Cogeneration

Cogeneration is the production of electricity and heat from the same primary fuel source. Unlike other types of power generation, cogeneration recovers and utilises the process heat (Naughten and Dlugosz 1996). Power from cogeneration is usually generated close to the end user. The electricity can be used on site or sold into the electricity grid. The heat produced from cogeneration is typically converted into steam and used in local industrial and commercial processes.

A wide range of fuels can be used in cogeneration plants, including fossil fuels and renewables such as bagasse (sugar cane residue) and landfill gas.

The use of cogeneration in the energy market offers a number of potential benefits, including environmental benefits. Electricity generation is a major contributor to Australia's total greenhouse gas emissions. The long term reduction in these emissions has been a key factor in many recent government energy policy initiatives. The objectives of these initiatives include an acceleration in the uptake of less emission intensive electricity generating technologies, including renewable cogeneration. A key policy initiative that could assist in the growth of renewable cogeneration is the implementation of the '2 per cent' renewable mandated target.

The objective in this article is to assess the implications of energy market developments and policy initiatives for the prospects of cogeneration in Australia.

Cogeneration in Australia

Since 1979-80, the average rate of growth of cogeneration electricity in Australia has been around 4.6 per cent a year (faster than the
3.9 per cent growth rate for total electricity generation).

The current electricity market share of cogeneration is around 5 per cent (compared with 3.5 per cent a decade ago), with about 40 per cent of cogeneration electricity sold into the grid (ACA 1999; Bush et al. 1999). In line with ABARE projections (Bush et al. 1999), under a ‘business as usual’ scenario (which excludes the effect of the mandated renewable target), the electricity market share of cogeneration in 2010 is projected to be around 7 per cent.

Australia has a lower market penetration for cogeneration than a number of industrialised countries and most cogeneration in Australia is designed to supply small to medium sized niche markets. This feature can be attributed to a number of factors, including the dominance of coal fired generation, lower demand for heating in Australia’s temperate climate and less agglomeration of industrial sites (Naughten and Dlugosz 1996).

In Australia, cogeneration plants range in size from less than 1 megawatt (for example, hospitals) to over 300 megawatts (for example, industrial sites). Natural gas is the most commonly used fuel for cogeneration (around 56 per cent of current capacity) — Figure A (ACA 2000a). Of potential new cogeneration capacity currently under evaluation, natural gas accounts for around 90 per cent (3300 megawatts). The majority of these potential projects are located in eastern Australia (ACA 1997, 2000a).

In December 1999, there were 133 cogeneration sites operating in Australia, with a total installed generation capacity of around 2200 megawatts (ACA 2000a). Among industries, alumina has the highest installed cogeneration capacity (around 500 megawatts in 1998-99). Total Australian electricity cogeneration in 1998-99 was 9522 GWh, with around 40 per cent of this total exported to the grid (ACA 1999, 2000a).

Western Australia contributes around 40 per cent of Australia’s total electricity cogeneration (figure B). However, New South Wales and Victoria account for more than 50 per cent of total cogeneration electricity exported to the grid (ACA 1999).

The key statistics of the cogeneration industry in 1998-99 are shown in table 1.

---

**Figure A:** Cogeneration capacity, by fuel at December 1999

- Natural gas: 56%
- Coal: 16%
- Bagasse: 15%
- Waste gas: 7%
- Oil: 5%
- Others: 0.5%
- Digester gas: 1%

**Figure B:** Installed capacity and electricity production, by state

- New South Wales
- Queensland
- South Australia
- Victoria
- Western Australia
- Tasmania
- Northern Territory

<table>
<thead>
<tr>
<th>State</th>
<th>Installed Capacity at 31 Dec 1999</th>
<th>Electricity Production, 1998-99</th>
</tr>
</thead>
<tbody>
<tr>
<td>New South Wales</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Queensland</td>
<td></td>
<td></td>
</tr>
<tr>
<td>South Australia</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Victoria</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Western Australia</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tasmania</td>
<td></td>
<td></td>
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<tr>
<td>Northern Territory</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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_Australian Commodities, vol. 7, no. 4, December quarter 2000_
COGENERATION

