VICTORIAN ANNUAL PLANNING REPORT UPDATE

Victoria's Electricity and Gas Transmission Network Planning Document

2009

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

VICTORIAN ELECTRICITY AND GAS TRANSMISSION NETWORKS

Disclaimer

This publication has been prepared by the Australian Energy Market Operator Limited (AEMO) based on information provided by electricity and gas industry participants. This is the completing part of the annual planning review, the first part of which was published in the Victorian Annual Planning Report (VAPR) in June 2009 and meets outstanding obligations under Rule 323 of the National Gas Rules.

AEMO has not independently audited or verified the data or information provided by participants but has reasonably endeavoured to ensure that this document accurately reflects the information provided to AEMO by those participants. Anyone proposing to use the information in this VAPR Update should independently verify and check the accuracy, completeness, reliability and suitability of the information to their satisfaction prior to taking any action on the VAPR Update or any part of it. This publication contains certain predictions, estimates and statements that reflect various assumptions. Those assumptions may or may not prove correct. The forecasts in this document may change from year to year. Those forecasts may or may not prove to be correct.

The information contained in this publication might contain errors or omissions, and may or may not prove to be correct. In all cases, anyone proposing to rely on or use the information in this publication should independently verify and check the accuracy, completeness, reliability, and suitability of that information (including information and reports provided by third parties) and should obtain independent and specific advice from appropriate experts. Accordingly, to the maximum extent permitted by law, neither AEMO, nor any of AEMO's advisers, consultants or other contributors to this publication (or their respective associated companies, businesses, partners, directors, officers or employees):

a) make any representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of this publication and the information contained in it; and

b) shall have any liability (whether arising from negligence, negligent misstatement, or otherwise) for any statements, opinions, information or matter (expressed or implied) arising out of, contained in or derived from, or for any omissions from, the information in this publication, or in respect of a person's use of the information (including any reliance on its currency, accuracy, reliability or completeness) contained in this publication.

Copyright Notice

Acknowledgment

AEMO acknowledges the support, co-operation and contribution of all participants in providing the data and information used in this VAPR Update.

[This page is intentionally left blank]

Table of Contents

Executive summary

The Victorian Annual Planning Report (VAPR) is an independent planning report prepared by AEMO in accordance with Section 5.6.2A of the National Electricity Rules and Rule 323 of the National Gas Rules (NGR). It provides forecasts for Victorian energy demand and supply, and assesses the adequacy of Victoria's gas and electricity transmission networks.

This is the completing part of the annual planning review, the first part of which was published in the Victorian Annual Planning Report (VAPR) in June 2009. This report meets outstanding obligations under Rule 323 of the National Gas Rules.

The VAPR Update can be read in conjunction with the 2009 VAPR published in June and provides the latest gas demand forecasts.

Highlights

Forecasts suggest that gas demand on the Victorian Declared Transmission System (DTS) will increase by 13% by 2019.

This represents significant growth in gas powered generation (GPG) demand, which is expected to increase from around 15 PJ in 2009 to 38 PJ by 2019. Economic and environmental factors are expected to suppress system demand growth, which includes residential, commercial and industrial loads on the DTS but excludes GPG demand.

- System demand is expected to increase 3.1% by 2019;
- Residential (Tariff V) demand is forecast to remain in line with population and household income growth, increasing 6.2% by 2019; and
- Commercial and industrial (Tariff D) demand is expected to decrease 1.4% by 2019.

The main changes since the 2008 forecasts were prepared include some recently announced manufacturing plant closures and economic recovery occurring slightly faster than previously forecast.

- Annual system demand (total demand excluding GPG) is now expected to reach 213.9 PJ in 2018, compared to the 2008 forecast of 215.1 PJ by 2018;
- Residential demand (Tariff V) is now forecast to be 129.7 PJ in 2018, compared to the 2008 forecast of 126.4 PJ in 2018; and
- Commercial and industrial (Tariff D) demand is now forecast to be 84.2 PJ in 2018, lower than the 88.7 PJ forecast in 2008.

In the 2008 VAPR Update it was noted that GPG demand growth on the DTS is difficult to predict as new GPG will not necessarily receive gas supply directly from the DTS. In many cases, dedicated pipelines may be built independently of the DTS. Since the 2008 VAPR Update forecasts were prepared, the Mortlake Power Station has moved to committed status and is expected to be commissioned by October 2010[1]. Mortlake Power Station will source gas via a dedicated pipeline and hence will not impose gas demand on the DTS. Other proposed GPG projects in Victoria are likewise not expected to contribute to gas demand on the DTS.

The GPG forecasts included in this VAPR Update reflect growth in GPG demand on the DTS only. This growth is expected to arise chiefly from increasing demand at existing power stations in response to the proposed CPRS. By 2019, GPG demand on the DTS is forecast to increase to approximately 2.5 times the current levels.

The information in this VAPR Update allows industry and other stakeholders to cater for demand increases and develop a safe, secure, reliable and economically viable DTS. This information will enable the assessment of future requirements for gas supplies and DTS augmentation, as well as the availability of spare capacity for new system connections.

Peak day gas demand forecasts

Peak demand forecasts are key inputs to the planning processes for gas networks. Table 1 shows the 1 in 2 and 1 in 20 peak day system demand for the forecast period (excluding GPG

[1] See AEMO Generator Information Page http://www.aemo.com.au/data/gendata.shtml

demand, Iona withdrawals and exports). The annual average growth rates for the forecast period are 0.53% and 0.58% per annum for the 1 in 2 and 1 in 20 forecasts respectively. Peak day growth rates are forecast to be higher than annual demand growth rates, reflecting the temperature-sensitive component of residential gas demand which varies with population growth rather than economic factors.

The actual peak demand in 2009 was 1,121 TJ and this occurred on Tuesday, 9 June. The 2009 peak demands shown in Table 1 are the actual peak day demands weather-normalised to the 1 in 2 and 1 in 20 peak day conditions.

Table 1 Peak day gas demand forecasts, 2009-2019 (TJ)

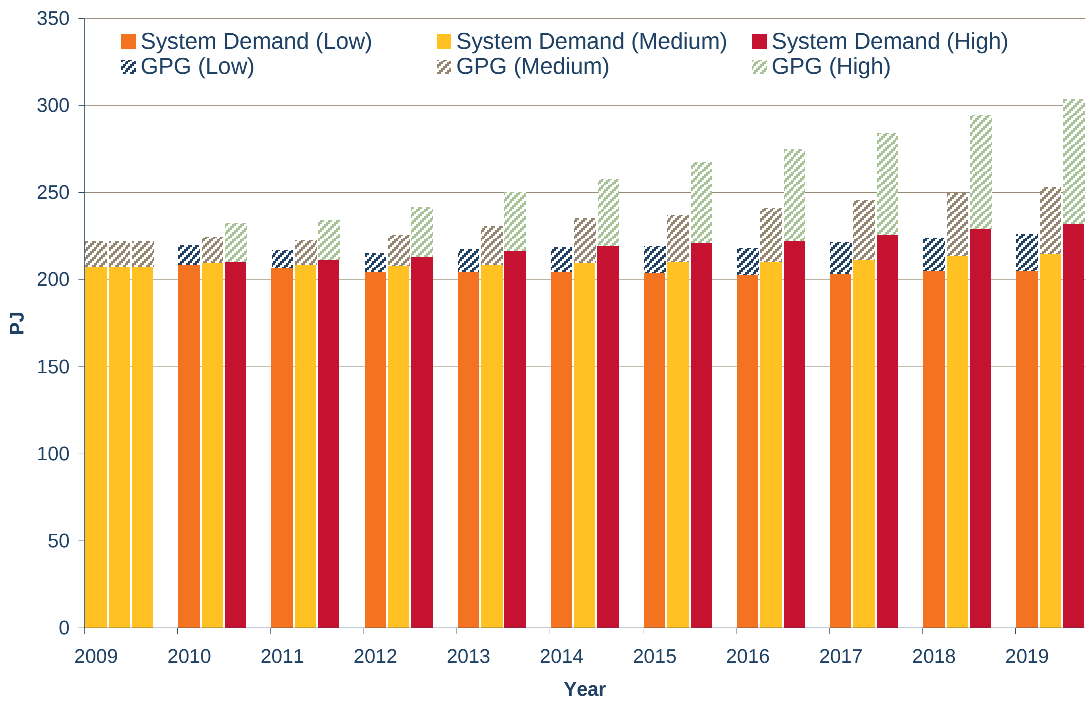
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	AVERAGE ANNUAL GROWTH 2010-2019
1 IN 2	1,154	1,181	1,193	1,197	1,198	1,204	1,209	1,213	1,223	1,231	1,238	
ANNUAL GROWTH		2.30%	1.07%	0.31%	0.09%	0.44%	0.45%	0.31%	0.87%	0.61%	0.63%	0.53%
1 IN 20	1,242	1,296	1,310	1,315	1,317	1,323	1,330	1,334	1,347	1,356	1,365	
ANNUAL GROWTH		4.40%	1.08%	0.35%	0.15%	0.49%	0.49%	0.36%	0.92%	0.66%	0.68%	0.58%

Annual gas demand forecasts

Figure 1 provides an overview of the annual system demand and GPG demand forecasts. These forecasts exclude Iona withdrawals and exports, and are made for the low, medium and high economic growth scenarios. The annual average growth rates for the forecast period are -0.2%, 0.3%, and 0.8% per annum for the low, medium and high economic growth scenarios, respectively.

GPG demand forecasts include DTS demand only.

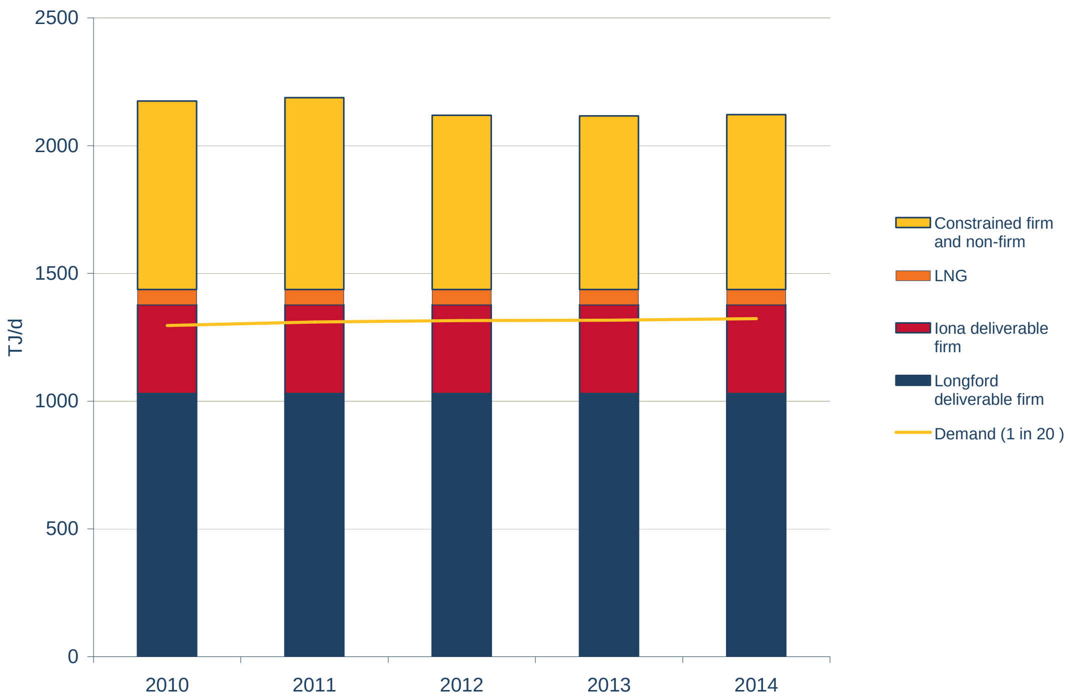
Figure 1 Annual system and GPG gas demand forecast, 2009-2019



Gas transmission capacity

Figure 2 provides an overview of the forecast peak day demand, supply, and transmission system capacity for the DTS. It gives a summary of the deliverable winter peak day firm and LNG supplies against the forecast 1 in 20 peak day demand for the forecast period. Deliverable winter peak day firm supplies are limited by pipeline capacity and deliverable LNG supplies are assumed to be a maximum of 60 TJ/d for within-day balancing. The firm supply from Iona, which is constrained by existing pipeline capacity, is also shown. Supplies shown in Figure 2 were provided to AEMO by gas market participants.

Figure 2 Peak day gas demand and supply forecast, 2010-2014 (TJ)



Liquefied Natural Gas (LNG) requirements

Table 2 lists a summary of the LNG requirements resulting from modelling 1 in 20 peak day system demand (excluding GPG demand). On a 1 in 20 peak day the capacity to supply GPG is very limited. The peak day assessment is based on the planning assumption that 60 TJ/d of LNG is available for effective within-day balancing. This assumes 11 hours of LNG vapourisation at the contract rate of 100 t/h.

The modelling assesses LNG requirements using flat and profiled injection rates from Iona. A profiled injection rate refers to higher injections in the morning and lower injections in the afternoon.

The results for 1 in 2 peak day and 1 in 20 peak day LNG requirements show that the LNG required to 10 pm will not exceed the 60 TJ/d available for within-day balancing in 2010. This is the case for both flat and profiled injection rates, although to a lesser extent with a profiled injection rate.

Table 2 1 in 20 peak day LNG requirements, 2010-2014 (TJ)

	2010	2011	2012	2013	2014
FORECAST SYSTEM DEMAND	1,296	1,310	1,315	1,317	1,323
LNG REQUIREMENT FOR FLAT INJECTION RATE AT IONA	37	40	42	42	44
LNG REQUIREMENT FOR PROFILED INJECTION RATE AT IONA	19	24	26	26	28

Electricity Value of Customer Reliability (VCR)

The electricity VCR is a measure of the cost of unserved energy and is used in regulatory test assessments of planned electricity transmission augmentations in Victoria.

Up until 2007, the VCR was estimated every five years using surveys to estimate direct end-user customer costs when electricity supply is lost. The ‘headline’ VCR increased from $29,600 to $47,850 per MWh between 2002 and 2007. Given its important role in evaluating network investment options, AEMO has now adopted an income/economic growth indexation approach to annually adjust the estimate and minimise such large jumps in the future.

Following application of this indexation approach to the 2007 VCR, the 2008 and 2009 VCRs are $51,000 and $55,000 per MWh respectively.

The 2010 figure of VCR will be calculated ahead of the electricity network analysis associated with the production of the 2010 VAPR.

Introduction

About this report

The Victorian Annual Planning Report 2009 Update (VAPR Update) is an independent report prepared by AEMO for the period 2010 to 2019. This is the completing part of the annual planning review, the first part of which was published in the Victorian Annual Planning Report (VAPR) in June 2009, and meets outstanding obligations under Rule 323 of the National Gas Rules.

The VAPR Update can be read in conjunction with the 2009 VAPR published in June and provides the latest gas demand forecasts.

This VAPR Update publishes forecasts of Victorian gas demand and supply, and informs market participants of any material changes to the VAPR 2009 for both gas and electricity.

The VAPR and the VAPR Update satisfy AEMO's obligations under Section 5.6.2A of the National Electricity Rules (NER) and Rule 323 of the National Gas Rules (NGR). Under the NER, AEMO is required to issue an electricity Annual Planning Report (APR) for Victoria by 30 June each year. Its primary purpose is to set out the demand and energy forecasts for Victoria, and review the adequacy of the shared transmission network over the next ten years.

The NGR requires AEMO to publish a Gas Annual Planning Review by 30 November each year. The Gas APR provides an assessment of the supply-demand outlook and the adequacy of system capacity. Additional information on maintenance plans, gas reserves and gas pipeline developments is also provided.

Prior to 2008 electricity and gas planning were addressed in separate planning reports published in June and November respectively. In 2008, a VAPR combining gas and electricity planning information was published for the first time in June, followed by a VAPR Update in November. This same approach has been followed in 2009[2].

All of the requirements of the NER and NGR of AEMO to publish annual planning reports for electricity and gas planning can be satisfied with a combined VAPR published in June except for the latest gas forecast information and information about liquefied natural gas (LNG) usage for the following winter period. The latest gas forecast information can only be prepared using the most recent winter observations once the peak winter period (June – August) is over. This information is included in the VAPR Update.

The VAPR Update also provides information on gas supply. Gas supply forecasts must be provided to AEMO by industry participants by the end of September and published by the end of November.

In this report:

- Chapter 1 presents forecasts of annual, monthly, peak day and peak hour gas demand for a ten year period from 2010;
- Chapter 2 presents supply forecasts including annual and peak day supplies of gas transported through the Declared Transmission System (DTS), for a five year period from 2010;
- Chapter 3 presents gas supply-demand balance information for 2010, and transmission network capacity forecasts for the next five years; and
- Chapter 4 presents the results of the latest Electricity Value of Customer Reliability (VCR) study and the Terminal Station Demand Forecasts (2009/10 – 2018/19).

The report also includes:

[2] The decision to combine gas and electricity APRs in this way was supported by the Australian Energy Regulator (AER) and the Gas Market Consultative Committee (GMCC), now known as the Gas Wholesale Consultative Forum (GWCF), and reflects the increasing physical, organisation and institutional linkages between the gas and electricity markets.

- Gas forecast methodologies (Appendix 0) and probability of exceedence (POE) standards (Appendix A2);
- Comparison of the 2008 and 2009 VAPR Update gas peak day and annual demand forecasts for the period 2009 to 2013 (Appendix A5);
- Details of Gas Power Generation (GPG) demand forecasts.

About AEMO

AEMO performs a number of functions within Victoria's electricity and gas industries. Pivotal to the delivery of a safe, secure and reliable supply of electricity and gas for all Victorians, its role involves planning and recommending expansion of Victoria's electricity and gas transmission networks, which provide a key link in the supply chain to the State's 2.2 million electricity and gas customers.

Closer gas and electricity market linkages are making it increasingly appropriate to consider gas and electricity together when planning either network. Gas suppliers are pursuing potential GPG opportunities to grow the gas market, which will increasingly link these two energy markets. At the same time, market mergers and acquisitions are tending to link these energy markets organisationally, and government action to streamline regulation is linking them institutionally, to the point that the Council of Australian Governments (CoAG) has implemented a move to a single national regulatory structure for the energy industry.

For information about electricity or gas planning

AEMO is pleased to provide interested parties with more detailed information about specific electricity or gas planning issues. See the AEMO website (www.aemo.com.au) for more information about other AEMO planning documents. For additional information that cannot be found on the website or for more detailed information about specific planning issues, contact the:

AEMO Help Desk

PO Box 413, World Trade Centre, Vic 8005

Phone: 03 8664 6500

Fax: 03 8664 6511

Email: helpdesk@aemo.com.au

Website: www.aemo.com.au

In line with AEMO's focus on continuous improvement, interested parties wishing to comment on the format and content of this report are encouraged to do so by emailing AEMO at the above address.

1 Gas demand forecasts

This chapter presents forecasts of annual, monthly, peak day and peak hour demand for gas supplied through the Declared Transmission System (DTS).

Forecast and actual data in this chapter pertain to gas days starting from 6am. Unless otherwise stated 'system demand' refers to demand from Tariff V customers (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D customers (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum), and excludes GPG demand, exports, and gas withdrawn at Iona. Distribution losses are implicitly included in the forecasts and transmission losses are negligible and are assumed to be zero.

In this chapter:

- Section 1.1 presents DTS gas demand forecasts
- Section 1.2 presents System Withdrawal Zone gas demand forecasts

1.1 Declared Transmission System gas demand forecasts

1.1.1 Annual gas demand forecasts

Annual demand forecasts are prepared for low, medium and high economic growth scenarios. The annual demand forecast calculations for the 2009 calendar year involve eight months of weather normalised actual metering data, to the end of August 2009, and demand forecasts for the period September-December 2009.

Table 1.1 lists the annual demand (excluding GPG) forecasts for the low, medium and high economic growth scenarios. See Section 1.1.6 for information on GPG demand forecasts.

Table 1.1 Annual system gas demand forecasts 2009-2019 (PJ)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	AVERAGE ANNUAL GROWTH 2010-2019
SYSTEM DEMAND												
HIGH	206.2	212.5	215.4	217.2	218.6	220.1	221.6	223.1	225.1	226.9	228.8	0.83%
MEDIUM	206.2	208.2	210.1	210.7	211.1	211.4	211.9	212.3	213.1	213.9	214.6	0.34%
LOW	206.2	204.4	205.2	204.8	204.1	203.5	202.9	202.3	202.1	201.8	201.5	-0.16%
SYSTEM DEMAND BY TARIFF GROUP (MEDIUM GROWTH)												
TARIFF V	121.1	123.2	124.2	124.7	125.1	125.8	126.6	127.4	128.6	129.7	130.8	0.67%
TARIFF D	85.1	85.0	85.9	86.0	86.0	85.6	85.2	84.9	84.5	84.2	83.8	-0.16%

Tariff V demand increases are driven by population growth, employment levels and household income, and are mitigated by improved gas appliance efficiency, increased reverse cycle air conditioner usage for heating, and reduced water heating demand due to lower water usage. Factors affecting Tariff D demand include building cycle sensitivities, increased competition from overseas imports in the manufacturing sectors and responses to a future Carbon Pollution Reduction Scheme (CPRS).

The system demand forecasts shown in Table 1.1 show a similar growth rate to those in the 2008 VAPR Update.

1.1.2 Monthly system gas demand forecasts for 2010

Table 1.2 lists the monthly system demand forecasts for the period January-December 2010. Forecast monthly system demand:

- varies between 10.7 PJ and 20.5 PJ in the months January-May and October-December; and
- reaches a maximum 27.9 PJ in July, the forecast coldest month of the year.

Table 1.2 Monthly system gas demand forecasts, January-December 2010 (PJ)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
SYSTEM DEMAND	10.8	10.7	12.1	14.8	20.5	25.0	27.9	25.4	20.3	16.4	12.7	11.7

1.1.3 Peak day gas demand forecasts

Peak day demand forecasts are prepared for the medium economic growth scenario, and exclude withdrawals from Iona, GPG demand, and export demand. Table 1.3 shows the weather normalised 2009 1 in 2 and 1 in 20 peak day system demand and the 1 in 2 and 1 in 20 peak day system demand forecasts.

Table 1.3 Peak day gas system demand forecast, 2009-2019 (TJ)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	AVERAGE ANNUAL GROWTH 2010-2019
1 IN 2	1,154	1,181	1,193	1,197	1,198	1,204	1,209	1,213	1,223	1,231	1,238	0.53%
1 IN 20	1,242	1,296	1,310	1,315	1,317	1,323	1,330	1,334	1,347	1,356	1,365	0.58%

Table 1.3 shows the peak day system demand for 2009 normalised for 1 in 2 and 1 in 20 peak day conditions. The actual peak day system demand in 2009 was 1,121 TJ. This peak demand occurred on Tuesday 9 June, which was the coldest day in the 2009 winter on an effective degree day (EDD) basis, having had an EDD of 13.8, below the 1 in 2 year weather standard of 14.55 and the 1 in 20 year weather standard of 16.8.

