Shareholder Review of Queensland Government Owned Corporation Generators

November 2010

Queensland Government

Contents

Introduction	3
Market history	4
Market developments	6
Vertically-integrated retailers	6
CPRS and other greenhouse gas reduction policies affecting the electricity industry	7
Liquefied Natural Gas (LNG)	7
Private sector investment	8
Capacity oversupply	8
Expected low prices and increased input costs since the 2006 – 2008 drought	9
Genco risk analysis	10
Policy context	10
Limit the Gencos' mandate to invest in new capacity	10
The cost of maintaining and renewing the portfolio	11
An alternative structure	11
Impact on contracting	12
Policy going forward	13
Refocus the Gencos	13
Portfolio of generation assets	13
Ongoing management of generation assets	14
Abbreviations	15

Introduction

In the 2008-09 Major Economic Statement Mid-Year Fiscal and Economic Review the Queensland Government announced that it would:

> ***"…undertake a shareholder review of the structure and preparedness of the Government owned corporation (GOC) generators to meet the new challenges facing these businesses, particularly in respect of the impending Carbon Pollution Reduction Scheme and competition from large vertically integrated retailers."***

This shareholder review commenced in February 2009 and was undertaken by Queensland Treasury, with the assistance of expert advice from the Department of Employment, Economic Development and Innovation (DEEDI), the Department of the Premier and Cabinet (DPC), Queensland Treasury Corporation (QTC), the Government owned corporation generators (Gencos) and other market participants.

Queensland's electricity generation requirements are supplied by both the public and private sectors. Through its role as owner of three electricity generators – CS Energy Limited (CS Energy), Stanwell Corporation Limited (Stanwell) and Tarong Energy Corporation Limited (Tarong) – the Government plays an active role in the Queensland generation sector.

The Government remains committed to retaining its portfolio of electricity generation assets. The Government rejected the option of selling these assets as identified in the 2006 Queensland Energy Structure Review undertaken by The Boston Consulting Group (BCG). The policy of retaining ownership of electricity generation assets remains firm Government policy and sale of these assets has not been considered as part of this review.

This commitment to continued ownership of generation assets is not considered a barrier to further private sector investment in generation. BCG in its 2006 report identified that potential private sector investors were concerned with Queensland's relatively high reserve ratios (that were negatively impacting returns) and whether these high reserves would be maintained through future Government investment in base-load capacity. There have been a number of changes in the Queensland electricity market since the BCG report. Accordingly, the Government's continued ownership of generation assets is not considered to be a barrier to private sector investment. In this context, it has become clear that the structure of the State's Gencos needs to be reconsidered.

This review examines the changing market environment and the risks to Government of maintaining its existing three Genco model. Under the current environment, the three Genco structure does not appear sustainable into the future. The Government must consider how to best manage its portfolio of generation assets to ensure value for money for all Queenslanders. Developing a model which secures the viability of the generation assets has been a key consideration for the review.

Market history

Prior to the introduction of the National Electricity Market (NEM), the electricity industry in Australia was mainly dominated by vertically integrated government-owned authorities that were responsible for the generation, transmission, distribution and retailing of electricity.[1]

Historically, the *Electricity Act 1976* (Qld) provided the legislative framework for the electricity industry. The Act established the Queensland Electricity Commission (QEC) and seven regional electricity boards. QEC was a vertically integrated Government-owned organisation that was responsible for generation and bulk transmission in the State. QEC supplied electricity to the regional electricity boards who in turn were responsible for the supply of electricity to consumers within their designated areas.

The organisation of the electricity industry in Queensland, as with other states and territories, is now significantly different. Reforms in the electricity industry since the 1990s have resulted in the break-up of the industry into its functional components of generation, transmission, distribution and retail. In addition, competition has been introduced into the generation and retail sectors.

The restructure of the Queensland electricity industry began in 1995 with the break-up of QEC into two separate Government-owned entities:

- the Queensland Generation Corporation (QGC)
- the Queensland Transmission and Supply Corporation (QTSC), later known as the Queensland Power Trading Corporation (QPTC) trading as Enertrade.

QGC operated the Government-owned electricity generators in Queensland. The Queensland Electricity Transmission Corporation (QETC) (trading as Powerlink), a subsidiary of QTSC, was responsible for transmission. Distribution and retail functions continued to be performed by the seven distribution companies (also subsidiaries of QTSC).

In 1997 the Queensland Government announced its electricity reform strategy, based on the recommendations of the Queensland Electricity Industry Structure Task Force.[2] The strategy involved the separation of QGC into the three current Government-owned generators and an engineering services organisation:[3]

- Stanwell
- Tarong
- CS Energy
- AUSTA Energy.

Powerlink and the seven distribution companies were established as independent Government-owned corporations and retained responsibility for transmission and distribution.[4] Retail and distribution functions were separated with the creation of three new retail corporations: Southern Electricity Retail Corporation (known as ENERGEX), Central Electricity Retail Corporation (known as Ergon Energy) and Northern Electricity Retail Corporation (known as Omega Energy).[5]

In February 1998, Ergon Energy and Omega Energy merged to trade as Ergon Energy.[6] Limited retail competition also began in 1998 where large 'contestable customers' with an energy usage greater than 40 gigawatt hours (GWh) per annum (examples would be a large metropolitan hospital or heavy manufacturing plant) were able to choose their electricity supplier.[7]

The restructure of the electricity industry in Queensland was part of a broader national reform agenda which included the formation of a national market for electricity.

The NEM commenced operation in December 1998. The NEM is an interconnected wholesale electricity market which covers all Australian states and territories except Western Australia and the Northern Territory. It is operated under a nationally consistent regime comprising the National Electricity Law, the National Electricity Regulations and the National Electricity Rules (the Rules). While Queensland was part of the NEM, it was isolated until the Queensland/New South Wales interconnector (QNI) commenced operation in 2001.

