QLD Gas Generator Forum

Detailed Report:
Future of the Queensland Gas Scheme

September 08

Cover Note:

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1 Background

During July 2008 the Australian Federal Government released the Carbon Pollution Reduction Scheme Green Paper (CPRSGP) which outlines a range of policy initiatives associated with the commencement of an Australian Emission Trading Scheme (AETS). Chapter 12 of the CPRSGP addresses a number of Transitional Issues relating to the lead up to an AETS. One of those issues addressed is the transition of two state-based schemes operating in the electricity market. The preferred position for the Federal Government as outlined by the CPRSGP is that the *Greenhouse Gas Abatement Scheme* (GGAS) and the *Queensland Gas Scheme* (QGS) are discontinued by the State Governments upon commencement of the AETS.

A number of Queensland Gas Generators believe that the Federal Government's position is based on a misunderstanding of the QGS' nature and its implications on existing and future Queensland gas generation projects of discontinuing the QGS. A very strong case can be made refuting the basis upon which the Green Paper concludes that the QGS should be discontinued and supporting the need for the QGS to run its full course in accordance with previous State Government policy announcements.

As a result the Queensland Gas Generators Forum was formed by a number of the main owners and operators of Queensland's major gas fired generation projects. The current members of the Queensland Gas Generators Forum (QGGF) are as follows:

- Arrow Energy Limited
- B & B Power
- ERM Power
- Queensland Gas Company

Together the QGGF members represent the majority of the current scheduled generation fired by gas in the Queensland region of the NEM and the currently committed future gas fired generation projects in the Queensland region of the NEM.

This paper has been drafted by a consulting firm, Energy Edge, on behalf of the members of the QGGF to provide the Federal Government and relevant departments of the Queensland State Government an overview of the key points that support the case for retaining the current policy with regards to the Queensland Gas Scheme until at least 2020. Qualitative and quantitative analysis to support the position of the QGGF will be presented to the Queensland and Federal Governments by 10 September 2008.

2 Key Notes in support of the Queensland Gas Scheme

The following are the eleven key points that the QGGF believe make an irrefutable case for the continuation of the Queensland Gas Scheme (QGS) in parallel with an Australian Emission Trading Scheme (AETS) until the expiration of the current Queensland Government policy in 2020. The key points are expanded in subsequent sections.

1. **The QLD Gas Scheme (QGS) has been the most successful of all the environmental schemes** - QGS has been the main driver of supply-side growth for energy across the NEM, ensuring that the NEM, and Queensland in particular, is able to meet the rapid growth in electricity demand experienced over the last five years. The expected revenue generated by the sale of Gas Electricity Certificates (GEC) has directly resulted in over 500MW of new base load gas fired electricity generation and over 500MW of intermediate gas fired generation. Furthermore there is more than 1000MW of intermediate to base-load gas-fired generation committed for development over the next 5 years.

   "**The reduction of carbon intensity is really fundamentally an *energy* issue, not a *peak power* issue. The QGS is needed to not only ensure gas fired power stations are developed but that they run at sufficiently high capacity factors to displace material volumes of coal fired *energy*."**

2. **QGS Objective to underwrite the emerging gas industry** – The QLD Gas Scheme policy has been in the public domain since just prior to the schemes commencement in 2005. The policy objective has always been to underwrite the development of the domestic gas sector and associated infrastructure in QLD, in an analogous to an emerging industry like the renewable energy sector. Therefore the QLD Gas Scheme is much more like the MRET scheme, which is to be continued, rather than the GGAC scheme which will be terminated.

3. **QGS and AETS Policy developed in parallel** - The QLD Gas Scheme policy has been developed and implemented in parallel to the Australian carbon policy and an associated AETS which has been undertaking major policy debate and consultation since the early days of the Australian Greenhouse Office in 1999. The impact of carbon upon the electricity sector has always revolved around grandfathered permits, compensation and/or the ability to offset costs through rising electricity prices. The European ETS commenced in 2005, the same year as the QLD Gas Scheme, and has always resulted in an increase in electricity prices and improved gross margins for low carbon intensity electricity generation such as gas. It is therefore reasonable to conclude that project feasibilities included GEC revenue assumptions and carbon cost benefits existing in parallel to each other.

4. **Investment growth based on expectations of QGS and ETS in parallel** - The QLD Gas Scheme policy has been consistent in duration, and in fact grown in scale quite recently, throughout the period in which it has been apparent an AETS would eventually exist in Australia and an increase in electricity price would arise (as experienced in Europe from 2005 onwards).

   As a result all QLD gas fired generation investment decisions to date have been made on the expectation that the revenue generated from the sale of GEC and the improved gross margins in electricity prices as a result of an AETS impact would exist in parallel and jointly contribute to underwriting the feasibility of gas fired generation as base load and intermediary sources of electricity supply. Without these dual benefits the existing and future gas fired projects cannot be assured.

5. **Lower carbon intensity and therefore carbon cost –** The QLD Gas Scheme has directly contributed to lowering the carbon intensity associated with QLD electricity. This will mean that the price impact of carbon on electricity consumed in Queensland will be less than in other states providing the consumer with an offset against the cost of the QGS.

   To date the QGS has "contributed an annual carbon reduction of around 3.1M tCO2 compared to an alternative where the generation is offered by a Swanbank B style of generator. At the notional carbon cost of $20/tCO2, this equates to $62M per annum which more than offsets the cost of GECs to consumers."

6. **Gas Fired Generation marginal without QGS** – At current electricity prices and forward prices for post AETS periods, gas fired projects Long Run Marginal Cost (LRMC) struggles to be commercial without the benefit of revenue earned from the sale of GEC's. The expected upward pressure on domestic gas prices, capital costs and operating expenses are likely to see a dramatic reduction in gas fired generation investment without a continuation of the QGS. Alternatively electricity prices will rise more than what the QGS currently costs the QLD consumer.

   "If we, assume that the full carbon cost is passed through to the pool price, then to achieve the same contribution to the gross margin without the QGS the carbon price required must be at least ($12.83 /0.5)/0.9 = 28.50 $/tCO2. The European pass through was around 70%. Under that scenario, the carbon price in the calculation above would need to rise to 28.50/0.7 = $40.86/tCO2 in order for the representative generator to maintain the relative competitive position which is currently achieved through the QGS."

7. **Electricity Supply and Demand Issues –** Electricity prices will rise dramatically in Queensland if gas fired generation investment does not continue in the region. Demand for electricity is likely to continue to grow strongly in Queensland. However, coal fired generation will not be an acceptable source of further supply in a carbon constrained economy until carbon capture and storage becomes commercial. Therefore between 2010 and 2020 the only viable source of new wholesale electricity supply in Queensland is from gas fired generation. The cost to Queensland's economy and employment rates as a result of higher electricity prices will be far more significant than the impact of the cost of GEC imposed on 13 – 18% of total electricity costs.

   "With no GECS, to make the Combined Cycle Gas Turbine (CCGT) competitive requires a carbon price of around $31/tCO2. In the case of an Open Cycle gas power station, this level rises much higher to over $40/tCO2. If we entertain a scenario of gas reaching $5/GJ, which is probable as the domestic gas market moves towards LNG export parity, and with no GECS, to make the CCGT competitive requires a carbon price of around $57.60/tCO2. In the case of an Open Cycle gas power station, this level rises much higher to $88.97/tCO2."

8. **Sovereign Risk –** The investment environment in the Australian energy sector is very challenging at the moment with credit tightness and uncertainty created by the ongoing debate with regards to the exact nature of the AETS. The perceived sovereign risk associated with previous policy commitments, such as QGS, being abandoned after long term investment decisions have been made will be significant. The private sector, which has currently underwritten the development of the gas industry and the lowering of QLD's carbon intensity, will become very reluctant to pursue further investment on the basis of QLD Government policy initiatives. This will result in underinvestment in electricity supply in QLD and an increase in cost to the consumer.

9. **Limited economic wholesale renewable energy in QLD** – Apart from the burning of biomass, Queensland does not have an abundant source of viable renewable energy solutions. There are limited suitable wind sites and solar remains limited and very expensive as a wholesale source of electricity. As a result gas fired electricity is Queensland's only economically viable wholesale source of electricity capable of significantly lowering our carbon intensity during the transitional period of 2010 to 2020. Like renewable energy, gas fired electricity requires underwriting during this transitional period in order to ensure its long term development and feasibility. However, gas only requires an impost of $10 - $15/MWh across 13% - 18% of demand whereas renewable energy requires a cost impost of $45 - $55/MWh across 20% of electricity consumed. On the basis of the ratio of cost per tonne of carbon intensity reduction for electricity production, gas fired generation is currently a more economic solution than wind or solar and is the only solution that is capable of meeting up to 300MW in Queensland electricity demand growth per annum.

10. **GEC and AETS are market based mechanisms** - Current returns with the QGS in place have driven significant investment in gas fired generation projects since its inception a little over three years ago. As a result of strong supply side response the spot price for GEC's has fallen from approximately $16/GEC (the tax adjusted penalty rate) to approximately $10/GEC. The electricity and GEC markets are very competitive.

    If the introduction to AETS did in fact provide additional gross margin benefits to generators, such that risk adjusted returns for gas fired projects improve whilst the QGS is retained, even more substantial investment commitments would be made and the value of GEC's would continue to fall until the net value benefits of AETS and QGS operating in parallel are just enough to exceed LRMC for gas fired projects. The removal of QGS and the GEC revenue stream not only creates issues of sovereign risk for environmental markets but also removes the Queensland Governments only successful safety valve for ensuring the viability of gas fired generation and therefore Queensland's only possible medium term solution for providing a smooth transition into a carbon constrained economy.

11. **GEC Sales Agreements are key to obtaining financial close on new gas fired generation projects –** The experience of the QGGF members has been that GEC revenue streams are crucial in obtaining financial close on new gas fired power stations. The global credit crisis and the volatile nature of carbon prices and electricity revenue streams means that significant certainty in revenue streams and gross margins is necessary before banks will provide the necessary funding for new gas fired generation projects. The long term sale of GEC's produced under the QGS are a crucial component associated with reducing merchant risk attached to developing new gas fired power stations and obtaining funding from financial institutions. The prospect of an uncertain future for the QGS is already threatening the feasibility of prospective gas fired power stations as long term GEC sale agreements are no longer achievable. This risk is further exacerbated by the inability of industry participants to hedge electricity prices and carbon prices long term particularly during the transitional years into an AETS.

3 The QLD Gas Scheme (QGS) has been the most successful of all the environmental schemes

3.1 Introduction

QGS has been the main driver of supply-side growth for energy across the NEM, ensuring that the NEM, and Queensland in particular, is able to meet the rapid growth in electricity demand experienced over the last five years. The expected revenue generated by the sale of Gas Electricity Certificates (GEC) has directly resulted in over 500MW of new base load gas fired electricity generation and over 500MW of intermediate gas fired generation. Furthermore there is more than 1000MW of intermediate- to base-load gas-fired generation is committed for development over the next 5 years.

> **"We have around 3,000 megawatts of gas-fired generation in the pipeline. Gas is good for the economy and good for the environment."**
>
> Geoff Wilson, Queensland Minister for Mines and Energy, 30 June 2008, [GW2008]

3.2 New investment driven by the QGS

A large volume of new investment in the Queensland electricity market is attributed to gas-fired generators with behaviour motivated by the QGS. Queensland has seen a much higher-than-average construction of gas-fired plant since 2002.

The ratio of new gas plant is startling. And the motivation is principally driven from the QGS, because in the early years, there was a *deficiency* of gas to be able to actually run gas power stations with any real intensity.

In other words, the gas generation industry was seeded on the expectation of a growing gas industry. Otherwise, no-one would feasibly build a $400M, baseload generator of 385MW capacity like Swanbank E without the gas to actually operate it.

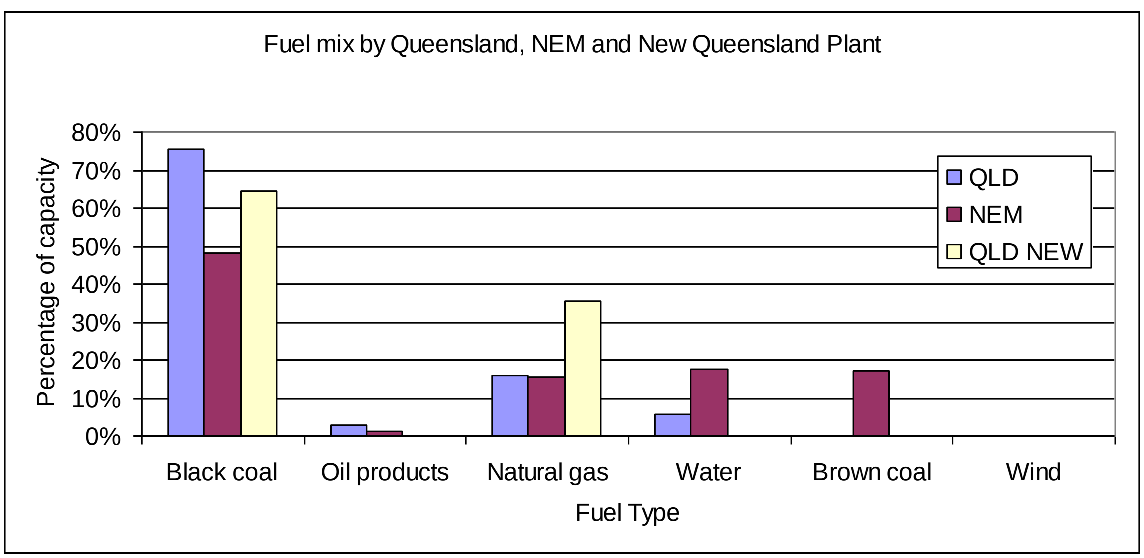


Figure 1: Proportion of installed capacity by fuel type for all of Queensland plant, for all generators in the NEM and for all "NEW" Queensland plant installed in 2002 or later.

The trends in Figure 1 show that Queensland's mix of plant contains about the same proportion of gas fired capacity as the NEM's average at around 16%. However, investments since 2002 have seen a much stronger push towards gas fired generators, with the average being over double that amount at 35%.

This large investment has occurred in the context of the emergence of massive supercritical generators such as Callide C3 and C4, Millmerran Power Plants 1 and 2, Tarong North Power station and Kogan Creek. These power stations have been commissioned on seams of extremely low cost coal and existing transmission infrastructure close to population centres. The QGS has succeeded not only in getting gas power stations commissioned, but bootstrapping an entire industry to compete with an existing sector which experiences some of the cheapest fuel in the world.

If the statistics are calculated based on projects under construction or in advanced stages of planning, such as the Condamine Power Station and the Darling Downs Power Station, then the transition to gas is even more apparent. In fact, there are no proposed coal-fired generators as serious contenders for new supply.

Following a synergistic path, the generation and gas industry have grown together. The investment in generators like Swanbank E, and the additional revenues achieved from GEC sales have enabled the generators to support the exploration and development of gas fields and the innovative Coal Seam Methane production processes. In turn, the local gas producers have grown (see Figure 5) and been able to provide additional low cost gas, which has subsequently provided the incentive for new investment in gas generators.

With the sector kick-start provided by Swanbank E, the market has subsequently seen Yabulu and the Braemar power stations commissioned. With the additional revenues from the QGS, the plants have remained viable against coal fired stations burning what is likely to be the world's cheapest source of alluvial coal. The real benefits provided by the QGS are that the revenues have not provided abnormal profits to the new gas generators, but have enabled investment in the underlying infrastructure to support the gas industry and enable the security of supply to source a reliable low carbon generation source.

3.3 New Investment in the NEM

Additional investments across the NEM have also concentrated on gas fired generators. A valid question is whether the Queensland generation mix would have trended toward the gas solution even without the support of QGS.

The following arguments confirm that investment decisions in Queensland were reliant on the environment of the QGS, and outcomes may have been far different without the GEC revenue stream.

