell these relativities could change. The important point is that while the impact of dry or hybrid cooling on LRMC is relatively small—around four per cent—it could alter the relative competitiveness of these alternatives at high capacity factors.

Changes to water and carbon permit prices would affect these outcomes as would movements in fuel prices. If intelligent decisions are to be made by power station owners about the best solutions to adopt in the future, it is important that these input prices are not distorted.

7.2 Factors affecting operating systems

Decisions on when to generate electricity are made on recovering short run marginal costs (SRMC). This reflects variable costs including fuel and water and other operation costs that vary with output. As long as the pool price exceeds the SRMC in any period, the generator will bid to supply the market.

Security of supply is also an important factor in electricity markets. During times of high demand or when supply is constrained due to planned or unplanned maintenance somewhere in the system, generators place a high premium on being able to supply the market. At such times the pool price can rise for short periods to levels significantly higher than the average pool price. It is important that generators can supply the market in these periods. It is also important for the system as a whole, that generators have an incentive to undertake the investment necessary to meet the market in these times.

The security of supply of inputs such as fuel and water are critical for most generators but are especially critical in times of high demand or when supply is constrained. Security of tenure over water supply arrangements is therefore important both to the economics of generators as well as to ensuring sufficient generation capacity to meet supply security criteria set for the market as a whole.

Water supply risks may be reduced though a diversified portfolio of water supplies with different security levels and different prices. While most generators in Australia depend on one or two high security licences specifically tailored to their circumstances, some contract additional supplies at a range of security levels to meet the market in periods of high demand.

For an efficient market in the future, it is important that water supply access arrangements do not constrain such risk management practices.

7.3 Policy implications

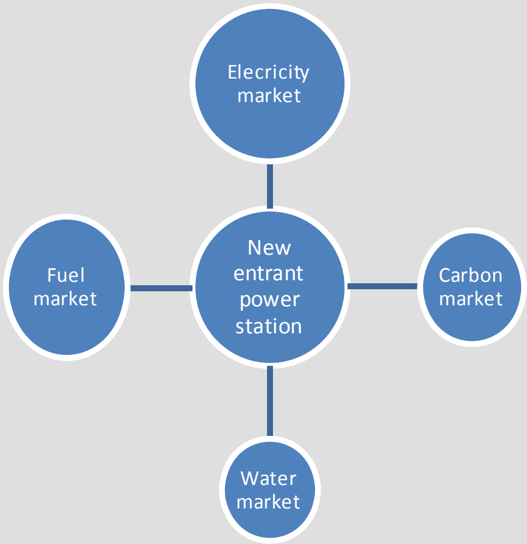
The value added per ML of water used in the electricity industry is high and the value of water used in electricity generation can be higher than the going price of water at certain times of the year. It is important that in the longer term water is allowed to move to its highest value use after taking into account sustainable levels of extraction and environmental flows in water management areas.

Water access arrangements for electricity generators vary around Australia reflecting legacy arrangements from earlier industry structures. However, they may not always be suited to the emerging challenges of a water constrained future, the introduction of the CPRS, and an increased focus on energy security.

The electricity generation industry must balance an increasingly complex array of economic and risk management factors when deciding how to best manage water use in existing power stations as well as in future new investments.

Once the CPRS is implemented, power stations will operate in four key markets–electricity, fuel, emission permits and water (see box 2).

Box 2 **Interaction between markets**



The electricity market is large and relatively sophisticated where wholesale prices, in the main, provide efficient price signals to market participants. The fuel market is also competitive and quick to respond to market developments.

The Australian Government has announced a conditional target to reduce emissions of CO_2-e to up to 25 per cent below 2000 levels by 2020 if there is global agreement to stabilise levels of CO_2-e at 450 ppm or lower by 2050. The government has also announced an unconditional target of five per cent and a commitment to reduce emissions by up to 15 per cent by 2020 if there is an agreement where major developing economies commit to substantially restrain emissions and advanced economies take on commitments comparable to Australia's (Wong, 2009). The initial price of purchasing an emissions permit will be set at $10 per tonne CO_2-e for the first 12 months of the scheme, however beyond that the price will be set by the market. Emissions trading will therefore commence in mid 2011.

The emerging water markets are less well developed and subject to some constraints. Yet prices in water markets and prices in energy markets often intersect. The value of water to the electricity industry is extremely high during periods of power and water constraints, as movements in the pool price confirmed in the recent drought periods.

When conflicts arise over the value of water for electricity generation as compared with other consumptive use, price is an important mediator. Water that is pumped into the Sydney catchment has an opportunity cost determined by its value in generating electricity. However when this is drawn on to supply Sydney's water the water enters a price regulated market.

The interaction between these markets with different structures, different regulatory arrangements and different risk profiles is likely to increase not decrease in future. Policy makers need to consider whether the past arrangements are suitable for the future.

7.3.1 Uncertainty and risk

Many of the generators interviewed noted that uncertainty about the CPRS and about their security of tenure for water access entitlements were issues of concern. All agreed that the former was the highest concern but this did not diminish concerns about water supply.

Changes in water availability and in pricing and contracting arrangements in response to drought in some jurisdictions will also influence investment decisions. As discussed in Chapter 4, arrangements set in place in south east Queensland have improved the security of supply. However the water supply contract arrangements include a high proportion of take or pay component that could create a disincentive to considering dry cooling.

Uncertainty over the security of water supply arrangements is becoming an issue for generators when seeking refinancing of existing debt or seeking to finance new investments. While some generation companies were large enough to finance new investments off their balance sheet, uncertainty of water supplies created a heightened perception of risk by their bankers. This is a concern in relation to refinancing debt as well as financing new investments in some cases.

7.4 Conclusions

Investors in electricity generation do so in a relatively sophisticated market for wholesale electricity. For some time yet, water markets are not likely to be as well developed. There is potential for less than optimal investment in generation capacity, water use efficiency and risk management by generators under these circumstances.

Investors in new electricity generation must make trade-offs between location, access to transmission infrastructure, access to fuel and water including levels of supply security, technology including different cooling options, along with expected pool price paths and prices of inputs.

If owners of power stations and investors in new generation capacity are to make sensible decisions on existing operations as well as new investments it is important that, as far as possible, the price signals and water markets are efficient both in terms of the opportunity cost of water and its security level.

8. Energy related issues

The water used in electricity generation has a high economic value (see section 1.2). Efficient water access arrangements for current and future electricity generation are important both for economic efficiency and energy security.

There is a range of options to increase water use efficiency and supply security for existing and future electricity generators, most of which involve higher costs and some result in higher emissions. While increased use of renewable energies such as wind, solar and geothermal will reduce total emissions from the electricity generation industry, there will still be a need for fossil fuel emitting resources.

Coal or gas-fired plants that can draw on saline cooling water from the sea can achieve improved water use efficiency and reduce fossil fuel emissions (as discussed in Chapter 2.4.3). In areas where this is not possible, there are alternative options—including recycling on site, use of purified recycled water, purchase of water, desalination and dry cooling—available to address water requirements in a more efficient way.

8.1 Industry response

In 2006, the National Generators Forum (NGF) released two policy statements on water use and recycling for the electricity industry (National Generators Forum, April 2006 and National Generators Forum, November 2006). These statements outlined the policies that the industry has adopted for water use and water planning.

In August 2007, the NGF issued a further briefing paper setting out the importance of water to electricity generation and the approaches that the industry has taken to address the challenges (National Generators Forum, August 2007).