In the NEM, electricity supplied from private and publicly owned generators is traded through a central pool. Generators compete with each other by submitting offers to supply electricity (dispatch offers) to a central market operator, the Australian Energy Market Operator (AEMO). In simple terms, AEMO matches supply to demand in real time, taking the lowest priced dispatch offers first and progressively accepting higher priced offers until demand is satisfied. The market where electricity supply is matched with demand is called the 'spot market'. All generators receive the 'spot price' for the volume of electricity that they

1 Department of the Parliamentary Library, *Electricity Industry Restructuring: The State of Play,* Research Note 14, 1997-1998 ‹www.aph.gov.au/library/pubs/rp/1997-98/98rp14.htm› accessed on 26 March 2010.

2 Department of the Parliamentary Library, *Electricity Industry Restructuring: The State of Play*, Research Note 14, 1997-1998 ‹www.aph.gov.au/library/pubs/rp/1997-98/98rp14.htm› accessed on 26 March 2010.

3 Enertrade was also responsible for trading the Government's mainly loss-making power purchase agreements (PPA).

4 Department of the Parliamentary Library, *Electricity Industry Restructuring – A Chronology*, Briefing Paper 21, 1997-1998 ‹www.aph.gov.au/library/pubs/bp/1997-98/98bp21.htm› accessed on 26 March 2010.

5 Department of the Parliamentary Library, *Electricity Industry Restructuring: The State of Play,* Research Note 14, 1997-1998 ‹www.aph.gov.au/library/pubs/rp/1997-98/98rp14.htm› accessed on 26 March 2010.

6 Department of the Parliamentary Library, *Electricity Industry Restructuring – A Chronology*, Briefing Paper 21, 1997-1998 ‹www.aph.gov.au/library/pubs/bp/1997-98/98bp21.htm› accessed on 26 March 2010.

7 Department of the Parliamentary Library, *Electricity Industry Restructuring: The State of Play*, Research Note 14, 1997-1998 ‹www.aph.gov.au/library/pubs/rp/1997-98/98rp14.htm› accessed on 26 March 2010.

supply. This price can fluctuate dramatically depending on market conditions, including the balance of supply and demand.

Following the introduction of the NEM, reform of the distribution and retail sectors in Queensland continued. In 1999 the separate distribution companies were amalgamated into two retail businesses (ENERGEX and Ergon Energy).[8]

ENERGEX and Ergon Energy remain as separate distribution companies in Queensland. ENERGEX operates the distribution networks in Brisbane, Gold Coast, Sunshine Coast and surrounds. Ergon Energy operates the distribution networks in country and regional Queensland. Country Energy, owned by the NSW Government, owns some distribution networks in southern regional Queensland.

In 2007, the Queensland Government introduced full retail contestability. At the same time it sold the retail businesses of ENERGEX and Ergon Energy to Origin Energy (Origin) and AGL Energy (AGL). The Queensland Government also sold the gas businesses of Enertrade to AGL and Arrow Energy.[9] Ergon Energy Queensland, a subsidiary of Ergon Energy, retained the regional retail customers (which were largely unprofitable).

On 15 May 2007, the Queensland Government announced its decision to relocate to other energy GOCs and/or sell the business activities of Enertrade.[10] Enertrade's assets were transferred as follows:

- the Power Purchase Agreement (PPA) and associated businesses of Collinsville Power Station (Collinsville) were transferred to CS Energy[11]
- the Interconnection and Power Pooling Agreement (IPPA) and associated businesses of Gladstone Power Station (GPS) were transferred to Stanwell
- the PPA relating to the Oakey Power Station was sold to AGL.[12]

Enertrade was formally wound up by regulation on 18 April 2008.[13]

In 2007 the Queensland Government also announced the sale of the State's wind farm holdings to Transfield Services Infrastructure Limited. Both Stanwell and Tarong had owned wind farms located across South Australia, Queensland, Victoria and Western Australia.[14]

8 Department of Mines and Energy, *National Electricity Market* ‹www.dme.qld.gov.au/Energy/national_electricity_market.cfm› accessed on 26 March 2010.

9 Queensland Government, *Gas Sale kick starts Queensland Climate Change Fund,* Media Statement, 7 November 2007 ‹ www.statements.cabinet.qld.gov.au/MMS/StatementDisplaySingle.aspx?id=54955› accessed on 30 March 2010.

10 Queensland Government, *Smart State Move on Energy Assets,* Media Statement, 15 May 2007 ‹www.statements.cabinet.qld.gov.au/MMS/StatementDisplaySingle.aspx?id=51804› accessed on 30 March 2010.

11 Queensland Government, *Smart State Move on Energy Assets,* Media Statement, 15 May 2007 ‹www.statements.cabinet.qld.gov.au/MMS/StatementDisplaySingle.aspx?id=51804› accessed on 30 March 2010.

12 AGL, *AGL purchases output and dispatch rights from Queensland's Oakey Power Station,* ASX Release, 13 August 2007 ‹www.agl.com.au/Downloads/070813_AGL-purchases-output-and-dispatch-rights-from-Qlds-Oakey-Power-Station_Investor-Relations_ASX-Release.pdf› accessed on 30 March 2010.

13 Queensland Treasury, *Government Owned Corporations performance and governance* <www.treasury.qld.gov.au/knowledge/docs/annual-reports/2007-08/outputs/goc.shtml#footnote2-1› accessed on 30 March 2010.

14 Queensland Government, *Wind Sales Offers Massive Boost to Climate Change Fund,* Media Statement, 29 November 2007, ‹www.cabinet.qld.gov.au/MMS/StatementDisplaySingle.aspx?id=55404> accessed on 26 March 2010.

Market developments

Since the BCG report in March 2006 a number of developments have occurred that have changed the dynamics of the Queensland electricity market:

1. the emergence of vertically-integrated retailers (gentailers)
2. the Australian Government's proposed Carbon Pollution Reduction Scheme (CPRS) and other climate change policies
3. development of a liquefied natural gas (LNG) industry in Queensland
4. substantial private sector investment in generation capacity
5. an oversupply of generation capacity
6. low pool prices and increased input costs since the 2006–2008 drought.