The cogeneration industry in Australia, 1998

<table>
<thead>
<tr>
<th>Operating sites a</th>
<th>120 sites</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total installed capacity a</td>
<td>2,168 MW</td>
</tr>
<tr>
<td>Total operating capacity b</td>
<td>2,015 MW</td>
</tr>
<tr>
<td>Electricity generation c</td>
<td>34.2 PJ (9,522 GWh)</td>
</tr>
<tr>
<td>Electricity exports to grid c</td>
<td>13.3 PJ (3,718 GWh)</td>
</tr>
<tr>
<td>Total thermal production c</td>
<td>171 PJ</td>
</tr>
<tr>
<td>Fuel consumption c</td>
<td>328 PJ</td>
</tr>
<tr>
<td>Thermal efficiency c</td>
<td>62.7 %</td>
</tr>
<tr>
<td>– in process heat d</td>
<td>52.3 %</td>
</tr>
<tr>
<td>– in electricity generation</td>
<td>10.4 %</td>
</tr>
</tbody>
</table>

a As at December 1998. The number of sites increased to 133 with installed capacity of 2,203 MW at December 1999.

b As at December 1998.


d Part of the process heat energy in the form of steam is captured for use in mechanical drives (mainly in sugar mills).


Features of cogeneration

Generation factors

The relative advantages of cogeneration depend on the costs (capital, operating and transmission) of cogeneration electricity production compared with other electricity generation technologies and on the derived benefits from using the heat produced.

In a conventional thermal or gas turbine generator, 50–70 per cent of primary energy in the electricity generation process is lost in the form of waste heat. In cogeneration plants both the electricity and the surplus process heat are used; consequently the energy efficiency of cogeneration plants is significantly higher than that of combined gas cycle plants or coal generation plants (table 2).

Cogeneration offers advantages in localised markets, where the plant configuration can be efficiently matched to end users’ heat and electricity requirements. Cogeneration plants are less capital intensive and offer shorter installation lead times (as they can be built in smaller capacity units) than coal fired generators. These features enhance the potential use of cogeneration for new peaking capacity.

Typically, coal fired generators are located at some distance from major demand centres, a feature that requires investment in long distance, high voltage transmission networks. In contrast, cogeneration plants are typically located close to end users and have lower transmission costs (and losses), a characteristic that reduces the requirements for network upgrades.

Environmental factors

Over the period 1990–98, total emissions from electricity generation in Australia, increased by around 30 per cent (Australian Greenhouse Office 2000), compared with a 24 per cent increase in electricity generation (Bush et al. 1999). The increase in emissions can be primarily attributed to the continued dominance of coal fired generation and a higher capacity utilisation of brown coal plants (lower thermal efficiencies). This trend is in contrast to many other industrialised countries, where there has been a substitution of gas for coal fired generation, and which have (over a similar timeframe) either reduced or significantly constrained increases in total emissions from electricity generation (Unander 2000).

Government policies to reduce greenhouse gas emissions include the encouragement of lower emission electricity generating technologies (includes gas fired and renewable generation). Reduction of transmission losses (and associated greenhouse gas emissions) is also considered to be a significant way of limiting emissions (Department of Industry, Science and Resources 1999).

Thermal efficiency and carbon dioxide emissions

<table>
<thead>
<tr>
<th>Thermal efficiency</th>
<th>CO₂ emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>%</td>
</tr>
<tr>
<td>Cogeneration</td>
<td></td>
</tr>
<tr>
<td>– gas</td>
<td>77</td>
</tr>
<tr>
<td>– renewables</td>
<td>60–85</td>
</tr>
<tr>
<td>Combined cycle – natural gas</td>
<td>48</td>
</tr>
<tr>
<td>Thermal – natural gas</td>
<td>38</td>
</tr>
<tr>
<td>Thermal – black coal</td>
<td>35</td>
</tr>
<tr>
<td>Thermal – brown coal</td>
<td>29</td>
</tr>
</tbody>
</table>

Note: CO₂ emissions for cogeneration reflect unit of output (includes heat and electricity production). Source: ACA (1999).
Depending on its location and fuel source, cogeneration typically offers a number of environmental benefits. Cogeneration typically produces less carbon dioxide emissions per unit of usable energy generated (electricity and usable process heat) than conventional coal and gas fired generation (table 2).