1. Investments in new power stations using low cost coal were made in parallel. The Kogan Creek Power station was commissioned in 2007, and constructed in full knowledge of the QGS. It is an economically viable station with an extremely low fuel cost and has proven profitable with baseload dispatch. If the Kogan solution is so viable, then we can conclude that without the QGS, other investments would also have turned to the low-cost coal solution, and we would have seen no baseload gas fired generators.

2. Queensland power investments have acted as proxy sources of supply for the NSW region, which generally operates in mode a supply-deficiency, relying upon imports to meet demand and security. The Hunter region of NSW experiences low coal prices akin to coal in the Queensland region. Imports of electricity from Queensland includes output from the gas fired generators, which have found it superior to invest in Queensland, with a typically lower pool price, but with the security that the GEC scheme is driving the overall desired outcomes of building long-term gas security and lowering the NEM's carbon intensity.

3. There have been very limited investments in other regions since 2002. The installation of the Laverton North gas turbine in Victoria has been undertaken in a State with a highly developed gas market, exhibiting transparent published spot prices, and possessing a comprehensive transport network. The existing infrastructure raises the viability of gas power plant installation since the reliable fuel sources are proven, and the generation project is simplified to building a generator, not developing gas fields and infrastructure. The case for additional supply in Victoria has been made apparent in recent years as the Summer peak demand forecasts have put NEMMCO on alert with reserve shortfalls. If the Victorian experience has warranted the addition only *limited* gas fired generation with its extensive gas infrastructure, then not much could be expected from Queensland, with a supply surplus and limited known reserves of natural gas and a transport network that consisted principally of the single Roma to Brisbane pipeline.

4. An analysis of the marginal cost base (Section 8) confirms that projects such as Swanbank E would remain uneconomic without the support of direct GEC revenue. In fact, the early years of Swanbank E have seen significant asset value write-downs (source: CS Energy Annual Report 2004, 2005) as pool revenues failed to live up to forward expectations.

5. The dispatch patterns of the gas fired stations in Queensland have tended much more towards baseload dispatch than would otherwise be observed. When the dispatch patterns of two comparable stations are compared, say Laverton and Braemar, we see that the Braemar output is far heavier. There can be no way of truly detecting if the driving influences are fuel contracts, plant constraints or other business influences, but the trend supports an observation consistent with output earning GEC revenues.

3.4 Dispatch patterns influenced by the QGS

This section describes how the contribution of GEC revenue has encouraged gas generators to dispatch in a different way, and displace marginal coal fired generation.

The peculiarities of gas supply contracts and power station dispatch constraints are not known. However, the analysis reveals the observed dispatch behaviour of gas fired power stations against a prevailing pool price.

Suppose that a power station has a fuel supply agreement, with the marginal cost of fuel corresponding to $25/MWh and suppose that the power station has financial contracts for electricity at $40/MWh. Assume that the station is able to sell the GECS that it creates on the spot market for an equivalent of $12/MWh.

Provided that the pool price is higher than $13/MWh (= 25 – 12), the optimal strategy of the station is to dispatch at *full load*. When the pool price falls lower, the optimal behaviour is to purchase electricity from the market to deliver for its contractual obligations. In the absence of GECs, the threshold price is $25/MWh. These costs and contract prices are representative of the actual values [ACIL]. Here we show the large difference in dispatch patterns that would arise under the scenario of with/without GECs. An underlying assumption of the modeling is to neglect the second order effects that the withdrawal of the gas fired stations will feed back to impact on the pool price.

Period	**Dispatch capacity factor *without* GECs (%)**	**Dispatch capacity factor *with* GECs (%)**
Q01-2005	13	94
Q02-2005	22	97
Q03-2005	15	88
Q04-2005	18	92
Q01-2006	17	92
Q02-2006	15	95
Q03-2006	20	99
Q04-2006	19	97
Q01-2007	69	100
Q02-2007	99	100
Q03-2007	93	100
Q04-2007	63	99
Q01-2008	48	97
Q02-2008	70	100
AVERAGE	**41.5%**	**96.4%**

Table 1: Optimal dispatch patterns driven by pool price behaviour for gas fired generator with $25/MWh marginal cost with/without GEC revenues equating to $12/MWh

Of course, there are suitable gas fired machines which are designed for low levels of dispatch, and they operate successfully as peaking machines in the NEM and elsewhere. However, without the benefit of the QGS, there would be no incentive to make long-term investment decisions for gas-fired equipment that is able to generate in a baseload fashion.

The reduction of carbon intensity is really a fundamentally an *energy* issue, not a *peak power* issue. While open cycle gas turbines can accommodate peaking loads and assure system security, they are not able to deliver the day-in, day-out reduction in carbon intensity that is necessary to make any substantive difference to the prevailing carbon footprint.

The QGS has enabled investment in the right sort of plant to deliver a solution for the future. Furthermore, the demand for baseload gas supplies has been fundamental to the expansion of the gas producers (directly in line with the QGS objectives and the State's strategy). The cost subsidy has created the gas demand, and the gas demand has created the incentive for infrastructure development. Continuation of the QGS will provide business with the required certainty to see out the execution of those long term investments.

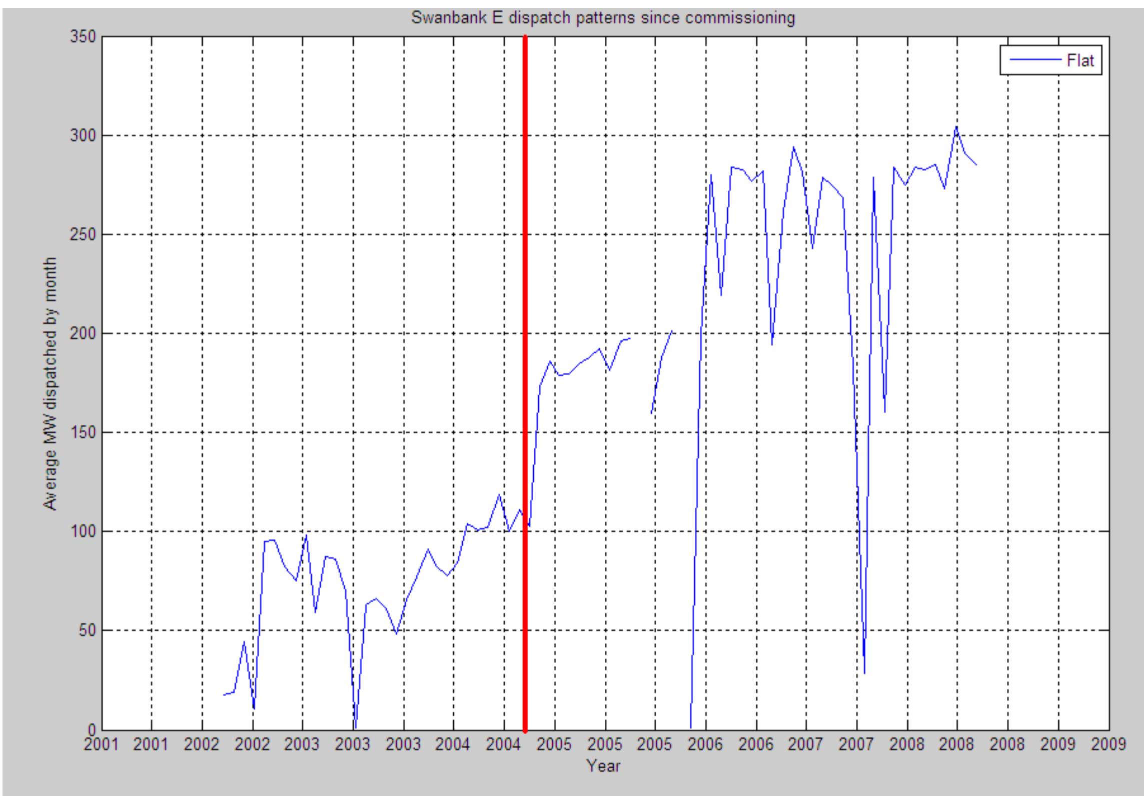


Figure 2: Swanbank E: distinct change in dispatch behaviour upon commencement of the QGS

A good illustration is presented by the figure below for Townsville Power Station (Yabulu). It demonstrates that the station's historical capacity factor is consistent with a price-based dispatch associated with a cost base of $31.20/MWh less a subsidy for

GECs (here nominally $12/GEC). If the station was dispatched against a cost of $31.20/MWh, the capacity factor is seen to be significantly lower.

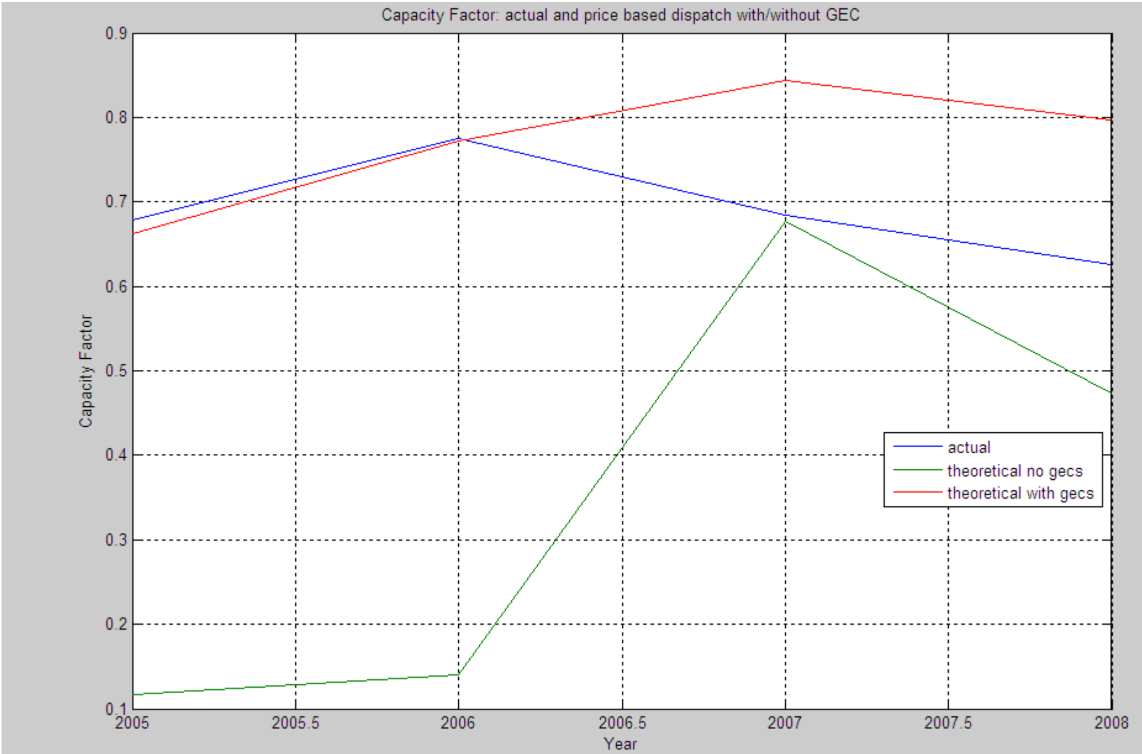


Figure 3: Comparative capacity factors for Townsville Power Station (Yabulu) in annual resolution over 2005 - 2008. Actual dispatch, theoretical dispatch against GEC subsidised cost and dispatch against full SRMC with no GEC subsidy.

3.5 Dispatch Patterns of Queensland Gas Generators

For a representative plant, we take a Braemar unit (BRAEMAR1). The Braemar station is manufactured from a class of open cycle gas turbines which is typically used to accommodate intermediate and peaking loads. The ACIL estimates [ACIL] put the short-run marginal cost at around $33/MWh.

The scatter plot in the figure below demonstrates that the Braemar unit generates significant quantities and prices well below the $33/MWh threshold.

In fact, there appears a distinct threshold at around $17/MWh: above this price, generation is enabled, but below the generation is toned down.

Not coincidentally, under an assumption of GEC prices at around $15/MWh (the price cap), the GEC subsidized cost becomes $33 – 15 = $18/MWh, consistent with the observed threshold.

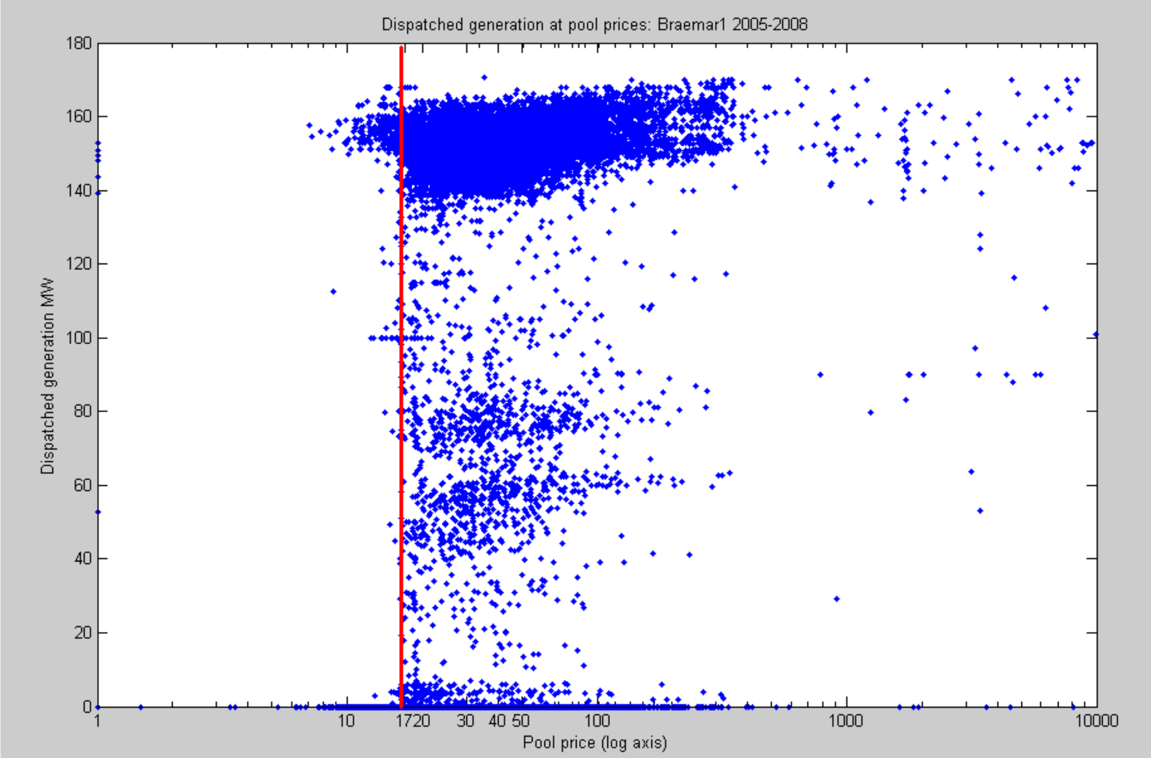


Figure 4: Scatter gram of dispatch for Braemar 1 against prevailing pool price in half-hourly resolution, 2005-2008

While there may be other influences in play, the empirical arguments present an unequivocal case that the dispatch of the gas fired stations has been much harder than would be the case without GECs.

In fact, undertaking an experiment where we assume *NO* GEC subsidy, we can calculate the dispatch of the Braemar 1 station based on a cost threshold of $33/MWh (no GEC subsidy to the SRMC). The change in the capacity factor is stark.