Vertically-integrated retailers

Electricity has many characteristics but two set it apart from most other traded commodities:

1. it cannot be stored, therefore supply must vary dynamically when demand changes
2. it is impossible to distinguish which generator produced which electricity.

In the NEM electricity is traded through a pool where the output from all generators is aggregated and scheduled to meet demand. A dispatch price is determined every five minutes, and six dispatch prices are averaged every half-hour to determine the spot price for each trading interval for each of the regions of the NEM. AEMO uses the spot price as the basis for the settlement of financial transactions for all energy traded in the NEM.

Unlike other commodity markets the maximum and minimum price of electricity is defined and this range is set out in the Rules. The Market Price Cap (MPC) is $12,500 per megawatt hour (MWh)[15] and the Market Floor Price (MFP) is negative $1,000 per MWh.

The spot price of electricity is extremely volatile and often changes dramatically between half-hour intervals depending on supply and demand, available plant and the trading behaviour of market participants. To illustrate the impact of high prices, for Queensland the average pool price for 2009-10 was $33/MWh and average demand was around 6,000 megawatts (MW). At these levels the cost of Queensland electricity traded in the NEM would be $198,000 per hour. If during that hour the price was at the MPC ($12,500/MWh) for five minutes the cost would be $6.4 million for the hour. It is unacceptable for household consumers and small-to-medium businesses to be exposed to such fluctuations and this is where retailers fulfil their role in the market.[16] Retailers provide customers with fixed-price electricity and take responsibility for managing the associated pool price risk.

15 The MPC was increased from $10,000/MWh to $12,500/Mwh on 1 July 2010.

Retailers can manage pool price risk in a number of ways including:

- contracting with generators
- over the counter (OTC) financial instruments such as swaps and caps
- Sydney Futures Exchange electricity futures
- vertical integration through ownership or control of generation by gentailers.

Of these risk management methods it is the last one that has the greatest potential to impact negatively on the Gencos. Gentailers are vertically-integrated retailers that own or control peaking generation capacity. Such entities have developed in Queensland since the commencement of full retail competition.

Gentailers use their peaking generation to hedge against and/or suppress price spikes. This reduces pool price volatility and pushes down average pool prices overall.[17] This places the Gencos at a disadvantage because base-load generators depend on contracting and the expectation of the benefits of that volatility to manage their generation assets.

In summary the gentailers have contributed towards:

1. lowering current average pool prices to sub-economic levels
2. lower forward contract prices for electricity
3. reduced demand for contracts from the State's Gencos because gentailers are less likely to seek protection against pool price volatility as a result of their access to generation owned or controlled by them.

16 Large energy users (such as mines) generally have the option of contracting with retailers or managing risk themselves through contracting directly with generators.

17 Analysis has shown how one gas-fired generator has been able to suppress pool prices. On one evening peak during 2009, when the pre-despatch forecasts were around $200/MWh and higher, a gas-fired generator rebid all of its capacity at negative $1,000/MWh and when it was subsequently despatched prices fell to around $30/MWh.

CPRS and other greenhouse gas reduction policies affecting the electricity industry

The Australian Government has now established a Multi-Party Climate Change Committee to help build consensus on how Australia will tackle climate change. The Committee will consider mechanisms for introducing a carbon price including a broad-based emissions trading scheme, a broad-based carbon levy, a hybrid of both, and economy-wide and sector-based approaches. The Committee will also consider issues such as international trends, implementation issues, assistance measures for households and businesses and review provisions.

At this time, pending processes currently underway through the Multi-Party Climate Change Committee, a CPRS remains the key component of the Australian Government's greenhouse gas (GHG) reduction policies. Full operation of the CPRS (i.e. largely as outlined in the White Paper) was proposed to commence on 1 July 2012.

With respect to electricity generation, a CPRS is designed to displace generation from the most emissions-intensive generators (i.e. coal-fired generation) and encourage less emissions-intensive forms of generation. Coal-fired generation makes up 85 per cent of the Gencos' fleet. Despite the fact they are broadly the least emissions intensive coal-fired generation fleet in the NEM (especially when compared with the Victorian brown coal fired generators), the introduction of a CPRS is expected to place pressure on generation margins and volumes for the Gencos. Furthermore, as carbon permit prices increase under a CPRS, the Gencos are likely to be forced to retire older coal-fired plants prior to the end of their engineering lives.

In conjunction with a CPRS, the Australian Government proposed assistance to the coal-fired generators under the proposed Electricity Sector Adjustment Scheme (ESAS). Under the ESAS, assistance was proposed to be allocated to generators with emissions above the NEM average for coal-fired plant (currently 0.86 tonnes of carbon dioxide equivalent per MWh), under the assumption they are likely to be most disadvantaged by the introduction of the scheme. The lower emissions intensity of the Queensland coal-fired generators in comparison to other States resulted in only a small proportion of the compensation available being likely to be allocated to Queensland-based plants. The Genco coal-fired generators were estimated to receive only approximately $100 million (or less than 1.5 per cent of the $7.2 billion pool).

The Australian Government was unable to secure the passage of the CPRS legislation through the Senate and announced it will not move to legislate a CPRS until at least 2013, when the Kyoto commitment period has ended. Legislation will also be contingent on there being sufficient international action and 'greater clarity on the actions of the major economies including the US and India.'[18]

With the deferral of the CPRS, there continues to be uncertainty due to the generally-accepted requirement for international action. As a result of the delay, there is also a possibility that if a CPRS is eventually introduced it could include very different initial carbon pricing than the original CPRS proposals.

Liquefied Natural Gas (LNG)

The successful exploration and development of Queensland's coal seam gas (CSG) resources has resulted in a number of proposed CSG to LNG export developments. The two most advanced projects each have State and Federal Government Environmental Impact Statement (EIS) approval. The British Gas Curtis Island LNG project has reached Financial Investment Decision (FID) approval for two trains with a combined capacity of 8.5 million tonnes per annum[19]. The Santos Gladstone LNG project is expected to reach its FID by the end of calendar year 2010[20]. The next most advanced project is the Origin Energy Australia Pacific LNG project, which has State Government approval of its EIS. While it may be that not all of the projects will proceed, a substantial CSG to LNG industry is expected to develop in Queensland over the next decade.