The policies adopted by the industry focus on:

- options for improving the efficiency of water use and recycling opportunities
- the need to clearly define access rights and water entitlements that are enforceable
- recognition of the economic value created through water used for electricity generation
- support for recycled water use where it is reliably sourced, compatible with power station processes, and safe for employees and the community, and
- discharge (environmental) licence requirements.

The industry has been responding to the challenges of a water constrained future and considerable progress has been made in improving water use efficiency. There are however some policy issues that need to be addressed in the near future to further this process.

8.2 Energy security

Electricity generation is an important component of Australia's energy sector as a source of energy for domestic, commercial and industrial consumers. It is also important in the delivery of other sources of energy. For example, electricity is important for pumping petroleum fuels from refineries, ports and terminals and for the operation of control systems in other energy sectors, including gas and liquid fuels.

The National Electricity Market Management Company (NEMMCO) drought scenario investigations outline the importance of the impact of the drought on the security of Australia's energy supplies (NEMMCO, 2009). The interaction between water availability for cooling and for hydro-electricity generation can result in significant electricity supply and price movements during periods of low rainfall. As the NEMMCO studies also show, the potential for curtailment of supplies in low rainfall periods is a risk that will become increasingly critical to market participants. Future energy security requires informed and efficient risk management by market operators and investors alike.

The interaction between water and electricity markets will be a factor in the efficiency and effectiveness with which these risks are managed in the future. Water security and energy security are linked through this mechanism. Increasingly, water policy and energy policy will become interlinked when considering longer term energy security.

Electricity generators should continue to develop strategies to manage risks associated with water supply security. It is important that water policy settings do not diminish the ability of generators to manage supply risks. This applies to consideration of supply options in regional water planning and contract terms.

8.3 Risk and assessment

Consultations with generators identified concern over the impact of uncertainties over water supply contracts and their ability to finance new investment. While this was not rated as significant as uncertainty over the impact of the Carbon Pollution Reduction Scheme (CPRS), it was seen as a constraint in financing new investment in generation capacity.

Take or pay provisions in water supply licences and limitations on trade in surplus water could result in less efficient risk management, may lead to higher levels of water supply than necessary and could also discourage investment in water saving measures. Such arrangements apply in south east Queensland where the three power stations now taking water from the South East Queensland Water Grid have a significant take or pay component in their water supply contracts.

Uncertainty over security of tenure of water supply licences and agreements is also not conducive to efficient investment decisions and risk management by generators. Policy should ensure that security of tenure is clear in all water access arrangements.

8.4 Energy market and planning issues

Sea water or other saline water cooled thermal generation have benefits in terms of lower demands on surface and groundwater resources and the need to reduce carbon emissions. Sea water cooled power stations do not incur the additional costs of dry cooling or the associated increase in CO_2-e emissions. Expansion of capacity at existing coal-fired power stations would be a lower cost option. The extensive gas transmission pipeline systems available in the eastern states may provide opportunities for sea water cooled combined cycle gas turbine (CCGT) plants in coastal areas. Western Australia and South Australia already have coastal power stations cooled by sea water.

Current pricing arrangements in the National Electricity Market (NEM) may work against greater use of sea water cooled power stations. The NEM is based on regional pool pricing where a single price is set for each state. Generators receive this price after an adjustment for regional loss factors to account for transmission losses. Under current arrangements energy markets in each state are not subdivided into regions. The Council of Australian Governments (COAG) Energy Market Review undertaken in 2002 noted that the existing arrangements provided inadequate locational signals for investment in new transmission infrastructure. The arrangements may also disadvantage further investment in coastal gas-fired generation compared with expansion of inland generation capacity – notably coal based capacity. This is because the true cost of transmitting power from inland generation to coastal regions may not be fully reflected in the price received by the inland station.

Planning and development approval for power stations in coastal regions is likely to be the sensitive issue for further investment in sea water cooled thermal power stations. Some state governments have developed accelerated approvals processes for important and critical infrastructure. Use of such mechanisms may be justified where opportunities for sea water cooled coal or gas-fired generation arise.

8.5 Australian research and development

Considerable research and development into carbon dioxide emissions from coal and gas-fired electricity generation is underway in Australia, Europe, North America and Asia. Australia also has an active research program for developing carbon capture and storage (CCS). The CSIRO and the CRC for Greenhouse Gas Technologies are leading research into CCS and a number of small scale CCS demonstration projects has commenced at Australian power stations. The Australian Government announced the Clean Energy Initiative (CEI) in the May 2009 Budget. The CEI complements the Carbon Pollution Reduction Scheme and Renewable Energy Target, by supporting the research, development and demonstration of low-emission energy technologies, including industrial scale CCS and solar energy. The CEI has three components including a CCS Flagship program which provides funding to support construction and demonstration of large-scale integrated carbon capture and storage projects in Australia, a Solar Flagships Program which provides funding to support construction and demonstration of large-scale solar power stations in Australia and the establishment of the Australian Centre for Renewable Energy which will promote the development, commercialisation and deployment of renewable technologies, through a commercial investment approach.

The development of more efficient ultra critical coal-fired, integrated gasification and combined cycle, as well as CCS technologies, are actively being researched overseas. However, not all countries are facing the water constraints being experienced in Australia. Australia and South Africa are two countries that most strongly face the challenge of reducing emissions in an acutely water constrained environment.

There is a case for giving priority to research and development into increasing water use efficiency in low emission thermal generation technologies. This would help to increase Australia's ability to absorb and adapt innovation in low emission technologies developed abroad to suit our water constrained environment.

8.6 Conclusions

The electricity generation industry is responding to the challenges of a future with ongoing water constraints. With the changes in outlook for water supplies and the challenges of responding to climate change it is unlikely that past arrangements for supplying water to generators will be appropriate for the future in all circumstances.

Policy settings should not diminish the ability of the electricity industry to efficiently respond to changes in water market and water supply arrangements or to manage supply risks effectively.

Key issues for review include security of tenure in existing water access arrangements, the regional design of the wholesale electricity markets, the efficiency of planning approvals processes for potential power stations located in coastal regions and the level of research and development into water use efficiency technologies in electricity generation in Australia.

9. Water reform

9.1 Progress of reform

Progress with water policy reform is important for most thermal electricity generators. This is relevant to solar thermal and geothermal as well as coal and gas-fired electricity generation. The National Water Initiative (NWI) provides the policy framework for reform (COAG, 2004).

Under the NWI, governments have agreed to a range of outcomes and specific actions on the basis of the following elements:

- water access entitlement and planning framework
- water markets and trading
- best practice water pricing
- integrated management of water for environmental and other public benefit outcomes
- water resource accounting
- urban water reform
- knowledge and capacity building, and
- community partnerships.

The first Biennial Assessment of Progress in implementing the reforms was released by the National Water Commission in August 2007 (National Water Commission, 2007). The assessment noted that governments had made considerable progress towards implementing the NWI agenda despite intensification of the challenges that have emerged since reforms were agreed.

The Commission noted that:

> "adapting to future water management challenges requires more work to improve and accelerate the implementation of NWI reforms, particularly in the areas of:
>
> • over-allocation of water resources
>
> • groundwater and surface water interaction
>
> • interception of water from land use change, and
>
> • integrated management of environmental water" (National Water Commission, 2007).

Progress in relevant jurisdictions is provided in the first Biennial Assessment (National Water Commission, 2007).