We can assume that the withdrawn generation would instead be supplied by carbon intense stations such as Swanbank B (1.05 tCO2/MWh), because the intermediate stations are those which retain spare capacity to substitute for the gas units. The carbon savings are large. The following table quantifies the benefits under the mid-range assumption of a carbon cost of $20/tCO2 [ER]

Station	Year	Actual capacity factor (%)	Capacity factor *without* GECS (%)	Annual Carbon Saving tCO2	Annual Carbon Expense Saving $
BRAEMAR	2005	NA	NA	NA	NA
BRAEMAR	2006	14.2	1.6	269,391	5,387,813
BRAEMAR	2007	44.9	51.7	-145,385	-2,907,709
BRAEMAR	2008	43.6	28.5	322,841	6,456,823
BRAEMAR	**AVERAGE**	**34.2**	**27.3**	**148,949**	**2,978,976**
SWANBANK E	2005	51.3	12.8	824,045	16,480,897
SWANBANK E	2006	59.9	13.8	986,713	19,734,269
SWANBANK E	2007	65.7	64.4	27,825	556,498
SWANBANK E	2008	78.8	52.8	556,498	11,129,956
SWANBANK E	**AVERAGE**	**63.9**	**36.0**	**598,770**	**11,975,405**
YABULU	2005	67.9	11.7	815,583	16,311,665
YABULU	2006	77.5	14.0	920,904	18,418,080
YABULU	2007	68.4	67.6	11,025	220,506
YABULU	2008	62.6	47.3	221,957	4,439,140
YABULU	**AVERAGE**	**69.1**	**35.2**	**492,367**	**9,847,348**

Table 2: Cost of displacing new gas power stations with high carbon alternatives. Anomalous negative outcome attributed to a model which does not incorporate the fuel, business and contractual constraints which may limit dispatch below optimal.

In other words, for the three major stations listed here, the GEC revenue is directly responsible for behaviour which provides an annual carbon reduction of 1.24M tCO2. This would be valued at around $25M per annum under a $20/tCO2 carbon scenario. There are more Queensland gas fired stations which earn GECs whose results have not been listed here, including Mica Creek and Oakey.

It cannot be denied that the Carbon saving comes at a cost to the consumer who ultimately bears the cost of purchasing GECs to acquit liabilities. However, the calculation in Table 2 calculates the *marginal* behaviour with and without the QGS. If the scheme was not in existence to begin with, then it is much more likely that the plant expansion program would have followed the conventional coal-fired trend laid down by Callide C, Millmerran, Tarong North and Kogan Creek.

In absolute terms, the three gas stations above contribute an annual carbon reduction of around 3.1M tCO2 compared to an alternative where the generation is offered by a Swanbank B style of generator. At the notional carbon cost of $20/tCO2, this equates to $62M per annum which more than offsets the cost of GECs to consumers.

Without the QGS, these stations would not have been built, and the carbon savings would not have been made.

The QGS should continue (i) to honour the commitments made which underlie the investment decisions which have enabled the industry development and carbon savings and (ii) to continue to provide the economic incentive which promotes behaviour to displace marginal carbon intensive generation.

4 QGS Objective to underwrite the emerging gas industry

4.1 Introduction

The QLD Gas Scheme policy has been in the public domain since prior to the scheme's commencement in 2005. The policy objective has always been to underwrite the development of the domestic gas sector and associated infrastructure in QLD, in an analogous way to supporting an emerging industry like the renewable energy sector. Therefore the QLD Gas Scheme is much more like the MRET scheme, which is to be continued, rather than the GGAC scheme which will also be terminated.

> **"The 13% Gas Scheme has delivered well over $1 billion of investment into Queensland's coal seam gas industry"**
>
> Geoff Wilson, Queensland Minister for Mines and Energy, 13 September 2007, [CSM2007]

4.2 Growth in gas business capitalization

The following graph indicates the growth in market capitalization of the major participants in the Queensland gas industry. The small gas-focused entities have achieved compounding growth of around 260% per annum.

The graph must be plotted on a logarithmic scale to capture the immense growth in the company capitalizations. The linear trend on the logarithmic scales corresponds with exponential growth.

The growth in these businesses directly contributes to the economic prosperity of the nation as the industry has expanded to become an export sector.

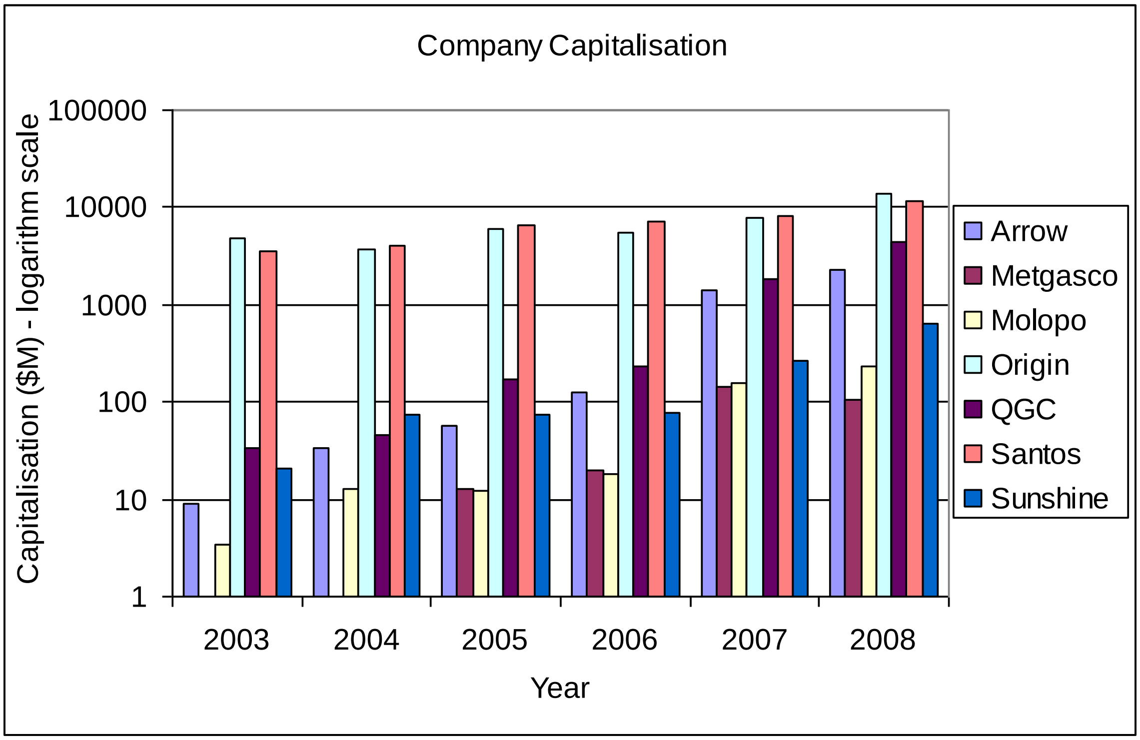


Figure 5: Growth in company capitalisation for Queensland gas producers

4.3 Delivery of Infrastructure

The new Rudd Federal administration has made central to its government's policy the objective to enhance the nation's infrastructure and remove bottlenecks.

For several years now the QGS initiative has been doing exactly that and continued support of the QGS by the Federal government is consistent with achieving the Commonwealth's stated infrastructure goals. From the very beginning, the QGS has a stated aim:

The Queensland Government's own media releases confirm: "coal seam gas projects have yielded around $1 billion worth of development across the state. We expect this investment to continue at more than $160 million a year and this means local jobs and a further boost to our regional economy." [AB2007]

The scheme has successfully diverted a small portion of public wealth to spur investment in a sector which has grown to provide huge private wealth and in turn, to guarantee the public prosperity and produce long-term savings in energy and carbon costs.

4.4 Success at growing the Queensland gas sector

This section confirms the success of the QGS at seeding the Queensland gas industry and delivering the pipelines and necessary infrastructure to allow the market to grow and mature.

It was not long ago that Queensland was contemplating becoming an energy *importer* with the PNG pipeline under serious consideration. With the injection of seed funding through the QGS, exploration and innovation in the Coal Seam Methane has seen the polar opposite occur. The East coast will become a major LNG exporter, and the state is fortunate to inherit the infrastructure that will come along with the project.

The realisation of the gradual decline of the Cooper Basin reserves in the late 1990's and the potential for an east coast gas shortfall resulted in a number of alternative strategies being pursued by various gas companies. The main two were:

- The exploration and development of the relatively new technique of extracting gas from coal seams inaccessible by mining due to their depth (CSG).
- The development of the PNG gas fields and construction of a gas pipeline to Australia from PNG.

Being such a huge project, the PNG pipeline took some years to come to a planning and feasibility stage. In the meantime those backing the CSG alternative worked hard to prove the technique and commercialise it. Once the technique had been pioneered successfully, a proliferation of new players entered the gas industry. The volumes of gas that were discovered and certified, together with the commencement of the commercialisation of some of these reserves were enough to scuttle the PNG pipeline project.

As a result of this 'race' to certify reserves and commercialise the CSG, Figure 6 illustrates the amount of reserves discovered in Queensland has grown exponentially.

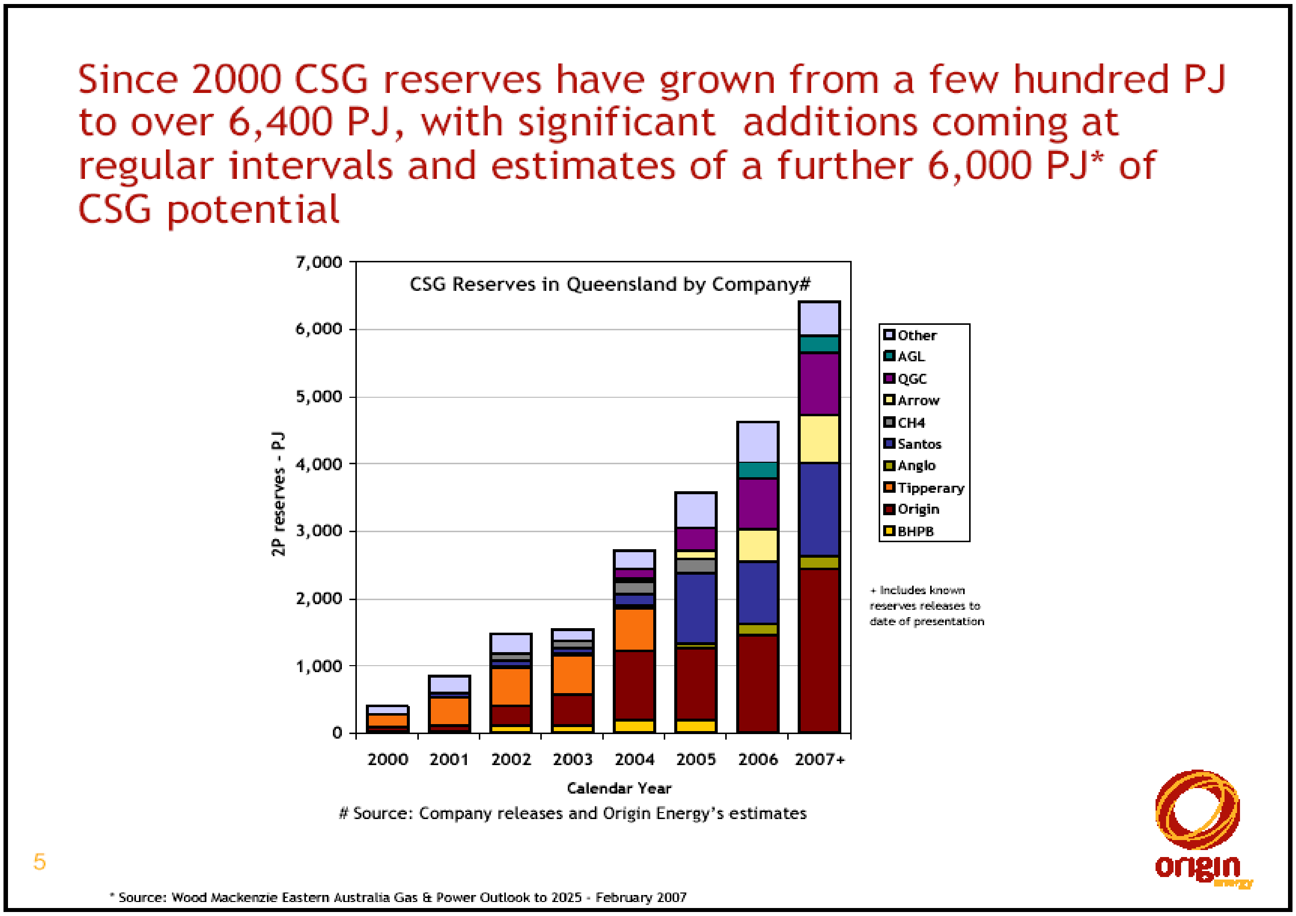


Figure 6: Growth of reserves in Queensland. Source: Origin Energy presentation entitled "Stepping on the Gas" to JP Morgan's Coal Seam Methane Corporate Access Day on 8 October 2007.

4.5 Existing infrastructure

The capacity of pipelines such as the Roma to Brisbane Pipeline (RBP) and the Queensland Gas Pipeline (QGP) are currently close to being fully utilized.

Following its capacity upgrade in 2001, the RBP now has a capacity of approximately 55 PJ/a (200 TJ/day). There is no available capacity on the RBP, and to date there has been no commitment by APT to upgrade the pipeline in the short term. They have flagged that if extra compression is to be added, the extra capacity is likely to be limited to 20 – 60 TJ/day.

The QGP has available capacity of just 1 PJ/a (2-3 TJ/day). Alinta are in the process of increasing the pipeline capacity from 27 PJ/a to 49 PJ/a which is due to be completed by early 2010. This expansion has been underwritten by an agreement with Origin Energy to transport 24 PJ/a for 21 years from 2010. This agreement is to support the gas supply agreement that Origin have with Rio Tinto Aluminium to supply 22.8 PJ/a for 20 years to Gladstone to support the expansion of the Yarwun Alumina Refinery from March 2010.

The lack of capacity on these pipelines is having a restrictive effect on some producer's ability to contract with some parties as there is no means to deliver the gas. Those with pipeline capacity have a position of power when it comes to the negotiation table.

The lack of capacity on these pipelines has lead and continues to lead to private pipeline investment.

4.6 Growth in pipeline infrastructure

The cost to use these pipelines, their criticality to producers to ensure an avenue to market and the pipeline owner's reluctance to increase capacity in a timely manner has resulted in some gas producers and electricity generators proposing to and/or building their own pipelines that replicate sections of these existing pipelines. It is impossible to isolate single driving factors for the investment, but it has stemmed from an environment of growing demand, driven initially by the QGS, and with continuing influence and by the increasing supply which is meeting that demand, and seeking new markets also.

Currently the following pipelines have been publicly proposed or commenced:

- QGC propose to build a pipeline from the Condamine Power Station to Wallumbilla. QGC's current fields at Berwyndale South and Argyle Kenya have been connected to each other and to the site of the Condamine PS.
- Origin Energy propose to build a pipeline from Darling Downs Power Station at Braemar to Wallumbilla. This will transport Spring Gully gas from Wallumbilla to its new power station near the Braemar Power Station. This $90m, 200km pipeline will pass by Talinga gas field, another of Origin Energy's CSG fields that is likely to be developed at a later point in time.
- The Moomba to Ballera Gas Pipeline (QSN Link) that Epic Energy (supported by AGL) is building is due to be operational by Jan 09. This will connect the Queensland gas market with the southern markets. The pipeline capacity is designed to be 250 TJ/day (91 PJ/a).
- The South West Queensland Gas Pipeline which is also owned by Epic Energy has historically flowed from west to east to transport conventional gas to Gladstone and Brisbane that was produced by the South West Queensland Producers. However, with the emergence of Queensland's abundance of CSG and demand for it in southern markets, combined with the reduction in gas being produced from the Cooper Basin, this pipeline is being reconfigured to flow from east to west. It is currently being upgraded to cater for increased gas flows from Wallumbilla to Moomba under an arrangement with AGL. The upgrade will involve additional compression at the eastern end of the pipeline and also mid line compression. Epic Energy on 17 December 2007 announced a second stage expansion following the exercise of an option by AGL that will involve installation of a further 2 compressor stations, and is expected to be completed no later than December 2013. This expansion is also fully contracted.
- The Queensland Hunter Gas Pipeline is proposed to transport gas from Wallumbilla to Newcastle and connect to the Newcastle to Sydney pipeline, providing Sydney with a third gas transmission route. It provides a cheaper gas supply to major gas users in Newcastle and a direct route to Newcastle for emerging gas producers in the Gunnedah Basin. The pipeline is due to be completed in the first quarter 2011.