The development of an LNG industry is expected to impact the Queensland electricity market in two stages. In the short to medium term, LNG proponents will look for options to deal with 'ramp-up' gas. The need to prove up reserves to support LNG plant investments means that there will be surplus gas prior to the commencement of each LNG production facility. This ramp-up gas has and will continue to increase the domestic supply of gas in the short to medium term.

Ramp-up gas changes the economics of gas-fired generation and will predominantly be used for electricity generation rather than injected into the gas transmission system (e.g. for export to southern states). Therefore, it is highly likely that new gas-fired generation will enter the Queensland market well ahead of the AEMO's assessment of the need for additional generation. This will exacerbate the current level of over-supply, further threatening the financial position of the Gencos.

18 2010-11 Australian Commonwealth Budget Papers, Budget Paper No. 1, p. 1-26.

19 British Gas Group News Release, 31 October 2010.

20 Santos investor presentation, *Delivering Transformational Growth*, October 2010.

In the longer term, following the commencement of LNG plant operation, the availability of ramp-up gas will diminish which, in the absence of alternative domestic gas supply increases, will tighten supply and increase the price of gas. This will make gas-fired generation relatively more expensive and is expected to exert upward pressure on pool prices. Higher gas prices will make it harder for new participants to enter the gas fired generation market because they will have to compete with incumbents that have access to their own upstream gas reserves. This may benefit the Gencos who own predominately coal-fired generators. Conversely, if LNG facilities are delayed or don't materialise there could be an ongoing surplus of gas thereby maintaining the economic advantage (relative to the Gencos) that ramp-up gas created for gas-fired generation.

The other aspect of LNG production that may affect the Gencos is that substantial amounts of electricity may be required for gas compression. This will assist the Gencos if they can secure commercially favourable contracts for supplying the electricity. However, if new generation is constructed to provide the electricity or if gas is used for compression, the supply/demand balance of the market will remain largely unchanged and there will be no benefits for the Gencos.

Private sector investment

Prior to the release of the BCG report in 2006, the private sector had shown a willingness to invest in new Queensland NEM-connected generation, with around 1,600 MW commissioned (from 1999 to 2003), comprising three coal-fired power stations and one gas-fired peaker, representing 55 per cent of all capacity commissioned over the period.[21]

In the 2008-09 Major Economic Statement Mid-Year Fiscal and Economic Review the Queensland Government signalled its intention to:

> *"...consider the GOC generators' position as dominant provider of electricity, particularly coal-fired base-load capacity, in the Queensland market with a view to reducing the share of the aggregate capacity the State owns or operates in Queensland from 65 per cent in 2010 to around 50 per cent...The target of 50 per cent will be progressively achieved primarily as a result of new capacity requirements being met by the private sector, expected to consist largely of gas-fired generation."*

As discussed earlier, the BCG report argued that potential private sector investors were concerned with Queensland's relatively high reserve ratios (negatively impacting returns) and whether these high reserves would be maintained through future Government expansion of base-load capacity. BCG argued that the Government would have to change its strategy to encourage private sector investment. At that time construction of CS Energy's Kogan Creek Power Station (Kogan Creek) was well under way and it was commissioned in 2007. Since then the Gencos have not built any new NEM-connected generation, given private sector investment in new capacity (principally in gas-fired generation).

Subsequent to BCG's report, the private sector has demonstrated that it will invest in the Queensland region of the NEM. Since 2006, the private sector has built four new gas-fired generators and enhanced the capacity of an existing kerosene fuelled plant for a total of 1,928 MW of new generation capacity.[22] It is expected that there is likely to be additional private sector investment in new Queensland generation capacity by 2013-14 subject to the timing of LNG developments.

Hence, private sector investment in large scale gas-fired generation does not appear to be hindered by Government's involvement in the Queensland generation market and demonstrates the private sector's capacity to respond both when the Government is constructing new generation and when it has ceased to undertake large scale generation investment.[23]

Capacity oversupply

The recent influx of new gas-fired generation has contributed to an oversupply of generation in the Queensland electricity market and this is expected to continue until at least 2014. The extent of the capacity oversupply is evident by the fact that Queensland exports a substantial amount of its output to New South Wales. For example in 2009, Queensland generators exported 4.7 terawatt hours (TWh) of electricity to New South Wales which represented 12-13 per cent of total Queensland generation output for 2009.

AEMO's 2010 Electricity Statement of Opportunities showed a need for an additional 726 MW of generation capacity by 2013-14 in Queensland to provide reliable electricity supply.[24] These requirements take into consideration the staged retirement of the 500 MW Swanbank B Power Station (Swanbank B)[25] and incorporate AEMO's revised Minimum Reserve Levels (MRL) for Queensland. However, ongoing private sector investment in new generation capacity is expected to be more than adequate to meet these requirements.

21 The private sector invested in: 852 MW Millmerran Power Station (Millmerran), 50 per cent of 840 MW Callide C Power Station (Calide C), 50 per cent of 443 MW Tarong North Power Station (TNPS) and the gas-fired 80 MW Roma Power Station (Roma). In November 2009 Tarong acquired TM Energy Australia Pty Ltd's 50 per cent interest in TNPS.

22 AEMO registered capacities: 519 MW Braemar Power Station (Braemar), 495 MW Braemar 2 Power Station (Braemear 2), 144 MW Condamine Power Station (Condamine), 644 MW Darling Downs Power Station (Darling Downs), and the kerosene fuelled 126 MW Mount Stuart Power Station (Mt Stuart).