Peak day demand is sensitive to weather conditions, with increased heating load expected on colder winter days. The peak day forecasts are presented for two weather standards:

- The 1 in 2 peak day, which represents a milder standard, with weather conditions for the day expected to be exceeded once every two years, or a 50% probability of exceedence (POE); and
- The 1 in 20 peak day, which represents more severe weather conditions, expected to be exceeded once in 20 years, or a 5% POE. This is the planning standard for assessing gas supply adequacy and transmission system capacity.

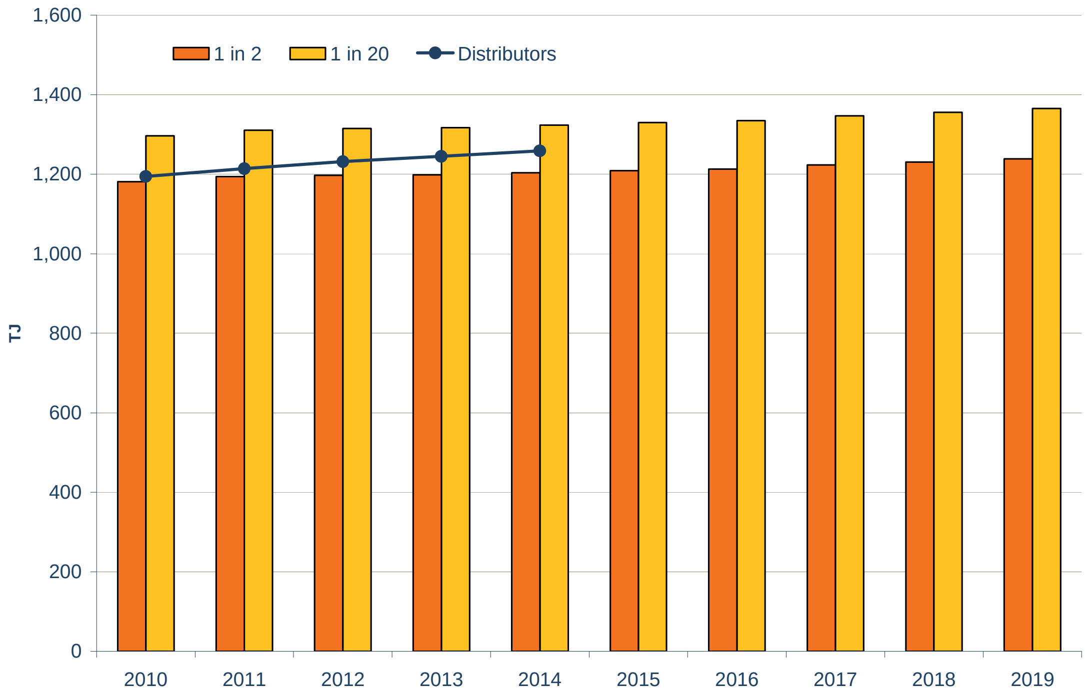
As shown in Table 1.3, the 1 in 2 peak day system demand is forecast to grow at an average annual rate of 0.53% over 2010-2019 and the 1 in 20 peak day system demand at an average annual rate of 0.58% over the same period. These peak day system demand growth rates are greater than the annual system demand growth rate, which is forecast to be 0.34% on average per annum over the same period.

Peak day growth rates are forecast to be higher than annual demand growth rates due to the temperature-sensitive component of residential gas demand which increases with population growth, rather than in response to economic factors. Historically, economic factors have tended to constrain residential gas usage during periods of mild temperature conditions to a greater extent than during severe weather conditions.

Over the 10 year forecast period, peak day system demand is now forecast to grow at a slower rate than was forecast in the 2008 VAPR Update. In the short term, from 2010 to 2013, system peak day demand is forecast to be higher than that forecast in the 2008 VAPR Update due to an earlier than previously forecast economic recovery.

Figure 1.1 shows the 1 in 2 and 1 in 20 peak day forecasts. The distributor forecast of 1 in 2 peak day demand is also shown.

Figure 1.1 Peak day gas system demand forecast, 2010-2019 (TJ)



See Appendix A5 for a comparison between the 2009 forecasts, presented above, and the 2008 peak day system demand forecasts.

1.1.4 Monthly peak day gas demand forecasts

Monthly peak day system demand is strongly influenced by weather conditions and seasonal industrial demand variations.

Table 1.4 lists the peak day system demand forecasts for the period January-December 2010.

Table 1.4 Peak day gas system demand forecasts, January-December 2010 (TJ)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1 IN 2	443	480	559	711	932	1,181	1,181	1,181	1,181	821	732	575
1 IN 20	500	568	673	825	1,045	1,296	1,296	1,296	1,296	940	846	689

For planning purposes, it is assumed that the 2010 peak day demand could occur at any time in June-September. Peak day forecasts for the October-April months are based on monthly weather standards.

The forecast 1 in 20 peak day system demand is approximately:

- 9.8% higher than the forecast 1 in 2 peak day system demand during the period of most-likely peak demand (June-September); and
- 12.2% to 20.4% higher than the forecast 1 in 2 peak day system demand in shoulder months (May, October, and November) due to greater variability in weather conditions in spring and late autumn.

1.1.5 Peak hour gas demand forecasts

Peak hour system demand forecasts have been prepared for the medium economic growth scenario. Table 1.5 lists the annual peak hour forecasts for 2010 to 2019, and Table 1.6 lists the monthly peak hour forecasts for 2010.

Table 1.5 Annual peak hour gas system demand, 2010-2019 (TJ)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 IN 2	74.2	75.0	75.5	75.3	74.6	74.5	74.9	75.4	75.9	76.3
1 IN 20	81.7	82.5	83.0	82.8	82.2	82.1	82.6	83.1	83.6	84.1

Table 1.6 Monthly peak hour gas system demand, 2010 (TJ)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1 IN 2	23.6	27.0	31.1	45.5	58.9	74.2	73.8	72.6	75.4	51.2	44.4	33.1
1 IN 20	26.7	32.2	37.7	53.0	66.3	81.7	81.2	79.9	83.0	58.8	51.5	39.8

1.1.6 Gas power generation (GPG) gas demand forecasts

GPG demand is sensitive to a number of factors, including:

- Weather conditions, particularly during extreme weather events in summer and winter when peak electricity demands are highest;
- Unplanned generation plant outages;
- Contractual arrangements between electricity retailers and individual GPGs; and
- Planned load transfers, associated with National Electricity Market (NEM) adequacy of supplies and regional capacity transfers.

The GPG demand forecasts published in the 2009 VAPR have been updated following a series of recent developments, including:

- The expected Federal Government CPRS, which will affect the gas demand for GPG located in Victoria; and
- The planned commissioning of Stage 1 of Mortlake Power Station (550 MW Open Cycle Gas Turbine) in October 2010 with associated dedicated gas pipeline; and
- Planned and publicly announced GPG projects with plans to source gas without contributing to demand on the Victorian DTS.

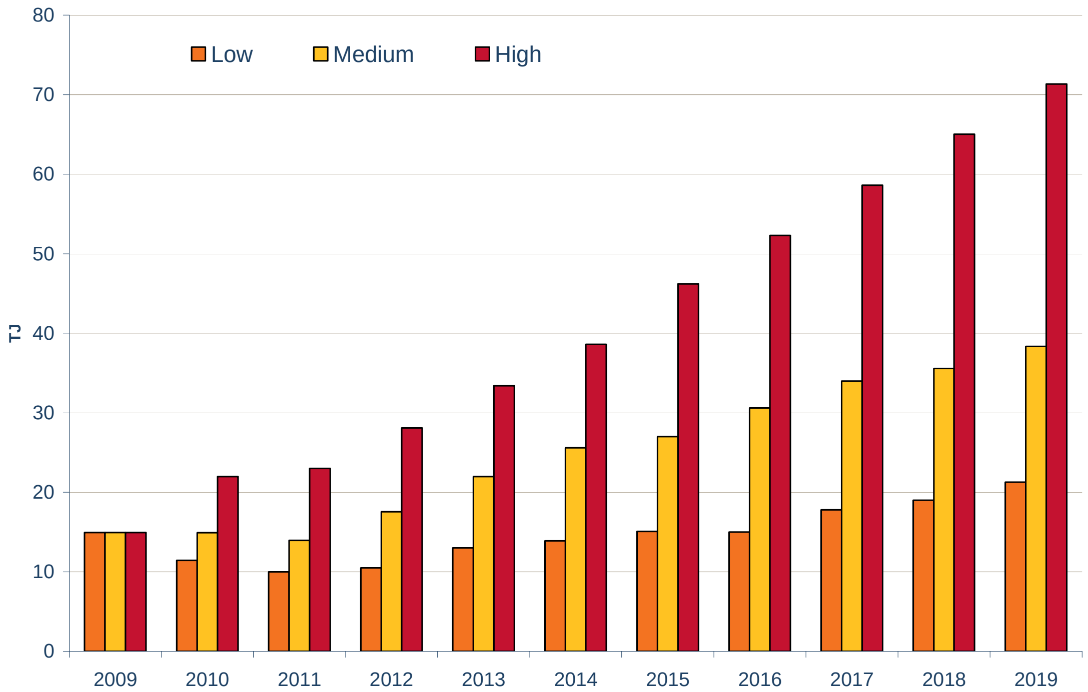
The GPG forecasts in the 2009 VAPR Update include only expected demand on the DTS. This demand is forecast to arise chiefly from increasing demand at existing GPG units.

GPG demand (medium scenario) is estimated to be 14.9 PJ in 2009 (based on partial year data, extrapolated to a full year estimate). The medium growth scenario projects this to remain relatively constant at 14.9 PJ in 2010, and then fall to 14.0 PJ in 2011 due to the impact of Mortlake commissioning.

GPG demand is then projected to start growing from 2012 onwards as the CPRS takes effect. By 2019 total GPG demand is forecast to be 38.3 PJ.

Forecasts are prepared for a low, medium and high GPG demand scenario. The GPG scenarios shown here include only DTS connected GPG demand. Figure 1.2 presents the GPG demand growth under all three scenarios. These forecasts are indicative only since annual GPG demand is highly variable. For example, annual GPG demand averaged 9.7 PJ from 2000 to 2006 and 29.6 PJ from 2007 to 2008.

Figure 1.2 Low, medium and high DTS connected GPG gas demand growth scenario 2010-2019 (PJ)



It is expected that the majority of the GPG growth will be driven by existing GPG plant increasing its output. Under the high economic growth scenario, additional demand from new Open Cycle Gas Turbine (OCGT) or Combined Cycle Gas Turbine (CCGT) plant, or conversion of existing OCGT to CCGT is forecast on the DTS.

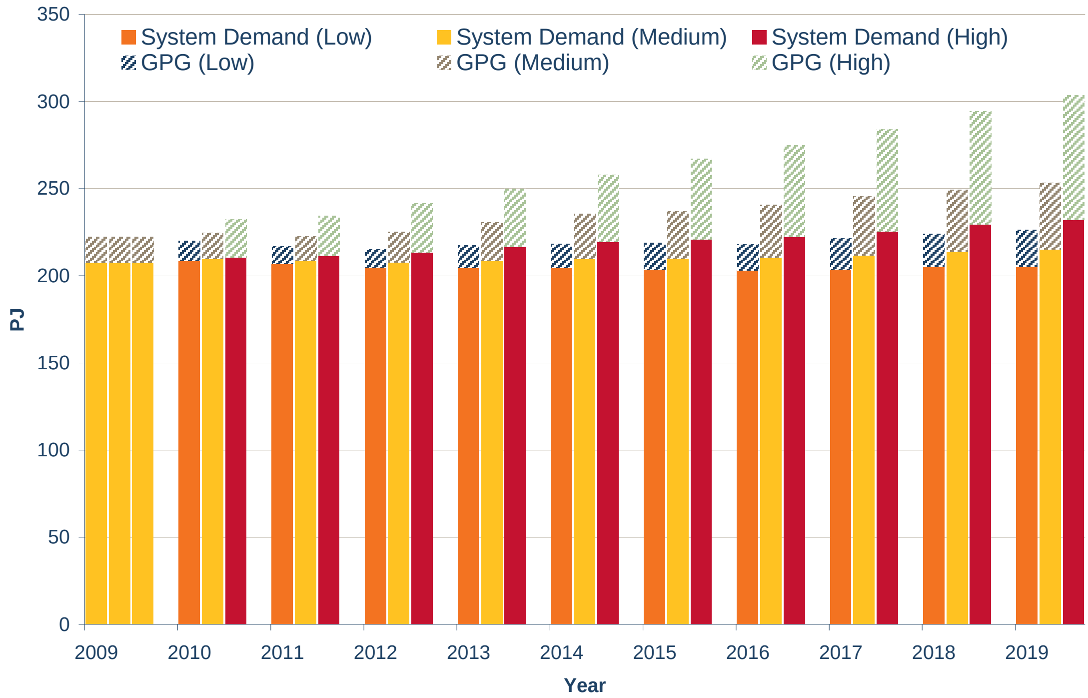
Table 1.7 lists the annual demand forecasts for a low, medium and high economic growth scenario combined with a low, medium and high GPG demand scenario, respectively.

Table 1.7 Annual system and GPG gas demand forecast, 2009-2019 (PJ)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	AVERAGE ANNUAL GROWTH 2010-2019
HIGH	221.1	234.5	238.4	245.3	252.0	258.7	267.8	275.4	283.7	291.9	300.2	2.78%
MEDIUM	221.1	223.1	224.0	228.3	233.1	237.1	238.9	242.9	247.2	249.4	252.9	1.40%
LOW	221.1	215.8	215.2	215.3	217.1	217.4	218.0	217.3	219.9	220.8	222.8	0.35%

Figure 1.3 shows the annual system demand and GPG demand forecasts for the low, medium and high economic growth scenarios for the period 2009-2019.

Figure 1.3 Annual system and GPG gas demand forecast, 2009-2019 (PJ)



1.1.7 Gas export demand

Possible scenarios for interstate exports over the next five years include the following:

In the past, exports to New South Wales via Culcairn normally occurred outside the winter peak period. Injections occurred at Culcairn from June to August in 2006, while for all months in 2007, there had been net exports. This trend has continued throughout 2008 and there have been no net imports through Culcairn. Higher exports have occurred since commissioning of the compressor at Culcairn in readiness for commissioning of the Uranquinty power station in NSW. For the 12 months to the end of September 2009, there were exports of 4.6 PJ for October 2008 to April 2009 and imports of 3.9 PJ for May 2009 to September 2009 at Culcairn compared to exports of 3.5 PJ for the year to September 2008. It is reasonable to assume that exports could increase in the future at Culcairn.

Interstate export via VicHub is currently negligible. Exports at VicHub can be delivered to either New South Wales or Tasmania. No significant change is expected to VicHub exports in 2010. Additional GPG in NSW could provide the opportunity for increased exports to NSW from VicHub.

1.2 System withdrawal zone gas demand forecasts

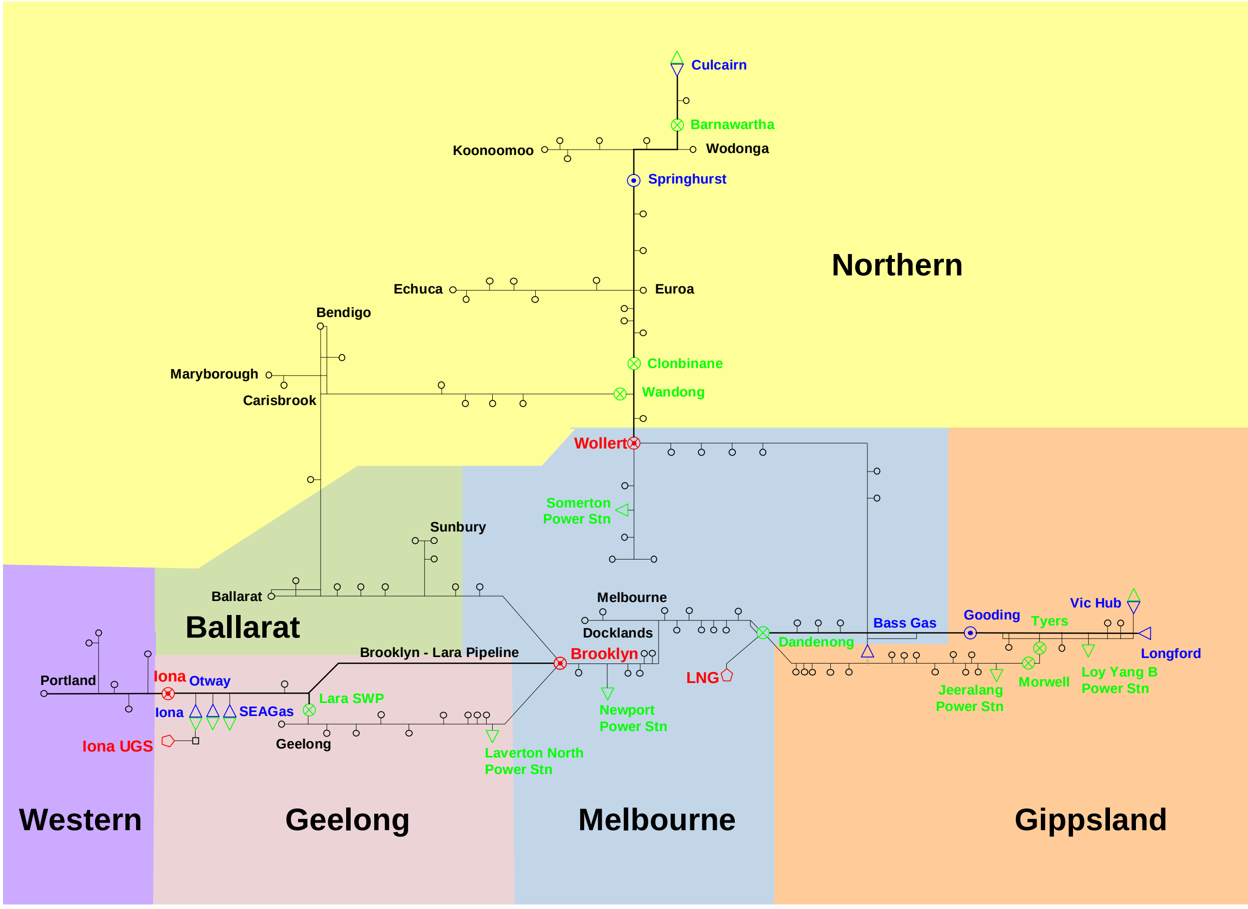
Under the NGR, AEMO is required to publish load forecasts by defined regions known as System Withdrawal Zones. These regions are shown in Section 1.2.1.

1.2.1 System withdrawal zones

The gas market comprises six system withdrawal zones (SWZs): Ballarat, Geelong, Gippsland, Melbourne, Northern, and Western. Demand forecasts are required for each SWZ as well as for the DTS as a whole.

Figure 1.4 shows the location of each SWZ.

Figure 1.4 System withdrawal zones



1.2.2 Annual gas demand by system withdrawal zone

The annual system demand forecasts by SWZ have been prepared for the medium economic growth scenario and are shown in Table 1.8. The annual demand forecast calculations for the 2009 calendar year involve eight months of weather-normalised actual metering data for the period January-August 2009, and demand forecasts for the period September-December 2009.

Table 1.8 Annual gas system demand forecast by SWZ, 2009-2019 (PJ)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	AVERAGE ANNUAL GROWTH 2010-2019
BALLARAT	8.9	9.0	9.1	9.1	9.2	9.3	9.3	9.4	9.5	9.5	9.6	0.73%
GEELONG	24.1	24.5	25.2	25.5	25.7	25.6	25.4	25.4	25.4	25.3	25.3	0.36%
GIPPSLAND	14.8	14.7	14.8	14.5	14.9	14.6	14.5	14.5	14.5	14.5	14.5	-0.16%
MELBOURNE	135.8	137.3	137.9	138.5	138.0	138.7	139.2	139.7	140.4	141.0	141.6	0.34%
NORTHERN	18.1	18.2	18.4	18.4	18.6	18.6	18.6	18.6	18.7	18.8	18.8	0.38%
WESTERN	4.5	4.6	4.7	4.7	4.8	4.8	4.7	4.8	4.8	4.8	4.8	0.53%
SYSTEM DEMAND	206.2	208.3	210.1	210.7	211.2	211.6	211.7	212.4	213.3	213.9	214.6	0.34%

The differences in growth rates between the six zones are primarily the result of differences in how the demand is distributed between Tariff D (industrial) and Tariff V (residential) and the different growth rates these two tariffs are expected to have. Zones with a higher percentage of Tariff D load relative to Tariff V load, i.e. Geelong and Western, have a lower growth rate than those with a larger percentage of Tariff V load, i.e. Northern and Ballarat. This reflects the expectation that industrial demand growth will reduce over time in response to slowed economic growth and accompanying decline in manufacturing growth, and the CPRS. On the other hand, increased Tariff V load growth is expected, in line with high population growth.

1.2.3 Monthly gas system demand forecasts by system withdrawal zone

Table 1.9 lists the monthly system demand forecasts by SWZ.

Table 1.9 Monthly gas system demand forecasts by SWZ, 2010 (PJ)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
BALLARAT	0.4	0.4	0.4	0.6	0.9	1.2	1.4	1.2	0.9	0.7	0.5	0.4	9.0
GEELONG	1.6	1.5	1.7	1.8	2.3	2.6	2.8	2.6	2.2	2.0	1.7	1.6	24.5
GIPPSLAND	1.0	0.9	1.0	1.1	1.4	1.5	1.6	1.5	1.3	1.2	1.0	1.0	14.7
MELBOURNE	6.5	6.6	7.5	9.5	13.7	17.1	19.2	17.4	13.7	10.7	8.0	7.2	137.3
NORTHERN	1.0	1.0	1.1	1.3	1.8	2.1	2.4	2.2	1.8	1.4	1.1	1.1	18.2
WESTERN	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.4	0.4	0.3	0.3	4.6
SYSTEM DEMAND	10.8	10.7	12.0	14.7	20.5	24.9	27.9	25.4	20.3	16.4	12.6	11.6	208.3

The monthly SWZ load profiles depend on levels of industrial and residential demand. Residential demand is highly influenced by the weather. Industrial demand is relatively constant, except for seasonal variations in some industries, such as dairy and food, which are more active in spring and summer.

1.2.4 Peak day gas demand forecasts by system withdrawal zone

Table 1.10 and Table 1.11 list the peak day forecasts, representing the forecast daily demand for each SWZ on the coincident system peak day. The peak demands shown for 2009 are the actual 2009 peak day demands weather normalised for 1 in 2 and 1 in 20 conditions.