- The Casino (northern NSW) to Swanbank gas pipeline is to be built by Metgasco subject to certification of 540 PJ in the field farmed in by CS Energy. This pipeline is directly attributable to the QGS as a dedicated pipeline to Swanbank to reduce CS Energy's reliance on the RBP, and provide a source of gas g. It is expected to transport at least 27 PJ/a by 2010.
- The proposed Central Queensland Gas Pipeline from Moranbah to Gladstone is likely to be developed by AGL and Arrow, allowing them to market gas in Gladstone from the Moranbah Gas Project, and providing another source of gas to Townsville. This is also likely to be built as part of Arrow's export LNG project which may be supplied from Moranbah.

There is little doubt that the development/upgrade of these pipelines will have a positive effect on the development and commercialization of Queensland's CSG fields, and in some cases allow development to occur sooner than might otherwise have been the case.

4.7 Coordination of Infrastructure

Because of the targeted nature of the QGS, the scheme has been able to pull together a robust and integrated system of infrastructure for the delivery of gas to generators and end-users, and as a consequence for export. There has been massive spending in a system of pipelines, compressors, exploration, wells and CSM production technologies.

In contrast, schemes such as GGAS and MRET have yielded much smaller, piecemeal and uncoordinated solutions. For example, the rewards of MRET have been smeared across independent wind farms and even domestic solar hot water. The GGAS scheme has successfully reduced emissions intensity, but the solution has spanned, variously domestic distribution of fluorescent light bulbs and small ad-hoc enhancements to coal fired power stations across the NEM, which were likely to have occurred anyway.

5 QGS and AETS Policy developed in parallel

5.1 Introduction

The QLD Gas Scheme policy has been developed and implemented in parallel to the Australian carbon policy and an associated AETS which has been undertaking major policy debate and consultation since the early days of the Australian Greenhouse Office in 1999. The impact upon the electricity sector has always revolved around grandfathered permits, compensation and/or the ability to offset costs through rising electricity prices. The European AETS commenced in 2005, the same year as the QLD Gas Scheme, and has always resulted in an increase in electricity prices and improved gross margins for low carbon intensity electricity generation such as gas.

"It's good for the economy and good for the environment. We're serious about tackling climate change and gas holds the key as a transitional fuel source.

"Gas produces half the emissions of coal-fired generation and is a vital way forward while emerging clean coal technologies are being developed.

Geoff Wilson, Queensland Minister for Mines and Energy, 16 April 2008, [FS2008]

5.2 Timeline of GEC and AETS

This section provides a timeline of actions and announcements which show how the QGS was developed in full cognizance of the likely eventuality of an emissions trading scheme.

It also shows the timeline of the introduction of European emissions trading.

"A price on carbon, through a national emissions trading scheme, is necessary to achieve structural change. But the price can be managed by setting targets that reflect short and long-term emission reduction opportunities. "

"In Queensland, we can all be part of the solution. "

Geoff Wilson, Queensland Minister for Mines and Energy, 27 February 2008, [AC2008]

5.3 Expansion of the QGS

Since mid-2007, the State Government has been announcing firm plans to continue the QGS and expand the scheme from a 13% to an 18% target.

In the words of the Queensland Premier in November 2007:

"Our world-leading 13% gas scheme requires retailers and other large electricity users to source at least 13 percent of their electricity from gas-fired generation. Under ClimateSmart 2050, this will increase to 18 percent by 2020." [AB2007]

Such announcements were delivered in the throes of a Federal election campaign where both major parties were vehemently agreeing on the need for an Emissions Trading Scheme to be introduced.

Under such circumstances it becomes clear that a commitment is offered that the QGS is here to stay, irrespective of the eventual form of a National Emissions Trading Scheme. And speeches, announcements and press releases by the Queensland Government have continued to support the driving factors for the QGS: supporting the development of the domestic gas industry at the same time as yielding a diversified energy mix and long-term benefits of carbon reduction.

Some representative statements by the Queensland government are listed below:

- "Gas is going full steam ahead in Queensland and the Bligh Government is backing it all the way. Its success is due in no small part to our 13% gas scheme which requires electricity retailers to source at least 13% of their energy form gas-fired generation. **We're going to increase the gas scheme to 18% by 2020**,"

  [GW2008] *A new e-bulletin and it's a gas*, Queensland Government Media Release, Minister for Mines and Energy The Honourable Geoff Wilson, 30 June, 2008

- "Under ClimateSmart 2050 **we're increasing our gas scheme to 18 per cent** by 2020," he said.

  [FS2008] *Full steam ahead for Queensland's gas industry*, Queensland Government Media Release, Minister for Mines and Energy The Honourable Geoff Wilson, 16 April 2008

- "The coal seam gas industry owes, in part, its beginnings to the Beattie Government's original 13% gas policy requirement. Our **raising that to 18%** has played a part in boosting investor confidence, which has lead to increased exploration efforts resulting in an announcement like today's"

  [AB2008] BLIGH WELCOMES $8 BILLION GAS INVESTMENT, Queensland Government Media Release, Premier The Honourable Anna Bligh, 3 February 2008

- “As part of *Climate Smart 2050,* we will increase the 13% Gas Scheme to 18 per cent by 2020.

  “This initiative is a key plank in our strategy to reduce carbon dioxide emissions.

  “Generating electricity using gas produces up to 50 per cent fewer emissions than conventional coal-fired generation, and gas gives Queensland the transitional step to lower emissions while clean coal technologies are being developed.”

  Geoff Wilson, Queensland Minister for Mines and Energy, 17 September 2007 [CSM2007]

- “As part of *Climate Smart 2050,* **we will increase the 13% Gas Scheme to 18 per cent** by 2020.

  [CSM2007] *Coal seam methane for a cleaner energy future*, Queensland Government Media Release, Minister for Mines and Energy The Honourable Geoff Wilson, 13 September 2007

6 Investment growth based on expectations of QGS and ETS in parallel

6.1 Introduction

Even since its initial drafting, the QLD Gas Scheme policy has been consistent in duration, and in fact grown in scale quite recently. Throughout the period in which it has been developed, it was always apparent an AETS would eventually exist in Australia and an increase in electricity price would arise (as experienced in Europe from 2005 onwards).

As a result all QLD gas fired generation investment decisions to date have been made on the expectation that the revenue generated from the sale of GEC and the improved gross margins in electricity prices as a result of an AETS impact upon electricity prices would exist in parallel and jointly contribute to underwriting the feasibility of gas fired generation as base load and intermediary sources of electricity supply. Without these dual benefits the existing and future gas fired projects cannot be assured.

Goal 3 Environment

"Reduce carbon emissions intensity of the electricity generation portfolio"

DME Strategic Plan 2008-2012, Queensland Department of Mines and Energy, [DME2008]

6.2 Gas Plant Operations with Multiple Schemes

The prevailing environmental schemes operating in Australia are all structured on baseline and credit models in contrast to the AETS which is proposed as a cap and trade approach.

A point of commonality amongst (i) the MRET scheme, (ii) GGAS and (iii) the QGS is that generators with particular attributes are able to create additional wealth by behaving in a particular manner. In each case, the end-user community is mandated to achieve certain targets which deliver the various objectives being respectively (i) grow the renewable energy sector, (ii) seek the minimum cost reduction of NSW greenhouse intensity and (iii) grow the Queensland gas sector.

An economy of certificates has been instigated, where accredited generators are able to produce and trade certificates, while all consumers acquire certificates through trade to acquit their liabilities.

Key to the observation is that the existing schemes are focused to provide financial assistance for *targeted* activities, but the cost is shared pro rata across all users.

In contrast, the proposed AETS does not directly contribute extra revenue to the generators, but imposes *differential costs* on all generators. The economic benefits to be achieved by categories (i), (ii) and (iii) will then arise by holding assets with less cost impositions than competitors.

The MRET, GGAS and QGS have been formulated with clauses that, in general, prevent double dipping. A gas generator in Queensland then has a distinct choice: to claim generation to create NGAC or GEC certificates and earn the associated revenues. There are participants who have operated validly under both schemes, for instance, generators on landfill gas which prevent CH4 emissions earn NGAC, while simultaneously using the fuel to generate electricity to earn RECs.

Conversely, the AETS is a universal cost imposed on all emitters of carbon, with the intent to sheet home the cost to all consumers. Consequently, it becomes infeasible to prevent operators from operating under both regimes.

The GGAS has a fundamental goal to use market mechanisms to achieve reductions in carbon intensity, from whatever technologies, which is almost identical to the AETS, it makes perfect sense to combine the two schemes, in accordance with recommendations in the Green Paper [CPRS2008].

However under AETS it is anticipated that gas fired generators will interact with both the GECs and AETS schemes in a perfectly valid way. QGS will continue to offer a revenue stream specific to its goals of enhancing the Queensland gas market, and maintaining the State government's commitment to retain that support, while the other will be a cost imposition in a business environment shared by all other generators and industries.

6.3 Benefits of Additional Compensation

If the Commonwealth is serious about the fundamental goal to reduce greenhouse emissions, then there should be no concern with an additional compensation scheme to Queensland generators which only acts to support the goal.

Generators in all of the NEM regions have become accustomed to managing their business and optimizing performance subject to a range of external influences and government policies. Certain generators face the MRET, NRET and GGAS simultaneously while others are faced with a business decision to claim between GGAS and QGS certificates.

Broad economic arguments have been mounted in the Green paper [CPRS2008] which claim an economic distortion if the various state-based schemes are left in play while the AEST is introduced.

It is clear that the objectives of the AEST and the GGAS scheme are so similar that it becomes incompatible to operate both simultaneously.

But the QGS has been motivated from the desire to enhance the state's gas industry with the consequential benefits of achieving a cleaner generation mix [CSM2007]. This objective remains even if AEST is in place.

The argument *does not apply* that broader Queensland industry is achieving some competitive benefit over industry in other states, because consumers must actually pay *more* for their electricity bill, with an additional cost to cover the acquisition of GECs to cover 13% of the energy consumed. This is naturally offset by Queensland's wealth of low-cost coal which has provided the State with a competitive advantage in the past. Under the AETS the cost base of this industry will rise, and the Queensland government's continued support of the QGS provides a long-term solution (transition to gas) without having to rely only to the Commonwealth government's proposed interventionist schemes such as the Climate Change Action Fund

Private investors are also free to build power stations and generate into Queensland to claim the QGS revenue. Any claims are refuted that investment in other regions are penalized because the context is simply that the benefits are *not* awarded for industry actions in other states which are not associated with the fundamental aim of the QGS: to enhance the Queensland gas industry.

If not for the QGS scheme, the new investment would have been directed to coal or heavier use of existing coal-fired plant. Consequently, the baseline carbon consumption would be higher than the present. Therefore, the QGS scheme has been successful In terms of a goal to reduce the absolute emissions level. The AEST aims to reduce the carbon intensity from the current baseline, but the QGS has achieved a fundamental goal of reducing the absolute emissions. The Green Paper [CPRS2008] accepts the benefits of actions which preemptively reduce carbon emissions in the section on '*Credit for Early Action*' but has only treated the backdating to 2007. The period of community discussion of global carbon reductions predates this date significantly.

The position recommended in the Green Paper is to *not* provide early action credits. This removes the incentive for preemptive investment in low emissions generation technology, which already experiences a long lead time.

12.3 Preferred position

A program for allocating early action credits would not be established.

Green Paper, Chapter 12 [CPRS2008]

In its opening lines, the Green Paper CPRS2008] states that

> "the challenge of adjusting to a lower emissions environment will be broadly shared across the economy."

Queensland is not naturally endowed with readily usable sources of low carbon intensity generation. The State have recognized this, and has proceeded with Carbon-proofing the generation industry by (i) installing supercritical coal-fired generation and by supporting the local gas industry through the QGS.

Without a scheme to support investment and continued dispatch of gas fired generation it will turn out that the Queensland economy experiences a higher component of the carbon burden than other regions.

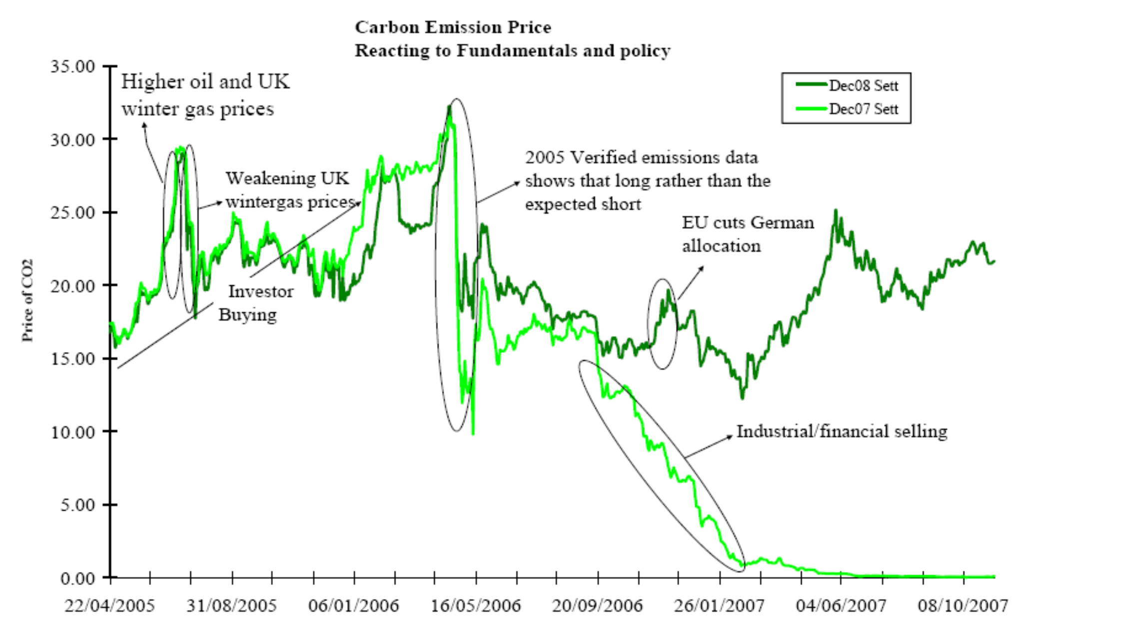
6.4 Competitiveness of Gas Plant under AETS

The Green Paper [CPRS2008] p7] makes a bold claim that

> "For most projects undertaken under either GGAS or the Queensland Gas Scheme, adverse impacts appear unlikely"

The basis for the conclusion is a qualitative argument that gas fired generators enjoy a lower carbon intensity than the average intensity, and therefore the input costs incurred to the business will be lower than the market's average. Presumably the arguments entertained by the authors assume that a high proportion of the full cost of carbon is passed through to the pool price, allowing the gas fired generators to enjoy a gross margin similar to their current profitability (including GEC revenues in the gross margin).

Several elements are raised to disturb the author's arguments. Firstly, the competitive benefit must be crystalised from a prevailing, market-traded carbon price, rather than an initial auction price or allocated value. The traded price of carbon will invariably fluctuate, as all market prices do, and therefore the level of certainty of the competitive advantage is highly diminished. The plots in Figure 17 illustrate the market outcomes of the European Emissions Trading scheme which highlights the strong uncertainty of the AETS certificate prices.



Source: Market Participant

Figure 17: Carbon prices in the European ETS have experienced significant volatility largely due to regulatory and sovereign risk associated with the market.

Conversely, the QGS scheme is attributed with a high degree of certainty, possessing price caps to protect consumers but endowed with a market structure to let the invisible hand of the market guide investors to achieve the scheme's objectives. Investments have been placed with the level of certainty inherent in the QGS, and should not be subject to a severe change in the rules underlying their business decisions.

If the benefits to be achieved by the gas fired generators are to be consistent with the revenues attained by a competitive advantage from cost reductions in permit acquisition, then a high price of carbon will be required. It is unlikely that the Federal government is seeking an extreme Carbon price, as this will be disruptive in a political business sense.