23 The Gencos (and the now dissolved Enertrade) commissioned over 2,000 MW of new capacity between 2000 and 2007.

24 AEMO, *Electricity Statement of Opportunities, 2010,* p. 137 and 148.

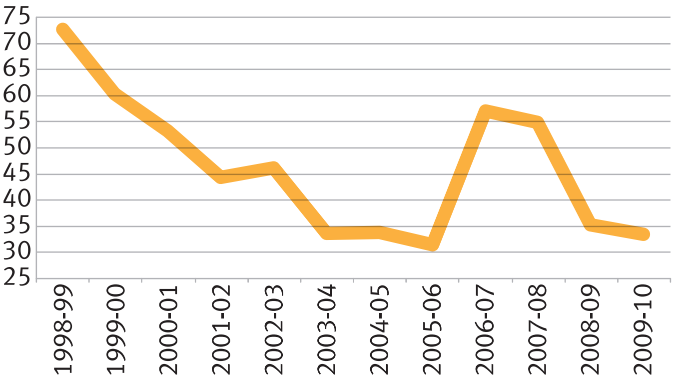
25 The 39 year old Swanbank B is to be gradually retired and taken out of service by the end of financial year 2012.

Expected low prices and increased input costs since the 2006–2008 drought

Since the NEM commenced in December 1998, Queensland real annual average pool prices have fallen although it should be noted that the 1998-99 prices were relatively high due to capacity constraints (see Chart 1). Drought-induced water restrictions raised pool prices in 2006-07 and 2007-08. Since then pool prices have fallen and are now close to pre-drought levels. However, over the same period fuel, labour and other costs have increased substantially for many generators.

Low pool prices have been driven by the factors described above, namely an oversupply of generation capacity in Queensland, competition from new entrant gas-fired generators and gentailers using their generation capacity to reduce pool price volatility.[26] While not shown in Chart 1, the September 2010 quarter pool price averaged $20.97/MWh (in 2009-10 dollars), which is the lowest September quarter average pool price (in real terms) since the commencement of the NEM.

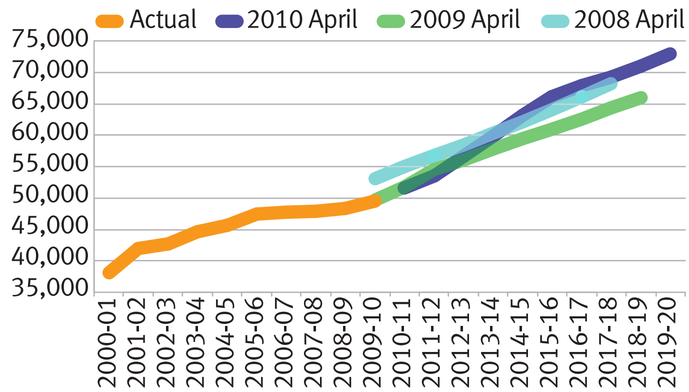
Chart 1: Queensland average time weighted pool price (2009-10 dollars per MWh)



Source: NEM – Review

The outlook for pool prices has also been dampened by reduced demand growth forecasts for Queensland. Chart 2 shows how Queensland's Transmission Network Service Provider (TNSP) Powerlink Queensland revised down its 2009 demand growth forecasts because of the economic downturn, increasing gas and solar hot water penetration (driven largely by incentives provided by the Renewable Energy Target [RET]) and energy efficiency policies.[27] The latest 2010 forecasts predict a further reduction in demand growth over the short-term (due to the reasons described above) and a large step change in demand by 2014-15, which is driven by LNG, mining and associated infrastructure.[28]

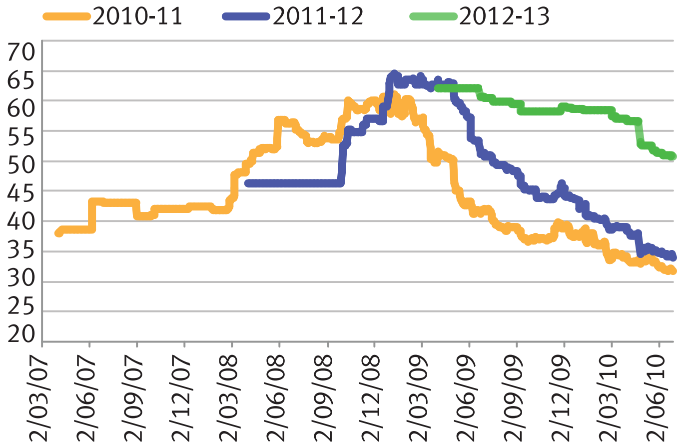
Chart 2: Queensland native demand actual and forecast (GWh) [29]



Source: Powerlink, Annual Planning Report, 2010

Chart 3 shows how Sydney Futures Exchange (SFE) Queensland flat electricity futures prices have behaved since March 2007. Some of the drops and spikes are attributable to CPRS-related announcements. The sharp spike in 2011-12 forward prices in December 2008 was caused by the release of the White Paper on 15 December 2008 confirming the CPRS was planned to commence on 1 July 2010. Following the withdrawal of the Opposition's support for the amended CPRS and subsequent rejection by the Senate for a second time on 2 December 2009, 2010-11 and 2011-12 prices dropped to levels that assume no carbon price with 2010-11 prices falling to $33/MWh. 2012-13 prices were still relatively high because they factored in the possibility of some form of carbon price being introduced by then.

Chart 3: Sydney Futures Exchange Queensland flat electricity future prices (nominal dollars per MWh)



Source: d-cypha Trade as of 28 June 2010

26 In contrast recent increases in retail electricity prices have been largely driven by higher network costs which account for almost 50 per cent of the cost of retail electricity. Over the next five years Queensland Network Service Providers (NSP) are expected to spend approximately $15 billion on capital expenditure and this has and will continue to cause upward pressure on network costs.

27 Powerlink, *Annual Planning Report, 2009*, p.22.

28 Powerlink, *Annual Planning Report, 2010*, p.3.

29 Native demand is the demand delivered to distribution networks and to direct connected customers, and includes the output of embedded exempted and non-scheduled generators which do not export to the grid.

