Final report

GasNet GPG forecasts

Review of GasNet gas power generation forecasts within the 2008-12 access arrangement period

Prepared for the ACCC

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ACIL Tasman

Economics Policy Strategy

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Contents

Boxes, charts, figures and tables

1 Background

Under the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code), the ACCC is responsible for regulating the transmission pipelines provided by GasNet in relation to the Victorian Principle Transmission System (PTS).[1] The current access arrangement period for the PTS applies to 31 December 2007.

On 30 April 2007, GasNet lodged a revised access arrangement (AA3) for the PTS with the ACCC for approval. GasNet's proposed revisions for AA3, including the supporting documentation, details the policies and basic terms and conditions for third party access to the PTS.

The ACCC is now required to consider and approve terms and conditions on which GasNet will make available access to third parties from 1 January 2008 to 31 December 2012. As part of the approval processes, the ACCC is required to assess all volume forecasts – including gas power generation (GPG) forecasts – in GasNet's access arrangement.

1.1 GPG within GasNet's access arrangement

Victoria's gas transmission network planner (VENCorp) has, with the assistance of the National Institute of Economic and Industry Research (NIEIR) published demand forecasts for the PTS for the period 2007-2011 as part of its 2006 Gas Annual Planning Report (GAPR). GasNet has adopted the annual GPG forecasts contained within VENCorp's 2006 GAPR for 2007-2011 along with further NIEIR forecasts covering the final year of the new access arrangement period (2012).

The NIEIR forecasts, including annual total GPG usage, are understood to have been finalised around October 2006 in time for publication in November in the 2006 GAPR. The ACCC is reviewing the NIEIR GPG forecasts because:

- GPG forecasts are sensitive to a changing electricity market environment (political and economic) for wind, hydro, gas and coal generation
- Observed outcomes in the electricity market subsequent to October 2006—specifically the effect of water shortages on patterns of electricity generation—may not have been accounted for in NIEIR's GPG demand forecasts

[1] The enabling legislation to transfer the ACCC's current functions in gas to the AER has yet to be enacted. However, the AER is providing the ACCC with advice for the GasNet review.

- The accuracy of annual GPG forecast will strongly affect GasNet's proposed revenue over 2008-2012.

GasNet has supplemented annual GPG forecasts with its own estimates of peak day volumes associated with gas-fired power generators.

The ACCC is reviewing GasNet's input into GPG forecasts—peak day volumes forecasts and the allocation of both peak and annual GPG forecasts amongst individual gas-fired generators. In particular, the ACCC is concerned that:

- There may be a correlation between annual GPG and peak forecasts meaning that if annual volume forecasts are amended, consequent changes will need to be made to peak forecasts
- GasNet's method of distributing annual and peak usage amongst gas-fired generators appears to be based on 2006 historical analysis which may not be a good distribution basis for 2008-2012.

Annual and peak demand and the distribution of annual and peak demand will have an impact on transmission tariffs for large and small users and between tariff zones.

1.2 Purpose of this report

Section 8.2(e) of the Code requires that any forecasts used in setting the Reference Tariff represent best estimates arrived at on a reasonable basis. ACIL Tasman has been engaged by the ACCC to review the GPG demand forecasts contained within GasNet's proposed access arrangement to assess their reasonableness. To the extent that ACIL Tasman does not consider the GPG forecasts adopted by GasNet to be reasonable, we have been tasked to supply projections which meet the requirements of Section 8.2(e).

This report represents the outcomes of ACIL Tasman's review of the GasNet GPG forecasts.

This report is structured as follows:

- Chapter 2 contains the review of GPG forecasts used by GasNet within its proposed access arrangement
- Chapter 3 discusses recent developments in relation to gas-fired generation connected to the PTS, in particular as a result of the drought impacts currently affecting the National Electricity Market (NEM)
- Chapter 4 presents ACIL Tasman's GPG projections based on NEM market modelling
- Chapter 5 discusses the differences between the GasNet and ACIL Tasman GPG series and provides recommendations to ACCC as to the appropriate figures to use for AA3.

2 Review of GasNet GPG forecasts

This section provides an overview of the GPG demand forecasts as used by GasNet within its proposed access arrangement. This review covers the four main elements of the GasNet GPG forecast, namely:

- forecast annual GPP consumption
- allocation of GPG consumption across GPG users
- forecast peak day GPG consumption
- allocation of forecast peak day GPG consumption across GPG users.

These elements are examined in the following sections.

2.1 Annual GPG consumption

VENCorp engages the National Institute of Economic and Industry Research (NIEIR) to produce independent long-term gas load forecasts for the PTS based on High, Medium and Low Economic scenarios. These forecasts include annual volumes as well as peak-day requirements. As part of this forecasting exercise, NIEIR also provides forecasts for annual GPG usage. Implied GPG demand forecasts have varied considerably over previous annual planning reports with forecasts consistently revised downwards over the past three years as shown in Table 1.

Table 1 **Medium economic growth scenario: annual forecast comparisons (PJ)**

Calendar year	System demand			System demand and GPG			Implied GPG demand		
	GAPR2004	GAPR2005	GAPR2006	GAPR2004	GAPR2005	GAPR2006	GAPR2004	GAPR2005	GAPR2006
2005	211.8	205.2		221.2	211.7		9.4	6.5	
2006	215.8	208.9	206.2	226.8	219.1	213.3	11.0	10.2	7.1
2007	220.4	212.7	210.3	233.5	223.5	217.2	13.1	10.8	6.9
2008	223.3	215.2	212.4	238.3	226.8	219.2	15.0	11.6	6.8
2009	226.1	215.3	212.8	242.8	229.5	219.6	16.7	14.2	6.8
2010		216.6	214.0		233.2	220.7		16.6	6.7
2011			215.0			221.8			6.8

Data source: VENCorp 2005 and 2006 Gas Annual Planning Reports; ACIL Tasman

GasNet has adopted the VENCorp/NIEIR annual GPG forecasts for the period 2008-12 as shown in Table 2.

Table 2 **GasNet GPG volume forecast (PJ)**

	2007	2008	2009	2010	2011	2012
Total GPG volume	6.836	6.842	6.732	6.725	6.727	6.735

Note: Based on calendar years

Data source: AER (sourced from forecast data provided by VENCorp)

The approach used by NIEIR to forecast GPG consumption is based upon a separate model as distinct from the econometric models used to forecast other sectoral components of gas demand.