In fact, consider a common gas turbine configuration, with a Carbon intensity of roughly 0.5 tCO_2/MWh, and with an assumed average QUF of 90%, and MLF and DLF combination of 0.95. Assume an average carbon intensity of 0.9 tCO_2/MWh. Assume a prevailing GEC price of $15/GEC. Then revenue from GECs is around $\$15 \times 0.9 \times 0.95 = \$12.83$/MWh. If we, assume that the full carbon cost is passed through to the pool price, then to achieve the same contribution to the gross margin without the QGS the carbon price required must be at least $(\$12.83 / 0.5) / 0.9 = 28.50$ \$/tCO_2. If a smaller percentage of pass through takes place (as has been observed elsewhere), then the break-even carbon cost must be commensurately even higher.

A study on the European experience [SNC2006] shows that the cost pass-through is relatively uncertain. Key to the estimate is whether the carbon target and resultant carbon cost is sufficient to change the fundamental merit order, for example, from coal to gas. When this takes place, the additional benefit of the alternate technology means that the stations do not have to pass through the full carbon cost and the wholesale price of electricity does not rise as high as the average carbon intensity would suggest.

On average, they found that the European pass through was around 70%. Under that scenario, the carbon price in the calculation above would need to rise to $28.50/0.7 = \$40.86$/$tCO_2$ in order for the representative generator to maintain the relative competitive position which is currently achieved through the QGS.

It is proposed that the business disruptions and political fallout from a carbon cost of $41/$tCO_2$ in the initial years of the AETS would be unacceptable. Continuing the QGS is a far less expensive and less disruptive solution to maintain the commitments to businesses who have made investments based on QGS.

7 Lower carbon intensity and therefore carbon cost

7.1 Introduction

The QLD Gas Scheme has already directly contributed to lowering the carbon intensity associated with QLD electricity. This will mean the price impact of carbon on electricity consumed in Queensland will be less than in other states providing the consumer with an offset against the cost of the QGS.

> **"We're serious about tackling climate change and we see gas as a vital way forward to a cleaner energy future"**
>
> Geoff Wilson, Queensland Minister for Mines and Energy, 30 June 2008, [GW2008]

7.2 Carbon Intensity of Queensland

NEMMCO publishes the NEM-wide carbon intensity of the NEM each week as a benchmark index. Although it fluctuates from week to week based on the generation mix, the intensity consistently remains around 1.05 tCO2/MWh. (The value is used as a threshold in the calculations underlying the GGAS program.)

The Carbon intensity of Queensland has traditionally been very high, driven by the prevailing fuel costs and unavailability of other fuel sources. The low hanging fruit of hydro generation was taken up a long time ago with the Kareeya and Baron stations. Gas fired generators were infeasible until very recently because the gas fields were not discovered, the Coal Seam extraction processes were not technologically possible and the distribution networks were not constructed to deliver gas to suitable generation sites.

With the support of the QGS, all of that has changed as the technology, infrastructure and economic incentive has arisen to support generation sources to reduce the overall carbon footprint of the State and contributing to a reduction in carbon intensity of the NEM.

The following calculations reveal the extent of the reduction in carbon intensity. At a notional price of carbon, the dollar value of carbon savings can also be calculated.

The calculations repeat and expand on the conclusions drawn in sections 3.4 and 3.5.

The QGS has spurred the investment to install new gas fired plant. Under the assumption that all of the new gas investment has been driven by the GEC scheme, the carbon savings can all be attributed to the QGS.

Based on 13% of the (non-exempted) state load, and calculated off a prevailing GEC price at around $13/GEC, the total annual cost to consumers for the GEC program is around $62M out of a total energy cost around $2.1B (approximately 3% contribution to the cost).

The carbon savings are significant. If the alternative dispatch which would have filled the gap was based on a combination of existing generating plant (carbon intensity 1.0 tCO2/MWh) and new supercritical generators (0.86 tCO2/MWh). The replacement plant is a mixture of open cycle and closed cycle gas turbines with a volume weighted carbon intensity of around 0.42tCO2/MWh.

When consumers comply with the GEC liabilities in a given year, the gas generators will have produced around 5.6M MWh of generation, with a carbon footprint of 2.3M tCO2. The alternative of generating without the gas sources would have produced 5.3M tCO2 of emissions. The savings of 3.0M tCO2 corresponds with a 6% abatement in the State's total emissions levels, and at $20/tCO2 means a reduction in the carbon 'bill' by around $60M.

This saving will continue every year into the future.

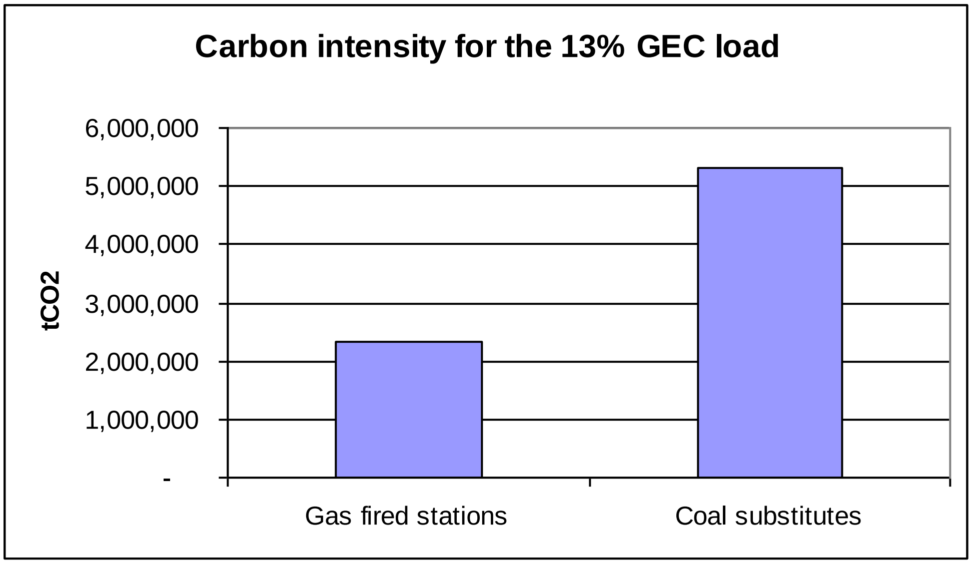


Figure 7: Carbon intensity of the actual generation and coal substitutes which may have eventuated without QGS stimulus

Coincidentally, the cost to consumers of the scheme at the GEC prices that we have observed in the market over recent times closely corresponds to this amount at around $69M. In other words, once Carbon trading is instituted, the QGS scheme yields an almost neutral mechanism to provide for carbon abatement.

But the benefits have been far larger, delivering to the nation infrastructure and technology to enable a faster and more intense transition to low carbon generation. Governments must recognize the large private investments that have underpinned the infrastructure, with current expenses that are reliant on cashflows into the future derived from GEC revenues. Those business plans are reliant upon continuation of the QGS.

8 Gas Fired Generation Marginal without QGS

8.1 Introduction

At current electricity spot prices and under the electricity forward prices within the AETS period, it can be calculated that the Long Run Marginal Cost (LRMC) struggles to be remain commercial without the benefit of revenue earned from the sale of GEC's. The expected upward pressure on domestic gas prices, capital costs and operating expenses are likely to see a dramatic reduction in gas fired generation investment without a continuation of the QGS. Alternatively, electricity prices will rise far beyond the current cost of the QGS to the QLD consumer.

8.2 Gas costs and channels to market

Recent times have seen dramatic rises in the cost of fossil fuels with export prices for thermal coal doubling and domestic gas prices also rising. Fortunately, most of Queensland's coal fired generators operate on coal of average quality which is not necessarily viable for export, and producers have typically agreed to long-term supply contracts.

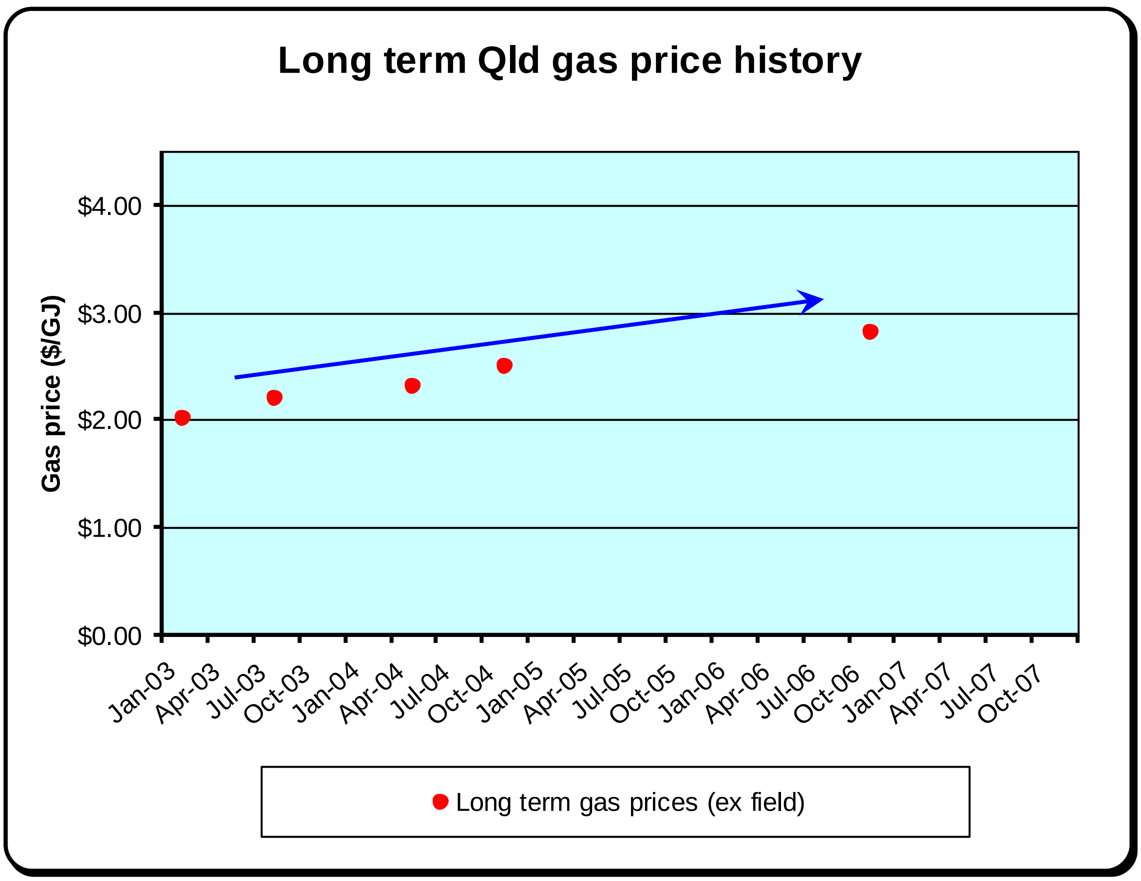


Figure 8: Inferred Queensland domestic gas prices

The recent activity to develop an export facility for LNG means that domestic gas producers in Queensland will attain an alternative channel to market for their product.

With the gas price tied to an international cost of energy, either the local prices will escalate dramatically, or producers will find far more profitable opportunities available in an exporting strategy.

Unlike coal, natural gas is a much more fungible quantity and it is not naturally distinguished into 'domestic' and 'export' qualities.

While this progression is a fantastic opportunity for Queensland gas producers, it will introduce price pressures for local gas consumers, and bodes poorly for the carbon intensity of local electricity production. If LNG export opportunities mean that gas-fired generation is reduced from the mix of available fuel sources, Australia will become more dependent on the far more expensive residual technologies to achieve emissions targets.

In essence, the QGS scheme provides a countermeasure for what is becoming an internationally trade exposed commodity. It will provide a subsidy for large infrastructure expenses to provide an incentive for gas producers to dispatch product and generate locally, rather than export gas.

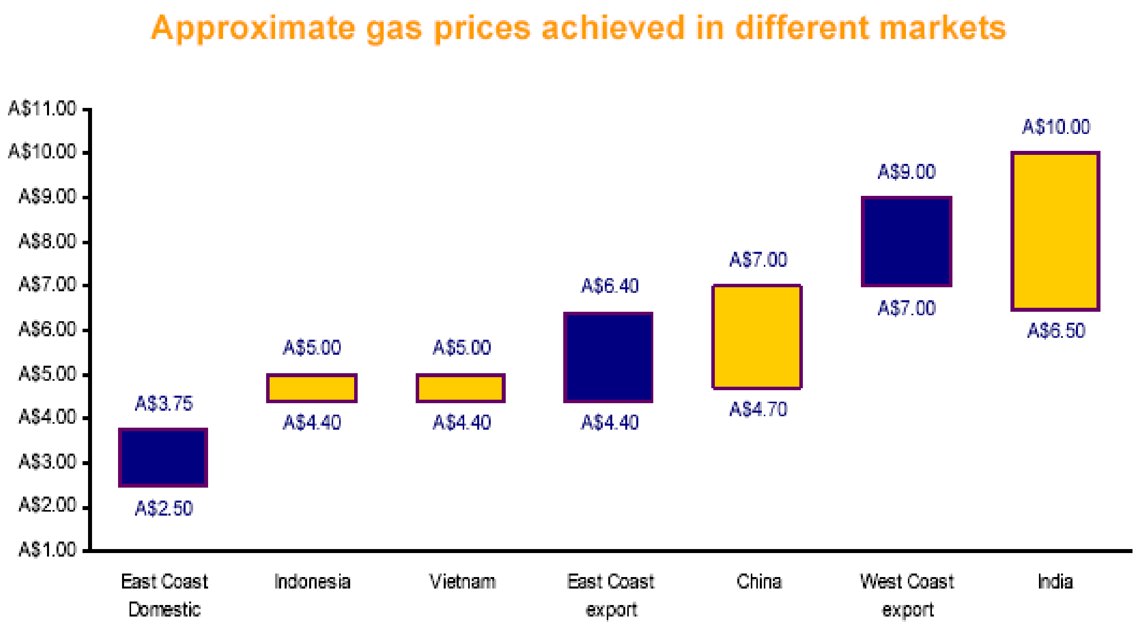


Figure 9: Comparison of international price of energy (gas). . Prices are $A/MCF converted at US$0.85/A$1.00 (1 MCF (million cubic feet) = 1.091 GJ). Source: Arrow Energy Investor Presentation, October 2007

A theoretical argument can be mounted that a volume of gas may be withheld from the domestic generation market due to high export prices. Consequently, the carbon intensity of generation on the NEM will rise as the only short-term energy substitute is coal-fired generation, and subsequently the cost of carbon may be driven higher to meet the Australian emissions targets. The theoretical argument then posits that economic pressures will draw *back* gas fired generators into generating electricity domestically with the competitive advantage of lower input costs relative to coal-fired generators.

However, several fundamental flaws arise with this argument:

1. The argument relies upon a very high Carbon price to provide the economic incentive to expand the gas-fired capability of local generation. It is unclear if there are desirable consequences from allowing the carbon price to be pushed to even higher levels than are currently being touted, of at least $20/tCO2. Heavy political and business consequences will arise. Maintaining the QGS scheme provides the insurance to ensure business continuity for local gas generation investment.
2. In the medium term of the AETS, there is likely to be only a moderate 'penalty cap' in place for emissions beyond the targets. Consequently, the price signals will be prevented from delivery to provide incentives for gas to switch from export to local generation. Under the circumstance that the draft AETS policy is switched from a market-based scheme to a carbon tax, the incentives are again attenuated.
3. A further economic argument can be mounted which states that the installation of gas fired generators will continue, which will be situated to oscillate between the alternative uses of local production (if carbon price signals are sent to warrant the additional generation) or export (if international prices are high). However, the installation of power stations is a capital intensive exercise with a significant lead time. A generating unit is intended as a long-term investment, not for short-term deficiencies. And gas contracts are typically structured to ensure continuing supply, even to a LNG export facility, because there is limited intermediate storage, and further gas storage facilities are extremely expensive.