Cogeneration electricity generation typically results in lower transmission losses, a feature that also reduces associated greenhouse gas emissions. Cogeneration plants may also use agricultural waste or landfill gas as fuel sources, a feature that can contribute to effective recycling of waste products.

Factors affecting the development of cogeneration

Australian energy markets have been undergoing significant reform since the early 1990s, with both electricity and gas markets being fundamentally restructured to enhance opportunities for private sector involvement. Since cogeneration operates in both markets, energy market reforms and their impacts on electricity and gas prices have significant implications for the prospects for cogeneration.

The Australian electricity industry has historically been dominated by a single vertically integrated state owned authority responsible for the generation, transmission and distribution of electricity. The gas industry historically had a single joint venture (private) producer and a single (government owned) transporter/retailer. Limited competition from alternative suppliers and limited trade between states restricted incentives to minimise the nationwide cost of providing electricity (and gas) services (Dickson and Warr 2000).

Since the early 1990s, electricity and gas industry reforms have occurred across Australia, albeit with differing time frames. In most states, the potentially competitive generation (electricity) and retail (electricity and gas) functions were separated from the ‘natural monopoly’ elements of the transmission and distribution sectors. The generation sector was horizontally separated into a number of competing businesses, while the transmission and distribution sectors were regulated to ensure nondiscriminatory access by third parties. Retail competition is being progressively introduced into the electricity and gas markets.

In many industrialised countries, energy market liberalisation has resulted in a significant increase in the market share of gas fired generation and cogeneration (Unander 2000). Energy market reforms in Australia were also expected to have resulted in a significant increase in the use of gas and cogeneration for electricity generation (Department of Industry, Science and Resources 1999). To date this outcome has not largely been realised.

There are a number of energy market features that may influence the development of cogeneration. The major factors are:

**Electricity prices**
- Increased coal and gas fired generation capacity and enhanced interstate grid interconnections are likely to constrain increases in electricity prices. This outcome is likely to restrict investment in new cogeneration capacity.
- Refinements to the network pricing regime may enhance the ability of the regime to reflect the comparative advantages of cogeneration and hence increase the competitiveness of cogeneration.

**Gas prices**
- Limited competition in gas supply, along with existing long term supply and transportation contracts, may impede access to lower priced gas supplies, restricting increases in gas fired cogeneration. Over the long term, however, access to new gas supplies could lower prices and increase the viability of gas fired cogeneration.

**Competition in electricity generation techniques**
- Coal and gas fired generation technologies have comparative cost advantages over cogeneration. Hence, under prevailing electricity prices, cogeneration and particularly renewable cogeneration will be viable mainly just for peak load generation.

**Policy initiatives**
- Government initiatives aimed at the long term reduction of greenhouse gas emiss-
sions should enhance the prospects for cogeneration. In particular, the 2 per cent renewable mandated target is expected to significantly increase the use of bagasse cogeneration.

Electricity prices

Impact of increased generation competition and excess capacity

The national electricity market (which currently excludes Tasmania, Western Australia and the Northern Territory) is a market for the supply and purchase of electricity that includes both wholesale and retail markets. The wholesale market commenced in late 1998 and provides for generator competition in electricity supply. Tasmania is expected to join the wholesale market in 2003 with the completion of the Basslink interconnector.

Lower electricity prices in recent years have tended to discourage investment in new cogeneration capacity.

There was a significant fall in wholesale electricity prices following the introduction of the spot market. At the commencement of the Victorian (1994) and New South Wales (1996) spot markets, wholesale prices in these states were around $43/MWh and $27/MWh respectively (ESAA 2000). In 1997-98, the average price in both markets had fallen to around $15/MWh. This price was below the entry price of new generation capacity. Increased competition among generators and excess generation capacity contributed to the lower electricity prices.

In 1998, electricity prices began to increase. The average wholesale price in 1999-2000 in New South Wales and Victoria was around $28/MWh (figure C).

Reflecting a closer balance between capacity and demand and limited interstate interconnections, electricity prices in Queensland and South Australia have typically been higher than in New South Wales and Victoria.

Capacity constraints in Queensland and South Australia will be eased by recent and expected interstate interconnections (for example, between Queensland and New South Wales; and between South Australia and New South Wales). A number of coal and gas fired power generation projects have also been committed or are proposed in these states. In the medium term, this increase in generation capacity is likely to continue to restrict investment in new cogeneration capacity, where project viability depends on dispatched electricity production.