It is not clear what type of model is used by NIEIR to forecast GPG consumption. The only explanation of the model or approach used by NIEIR that is available to ACIL Tasman is a brief statement in the 2006 GAPR which notes:[2]

> NIEIR's GPG forecast model takes the following factors into account:
>
> - Projected growth of 10% POE summer MD in Victoria and South Australia
> - Existing and new generation capacity in Victoria and South Australia
> - Existing and new capacity of interconnectors
> - The competitiveness of new GPGs versus new coal-fired base load generators.

This statement suggests that NIEIR does not model the NEM in detail, but instead relies on past trends and forecast changes to the generation mix, with the focus on Victoria and South Australia.

Given the potential size of the GPG component of gas demand in Victoria it is important that the forecast approach is as rigorous as possible. In our view, this requires a detailed market modelling approach as opposed to reliance on historical outcomes. Also, as the NEM is an interconnected system, we consider that a forecasting methodology for GPG should also include consideration of supply and demand side factors throughout all regions of the NEM.

However, notwithstanding these reservations with regard to the forecasting approach apparently used by NIEIR, we consider that the figures produced for the 2006 GAPR (and subsequently used by GasNet) appear reasonable given the information available to the market in mid-2006. Modelling conducted by ACIL Tasman for other client assignments at that time indicated similar levels of GPG consumption in Victoria for the AA3 period.

However, since mid-2006 events in the NEM such as the impact of drought conditions on generator availability and new plant commitments warrant a re-examination of the forecast GPG volumes.

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[2] VENCorp, 2006 Gas Annual Planning Review, Appendix A, p.76

At the request of the ACCC, ACIL Tasman has conducted its own projection of annual GPG consumption taking into account recent developments in the NEM. These projections are detailed in section 3.

2.1.1 Allocation between GPG users

GasNet has distributed the forecast volumes in Table 2 amongst GPG users over 2008-12 by scaling these forecasts in accordance with each GPG user's actual consumption as a percentage of total GPG usage over calendar year 2006. Actual consumption and contribution to total GPG consumption for 2006 is detailed in Table 3.

Table 3 **Actual GPG consumption by GPG user: calendar year 2006**

	Loy Yang A	Jeeralang	Loy Yang B/ Valley Power	Newport	Somerton	Laverton North	Total GPG
Gas use (GJ)	29,922	737,069	192,795	6,721,261	466,316	235,887	8,383,250
% of total	0.4%	8.8%	2.3%	80.2%	5.6%	2.8%	100%

Note: Valley Power did not have a separate meter until January 2007
Data source: AER (sourced from metered data provided by VENCorp)

The annual allocation of forecast GPG demand amongst GPG users for AA3 is shown in Table 4. As a result of this allocation method, the majority of GPG demand is assigned to Newport which accounted for just over 80% of total GPG use in 2006.

Table 4 **Allocation of forecast annual volumes by GPG user (TJ)**

Calendar year	Loy Yang A	Jeeralang	Loy Yang B/ Valley Power	Newport	Somerton	Laverton North	Total GPG
2008	24.4	601.6	157.3	5,485.6	380.6	192.5	6,842
2009	24.0	591.9	154.8	5,397.4	374.5	189.4	6,732
2010	24.0	591.3	154.7	5,391.8	374.1	189.2	6,725
2011	24.0	591.4	154.7	5,393.4	374.2	189.3	6,727
2012	24.0	592.2	154.9	5,399.8	374.6	189.5	6,735

Data source: ACIL Tasman

A number of potential issues arise in relation to this allocation methodology:

- It explicitly assumes a consistent consumption pattern among GPG users over the AA3 period
- Laverton North was only operational toward the end of 2006, potentially under-representing future consumption at this station while over-representing consumption for other GPG users.

Given the above and reservations regarding the annual volumes themselves, ACIL Tasman has also provided an independent projection of consumption by GPG users as part of the outcomes of its own modelling exercise.

2.2 Peak day GPG demand

Within the 2006 GAPR, VENCorp does not provide forecasts of peak day GPG demand. GasNet has used a constant assumption of 50 TJ/day with AA3.

Within their submission GasNet state:[3]

> With respect to gas-fired power generation, there is wide variation in the observed peak day, particularly given that the relevant peak day volume is coincident with the total system peak day. Forecasting is complicated by the fact that gas-fired power generation is a controllable load driven by prices in the electricity market.
>
> Based on historical analysis and previous statements from VENCorp, GasNet is projecting a peak day contribution of 50 TJ/day from gas-fired power generation.

GasNet has advised the ACCC that it has relied on a statement in the VENCorp 2005 GAPR (page 19) that 'up to 50 TJ of GPG demand has occurred on cold days close to the 1:2 EDD weather conditions'.

VENCorp notes that actual GPG consumption during the 2006 peak day was 77.6 TJ, out of a total demand of 1,148 TJ on 19 July 2006.[4] This value is verified by ACIL Tasman's analysis of GPG usage on historical peak days as shown in Table 5. GPG consumption has averaged 55.1 TJ on system peak days over the period 2001-2007.

Table 5 **Historical GPG usage on system peak days (GJ)**

System peak day	Total withdrawals	Loy Yang A	Jeeralang	Newport	Somerton	Laverton North	Loy Yang B/ Valley Power	Total GPG
20-Aug-01	999,168	11	48,921	0				48,933
22-Jul-02	1,102,848	27	29,129	43,435	0		10,699	83,290
29-Jul-03	1,087,424	10	18,657	21,974	1,015		5,881	47,537
17-Jun-04	1,057,208	0	12,537	47,693	956		3,390	64,576
10-Aug-05	1,217,653	31	0	20,398	0		18,892	39,321
19-Jul-06	1,156,423	16	10,886	60,537	6,058		37	77,534
17-Jul-07	1,288,628		271	15,212	0	2	9,105	24,590
Average								55,112

Note: Peak day for 2007 is up to 2 August 2007. Consumption at Loy Yang A was not available for 2007

Data source: ACIL Tasman analysis of VENCorp data

The 50 TJ peak day GPG usage assumed by GasNet is therefore slightly lower than the historical average. GPG usage has averaged around 130 TJ/day for the winter period so far this year (1 May to 22 July 2007).[5] However, on the

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[3] APA Group, GasNet Access Arrangement Submission, 14 May 2007, p.89

[4] VENCorp, 2006 Gas Annual Planning Report, p.7

[5] 22 July represents the most up-to-date data available to ACIL Tasman at the time of writing.

peak day for the year-to-date (17 July 2007) spot prices were at record highs (peaking at $336/GJ for one 4-hour period and averaging $81/GJ across the day) potentially making gas-fired generation less economic relative to on-selling gas entitlements to the market. Furthermore, system peak days could also result in significant uplift charges to GPG users through the injection of LNG for system security reasons. The impact of high spot prices and uplift charges on system peak days will typically—all else being equal—reduce incentives for GPG users to generate electricity.