9.2 Water resource planning

The NWI establishes the planning framework for water management and the principles under which water access entitlements are to be created. The 2007 Biennial Assessment reports that whilst states and territories have made good progress in implementing planning processes, the roll out of completed water plans has been slow. The eastern states have introduced legislation to formalise water planning processes and develop water allocation plans in the form of water resource plans as in Queensland, water sharing plans as in New South Wales and Victoria and water allocation plans as in South Australia.

Western Australia has been slowly progressing the introduction of new water reform legislation. During this time the Western Australian Government has continued with assessment of critical catchments, including the Upper Collie catchment. This catchment includes the wet cooled coal-fired power stations Collie and Muja and the new Griffin coal-fired power station.

The catchment by catchment water planning process, underway as part of implementation of the NWI, has not had a significant impact on the existing water access arrangements for existing generators.

Regional planning processes have had more impact in south east Queensland, in the Latrobe Valley in Victoria and in the Upper Collie catchment in Western Australia. The South East Queensland Water Supply Strategy has been important in securing supplies to power stations in the south east of the state.

Regional water planning activities work at a high level and provide the opportunity to apply consistent costing principles across a range of supply options including purified recycled water, desalination, optimisation of surface and groundwater resources and inter-basin transfers. It is important that such planning processes fully involve the electricity industry to ensure that all options are on the table.

The precautionary principle and the need to return some catchments to sustainable levels of extraction, has resulted in some water allocation plans limiting the issue of new water access entitlements for industrial purposes. This was noted earlier in this report in relation to the Hunter Regulated River Water Sharing Plan.

One concern expressed by some generators was the fact that they are often excluded from the community consultation process in the course of consideration and development of catchment management plans. This was observed in the Hunter catchment to some extent. Some generators feel that they are quarantined by planners from full engagement at this level. This is a concern particularly for some of the larger coal-fired generators that often invest in water systems beyond their boundaries which can deliver spill over benefits to agricultural enterprises. In this context the rural/non-rural divide in water use needs to be clarified.

9.3 Water access arrangements

Most of the water access arrangements for the electricity generation industry have been untouched by the NWI reforms. They tend to be for fixed terms and vary between jurisdictions.

These licences and contracts address power stations' need for very high security water. The cost of changing existing arrangements is likely to exceed the benefits, and as such, these arrangements are unlikely to be easily changed. However there is inconsistency between contracts in different jurisdictions. An issue for policy makers is whether differences are materially affecting the relative competitiveness of generators operating in national markets—the main interest being the National Electricity Market (NEM).

From the electricity generation industry's perspective, important dimensions of access conditions include:

- rights to extract water
- rights to water stored in reservoirs or in river flows
- rights to discharge water, and
- reliability of tenure.

While most of the supply licences address these dimensions, specific policies and conditions that may be inconsistent with efficient water use are frequently included in the licences. It is worth considering how such conditions and arrangements might affect power stations' future investment decisions on water use efficiency measures, or consideration of alternative water supply arrangements to reduce supply risks.

Some of these water licences impose restraints or conditions on trading surplus water by generators. This is the case in the Upper Collie catchment in Western Australia and in south east Queensland. Conditions also apply to water sold that has been supplied under certain licences in New South Wales. As discussed earlier in this report, such arrangements can limit the ability of generators to manage supply risks. They may also create a disincentive to invest in increased water use efficiency.

While there are sound policy reasons to apply the NWI access and pricing framework to all existing water access arrangements for generators, the costs of doing so would probably exceed the benefits. The existing licences and contracts are for very high security water and fundamentally restructuring them could be a major and potentially risky exercise.

Moving forward however, policy makers should consider the efficiency of the current arrangements for investment decisions in new generation capacity and the implications for water use efficiency. They should also consider the impact of any inconsistencies between the existing contracts on the relative competitiveness of existing generators in the NEM.

Some power stations have from time to time augmented their supplies by purchasing water in the market. This provides some scope for managing risk and maintaining supply security in times of high demand. Constraints on water markets have limited the scope for extending such strategies. Until water markets are fully developed there is not likely to be a case for substantially changing current arrangements.

An earlier National Water Commission Waterlines report noted that the dimensions of water entitlement products may be simple or sophisticated (Sinclair, Knight, Mertz, 2008). As water planning progresses and water markets mature, new entitlement products are likely to emerge. This offers the potential for entitlement products that are more suited to the future operating and risk management environment likely to be encountered by the electricity industry.

There is a risk that some current licensing arrangements may discourage the evolution of such products in the electricity industry. The consistency of the current arrangements, and their suitability for future efficient decision making should be reviewed.

9.4 Water pricing

All states and territories are now moving towards best practice pricing although progress is mixed. According to the first Biennial Assessment of the NWI reforms New South Wales is well advanced in implementing NWI pricing principles. However progress is less well advanced in other states. In most cases pricing policies for water supplied to power stations under specific licences or contracts reflect the policies adopted in the state and are subject to regulatory oversight.

Water pricing policies being adopted in regional schemes such as the South East Queensland Regional Water Security Program are based on a fixed and variable charge to recover the cost of assets including purified recycled water as well as storage and infrastructure. While these arrangements are consistent with the principles of the NWI there is a take or pay component associated with the fixed charge that on the surface appears to discourage generators from considering further investment such as dry cooling, as they will still be required to meet the take or pay commitment. They are not able to sell any water saved under such a scheme in the event that they do make further savings. This does not on the face of it appear to be consistent with the pricing framework of the NWI.

From a national perspective it would be desirable to review such practices, and if appropriate, apply a consistent approach to pricing and contracting arrangements.

9.5 Water returned to the environment

Another issue for electricity generation is the status of water returned to the environment. When water is taken under an access entitlement, it is removed from the consumptive pool but water provided from treated effluent is not part of the consumptive pool. If a generator reduces its extraction from the consumptive pool by substituting treated effluent it is reducing its call on the consumptive pool. Under these circumstances neither the generator's right to sell the water released as a result of this substitution, nor the status of water returned to the environment are clear. Such anomalies can create perverse incentives for generator use of water particularly where environmental regulation requires zero discharge from generation sites. Some environmental regulations require zero discharge policies that cause some water to be sent to evaporation ponds where recycling is not practical.

9.6 Release of unallocated water

Progress in developing policies to manage the release of unallocated water is mixed. The Biennial Assessment noted that Queensland and Victoria are well advanced in meeting their commitments in developing policies for the release of unallocated water. New South Wales and South Australia are developing policies for release of unallocated water. Western Australia has not fully allocated its water resources but is yet to implement legislation for reform and is understood to be still reviewing its policies in relation to release of unallocated water.

In most instances the electricity generation industry recognises that, for geographic as well as practical reasons, access to water for new power stations is likely to be constrained. Nevertheless, where unallocated water is available, it is highly desirable that the industry is not excluded from the right to bid for unallocated water for new investment in generation capacity, for expansion of existing capacity, or as part of a strategy to improve supply risk management.

There is no evidence that there are serious problems here although in some catchments access by industry to unallocated water is understood to be limited as in the Hunter Regulated River Allocation Plan.

For efficiency and energy security reasons it would be highly desirable that the electricity generation industry is not excluded in this way.

9.7 Security of tenure

Security of tenure for licence holders is important for risk management as well as commercial viability of generator businesses. There is a concern in the industry that contract terms may be overridden by governments in times of water shortage. This was the case in the 2007 drought in south east Queensland when Tarong Power Station was required to reduce generation to preserve water in Wivenhoe dam.

It is important that in future contract and licence arrangements terms provide clear circumstances when force majeure conditions will apply and that at all other times contract and licence conditions will be observed.