Table 1.10 1 in 2 peak day gas system demand forecast by SWZ, 2009-2019 (TJ)

1 IN 2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	AVERAGE ANNUAL GROWTH 2010-2019
BALLARAT	58	61	62	62	63	63	64	64	65	65	66	0.75%
GEELONG	111	110	113	113	114	114	114	114	114	115	115	0.47%
GIPPSLAND	60	62	63	62	63	63	63	63	63	63	64	0.20%
MELBOURNE	817	827	834	837	836	841	846	849	857	863	869	0.55%
NORTHERN	92	102	103	103	104	104	104	105	106	106	107	0.51%
WESTERN	16	18	18	18	19	19	19	19	19	19	19	0.62%
SYSTEM DEMAND	1,154	1,180	1,193	1,195	1,199	1,204	1,210	1,214	1,224	1,231	1,240	0.53%

Table 1.11 1 in 20 peak day gas system demand forecast SWZ, 2009-2019 (TJ)

1 IN 20	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	AVERAGE ANNUAL GROWTH 2010-2019
BALLARAT	62	68	69	70	70	70	71	71	72	73	73	0.77%
GEELONG	120	118	121	122	122	122	122	122	123	123	124	0.51%
GIPPSLAND	64	67	67	67	68	67	67	67	68	68	68	0.27%
MELBOURNE	879	913	921	925	924	930	936	940	949	955	963	0.59%
NORTHERN	99	112	113	113	113	114	114	115	116	116	117	0.55%
WESTERN	18	19	19	19	20	20	20	20	20	20	20	0.66%
SYSTEM DEMAND	1,242	1,297	1,310	1,316	1,317	1,323	1,330	1,335	1,348	1,355	1,365	0.58%

As with the SWZ annual demand forecast growth rates, the differences in the growth rates between the zones for the 1 in 2 and 1 in 20 SWZ peak demand forecasts are due to the different proportions of Tariff D and Tariff V loads in the zones, and the different growth rates expected for these loads over the forecast period. Table 1.12 and Table 1.13 list the monthly peak system demand forecasts for each SWZ for the 2010 year under the 1 in 2 and 1 in 20 peak day conditions.

Table 1.12 Monthly 1 in 2 peak day gas system demand forecasts by SWZ, 2010 (TJ)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
BALLARAT	17	19	24	33	46	61	61	61	61	40	34	25
GEELONG	58	61	66	77	93	110	110	110	110	85	79	68
GIPPSLAND	35	37	40	45	53	62	62	62	62	49	46	40
MELBOURNE	280	307	365	478	642	827	827	827	827	560	494	377
NORTHERN	42	45	51	64	82	102	102	102	102	73	65	52
WESTERN	12	12	13	14	16	18	18	18	18	15	14	13
SYSTEM DEMAND	444	481	559	711	932	1,180	1,180	1,180	1,180	822	732	575

Table 1.13 Monthly 1 in 20 peak day gas system demand forecasts by SWZ, 2010 (TJ)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
BALLARAT	20	24	31	40	53	68	68	68	68	47	41	32
GEELONG	62	67	74	85	100	118	118	118	118	93	87	75
GIPPSLAND	37	40	44	49	57	67	67	67	67	54	50	44
MELBOURNE	322	372	450	563	726	913	913	913	913	648	578	462
NORTHERN	46	52	60	73	91	112	112	112	112	82	75	62
WESTERN	12	13	14	15	17	19	19	19	19	16	15	14
SYSTEM DEMAND	499	568	673	825	1,044	1,297	1,297	1,297	1,297	940	846	689

1.2.5 Peak hour gas demand forecasts by system withdrawal zone

Peak hour system demand forecasts have been prepared for the medium economic growth scenario. Table 1.14 lists the annual peak hour forecasts for each SWZ, and Table 1.15 lists the monthly peak hour forecasts for each SWZ. Note that peak hour demands for individual zones are not coincident across the SWZs.

Table 1.14 Annual peak hour gas system demand by SWZ, 2010-2019 (TJ)

	SWZ	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 in 2	BALLARAT	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.3	4.3	4.3
	GEELONG	6.3	6.5	6.5	6.6	6.5	6.4	6.4	6.5	6.5	6.5
	GIPPSLAND	3.5	3.5	3.5	3.5	3.4	3.4	3.4	3.4	3.4	3.5
	MELBOURNE	52.9	53.4	53.8	53.5	53.1	53.1	53.4	53.8	54.2	54.5
	NORTHERN	6.3	6.4	6.4	6.4	6.4	6.3	6.4	6.4	6.5	6.5
	WESTERN	1.0	1.0	1.1	1.1	1.1	1.0	1.0	1.1	1.1	1.1
	TOTAL SYSTEM	74.1	75.1	75.5	75.3	74.7	74.4	74.8	75.5	76.0	76.4
	SWZ	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1 in 20	BALLARAT	4.6	4.7	4.7	4.7	4.7	4.7	4.7	4.8	4.8	4.8
	GEELONG	6.8	7.0	7.0	7.0	6.9	6.9	6.9	6.9	7.0	7.0
	GIPPSLAND	3.7	3.7	3.7	3.8	3.7	3.7	3.7	3.7	3.7	3.7
	MELBOURNE	58.5	59.1	59.5	59.2	58.8	58.8	59.2	59.6	60.0	60.4
	NORTHERN	6.9	7.0	7.0	7.0	7.0	6.9	7.0	7.0	7.1	7.1
	WESTERN	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
	TOTAL SYSTEM	81.6	82.6	83.0	82.8	82.2	82.1	82.6	83.1	83.7	84.1

Table 1.15 SWZ Monthly Peak Hour Gas Forecast, 2010 (TJ)

FORECAST	MONTH	BALLARAT	GEELONG	GIPPSLAND	MELBOURNE	NORTHERN	WESTERN	TOTAL SYSTEM
1 IN 2	JANUARY	1.0	2.8	1.7	15.4	2.1	0.6	23.6
	FEBRUARY	1.2	3.1	1.8	18.1	2.3	0.6	27.1
	MARCH	1.5	3.3	2.0	21.1	2.6	0.7	31.2
	APRIL	2.3	4.3	2.5	32.0	3.6	0.8	45.5
	MAY	3.1	5.3	3.0	41.7	5.0	0.9	59.0
	JUNE	4.1	6.3	3.5	52.9	6.3	1.0	74.1
	JULY	4.1	6.6	3.5	52.7	5.9	1.0	73.8
	AUGUST	4.0	6.5	3.5	51.8	5.9	1.0	72.7
	SEPTEMBER	4.1	6.5	3.6	54.2	6.1	1.0	75.5
	OCTOBER	2.6	4.8	2.6	36.3	4.1	0.8	51.2
	NOVEMBER	2.3	4.2	2.4	31.3	3.5	0.7	44.4
	DECEMBER	1.5	3.4	2.1	22.6	2.8	0.7	33.1
	MONTH	BALLARAT	GEELONG	GIPPSLAND	MELBOURNE	NORTHERN	WESTERN	TOTAL SYSTEM
1 IN 20	JANUARY	1.2	3.0	1.9	17.8	2.3	0.6	26.8
	FEBRUARY	1.6	3.4	2.0	21.9	2.6	0.6	32.1
	MARCH	1.9	3.7	2.2	26.0	3.1	0.7	37.6
	APRIL	2.8	4.8	2.7	37.7	4.1	0.8	52.9
	MAY	3.6	5.8	3.2	47.2	5.6	1.0	66.4
	JUNE	4.6	6.8	3.7	58.5	6.9	1.1	81.6
	JULY	4.5	7.1	3.7	58.3	6.5	1.0	81.1
	AUGUST	4.4	7.0	3.8	57.3	6.5	1.0	80.0
	SEPTEMBER	4.6	7.0	3.8	60.0	6.6	1.0	83.0
	OCTOBER	3.1	5.3	2.9	42.1	4.6	0.8	58.8
	NOVEMBER	2.7	4.7	2.6	36.8	4.0	0.8	51.6
	DECEMBER	2.0	3.8	2.3	27.7	3.3	0.7	39.8

[This page is intentionally left blank]

2 Gas supply forecasts

This chapter presents the five-year supply forecasts for gas for from 2010–2014. This includes annual and peak day supplies of gas transported through the Declared Transmission System (DTS). Supplies are those available to the Victorian Gas Market whether used or not.

The gas supply forecasts, which are based on information provided by gas producers, storage providers and market participants, assume that there are not likely to be any external factors preventing gas supplies to the Victorian gas market, should an event affecting supply occur in markets elsewhere.

In this chapter:

- Section 2.1 presents forecasts of peak day and annual gas supplies and storage, as well as monthly forecasts for 2010; and
- Section 2.2 presents Liquefied Natural Gas (LNG) requirements for within-day balancing and for peak day.

2.1 Gas supply forecast

2.1.1 Peak day gas supply forecasts by system withdrawal zone

For planning purposes, gas supply is classified as either firm or non-firm, where:

- firm supply is the aggregate contracted maximum daily quantities (MDQ) available to the market through commercial arrangements between market participants and gas producers or storage providers; and
- non-firm supply is subject to participants offering gas on the gas day, and may depend on interconnecting pipeline operating conditions and contracts.

Table 2.1 lists a summary of the forecast winter peak day firm and non-firm supplies by system withdrawal zone (SWZ) and injection point for the forecast period. It also compares the 2009 Victorian Annual Planning Report (VAPR) peak day gas supply forecasts for 2010 with the current forecasts. The gas supply forecasts are provided by gas market participants.

Table 2.1 Peak day gas supply forecast, 2010-2014 (TJ/d)

SYSTEM WITHDRAWAL ZONE	INJECTION POINT	2010 (2009 VAPR)	2010	2011	2012	2013	2014
GIPPSLAND	Longford firm	925	969.5	982.5	893	891	891
	Longford non-firm	130	134.5	148	168.3	162.3	166.7
	VicHub firm	70	63	60	0	0	0
	VicHub non-firm	40	10	0	0	0	0
	BassGas firm	67	67	67	67	67	67
TOTAL LONGFORD, VICHUB AND BASSGAS		**1232**	**1244**	**1257.5**	**1128.3**	**1120.3**	**1124.7**
WESTERN	Iona UGS firm	500	288	236	236	236	236
	Iona UGS non-firm	0	282	334	334	334	334
	Otway firm		189	189	189	189	189
	Otway non-firm		0	0	0	0	0
	SEA Gas firm	78	110	110	100	100	100
	SEA Gas non-firm	9	1.5	1.5	1.5	5	5
TOTAL IONA AND SEA GAS[1]		**587**	**870.5**	**870.5**	**860.5**	**864**	**864**
NORTHERN	Culcairn firm		35	35	35	35	35
	Culcairn non-firm	10	15	15	15	15	15
TOTAL (EXCLUDING LNG)		**1829**	**2164.5**	**2178**	**2038.8**	**2034.3**	**2038.7**
MELBOURNE (LNG FIRM)[2]		87	87	87	87	87	87
TOTAL (INCLUDING LNG)		**1916**	**2251.5**	**2265**	**2125.8**	**2121.3**	**2125.7**

1. It is understood that the total for Iona and SEA Gas is available to both South Australia and Victoria and the quantity available to the Victorian Market will be dependent on the market.

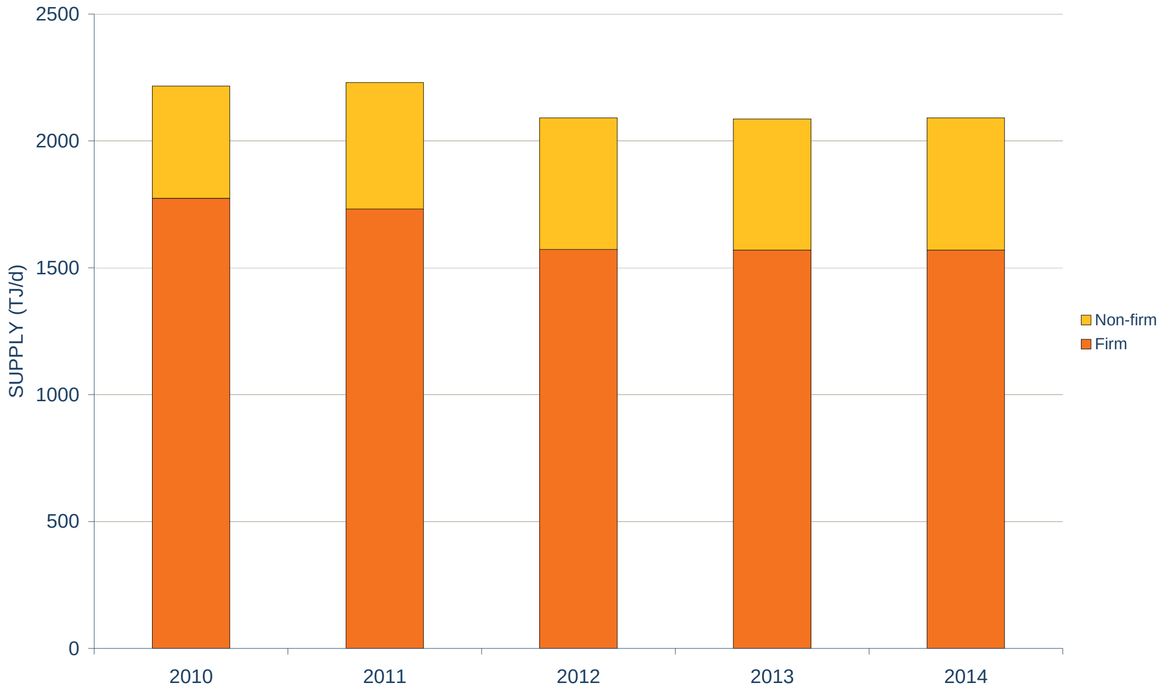
2. APA Group advises that all retailer contracts for LNG storage expire on 31 January 2010.

The forecast totals represent an aggregate of the individual sources of supply at each location (as provided by participants). For example, supply from the Casino field is included in the Iona/Underground Storage (UGS) forecast for the forecast period.

It should be noted that the producers at Longford are negotiating for further contracted capacity for 2010 onwards.

Figure 2.1 shows the total winter peak day firm (including LNG) and non-firm supplies for the forecast period.

Figure 2.1 Peak day gas supply forecast, 2010-2014 (TJ/d)



2.1.2 Annual gas supply forecasts

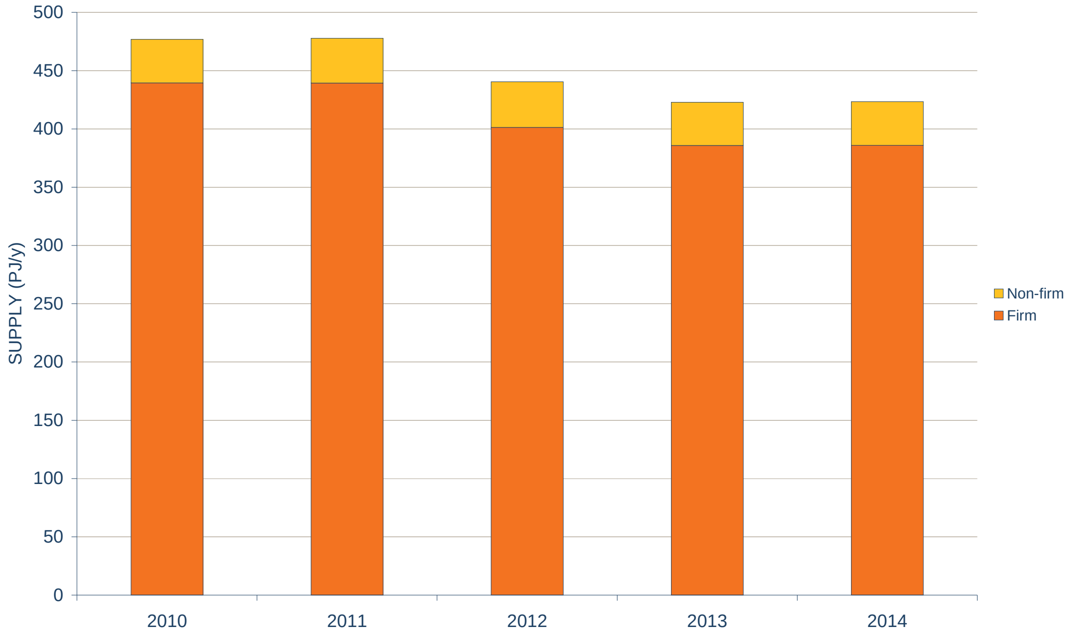
Table 2.2 lists a summary of the annual firm (excluding LNG) and non-firm supplies by SWZ and injection point for the forecast period. See Section 2.1.4 for more information about changes to specific supplies.

Table 2.2 Annual gas supply forecast, 2010-2014 (PJ/yr)

SYSTEM WITHDRAWAL ZONE	INJECTION POINT	2010	2011	2012	2013	2014
GIPPSLAND	Longford firm	295.2	302.2	285.5	268.5	268.5
	Longford non-firm	33.9	38.1	38.6	35.4	35.7
	VicHub firm	18.0	18.0	0.0	0.0	0.0
	VicHub non-firm	3.0	0.0	0.0	0.0	0.0
	BassGas firm	20.0	21.6	21.3	22.7	22.8
	BassGas non-firm	0.0	0.0	0.0	0.0	0.0
TOTAL LONGFORD, VICHUB AND BASSGAS		**370.1**	**379.9**	**345.4**	**326.6**	**327**
WESTERN	Iona UGS firm	50.1	40.6	40.6	40.6	40.6
	Iona UGS non-firm	0.0	0.0	0.0	0.0	0.0
	Otway firm	54.0	54.0	54.0	54.0	54.0
	Otway non-firm	0.0	0.0	0.0	0.0	0.0
	SEA Gas firm	2.2	2.9	0.0	0.0	0.0
	SEA Gas non-firm	0.5	0.5	0.5	1.8	1.8
TOTAL IONA, OTWAY AND SEA GAS		106.8	98.0	95.1	96.4	96.4
NORTHERN	Culcairn non-firm	0.0	0.0	0.0	0.0	0.0
TOTAL (EXCLUDING LNG)		**476.9**	**477.9**	**440.5**	**423.0**	**423.4**
MELBOURNE	LNG firm	0.5	0.5	0.5	0.5	0.5
TOTAL (INCLUDING LNG)		**477.4**	**480.4**	**441**	**423.5**	**423.9**

Figure 2.2 shows the total annual firm and non-firm supplies for the forecast period.

Figure 2.2 Annual gas supply forecast, 2010-2014 (PJ)



2.1.3 Monthly peak day gas supply forecasts for 2010

This section presents the monthly demand forecasts and the monthly demand-supply outlook for January-December 2010.

Table 2.3 lists the monthly peak day firm and non-firm supply forecasts provided by participants. The quantities available at each system injection point have been adjusted to reflect plant maintenance outages and their recall times and ramp rates (where applicable). These adjustments particularly affect the LNG and UGS facilities. Participants have indicated that there are contracts for imports and exports for gas through Culcairn. What occurs on any day will be driven by the Market.

The total reported gas supplies have increased mainly due to increases reported from the Otway basin.

Table 2.3 Monthly firm and non-firm gas supply, January-December 2010 (TJ/d)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
LONGFORD	1,099.0	1,099.0	1,099.0	1,104.0	1,094.0	1,094.0	1,094.0	1,094.0	1,094.0	1,104.0	1,104.0	1,104.0
VICHUB	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5
BASSGAS	67.0	67.0	67.0	67.0	67.0	67.0	67.0	67.0	0	67.0	0	67.0
IONA	570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0	570.0	0	570.0	570.0
SEA GAS	111.5	111.5	111.5	111.5	111.5	111.5	111.5	111.5	111.5	111.5	111.5	111.5
OTWAY	189.0	189	189	189	189	189	189	189	189	189	189	189
CULCAIRN	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
LNG	87	65	43	87	76	87	87	87	87	43	43	87
TOTAL SUPPLY	2,231.0	2,209.0	2,187.0	2,236.0	2,215.0	2,226.0	2,226.0	2,226.0	2,159.0	1,622.0	2,125.0	2,236.0

2.1.4 Gas supplies and storage

Longford

The Longford plant, located near Sale in South Gippsland, processes gas flowing from Bass Strait's Gippsland Basin gas fields and injects it into the DTS via the Longford metering station. The Longford plant is the largest producer of gas for the Victorian market.

The winter peak day firm supply from Longford is 969TJ/d for 2010. There is a slight decrease in the reported firm supply in 2010 which can be explained by a market environment that is taking a shorter-term approach to entering into firm-supply contracts and new supplies from the Otway Basin. As a result, there will be a greater reliance on non-firm supplies from 2010 onwards. It is expected that participants will negotiate further firm supplies closer to the time required.

VicHub

VicHub, located at Longford, has a system injection point for gas flow from the Eastern Gas Pipeline (EGP). VicHub has a winter peak day injection capacity of up to 110 TJ/d. Current advice, however, has the availability for winter 2010 at 63 TJ/d firm and 10 TJ/d non-firm supply. It has been advised that this will remain the same for the forecast period.

BassGas

BassGas, located near Pakenham, is the system injection point for gas from the offshore Yolla gas field, which is supplied via the BassGas undersea pipeline and processed at Lang Lang. The winter peak day firm supply from BassGas is 67 TJ/d for the forecast period.

Iona

The Iona gas plant facility, located near the township of Port Campbell in South West Victoria, has a winter peak day processing/injection capacity of approximately 570 TJ/d, and is the processing and system injection point for gas from the offshore Casino gas field.

The operating boundary of the South West Pipeline (SWP) during normal winter operations limits the scheduling of gas for DTS injection at Iona to 286 TJ/d. However, at its maximum operating pressure, the capacity of the SWP is 347 TJ/d. Iona gas is also injected into the SEA Gas pipeline for export to South Australia.

The 18 PJ holding capacity of the UGS is assumed to be full or nearly full before the start of each winter. Holding capacity will be increased to 20 PJ during 2010 and further increased to 22 PJ for 2011. Higher Iona UGS firm supply forecasts are due to additional contributions from the Casino gas field.

SEA Gas

The SEA Gas plant, located near the township of Port Campbell in South West Victoria, is the system injection point for gas from the offshore Minerva gas field and the Otway Basin, Geographe and Thylacine gas field supply developments. From this injection point, gas can be injected into the DTS, the SEA Gas pipeline (for export to Adelaide), or the UGS.

The winter peak day firm supply from SEA Gas is 100 TJ/d for the forecast period. Additional supply from SEAGas up to plant capacity could be available to the DTS dependent on Market conditions.

Otway

The Otway gas plant located north of Port Campbell in South West Victoria began production in September 2007.

Conventional gas from the offshore Thylacine and Geographe gas fields in the Otway basin is transported via an offshore and onshore pipeline and is processed at the Otway gas plant.

Gas from the Otway plant can be injected into the Victorian DTS through the Otway, SEA Gas or Iona injection points.

Culcairn

The New South Wales interconnect, which is metered at Culcairn in New South Wales, has the capacity to import 90 TJ/d into the Victorian gas market when both the Young and Springhurst compressors are operating and Uranquinty Power Station is not operating. Participants indicate that supplies of 35 TJ/d will be firm for 2010 and an extra 15 TJ/d will be non-firm in later years. Other participants indicate that there could be export at Culcairn.

APA GasNet has informed AEMO that augmentation to the DTS in the Northern Zone has been approved and will be completed by winter 2010. This will involve installation of two new compressors at the Wollert Compressor Station, pipeline operating pressure uprating of the Wollert to Euroa pipeline and installation of flow reversal capability at the Springhurst Compressor Station.

LNG

The LNG storage facility, located at Dandenong, liquefies and stores LNG for maintaining system security on high demand days and for peak shaving. LNG is also a critical supply for managing system security in the event of a sustained supply or transmission failure from Longford or Iona.