In addition, system peak days which approach 1 in 20 peak day levels may also create system constraints, potentially resulting in demand curtailment. During such periods it is likely that GPG loads will be curtailed with some having the ability to switch to liquid fuels.[6]

On balance the 50 TJ peak day assumption used by GasNet appears reasonable given the historic values and potential arbitrage opportunities for GPG users during these peak day events.

2.2.1 Allocation between GPG users

GasNet has distributed the 50 TJ of forecast peak-day GPG demand between the six GPG users by reference to the 2006 actual annual volume as detailed in Table 3. Therefore most of the peak usage is also allocated across 2008-2012 to Newport as detailed in Table 6.

Table 6 **Allocation of peak day GPG consumption between users (GJ)**

	Loy Yang A	Jeeralang	Loy Yang B/ Valley Power	Newport	Somerton	Laverton North	Total GPG
2008-12	178	4,396	1,150	40,087	2,781	1,407	50,000

Data source: ACIL Tasman

Due to highly uncertain nature of peak day GPG consumption (which as previously discussed may see the system peak day as a low GPG day as generators take advantage of high spot gas prices in the market), ACIL Tasman believes this allocation based on annual volumes to be reasonable. Alternative approaches would be to pro-rate contribution to peak day GPG consumption based on historical GPG usage on peak days (as detailed in Table 5) or based on installed plant capacity (effectively reflecting the *potential* contribution of each plant to peak day GPG usage). However, it is in our view not clear that either of these methods would necessarily provide a more accurate means of

[6] The construction of the Corio loop may result in fewer instances of demand curtailment over the access arrangement period as additional supply capacity would be available from SEAGas and other Otway Basin sources.

forecasting peak day contributions to GPG demand so as to warrant a shift from the approach taken by GasNet.

3 ACIL Tasman projections

ACIL Tasman has used its NEM market model – *PowerMark* – to create projections for PTS GPG consumption over the AA3 period.

Due to the nature of gas plant on the PTS, GPG consumption forecasts have the potential to vary widely. The primary driver for the use of gas in power generation in Victoria is the Victorian regional reference price (RRP). Prices themselves are notoriously difficult to forecast, and hence any projections of GPG consumption must be used with caution. VENCorp note within the GAPR:[7]

> Gas usage by power generation is very volatile because GPG is not an end-use, but, rather, is an outcome of two energy markets supplying end-use energy. Both short and medium-term outlooks for gas power generation is uncertain, as the load is very sensitive to unpredictable factors such as weather conditions, unplanned generator outages and the electricity spot price.

When prices are above certain levels, gas-fired generation becomes economic. However, other factors such as hedge positions and contracting strategy are also important considerations.

With the purpose of regulation of the PTS in mind, ACIL Tasman has constructed a scenario which, in its view, represents a best estimate for GPG consumption. Assumptions used within this analysis are considered by ACIL Tasman to be reasonable for this purpose.

3.1 Key input assumptions

This section provides an overview of the key modelling assumptions used within ACIL Tasman's projections of GPG demand on the PTS.

3.1.1 Demand

The demand series used in the analysis is drawn directly from the latest official NEMMCO forecast as prepared for the yet-to-be-released 2007 Statement of Opportunities (SOO). These demand forecasts are based upon work by each of the jurisdictional planning bodies and NIEIR.

The demand and energies used for each region have been taken from the medium economic growth scenario at the 50% probability of accedence (POE) level. The 50% POE demand projections, for a given season, are expected to

[7] VENCorp, 2006 Gas Annual Planning Review, pg14

be met or exceeded, on average, five years in every ten. A forecast at this level is associated with average temperature conditions.

Table 7 details the energy forecast used for each region over the relevant period on a sent-out basis.[8] In the period 2006-07 to 2012-13, Victoria's energy demand is forecast to grow by 2.2% (equivalent to a compound growth rate of 0.4% per annum). This low growth rate is a result of underlying economic conditions and the introduction of non-scheduled wind capacity. Wind farms are expected to reduce summer maximum demand by 285 MW and annual energy by 3,498 GWh by 2009-10.[9]

Table 7 **Scheduled energy projections: 50% POE, medium economic growth**

Year	Queensland		New South Wales		Victoria		South Australia		Tasmania	
	Energy (GWh)	Growth (%)	Energy (GWh)	Growth (%)	Energy (GWh)	Growth (%)	Energy (GWh)	Growth (%)	Energy (GWh)	Growth (%)
2006/07	48,163		74,090		47,508		12,826		10,091	
2007/08	51,058	6.0%	75,710	2.2%	47,599	0.2%	12,631	-1.5%	10,221	1.3%
2008/09	53,129	4.1%	76,900	1.6%	46,468	-2.4%	13,064	3.4%	10,418	1.9%
2009/10	55,109	3.7%	78,000	1.4%	46,362	-0.2%	13,212	1.1%	10,661	2.3%
2010/11	57,355	4.1%	78,890	1.1%	47,085	1.6%	13,410	1.5%	10,781	1.1%
2011/12	59,389	3.5%	80,060	1.5%	47,713	1.3%	13,628	1.6%	10,927	1.4%
2012/13	61,730	3.9%	81,520	1.8%	48,574	1.8%	13,834	1.5%	11,087	1.5%

Note: Values for 2006/07 are an estimate based on part-year actuals. Energy is presented on a sent-out basis

Data source: NEMMCO, Australia's National Electricity Market 2007 Energy and Demand Projections, Summary Report, July 2007

Table 8 and Table 9 detail the summer and winter maximum demand values respectively over the relevant period.

Maximum demands in Victoria are forecast to experience limited growth relative to other NEM regions. In particular, the winter peak demands are expected to fall over the period to 2012. This is a marked reduction relative to previous NEMMCO forecasts – for example, the 2006 SOO forecast Victorian peak winter demand of 8,311 MW in 2012, compared to the latest forecast of 7,782 MW.