Impact of network regulation

The majority of new cogeneration projects are likely to be installed in eastern Australia (where the majority of new gas fired projects currently under evaluation and potential renewable cogeneration projects are located) (ACA 1997, 2000a). Given that a significant percentage of these projects would be connected to the electricity grid, network regulation will have an increasing impact on the cogeneration industry.
The characteristics of gas fired cogeneration (for example, high loading and peak factors, contracted and interruptible supply) require flexible pricing arrangements. Reforms that could enhance the competitiveness of cogeneration include refinements of network pricing regimes to better reflect the benefits of cogeneration (for example, lower transmission costs).

The current National Electricity Code Administrator review of electricity network pricing (NECA 2000) is addressing whether amendments to the current pricing system could deliver more efficient market outcomes, both in terms of location and in the use of transmission augmentation, new local generation or demand side management.

Issues that may affect the use of cogeneration are:

- **Network service charges**
  The electricity code requires that network service providers allow nondiscriminatory access to the network, and provides guidelines for setting network charges (for example, transmission and distribution use of system charges). System use fees are generally based on a cost allocation that includes a cost reflective component and an average 'postage stamp' (delivery) charge.

  The use of cogeneration when there is a relative reduction in network load may result in the network service provider incurring lower system costs (for example, through deferred grid augmentation). Although the current regime allows for the negotiated passing on of these 'avoided' costs to the relevant generator, calculating these costs presents practical and technical difficulties and involves an element of averaging, which reduces the effectiveness of the cost reflective component of the charges (NECA 1999).

  In addition, the competitive elements between network service providers and embedded generators (including small cogenerators) may provide network owners with incentives to discriminate against these generators (for example, through excessive connection and/or standby charges).

- **Locational pricing signals**
  Locational signals are provided through the use of loss factors when determining generator dispatch and calculating spot prices, and through the cost reflective component of network charges. A theoretically ideal network pricing system would incorporate marginal and dynamic transmission and distribution losses (which may change over a day according to the degree of network congestion).

  Cogenerators (typically located closer to the load than standard generators) generally have lower transmission and distribution losses — hence, a system where variable network charges fully reflected marginal losses would be more favorable for cogenerators. However, the relative benefits of a network pricing system that incorporates marginal and dynamic losses will depend on the system costs involved in calculating those losses.

  The current regime delivers muted locational signals, given the use of average marginal losses at the transmission level and average losses at the distribution level. This regime may provide a poor representation of actual dispatch (and losses) and may not adequately reflect the benefits of cogeneration. Locational signals could be strengthened by a more comprehensive application of marginal loss factors (including the application of separate peak and offpeak loss factors).

  The current NECA (2000) review has made a number of recommendations aimed at improving the locational signals of the current regime. These include incorporating a forward looking treatment of constraints and losses for transmission, and using location specific average distribution loss factors for large embedded generators (including some cogenerators).

  At the retail level, end users’ electricity prices should be reflective of retailers’ wholesale prices. However, legislation in some states (for example, South Australia and Queensland) currently limits the ability of retailers to expose customers to locational price variations (National Retailers Forum 2000).

**Implications of electricity pricing for cogeneration**
Refinements to the network pricing regime may enhance the ability of network pricing to reflect the comparative advantages of
C O G E N E R A T I O N

cogeneration and increase the competitiveness of cogeneration.

In the medium term, increased generation capacity in the national electricity market and enhanced interstate connections are likely to discourage investment in new cogeneration capacity.

If strong growth in electricity demand continues in the longer term, excess generation capacity should fall and average electricity prices rise, providing greater incentives for new generators (including cogenerators) to enter the market.

Gas prices
As gas is likely to continue to be the most commonly used fuel in cogeneration, gas market competition and its ability to deliver lower gas prices will have a significant impact on the prospects for cogeneration. The key factors that will have an impact on gas prices are supply competition and network regulation.

Impacts of supply competition
Gas is the major fuel used for cogeneration and the cost of gas represents in excess of 60 per cent of the total generated cost of gas fired electricity generation (ACA 1997). Lower gas prices (assuming coal prices do not change) could therefore make gas fired power generation and gas cogeneration more cost competitive.