Genco risk analysis

The developments previously outlined illustrate how the market has changed such that any previously perceived barriers to entry attributable to the Gencos have largely evaporated. This is evidenced by the influx of large private sector investments in new gas-fired generation capacity. Furthermore, the new market conditions are affecting and will continue to adversely affect the profitability of the Gencos and ultimately the viability of their operations. Table 1 summarises the market factors and how they are expected to affect the Gencos over time.

Table 1: Generator market risk summary

Market factors	Short term (2010 – 2013)	Long term (Post 2013)
Gentailers	• Reduce pool price volatility leading to reduced pool prices and forward contract prices • Reduce contract demand	• Same as short term • Loss in value
CPRS	• Uncertainty	• Reduced generation output from coal fleet which results in reduced earning capacity to absorb fixed costs • Early plant retirement • Limited ability to pass through carbon cost • Loss in value
LNG	• Cheap ramp-up gas • More gas-fired generation • Reduce pool price volatility leading to reduced pool prices and forward contract prices • Reduce contract demand	• Higher gas price • Increase pool prices
Capacity oversupply	• Reduce pool price volatility leading to reduced pool prices and forward contract prices • Reduce contract prices	

Policy context

In the 2008-09 Major Economic Statement, the Government indicated a policy position of seeking increased private sector investment in generation infrastructure. This reflects the maturing of the deregulated NEM. It is clear Government can retain ownership of its existing assets without impacting on the timely private sector development of new generation.

Limit the Gencos' mandate to invest in new capacity

To remove any perceived residual risk that the Government's presence in the market could discourage future new entrants, Government could confirm to the market that it no longer intends to increase the size of existing generation capacity. This can be done in the form of a cap on the total installed capacity of the Gencos at current levels. Such an approach gives the Government and the Gencos the flexibility to renew and rebalance the portfolio periodically to enhance shareholder value in a challenging environment. The staged retirement of CS Energy's Swanbank B represents a first step in signalling to the market that the Government will retire plant when it is commercially unviable after having reached the end of its economic life (Swanbank B was first commissioned in 1971).

Adopting such a policy approach could potentially raise security of supply concerns, particularly if there are concerns that the private sector will not respond to market signals in a timely manner and build new generation when needed. To mitigate this perception the Government could create an exception to its general policy where it would act as an 'investor of last resort'.[30]

30 Boston Consulting Group, *Queensland Energy Structure Review, March 2006,* pp 33-34.

The cost of maintaining and renewing the portfolio

The Gencos have each indicated that they will need to invest to renew their portfolios with more cost efficient plant (e.g. either gas-fired or less carbon intensive coal burning) including retrofitting their existing plant with low emissions technology or face declining returns. This places Government at a crossroad. The investment required for converting the existing portfolio to gas and low emissions generation would amount to several billion dollars. With declining financial viability, the cost would require significant borrowings by the Gencos. This would be contrary to the position adopted by the Government in its December 2008 Major Economic Statement.

In this context, the key issue for Government is how best to manage its existing portfolio of assets to maximise the viability of the Gencos and ensure that existing Genco coal-fired plants continue to operate until an orderly closure is appropriate, for instance when some form of carbon pricing is introduced which shortens the economic life of plants. A planned retirement of existing plant according to carbon price signals is essential to ensuring a smooth transition of the Queensland energy market to lower-emissions generation and maintaining employment at current facilities in the meantime.

As described earlier, developments in the electricity market are impacting negatively on the viability of the Gencos and this situation is only expected to deteriorate further. For the Gencos, many costs remain fixed (or rising) and the financial viability of individual Gencos could be affected even when individual plants remain viable (e.g. where corporate office costs exceed plant profitability). While the three Genco structure was appropriate at the time it was created to ensure adequate competition in the then isolated Queensland market, the early retirement of plants within these portfolios could impact on the remaining assets.[31]

Because decisions must be made independently within each business (for competition law reasons), decisions may occur at a company level which are not optimal with respect to the overall portfolio. The potential for misalignment between the corporate interests of each Genco under the current structure and the overall interests of the State indicates the need for structural reform of the Gencos.

31 “Isolated” refers to the fact that Queensland was not connected to the rest of the NEM when the three Genco structure was created.

An alternative structure

The Review recommends to Government a strategy that provides for a restructure of the State’s three Gencos to enable management of the generator portfolio under a two Genco model. The key elements of the proposal are outlined in the remaining sections of this report.

A two Genco structure would partially mitigate the adverse impacts that the Gencos are currently experiencing and offer a range of benefits that will better position the generators to manage the upcoming challenges. The major benefits are:

1. Creating synergies by allowing lowest cost plants to be fully dispatched, with higher cost plants operating in an intermediate role.

2. Restructuring existing assets into two portfolios would facilitate the orderly management of asset maintenance schedules to ensure highest-cost plants are retired first and the viability of existing more efficient plants is maintained. Grouping generation units of the same type within each of the two portfolios would improve maintenance efficiencies.

3. Restructuring into two portfolios would allow existing intermediate and peaking assets to be allocated to both portfolios which will facilitate improved contract and trading strategies. The two portfolio structure would increase the capacity available for contracting because the N-1 requirements would be reduced.[32]

4. Head office cost synergies may be realised in terms of reduced management and executive costs, integration of systems and reduced financial reporting costs etc.

5. Under the current structure the financial outlook for the merchant generation operations of the Gencos is challenging. This, in conjunction with their future capital expenditure requirements, is likely to necessitate the Government having to make substantial equity injections into the Gencos to maintain credit metrics consistent with investment grade standards. These taxpayer funded equity injections would be in the hundreds of million dollars. Under a restructured model, the two larger Gencos would have increased revenue, cost savings and the ability to offset profitable assets against loss-making assets. As financially stronger businesses, they will be better able to manage current and future challenges

32 The N-1 rule provides that a generator should contract its available capacity less the capacity of its largest unit, to ensure that a failure of any unit does not result in the generator having available capacity less than its contract commitments. The largest units under the existing three Genco structure are Kogan Creek (750 MW), Tarong North Power Station (TNPS) (443 MW) and a Stanwell Power Station (SPS) unit (350MW). Under the two Genco model, SPS’s 350 MW capacity is no longer subtracted from contractable capacity.

and this will translate to better credit metrics which will reduce the size of any taxpayer funded equity injections.