[8] As the market is modelled on a generated basis, these energies were converted to generator terminal values using average auxiliaries.

[9] NEMMCO, Australia's National Electricity Market 2007 Energy and Demand Projections, Summary Report, July 2007, pg 20.

Table 8 **Summer maximum demand: 50% POE, medium economic growth**

Year	Queensland		New South Wales		Victoria		South Australia		Tasmania	
	Demand (MW)	Growth (%)	Demand (MW)	Growth (%)	Demand (MW)	Growth (%)	Demand (MW)	Growth (%)	Demand (MW)	Growth (%)
2006/07	8,611		12,876		9,062		2,862		1,371	
2007/08	9,461	9.9%	13,820	7.3%	9,198	1.5%	2,990	4.5%	1,381	0.7%
2008/09	9,883	4.5%	14,260	3.2%	9,263	0.7%	3,089	3.3%	1,406	1.8%
2009/10	10,268	3.9%	14,620	2.5%	9,409	1.6%	3,146	1.8%	1,438	2.3%
2010/11	10,660	3.8%	14,970	2.4%	9,601	2.0%	3,180	1.1%	1,456	1.3%
2011/12	11,042	3.6%	15,320	2.3%	9,780	1.9%	3,244	2.0%	1,477	1.4%
2012/13	11,457	3.8%	15,740	2.7%	9,975	2.0%	3,329	2.6%	1,500	1.6%

Note: Values for 2006/07 are actuals. Demand is presented on a generator terminal basis

Data source: NEMMCO, Australia's National Electricity Market 2007 Energy and Demand Projections, Summary Report, July 2007

Table 9 **Winter maximum demand: 50% POE, medium economic growth**

Year	Queensland		New South Wales		Victoria		South Australia		Tasmania	
	Demand (MW)	Growth (%)	Demand (MW)	Growth (%)	Demand (MW)	Growth (%)	Demand (MW)	Growth (%)	Demand (MW)	Growth (%)
2007	7,895		13,700		7,831		2,432		1,751	
2008	8,210	4.0%	14,070	2.7%	7,890	0.8%	2,499	2.8%	1,781	1.7%
2009	8,538	4.0%	14,370	2.1%	7,860	-0.4%	2,584	3.4%	1,816	2.0%
2010	8,865	3.8%	14,650	1.9%	7,805	-0.7%	2,603	0.7%	1,839	1.3%
2011	9,193	3.7%	14,970	2.2%	7,781	-0.3%	2,627	0.9%	1,873	1.8%
2012	9,481	3.1%	15,300	2.2%	7,782	0.0%	2,647	0.8%	1,902	1.5%

Note: Values for 2007 are actuals. Demand is presented on a generator terminal basis

Data source: NEMMCO, Australia's National Electricity Market 2007 Energy and Demand Projections, Summary Report, July 2007

Translation of forecasts to a load profile

ACIL Tasman generally simulates the NEM on an hourly basis (that is, using hourly settlement periods). Therefore, a set of hourly loads for each region is required for each year of the projection. It is possible to use as a basis the set of actual hourly loads for any of the past recent years and then grow this set of loads to the forecast winter/summer peak demands and annual energy provided. However, it is well recognised that load is affected by weather and therefore the risk of using this approach is the assumption that the weather of the past few years is typical and will continue into the future.

Instead of making this assumption, the approach used in creating a set of hourly loads attempts to remove atypical weather effects to produce a load profile that could be expected given typical weather patterns derived from normalised long-run meteorological data.

The simulated hourly load profile for each region is based on actual half-hour generated load observations for the four years 2002-03 to 2005-06 and temperature and humidity data for 1970-71 to 2005-06.

A summary of the process used to create a standard set of hourly loads is described in the following box.

Box 1 Process for constructing a standard set of hourly loads

Step 1 - The actual hourly loads from 2002-03 to 2005-06 are grown to 2005-06 levels by modelling a general level of growth across the four years on a quarterly basis. This has the outcome of accounting for economic growth over the previous four years but does not remove the impact of weather on the loads. In a sense, four sets of loads are produced for 2005-06 accounting for each of the annual weather patterns of the previous four years.

Step 2 – At the completion of Step 1, there exists 36 years worth of weather data and 4 years worth of load data, which overlap in terms of time. The purpose of Step 2 is to create 36 sets of load data – one for each of the 36 'weather years'. The hourly load profile for each day for each weather year is selected from the four load data years with the closest matching temperature conditions (as well as accounting for day type and season). This is achieved by finding the closest least squares match between the temperature profile for that day and the temperature profile for a day in one of the four load data years.

Step 3 – At the completion of Step 3, there exists 36 sets of annual hourly load data. Each set differs and this difference is directly related to the weather conditions associated with each set. The purpose of Step 3 is to create a single representative combination of the 36 sets of loads – referred to as the 'standard year of loads'. If there existed only one region then an approach to ensure that the standard year of loads represented the 36 sets of loads would be to choose the median set of hourly loads for each day of the year. However, because there a multiple regions and we wish to preserve the correlation between regional loads another approach is required. This is achieved by randomly choosing one of the 36 load sets for each day of the standard year.

Step 4 – At the completion of Step 4, there exists, for each region, a single set of hourly load data – representing the standard year of loads. Given that a random number generator is used to construct this set of loads there is no guarantee that the resulting set of loads is indeed representative of the 36 sets. Therefore, the purpose of Step 4 is to ensure that the standard year of loads is representative. This is done using a number of summary statistics and graphs.

Step 3 and 4 are repeated until a reasonably representative set of loads is selected.

The standard year of simulated hourly loads is then scaled for each year of the projection based on the projected winter and summer peak demands and annual energy. Technically, a non-linear transformation method is used to ensure all hourly data conform to both the annual energy and the winter and summer peak loads.

The outcome of this process is a set of loads that could be expected given typical weather conditions. In other words, the short-term stochastic influences of weather on load have been removed. This process is used for the four mainland regions. For Tasmania, ACIL Tasman does not have access to sufficient historical load data to utilise this approach. Instead, a single set of historical hourly load data for Tasmania is scaled to the winter/summer peak load and annual energy parameters.