This might be considered in future as new licence arrangements are drawn up or existing licences renewed.

9.8 Joint management of surface and groundwater resources

The importance of mine dewatering as a water source for power stations underlines the need to accelerate work on joint management of surface and ground water. This also applies to management of water released from coal seam gas production that may be used for electricity generation. For example, the soon to be established Darling Downs gas power station in Queensland will use treated water from coal seam gas production for its cooling.

Water from such sources could also be important for solar thermal power plants that might be developed inland, particularly in Queensland. Lack of clarity in the accounting and management of such water is not consistent with efficient decision making either by coal seam gas producers or power station planners. Legislation is also not consistent in all cases. For example in Queensland water produced from coal seam gas operations is administered under environmental legislation. While there has been a rationalisation between environmental and water legislation some anomalies still exist for producers seeking approval to treat and sell such water.

Water associated with coal deposits is also important for in situ coal gasification that might in future be a component of integrated gasification and combined cycle (IGCC) power station technologies. This is already being considered as an option for IGCC power stations in Queensland (M Buchannan, 2009).

The status of such water resources is not clear in some jurisdictions. Progress under the NWI water reforms to improve the accounting for ground water resources will be an important step in the longer term management of these assets.

9.9 Water resources knowledge and accounting

Consultations did not detect major concerns with the adequacy of hydrology data for planning purposes. Most generators had access to adequate hydrology modelling from government, private consultants or internal resources. While security of supply is a major concern for generators, they acknowledge the practical limitations of weather and rainfall forecasts and adopt appropriate risk management strategies that incorporate these uncertainties.

Knowledge of the interaction between groundwater and surface water resources is an issue of some concern. This relates more to development of water management plans than to reliability of supplies for generators. However lack of consistent accounting between surface and ground water resources could affect water resource decisions that impact on the electricity industry.

It is a reality that in many cases future investment in water supply arrangements for generators will be made in the context of uncertainty over future water availability. In many situations, effective regional water planning is as important to energy security as it is to water security. While governments are progressively addressing knowledge gaps, the electricity industry must make investment decisions with the information available today. Under these circumstances it is important that they are able to avail themselves of any risk management products in water markets that may emerge as water markets mature.

Development of a National Water Accounting Model is an important component of national water reform. The 2007 Biennial Assessment found that water accounting in Australia has been developed in an ad-hoc fashion. Work on developing a national accounting system is underway and includes development of national standards for water markets, resource and environmental water accounting. National standards are also to be developed for water accounting information systems. These accounting reforms are very important developments for the electricity industry.

9.10 Conclusions

To date the NWI reforms have only had a marginal impact on the electricity generation industry. The water requirements of existing power stations have been by and large taken into account in catchment level water planning, but this does not appear to have had a material impact on their water access arrangements. Some in the industry commented that it was difficult to get involved in local community consultation processes where adjustments to supply arrangements were considered. There has been some water trading at the margin, although there is a view that water markets are far less transparent than is desirable.

Regional planning has had the most impact on integration of electricity industry requirements in regional water resource planning. The electricity generation industry needs to be fully engaged in these planning processes to ensure that all water use and supply options both outside and inside the power station are considered.

Moving forward, it will be important that policy makers examine how the existing and emerging arrangements are facilitating efficient resource allocation over time and encouraging power stations to implement the most economically efficient water use.

This is particularly so for power stations that compete with those in other jurisdictions. The access and pricing framework of the NWI provides a good starting point for any such assessment.

Other areas for consideration include joint management of groundwater and surface water where the progress of reform has been slow. New investment in geothermal and solar thermal in inland locations will most likely depend on groundwater supplies. This will also be important for use of water supplied from coal seam gas production and from in-situ coal gasification processes that might be associated with future IGCC power stations.

10. Findings and recommendations

The changed outlook for water availability affects both hydro-electricity and thermal electricity generation and can lead to price volatility in wholesale electricity markets. Ongoing drought conditions and lower water inflows in some parts of Australia have the potential to reduce water available to electricity generators, and in the longer term, continued growth in electricity demand will require additional investment in power stations that need water for electricity generation.

Although water scarcity affects hydro-electricity generators, as has been evident in Tasmania in recent years, the impact on coal and gas-fired generation and the emerging geothermal and solar thermal technologies has been the most critical at this time. Constraints on water supplies and the need to reduce water use in coal and gas-fired power stations, in particular, are important for long term investment decisions but also have implications for carbon emissions .

10.1 Technical options to address water availability

The electricity industry has a number of short and longer term technical options for reducing water requirements. These include increasing water use efficiency, dry or hybrid cooling, saline water cooling, recycled waste water, purified recycled water, coal seam gas water and desalination.

Options to dramatically reduce freshwater requirements of thermal power plants such as saline water cooling and dry/hybrid cooling are most applicable to new power plants, as there are significant cost and logistical issues associated with retrofitting dry cooling to existing power plants. Issues to be considered with saline water cooling include the cost implications of transporting fuel to power plants and planning constraints that apply in coastal areas.

Dry cooling can reduce water consumption of thermal power stations by more than 90 per cent and is most applicable to power plants located in inland areas. However, dry cooling reduces the sent-out efficiency of power plants by around two to three per cent and increases carbon dioxide emissions of coal-fired power plants by up to six per cent, depending on the fuel source.

10.2 Market options to address water availability

The National Water Initiative (NWI) offers the potential for the electricity generation industry to acquire water through trading and to manage water supply risks more effectively though participation in water markets.

Current water access arrangements for the electricity industry are dominated by licence and contract arrangements specifically tailored for the supply of water to electricity generators. These licence arrangements provide very high security water to large power stations. While aspects of these arrangements are consistent with the access framework set out by the NWI, in many important areas they are not. Examples of where they do not meet the requirements include:

- limited tenure rather than perpetual;
- limitations or conditions on trading;
- imposing conditions such as water use efficiency and discharge rules; and
- take or pay conditions.

The key issue arising out of the consultations and economic analysis undertaken for this study is the interaction between the markets for wholesale electricity, carbon, fuel and water supply. These markets are important drivers of investment decisions in water use efficiency measures and for selection of cooling technologies for new generators. They also influence risk management which is ultimately reflected in energy security.

It is important that these markets operate efficiently to allow sound business decisions to be made by those investing in new technologies, emissions reduction and water use efficiency measures. Of the four markets, the water market is likely to require the longest time to evolve once the Carbon Pollution Reduction Scheme (CPRS) is fully implemented. As long as this situation persists, there remains a risk of inefficient investments in water use efficiency measures by generators.

There is strong evidence that the electricity generation industry is actively investing in improvements in water–efficiency, in part due to the impact of lower water inflows in most areas and of the ongoing drought. Regional water planning has also emerged as an important development that affects particular generators—notably in south east Queensland, the Latrobe Valley in Victoria and in the Upper Collie catchment in Western Australia. However, there is evidence that, in some areas, the electricity industry could be more engaged in public consultations undertaken as part of the water planning process.

While a fundamental revision of existing water licence arrangements for generators is not likely to be practical, it will be important that future arrangements are as consistent as possible with the framework principles for access and pricing under the NWI.

7.4.1.1 Recommendation 1

Governments should ensure that future licence arrangements are made as consistent as possible with the pricing and access frameworks of the National Water Initiative particularly with respect to supply security; *security of tenure; trading entitlements and pricing*.

7.4.1.2 Recommendation 2

To facilitate improved water use efficiency by the electricity generation industry, water supply access arrangements should not mandate take or pay arrangements, nor exclude participation in water trading unless agreed by electricity generators.