However, limited competition in supply along with existing long term supply and transportation contracts may impede access to lower priced gas supplies for new gas fired cogeneration.

Impacts of network regulation
Asset valuations (generally depreciated optimised replacement cost) and rates of return are used to set capped transmission and distribution tariffs. These tariffs form a significant portion of the delivered price of gas and affect the competitiveness of gas fired cogeneration. Key issues are:

• Variations in asset valuations
Such variations can affect the consistency of regulatory outcomes within and between the gas and electricity markets — for example, while most decisions have employed a full depreciated optimised replacement cost value, others have incorporated a discounted value (associated with relatively lower tariffs).

In addition, customer contributions may be included or excluded from the capital base of the network operator. If included, the outcome may be relatively higher average tariffs (reflecting the capital contribution). Customers (for example, cogeneration plants that contribute to new gas pipeline investment) cannot easily determine whether their capital contribution is reflected in an appropriately discounted transportation tariff.

Implications of gas market competition for cogeneration
Potential new gas supplies (for example, from Papua New Guinea and the Timor Sea) and pipeline interconnections will facilitate interregional flows and should enhance the development of competitive secondary trading in the eastern Australian gas market (Harman 2000). These developments are expected to place downward pressure on delivered gas prices.

To date, there have been some reductions in average gas transportation tariffs, although this outcome varies between market segments. Lower delivered gas prices would also require lower well-head prices.

The relative absence of upstream competition and the presence of long term fixed price supply contracts (often signed by previous state owned utilities) mean that it is unlikely that the average supply price of gas will fall in the medium term. This outcome would restrict any decreases in the delivered price of gas and constrain the increased use of gas fired cogeneration.
Competition in electricity generation techniques

Coal fired generation
Coal is the major fuel used in electricity generation, reflecting its abundance and low cost in Australia, and the low operating costs of coal fired plants. In addition, since the cost of supplying electricity from refurbished existing coal fired stations is typically lower than from any new capacity, it is likely that the operational life of many existing coal fired plants will be extended.

Technological innovations have reduced the operation and maintenance costs of coal fired generation plants and present opportunities for improvements in thermal efficiency and emissions control. Given that advanced coal technologies have higher capital costs, these technologies are less attractive in eastern Australia where there is a relative abundance of low cost coal (Naughten 2000).

Gas fired power generation
Compared with coal, gas fired generators have lower capital and operating costs, shorter construction periods and can be built with smaller capacity units. Gas fired generation capacity can also be designed to more efficiently match peak and variable demand loads.

Combined cycle gas turbine (CCGT) plants have the highest efficiency of any fossil fuel power plant. However, the economic viability of CCGT and other gas plants is highly dependent on delivered gas prices. Delivered gas prices in major Australian markets are typically at least $3/GJ, a price that equates to ex generator prices of around $35/MWh.

The comparative costs of alternative electricity generating technologies are illustrated in table 3.

Implications for cogeneration
Reflecting comparative generation costs and prevailing electricity prices, coal fired generation dominates base load generation, with gas fired generation (including cogeneration) primarily used for peak load generation.

Gas fired generation and cogeneration may become more viable for base load generation after 2005, as a result of an expected decline in excess generation capacity (assuming continued strong growth in electricity demand) and an associated increase in the electricity to gas price ratio.

### Costs of generation technologies

<table>
<thead>
<tr>
<th>Technology</th>
<th>Fuel cost</th>
<th>Fixed operation and maintenance costs</th>
<th>Capital charge</th>
<th>Total unit cost a</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$/GJ</td>
<td>$m/GW</td>
<td>$m/MW</td>
<td>$/MWh</td>
</tr>
<tr>
<td><strong>Gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CCGT</td>
<td>2.5–3.5</td>
<td>10–11</td>
<td>0.4–8.0</td>
<td>35–50</td>
</tr>
<tr>
<td><strong>Coal</strong> b</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Brown</td>
<td>1.0–1.5</td>
<td>17–22</td>
<td>1.5–2.0</td>
<td>25–39</td>
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<td>15–20</td>
<td>1.2–1.5</td>
<td>30–36</td>
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<td><strong>Cogeneration</strong></td>
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<td></td>
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<tr>
<td>Gas</td>
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<tr>
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<td>20</td>
<td>1.2–1.5</td>
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<tr>
<td><strong>Hydro</strong></td>
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<td>2.0–5.0</td>
<td>40–100</td>
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<tr>
<td><strong>Solar</strong></td>
<td>0</td>
<td>10</td>
<td>2.7–3.5</td>
<td>170–220</td>
</tr>
<tr>
<td><strong>Wind</strong></td>
<td>0</td>
<td>5–10</td>
<td>2.0</td>
<td>80–120</td>
</tr>
</tbody>
</table>