6. The allocation of generation assets under the recommended restructure will reduce the likelihood of one of the Gencos being impacted by network constraints. Network constraints occur where transmission between network areas, for example central Queensland and south east Queensland, is restricted due to factors such as energy flows being at transmission line capacity or some form of transmission line or equipment outage or other restriction. Constraints generally affect generators located in central Queensland and under the current structure all of Stanwell's generation assets are located in central Queensland or further north. Under the structure identified, each Genco has a good geographical spread of assets in north, central and south east Queensland.

The new Gencos should be directed to focus on the management of existing assets to ensure costs are minimised, and that maintenance and overhaul expenditures are appropriate having regard to the economic life of the plant. As part of this focus, the companies would not engage in expansionary business development activities related to investment in new generation, although business development activities aimed at most efficiently managing the value of the existing portfolio would be maintained.

In the future, opportunities may arise for carbon capture and storage (CCS) or other carbon-reducing technologies (e.g. algae, solar boost etc) to be retrofitted to existing plants to improve energy efficiency and reduce carbon footprint. At present, these technologies are prohibitively expensive, however if CCS becomes available at commercial scale and appropriate cost, the installation of CCS could extend the economic life and substantially increase the value of existing assets. Part of the new Gencos' mandate to manage existing assets should include a requirement to monitor CCS and other carbon reduction opportunities and present any commercial retrofitting proposals to the Government for consideration.

Impact on contracting

The recommended two Genco structure would allow the portfolio to offer more contracted supply to retailers or large commercial and industrial loads, and to service contracts with lowest cost plant. In broad terms, more units with greater diversification of supply provides for greater contracting capacity. The revised arrangements would reduce the number of generation units that are not contracted under the N-1 rule (i.e. the capacity of each Genco's largest unit are not contracted) from three to two. There will be an additional 350 MW of capacity available for contracting. This is timely because Swanbank B has reached the end of its economic life and the retirement of its remaining units will reduce Genco capacity by 250 MW.

The additional contracting capacity will be available for non-integrated retailers that want to enter the Queensland market or expand existing operations particularly if existing gentailers continue to dominate the construction of new entrant plants. By increasing the capacity available for contracting, the recommended restructure may improve competition in the supply of contracts to non-integrated electricity retailers and encourage new entrant retailers.

The benefits that accrue from restructuring are expected to be derived from synergies and efficiencies. As described previously there are many factors (gentailers, capacity oversupply, new entrant generation, carbon price and LNG ramp-up gas) that are expected to impact both positively and negatively on wholesale prices while gaming opportunities (if any) are expected to be limited. As a result of the increased capacity available for contracting, the restructure has the potential to facilitate more competition in the retail electricity market.

Policy going forward

The Government has decided to implement the following changes to the Gencos:

- Move to refocus the Gencos' collective corporate strategies from new business development and growth to one of cost and performance efficiency for the existing asset base (including retrofitting plant with emerging low emissions technology). This clearly signals to the market that Government expects the private sector to develop new additional capacity as and when required to meet increased demand. This change is to be reflected in all Gencos' Statements of Corporate Intent and Corporate Plans.
- Commence a process where each Genco, in accordance with its statutory obligations, consults with Unions and employees regarding the restructure of the sector from a three Genco structure to a two Genco structure effective from a target date of 1 July 2011.
- Beyond the short to medium term, monitor developments in the generation and retail markets and maintain policy flexibility.

Refocus the Gencos

The withdrawal from service of Swanbank B signals to the market that the State will operate its coal-fired assets according to commercial principles. These actions clearly signal to the private sector that Government will observe commercial incentives with respect to its investment in the wholesale electricity market.

The Government will immediately refocus the business strategy of the Gencos away from one of growth to one of cost and performance efficiencies for the existing asset base. Based on the current Corporate Plans provided by the Gencos, this could avoid substantial business development capital expenditure over the next five years.

Establishing and communicating clear conditions for future Government investment (i.e. focus on existing assets and CCS if and when it becomes available) will underpin private sector investor confidence and help ensure new generation capacity is added in a timely fashion. It is important that Government send a clear and strong signal to the market regarding its position on new generation, as this will help remove any residual doubts on the part of private sector investors.

Some flexibility would be required regarding the treatment of existing business development programs to ensure that any sunk investments are assessed commercially.

Portfolio of generation assets

The preferred structure of the new Gencos has been developed with a view to a number of key issues including:

- increasing the scale of operations (i.e. spreading corporate overhead across a greater generation output)
- maximising the diversity of each corporation's portfolio (i.e. regarding size, type, location and fuel) to better hedge variability in returns
- ensuring an appropriate north/south geographical split, to ensure no impediments to contracting or trading as a result of potential transmission constraints
- ensuring those stations co-located on sites remain within a single corporation (e.g. both stations at the Callide site)
- seeking to place 'units' with similar technical specifications together (e.g. the Stanwell Power Station (SPS), Tarong Power Station (TPS) and Callide B Power Station (Callide B) 350 MW units)
- ensuring that this restructure maintains policy flexibility with respect to components of the overall portfolio.

Restructuring the portfolios as set out in Table 2 provides for both geographical diversification and a balance between peak/intermediate and base-load capacity.