3.1.2 Supply

Table 10 details the assumptions in relation to changes in NEM-scheduled plant over the period 2008-12. In aggregate generation capacity is increased by 3,735 MW over the period. Aside from the assumed development of a 500 MW well-head coal seam gas development in 2012 (notionally labelled Spring Gully) and return to full-time service of the 6th Gladstone unit, all changes to capacity are currently committed. Price signals from the modelling as a result of this plant program suggest that no additional new entrants could be supported by the market over the AA3 period.

Table 10 **Changes to NEM-scheduled plant**

Region	Station	Proponent	Details	Fuel	Size	Timing
QLD	Kogan Creek	CS Energy	Construction of 750 MW black coal unit	Coal	+750 MW	Q3 2007
NSW	Eraring GT	Eraring Energy	Construction of black start gas turbine	Distillate	+40 MW	Q1 2008
NSW	Tallawarra	TRUenergy	Construction of 380 MW CCGT	Natural gas	+410 MW	Q3 2008
SA	Quarantine	Origin Energy	Addition of a GE Frame 9 OCGT unit	Natural gas	+120 MW	Q4 2008
NSW	Uranquinty	Babcock Brown Power	Construction of gas-fired OCGT at Wagga	Natural gas	+660 MW	Q4 2008
QLD	Condamine	Queensland Gas Co.	Early development of OCGT portion of station	Natural gas	+100 MW	Q1 2009
NSW	Mt Piper	Delta Electricity	Station capacity upgrade	Coal	+180 MW	Q1-Q2 2009
QLD	Condamine	Queensland Gas Co.	Conversion of OCGT to CCGT	Natural gas	+40 MW	Q3 2009
TAS	Bell Bay	Alinta Ltd	Closure of existing thermal units	Natural gas	-240 MW	Q3 2009
TAS	Tamar	Alinta Ltd	Tamar Valley power station (CCGT)	Natural gas	+200 MW	Q3 2009
TAS	Bell Bay Three	Alinta Ltd	Expansion of existing OCGT units to 180MW	Natural gas	+75 MW	Q3 2009
NSW	Munmorah	Delta Electricity	Construction of Munmorah OCGT stage 1	Natural gas	+330 MW	Q4 2009
QLD	Darling Downs	Origin Energy	Construction of 630MW CCGT (360 GT/270 ST)	Natural gas	+630 MW	Q1 2010
VIC	Bogong	AGL Energy	Expansion of Bogong hydro	Hydro	+140 MW	Q3 2010
QLD	Gladstone	Stanwell Corporation	Assumed return to full-time service of unit 6	Coal	+280 MW	Q1 2011
QLD	Swanbank B	CS Energy	Announced retirement of Swanbank B units	Coal	-480 MW	Q2 2011
QLD	Spring Gully	Origin Energy	Assumed stage 1 of Spring Gully project (or similar well-head coal seam gas development)	Natural gas	+500 MW	Q1 2012

Data source: ACIL Tasman; various company media releases

The 400 MW Integrated Drying and Gasification Combined Cycle (IDGCC) demonstration plant[10] proposed by HRL is assumed to commence after the projection period. Should this demonstration plant be committed and completed within the AA3 period, it is likely to have the effect of suppressing GPG volumes once it comes on line.

For existing plant drought impacts have been incorporated through the adoption of assumptions as follows:

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[10] See HRL media release: New clean coal power station to be built in Latrobe Valley, 12 March 2007

- Reduced annual output from Snowy hydro over the next three years before recovering to normal output levels by the end of the period. Annual dispatch volumes for Snowy hydro are:
  - 3,300 GWh in 2008-9; 3,900 GWh in 2010; 4,700 GWh in 2011; 5,100 GWh in 2012
- Laverton North is assumed to return to peaking duties only from September 2007 onwards
- Reduced capacity at Swanbank B until the commissioning of Stage 1A of the Queensland Government's Western Corridor Recycled Water Project (WCRWP), scheduled for completion in August 2007
- Reduced capacity for Tarong and Tarong North stations until Stage 1B of the WCRWP is complete (assumed August 2008).

3.1.3 Interconnectors

Interconnectors can either be a source of lower priced electricity coming into a region, or a means to export surplus capacity. A summary of the interconnectors and capacities assumed in the base case is shown in Table 11.

Table 11 **Interconnector capacity**

Sending Region	Receiving Region	Capacity (MW)
Snowy	VIC	1900
VIC	Snowy	1200
Snowy	NSW	3200 (Peak); 3000 (Off-Peak)
NSW	Snowy	1150
VIC	SA	460
SA	VIC	300
VIC (Murraylink)	SA (Murraylink)	220
SA (Murraylink)	VIC (Murraylink)	120 (Off-Peak); 70 (Peak - Summer); 70 (Peak - Winter)
VIC	TAS	300
TAS	VIC	480 (600 for up to 3 consecutive hours)
NSW	QLD	600
QLD	NSW	1078
NSW (Terranora)	QLD (Terranora)	100 (Summer); 130 (Winter)
QLD (Terranora)	NSW (Terranora)	180 (Summer); 238 (Winter)

Data source: ACIL Tasman

ACIL Tasman uses the quadratic loss equations for each interconnector as specified annually by NEMMCO.