Other countries also desire to curb their domestic emissions, and gas fired electricity is viewed universally as the most promising solution for transition to a carbon constrained world. It would not be successful government policy to be seen to be assisting the international community to meet their targets, but not being able to meet our own because the low-intensity domestic fuel is exported.

Once export facilities are in place, and once the capability to export is shared amongst local gas producers, there is very little friction preventing the domestic gas price from being strongly tied to the international price.

Western Australia has experienced exactly this scenario. In WA, where LNG is now exported, local prices have risen. (Refer graph below). This has been due partly to the opening up of gas pricing to international pricing through LNG, as well as certain pipeline constraints restricting the supply of gas.

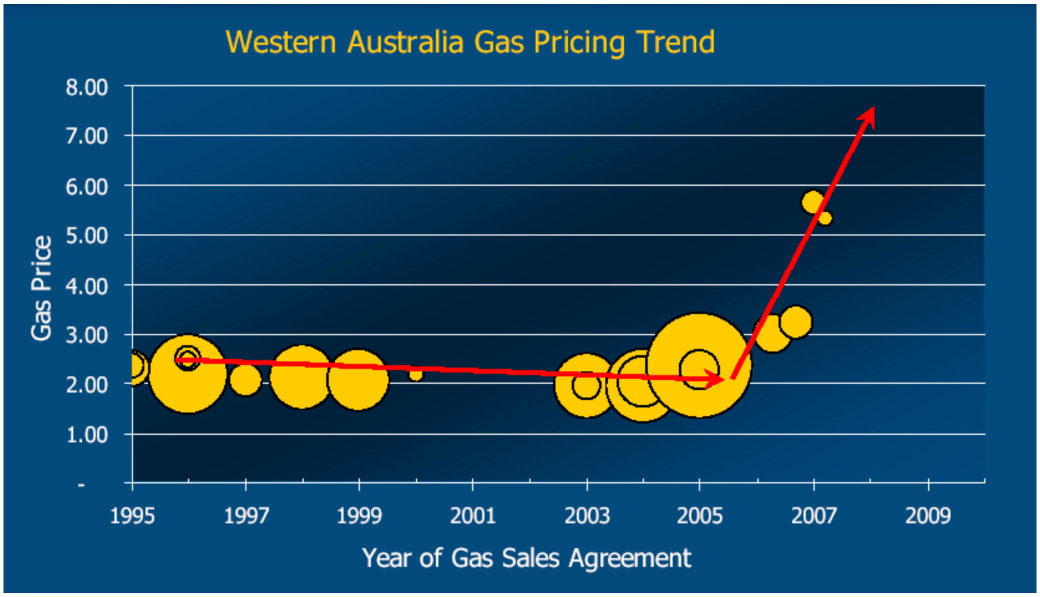


Figure 10: Western Australia Gas Prices lifted with the commencement of LNG export. Source: Santos presentation entitled "Value in the Energy Sector" to UBS Resources Conference, 27 June 2007

8.3 Erosion of Competitive Advantage

The Federal government has announced that the transition to the Carbon constrained world of the future will be eased by the introduction of the Climate Change Action Fund. Media releases state that the government proposes "direct assistance to existing coal-fired electricity generators" [WMR2008].

The form of the assistance has been announced to be a combination of allocation of free permits, and direct compensation.

Investments to date in gas fired electricity generation in Queensland have been based on the assumption of continuation of the QGS. Long term business decisions have factored in an assumption of GEC revenues associated with new gas plant. While the price of GECs may fluctuate, some business deals have been able to prove viability and achieve financial close by selling forward the production of GECs at a fixed price.

Conversely, no such market presently exists for AETS, and it may be some time before the market fully appreciates the supply and demand balance and the consequences of the full market structures. The resetting nature of the AETS (the targets are reset from time to time which changes the underlying supply/demand balance and market price expectations) also contrasts with the long-term stability in the structure of the QGS scheme (to 2020).

If financial assistance is offered to coal-fired stations, then it will enable them to dispatch to the market at a reduced price, knowing that the lost profitability will be subsidized by the offsetting compensation. On the other hand, the revenue from gas fired generators may not achieve the same compensation levels. The direct result is an erosion of the competitive benefit offered by gas fired generation. If the QGS is removed, gas fired generators will be exposed to competing against subsidized coal fired stations, and the incentive for investment and for plant dispatch to reduce carbon costs will have been pulled away.

The overall consequence of removing the QGS is an erosion of the competitive advantage of low-carbon generation which results in continuing reliance on coal fired generators, continued high dispatch from coal, removal of incentives to generate with gas and increased uncertainty in the market for investment in gas fired generation.

8.4 Comparison of SRMC and LRMC with Cost and Revenues

This section expands on the calculations provided in section 3.4 and 3.5 which analyse the short run marginal cost of a gas fired generator in the environment of QGS and AEST.

This section provides information from public sources on the competitiveness of gas fired generators incorporating the cost and revenue elements from AETS and GECs. The analysis confirms that the investment decision of installing new baseload gas fired generation remains marginal without either (i) prohibitively high pool prices, or (ii) a very large Carbon cost or (iii) the moderate compensation delivered through a direct incentive scheme such as the QGS.

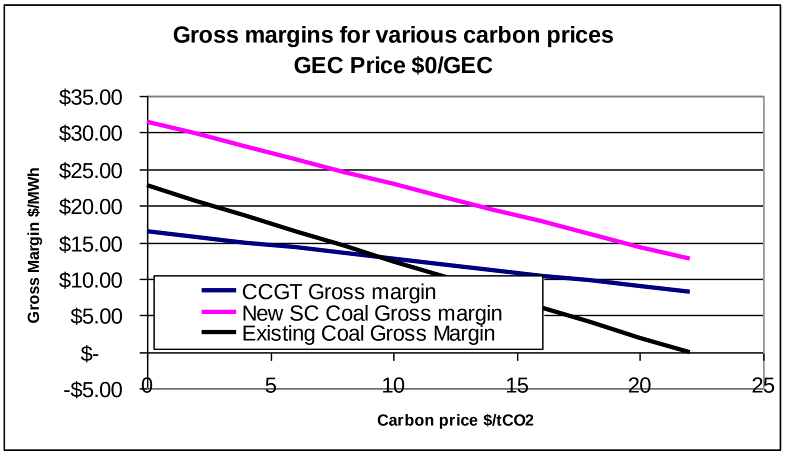
Our analysis makes a comparison between:

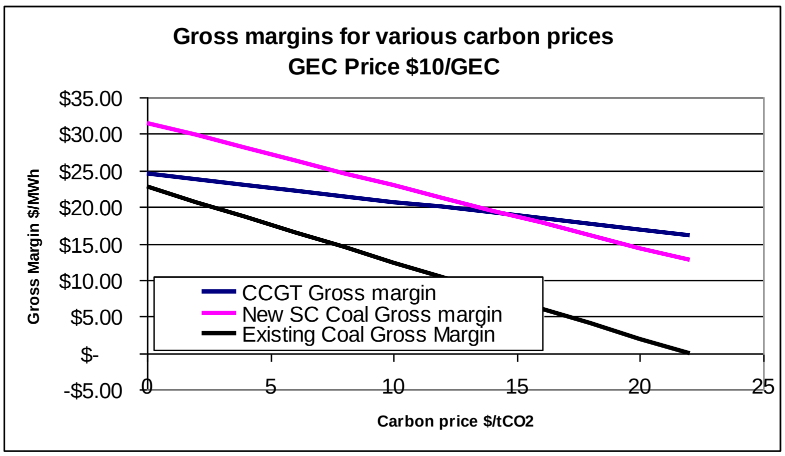
1. Investment in a new CCGT power station;
2. Investment in a new coal-fired power station;
3. Marginal increases in dispatch of an existing coal-fired power station with moderate carbon intensity

The time scales are divided into the short run (dispatch decisions based on SRMC) and long run (decision whether or not to invest).

The short-run decision assumes that the plant is built and is a sunk cost. The choice to generate or not then depends upon whether the resultant gross margin is positive or not. In order to foster a market environment which encourages low carbon output, emissions targets should be set to yield a price of carbon which provides an adequate price advantage of gas or renewable generation over dirty coal plant.

Using the standard assumptions from the ACIL report [ACIL], the following chart indicates the breakeven price for carbon where it becomes more economic to switch from coal to gas dispatch in a scenario where the pool price is $40/MWh and the GEC price is variously $0/MWh, $8/MWh and $10/MWh equivalents (approximately $0/GEC, $9.60/GEC and $12/GEC respectively, taking into account MLF, DLF, QUF).





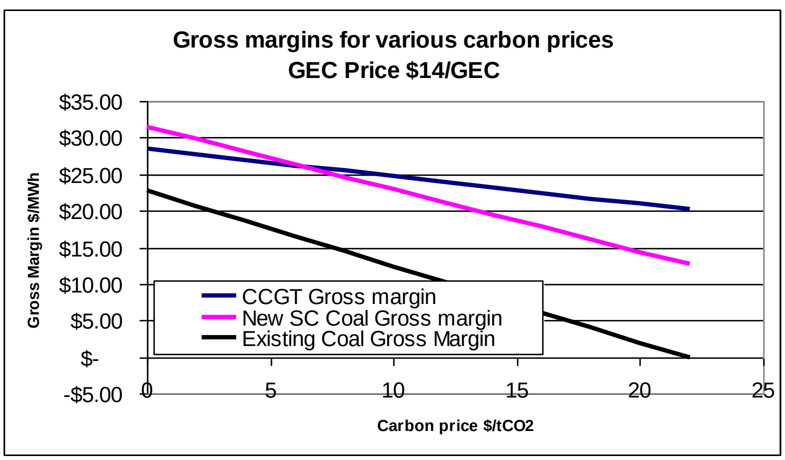


Figure 11: Gross margin from generation with pool price of $40/MWh deciding between CCGT and supercritical and existing coal station dispatch.

Figure 11 illustrates that GEC revenue is required to maintain competitiveness of CCGT dispatch, even under a world with carbon costings. With no GECS, to make the CCGT competitive requires a carbon price of around $31/tCO2. In the case of an Open Cycle gas power station, this level rises much higher to over $40/tCO2.

Under a moderate scenario of GECs priced at $10 per certificate, and a Carbon price at $14/tCO2, the CCGT becomes marginal. It is important to note that this must take place in a commercial environment where the coal-fired generators do not receive subsidies or compensation that might promote their dispatch. The Action Fund described in the Green Paper [CPRS2008] makes it clear that the stationary energy industry is likely to receive some degree of compensation, which will act to push the carbon threshold even higher.

If the export environment begins to link the local gas price with the international price of energy, then the high gas prices suggested in Figure 9 will be felt by the local market.

If we entertain a scenario of gas reaching $5/GJ, which is at the low end of all of the trading parties, then the figure is revised to **Error! Reference source not found.**. The impact of escalating gas costs are already being felt as retailers such as Country Energy have argued (and IPART agreed) for passing through annual increases in the retail cost of gas of 12% based upon increased wholesale costs [IPART2008].

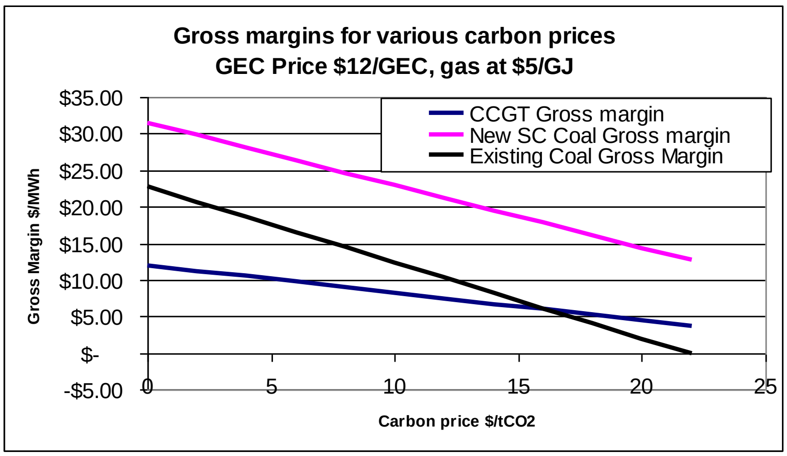


Figure 12: Gross margin from generation with pool price of $40/MWh deciding between investment in CCGT enduring $5/GJ gas price or supercritical or harder dispatch from existing coal station.

Figure 12 illustrates the large hit to Gross Margin from a high gas price, even with the support of GEC revenue. The erosion of gross margin from a greatly inflated fuel price simply means that the benefit from carbon savings must be commensurately larger to make investment in gas generation assets attractive.

Similar to the earlier analysis we can establish the breakeven carbon price which would be required to make an OCGT or a CCGT plant competitive with a new (supercritical) coal fired station.

With no GECS, to make the CCGT competitive requires a carbon price of around $57.60/tCO2. In the case of an Open Cycle gas power station, this level rises much higher to $88.97/tCO2.

Under a moderate scenario of GECs priced at $10 per certificate, and a Carbon price at $40.82/tCO2, the CCGT becomes marginal, while the OCGT requires carbon at $72.22/tCO2 to become viable over a coal fired unit. Again, it is important to note that this must take place in a commercial environment where the coal-fired generators do not receive subsidies or compensation (that is, no support from the Climate Action Fund) that might promote their dispatch.

The long run cost of the plant is constituted chiefly from recovery of the project's capital costs and the short run cost of operating.

Based on capacity factors of 85%, reference [ACIL], table 98 provides the capital cost recovery under appropriate assumptions of typical plant and cost of capital. In 2008 dollars, they have

CCGT: \$85/kW/year $\times$ 1000 kW/MW / 8760 hours/year / 85% = \$11.41/MWh

Coal: \$143/kW/year $\times$ 1000 kW/MW / 8760 hours/year / 85% = \$19.20/MWh

The high capital costs of new power station are exemplified in **Error! Reference source not found.**. It illustrates that if spare capacity is available at an existing power station, even with a high carbon intensity of 1.05 tCO2/MWh, then the most economically viable alternative is to work that capacity harder rather than install new clean plant.

Without the subsidy of GECs, the threshold price at which an investment decision will switch from the new coal technology to a CCGT is \$15/tCO2. This makes the assumption that sufficient infrastructure is available to supply the gas at the relatively low assumed delivered cost. The assumptions are that CCGT costs \$1070/kW to install and coal \$1700/kW, a requirement to build significant pipeline or transmission can raise the CCGT cost significantly. To date, the GEC revenues have enabled such investments to be made.

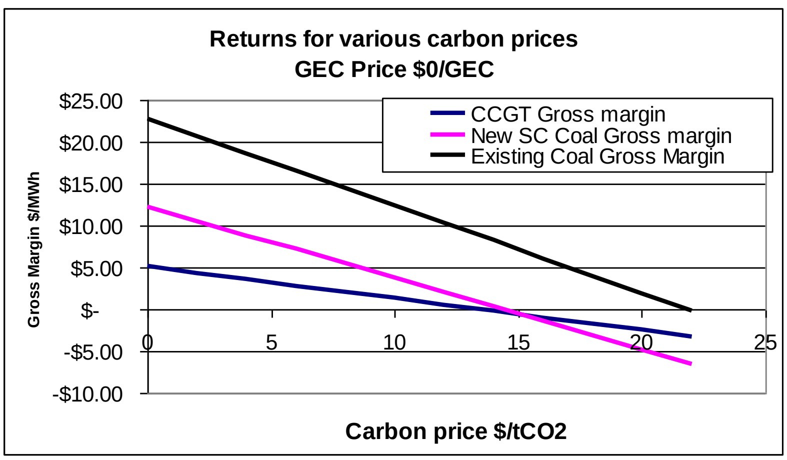


Figure 13: Returns (includes LRMC) from generation with pool price of \$40/MWh deciding between investment in CCGT or supercritical or harder dispatch from existing coal station.