Table 2 – AEMO registered capacities for current and restructured Genco portfolios[33]

Current Gencos

CS Energy[34]	MW
Kogan Creek	750
Callide B	700
Callide C	420
Swanbank B	250
Swanbank E	385
Collinsville	195
Total	2,700

Stanwell Corporation	MW
Stanwell	1,400
Gladstone	800
Hydro/Peaking Plant[35]	183
Total	2,383

Tarong Energy	MW
Tarong	1,400
Tarong North	443
Wivenhoe	500
Total	2,343

Restructured Gencos

CS Energy	MW
Kogan Creek	750
Gladstone	800
Callide B	700
Callide C	420
Wivenhoe	500
Hydro/Peaking Plant[35]	183
Total	3,353

Stanwell - Tarong[34]	MW
Stanwell	1,400
Tarong	1,400
Tarong North	443
Collinsville	195
Swanbank E	385
Total	3,823

CS Energy is the smaller of the two portfolios with around 500 MW less capacity than Stanwell-Tarong. While it is the smaller of the two Gencos, it contains substantial base-load capacity. CS Energy has the State's most modern super critical coal-fired power station, the 750 MW Kogan Creek (commissioned in 2007) along with the relatively new super critical 420 MW Callide C Power Station (Callide C) commissioned in 2001. Callide B is powered by two of the ten 350 MW units referred to previously. However because it is co-located with Callide C, it is included in CS Energy's portfolio.

CS Energy has ample peaking capacity with the 500 MW Wivenhoe pump storage Power Station (WPS) and a number of smaller hydro-electric power stations such as the 81 MW Kareyeea Power Station and 60 MW Barron Gorge Power Station. The N-1 contracting limitation for CS Energy is the single 750 MW Kogan Creek unit.

CS Energy is geographically diverse with Kogan Creek and WPS located in south east Queensland, Callide B and C and GPS in central Queensland and most of the 183 MW of hydro-electric and gas-fired peaking plant located in north Queensland.

33 Though not shown in the restructured portfolios, Swanbank B will form part of the Stanwell-Tarong portfolio and it will be responsible for the progressive retirement of the plant.

34 Owns non-NEM connected 345 MW Mica Creek Power Station.

35 Hydro/Peaking Plant, to transfer from Stanwell to CS Energy, relates to Barron Gorge Hydro Power Station, Kareeya Hydro Power Station, Koombooloomba Hydro Power Station, Mackay Gas Turbine Power Station and Wivenhoe Small Hydro Power Station.

Stanwell-Tarong will have the greater base-load capacity of the two new Gencos, containing two of the State's larger power stations (TPS and SPS) and the modern super critical Tarong North Power Station (TNPS) (commissioned in 2003). Intermediate and peaking gas-fired generation will be provided by the modern 385 MW Swanbank E Power Station (Swanbank E, commissioned in 2002). Stanwell-Tarong will also contain the non-NEM connected 345 MW Mica Creek Power Station located at Mount Isa. The N-1 limitation on contracting will be the single 443 MW TNPS unit.

Geographic diversity is provided for with the 1,400 MW SPS located in central Queensland (and to a lesser extent the 195 MW Collinsville located in north Queensland). The rest of Stanwell-Tarong's NEM connected capacity (2,228 MW) is located in south east Queensland.

One of the benefits of this portfolio's structure is that it creates maintenance synergies by grouping together eight of the ten 350 MW units.

Ongoing management of generation assets

Having determined that the Government wishes to retain its existing interest in the generation sector and promote the opportunity for investment in new generation capacity to the private sector, the amalgamation of generation assets into two Gencos should mitigate some of the likely challenges resulting from any future CPRS and market effects from vertically-integrated entities.

The proposed amalgamation should preserve flexibility for future changes to the structure, as it does not 'lock-in' any long term arrangements (e.g. PPAs). Changes may be required for example due to plant retirements (including early retirements as a result of the introduction of a future CPRS) or to promote other energy market objectives. Maintaining flexibility to address changing market conditions will be important given the electricity market is currently facing uncertain times.

Abbreviations

AEMO	Australian Energy Market Operator
BCG	Boston Consulting Group
BRCI	Benchmark Retail Cost Index
Callide B	Callide B Power Station
CCS	Carbon capture and storage
Collinsville	Collinsville Power Station
CPRS	Carbon Pollution Reduction Scheme
CSG	Coal seam gas
DEEDI	Department of Employment, Economic Development and Innovation
DPC	Department of Premier and Cabinet
EIS	Environmental Impact Statement
ESAS	Electricity Sector Adjustment Scheme
ESOO	Electricity Statement of Opportunities
FID	Final Investment Decision
Genco	Generator GOC
Gentailers	Vertically-integrated retailers
GHG	Greenhouse Gas
GOC	Government owned corporation
GPS	Gladstone Power Station
GW	Gigawatt (1,000 MW)
GWh	Gigawatt hour (1,000 MWh)
IPPA	Interconnection and Power Pooling Agreement
KW	Kilowatt (1,000 watts)
KWh	Kilowatt hour (1,000 watt hours)
Kogan Creek	Kogan Creek Power Station
LNG	Liquefied Natural Gas
MFP	Market Floor Price
MPC	Market Price Cap
MRL	Minimum Reserve Level
MW	Megawatt (1,000 KW)
MWh	Megawatt hour(1,000 KWh)
NEM	National Electricity Market
NSP	Network Service Provider
OTC	Over the counter
PPA	Power Purchase Agreement
QETC	Queensland Electricity Transmission Corporation (trading as Powerlink)
QGC	Queensland Generation Corporation
QNI	Queensland/New South Wales Interconnector
QPTC	Queensland Power Trading Corporation (trading as Enertrade)
QTC	Queensland Treasury Corporation
REC	Renewable Energy Certificate
RET	Renewable Energy Target
SFE	Sydney Futures Exchange
SOO	Statement of Opportunities
SPS	Stanwell Power Station
Stanwell	Stanwell Corporation Limited
Swanbank B	Swanbank B Power Station
Swanbank E	Swanbank E Power Station
Tarong	Tarong Energy Corporation
The Rules	National Electricity Rules
TNPS	Tarong North Power Station
TNSP	Transmission Network Service Provider
TPS	Tarong Power Station
TW	Terawatt (1,000 GW)
TWh	Terawatt hour (1,000 GWh)
TWPP	Time weighted pool prices
White Paper	Australian Government, Carbon Pollution Reduction Scheme Australia's Low Pollution Future White Paper, December 2008
WPS	Wivenhoe Power Station

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