7.4.1.3 Recommendation 3

In line with the National Water Initiative, the full opportunity cost of all supply and savings options should be reflected in the price of all supply options when considering these in regional water planning processes. This should form the basis of pricing for the selected options for generators.

7.4.1.4 Recommendation 4

Policy makers should ensure that the electricity generation industry is included in consultations between water planners, the community and other users as part of the longer term development of planning and policy options for future water resource management.

7.4.1.5 Recommendation 5

The legislation and regulations for use and disposal of water produced from coal seam gas should be reviewed to ensure that there are no unnecessary regulatory or legislative constraints on the use of that water.

7.4.1.6 Recommendation 6

In the light of the need to reduce carbon emissions and the impact on water demand for cooling in power stations priority should be given to focusing research and development in Australia on water management and efficiency in electricity generation.

A. Glossary of Terms

ACC	Air cooled condenser
CCGT	Combined cycle gas turbine – a combined gas turbine and steam turbine with the waste heat from the gas turbine producing steam for the steam turbine
CCS	Carbon Capture and Storage
COAG	Council of Australian Governments
Consumptive pool	Amount of water resource that can be made available for *consumptive* use in a given water system under the rules of the relevant water plan
Consumptive use	Private use of water including for irrigation, industry, urban and stock and domestic purposes
Cooling tower blowdown	Portion of the circulating cooling water flow that is removed to maintain the amount of dissolved solids and other impurities at an acceptable level
Condensate	Water that is condensed from steam
CO2-e	Carbon dioxide equivalent
CPRS	Carbon Pollution Reduction Scheme
CSG	Coal Seam Gas
Cycling up	Increasing the number of times cooling water is cycled through a cooling tower
Dewatering	Removal of water from a mining operation
Dosing	Adding chemical treatment to water to reduce fouling
Dry bulb temperature	Ambient temperature
Fogging	Adding a fine water spray to the gas/air mixture in a gas turbine
Forced generation	Occurs when water is passed through a hydro elecricity power station to provide water for downstream use
Force majeure	Provision in a *contract* that releases the parties from their obligations in the event of circumstances – like war, flood or other natural disaster (and sometimes workforce disruption) beyond either party's control - that prevents a party maintaining or completing its obligations under the contract
GL	Gigalitre
GWh	Gigawatt hour
Heat exchanger	A system of pipes in a cooling tower that transfer heat from steam or hot water

	to the atmosphere
Heat exchanger packing	Honeycomb like structures that break up air flow to maximise the surface area of heat transfer in a heat exchanger
Heat rate	Heat rate is the ratio of the energy in fuel consumed to the energy sent out
Heat recovery steam generator	Generators where heat exchangers are used to convert water into steam from heat produced from the exhaust of a gas turbine in a Combined Cycle Gas Turbine
HHV	High heating value which includes the latent heat of vaporization of moisture in the fuel
HRSG	Heat Recovery Steam Generator
IDGCC	Integrated drying gasification combined cycle – a power station where coal is dried and converted into syngas for injection into the gas turbine component of a combined cycle plant
IGCC	Integrated Gasification and Combined Cycle
ITD	Initial temperature difference
KL	Kilolitre
Levelised Capital Costs	The annual charge that recovers the capital cost over the economic life of an asset
LNG	Liquefied natural gas
LRMC	Long Run Marginal Cost
Make-up water	Water added to the flow of cooling water used to cool condensers in electric power plants, replacing cooling water lost by evaporation of the cooling water through cooling towers or discharged in blowdown from the cooling towers
ML	Megalitre
MPa	Mega Pascals – a unit of pressure
MWh	Megawatt hour
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NGF	National Generators Forum
NOx	Oxides of nitrogen
NWI	National Water Initiative
OCGT	Open cycle gas turbine

PRW	Purified recycled water
Rankine cycle	A thermodynamic cycle, named after William John Macquorn Rankine, which converts heat into work - it uses steam as the working fluid and the heat is supplied externally (almost all coal and nuclear power stations use this cycle)
Scaling	A build up of deposits inside cooling systems as a result of evaporation of water containing soluble salts and carbonates
Sent-out efficiency	The percentage of energy sent out from a power station as electricity compared to the amount of energy consumed to produce that electrical energy
SEQGM	South East Queensland Grid Manager
SEQWG	South East Queensland Water Grid
Step change	A significant and sudden change
SOx	Oxides of sulphur
Syngas	Natural gas produced from gasifying coal
SWIS	South West Interconnected System
Take or pay	A contract term that describes a requirement to pay for a quantity of water or energy as defined in a contract regardless of the amount actually taken in a defined period
TDS	Total dissolved solids
TTD	Terminal temperature differential
WAP	Water Allocation Plan
Water intensity	The volume of water used per unit of electricity output
Wet bulb temperature	Temperature at the point where water is evaporating
WSP	Water Sharing Plan

B. Terms of reference

TERMS OF REFERENCE

Purpose

The National Water Commission (NWC) and the Department of Resources, Energy and Tourism (RET) (formerly the Department of Industry, Tourism and Resources) are seeking to engage a consultant to investigate and produce a report on the impact of changed water availability on the electricity generation industry, to facilitate informed consideration by the industry of future water management options and needs for its planning and investment strategies. This investigation will provide evidence based information to assist in these considerations.

This review will form part of the NWC's publications program which is a series of works on key water issues. NWC may provide a template for the structure and format for the report. Other NWC documents released to date are available from the NWC's website at: http://www.nwc.gov.au/publications/index.cfm. The report will also be posted on the RET website at http://www.ret.gov.au/, and will carry RET and NWC branding in recognition of its co-sponsorship.

Context

National Water Initiative

The National Water Initiative (NWI) is Australia's blueprint for national water reform. The NWI Agreement has been agreed by all Australian governments and commenced in June 2004. The NWI sets out objectives, outcomes, and actions for the on-going process for national water reform, and timelines to achieve this reform. A copy of the National Water Initiative is located at: http://www.nwc.gov/nwi/docs/iga national water initiative.pdf

An overarching objective of the NWI is to optimise economic, social and environmental outcomes by achieving policy settings which facilitate water use efficiency and innovation, including frameworks for water access entitlements, water markets and trading, best practice water pricing and water resource accounting.

Water Management and the Electricity Generation Industry

Approximately sixty-five per cent of the generating capacity in the National Electricity Market (NEM) is currently dependent on freshwater for energy (hydro-electric) or cooling (coal or gas-fired generation). Already drought related water availability has impacted on the capacity of freshwater dependent generators to generate electricity in the NEM. While the current impacts are primarily price-related, the combined effect of the water reforms through the NWI, changed water availability through drought and climate change and increased demand for water and electricity will lead to the need for the electricity generation industry to factor water security and efficiency issues into its investment strategies.

Issues to Address

The study will investigate the impact of changed water availability on electricity generation in Australia including the following.