3.1.4 Other assumptions

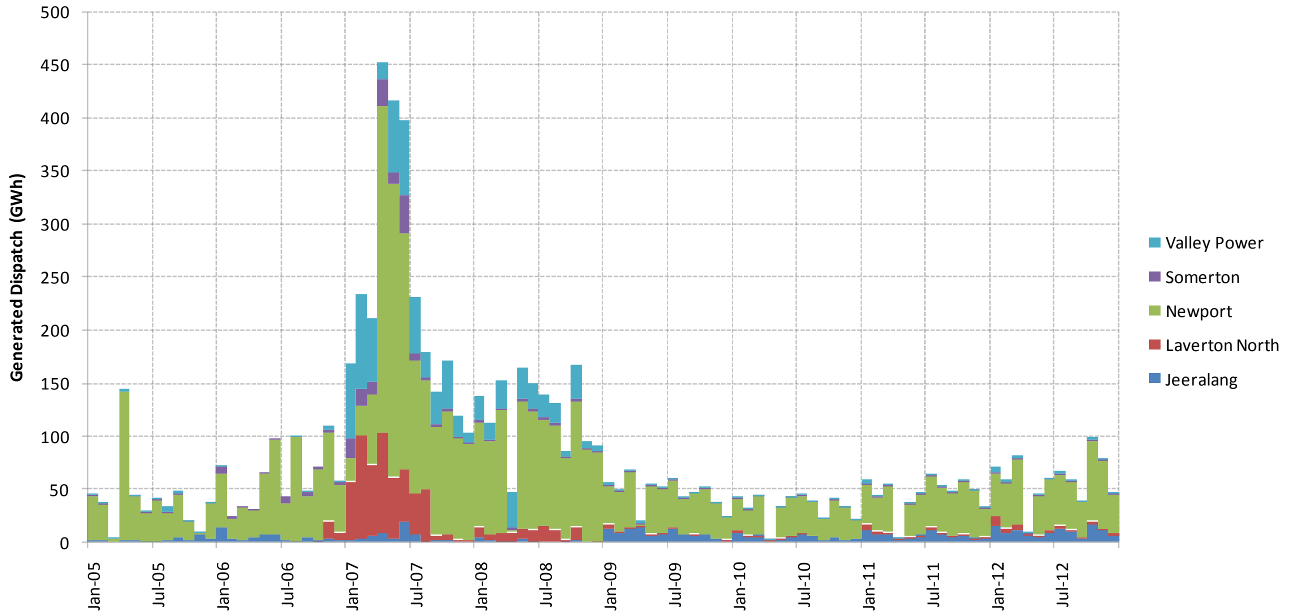
While the introduction of an emissions trading scheme now appears almost certain, the timing and design of the scheme remains unclear. Importantly for this project, the introduction of a comprehensive scheme is most likely to occur from late 2011 onwards. While emissions trading will have a positive impact upon gas-fired generation relative to coal (due to the lower emission intensity of gas-fired generation) it is likely that initial permit prices will be relatively moderate. Furthermore, removal of existing State-based environmental schemes may potentially offset any benefits from emissions trading in the early years until permit prices increase.[11]

For the purposes of this project it has been assumed that emissions trading does not commence within the AA3 period and that existing State-based schemes continue throughout.

3.2 Results

Figure 1 shows the resulting GPG dispatch from the modelling. Price levels in the NEM are expected to result in heightened levels of gas-fired dispatch from the Victorian peaking stations until early 2009.

Figure 1 **Victorian GPG dispatch: January 2005 to December 2012**



Note: Excludes non-PTS stations. Actuals presented to 31 July 2007. Values presented on a generated basis

Data source: Historical data from NEMMCO, ACIL Tasman PowerMark modelling

[11] Transitional arrangements may provide financial compensation, however this may not be tied to operational decisions regarding plant dispatch.

Table 12 details the annual dispatch for each GPG user on the PTS.

Table 12 **Projected Victorian GPG dispatch (GWh)**

Calendar Year	Jeeralang	Laverton North	Newport	Somerton	Valley Power
2006	46	24	638	34	7
2007	48	535	1,539	130	534
2008	14	91	1,097	27	236
2009	99	12	432	6	12
2010	50	6	335	3	6
2011	80	17	433	6	16
2012	116	34	533	7	23

Note: Actual dispatch shown to 31 July 2007. Values presented on a generated basis
Data source: Historical values from NEMMCO, ACIL Tasman *PowerMark* modelling

3.3 Converting dispatch to gas use

In converting the dispatch results from *PowerMark* into gas use by GPG user, ACIL Tasman has relied upon historical implied thermal efficiencies for each plant. Table 13 details generated dispatch (obtained from 30 minute NEMMCO data), gas use (obtained from daily VENCorp meter data) and calculated implied average heat rate (in GJ/MWh generated) for each station.

It should be noted that within Table 13 the calculated heat rates for Valley Power in years prior to 2007 are likely to be distorted by gas use at Loy Yang B.[12] For this reason the calculated heat rate for 2007 has been used rather than the average across all years as with other stations.

[12] A separate meter for the Valley Power station was only introduced from January 2007.

Table 13 **Historical thermal efficiencies of GPG users**

Calendar Year	Jeeralang	Newport	Somerton	Laverton North	Valley Power
Generated Dispatch (MWh)					
2001	60,229	1,148,208	0	0	0
2002	46,741	581,643	7,653	0	46,824
2003	73,962	286,325	8,603	0	19,738
2004	185,205	1,275,715	14,350	0	35,127
2005	22,035	449,317	4,542	0	17,761
2006	46,475	638,197	33,565	23,778	6,946
2007	48,932	1,002,224	125,157	442,516	412,547
Total	483,579	5,381,627	193,870	466,294	538,942
Gas use (GJ)					
2001	899,373	11,811,624	625	0	93,977
2002	706,246	6,093,859	128,667	0	769,417
2003	1,192,156	3,020,393	141,605	0	395,028
2004	2,821,365	13,078,153	212,497	0	622,502
2005	352,685	4,710,808	74,670	0	348,259
2006	737,069	6,721,168	466,316	236,362	192,796
2007	658,618	9,995,493	1,708,697	5,148,927	5,983,430
Total	7,367,512	55,431,498	2,733,077	5,385,289	8,405,410
Implied heat rate (GJ/MWh generated)					
2001	14.9	10.3			0.0
2002	15.1	10.5	16.8		16.4
2003	16.1	10.5	16.5		20.0
2004	15.2	10.3	14.8		17.7
2005	16.0	10.5	16.4		19.6
2006	15.9	10.5	13.9	9.9	27.8
2007	13.5	10.0	13.7	11.6	14.5
Average HR	15.2	10.3	14.1	11.5	14.5
Efficiency	23.6%	35.0%	25.5%	31.2%	24.8%

Note: Assumes all generation is gas-fired, with no distillate/liquids use
Data source: VENCorp, NEMMCO, ACIL Tasman