The LNG system security reserve level requirement for 2010 has now been reviewed (see Section 2.2.4 for more information). The existing LNG tank has a storage capacity of 12,000 tonnes (659 TJ)[3], with approximately:

- 9,900 tonnes (543 TJ) available to gas market participants.
- 1,500 tonnes (83 TJ) held in reserve by AEMO for system security. AEMO plans to reduce this reserve to zero from 1 February 2010.
- 600 tonnes (33 TJ) contracted to a third party.

Assumptions involving the LNG storage facility include the following:

- The LNG tank will be full or nearly full prior to the start of each winter.
- A firm vapourising capacity of up to 100 tonnes per hour (t/h) will be available over 16 hours for peak shaving[4]. This capacity equates to the vapourisation of 87 TJ/d, reflecting the contracted firm rate for the forecast period.

Normally, LNG is not scheduled from the beginning-of-day, but is included in a reschedule later in the day[5]. For within-day balancing purposes, LNG only effectively supports system pressures when injected by 10 pm on the day it is required.

Given LNG for peak shaving is only available over 11 hours rather than the contracted time of 16 hours, peak day planning assumes 60 TJ/d is available for within-day balancing[6]. After 10 pm, further LNG injections only build up linepack for the following day.

LNG liquefaction to replenish stock levels is planned on a monthly basis, with the potential to order liquefaction of up to 1,500 tonnes per month (t/m), averaging approximately 50 tonnes per day (t/d) which equates to 2.7 TJ/d.

2.2 Liquefied Natural Gas (LNG) requirements

2.2.1 LNG requirements for within-day balancing

This section presents an analysis of LNG requirements for peak day within-day balancing and for the winter peak periods (May to September) for the forecast period (2010-2014).

This chapter presents forecasts of the daily supply of gas available for injection. Transmission constraints and pipeline operating boundaries, however, limit the available daily supply. As a result, LNG is required on high demand days to address within-day constraints due to limited pipeline capacity and usable linepack.

LNG use falls into one of three categories (the first two of which are modelled for this analysis):

- LNG required for within-day balancing, scheduled out of price-merit order (to manage transmission constraints, supply or transmission outages).
- LNG required for peak shaving on very high demand days, scheduled in price-merit order.
- LNG scheduled in merit order on high demand days because it is priced lower than scheduled gas from other marginal supplies (such as Iona or VicHub).

The Longford and BassGas plants generally have adequate supply and capacity over the summer months to support system demand, gas power

[3] APA Group advise (as at September 2009) that 1 tonne of LNG has an energy equivalent of 54.9 GJ.

[4] This is based on APA Group's firm LNG rate, which allows for an outage of one of three pumps and one of three vapouriser units.

[5] LNG can be scheduled from the beginning-of-day.

[6] The LNG used at 100 t/h for 11 hours (11 am-10 pm) is 1,100 tonnes (60 TJ).

generation (GPG) demand, and withdrawals at Iona, Culcairn and VicHub.

To analyse future demand growth and assess the adequacy of gas supplies and LNG storage during winter, AEMO uses two measures for the forecast period that involve forecasting LNG requirements for:

- peak days using deterministic modelling; and
- the winter peak period using probabilistic modelling, based on outcomes from simulations applying the full range of weather conditions.

2.2.2 Peak day LNG requirement

Table 2.4 lists the LNG requirements for 1 in 2 peak day modelling, with system demand based on the current five-year forecasts and GPG demand based on an assumed 90 TJ/d (making total demand approximately equal to a 1 in 20 day), and with injections at Iona at a flat and a profiled rate. A profiled injection rate refers to higher injections in the morning and lower injections in the afternoon.

Table 2.5 lists the LNG requirements for 1 in 20 peak day modelling with no GPG demand, and with injections at Iona at a flat rate and a profiled rate.

Table 2.6 lists the LNG requirements for 1 in 20 peak day modelling with an assumed 25 TJ/d GPG demand (observed in July 2007), and with injections at Iona at a flat rate and at a profiled rate.

The results for 1 in 2 peak day and 1 in 20 peak day LNG requirements demonstrate that the LNG required to 10 pm will not exceed the 60 TJ/d available for within-day balancing in 2010. This is the case for both flat and profiled injection rates at Iona, although to a lesser extent with a profiled injection rate.

In both the 1 in 2 and 1 in 20 peak day cases, profiled injection rates can be used to supplement the role of LNG to address within-day constraints and usable linepack.

More LNG is used in the 1 in 2 peak day case including GPG compared to the 1 in 20 peak day case even though there is more total demand on the 1 in 20 peak day because it is assumed that most of the GPG is used before 10 pm. This depletes linepack more than system demand for the same total demand.

Table 2.4 1 in 2 peak day LNG requirement, 2010-2014 (TJ/d)

	2010	2011	2012	2013	2014
FORECAST SYSTEM DEMAND	1,181	1,193	1,197	1,198	1,204
ASSUMED GPG DEMAND	90	90	90	90	90
LNG REQUIREMENT FOR FLAT INJECTION RATE AT IONA	46	50	51	52	54
LNG REQUIREMENT FOR PROFILED INJECTION RATE AT IONA	27	31	32	32	34

Table 2.5 1 in 20 peak day LNG requirement, 2010-2014 (TJ/d)

	2010	2011	2012	2013	2014
FORECAST SYSTEM DEMAND	1,296	1,310	1,315	1,317	1,323
ASSUMED GPG DEMAND	0	0	0	0	0
LNG REQUIREMENT FOR FLAT INJECTION RATE AT IONA	37	40	42	42	44
LNG REQUIREMENT FOR PROFILED INJECTION RATE AT IONA	19	24	26	26	28

Table 2.6 1 in 20 peak day LNG requirement with GPG demand, 2010-2014

	2010	2011	2012	2013	2014
FORECAST SYSTEM DEMAND	1,296	1,310	1,315	1,317	1,323
ASSUMED GPG DEMAND	25	25	25	25	25
LNG REQUIREMENT FOR FLAT INJECTION RATE AT IONA	49	55	57	58	61
LNG REQUIREMENT FOR PROFILED INJECTION RATE AT IONA	36	42	45	46	49

2.2.3 Winter peak period LNG requirement

At the start of each winter, LNG storage is normally[7]:

- 626 TJ (11,400 tonnes), including the revised LNG system security reserve of 83 TJ (1,500 tonnes) to be maintained by AEMO; or
- 543 TJ (9,900 tonnes), if the system security reserve is not taken into account.

Considering a normal refill rate each month, 600-700 TJ[8] represents a high-level gauge of whether there will be sufficient LNG supplies for winter. An LNG requirement in excess of this level in any given year means there is a possibility that storage may be insufficient if refill rates remain the same.

LNG enables a rapid response to changing demand due to its variable injection rate and its proximity to the Dandenong City Gate (a critical system pressure point). As a result, GPG demand significantly influences LNG use, as GPG withdrawals represent a much greater volume over a shorter timeframe than industrial or residential loads. In order to avoid drops in linepack and pipeline pressure, however, meeting this demand requires a faster response from supply sources, which is achieved with the vapourisation and injection of LNG.

Table 2.7 lists the forecast LNG requirement for the winter peak period, with injections at Iona at a flat rate, and Table 2.8 lists the forecast LNG requirement for the winter peak period, with injections at Iona at a profiled rate. These figures are presented as a theoretical exercise and make no allowance for limitations to profiling that may result from other peak day condition considerations.

The analysis presented in the tables incorporates:

- three GPG forecast scenarios (see Chapter 1, Section 1.1.6, for more information about the GPG scenarios);
- the profiling of existing open cycle gas turbine (OCGT) gas demand using actual winter GPG demand data from 2004, 2006 and 2007; and
- the assumption that the combined cycle gas turbine/s (CCGT) will be running at full capacity during winter.

The results demonstrate that the use of profiled injection rates at Iona will enable a substantially reduced winter LNG requirement. This is because:

- the Brooklyn-Lara Pipeline (BLP) effectively increases system capacity and linepack; and
- profiled injection rates at Iona provide a supply flexibility similar to the flexibility associated with LNG.

Without .profiled injections at Iona a major system augmentation could be required.

[7] This excludes the 33 TJ (600 tonnes) of LNG contracted to a third party.

[8] This range assumes that LNG storage is at full capacity at the beginning of winter.

Table 2.7 Winter peak period LNG requirement, flat injection rate, 2010-2014 (TJ/winter)

	2010	2011	2012	2013	2014
LOW GPG DEMAND					
19 IN 20 WINTER (95% POE)	0	0	0	0	0
1 IN 2 WINTER (50% POE)	30	29	28	32	31
1 IN 20 WINTER (5% POE)	115	115	115	131	132
NORMAL GPG DEMAND					
19 IN 20 WINTER (95% POE)	0	0	1	7	18
1 IN 2 WINTER (50% POE)	62	72	97	141	190
1 IN 20 WINTER (5% POE)	187	194	258	331	423
HIGH GPG DEMAND					
19 IN 20 WINTER (95% POE)	10	21	52	108	175
1 IN 2 WINTER (50% POE)	160	212	317	461	645
1 IN 20 WINTER (5% POE)	366	454	664	897	1162

Table 2.8 Winter peak period LNG requirement, profiled injection rate, 2010-2014 (TJ/winter)

	2010	2011	2012	2013	2014
LOW GPG DEMAND					
19 IN 20 WINTER (95% POE)	0	0	0	0	0
1 IN 2 WINTER (50% POE)	9	8	8	11	12
1 IN 20 WINTER (5% POE)	85	85	85	90	93
NORMAL GPG DEMAND					
19 IN 20 WINTER (95% POE)	0	0	0	0	0
1 IN 2 WINTER (50% POE)	31	36	54	88	130
1 IN 20 WINTER (5% POE)	139	152	198	266	343
HIGH GPG DEMAND					
19 IN 20 WINTER (95% POE)	0	0	20	53	110
1 IN 2 WINTER (50% POE)	104	150	247	361	523
1 IN 20 WINTER (5% POE)	295	381	555	766	1040

2.2.4 Historical LNG use

Winter LNG use over the last nine years (2001-2009) averaged 152 TJ. LNG use in 2007 increased significantly as a result of the increase in GPG demand, driven predominantly by the reduced availability of hydroelectric generation. The dramatic reduction in LNG use in 2008 and 2009 was mainly due to commissioning of the BLP in 2008. Table 2.9 lists the winter LNG use for the last nine years.

Table 2.9 Historical winter LNG use (2001-2009)

	2001	2002	2003	2004	2005	2006	2007	2008	2009
TJ	29	217	175	199	88	270	321	45	26
TONNES	525	3,974	3,206	3,631	1,615	4,918	5,827	823	471

Occasional supply outages (approximately every three years) may require significant extra LNG vapourisation of 1,000 - 2,000 tonnes. See Section 2.1.4 for information about current LNG storage.

[This page is intentionally left blank]

3 Gas transmission system adequacy

This chapter presents supply-demand balance information for the year 2010, and transmission network capacity forecasts for the forecast period (2010-2014). The gas projections involve forecasts for the demand-supply-capacity outlook and peak day gas transmission network capacity.

In terms of the gas transmission network, this chapter aims to assist existing and potential gas transmission network users to understand:

- the capacity of the main pipelines to transfer gas to major demand centres; and
- the extent to which the forecasts of deliverable gas supplies meet forecast demand.

3.1 Monthly peak day gas demand-supply scenarios for 2010

Table 3.1 lists the monthly peak day demand-supply scenarios, including GPG demand and exports.

Table 3.1 Monthly peak day gas demand-supply scenarios, January-December 2010 (TJ/d)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
NOMINAL SUPPLY (EXCLUDING LNG)	1030	1030	1030	1030	1316	1316	1316	1316	1316	1316	1030	1030
SCHEDULED LNG	0	0	0	0	0	37	37	37	37	0	0	0
1 IN 20 SYSTEM DEMAND	500	568	673	825	1045	1296	1296	1296	1296	940	846	689
EXPORTS	70	68	65	59	47	35	35	35	35	51	58	66
GPG	200	200	150	125	100	20	20	20	20	100	100	150
SURPLUS	260	194	142	21	124	2	2	2	2	225	26	125
SPARE LNG	87	65	43	87	76	50	50	50	50	43	43	87

The availability of supply from Longford, VicHub and BassGas from January-April and November-December is assumed constrained to 1,030 TJ/d by the current Longford pipeline injection capacity as a worst supply case scenario. From recent experience, supply will be available from Otway sources in non-winter months. It is also assumed that 1,316 TJ/d is available for the May-October period, based on the aggregate of deliverable supply from the Longford pipeline and Iona (no supply is assumed via Culcairn). Scheduled maintenance at Longford during November-March is not expected to effect total supplies from Longford, VicHub and BassGas. See Chapter 3, Section 3.3 for more information about the peak day transmission system capacity forecasts.

The monthly peak day demand-supply scenario assumes that:

- 1 in 20 peak day system demands will apply every month, except in the forecasts for the months from December-February, which assume GPG demand drives peak DTS demand on very hot days. As a result, summer peak day system demand forecasts are adjusted to have no heating demand for December-February, and are lower than the forecasts in Table 1.4;
- there will be minimal exports from June-September on 1 in 20 peak days;
- there could be approximately 70 TJ/d of exports/Iona withdrawals from December-February with lower values over the shoulder and winter period of up to 35 TJ/d;
- up to 200 TJ/d of GPG demand occurs in January and February; and
- due to the severity of the June-September system demand profile, LNG is required for within-day balancing on peak days. In 2010, approximately 37 TJ of LNG is expected from June-September on 1 in 20 peak days based on the modelling of within-day balancing LNG

requirements (see Chapter 2, Section 2.2 for more information about LNG requirements).

3.2 Peak day gas demand - supply - capacity forecasts

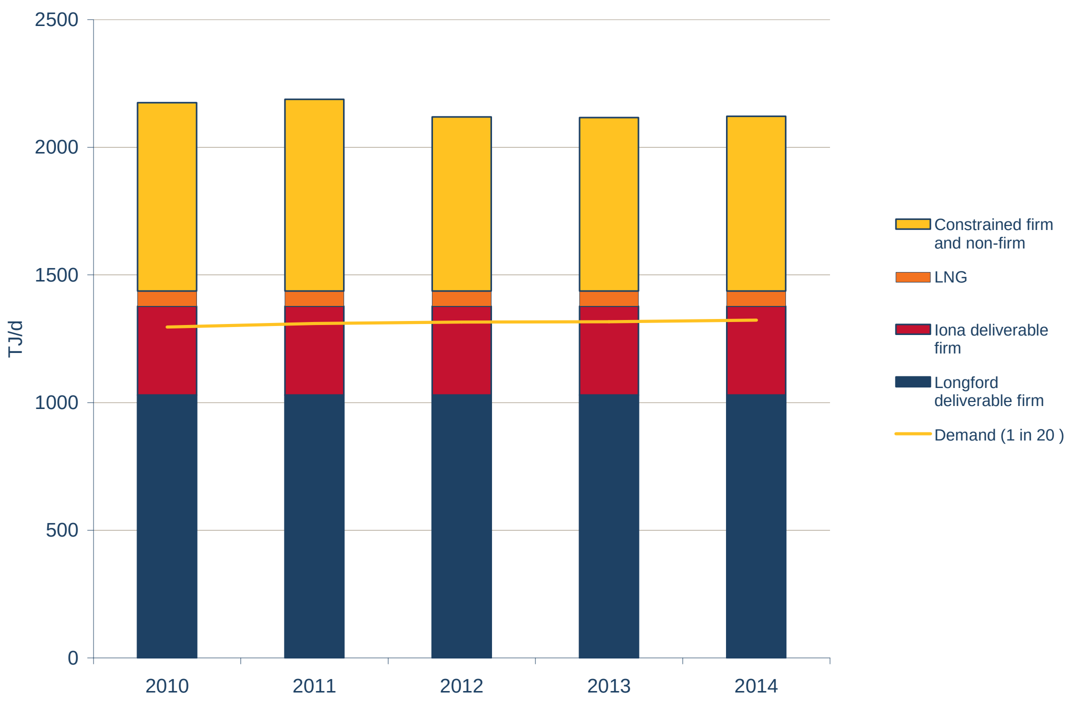
Under ideal winter conditions, the deliverable gas supply from all system injection points is 1,316 TJ/d, comprising 1,030 TJ/d via the Longford to Melbourne pipeline and 286 TJ/d via the South West Pipeline (SWP). Including LNG, the total deliverable gas supply is 1,376 TJ/d.

The non-winter peak day demand-supply-capacity assumptions account for different operating modes due to increased exports, plant maintenance, and the seasonality of firm supply.

Figure 3.1 provides an overview of the forecast peak day demand, supply, and transmission system capacity for the DTS. It gives a summary of the deliverable winter peak day firm supplies (as limited by pipeline capacity) and LNG (assumed to be a maximum deliverable of 60 TJ/d for within-day balancing), against the forecast 1 in 20 peak day demand for the forecast period. The firm supply from Iona, which is constrained by the existing pipeline capacity, is also shown.

The capacity of the DTS limits Melbourne's access to gas supply from Iona and Underground Gas Storage (UGS), even with the BLP. This situation means that there will be a continued reliance on supply from Longford.

Figure 3.1 Peak day gas demand - supply - capacity forecast, 2010-2014 (TJ/d)



3.3 Peak day gas transmission system capacity by pipeline

AEMO's modelling identified the maximum peak day injections or pipeline operating boundaries for the following injection points:

- 1,030 TJ/d at Longford (Exxon-Mobil and VicHub) and Pakenham (BassGas), via the Longford to Melbourne pipeline; and
- 286 TJ/d at Iona (Iona gas plant and Underground Gas Storage (UGS), and SEA Gas), via the SWP. However, the SWP can transport up to 347 TJ/d under favourable linepack conditions and when pressure at Iona is up to 10,000 kPa;
- Approximately 90 TJ/d at Culcairn (Moomba gas field/Culcairn imports) via the New South Wales interconnect[9]; and

[9] This figure represents the potential pipeline capacity only. 35 TJ/d firm and 15 TJ/d non-firm

- 28 TJ/d at Iona, via the Western Transmission System.

The modelling scenarios assume that injections are available to meet peak demand. The scenarios also assume 60 TJ/d of LNG injection is available for within-day balancing, and will be required depending on the severity of the peak day profile and the beginning-of-day linepack conditions.

Longford to Melbourne pipeline

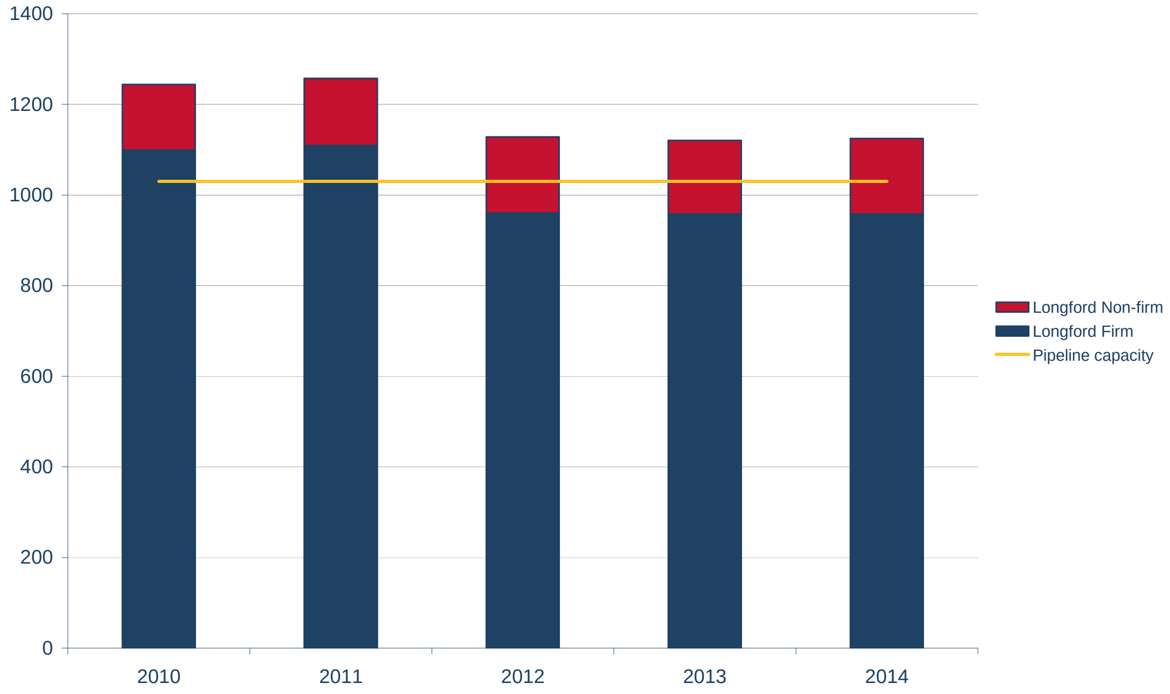
Figure 3.2 provides a comparison of the available supply from Longford, VicHub and BassGas against the available Longford to Melbourne pipeline capacity.

The maximum available plant capacity at Longford is 1150 TJ/d but the combined supply from Longford, VicHub and BassGas is constrained to 1,030 TJ/d due to back-off effects on the Longford to Melbourne pipeline when pipeline capacity has been reached. While pipeline capacity remains constant for the forecast period, contracted supplies from the participants at Longford are decreasing. In 2010 and 2011, the 1,030 TJ/d limit from Longford to Melbourne is lower than the reported total contracted gas. It is understood that negotiations are proceeding on contracting additional Longford supply.

---

supplies have been forecast from the Culcairn injection point for the forecast period.

Figure 3.2 Total Longford, VicHub and BassGas peak day contracted and non-contracted gas supply and capacity forecast, 2010-2014 (TJ/d)



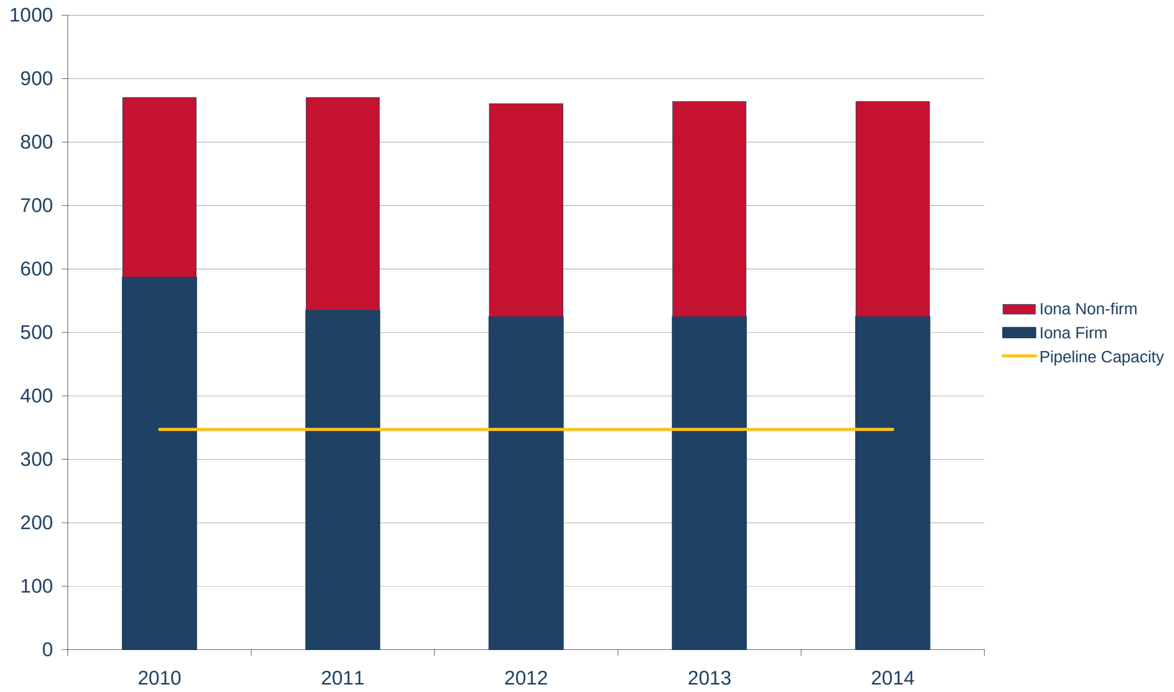
The quantity of gas that can be made available at Longford for injection into the DTS is higher than the pipeline capacity. There is therefore potential to augment the Longford pipeline to increase overall supply as presented in major augmentation studies for the 2009 VAPR.