- A short summary of existing water access arrangements for generators.
- The implications of changed water availability and potential water scarcity on the electricity generation industry for short and long term strategic investment decisions. This covers a broad range of issues that may include:
  - an analysis of how the current generators may have already adapted their existing water requirements including where there is a strong reliance on a single water source (e.g. hydro-electricity).
  - an analysis of how new generation investment required to meet demand requirements will factor water availability into strategic decision-making.
- The implications of the National Water Initiative for the electricity generation industry, particularly water planning arrangements, the emergence of water markets and the application of full cost recovery principles for water infrastructure and management. This may include a discussion of implications for
  - energy pricing
  - water users competing for water using (where relevant) evidence based examples where this has already occurred.
- The available innovative options for the electricity generation industry to respond to changed water availability and an analysis of the costs and benefits, technical considerations, risks and impacts that these options would have on electricity generators, other likely affected water users and the environment. Innovative options to be considered include, but are not limited to:
  - the use of water markets, including purchasing water from other water users, developing mutually beneficial water banking and trading arrangements with other water users and or altering water access arrangements; and any associated investment costs if new pipelines, pumping stations, treatment facilities and storages are required;
  - dry (air) cooling;
  - hybrid (water/dry) cooling;
  - recycled water;
  - desalinated water;
  - seawater; and
  - water use efficiency measures.
- The degree to which current and planned arrangements for publication of water information could provide appropriate information and signals for the electricity generation industry to consider short and long term strategic decisions for investment in innovative options to manage changes in water availability. The research could also incorporate:
  - the economics for new generator investment, including location considerations (fuel, transmission and water sources); and
  - the economics for existing generators, including investment in water efficient technologies, investment in alternate sources of water and purchasing from other users.
  - The extent and nature of likely trade-offs between water management considerations such as water use efficiency, and energy efficiency and air emissions.

C. Organisations consulted

AGL Energy, VIC
Babcock & Brown Power, QLD
CS Energy, QLD
Delta Electricity, NSW
Department of Infrastructure, Energy and Resources, VIC
Department of Minerals and Energy, QLD
Department of Natural Resources & Water, QLD
Department of Primary Industries, VIC
Department of Primary Industries and Water, TAS
Department of Water & Energy, NSW
Department of Water, WA
Energy Developments, QLD
Eraring Energy, NSW
HRL Limited, Victoria
Griffin Energy, WA
Tas Hydro, TAS
InterGen (Aust) Ltd, QLD
Loy Yang B Power Station, VIC
Macquarie Gen, NSW
National Energy Markets Corporation
NEMMCO, VIC
Office of Energy, WA
Origin Energy, NSW
SA Energy, SA
SA Water, SA
SnowyHydro, NSW
Stanwell Corporation, QLD
Tarong Energy, QLD
TRUenergy, VIC
Verve Energy, WA

D. Questionnaire

a. Current water acquisition arrangements

Please outline the current arrangements by which water supplies are contracted for the generators in your organisation including:

- Whether water is supplied through a water access entitlement, a contract with a water authority or is purchased in a water market
- The organisations from whom water is contracted, allocated or purchased

b. Future trends in water acquisition

Outline any changes in acquisition arrangements expected for current and future power stations.
Is the outlook for water supply a constraint on future investment? If so in which catchments?

c. Hydrological and meteorological data

Outline current data and information used by your organisation for operation and planning of generators.
Comment on the adequacy of the information that is available for operations and planning.
Outline any suggestions that might improve the management of water use by generators in the future taking into account costs that might arise for government agencies.

d. Water use technologies

Outline current arrangements for water use by generators in your portfolio.
Describe any recent actions to improve water use efficiency and their effect.
Outline any emerging water conservation actions or investments that the company might consider in future to increase water use efficiency.

e. Water reform

The National Generator’s Forum has issued a set of water management policies to guide future actions by generators in Australia. Do you consider they are sufficient?
Comment on any policy areas in the National Water Initiative that you consider critical to your future ability to manage the water requirements for generation in the future.
Do you consider that progress in implementing these reforms is sufficient to allow you to make the operational and investment decisions necessary to maintain your generation businesses?

E. Comparison of water use, efficiency and carbon dioxide emissions

a. Impact of dry cooling on sent-out efficiency

Dry cooling is where air is passed over finned tubes in a cooling tower to reduce the temperature of the steam in the condenser. The performance of an air cooled condenser (ACC) is critically dependent upon on the initial temperature difference (ITD)—the difference between the ambient dry bulb temperature and the steam condensing temperature. The ITD chosen during design can vary between 10–30°C. A low ITD represents a larger, higher capital cost unit that is able to maintain a low condensing temperature on hot days. A high ITD represents a smaller and less costly tower that results in higher condensing temperatures, higher turbine back pressures and lower plant efficiency during hot periods.

With a dry bulb temperature of 25°C, the achievable steam condensing temperature will be in the range of 35–55°C.

The implication for efficiency is that a plant with dry cooling will achieve a lower efficiency if less capital is spent on the cooling system and a higher efficiency if more capital is spent (i.e. there is a trade-off between capital and efficiency). Typically the trade-off results in a sent out plant efficiency around two per cent lower than it will achieve with wet cooling towers or a once through cooling system. Secondly, there is some capacity penalty for the additional pumping and fan loads for a dry cooling system. As a result, for dry cooling, the carbon intensity of the power station will be higher (by the order of 10–15 kg/MWh). For a 500 MW base loaded machine (say 80 per cent capacity factor) this could result in an increase of 35 000–50 000 tonnes of CO_2-e each year of operation.

b. Impact of wet cooling technologies on sent-out efficiency

This section reviews the impact of selecting different cooling technology arrangements for a thermal Rankine Cycle. It is worth noting that the impacts noted here will apply equally to the steam cycle of a combined cycle gas turbine (CCGT), sub-critical and super-critical coal plants and other power stations that are fired on fuels other than coal. All of these generation types are based on the Rankine Cycle and therefore are subjected to the same operational and efficiency constraints for cooling water temperature. The individual cycle may use a range of technology to improve the cycle efficiency, but the efficiency gains from the cooling system are dependent on the discussion below.

For our cooling system comparison below, a combined cycle generation plant with the following specifications will be considered.

For each of the cooling options discussed below, the only change in each of the conditions will be the auxiliary power needs, the water requirements for the cooling and the ability to remove the heat load from the steam condenser.

Table 31 CCGT plant for comparison

Combined Cycle Gas Turbine Plant for Comparison	
Quality	**Value**
Nominal Plant Capacity	500 MW
Configuration	1 Gas Turbine x 1 HRSG x 1 Steam Turbine
Gas Turbine Output (MW)	330MW
Steam Turbine Output (MW)	170MW
GT Technology	F Class machine
Avg Dry Bulb Temperature (°C)	25
Avg Wet Bulb Temperature (°C)	18

Open Cycle Cooling

As discussed in Section 2.4.1 open cycle cooling draws water from a natural source (sea, lake, river) and passes it through the power station condenser before returning it at an elevated temperature to the original water source. For the case above, the system would be designed based on the desired cooling water temperature differential. For the CCGT plant considered, to obtain a temperature differential of 8–14°C a cooling water flow of 5000 l/s to 8500 l/s is needed equating to a range of 30–50 l/s/MW. This represents the volume of water extracted from the source with typically one per cent or 0.3–0.5 l/s/MW (of steam turbine) being consumed through evaporation following discharge.

The achievable steam condenser temperature is dependent on the terminal temperature difference (TTD) of the condenser, the cooling water temperature range (cooling water temperature inlet verses cooling water temperature outlet) and the initial temperature of the water source. Typical TTD of steam condensers are around about 4–6°C and the typical cooling water temperature range—around 15°C. So assuming that the water source is around say 20°C, the achievable steam condensing temperature will be in the range of 39–41°C. A low condensing temperature provides a very low back pressure to the steam turbine, allowing the turbine to extract more energy out of the steam and subsequently producing a more efficient overall cycle. A higher condensing temperature means a higher back pressure and lower efficiency.