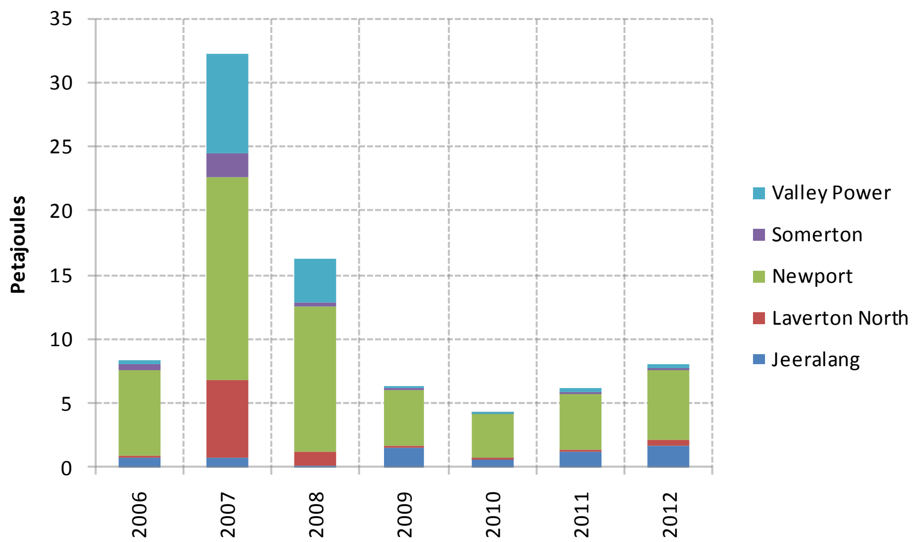
Using these heat rates, ACIL Tasman has converted the projected dispatch by GPG user into projected annual gas volumes as detailed in Table 14 and shown graphically in Figure 2. Aggregate GPG gas consumption is projected to reach 32.3 PJ in calendar year 2007, falling to 16.4 PJ in 2008. Years 2009 through to 2012 see GPG use in single digit figures as the impact of drought conditions is relieved and new plant is introduced to the system. 2010 is projected to be especially low with only 4.4 PJ as a result of new plant introduced in late 2009/early 2010 (as detailed in Table 10) which suppresses spot electricity prices.

Table 14 **Projected annual GPG consumption (PJ)**

Calendar Year	Jeeralang	Laverton North	Newport	Somerton	Valley Power	Total GPG
2006	0.7	0.2	6.7	0.5	0.2	8.4
2007	0.7	6.2	15.9	1.8	7.7	32.3
2008	0.2	1.1	11.3	0.4	3.4	16.4
2009	1.5	0.1	4.5	0.1	0.2	6.4
2010	0.8	0.1	3.4	0.0	0.1	4.4
2011	1.2	0.2	4.5	0.1	0.2	6.2
2012	1.8	0.4	5.5	0.1	0.3	8.1

Note: Year 2006 and 2007 are provided for reference only.
Data source: ACIL Tasman *PowerMark* modelling

Figure 2 **Projected annual GPG consumption**



Data source: ACIL Tasman *PowerMark* modelling

3.4 Peak demand sensitivities

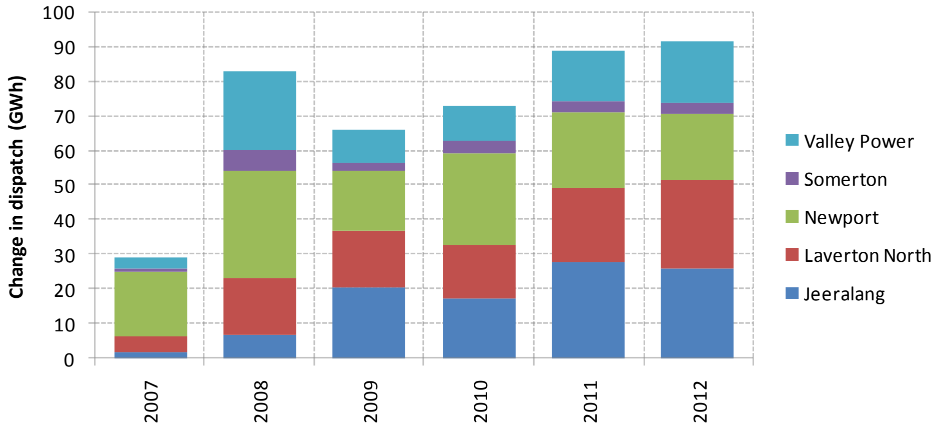
To test the robustness of the above results, high and low demand sensitivities were also run. The demand sensitivities were constructed as follows:

- High case: NEMMCO 10% POE demand forecast for Victoria and South Australia
- Low case: NEMMCO 90% POE demand forecast for Victoria and South Australia.

Changes were only applied to Victoria and South Australia due to weather correlation between these regions. No changes to annual energy or plant assumptions were made.

Figure 3 shows the change in dispatch from the High case (10% POE demands) relative to the base case. As a result of the higher demand forecast, additional GPG dispatch occurs ranging from 60 GWh to 90 GWh per annum. The impact upon 2007 is lower due to this year containing 6 months of actual data.

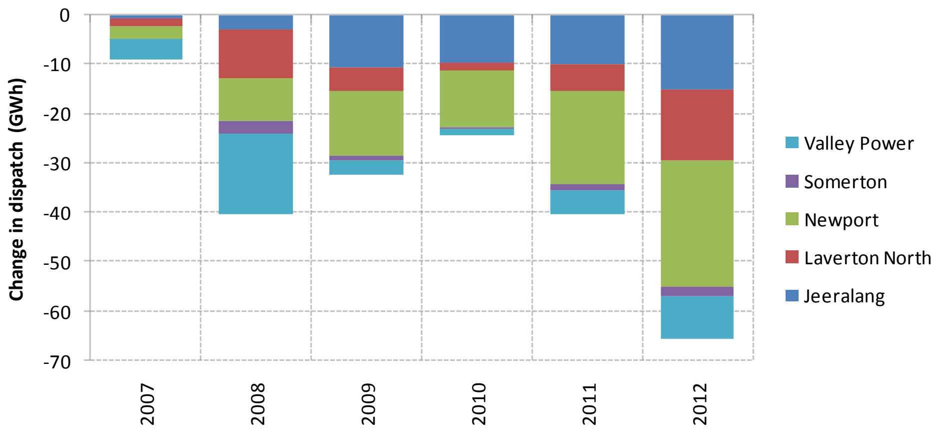
Figure 3 **Change in dispatch for PTS GPG users: High case**



Data source: ACIL Tasman *PowerMark* modelling

Figure 4 shows the change in dispatch relative to the Base Case under the 90% POE demand forecast (the Low Case). The Low case results lower GPG consumption with the impact generally smaller than seen in the high case. This is a result of the skewed nature of price distributions in the NEM.

Figure 4 **Change in dispatch for PTS GPG users: Low case**



Data source: ACIL Tasman *PowerMark* modelling

Table 15 summarises GPG consumption over the period 2007-12 under the Base case and demand sensitivities. The incremental gas consumption is also shown in Figure 5.