South West Pipeline (SWP)

Figure 3.3 provides a comparison of the available supply from Iona and SEA Gas (including Otway) against the available SWP pipeline capacity. The figure indicates that pipeline capacity is the overriding constraint for suppliers injecting via the Iona and SEA Gas injection points, with the combined Iona and SEA Gas supplies being significantly larger than the pipeline's capacity.

Pipeline capacity currently constrains supply to 286 TJ/d due to normal winter beginning-of-day SWP operating pressures. The SWP can transport up to 347 TJ/d under favourable linepack conditions and the pressure at Iona is up to 10,000 kPa. See Chapter 2, Section 2.1.4, for more information. The 2009 VAPR reported that a compressor at Stonehaven may be justified for winter 2013, or potentially earlier with higher GPG demand. Modelling indicated that this would increase system capacity by approximately 46 TJ/d at normal operating conditions, but will only marginally increase system linepack, which is insufficient for peak day requirements. With different operating conditions, this increase in capacity could vary.

Figure 3.3 Total Iona and SEA Gas peak day gas supply and capacity forecast, 2010-2014 (TJ/d)



Increasing quantities of gas sourced from the Minerva and Thylacine fields are also likely to be offered into the gas market via the SEA Gas interconnect, resulting in competition with the UGS facility for limited SWP pipeline capacity.

The Otway project is not connected to the DTS and therefore injections/withdrawals pass through the SEA Gas connection point. Total SEA Gas and Otway injections are limited to 200 TJ/d and withdrawals to 135 TJ/d based on the current SEA Gas connection agreement.

New South Wales interconnect

The New South Wales interconnect pipeline capacity is 90 TJ/d. Participants advise that there are 35 TJ/d firm and 15 TJ/d non-firm supplies from New South Wales for the forecast period. Gas offered into the Victorian market may be limited:

- when New South Wales and Victoria experience high demand at the same time; or
- subject to operating conditions and/or contract arrangements on the Moomba-Sydney pipeline[10].

Western Transmission System

The Western Transmission System pipeline capacity is 28 TJ/d. This pipeline is currently supplied exclusively from Iona, for supply to the Western SWZ.

3.4 Maintenance and plant outages for Gas in 2010

Table 3.2 lists the DTS maintenance schedules and infrastructure and plant outages for gas in 2010.

[10] Peaking GPG at Uranquinty, near Wagga Wagga, could result in exports of 70 TJ/d in summer and 35 TJ/d in winter, affecting this pipeline's current operating conditions. AEMO has been advised by APA Group that they will complete augmentation of Wollert and Springhurst compressor stations.

Table 3.2 Declared Transmission System maintenance, infrastructure and plant outages for 2010

INFRASTRUCTURE	DESCRIPTION, ROLE AND REQUIRED MAINTENANCE
BROOKLYN COMPRESSOR STATION	**Description:** One 850 kW compressor (Unit 8), one 950 kW compressor (Unit 9), two 2,850 kW compressors (Units 10 and 11), and one 3,500 kW compressor (Unit 12). **Primary Role:** Provides compression to the Brooklyn-Corio pipeline (and ultimately the SWP) and the Brooklyn-Ballarat-Bendigo pipeline. **Maintenance required:** With increased production of gas from the Otway fields, it is expected that Otway gas, rather than Longford gas, will be used to replenish UGS. As a result, there will be less compression required at Brooklyn to replenish the UGS. There will, however, be increased Brooklyn compression to supply the GPG at Laverton North. Units 8 and 9 will be out of service for maintenance for four weeks each during January and February respectively. Units 10 and 11 will be out of service for four weeks each during September and April respectively. Unit 12 will be out of service for four weeks in March. These outages are not expected to cause a transmission constraint. Ongoing consultation between AEMO and APA Group should enable maintenance to be carried out whilst minimising the risk to system security. Note: Brooklyn unit 10 is a standby machine and will only be operated if unit 11 or unit 12 has failed.
GOODING COMPRESSOR STATION	**Description:** Four 2,850 kW compressors (Units 1, 2, 3 and 4). For normal winter operation, up to three compressors are operated simultaneously. One compressor is available as a standby in case of failure. **Primary Role:** Provides compression to the Longford-Melbourne pipeline. **Maintenance required:** Normal annual maintenance (making alternate compressors unavailable for up to four weeks at a time) from January-April. As the works are to occur when Gooding compression is unlikely to be required, this outage is not expected to cause a transmission constraint.
IONA COMPRESSOR STATION	**Description:** Two 298 kW reciprocating compressors (Units 1 and 2). **Primary Role:** Provides compression to the Western Transmission System (WTS) from the SWP. **Maintenance required:** Alternate units will be out of service for one week in November. During this period, a standby compressor failure would limit Iona withdrawals to approximately 25 TJ/d to maintain a pressure of approximately 4,500 kPa at Iona and ensure supply to the WTS.
SPRINGHURST COMPRESSOR STATION	**Description:** One 4,550 kW compressor (Unit 1). **Primary Role:** Provides compression for imports via the New South Wales interconnect. **Maintenance required:** This compressor will be out of service for general maintenance during May. This normally reduces interconnect import capacity from 50 TJ/d to 35 TJ/d when Young compressor is not operating. APA Group propose to upgrade the station to allow compression northwards.
WOLLERT COMPRESSOR STATION	**Description:** Two 850 kW compressors (Units 1 and 3) and one 950 kW compressor (Unit 2). Up to two units are operated in winter with one on standby, minimising the risk of transmission constraints. APA Group propose to install two new compressors at Wollert to increase export capacity to Culcairn. **Primary Role:** Provides compression to the Wollert – Wodonga pipeline and assists supply to the NSW Interconnect at Culcairn. Exports to New South Wales are generally not possible without Wollert compression. **Maintenance required:** Alternate units will be out of service for four weeks each for annual maintenance from January-March. This is not expected to further restrict export capacity.

In addition to compressor maintenance, general compressor station maintenance is also scheduled to take place at different times of the year. This maintenance:

- does not normally require extensive equipment outages;
- has a rapid recall period (usually four hours); and
- does not represent a major risk to gas transport and system security.

LNG plant maintenance

The LNG facility has a maximum vapourisation capacity of 180 t/h, requiring three vapourisers, three pumps, and one boil-off compressor to be available. Failure of either a pump or a vapouriser can reduce capacity by 17% to 44%. The LNG firm contracted rate is for 100 t/h for 16 hours, providing up to 87 TJ/d. This provides for plant redundancy in case of an outage of one pump and one vapouriser.

The facility will undergo general maintenance in February and May. The recall period (usually four hours) minimises the risk to system security.

Annual vapouriser maintenance requires each unit to be out of service for four weeks during the low demand period in March, October and November. During this period, the vapourisation capacity will be reduced to 56% (when vapouriser C is unavailable), and 83% (when either vapouriser A or B is unavailable). Boil-off compressor maintenance does not affect vapourisation.

3.5 Supply and Underground Gas Storage maintenance

Table 3.3 lists supply and UGS infrastructure maintenance schedules, Table 3.4 lists monthly planned maintenance for 2010, Table 3.5 lists monthly pipeline capacity, and Table 3.6 lists monthly compressor requirement and availability for 2010 and lists monthly pipeline capacity.

Table 3.3 Supply and UGS infrastructure maintenance schedules, 2010

INFRASTRUCTURE	PLANNED MAINTENANCE
THE LONGFORD PLANT	Maintenance is scheduled to occur during the lower demand summer period. In addition, Esso and BHP Billiton will undertake maintenance activities required for the Kipper, Tuna and Turrum projects, including the installation of the newest platform in Bass Strait, Marlin B. While final scheduling is not confirmed, some of these activities are currently planned for Winter and Spring 2010. AEMO and Exxon-Mobil work jointly to plan Longford plant maintenance.
THE UGS FACILITY	The commissioning of a second Iona gas processing train is expected to happen in August 2010 but may be delayed due to high gas demand in August or a project delay. This will require a five day shutdown. No other capacity restrictions are expected.
VICHUB	Limited maintenance is planned.
SEA GAS	Limited maintenance is planned.
BASS GAS	Maintenance is scheduled for October 2010. This will require a five day shutdown.
PIPELINE INSPECTION	The following pipeline inspection (pigging) works are scheduled: • Iona - Paaratte 150 mm pipeline (early 2010). • Paaratte-Allansford 150 mm pipeline (early 2010). • Allansford-Portland 150 mm pipeline (early 2010). • Metropolitan Ringmain 450 mm pipeline (November 2009). • Wollert-Wodonga 300 mm pipeline (late 2009). • Keon Park-Wollert 600 mm pipeline (Summer 2009/10). • Brooklyn – Corio 350 mm pipeline (late 2010) The exact timing of these works will depend on resource availability and suitable flow and pressure conditions. As pigging is carried out on a live pipeline, there is no effect on pipeline capacity. Pigging runs are not always successful, and may need to be rerun under different conditions to enable collection of reliable data.
THIRD PARTY PROJECTS	Occasionally, bodies such as VicRoads or Melbourne Water request APA Group to make pipeline alterations. Under these circumstances, APA Group and AEMO work jointly to determine the appropriate timing of the work to ensure that peak demand can be met.

Table 3.4 APA Group planned maintenance and outages, 2010[1]

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
BROOKLYN COMPRESSOR STATION												
Unavailable unit	Unit 8	Unit 9	Unit 12	Unit 11					Unit 10			
GOODING COMPRESSOR STATION												
Unavailable unit	Unit 1	Unit 2	Unit 3	Unit 4								
IONA COMPRESSOR STATION												
Unavailable unit											Unit 1,2	
SPRINGHURST COMPRESSOR STATION												
Unavailable unit					Unit 1							
WOLLERT COMPRESSOR STATION												
Unavailable unit	Unit 1	Unit 2	Unit 3									
LNG FACILITY												
LNG facility unavailable		Total facility			Total facility							
Vapouriser unavailable			Unit C							Unit A	Unit B	
Boil-off compressor unavailable		Unit B		Unit A								
Pump unavailable												

1. Only including major maintenance and outages with a recall time longer than 24 hours.

Table 3.5 Monthly gas pipeline capacity (TJ/d)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
LONGFORD PIPELINE	1030	1030	1030	990	1030	1030	1030	1030	1030	990	1030	1030
SOUTHWEST PIPELINE	286	286	286	286	286	286	286	286	286	286	286	286
NSW INTERCONNECT	50	50	50	50	50	50	50	50	50	50	50	50
WESTERN TRANSMISSION SYSTEM	17	17	17	17	17	28	28	28	28	17	17	17
LNG	87	65	43	87	76	87	87	87	87	43	43	87

Table 3.6 Compressor requirement and availability, 2010

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
GOODING COMPRESSOR STATION												
4 Centaurs @ 2,800 kW												
Available	3	3	3	3	4	4	4	4	4	4	4	4
Required	0	0	0	2	2	3	3	3	3	3	2	0
Redundant	3	3	3	1	2	1	1	1	1	1	2	4
Maintenance	1	1	1	1	-	-	-	-	-	-	-	-
BROOKLYN COMPRESSOR STATION												
2 Centaurs @ 2,850 kW and 3,500 kW[1]												
Available	2	2	1	1	2	2	2	2	2	2	2	2
Required	0	0	0	0	0	1	1	1	1	0	0	0
Redundant	2	2	1	1	2	1	1	1	1	2	2	2
For TRUenergy GS withdrawal												
Available	2	2	1							2	2	2
Required	2	2	1							2	2	2
Redundant	0	0	0							0	0	0
Maintenance	-	-	1							-	-	-
2 Saturns @ 850 kW and 950 kW												
Available	1	1	2	2	2	2	2	2	2	2	2	2
Required	0	0	0	0	1	2	2	2	2	1	0	0
Redundant	1	1	2	2	1	0	0	0	0	1	2	2
Maintenance	1	1	-	-	-	-	-	-	-	-	-	-
WOLLERT COMPRESSOR STATION												
3 Saturns @ 850 kW												
Available	2	2	2	3	3	3	3	3	3	3	3	3
Required	2	2	2	2	2	2	2	2	2	2	2	2
Redundant	0	0	0	1	1	1	1	1	1	1	1	1
Maintenance	1	1	1	-	-	-	-	-	-	-	-	-
SPRINGHURST COMPRESSOR STATION												
1 Centaur @ 4,500 kW												
Available	1	1	1	1	0	1	1	1	1	1	1	1
Required	0	0	0	0	0	0	0	0	0	0	0	0
Redundant	1	1	1	1	0	1	1	1	1	1	1	1
Maintenance	-	-	-	-	1	-	-	-	-	-	-	-
IONA COMPRESSOR STATION												
2 Caterpillars @ 300 kW												
Available	2	2	2	2	2	2	2	2	2	2	1	2
Required	1	1	1	1	1	1	1	1	1	1	1	1
Redundant	1	1	1	1	1	1	1	1	1	1	0	1
Maintenance	-	-	-	-	-	-	-	-	-	-	1	-

1. Only two Centaur compressors are shown on the basis that Unit 10 (wet-seal compressor) is used as a backup only when dry-seal compressors (Unit 11 and 12) are not available

[This page is intentionally left blank]

4 *Electricity developments*

In this chapter:

- Section 4.1 presents the results of the Electricity Value of Customer Reliability (VCR) study 2008
- Section 4.2 presents the Terminal Station Demand Forecasts 2009/10 to 2018/19

4.1 Electricity Value of Customer Reliability (VCR)

4.1.1 Background

The VCR is a measure of the cost of unserved energy and aims to capture the value of energy to users. In simple terms it represents the cost to consumers of being without electricity, and is an important input for regulatory test assessments of planned electricity transmission augmentations in Victoria.

The VCR was last estimated in 2007 and before that in 2002 using surveys to estimate direct end-user customer costs when electricity supply is lost for durations from 20 minutes up to 24 hours. The 'headline' VCR increased from $29,600 to $47,850 per MWh between 2002 and 2007, representing an average annual increase of approximately 10 per cent. In light of the large jump in the estimate, and given its important role in evaluating network investment options, AEMO has decided to adopt an income/economic growth indexation approach to adjust the estimate and minimise such large jumps in the future. An income/economic growth approach reflects the strong theoretical link between measurements of income and economic activity and the estimate of the VCR and clearly outperformed alternative indexation approaches at predicting earlier VCRs. The VCR estimate is strongly influenced by changes in the price of substitute goods and services, which are in turn closely linked to income and other measures of economic activity.

Following application of the income/economic growth approach of indexation to the 2007 VCR, the 2008 and 2009 VCRs are $51,000 and $55,000 per MWh respectively. The indexed VCR estimate will be updated annually and reported in AEMO's Annual Planning Report (APR).

The 2010 figure of VCR will be calculated ahead of the network analysis associated with the production of the 2010 VAPR.

4.2 Terminal Station Demand Forecasts (2009/10 – 2018/19)

AEMO has prepared and makes available load forecasts for points of connection with the shared electricity transmission network in Victoria. These forecasts show the maximum active power demands forecast to occur for summer and winter on average one year in two (50% POE) and one year in 10 (10% POE).

The forecasts for each terminal station in Victoria are provided in the following tables, and the detailed report "Terminal Station Demand forecasts 2009/10 – 2018/19", which include the reactive power demand is available online on AEMO's website under the Planning and Transmission Services section:

http://www.aemo.com.au/planning/0400-0002.pdf.

Table 4.1 Electricity summer peak forecasts by Terminal Station

TERMINAL STATION	POE	2009/10 MW	2010/11 MW	2011/12 MW	2012/13 MW	2013/14 MW	2014/15 MW	2015/16 MW	2016/17 MW	2017/18 MW	2018/19 MW
Altona West 66kV	10	174.7	179.5	185.0	191.6	197.6	203.8	210.2	216.8	208.0	231.1
	50	166.6	171.1	176.4	182.7	188.4	194.4	200.4	206.7	198.4	220.3
Altona/Brooklyn 66 kV	10	296.6	298.0	307.5	311.6	317.5	323.8	330.1	336.4	360.8	367.2
	50	287.9	289.5	298.9	303.1	308.8	315.0	321.1	327.3	351.3	357.6
Ballarat 66 kV	10	176.1	179.5	185.3	188.6	191.7	195.1	198.4	201.7	204.6	207.5
	50	169.3	172.6	178.2	181.3	184.4	187.6	190.8	194.0	196.7	199.5
Bendigo 22 kV	10	59.9	67.9	69.6	81.6	83.5	85.4	87.5	89.5	91.5	93.6
	50	52.9	60.0	61.5	72.1	73.8	75.5	77.3	79.1	80.9	82.7
Bendigo 66 kV	10	185.2	187.0	190.2	184.7	187.8	191.1	194.3	197.6	201.2	204.9
	50	171.5	173.2	176.1	171.0	173.9	177.0	179.9	183.0	186.3	189.7
Brooklyn 22 kV	10	65.7	66.9	68.2	69.5	70.9	72.3	73.7	75.2	73.4	74.8
	50	65.4	66.6	67.9	69.2	70.5	71.9	73.3	74.8	73.0	74.4
Brooklyn-SCI 66 kV	10	66.2	66.2	66.2	66.2	66.2	66.2	66.2	66.2	66.2	66.2
	50	66.2	66.2	66.2	66.2	66.2	66.2	66.2	66.2	66.2	66.2
Brunswick 22 kV	10	99.0	100.9	102.6	104.2	105.9	107.8	109.8	111.8	113.8	115.9
	50	92.3	94.0	95.6	97.1	98.7	100.5	102.3	104.2	106.1	108.0
Cranbourne 66 kV	10	371.7	383.4	417.6	439.1	461.7	484.6	508.4	534.3	562.0	591.3
	50	350.3	361.2	393.3	413.5	434.8	456.4	478.8	503.2	529.3	556.9
East Rowville 66 kV	10	515.3	530.9	536.1	556.9	578.0	596.4	614.0	633.8	654.9	676.3
	50	481.4	495.8	500.1	519.5	539.1	556.3	572.7	591.2	610.8	630.9
Fishermans Bend 66 kV	10	255.7	270.5	281.0	290.3	299.6	309.7	320.0	330.3	339.7	346.7
	50	243.4	257.4	267.4	276.3	285.1	286.7	304.5	314.3	323.3	330.0
Geelong 66 kV	10	434.8	450.6	465.5	481.1	490.0	500.9	512.0	520.7	530.9	539.6
	50	426.8	442.6	457.5	473.1	482.0	492.9	504.0	512.7	522.9	531.6
Glenrowan 66 kV	10	110.7	112.4	114.2	116.9	119.6	122.4	125.3	128.3	131.3	134.4
	50	104.4	106.1	107.7	110.3	112.9	115.5	118.2	121.0	123.8	126.8
Heatherton 66 kV	10	339.7	346.2	354.9	361.6	368.0	372.8	376.6	381.5	386.6	391.5
	50	321.4	327.3	335.2	341.4	347.4	351.9	355.4	359.9	364.7	369.3
Heywood 22 kV	10	2.6	2.6	7.1	7.2	7.3	7.3	7.4	7.5	7.6	7.6
	50	2.6	2.6	7.1	7.2	7.3	7.3	7.4	7.5	7.6	7.6
Horsham 66 kV	10	88.4	90.5	92.2	93.3	94.4	95.5	96.6	97.8	98.9	99.9
	50	86.4	88.5	90.2	91.3	92.4	93.5	94.6	95.8	96.9	97.9
Keilor 66 kV	10	625.1	654.1	676.1	698.0	720.0	740.4	758.6	777.4	796.6	807.1
	50	593.1	620.6	641.5	662.2	683.1	702.5	719.8	737.8	756.0	765.9
Kerang 22 kV	10	11.7	11.8	11.9	12.1	12.2	12.3	12.4	12.6	12.7	12.8
	50	11.3	11.4	11.5	11.7	11.8	11.9	12.0	12.2	12.3	12.4
Kerang 66 kV	10	57.9	59.5	60.9	61.9	62.9	64.2	65.2	66.2	67.4	68.7
	50	56.9	58.5	59.9	60.9	61.9	63.2	64.2	65.2	66.4	67.7
Loy Yang 66 kV	10	24.0	24.1	24.1	24.2	24.3	24.3	24.4	24.5	24.6	24.6
	50	23.6	23.6	23.7	23.8	23.8	23.9	24.0	24.1	24.1	24.2
Malvern 22 kV	10	39.7	40.0	40.7	41.2	41.7	42.1	42.4	42.7	43.1	43.5
	50	36.7	36.9	37.5	37.9	38.4	38.7	39.0	39.3	39.7	40.0
Malvern 66 kV	10	176.5	181.4	187.8	193.0	198.0	202.1	204.5	207.6	210.8	213.9
	50	163.3	167.7	173.5	178.2	182.8	186.6	188.7	191.5	194.5	197.3