For comparative purposes it is assumed that at this condensing temperature the CCGT being analysed achieves an overall sent out plant efficiency of around 52 per cent HHV requiring around 6900 GJ of heat input for each MWh sent out. Under these conditions the typical carbon dioxide intensity of such a machine will be around 350 kg/MWh.

Closed Cycle Wet Cooling

Closed cycle wet cooling is where the cooling water is passed through the condenser to pick up the heat load exhausting through the turbine and uses a cooling tower to reduce the temperature of the now heated cooling water via evaporation (see Section 2.4.1).

There are two main types of closed wet cooling towers. These are natural draft cooling towers and forced draft cooling towers. The performance of the two types of cooling towers only varies in hot, more humid conditions. In these conditions the fans of the forced draft cooling towers provide an advantage over the natural draft towers.

The water required by both cooling tower designs is very similar. Initially the entire system needs to be filled with water, which requires a significant amount of water. Once operational however the water used is significantly less. Closed cycle wet cooling systems have very similar flow requirements to the open cycle cooling described above. Therefore 5000 l/s to 8500 l/s is needed for the CCGT under consideration or 30–50 l/s/MW.

The water that is lost to evaporation in wet cooling towers can be calculated as the volume of water to be evaporated to remove the heat load that has been picked up from the exhaust of the turbine. Calculations show this volume to be around 0.68 ML/GWh or around 0.34 ML/hr for this CCGT at full load. Water is also lost from the cooling tower from blowdown which is an essential part of the cooling tower operation to control the concentration level of contaminates and pollutants in the water. The amount of blowdown depends on the environmental conditions of the area and quality of the water being used, however based on a typical six cycles of concentration about 0.12 ML/GWh or 0.06 ML/hr is needed. The total water lost in a wet cooling tower is therefore about 0.4 ML/hr while operating at full load. For the CCGT case study above, 110 l/s is needed as make-up for the cooling tower at full load.

The performance of a wet cooling tower is a little bit more complicated than the open cycle cooling system. The achievable steam condensing temperature is dependent on a couple of constraints. The first is the efficiency of the cooling tower to reduce the water temperature to the wet bulb temperature. Forced draft towers are better at doing this than natural draft towers but on average this difference is in the range of 5–8.5°C (known as the approach temperature). The next constraint is known as the tower range and is simply the difference between the inlet and outlet temperature of the cooling tower. Natural draft tower systems often perform better than forced towers here due to their ability to handle a larger volume of water. The tower range is typically in the order of 15°C. The final constraint on condenser performance is the TTD of the condenser, which is around about 4–6°C as discussed above.

Based on the above information and a wet bulb temperature of 18°C, the achievable steam condensing temperature will be in the range of 38–41.5°C.

The implication for efficiency is that the plant is likely to achieve an overall sent out plant efficiency around the same order as for once through cooling but will be less stable (since seawater temperature is more constant than atmospheric wet bulb temperature) and more prone to poorer performance particularly during hot humid days.

F. Generators and cooling technologies

Table 32 **Generators and cooling technologies (sorted by power station name)**

Station Name	Owner	State	TYPE	Physical Unit No.	Station Size (MW)	Utilisation %	Typical Annual Generation (GWh)	Cooling Technology
Broadwater Power Station	Delta Electricity	NSW	Thermal - Bagasse	1	30		0.00	Direct Cooling - from river
Condong Power Station	Delta Electricity	NSW	Thermal - Bagasse	1	30		0.00	Forced Draft Cooling Tower
Mt Piper Power Station	Delta Electricity	NSW	Thermal - Coal	1-2	1320	83.21	9595.38	Natural Draft Cooling Tower
Munmorah Power Station	Delta Electricity	NSW	Thermal - Coal	3-4	600	49.58	2598.79	Once through direct cooling. Lake Munmorah (Sea)
Eraring Power Station 330kV	Eraring Energy	NSW	Thermal - Coal	1-2	1320	71.23	8213.90	Once through direct cooled. Lake Macquarie (Sea)
Eraring Power Station 500kV	Eraring Energy	NSW	Thermal - Coal	3-4	1320	75.94	8757.04	Once through direct cooled. Lake Macquarie (Sea)
Eraring Power Station 500kV	Eraring Energy	NSW	OCGT	1	41.5		0.00	No Cooling
Bayswater Power Station	Macquarie Generation	NSW	Thermal - Coal	1-4	2640	73.85	17 032.06	Natural Draft Cooling Tower
Liddell Power Station	Macquarie Generation	NSW	Thermal - Coal	1-4	2000	69.31	12 109.84	Once through direct cooled. Lake Illawarra
ISIS Central Sugar Mill Co-generation Plant	AGL Energy	Qld	Thermal - Bagasse	1	25		0.00	Cogeneration
Braemar Power Station	Babcock & Brown Power	Qld	OCGT - Gas	3	503			No Cooling
Oakey Power Station	Babcock & Brown Power (50%) AGL Hydro Partnership	Qld	OCGT - Fuel oil	1-2	282		0.00	No Cooling
Gladstone	Comalco/NRG PPA with Stanwell Corporation Limited	Qld	Thermal - Coal	6	1680	59.47	8728.10	Once through direct cooled. Sea.

Station Name	Owner	State	TYPE	Physical Unit No.	Station Size (MW)	Utilisation %	Typical Annual Generation (GWh)	Cooling Technology
Callide Power Plant	CS Energy 50% Intergen 50% Callide Power Trading Pty Ltd	Qld	Thermal - Coal	3-4	840	82.55	6057.72	Natural Draft Cooling Tower
Callide A Power Station	CS Energy Limited	QLD	Thermal - Coal	1-4	120	0	0.00	Natural Draft Cooling Tower
Callide B Power Station	CS Energy Limited	QLD	Thermal - Coal	1-2	700	76.36	4669.57	Natural Draft Cooling Tower
Collinsville Power Station	CS Energy Limited	QLD	Thermal - Coal	1-3	96	52.55	440.71	Forced Draft Cooling Tower
Collinsville Power Station	CS Energy Limited	QLD	Thermal - Coal	4	33	52.255	150.64	Forced Draft Cooling Tower
Collinsville Power Station	CS Energy Limited	QLD	Thermal - Coal	5	66	48.59	280.16	Forced Draft Cooling Tower
Kogan Creek	CS Energy Limited	QLD	Thermal - Coal	1	781.2	85.855	5859.23	Air Cooled Condenser
Invicta Mill	CSR Limited	QLD	Thermal - Bagasse	1	38.8		0.00	Cogeneration Forced Draft Cooling Tower
Barcaldine Power Station	Ergon Energy Queensland Pty Ltd	Qld	CCGT - Gas	1	57	18.55	92.37	Forced Draft Cooling Tower
Millmerran Power Plant	Millmerran Energy Trader Pty Ltd	Qld	Thermal - Coal	1-2	852	88.89	6616.15	Air Cooled Condenser
Mt Stuart	Origin Energy (100%) PPA with	Qld	OCGT	1	288		0.00	No Cooling
Pioneer Sugar Mill	Pioneer Sugar Mills Pty Ltd	Qld	Thermal - Bagasse	1	30.86		0.00	Forced Draft Cooling Tower
Pioneer Sugar Mill	Pioneer Sugar Mills Pty Ltd	Qld	Thermal - Bagasse	2	36.92		0.00	??
Northern Power Station	Babcock & Brown Power	SA	Thermal - Coal	1-2	530	88.49	4097.16	Once through direct cooled Sea
Playford B Power Station	Babcock & Brown power	SA	Thermal - Coal	1-4	240	93.065	1951.24	Once through direct cooled. Sea.
Pelican Point Power Station	International Power	SA	Gas Turbine - Gas (CC)	2 + 1	487	88.8	3777.94	Direct Cooled - from sea