Table 15 **Projected gas consumption: demand sensitivities (PJ)**

Calendar Year	High Case	Base Case	Low Case
2007	32.7	32.3	32.2
2008	17.4	16.4	15.9
2009	7.2	6.4	6.0
2010	5.3	4.4	4.1
2011	7.3	6.2	5.7
2012	9.3	8.1	7.3

Note: 2007 contains actuals to 30 June.
Data source: ACIL Tasman

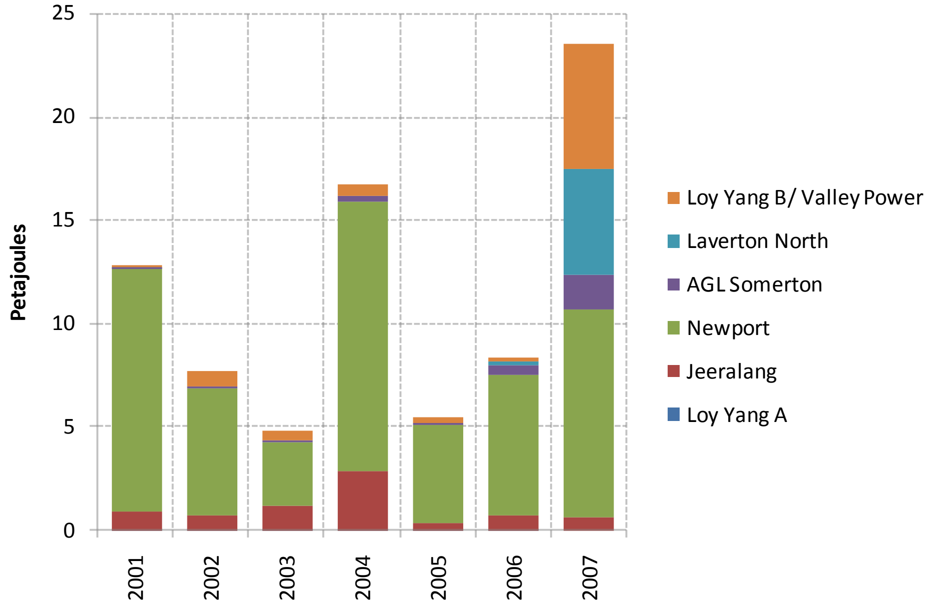
Figure 5 **Impact on GPG consumption relative to the Base case**

Note: 2007 contains actuals to 30 June.
Data source: ACIL Tasman

4 Conclusions

Historical GPG consumption has been volatile in recent years as shown in Figure 6. It is influenced by a number of factors including the level and volatility of wholesale electricity spot prices, electricity demand, planned and unplanned generator outages. GPG consumption is therefore difficult to predict accurately.

Figure 6 **Historical GPG consumption: 2001 to present**



Note: 2007 represents year to 30 June

Data source: ACIL Tasman based on VENCorp meter data

ACIL Tasman has reviewed the GPG forecast adopted by GasNet for AA3. These forecasts have relied heavily upon work by NIEIR which was commissioned by VENCorp and used within the 2006 GAPR. GasNet has also supplemented these forecasts with assumptions regarding allocations amongst GPG users and peak-day GPG consumption.

ACIL Tasman has derived its own projections of GPG consumption over the AA3 period due to two primary concerns with the existing analysis:

- An apparent lack of detail in the modelling approach and assumptions used by NIEIR within the 2006 GAPR forecasts
- Drought impacts upon the NEM which have resulted in abnormally high levels of GPG consumption throughout much of 2007, and potentially continuing in the short – medium term and affecting GPG consumption within AA3.

The results of ACIL Tasman's analysis are detailed in Table 16.[13]

Table 16 **Projected annual GPG consumption by GPG user (PJ)**

Calendar Year	Jeeralang	Laverton North	Newport	Somerton	Valley Power	Total GPG
2008	0.2	1.1	11.3	0.4	3.4	16.4
2009	1.5	0.1	4.5	0.1	0.2	6.4
2010	0.8	0.1	3.4	0.0	0.1	4.4
2011	1.2	0.2	4.5	0.1	0.2	6.2
2012	1.8	0.4	5.5	0.1	0.3	8.1

Data source: ACIL Tasman *PowerMark* modelling

We believe these projections to be more reliable than the NIEIR projections used by GasNet, for three primary reasons:

- Values are derived through detailed simulation of the NEM
- The most up-to-date information including announced new plant commitments and demand forecasts from NEMMCO have been used
- Our projections take into account drought effects on NEM operations that were not anticipated when the NIEIR projections were prepared.

ACIL Tasman has also tested the sensitivity of these GPG projections to forecast peak demand for Victoria and South Australia. As shown in Table 17, projected GPG demand is, on average, around 1 PJ/a higher under the 10% POE demand forecast and 0.5 PJ/a lower under the 90% POE demand forecast. The differences between the high and low sensitivities reflect the skewed nature of electricity spot prices and hence, peaking station utilisation.

Table 17 **Impact of demand forecast upon GPG consumption (PJ)**

Calendar Year	High case (10% POE demand forecast)	Low case (90% POE demand forecast)
2007	+0.3	-0.1
2008	+1.0	-0.5
2009	+0.9	-0.4
2010	+0.9	-0.3
2011	+1.2	-0.5
2012	+1.2	-0.8

Data source: ACIL Tasman

In relation to the peak day GPG forecasts, ACIL Tasman considers the 50 TJ/day figure proposed by GasNet to be not unreasonable, based on historical observations.

[13] While some gas use is reported for Loy Yang A and Loy Yang B, ACIL Tasman has not included this within its analysis as these volumes are considered immaterial.

Given the difficulties in projecting peak usage, the allocation of the peak day GPG volumes across users in accordance with the annual forecast volumes for each user is considered to be as reliable as other methods that could logically be applied.

Table 18 **Projected peak day GPG consumption by GPG user (TJ)**

Calendar Year	Jeeralang	Laverton North	Newport	Somerton	Valley Power	Total GPG
2008	0.7	3.2	34.5	1.2	10.4	50.0
2009	11.9	1.1	35.0	0.6	1.4	50.0
2010	8.6	0.8	39.0	0.5	1.1	50.0
2011	9.8	1.6	36.1	0.7	1.8	50.0
2012	10.9	2.5	33.9	0.6	2.1	50.0

Data source: ACIL Tasman *PowerMark* modelling