9 Electricity Supply and Demand Issues

9.1 Introduction

Electricity prices will rise dramatically in Queensland if gas fired generation investment does not continue in the region. Demand for electricity is likely to continue to grow strongly in Queensland. However, coal fired generation will not be an acceptable source of further supply in a carbon constrained economy until carbon capture and storage becomes commercial. Therefore between 2010 and 2020 the only viable source of new wholesale electricity supply in Queensland is from gas fired generation. The cost to Queensland's economy and employment rates as a result of higher electricity prices will be far more significant than the impact of the cost of GEC imposed on 13 – 18% of total electricity costs.

Goal 1: Economy

Enhance the efficiency and effectiveness of energy markets. Ensure quality and reliability of energy markets and electricity supply.

DME Strategy Plan 2008-2012 [DME2008]

9.2 Supply and Demand in the NEM

As with all commodity markets the National Electricity Market has experienced periods of under and over supply and the associated price cycles that go with it. The balance in electricity markets represents a special case because:

- the commodity is an essential service that produces considerable social and industrial stresses if not supplied
- there are limited commercial means to store the commodity to act as a buffer into future periods or to carry excess product into the future.

According to NEMMCO's Statement of Opportunities, Queensland is experiencing ongoing demand growth approaching 4% per annum, at over 200 MW in average load and over 300 MW in peak load. This is equivalent to a typical sized CCGT every year. Other regions of the NEM are also experiencing growth, but at a more moderate rate.

A period of oversupply was experienced in NSW in the early 1990s with the state's construction of a large number of baseload coal stations. The operating regime still sees some of these stations passing through rotation cycles.

A period of undersupply in Victoria has been experienced in recent summers as NEMMCO has announced reserve shortfalls and the forecast that the supply stack would be unable to meet demand upon a credible occurrence of peak summer demand.

Going forward, demand growth in all regions of the NEM and especially Queensland will mean that additional stations must be built, even with demand saving programs in place. Those new stations must necessarily come from a lower carbon source as the impacts of carbon constraints begin to bite. Not only must the new energy supplies be lower intensity than existing, they must be so much lower that they displace the existing carbon-intense stations and bring down the total carbon emissions in an environment of growing total demand.

Several analysts have put this goal as almost out of reach, even with immense social and business efforts. The technologies to produce such large reductions are only in embryonic stages: geo-sequestration and centralized renewable supply on a massive scale. Our only chance is to ensure the uptake of transitional technologies as soon as possible.

The arguments justified in Figure 11 confirm that incumbent stations are able to produce power at a low marginal cost because the sunk cost from the plant is a fixed cost not relevant in the marginal dispatch considerations. Consequently, for gas fired plant to become viable, the returns must be sufficient to ensure that they make a living themselves, but also to be sufficiently strong to 'muscle out' existing generators.

The QGS provides the economic incentive to make the change to the transitional technology and provides sufficient stimulus to support the new investment against incumbents.

If uncertainty continues and investment is allowed to stall from the conclusion of the QGS, the same situations may arise as Victoria and NSW have experienced. Victoria has suffered warnings from NEMMCO that "the lights might go out" in peak demand periods. NSW has suffered from a lack of new investment and has been relegated to a net importer with a base of old generation assets that pose a large risk to their owners with high carbon intensity and maintenance issues typical of old assets.

As a net importer, the NSW pool price is higher than its Queensland neighbour, and the costs to business are commensurately higher. By ensuring continuation of the QGS, the assured GEC revenues stimulate the investment and supports continuing dispatch of gas generation. The small cost shared by all of the community ensures upgrades to new technology of generation plant and assists in Carbon-proofing the generation industry. The cost to Queensland's economy and employment rates as a result of higher electricity prices would be far more significant than the impact of the capped cost of GECs imposed on 13 – 18% of total electricity costs. Shocks to the Queensland pool prices during 2007 spurred by the withdrawal of capacity due to drought conditions have shown how a relatively small deficiency in supply translates to large increases in the pool price of electricity and the resulting increased cost to business and the economy.

9.3 Water saving incentives

In comparison to coal fired stations, gas generating units possess a far lower intensity of *water* consumption. The cooling towers of Swanbank coal-fired power station of 480 MW consume sufficient potable drinking water to supply the domestic consumption of a small city. The Swanbank E gas fired power station next door, with 385 MW capacity consumes less than 10% of this amount.

In the prevailing drought circumstance, and looking to a future where climate change can mean that lower rainfalls are apparent, any mechanisms to save on bulk industrial potable water consumption are valuable. The QGS has provided incentives for gas generation as a viable alternative to cheap coal. The proposed Emissions Trading Scheme is a targeted instrument to purely reduce *carbon intensity*. In its own, it does not incentivise water conservation programs, and activities such as geothermal are relatively water intense.

While the energy sector has made a natural progression to a market-based industry with relatively few network externalities, the water sector has not yet moved into such a modern environ. Consequently, there are only immature market solutions based on water price signals to provide incentives to redirect investment away from coal-fired generation towards water-saving alternatives.

The intense population growth which has been experienced in Queensland and which is expected to continue must be met by a growth in generating capacity. Motivations to save on water are implicit in any schemes which provide incentives to invest in gas generation. The QGS has been successful in saving water, and its continuation along the lines of announced policy will provide business incentives to continue the trend.

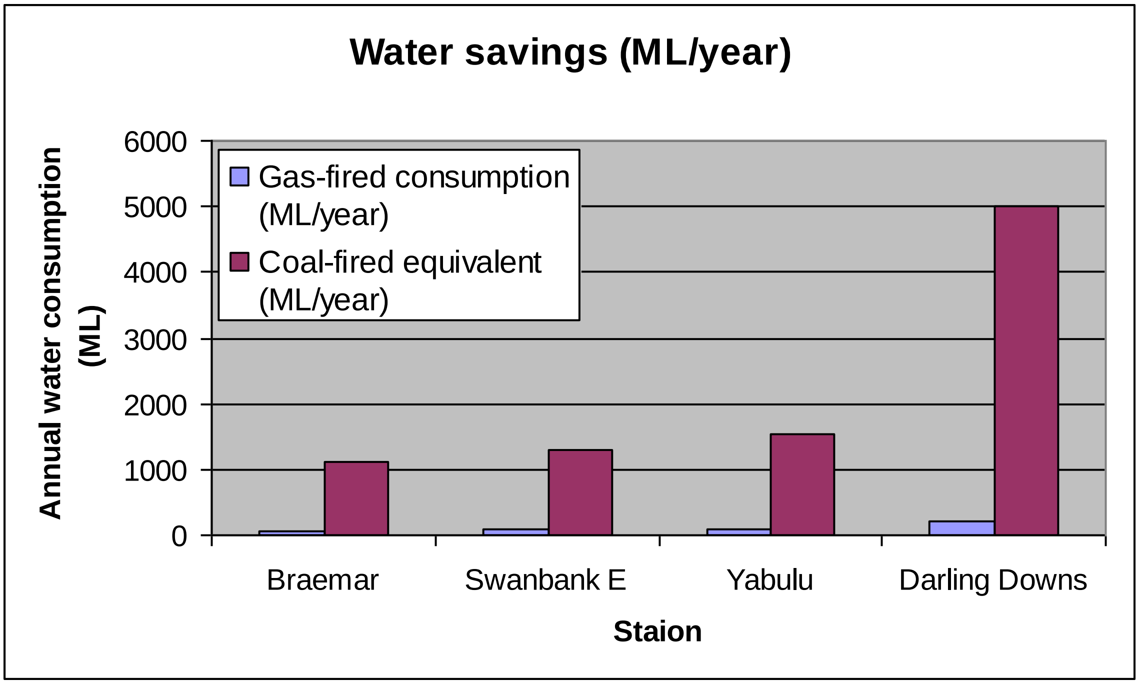


Figure 14: Water consumption from gas generators and consumption from equivalent dispatch from conventional coal-fired station

The State government itself has identified ancillary benefits of the gas industry: “Another plus is that part of the gas extraction process produces large volumes of underground water of bore-water quality, some of which can be used as town water after further processing.” [AB2008]

10 Sovereign Risk

10.1 Introduction

The investment environment in the Australian energy sector is very challenging at the moment with credit tightness and uncertainty created by the ongoing debate with regards to the exact nature of the AETS. If previous policy commitments, such as QGS are abandoned after long term investment decisions have been made, the perceived sovereign risk associated with business activities in Australia will be significant. The private sector, which has currently underwritten the development of the gas industry and the lowering of QLD's carbon intensity, will be very reluctant to pursue further investment on the basis of QLD Government policy initiatives. This will result in underinvestment in electricity supply in QLD and an increase in cost to the consumer.

"Gas is going full steam ahead in Queensland and the Bligh Government is backing it all the way."

"Its success is due in no small part to our 13% gas scheme which requires electricity retailers to source at least 13% of their energy form gas-fired generation. We're going to increase the gas scheme to 18% by 2020,"

Geoff Wilson, Queensland Minister for Mines and Energy, 30 June 2008, [GW2008]

10.2 Queensland Government's Commitments

The Queensland Government has conveyed clear and explicit signals to business to support the continuation and expansion of the QGS arrangements.

Policy announcements are accepted in good faith by investors, and become crucial inputs to the complex process of valuing new investments and developing business cases to attain financing and confirm the viability of long-term projects.

An environment of low regulatory and sovereign risk means that investors can confidently plan new investment in an environment of lower risk. If government policy is instituted in a manner without firm backing, or with a possibility of being reversed, then businesses must incorporate a significant risk premium which represents an expectation of potential losses arising from policy reversals. Project viability is then burdened with additional risk costs and becomes more marginal, and subsequent new investment will be deferred or looks elsewhere.

The Commonwealth and Queensland state governments have strong records of supporting a progressive, industry-friendly business environment and much of the investment boom can be linked to the regulatory and policy stability of the government. The QGS has been a large policy initiative which has underpinned massive investments in gas-fired generation and an unprecedented expansion in the development of the natural and CSM gas industries. The viability of each generation, exploration and gas development project has been assessed on the basis of existing regulatory environment and the likelihood that announced policy will eventuate. Businesses operating in Queensland have consistently held confidence that announced policies will be enacted and the economy has grown as a consequence.

The Queensland government has demonstrated its willingness to ensure continuity of business by assuring that its policy commitments are kept even when external or regulatory issues interfere. The guarantee for continuation of Xtrata's mining operations in 2007 is a key example per reference [X2007].

The Queensland Government's own submission [QS2007] to the Garnaut review highlights the stability which the State government needs to offer business and capital investors in the presence of uncertainty surrounding AETS and the future of QGS. The submission emphasizes the business uncertainty surrounding predicting regulatory change with the introduction of AETS and how business might have "judged carbon risk wrongly". Maintenance of the QGS would be the best contribution that governments can make to ensure the status quo. It maintains faith in the continuation of government policy, and continues to assure that the intended effects are promoted: seeding the domestic gas sector, providing an incentive for gas fired generation and promoting a low carbon alternative to the cheap-coal alternative.

The Federal government, in its new era of cooperation with the states is also bound to respect the commitments made by the states, and should support the continuation of the QGS alongside AETS.

10.3 Key Policy Announcements

In 2007, the Queensland Government announced that the 13% GEC Scheme was to be increased to 18% by 2020. Whilst no details have yet been released relating to the transition to 18%, this increased target is likely to impact the installation of further gas fired generation, thereby increasing the requirement for Queensland's gas. Announcements have unequivocally assured the continuation of the QGS, even in the face of the AETS.

- "Gas is going full steam ahead in Queensland and the Bligh Government is backing it all the way. Its success is due in no small part to our 13% gas scheme which requires electricity retailers to source at least 13% of their energy form gas-fired generation. **We're going to increase the gas scheme to 18% by 2020**,"

  [GW2008] *A new e-bulletin and it's a gas*, Queensland Government Media Release, Minister for Mines and Energy The Honourable Geoff Wilson, 30 June, 2008

- "Under ClimateSmart 2050 **we're increasing our gas scheme to 18 per cent** by 2020," he said.

  [FS2008] *Full steam ahead for Queensland's gas industry*, Queensland Government Media Release, Minister for Mines and Energy The Honourable Geoff Wilson, 16 April 2008

- "The coal seam gas industry owes, in part, its beginnings to the Beattie Government 's original 13% gas policy requirement. Our **raising that to 18%** has played a part in boosting investor confidence, which has lead to increased exploration efforts resulting in an announcement like today's"

  [AB2008] BLIGH WELCOMES $8 BILLION GAS INVESTMENT, Queensland Government Media Release, Premier The Honourable Anna Bligh, 3 February 2008

- "As part of *Climate Smart 2050,* we will increase the 13% Gas Scheme to 18 per cent by 2020.

  "This initiative is a key plank in our strategy to reduce carbon dioxide emissions.

  "Generating electricity using gas produces up to 50 per cent fewer emissions than conventional coal-fired generation, and gas gives Queensland the transitional step to lower emissions while clean coal technologies are being developed."

  Geoff Wilson, Queensland Minister for Mines and Energy, 17 September 2007 [CSM2007]

- "As part of *Climate Smart 2050,* **we will increase the 13% Gas Scheme to 18 per cent** by 2020.

  [CSM2007] *Coal seam methane for a cleaner energy future*, Queensland Government Media Release, Minister for Mines and Energy The Honourable Geoff Wilson, 13 September 2007

10.4 Importance of Sovereign Risk in Electricity Investment

Internationally, the risks associated with sovereign and regulatory risk for investment in power generation have seen projects and supply sources collapse in financial ruin. Famous examples such as Enron in India litter the financial press.

Almost universally, the requirements for merchant investors to build power stations have required extensive IPPA contracts, typically with government. Such activities act to, essentially, remove the investment out of the market, and provide a long-term hedge.

On the other hand, the remarkable success of Australia's market has been seen Internationally to contravene this convention. We are enjoying increasing numbers of investors who build plant and infrastructure to dispatch on short term markets, secure in the knowledge that the businesses operate in an environment of very low sovereign and regulatory risk.

Of course, the business environment must fit in with the public good, and there are examples where sovereign risk has impacted with business decisions.

An example is the continued regulatory uncertainty in NSW, where, for several years, the position of the State government has fluctuated over the future of the generation sector.

The consequence has been the fact that until Tallawarra, the new generation supply has expanded by less than 2% since the mid 1980s. The most recent deliberations on the ownership future of the state assets has further seen business standing aside.

Such actions contrast with decisive and fair regulatory change which poses no sovereign risk. The introduction of the GGAS scheme in 2003 offered a fair transition (in fact opportunities) to a new regulatory framework. The introduction of full retail contestability sale of the Queensland retailing businesses was performed rapidly and without significant disruptions to the remainder of the electricity industry.

The NSW Government has remained consistent on its proposal to phase out the GGAS upon the transition to Emissions Trading. The GGAS is structured to state that generation can only achieve revenue from a single Greenhouse reduction scheme: in other words, double dipping in multiple schemes is prohibited.

From the IPART Consultation paper "Transitional arrangements for the NSW Greenhouse Gas Reduction Scheme", it states:

> "GGAS and the NETS will not operate in parallel. In November 2006 the Electricity Supply Act 1995 was amended such that GGAS may be terminated if NSW participates in a NETS that will achieve greenhouse outcomes at least as stringent as GGAS."

Similarly, the Queensland government has maintained a consistent position on the maintenance of the QGS.

In the era of a new cooperative environment between the federal and state governments, the commitments of each should be respected, especially in the circumstances where the economic distortions are proven to be beneficial for the entire nation.

11 Limited economic wholesale renewable energy in QLD

11.1 Introduction

Apart from the burning of biomass, Queensland does not have an abundant source of viable renewable energy solutions. There are limited suitable wind sites and solar remains limited and very expensive as a wholesale source of electricity. As a result gas fired electricity is Queensland's only economically viable wholesale source of electricity capable of significantly lowering our carbon intensity during the transitional period of 2010 to 2020. Like renewable energy, gas fired electricity requires underwriting during this transitional period in order to ensure its long term development and feasibility. However, gas only requires an impost of $10 - $15/MWh across 13% - 18% of demand whereas renewable energy requires a cost impost of $45 - $55/MWh across 20% of electricity consumed. On the basis of the ratio of cost per tonne of carbon intensity reduction for electricity production, gas fired generation is currently a more economic solution than wind or solar and is the only solution that is capable of meeting up to 300MW in Queensland electricity demand growth per annum.