**Note:** Costs are indicative only and are derived from the sources listed below.

**Sources:** ABARE MARKAL database (2000); Redding Energy Management (1999); Department of Industry, Science and Resources (1999).
With the comparative cost advantage of fossil fueled electricity generation, exported renewable cogeneration electricity also tends to be more competitive for peak load generation. In the longer term, it is expected (given relative technological advances) that more efficient renewable cogeneration will erode the existing comparative economic advantages of fossil fueled generators.

**Policy initiatives**

*Greenhouse gas abatement and renewable energy initiatives*

Growing international concerns about greenhouse gas emissions have provided a motive for the promotion of gas fired and renewable resources in electricity generation. The dominant use of coal in Australian electricity generation results in that form of generation having a higher contribution to total national carbon dioxide emissions than is the case in many other industrialised countries (Unander 2000).

In response to Australia’s commitment to limit greenhouse gas emissions, the Commonwealth and state governments have announced initiatives (for example, the Renewable Energy Initiative and the Greenhouse Gas Abatement program) to promote the use of renewable and low emission energy sources.

One of the key government initiatives has been the setting of a mandatory target for electricity retailers and large buyers to source an additional 2 per cent of their electricity (to a total of around 12.5 per cent in 2010) from renewable or specified waste product energy sources (Australian Greenhouse Office 1999). The legislation associated with mandating this target was passed by the Senate in early December. Achieving the mandated target would require the construction of at least 1750 megawatts of renewable energy generation (ACA 2000b; Redding Energy Management 1999).

*Implications for cogeneration*

The implementation of government policies aimed at the long term reduction of greenhouse gas emissions should lead to increased accountability of the environmental benefits of cogeneration and enhance the prospects of both gas fired and renewable cogeneration. Given implementation of the mandated target, it would be expected (based on cost advantages relative to other renewables and feedstock abundance) that a significant percentage of electricity from new renewable sources would come from bagasse cogeneration in Queensland and northern New South Wales.

The mandated target applies not only to a mandated target for 2010, but also includes incremental targets for the ‘phasing in’ period 2001–10. To illustrate the potential impact of the renewable target on the cogeneration industry, ABARE’s Australian version of the energy system model MARKAL has been used to compare the least cost outcome for meeting the mandated target with a ‘business as usual’ scenario.

Assuming the mandated target is met, the model results indicate that bagasse cogeneration would increase its expected market share of total renewable electricity generation in 2010 by around 9 percentage points compared with the ‘business as usual’ scenario. With this estimated increase in bagasse cogeneration (and assuming this increase does not affect the expected growth of fossil fueled cogeneration), the electricity market share of cogeneration in 2010 under the mandated target would be approximately 60 per cent higher than its current market share.

**Conclusion**

Although energy market reforms have the potential to increase the market share of cogeneration, to date large gains have not been realised. Given that gas should continue to be the major fuel used for cogeneration, investment in new gas fired cogeneration capacity will be related to lower delivered gas prices, an outcome that is more likely in the medium–longer term as competition (upstream to retail) increases in the gas market.

If electricity demand remains strong, leading to a progressive reduction in excess generation capacity and associated increases in electricity prices, the prospects for new cogeneration capacity improve in the medium term. Refinements to current network charging policies may also enhance the viability of cogeneration.
The implementation of government policy initiatives aimed at reducing greenhouse gas emissions should also enhance the prospects for cogeneration. In particular, the mandated target for renewables is likely to provide an impetus for new investment in renewable cogeneration. Total cogeneration capacity could then be expected to increase significantly in the medium term, with a possible change in the fuel mix in favor of increased use of renewables.

References