TERMINAL STATION	POE	2009/10 MW	2010/11 MW	2011/12 MW	2012/13 MW	2013/14 MW	2014/15 MW	2015/16 MW	2016/17 MW	2017/18 MW	2018/19 MW
Morwell/Loy Yang 66 kV	10	455.6	466.3	477.2	494.1	511.5	529.6	548.3	567.7	587.8	608.6
	50	430.3	440.4	450.7	466.6	483.1	500.1	517.8	536.1	555.0	574.7
Mount Beauty 66 kV	10	34.6	34.9	35.2	35.6	36.1	36.6	37.1	37.6	38.1	38.6
	50	32.6	32.9	33.2	33.6	34.1	34.5	35.0	35.5	35.9	36.4
Red Cliffs 22 kV	10	41.2	42.3	43.2	44.0	44.9	45.7	46.6	47.5	48.5	49.4
	50	39.0	40.1	40.9	41.7	42.5	43.3	44.1	45.0	45.9	46.8
Red Cliffs 66 kV	10	170.8	176.9	141.1	143.9	146.9	149.8	152.5	155.3	158.1	161.1
	50	165.1	170.9	136.3	139.1	141.9	144.8	147.3	150.0	152.8	155.6
Richmond 22 kV	10	77.6	79.2	80.4	81.6	82.9	84.1	85.4	86.7	87.9	89.2
	50	71.8	73.3	74.5	75.6	76.8	77.9	79.1	80.2	81.4	82.6
Richmond 66 kV	10	574.5	590.5	604.0	616.2	627.5	638.3	648.9	659.9	670.9	682.0
	50	531.4	546.2	558.6	569.9	580.3	590.3	600.1	610.2	620.4	630.6
Ringwood 22 kV	10	99.7	101.9	104.8	107.5	110.3	112.9	115.5	118.3	121.2	124.1
	50	93.3	95.3	98.0	100.5	103.1	105.6	108.0	110.6	113.3	116.0
Ringwood 66 kV	10	521.2	534.2	549.7	571.0	593.0	615.2	637.9	661.9	687.0	713.1
	50	489.8	502.0	516.4	536.4	557.1	578.0	599.4	622.0	645.6	670.1
Shepparton 66 kV	10	301.0	305.6	312.8	317.4	321.5	325.6	329.7	334.0	338.3	342.7
	50	286.0	290.6	297.8	302.4	306.5	310.6	314.7	319.0	323.3	327.7
South Morang 66 kV	10	235.7	247.5	258.9	273.0	287.6	301.3	315.8	331.0	347.0	363.9
	50	222.4	233.5	244.2	257.6	271.3	284.3	297.9	312.3	327.4	343.3
Springvale 66 kV	10	477.8	491.6	512.4	523.1	532.8	541.3	547.7	555.6	564.0	572.1
	50	441.6	454.0	472.8	482.6	492.0	499.2	504.9	512.2	519.9	527.2
Templestowe 66 kV	10	344.8	349.7	357.5	365.3	373.0	379.9	386.4	393.5	400.8	408.2
	50	321.9	326.3	333.5	340.7	347.9	354.3	360.3	366.9	373.8	380.7
Terang 66 kV	10	195.3	200.7	205.6	209.4	212.9	216.2	219.5	222.9	226.4	229.6
	50	192.3	197.5	202.4	206.1	209.5	212.8	216.1	219.4	222.9	226.0
Thomastown 1&2 66 kV	10	268.7	275.7	281.8	290.5	300.0	308.1	316.5	325.2	334.1	343.3
	50	253.5	260.1	265.8	274.1	283.0	290.7	298.6	306.8	315.2	323.9
Thomastown 3&4 66 kV	10	268.6	275.5	282.5	292.3	301.7	307.5	313.3	319.3	325.3	331.5
	50	253.4	259.9	266.5	275.7	284.7	290.1	295.6	301.2	306.9	312.8
Tyabb 220 kV	10	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3
	50	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3	65.3
Tyabb 66 kV	10	265.5	271.3	281.9	290.2	298.2	304.1	309.0	315.0	321.5	327.7
	50	244.7	249.8	259.4	266.9	274.2	279.6	283.9	289.5	295.4	301.0
Wemen 66 kV	10	0.0	0.0	51.8	54.4	56.3	57.7	58.9	59.7	60.5	61.2
	50	0.0	0.0	50.1	52.6	54.4	55.8	56.9	57.7	58.5	59.2
West Melbourne 22 kV	10	96.9	105.8	110.0	114.2	118.5	122.8	127.1	131.5	135.9	140.4
	50	91.5	99.8	103.8	107.8	111.8	115.8	119.9	124.1	128.2	132.4
West Melbourne 66 kV	10	483.9	500.1	516.5	538.3	554.8	571.2	587.7	604.4	621.4	638.5
	50	456.3	471.5	487.0	507.6	523.2	538.6	554.2	569.9	585.9	602.0
Wodonga 22 kV	10	33.6	34.7	35.7	36.8	37.9	39.0	40.2	41.4	42.6	43.9
	50	31.7	32.7	33.7	34.7	35.7	36.8	37.9	39.0	40.2	41.4
Wodonga 66 kV	10	68.6	69.3	69.9	71.0	72.0	73.0	74.1	75.2	76.3	77.4
	50	64.7	65.3	66.0	66.9	67.9	68.9	69.9	70.9	72.0	73.0
Yallourn 11 kV	10	6.6	6.7	6.8	6.8	6.9	7.0	7.1	7.2	7.3	7.4
	50	6.3	6.3	6.4	6.5	6.5	6.6	6.7	6.8	6.9	7.0

Table 4.2 Electricity winter peak forecasts by Terminal Station

TERMINAL STATION	POE	2009 MW	2010 MW	2011 MW	2012 MW	2013 MW	2014 MW	2015 MW	2016 MW	2017 MW	2018 MW
Altona West 66kV	10	142.0	140.1	144.1	148.3	153.6	158.2	163.0	168.1	173.2	163.3
	50	138.9	137.0	140.9	145.1	150.3	154.8	159.5	164.5	169.5	159.8
Altona/Brooklyn 66 kV	10	296.8	309.5	311.6	320.5	323.9	329.1	332.8	338.4	344.0	367.8
	50	293.5	306.2	308.2	317.1	320.5	325.6	329.3	334.9	340.4	364.0
Ballarat 66 kV	10	163.9	166.2	168.8	173.6	176.2	178.6	181.3	183.8	186.4	187.9
	50	163.9	166.2	168.8	173.6	176.2	178.6	181.3	183.8	186.4	187.9
Bendigo 22 kV	10	37.2	38.5	44.4	45.4	54.1	55.3	56.6	57.8	59.1	60.5
	50	37.2	38.5	44.4	45.4	54.1	55.3	56.6	57.8	59.1	60.5
Bendigo 66 kV	10	134.9	136.6	138.2	140.4	135.0	137.2	139.4	141.6	144.0	146.4
	50	134.9	136.6	138.2	140.4	135.0	137.2	139.4	141.6	144.0	146.4
Brooklyn 22 kV	10	60.7	60.0	61.1	62.2	63.3	64.5	65.6	66.9	68.1	66.2
	50	60.4	59.7	60.8	61.9	63.0	64.2	65.3	66.6	67.8	65.8
Brooklyn-SCI 66 kV	10	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6
	50	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6	62.6
Brunswick 22 kV	10	87.3	88.0	89.4	90.7	91.9	93.1	94.5	95.9	97.3	98.7
	50	83.9	84.6	86.0	87.2	88.3	89.5	90.8	92.2	93.5	94.9
Cranbourne 66 kV	10	247.6	266.9	284.7	290.2	296.8	303.6	310.1	317.1	324.4	331.7
	50	236.1	254.8	271.6	276.7	282.9	289.4	295.6	302.3	309.2	316.2
East Rowville 66 kV	10	400.3	409.2	408.3	417.2	428.5	440.4	451.3	463.7	476.6	489.6
	50	385.4	393.7	393.0	401.3	412.1	423.5	433.8	445.8	458.1	470.6
Fishermans Bend 66 kV	10	201.5	221.9	234.5	240.7	253.0	263.0	273.3	283.7	286.2	300.5
	50	195.7	215.5	227.8	233.9	245.8	255.5	265.5	275.6	285.8	291.9
Geelong 66 kV	10	351.2	363.2	378.4	392.1	405.6	413.5	423.0	432.4	440.1	448.7
	50	351.2	363.2	378.4	392.1	405.6	413.5	423.0	432.4	440.1	448.7
Glenrowan 66 kV	10	109.4	110.2	111.0	112.2	113.5	114.7	116.0	117.3	118.5	119.9
	50	103.2	103.9	104.7	105.9	107.0	108.2	109.4	110.6	111.8	113.1
Heatherton 66 kV	10	255.6	260.6	266.1	268.9	274.1	279.7	284.1	289.7	295.4	301.1
	50	248.2	252.8	258.0	260.6	265.6	271.0	275.3	280.7	286.3	291.8
Heywood 22 kV	10	2.6	2.6	7.1	7.2	7.3	7.3	7.4	7.5	7.6	7.6
	50	2.6	2.6	7.1	7.2	7.3	7.3	7.4	7.5	7.6	7.6
Horsham 66 kV	10	68.8	70.5	71.8	73.1	74.0	74.7	75.6	76.4	77.2	78.0
	50	68.8	70.5	71.8	73.1	74.0	74.7	75.6	76.4	77.2	78.0
Keilor 66 kV	10	462.6	474.0	497.8	515.8	532.0	549.0	564.4	577.6	591.3	605.3
	50	453.6	464.7	488.0	505.6	521.6	538.2	553.3	566.3	579.7	593.4
Kerang 22 kV	10	11.1	11.2	11.3	11.4	11.6	11.7	11.8	11.9	12.0	12.1
	50	11.1	11.2	11.3	11.4	11.6	11.7	11.8	11.9	12.0	12.1
Kerang 66 kV	10	50.0	51.1	52.6	53.7	54.8	55.8	56.9	58.0	59.1	60.4
	50	50.0	51.1	52.6	53.7	54.8	55.8	56.9	58.0	59.1	60.4
Loy Yang 66 kV	10	32.5	32.7	32.8	32.9	33.0	33.1	33.2	33.4	33.5	33.6
	50	31.9	32.0	32.1	32.2	32.3	32.4	32.6	32.7	32.8	32.9
Malvern 22 kV	10	34.5	34.7	35.2	35.5	36.0	36.6	37.1	37.7	38.3	38.9
	50	33.5	33.7	34.1	34.3	34.9	35.5	35.9	36.5	37.1	37.7
Malvern 66 kV	10	126.6	129.9	133.4	135.1	137.9	140.7	143.2	145.4	147.7	149.9
	50	122.8	126.0	129.3	130.9	133.5	136.3	138.7	140.9	143.0	145.2

TERMINAL STATION	POE	2009 MW	2010 MW	2011 MW	2012 MW	2013 MW	2014 MW	2015 MW	2016 MW	2017 MW	2018 MW
Morwell/Loy Yang 66 kV	10	426.8	430.4	434.1	439.5	445.1	450.7	456.4	462.2	468.1	474.0
	50	403.2	406.6	410.0	415.2	420.5	425.8	431.2	436.6	442.1	447.7
Mount Beauty 66 kV	10	53.0	53.3	53.7	54.2	54.6	55.1	55.6	56.1	56.6	57.1
	50	50.0	50.3	50.6	51.1	51.5	52.0	52.5	53.0	53.4	53.9
Red Cliffs 22 kV	10	21.9	22.9	23.7	24.2	24.7	25.2	25.7	26.2	26.7	27.3
	50	20.8	21.8	22.6	23.1	23.6	24.1	24.6	25.1	25.6	26.2
Red Cliffs 66 kV	10	103.1	111.5	93.4	96.0	98.7	101.4	103.1	104.7	106.3	108.0
	50	100.3	108.5	90.9	93.4	96.0	98.6	100.3	101.9	103.4	105.1
Richmond 22 kV	10	62.6	64.5	65.7	66.7	67.8	68.8	69.9	70.9	72.0	73.0
	50	60.2	62.1	63.2	64.2	65.2	66.2	67.2	68.2	69.2	70.2
Richmond 66 kV	10	431.8	445.5	457.2	466.6	476.4	485.7	494.8	504.2	513.6	523.1
	50	415.6	428.8	440.0	449.0	458.4	467.4	476.2	485.2	494.3	503.4
Ringwood 22 kV	10	75.8	77.5	79.4	81.2	83.4	85.5	87.7	90.0	92.3	94.7
	50	72.2	73.8	75.6	77.3	79.3	81.4	83.4	85.6	87.8	90.1
Ringwood 66 kV	10	374.1	382.2	390.8	403.2	416.8	431.0	445.3	460.4	476.0	492.2
	50	355.3	362.8	370.9	382.6	395.5	408.9	422.4	436.7	451.5	466.8
Shepparton 66 kV	10	203.2	207.4	210.8	215.5	218.8	221.7	224.6	227.6	230.7	233.8
	50	203.2	207.4	210.8	215.5	218.8	221.7	224.6	227.6	230.7	233.8
South Morang 66 kV	10	119.9	192.3	199.8	208.0	215.8	223.6	230.0	236.7	243.5	250.6
	50	113.1	183.0	190.1	198.0	205.4	212.8	219.0	225.3	231.8	238.5
Springvale 66 kV	10	355.5	361.6	372.6	382.0	389.5	397.5	403.9	411.9	420.1	428.2
	50	344.7	350.4	360.9	369.8	377.0	384.8	390.9	398.7	406.6	414.5
Templestowe 66 kV	10	278.0	283.5	287.5	291.9	297.4	302.9	308.0	313.6	319.2	325.0
	50	266.2	271.4	275.2	279.4	284.5	289.8	286.7	300.0	305.4	310.9
Terang 66 kV	10	180.8	186.9	190.8	195.0	198.2	200.7	203.4	206.2	209.0	211.8
	50	180.8	186.9	190.8	195.0	198.2	200.7	203.4	206.2	209.0	211.8
Thomastown 1&2 66 kV	10	253.4	185.5	189.2	192.4	196.1	200.2	203.2	206.2	209.3	212.4
	50	242.5	176.8	180.4	183.5	187.0	190.9	193.7	196.6	199.5	202.5
Thomastown 3&4 66 kV	10	210.4	223.4	229.1	234.4	242.0	249.4	253.4	257.4	261.6	265.8
	50	203.3	215.9	221.3	226.5	233.9	241.0	244.8	248.7	252.7	256.8
Tyabb 220 kV	10	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2
	50	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2	64.2
Tyabb 66 kV	10	217.8	205.9	210.0	212.0	215.9	220.1	223.4	227.5	231.7	235.9
	50	211.4	199.7	203.6	205.4	209.2	213.2	216.4	220.4	224.5	228.5
Wemen 66 kV	10	0.0	0.0	27.0	28.7	29.7	30.5	31.2	31.8	32.1	32.5
	50	0.0	0.0	26.3	27.9	28.9	29.7	30.3	30.9	31.2	31.6
West Melbourne 22 kV	10	86.5	90.5	94.8	98.7	102.7	106.8	110.8	115.0	119.1	123.3
	50	83.2	87.0	91.1	94.9	98.8	102.7	106.6	110.5	114.5	118.6
West Melbourne 66 kV	10	359.1	377.4	390.8	404.6	422.4	436.3	450.0	463.9	478.0	492.1
	50	345.7	363.3	376.2	389.5	406.6	420.0	433.3	446.6	460.1	473.8
Wodonga 22 kV	10	29.0	29.9	30.8	31.7	32.7	33.7	34.7	35.7	36.8	37.9
	50	27.4	28.2	29.1	29.9	30.8	31.8	32.7	33.7	34.7	35.7
Wodonga 66 kV	10	53.7	54.2	54.8	55.5	56.3	57.1	57.9	58.7	59.5	60.4
	50	50.7	51.2	51.7	52.4	53.1	53.9	54.6	55.4	56.2	57.0
Yallourn 11 kV	10	4.3	4.3	4.4	4.4	4.5	4.6	4.6	4.7	4.7	4.8
	50	4.1	4.1	4.1	4.2	4.2	4.3	4.4	4.4	4.5	4.5

[This page is intentionally left blank]

A1 Gas forecast methodology and assumptions

This chapter outlines the methodology used to prepare the forecasts. Forecasts were prepared for the DTS and for each SWZ for the following aspects of system demand:

- Peak hour demand (annual and monthly)
- Peak day demand (annual and monthly)
- Monthly demand
- Annual demand
- Annual GPG demand

A1.1 Peak hour demand forecast approach

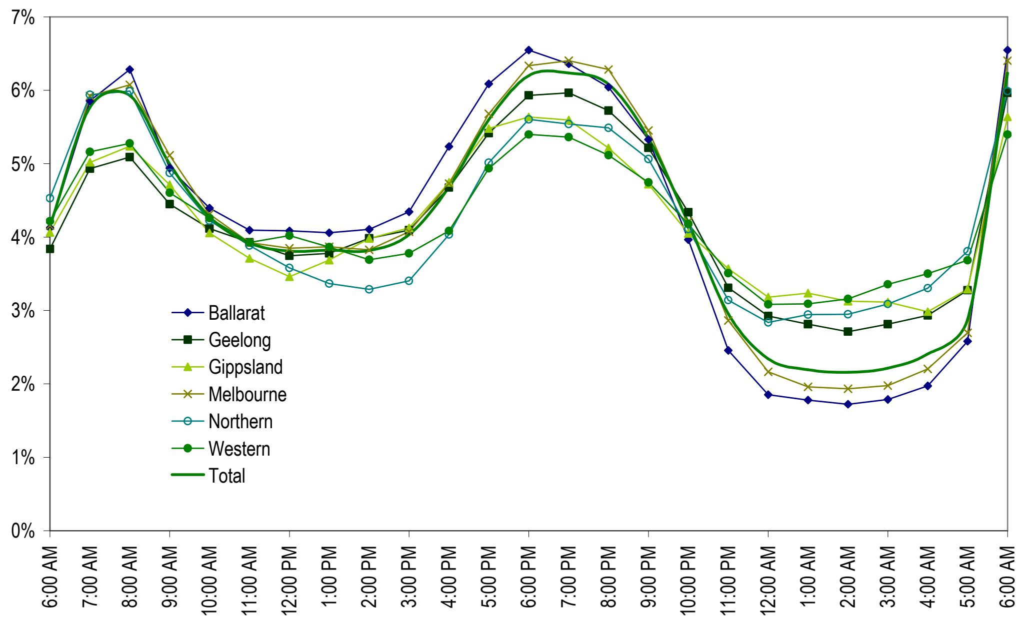
Winter peak day hourly demand profiles for each SWZ and the total system are shown in Figure A1.1. Demand picks up in the morning after 6am due to residential area heating, water heating and industry start-up. Demand for gas heating increases again from 5pm and declines by midnight.

The peak hour forecasts are produced by applying the proportion of gas used in the peak hour on a selection of high demand days in the previous winter to the peak day forecasts (see Section A1.2). The growth rates are assumed to be the same as for the peak day forecasts. The same approach is used for monthly peak hour forecasts.

Peak hour system demand forecasts are prepared for 1 in 2 and 1 in 20 peak day weather standards. See Appendix A2 for more details on the weather standards.

The peak hour forecasts are non-coincident, with some SWZs having morning peaks rather than evening peaks for some months of the year. Generally, the peak hour is in the evening during the winter months May through September and in the morning in the remaining months. Evening peaks associated with residential gas heating usually occur between 6pm and 7pm. Morning peaks due to heating, hot water and industry start-up usually occur between 7am and 8am.

Figure A1.1 Winter peak day hourly demand profiles



A1.2 Peak day demand forecast approach

Peak day system demand is driven by increased heating consumption by households on cold winter days. The forecast growth in peak day demand depends on the relative growth of temperature-sensitive Tariff V demand versus less temperature-sensitive Tariff D demand, and may differ from the forecast growth of annual system demand.

The peak day system demand forecast is determined by applying load factors (see below) to the average daily demand derived from the annual system demand forecasts. Peak day forecasts are calculated for Tariff D and V separately, which are then added to provide the DTS forecast. See Section A1.4 for the annual system demand forecast approach.

The load factor is defined as the ratio of the average daily demand to the peak day demand. The load factors for each of the Tariff D and V demands were determined as follows:

- the temperature sensitivity of the daily demand for the winter period[11] is determined by regression analysis to enable demands to be weather-normalised;
- the averages of the five peak demands in each of the previous three winters are calculated and weather-normalised to the 1 in 2 and 1 in 20 peak day weather standards (see Appendix 2 for the weather standards used);
- an average daily demand for the three previous years is calculated by normalising the annual demands to the annual weather standard and dividing by 365; and
- the load factor for each of the 1 in 2 and the 1 in 20 standards is taken as the ratio of the average daily demand to the peak day demand, averaged over the three previous years.

Monthly peak day system demand forecasts are generated for the SWZs for Tariff D and V separately. Monthly 1 in 2 and 1 in 20 peak days for the DTS and the SWZs are generated for each month by:

- using historical peak day demands for that month to determine a ratio between the peak day demand for that month and the 1 in 2 and 1 in 20 winter peak days[12]; and
- applying this ratio to the 1 in 2 and 1 in 20 peak day forecasts.

The forecasts are reconciled to take account of large load variations on the peak day profiles. Final forecasts for each SWZ are reconciled with the DTS monthly peak day forecasts.

A1.3 Monthly demand forecast approach

Monthly system demand forecasts are generated separately for Tariff D and V.

Forecast weather normalised monthly profiles for each SWZ and for the total DTS are extracted from historical monthly consumption data. This is performed for Tariff D and V accounting for large load variations due to known expansion / connections or closures at specific sites/locations. The forecast monthly load profiles are used to derive monthly demand forecasts from forecast annual system demand in each zone. The SWZ forecasts are reconciled with the monthly system demand forecasts for the DTS.

A1.4 Annual demand forecast approach

The annual system demand forecasts are generated from econometric models using key forecast economic inputs including:

- Victorian Gross State Product (GSP);
- State industry output projections; and
- Projections of state population, dwelling stocks, real household disposable income, gas/electricity price and CPI.

Other factors taken into account when preparing the forecasts include:

- Results of a survey of major industrial users on planned expansions or reductions including gas

---

[11] May to September excluding holidays

[12] Except January when daily loads increase progressively and generally peaking in late January as industries return to normal operations after Christmas-New Year close down.

cogeneration (see Appendix A4 for a report on the results of the survey);

- Market information obtained from media reports;
- Assumed Commonwealth and the State Government energy policies. See Appendix A3 for a summary of the policies likely to influence gas demand;
- Reduced water heating load;
- Increased penetration of reverse cycle air conditioners[13]; and
- Standard weather conditions. Victorian gas demand is highly sensitive to weather variations and therefore, gas demand forecasts are based on standard weather conditions discussed in Appendix A2, Section A1.2.

The econometric models generate annual demand forecasts for industrial, commercial and residential sectors, and for each major industry (ANZSIC) group[14]. The forecasts are adjusted with load variation information from the major gas customer survey and market information, and assumed policies that will influence gas demand. See Appendix A5 for a comparison of the 2009 assumptions with those used in the 2008 forecasts.

The annual system demand forecast by SWZ is generated by analysing historical Tariff D demand by industry sector to determine the trends in regional shares. These trends are extrapolated and used to split the forecast demand by industry sector into SWZs, after allowing for known load variations advised by participants or obtained from the major gas customer survey.

Historical Tariff V demand is analysed to determine heating and non-heating loads in each zone. Projected system growth is applied proportionately across all zones after allowing for growth in specific locations to reflect new housing projects.

Tariff V and Tariff D SWZ forecasts are combined to obtain the SWZ annual forecasts.

[13] Reverse Cycle Air conditioners can reduce the gas space heating load while increasing electricity winter loads.

[14] As defined by the *ANZSIC* codes (Australian and New Zealand Standard Industry Classifications).