> **"If we sat on our hands and did nothing, the Queensland electricity sector would be emitting more than 63 million tonnes of carbon dioxide a year by 2020.**
>
> **"Under our energy initiatives, we expect to reduce that to around 51 million tonnes by 2020.**
>
> Geoff Wilson, Queensland Minister for Mines and Energy, 27 February 2008, [AC2008]

11.2 Opportunities in Queensland and Elsewhere

The low-hanging fruit of renewable energy sources has already been tapped in Queensland. The 1950s saw construction of North Queensland hydro generators at Kareeya and subsequently at Baron Gorge.

Environmental considerations are now important factors that will act to limit any proposals to tap the natural resources of free flowing rivers in the North. There are very limited opportunities elsewhere.

The wind industry has proliferated in southern states and around the Roaring 40s and in places in WA. Queensland is not renowned for any reliable sources of wind, and the few potential sites such as Windy Hill in North Queensland have been harvested, relying on support from the MRET scheme.

It is certainly true that Queensland is endowed with ample sunshine, and solar energy should form an important component of the energy mix. Its benefits include distributed generation and a reasonable reliability of supply correlated with the demand shape. However, solar energy remains limited and very expensive as a wholesale source of electricity. The Queensland government has provided demonstrated efforts to support research through the Smart State fund into solar energy technology. The state has gone further, supporting the installation of solar export units in domestic residences and agreeing to purchase the energy produced at rates far in excess of the typical wholesale price.

However, the most carbon-effective solution for preparing for a low carbon economy is to support the transition to a gas fired generation base while the alternative renewable sources and geo-sequestration are explored.

Replacement of a unit of coal fired generation with a unit of gas fired generation saves around 50% on the carbon emissions. Of course, replacement with fully renewable generation saves 100%. But the gas replacement technology is available right *now*. For every year that the new technologies are delayed, the gas solution is able to continuously achieve its abatement goal immediately.

And in order to institute the gas generation technologies now, the State needs adequate gas production and transport infrastructure. This is exactly what the QGS is achieving by subsidizing the upstream activities from a revenue source funded across the entire spectrum of consumers.

Consequently, the QGS is an entirely valid approach to foster a gas-fired transition to a carbon constrained economy, and should be continued in Queensland. Other regions with their renewable resources are able to tap into them at a lower cost to achieve equivalent levels of abatement. The Green Paper [CPRS2008] implicitly recommends continuation of the MRET scheme, and the federal government has gone so far as to announce its continuation and expansion.

Investment in renewable energies in all regions will be undertaken in the context of both MRET and AETS schemes in an analogous way that gas generators have expected to operate with AETS in conjunction with GEC revenues. The federal government appears to have no problems with the strategy of double dipping to provide competitive advantages to renewable generators.

To continue the MRET but demand conclusion of the QGS is an inconsistent policy position. Under the AETS, the over riding objective is to achieve carbon reductions irrespective of the innovation or source. The federal government has felt free to pick a technology winner by supporting the MRET, and the Queensland government should feel comfortable with the same strategy. The case is particularly strong for the Queensland region which has yet to prove large-scale commercial solutions to exploit the particular nature of the renewable resources available to it.

12 GEC and AETS are market based mechanisms

12.1 Introduction

Current returns with the QGS in place have driven significant investment in gas fired generation projects since its inception a little over three years ago. As a result of strong supply-side response the spot price for GEC's has fallen from approximately $16/GEC (the tax adjusted penalty rate) to approximately $10/GEC. The electricity and GEC markets are very competitive.

If the introduction to AETS did in fact provide additional gross margin benefits to generators, such that risk adjusted returns for gas fired projects improve whilst the QGS is retained, even more substantial investment commitments would be made and the value of GEC's would continue to fall until the net value benefits of AETS and QGS operating in parallel are just enough to exceed LRMC for gas fired projects. The removal of QGS and the GEC revenue stream not only creates issues of sovereign risk for environmental markets but also removes the Queensland Government's only successful safety valve for ensuring the viability of gas fired generation and therefore Queensland's only possible medium term solution for providing a smooth transition into a carbon constrained economy.

12.2 GEC Price responses

The GEC revenues applied in the numerous arguments above do *not* provide a perfectly reliable revenue source to save private gas generators no matter what.

Figure 15 and Figure 16 below present plots of the last-traded GEC price, and illustrates the significant market volatility which has just delivered a price drop down to $10/GEC.

However, business wanting to shore up certainty of GEC revenue (in order to achieve financial close of a new project) typically apply a strategy of hedging the output in advance. Forward contracts are negotiated for the delivery of GECs at certain fixed prices. The removal of the QGS from such a business framework would lead to significant business upheaval in the participants who have structured such long-term agreements.

The fact that GEC prices are free to move allows the supply and demand balance to meet at a clearing market price. Some degree of protection has been offered to consumers in the form of price caps, which is a technique paralleled in the other environmental markets and to be instituted in AEST also.

Above average profits (possibly interpreted from Figure 11) means an opportunity for new generators to be built, with a willingness to sell GECs at a lower price, meaning that the industry has been seeded into competitive economy and the subsidies are no longer needed to be so strong.

We see this in Figure 15 as successions of news items are released promoting the intentions of the Darling Downs and Braemar 2 projects to come to fruition. Alternatively, the instability arising from the Green Paper's call to abolish the QGS scheme may be contributing, but as with all financial markets, it remains impossible to assign causes to price movements with perfect confidence.

If the AETS structured incorrectly, then the targets for the first five years can quite conceivably be met too easily (per the European experience) or be too hard (leading to unintended business disruption as feared by the BCA).

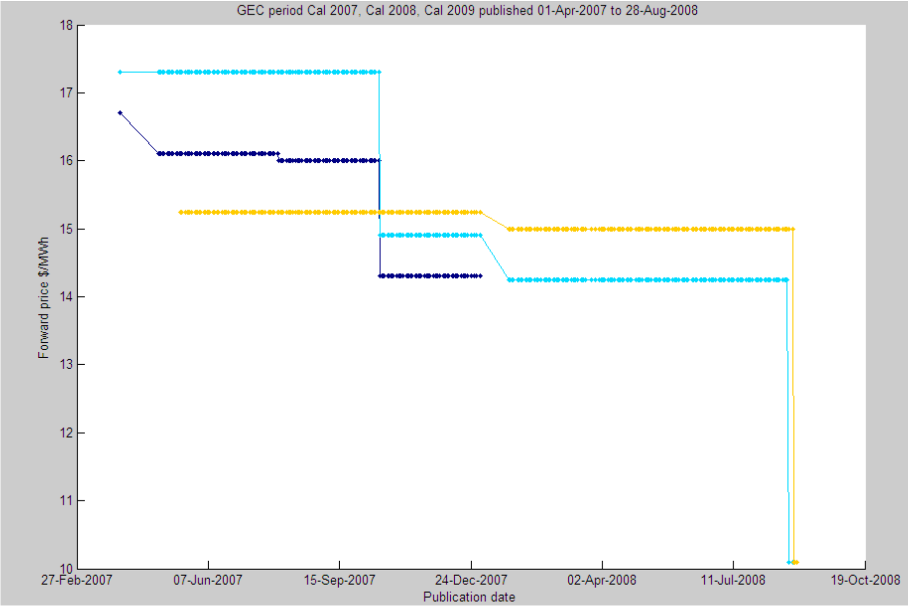


Figure 15: GEC prices April 2007 to present, 2008, 2009 and 2010 vintages of last-traded price as observed in broking market.

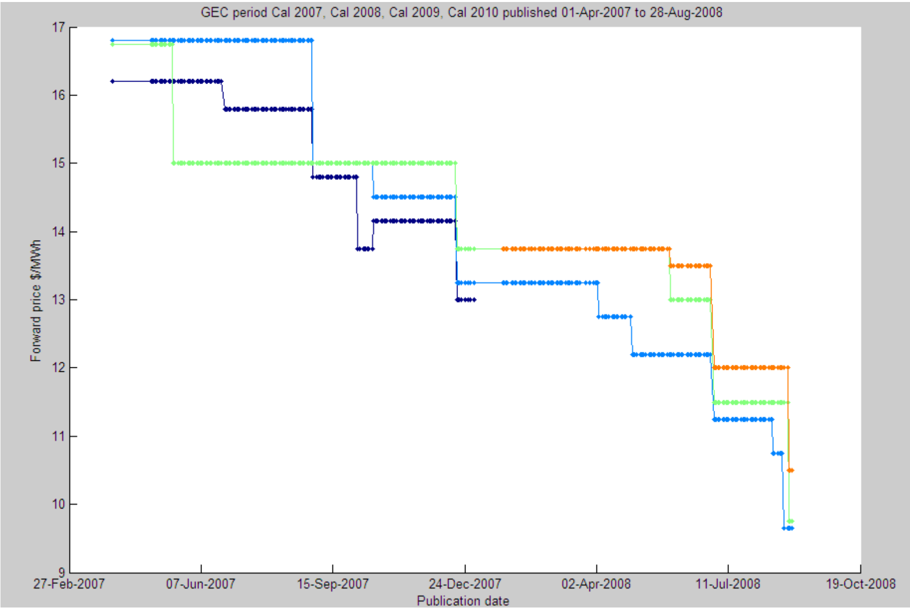


Figure 16: GEC market bid prices April 2007 to present, 2008, 2009 and 2010 vintages of last-traded price as observed in broking market.

If the financial rewards arising from carbon pricing under the AETS yield an even more competitive advantage to gas fired generators, then even more investment will be spurred in the sector. The value of GECs will become minimal as they are no longer needed to justify the further investment. The concerns expressed in the Green Paper are then allayed as the scheme has near zero cost to consumers and produces no distortion to the economy.

Conversely, if the AETS does not achieve the desired outcomes and does not provide enough stimulus to maintain interest in gas investment which remains in Queensland's state interest, then maintaining the QGS will ensure that the sector remains viable and assures prosperity for Queensland's industry.

13 Appendix A: Operations of the ETS, GEC, AETS and GGAS schemes

13.1 Introduction

This appendix provides a simplified illustration of the operation of the Queensland Gas Scheme (QGS), Australian Emissions Trading Scheme (AETS) Greenhouse Gas Abatement Scheme (GGAS) and Mandatory Renewable Energy Targets (MRET) environmental schemes. The body of the document makes reference to these illustrations. The objective is to illustrate the manner of cash flows associated with the schemes, and how the direct and indirect impacts on consumers and market participants.

13.2 QGC Scheme

The QGS operates by levying a *direct cost* on *all Queensland consumers* and making a *direct subsidy* to *eligible gas generators*.

The QGS creates a revenue stream for gas generators, enabling otherwise marginal investment to take place, and encouraging a higher level of dispatch from gas fired generators.

The eligibility conditions are targeted to ensure that only gas fired generation benefits from the subsidy. The reduction of greenhouse intensity is a secondary benefit which arises from the lower carbon intensity of gas fired generators.

The scheme is targeting to achieve a minimum level of gas dispatch in relation to the volume of electricity consumption.

Emphasis: The QGS provides a revenue stream for gas fired generators. Other generators miss out on that revenue. If gas is the marginal generation technology, then the QGS will provide a revenue stream to permit gas plant to operate with a lower revenue contribution purely from electricity, and enable it to make lower bids into the market. Therefore, the overall effect is a slightly depressed pool price for electricity. However, the GEC costs are passed through to consumers resulting in a slight net increase in costs in the short term from passing on the GEC costs.

13.3 AETS Scheme

The AETS operates by imposing a *direct cost* on all producers of emissions to enable them to carry on their business. Higher costs must invariably be passed through to consumers who will observe an increase in the costs of product.

Cost impositions vary depending on the carbon intensities of the individual producers. Entities with lower intensity incur a smaller cost, increasing the competitiveness of low emissions producers.

The cap structure of the scheme directly targets a specific carbon intensity outcome. Like the GGAS, the scheme seeks a market-based low cost solution to reducing carbon intensity, but without selecting winning technologies.

Emphasis: The structure of the AETS results in an increase in cost for all producers, but the less carbon intensive producers incur less cost, making them more competitive. The scheme does not target winning technologies but seeks a market-based low cost solution to reduce emissions intensity by whatever means.

13.4 GGAS Scheme

The GGAS operates by levying *a direct cost* on consumers and providing the funds as a cash *subsidy* for entities who are able to provide reductions in carbon intensity through a wide range of eligible activities. Similar to AETS the scheme targets, the GGAS sets a specific carbon target and seeks a low cost market solution to achieve the target.

Emphasis: The structure of the GGAS results in an alternative revenue stream for generators who can achieve low intensity production. The revenue stream enables the generators to bid lower and therefore capture more market and displace existing producers based purely upon their emissions intensity.

13.5 MRET Scheme

The MRET scheme operates by levying a *direct cost* on *all consumers* and making a *direct subsidy* to *eligible renewable generators*.

The MRET creates a revenue stream for renewable generators generators, enabling otherwise marginal investment to take place, and encouraging a higher level of dispatch from renewable plant.

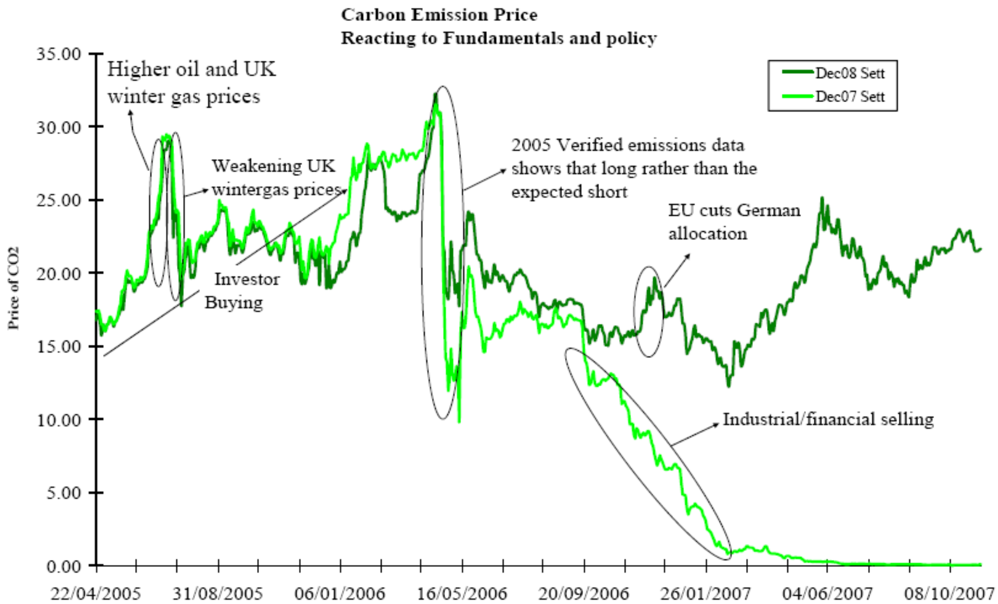
The eligibility conditions are targeted to ensure that only renewable generation benefits from the subsidy. The reduction of greenhouse intensity is a secondary benefit which arises from the lower carbon intensity of renewable power.

The scheme is targeting to achieve a minimum level of renewable generation dispatch in relation to the volume of electricity consumption.

Emphasis: The MRET provides a revenue stream for renewable generators. Other generators miss out on that revenue. Marginal renewable generation technology will become feasible with the additional revenue stream. The MRET costs are passed on directly to consumers who are liable to acquire the REC certificates.

13.6 ETS Scheme

The European Emissions Trading Scheme commenced in 2005 as a Phase 1 program to introduce a cap-and-trade model to limit emissions through European Union and meet Kyoto targets over a three year period.



Source: Market Participant

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