Station Name	Owner	State	TYPE	Physical Unit No.	Station Size (MW)	Utilisation %	Typical Annual Generation (GWh)	Cooling Technology
Ladbroke Grove	Origin Energy (100%)	SA	OCGT		80			No Cooling
Quarantine	Origin Energy (100%)	SA	OCGT		96		0.00	No Cooling
Osborne Power Station	Origin Energy (50%), ATCO (50%) PPA with Babcock & Brown Power	SA	Gas Turbine - Gas	1	118	76.645	790.09	Cogeneration
Osborne Power Station	Origin Energy (50%), ATCO (50%) PPA with Babcock & Brown Power	SA	Thermal - Gas	2	62	76.645	415.13	Cogeneration
Hallett	TRUenergy Pty Ltd	SA	Gas Turbine - Gas	11	180		0.00	No Cooling
Bell Bay Power Station	B&B	Tas	Thermal - Gas	1-2	240	60.05	1259.03	Once through direct cooled Tamar River
Bell Bay Three Power Station	B&B	Tas	Thermal - Gas	1-3	105		0.00	Once through direct cooled Tamar River
Bairnsdale Power Station	Babcock & Brown Power	VIC	OCGT - Gas		94		0.00	No Cooling
Jeeralang A	Ecogen (Owned by Industry Funds Management - 100%)	VIC	Thermal - Gas					
Jeeralang B	Ecogen (Owned by Industry Funds Management - 100%)	VIC	Thermal - Gas					
Newport Power Station	Ecogen (Owned by Industry Funds Management - 100%)	VIC	Thermal - Gas	1	500	44.55	1945.94	
Hazelwood Power Station	International Power	VIC	Thermal - Coal	1-8	1600	83.18	11626.57	Once through direct cooled. Lake

Station Name	Owner	State	TYPE	Physical Unit No.	Station Size (MW)	Utilisation %	Typical Annual Generation (GWh)	Cooling Technology
Loy Yang B Power Station	International Power (70%) Mitsui (30%)	VIC	Thermal - Coal	1-2	1000	96.48	8428.49	Natural Draft Cooling Tower
Loy Yang A Power Station	Loy Yang Power AGL(32.5%), TEPCO(32.5 %), Transfield(1 4%), Others	VIC	Thermal - Coal	1,3	1120	91.35	8937.98	Natural Draft Cooling Tower
Loy Yang A Power Station	Loy Yang Power AGL(32.5%), TEPCO(32.5 %), Transfield(1 4%), Others	VIC	Thermal - Coal	2,4	1000	93.25	8146.32	Natural Draft Cooling Tower
Anglesea Power Station	SECV	VIC	Thermal - Coal (Black)	1	150	96.3	1261.92	
Laverton North	Snowy Hydro	VIC	CCGT - Gas	1	320	4.8	134.18	??
Port Headland	Babcock & Brown power	WA	OCGT - Gas		210			No Cooling
Kwinana CoGen	International Power/Mitsui (70%) Transfield Services (30%)	WA	Gas Turbine - Gas		180			No Cooling
Kemmerton	Transfield Services PPA with Verve	WA	Gas Turbine - Gas	2	260		0.00	No Cooling
Cockburn	Verve Energy	WA	Gas Turbine - Gas (CC)	1	240		0.00	Direct Cooling - from sea
Collie	Verve Energy	WA	Thermal - Coal		330		0.00	Forced Draft Cooling Tower
Kwinana WPC	Verve Energy	WA	Thermal - Coal, Gas & Oil Gas Turbine - Oil	6 thermal 1 GT	880		0.00	Direct Cooling - from sea
Muja	Verve Energy	WA	Thermal - Coal	C 2 x 200 D 2 x 227	854		0.00	Forced Draft Cooling Tower
Pinjar	Verve Energy	WA	Gas Turbine - Multi Fuel		586		0.00	No Cooling
Redbank Power Station	Babcock & Brown Power	NSW	Thermal - Coal (Black)	1	150	82.23	1077.54	Forced Draft Cooling Tower
Rocky Point Cogeneration Plant	Rocky Point Power Project Pty Ltd	Qld	Thermal - Bagasse	1	28		0.00	

Station Name	Owner	State	TYPE	Physical Unit No.	Station Size (MW)	Utilisation %	Typical Annual Generation (GWh)	Cooling Technology
Roma	Origin Energy (100%)	Qld	OCGT	2	74	53.5	345.86	No Cooling
Smithfield Energy Facility	Marubeni Australia Power Services Pty Ltd (was Sithe Australia Power Services Pty Ltd)	NSW	Thermal - Gas	1-3	114	98.375	979.72	
Smithfield Energy Facility	Marubeni Australia Power Services Pty Ltd (was Sithe Australia Power Services Pty Ltd)	NSW	Thermal - Gas	4	62	98.375	532.83	
Somerton	AGL Energy	VIC	OCGT - Gas	4	150		0.00	No Cooling
Stanwell Power Station	Stanwell Corporation Limited	Qld	Thermal - Coal	4	1400	73.69	9012.58	Natural Draft Cooling Tower
Swanbank B Power Station	CS Energy Limited	QLD	Thermal - Coal	1-4	500	58.52	2556.15	Forced Draft Cooling Tower
Swanbank E Gas Turbine	CS Energy Limited	QLD	CCGT - Gas	1	385	69.48	2336.86	Forced Draft Cooling Tower
Tallawarra	TRUenergy Pty Ltd	NSW	Gas Turbine - Gas (CC)	1	400		0.00	Direct Cooling - from Lake Illawarra
Tarong North Power Station	Tarong Energy Corporation Limited	Qld	Thermal - Coal	1	450	82.52	3244.03	Forced Draft Cooling Tower
Tarong Power Station	Tarong Energy Corporation Limited	Qld	Thermal - Coal	4	1400	44.87	5487.78	Natural Draft Cooling Tower
Torrens Island Power Station "A"	AGL Energy	SA	Thermal - Gas	1-4	480	13.49	565.67	Once through direct cooled Sea
Torrens Island Power Station "B"	AGL Energy	SA	Thermal - Gas	1-4	800	37.84	2644.56	Once through direct cooled Sea
Vales Point "B" Power Station	Delta Electricity	NSW	Thermal - Coal	5-6	1320	63.08	7274.08	Once through direct cooling. Lake Macquarie (Sea)
Wagerup	Babcock & Brown power	WA	OCGT - Gas		380			No Cooling

Station Name	Owner	State	TYPE	Physical Unit No.	Station Size (MW)	Utilisation %	Typical Annual Generation (GWh)	Cooling Technology
Wallerawang "C" Power Station	Delta Electricity	NSW	Thermal - Coal	7-8	1000	70.73	6178.97	Natural Draft Cooling Tower
Yabulu	Tranfield Services	QLD	CCGT - Gas	1	220	70.935	1363.31	Forced Draft Cooling Tower
Yallourn W Power Station	TRUenergy Pty Ltd	VIC	Thermal - Coal	2	720	84.8	5333.85	Natural Draft Cooling Tower
Yallourn W Power Station	TRUenergy Pty Ltd	VIC	Thermal - Coal	3-4	760	80.28	5330.08	Natural Draft Cooling Tower

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