[This page is intentionally left blank]

A2 Weather standards

A2.1 Introduction

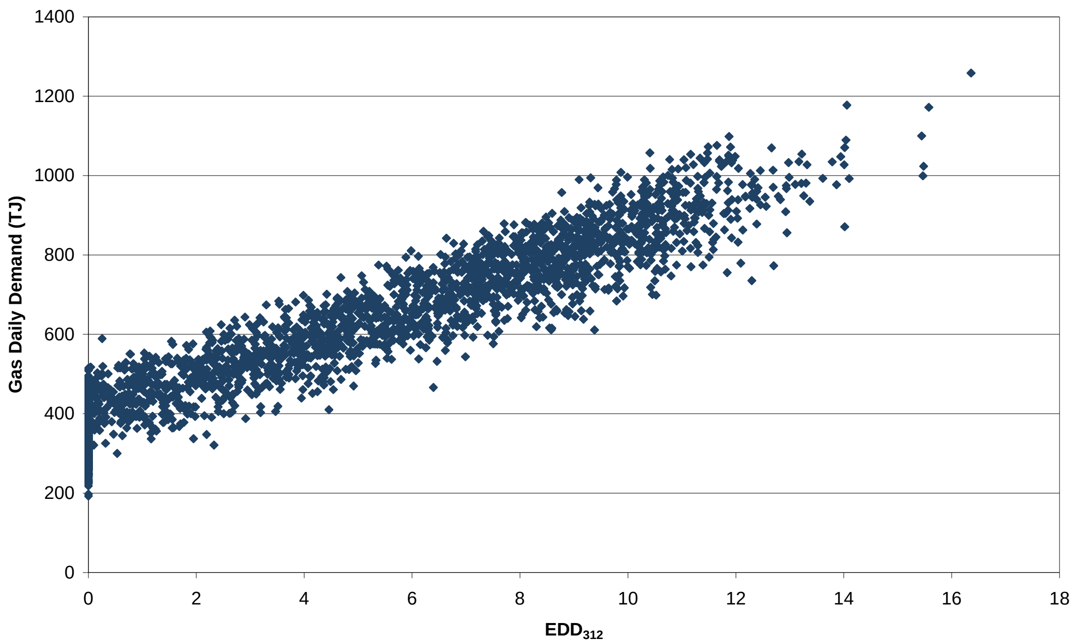
It has long been recognised that weather has a significant impact on gas demand. Understanding the factors that affect the consumption of gas is central in evaluating future energy demands. When temperatures are lower than normal, energy demand for residential heating increases. This strong relationship between gas demand and climate highlights the need to identify the weather conditions assumed when calculating forecast demand. In gas forecasts, the actual demand needs to be adjusted for weather before the underlying growth can be calculated. These weather adjustments can be simplified through the use of Effective Degree Day (EDD) variable.

The EDD index is a weather variable created from various climate variables which can include temperatures, wind speeds and daily sun hours as well as seasonal impacts to produce a linear relationship with gas demand. Wind speed and sun hours impact on demand is attributed to physiological effects. It has been noticed that consumers will tend to use more heating load on a windy day compare to day with no wind although the average temperature is the same. Similarly, consumers will tend to use less heating load on sunny days although the average temperature is the same. The seasonal effect accounts for the fact that consumers tend to use more heating load as winter progresses. The advantages of the EDD variable are:

- Simplification of the demand models because of linear relationship with demand; and
- Improvement of the fit of the weather-demand models.

Figure A2.1 illustrates how well the EDD index currently used by AEMO correlates with gas daily demand.

Figure A2.1 Daily EDD against daily gas demand



A2.2 The EDD_{312} formula

A review of the EDD_{129} and the EDD_{66} formula in 2006 concluded that a modified EDD model, the EDD_{312} index, is a better predictor of heating demand for 6am gas days. The EDD_{312} formula is shown below.

EFFECTIVE-DEGREE-DAY (EDD_{312})	=	
Temperature		Degree Day (**DD_{312}**)
Wind chill	plus	0.023 ***DD_{312} * $Wind_{312}$**
Insulation	minus	0.18 * Sunshine hours
Seasonality	plus	2 *Cosine (2π(day - 200)/365)

There are 4 components in the EDD_{312} formula.

Temperature T_{312}: This is the average of the nine three-hourly Melbourne temperature readings (in degree Celsius) from 3am to 12am the following day inclusive as measured at the Bureau of Meteorology's Melbourne Station. Equal weighting is applied to all observations. The gas day begins at 6am so the EDD formula implies a three-hour lag in demand to changes in ambient temperature.

The Degree Day (DD or HDD for Heating Degree Day)

DD_{312} = 18 - T_{312} if $T_{312} < 18$

= 0 if $T_{312} \geq 18$

18^{O}C represents the threshold temperature for residential gas heating – this threshold (of about 65 ^{O}F) is a fairly common standard internationally.

Average $Wind_{312}$: This is the average of the nine three-hourly wind observations (measured in knots) from 3am to 12am the following day inclusive measured at the Laverton and Moorabbin Stations. Equal weighting is applied to all observations.

Sunshine Hours: This is the number of hours of sunshine above a standard intensity as measured at the Weather Bureau's Tullamarine Station between 12am to 9pm inclusive.

Seasonal Factor (COSINE function): This factor models seasonality in consumer response to different weather. It indicates that residential consumers more readily turn on, adjust heaters higher or leave heaters on longer in winter than in the shoulder seasons for the same weather or change in weather conditions. For example, central heaters are often programmed once cold weather sets in resulting in more regular use. This change in consumers' behaviour is captured in the Cosine term in the EDD formula, which implies that for the same weather conditions heating demand is higher in winter than in the shoulder seasons or in summer.

A2.3 Comparison between EDD_{312} and alternative EDD models

Two alternative EDD indices have been tested and compared with the current EDD312 index in relation to their power (accuracy) of predicting 6am daily gas heating demand (D_{66}) and 6am peak day demand of the year.

The only changes to the formula used to calculate these alternative EDD indices are the variations to how daily average temperatures and average wind speeds are calculated. These alternative indices are shown below.

ALTERNATIVE EDD INDEX	DAILY AVERAGE TEMPERATURE AND WIND CALCULATIONS
EDD_{66}	• Three hourly observations between 6am current calendar day to 6am the following calendar day • A 50% weighting is applied to the 6am temperature and wind observations
EDD_{129}	• Three hourly observations between 12am to 9pm current calendar day • Equal weightings on all temperature and wind observations

Regression analysis of daily system demand against the above EDD indices is performed to test how well each of these indices fits system demand D_{66}. The analysis is based on D_{66} between May and September each year from 2004 to 2008.

Table A2.1 summarises the statistics used to assess the goodness-of-fit of each EDD index. The results are averaged over 2004 to 2008.

Table A2.1 Regression results (alternative EDD compared with benchmark EDD_{312})

	EDD_{66}	EDD_{129}	EDD_{312}
R-Square	95.3%	95.6%	**96.0%**
t-statistic for temperature sensitivity	85.0	88.1	**93.1**
Absolute % Error fitting peak day	2.8%	2.8%	**2.1%**
RMSE fitting top 5 peak days	46	46	**39**
RMSE fitting top 10 peak days	42	51	**40**

The regression results indicate that the EDD_{312} is the best predictor while the EDD66 and the EDD_{129} indices are slightly inferior to the EDD_{312} index.

Based on the above findings, it is recommended that AEMO continue to use the EDD_{312} index for modelling 6am gas day heating demand.

A2.4 Review of the annual and peak Day EDD standards

Reviews of the EDD weather standards (2000 to 2008)

AEMO reviewed the EDD weather standards in 2000, 2001, 2003, 2005 and 2006. The annual and peak day EDD standards were revised downward in each review to reflect the warming trend in Melbourne temperatures. Fixed annual and peak day EDD standards have been used in AEMO's medium to long-term demand forecasts. Historical annual and peak day EDD standards are summarised in Table A2.2.

Table A2.2 Historical annual and peak day EDD standards

	2000 REVIEW	2001 REVIEW	2003 REVIEW	2005 REVIEW	2006 REVIEW
Annual EDD	1,504	1,445	1,396	1,396	1,340
1-in-2 Peak Day EDD	15.15	15.15	14.60	14.60	14.35
1-in-20 Peak Day EDD	17.25	17.25	16.75	16.75	16.50

Review of the annual EDD standards in 2009

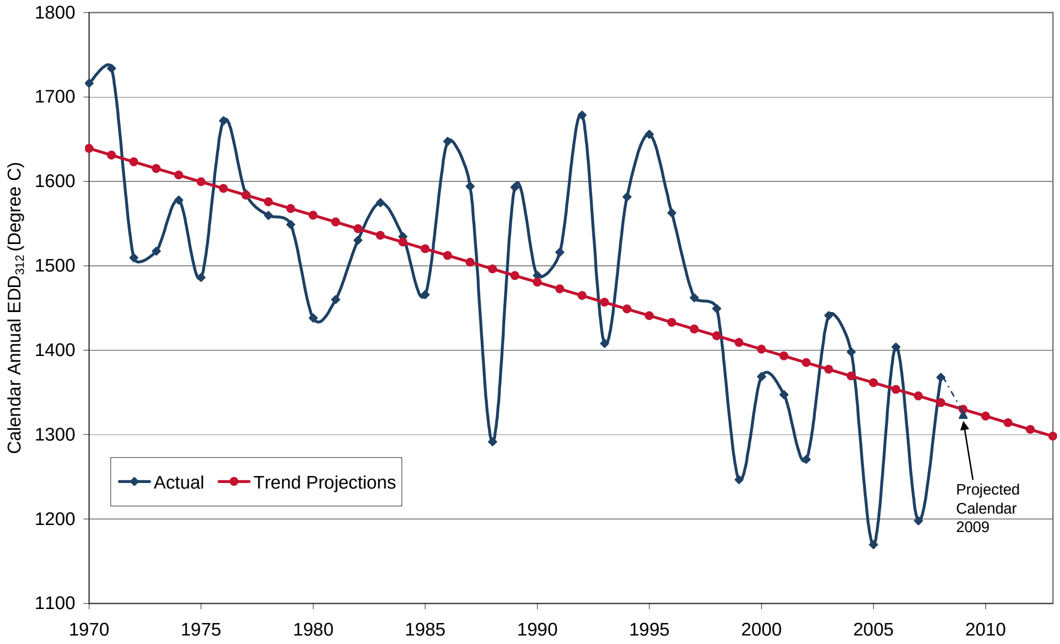
The methods used to develop the annual standards in the 2009 study are explained below. Both methods produced consistent annual standards for the planning period 2009-2013.

The *Long-Term Trend Projection Method for Annual EDD Standards* involves the following steps:

- fitting a regression line through the actual annual EDD of historical years;
- deriving the long-term warming trend from the slope of the regression line; and
- projecting the annual EDD standards for the planning period by extrapolation of the trend line.

Figure A2.2 depicts the warming trend and the year-to-year variations in annual weather between the 1970 and 2008 calendar years.

Figure A2.2 Annual warming trend 1970-2008 and trend projections



The regression analysis results shown in Table A2.3 indicate that the:

- warming trend in annual EDD_{312} has increased from about –5.4 EDD_{312}/year to -7.9 EDD_{312}/year over 2000 to 2008;
- estimated warming trend can be sensitive to the actual weather data included in the analysis, as can be seen when comparing the warming trend using calendar year data 1970-2000 with that derived from financial year data 1970-2000; and
- estimated warming trend is subject to large uncertainties due to the large variations in actual weather.

Table A2.3 The long-term warming trend in annual EDD_{312}

	BASED ON CALENDAR YEAR			BASED ON FINANCIAL YEAR	
Calendar Year	Warming Trend (EDD_{312}/yr)	95% C.I. (EDD_{312}/yr)	Financial Year	Warming Trend (EDD_{312}/yr)	95% C.I. (EDD_{312}/yr)
1970-2000	-5.4	-1.1 to -9.6	1970-2000	-4.7	-0.4 to -9.0
1970-2004	-6.6	-3.1 to -10.0	1970-2004	-6.4	-2.7 to -10.0
1970-2008	-7.9	-4.9 to -11.0	1970-2008	-8.0	-4.9 to -11.0

The *MAT9 (or the Nine-Year Moving Average) Projection Method* was used to establish the annual EDD_{312} standards in the 2006 EDD review.

The MAT9 method is designed to capture weather variations over both the medium-term and the long-term. The MAT9 projection for:

- year 1 is the average of the annual EDD of the most recent nine years plus five years of warming trend; and
- subsequent years are derived from the previous year's projection plus one year of warming trend.

The MAT9 projections are highly dependent on the actual annual EDD of the nine years included in the calculation of the first year's projection.

Annual EDD_{312} standards for 2009-2013

The long-term trend and the MAT9 projection methods are used to generate annual EDD_{312} standards for 2009-2013. Each method produces two sets of results using calendar and financial year actual weather data. The projected standards are shown in Table A2.4. The projections assume that the:

- long-term warming trend is –7.9 EDD_{312}/year (based on calendar 1970 to 2008) and –8.0 EDD_{312}/year (based on financial year 1970 to 2008); and
- nine-year moving average is the average of the annual EDD_{312} of the last nine calendar or financial years (2000-2008).

The results show that the trend-projected annual standards are colder than the MAT9 projections by about 6 to 16 EDD_{312}/year. This is because the two warmest years on an EDD_{312} basis since 1970 (2005, 2007) are included in the MAT9 projections. These differences total to approximately 29 to 82 EDD_{312} or 2 to 4 PJ of heating load over 2009-2013.

Table A2.4 Annual EDD_{312} standards calendar 2009 - 2013

	LONG-TERM TREND PROJECTIONS		MAT9 PROJECTIONS		DIFFERENCES IN EDD_{312}	
Calendar Year	Calendar Year (CY) Trend 1970-2008 (1)	Financial Year (FY) Trend 1970-2008 (2)	Average CY 2000-2008 +CY Trend (3)	Average FY 2000-2008 +FY Trend (4)	Calendar Year Difference (1) – (3)	Financial Year Difference (2) – (4)
2009	1,330	1,332	1,324	1,316	6	16
2010	1,322	1,324	1,316	1,308	6	16
2011	1,314	1,316	1,308	1,300	6	16
2012	1,306	1,308	1,300	1,292	6	16
2013	1,298	1,300	1,292	1,284	6	16
				Total Difference in EDD	29	82
				Total Difference in PJ	2	4

A2.5 Review of the peak day EDD_{312} standards 2009

The peak day EDD is the EDD on the maximum demand day of the year. The peak day EDD_{312} standards are required for forecasting 1-in-2 and 1-in-20 system peak days. The DTS capacity is planned to meet the forecast 1-in-20 system peak day.

The forecast 1-in-2 system peak day is the maximum demand of the year which has a 50% probability of being exceeded.

The forecast 1-in-20 system peak day is the maximum demand of the year which has a 5% probability of being exceeded.

The peak day EDD may not be the coldest day of the year. If the coldest day of the year fell on a Saturday or a Sunday the peak day of the year could be the second, third or fourth coldest day of the year. Table A2.5 shows that the average peak day EDD_{312} between 2004 and 2008 was 0.4 degree warmer than the average coldest day EDD_{312} over the same period.

Table A2.5 Historical coldest day EDD_{312} compared with historical peak day EDD_{312}

CALENDAR YEAR	COLDEST DAY EDD	PEAK DAY EDD	DIFFERENCE	COMMENT
2004	14.10	12.27	-1.83	Peak Day occurred on the fourth coldest day of the year
2005	15.58	15.58	0	
2006	12.94	12.66	-0.27	Peak Day occurred on the second coldest day of the year
2007	16.36	16.36	0	
2008	15.44	15.44	0	
Average	14.88	14.46	-0.42	

Three methods have been used to generate the peak day EDD312 standards for 2009-2013. These methods are explained below.

The long-term trend projection method for peak day EDD standards

This approach is similar to projecting annual EDD standards, as explained above, and involves:

- fitting a regression line through the actual coldest day EDD_{312} of historical years. The coldest day EDD_{312} data is used as a proxy for historical peak day EDD_{312} in the absence of historical 6am system peak day data prior to 2000;
- deriving the long-term warming trend in the coldest day of the year from the slope of the regression line;
- calculating the 1-in-2 peak day EDD standards for the forecast years by extrapolating the trend line; and
- calculating the 1-in-20 peak day EDD standards for the forecast years as 1-in-2 peak day EDD standards + 1.645 * standard deviation of the variations of the actual coldest day EDD from the trend line. (The 95th percentile of a normal probability distribution is 1.645 standard deviations above the mean.)

Figure A2.3 depicts the warming trend and the year-to-year variations in the coldest day EDD_{312} between 1970 and 2008.

Figure A2.3 Warming trend in coldest Day EDD_{312} 1970-2008 and trend projections

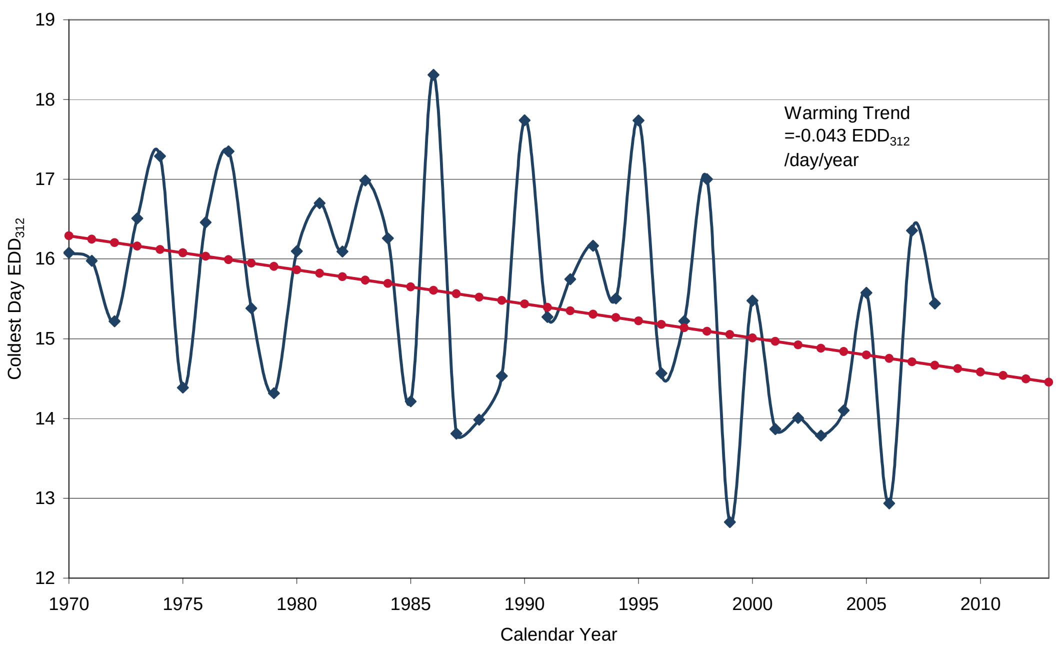


Table A2.6 shows that the:

- warming trend in coldest day EDD312 has increased from about -0.026 EDD312/day/year to -0.043 EDD312/day/year over 2000 to 2008; and
- estimated warming trend is subject to large uncertainties as evidenced by the 95% confidence intervals of the trend estimates.

Table A2.6 Long-term warming trend in coldest day EDD_{312}

CALENDAR YEAR	WARMING TREND (EDD_{312}/DAY/YEAR)	95% C.I. (EDD_{312}/DAY/YEAR)
1970-2000	-0.026	0.028 to -0.080
1970-2008	-0.043	-0.005 to -0.080

The MAT9 projection method for peak day EDD standards

The MAT9 1-in-2 peak day EDD_{312} for:

- year 1 is the average of the coldest day EDD_{312} of the most recent nine years plus five years of warming trend; and
- subsequent years are calculated from the previous year's projection plus one year of warming trend.

The MAT9 1-in-20 peak day EDD_{312} is calculated as 1-in-2 peak day EDD standards + 1.645 * standard deviation of the variations of the actual coldest day EDD from the long-term trend line.

The simulation method for peak day EDD standards

AEMO previously used the demand simulation method, which incorporates warming trends in the input weather data. The demand simulation approach entails that if a warmer annual EDD_{312} standard is chosen for a given year, the peak day EDD_{312} standard generated from the simulation method for that year will also be warmer. However, this may not necessarily reflect actual conditions. Therefore, the simulation method for peak EDD standards is used in this review, as it is independent of demand.

The simulation method approach involves:

- generating 1,000 simulated EDD's;
- fitting a regression line through the simulated EDDs;
- calculating the 1-in-2 peak day EDD standards for the forecast years by extrapolating the trend line; and
- calculating the 1-in-20 peak day EDD standards for the forecast years equal to 1-in-2 peak day EDD standards + 1.645 * standard deviation of the variations of the actual coldest day EDD from the trend line.

Peak day EDD_{312} standards for 2008-2013

Table A2.7 summarises the 1-in-2 and 1-in-20 peak day EDD_{312} standards for 2008- 2013.

There are three sets of peak day EDD_{312} standards:

- two sets generated from the trend and MAT9 projection methods; and
- one set of standards from the simulation method.

The results show that the:

- trend projections method produces the coldest peak day EDD_{312} standards ; and
- difference between the coldest and the warmest peak day standards is about 0.20 (for 1-in-2 peak day) and 0.23 EDD_{312} (for 1-in-20 peak day).

Table A2.7 1-in-2 and 1-in-20 peak day EDD_{312} standards calendar 2008 – 2013

		1-IN-2 PEAK DAY EDD_{312} STANDARDS		
CALENDAR YEAR	TREND PROJECTIONS	MAT9 PROJECTIONS	SIMULATED TREND PROJECTION	MAXIMUM DIFFERENCE
2009	14.63	14.59	14.46	0.16
2010	14.58	14.55	14.41	0.17
2011	14.54	14.50	14.36	0.18
2012	14.50	14.46	14.31	0.19
2013	14.45	14.42	14.26	0.20
		1-IN-20 PEAK DAY EDD_{312} STANDARDS		
2009	16.88	16.84	16.68	0.20
2010	16.83	16.80	16.64	0.21
2011	16.79	16.75	16.59	0.21
2012	16.75	16.71	16.55	0.22
2013	16.71	16.67	16.51	0.23

A2.6 AEMO's annual energy and peak day EDD_{312} standards

For transmission system capacity planning, AEMO intends to use:

- EDD_{312} for 6am gas days;
- annual EDD standards based on the long-term trend projection method, due to its increased stability compared to the MAT9-derived standards. Although the MAT9 approach minimises the error across a long time period, it is quite volatile from year to year as cold or warm years enter/leave the moving average. This potential for volatility in the forecast of capacity requirements for the transmission system is likely to impact the timing of augmentations, moving required augmentation dates as a result of changing peak day forecasts. This makes the MAT9 methodology less suitable for planning purposes;
- annual EDD standards based on calendar years to align with the VAPR. These standards will be used in forecasts for AEMO's 2009 VAPR Update and future VAPRs;
- peak-day EDD standards based on the calendar Trend-projected annual EDD standards;
- the annual and peak day EDD standards for 2011, which is the mid-point of the planning period 2009-2013, for all of the five years in the planning period. For system capacity planning, it has been AEMO's practice to use fixed peak day EDD standards. The use of a fixed peak day EDD standard for all the years in the planning period has the advantage of producing peak day forecasts standardised to consistent forecast weather conditions so that assessing the underlying growth in peak day demand due to other factors is clearer; and
- monthly energy and peak day EDD standards consistent with the above-mentioned methodology.

AEMO plans to review the Melbourne temperature warming trend and the EDD standards used for planning by June 2011 or earlier if and when required.

The previous (2006) and the new (2009) EDD standards are shown in Table A2.8.

Table A2.8 2006 and 2009 annual and peak day EDD_{312} standards

	2006	2009
ANNUAL EDD STANDARD	1,340	1,314
1-IN-2 PEAK DAY EDD STANDARD	14.35	14.55
1-IN-20 PEAK DAY EDD STANDARD	16.50	16.80

Compared to the previous annual standard of 1,340 EDD312 the new standard represents a reduction of 1.6 PJ (=26 EDD_{312} * 44.6 TJ/ EDD_{312}) in heating load per year and 8.0 PJ over the planning period 2009 to 2013.

A2.7 AEMO's monthly energy and peak day EDD_{312} standards

Monthly energy EDD standards

The new monthly energy EDD_{312} standards were generated by applying a long-term average (1970 to 2008) monthly EDD_{312} profile to the annual EDD_{312} standard of 1,324. [15]

Table A2.9 compares the 2008 and 2006 monthly EDD standards. The largest differences are in the shoulder months (April to May and September to November).

[15] Historical daily EDD_{312} data used to generate historical monthly EDD_{312} has been adjusted for the long-term calendar year warming trend.

Table A2.9 2008 and 2006 monthly energy EDD standards

MONTH	2008 STANDARD (EDD_{312})	2006 STANDARD (EDD_{312})	DIFFERENCE (EDD_{312} MINUS EDD_{66})
JAN	0.5	1.6	-1.1
FEB	2.2	1.2	1
MAR	9.3	10.1	-0.8
APR	58.8	53.9	4.9
MAY	159.5	154.4	5.1
JUN	250.3	251.1	-0.8
JUL	297.0	297.5	-0.5
AUG	253.1	259.0	-5.9
SEP	162.1	172.1	-10
OCT	83.9	96.1	-12.2
NOV	28.1	35.1	-7.0
DEC	9.0	8.0	1.0
ANNUAL	1,314	1,340	-26

Monthly peak day EDD standards

Monthly peak day EDD standards were generated using the trend projection method, which was also used to generate the annual peak day EDD standards. The focus was to derive the EDD_{312} for the peak day of each month of the year instead of the annual peak day EDD.

A review of the occurrences of historical system peak days indicates that there was a 50% chance that the highest demand day would occur in July. However, for planning purposes it is assumed that there is an equal chance that the peak day for a given year will occur in any of the winter months between June and September. The peak day EDD_{312} for these months are therefore set to equal to the annual peak day EDD_{312} standard. The 2008 and 2006 1-in-2 and 1-in-20 peak day EDD standards are compared in Table A2.10.

Table A2.10 2008 and 2006 1-in-2 and 1-in-20 monthly peak day EDD_{312} standards

MONTH	2008 1-IN-2	2008 1-IN-20	2006 1-IN-2	2006 1-IN-20
JAN	0.5	1.6	0	1.4
FEB	1.2	2.9	0	3.0
MAR	2.7	4.9	1.8	5.1
APR	5.6	7.8	5.4	8.4
MAY	9.8	12	9.0	13.1
JUN	14.55	16.80	14.35	16.50
JUL	14.55	16.80	14.35	16.50
AUG	14.55	16.80	14.35	16.50
SEP	14.55	16.80	14.35	16.50
OCT	7.7	10	8.0	11.8
NOV	6.0	8.2	5.0	9.1
DEC	3.0	5.2	1.2	4.7

[This page is intentionally left blank]

A3 Energy policy

This appendix discusses key Victorian and Federal Government policies influencing gas demand growth.

A3.1 Victorian Energy Efficiency Target

The Victorian Energy Efficiency Target (VEET) scheme, which commenced on 1 January 2009, sets a target for energy savings, initially in the residential sector, and requires energy retailers to meet their own targets through energy efficiency activities, such as providing households with energy saving products and services at little or no cost.

The VEET scheme plays an important role in achieving the Victorian Government's target of reducing greenhouse gas emissions from households by 10 per cent by 2010 and Victoria's overall emissions to 60 per cent by 2050 (see http://www.esc.vic.gov.au/public/VEET/).

The scheme operates by imposing a legal liability on large electricity and gas retailers in Victoria (known as relevant entities) to contribute to energy efficiency measures by acquiring and surrendering Victorian energy efficiency certificates (VEECs). A penalty will be imposed on entities that fail to surrender sufficient VEECs to meet their liability.

Under the VEET scheme, accredited persons are eligible to create VEECs for prescribed activities undertaken at residential premises. Each VEEC created represents one tonne of carbon dioxide equivalent (CO_2-e) abated by a prescribed activity.

The Victorian Energy Efficiency Target Act 2007 (VEET Act) provides for the VEET scheme to operate in three-year phases, with new scheme targets and prescribed activities set for each phase. The first phase of the VEET scheme will operate from 1 January 2009 to 31 December 2011.

Our forecasts incorporate a notional 'expected' impact of the VEET scheme on residential gas consumption. While the VEET scheme for some households may serve to increase residential gas consumption as these households substitute gas appliance usage for comparable electricity appliance use, the net effect across all households is likely to reduce gas consumption compared with a business-as-usual case.

A3.2 Carbon Pollution Reduction Scheme

On 15 December 2008, the Commonwealth Government released its White Paper on the Carbon Pollution Reduction Scheme (CPRS). The White Paper followed the Green Paper, which was released in July 2008 and canvassed options on the design on the scheme.

The proposed CPRS would establish a 'cap and trade' scheme with a cap on the total amount of greenhouse gas emissions being established for each year through the issue of permits.

Under the proposed scheme, significant emitters of greenhouse gases must acquire a permit for every tonne of gas emitted in a particular year. Entities obliged to acquire permits will be able to trade them, which will thereby place a price on emissions.

In short, the key points from the Paper were as follows:

- the Government has committed to a medium-term target range to reduce Australia's greenhouse gas emissions by between 5% and 15% below 2000 levels by 2020, and a long-term goal of reducing emissions to 60% below 2000 levels by 2050;
- the price of permits will be capped at $40/t CO_2-e, with the cap imposed for the first five years of the scheme, rising in real terms by 5% each year beyond 2015;
- coverage of the scheme is around 75% of Australia's emissions, involving mandatory obligations for around 1000 entities;
- around 25% of total permits will be issued free to 'emissions-intensive trade-exposed industries' (EITEs) at the scheme commencement, increasing to around 45% by 2020;
- the coal industry is classified a 'strongly affected industry' and will receive compensation under the Electricity Sector Adjustment Scheme (ESAS).

On 4 May 2009, the Prime Minister announced various amendments to the proposed CPRS legislation:

- a delay in the start date: from mid-2010 to mid-2011;
- fixed price permits (at $10 per tonne CO_2 equivalent) for the first year of the scheme;
- an increase in assistance to EITEs; and
- recognition of various voluntary emission reduction activities.

The proposed CRPS legislation is currently being negotiated between the major parties in the Federal Parliament and at the time of printing this document there remains significant uncertainty in relation to it.

The proposed scheme is expected to substantially increase the retail price of gas paid by residential, commercial and industrial customers (although to varying degrees). This retail price shock is likely to substantially reduce gas consumption in all sectors.

The current forecasts assume that the CPRS is introduced in mid 2011 with a permit price of $10 per tonne CO_2 equivalent. KPMG Econtech developed projections of carbon permit prices in April 2009, prior to the Government's announced changes to the CPRS scheme. To account for these changes, KPMG Econtech's carbon permit prices were shifted out by two years and the permit prices were set to the fixed permit price of $10/tonne CO_2 equivalent in the first year of the scheme.

From 2012/13, the permit prices in the medium and low energy growth scenarios grow by 4% per annum. In the high energy scenario it has been assumed that there is a "one-off positive technology shock" which reduces the carbon permit price in 2016/17, before resuming a 4% per annum growth rate.

A3.3 Minimum Energy Performance Standards

An important refinement to the assumptions underlying the current forecasts relates to the effect of proposed changes to the Minimum Energy Performance Standards (MEPS) Regulations. The Australian Government agencies responsible for product energy efficiency are currently investigating whether to mandate the energy performance of gas water heaters that are imported and manufactured in Australia[16]. Specifically, a proposal has been put forward to cease manufacturing or importing of gas water heaters with energy ratings of less than 5 stars from 1 October 2009. The proposal to introduce a minimum energy performance standard for gas water heaters, if implemented, will serve to reduce gas consumption by households in both new and existing dwellings.

[16] Australian Greenhouse Office (2007) 'Consultation cost benefit analysis on: proposal to mandate the energy performance of gas water heaters', Department of the Environment and Water Resources, Equipment Energy Efficiency, Gas and Electrical Committee 25 June 2007.

A4 Gas customer survey results

In August 2009, NIEIR undertook a survey of 193 industrial and commercial gas customers. The survey sought information regarding their recent and future gas consumption in order to assess gas consumption trends. This section provides a high-level overview of the survey responses.

Many survey respondents expressed some uncertainty regarding their projections, and in developing the forecasts for Tariff D demand NIEIR evaluated the survey information against other statistical information including published economic data and anecdotal insights.

A4.1 Response rate

Table A4.1 shows the number of returned surveys by industry and the share of gas consumption of responding customers. 95 out of 196 customers responded. The whole survey group consumed approximately 77.4 PJ of natural gas in 2008. Those customers who responded to the survey consumed approximately 48.7 PJ, or 63% of the total consumption of the whole survey group, in 2008.

The response rate for large gas customers was slightly higher than for small customers. The top 20 surveyed customers consumed more than 50% of the total gas consumed in 2008 by the survey group.

Table A4.1 Large customer survey – response rate by industry

INDUSTRY	NO. SENT	RESPONSE RATE	RESPONSE RATE IN TERMS OF GAS USE*
Agriculture, Forestry, Fishing & Hunting	6	50%	61%
Basic Metal Products, Fabricated Metal Products	12	58%	80%
Chemical, Petroleum and Coal Products	24	83%	98%
Construction Material	1	0%	0%
Finance, Property & Business Services	3	33%	48%
Food, Beverages and Tobacco	59	39%	51%
Non-Metallic Mineral Products	27	41%	50%
Paper, Paper Products, Printing and Publishing	13	38%	50%
Public Administration, Defence & Community Services	23	43%	61%
Recreation, Personal and Other Services	3	67%	87%
Textiles, Clothing and Footwear	10	70%	71%
Transport Equipment, Other Machinery and Equipment	9	44%	41%
Transport, Storage and Communication	3	0%	0%
Wood, Wood Products and Furniture	3	67%	2%
Grand Total	196	48%	63%

* based on 2008 energy consumed

A4.2 Results summary

Table A4.2 presents the aggregated gas projections of responding customers.

Nineteen of the top twenty gas customers responded to this survey. One major consumer is closing part of its plant by the end of 2009, and ceasing operation completely by the end of 2010 causing a decrease, compared to 2008 levels, of almost 1.9 PJ in Tariff D demand. Furthermore, two customers have both already ceased operations in 2009, reducing demand by 0.5 PJ compared to 2008 levels. An additional reduction in demand of 0.3 PJ is forecast, as another two customers indicated they are shutting down.

Aggregate gas consumption of the responding survey group is expected to fall by approximately 4.5 per cent in 2009, and then grow by 1.2 per cent in 2010, falling again in 2011. On average, gas consumption of the survey respondents is forecast to decrease by 1.3 per cent between 2009 and 2014.

Table A4.2 Recent and expected gas consumption of respondents only

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ANNUAL DEMAND (TJ)	45,583	46,806	47,603	48,659	46,471	47,017	46,019	46,393	45,076	45,049
ANNUAL PERCENTAGE CHANGE		2.7%	1.7%	2.2%	-4.5%	1.2%	-2.1%	0.8%	-2.8%	-0.1%

Many respondents indicated that they expected to reduce their gas consumption in response to the recent global financial crisis. Production and demand for many goods has been declining, and as gas consumption is related to demand for their products, it is likewise expected to decrease. Agriculture, Forestry and Fishing is the only industry forecasting a noticeable increase in consumption. Table A4.3 below shows that most industries other than Non-Metallic Mineral Products anticipate either no growth or a reduction in gas consumption.

Table A4.3 Actual (2004- 2008) and projected (2009-2014) gas consumption by large customers by industry (TJ)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Agriculture, Forestry, Fishing & Hunting	246	279	283	333	300	300	335	445	521	617
Basic Metal Products, Fabricated Metal Products	6,635	7,498	7,341	7,285	6,040	7,188	7,197	7,197	7,197	7,197
Chemical, Petroleum and Coal Products	15,563	15,942	17,264	19,007	17,905	17,132	16,056	16,503	16,594	16,421
Finance, Property & Business Services	164	160	155	163	160	160	160	160	160	160
Food, Beverages and Tobacco	6,983	6,843	6,306	6,268	6,413	6,411	6,436	6,432	6,437	6,437
Non-Metallic Mineral Products	6,445	6,336	6,275	5,970	6,132	6,211	6,238	6,077	6,117	6,157
Paper, Paper Products, Printing and Publishing	2,670	2,791	2,835	2,860	2,907	2,918	2,924	2,914	1,394	1,394
Public Administration, Defence & Community Services	2,711	2,953	2,905	2,840	2,759	2,801	2,796	2,790	2,781	2,781
Recreation, Personal and Other Services	463	494	475	471	470	470	475	480	480	485
Textiles, Clothing and Footwear	793	870	918	845	768	752	757	755	755	760
Transport Equipment, Other Machinery and Equipment	966	942	935	772	721	725	685	670	670	670
Wood, Wood Products and Furniture	1,946	1,697	1,912	1,845	1,897	1,950	1,960	1,970	1,970	1,970
Total	45,583	46,806	47,603	48,659	46,471	47,017	46,019	46,393	45,076	45,049
ANNUAL PERCENTAGE CHANGE (%)										
Agriculture, Forestry, Fishing & Hunting		13%	1%	18%	-10%	0%	12%	33%	17%	18%
Basic Metal Products, Fabricated Metal Products		13%	-2%	-1%	-17%	19%	0%	0%	0%	0%
Chemical, Petroleum and Coal Products		2%	8%	10%	-6%	-4%	-6%	3%	1%	-1%
Finance, Property & Business Services		-2%	-3%	5%	-2%	0%	0%	0%	0%	0%
Food, Beverages and Tobacco		-2%	-8%	-1%	2%	0%	0%	0%	0%	0%
Non-Metallic Mineral Products		-2%	-1%	-5%	3%	1%	0%	-3%	1%	1%
Paper, Paper Products, Printing and Publishing		5%	2%	1%	2%	0%	0%	0%	-52%	0%
Public Administration, Defence & Community Services		9%	-2%	-2%	-3%	2%	0%	0%	0%	0%
Recreation, Personal and Other Services		7%	-4%	-1%	0%	0%	1%	1%	0%	1%
Textiles, Clothing and Footwear		10%	6%	-8%	-9%	-2%	1%	0%	0%	1%
Transport Equipment, Other Machinery and Equipment		-2%	-1%	-17%	-7%	1%	-6%	-2%	0%	0%
Wood, Wood Products and Furniture		-13%	13%	-4%	3%	3%	1%	1%	0%	0%
Total		3%	2%	2%	-4%	1%	-2%	1%	-3%	0%

A5 Comparison with 2008 gas forecasts

A5.1 Peak day forecast comparison

Table A5.1 and Table A5.2 provide peak day system demand forecasts to 2018 under 1 in 2 year weather conditions and 1 in 20 year weather conditions for the medium growth economic scenario. Figure A5.1 presents the 1 in 2 peak day system demand forecasts to 2018 for the medium growth economic scenario.

These projections are contrasted with the forecasts prepared for the 2008 VAPR Update.

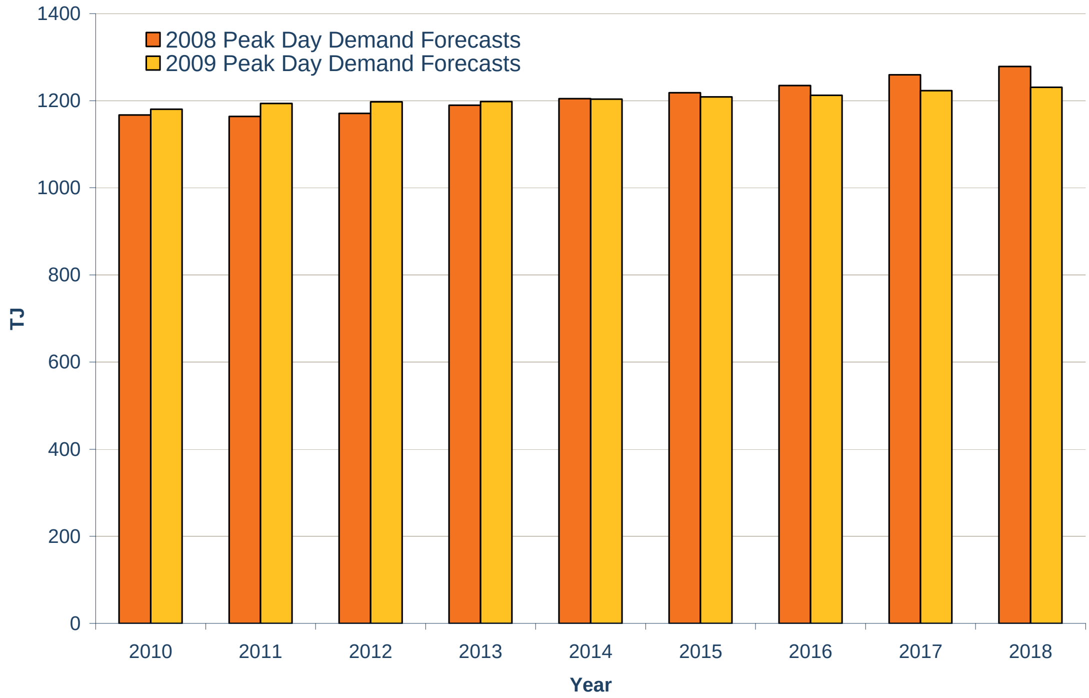
Table A5.1 1 in 2 peak day system demand forecasts, 2010-2018

YEAR	2009 FORECASTS (TJ)	2008 FORECASTS (TJ)	DIFFERENCE (%)
2010	1,181	1,167	1.2%
2011	1,193	1,164	2.5%
2012	1,197	1,171	2.3%
2013	1,198	1,190	0.7%
2014	1,204	1,205	-0.1%
2015	1,209	1,218	-0.8%
2016	1,213	1,235	-1.8%
2017	1,223	1,260	-2.9%
2018	1,231	1,279	-3.7%

Table A5.2 1 in 20 peak day system demand forecasts, 2010-2013

YEAR	2009 FORECASTS (TJ)	2008 FORECASTS (TJ)	DIFFERENCE (%)
2010	1,296	1,275	1.7%
2011	1,310	1,271	3.1%
2012	1,315	1,279	2.8%
2013	1,317	1,301	1.2%
2014	1,323	1,319	0.3%
2015	1,330	1,335	-0.4%
2016	1,334	1,355	-1.5%
2017	1,347	1,383	-2.6%
2018	1,356	1,405	-3.5%

Figure A5.1 Peak day demand forecasts, 2010-2018



The highest system day demand reading in 2009 was 1,121 TJ (occurring on 9 June 2009). 9 June was the coldest day this winter on an effective degree day (EDD) basis. The EDD reading for that day was 13.8, below the 1 in 2 year weather standard of 14.55 and the 1 in 20 year weather standard of 16.8.

The next coldest day (which recorded a 13.4 EDD) was on Friday 12 June 2009. The second highest demand reading this winter was 1,107 TJ (on Wednesday 10 June 2009). The EDD reading for that day was just 12.9.

The peak demand projections are predicated on specific weather conditions under assumed economic scenarios, namely the 1 in 2 year and 1 in 20 weather conditions (defined by the EDD index). The projections do not incorporate variations in actual system peak demand arising from other contemporaneous factors, such as 'weekend effects'.

The projected system peak levels in the near-term for both 1 in 2 year and 1 in 20 year weather conditions are slightly higher from those prepared for the 2008 VAPR Update due to an earlier than forecast economic recovery. However, the peak day system demand forecasts are forecast to grow at a slower rate than in the 2008 VAPR Update.

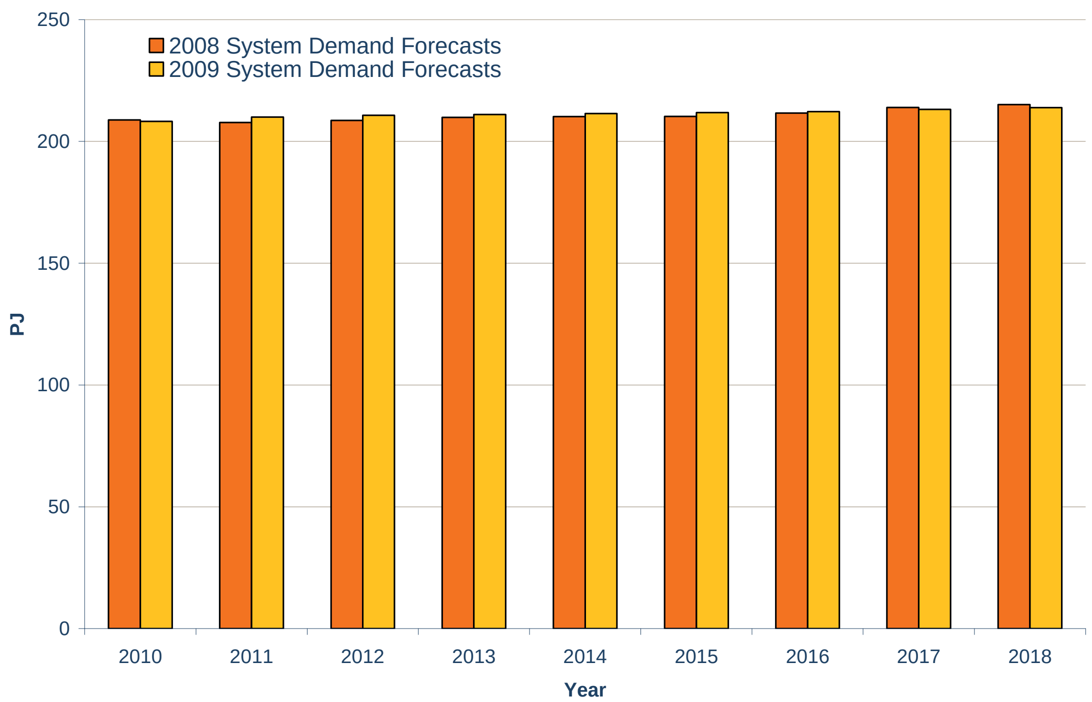
A5.2 Annual system demand comparison

Table A5.3 and Figure A5.2 presents annual system demand forecasts to 2018 for the medium growth economic scenario. These forecasts are contrasted with the forecasts prepared for the 2008 VAPR Update.

Table A5.3 Annual system demand forecasts, 2010 – 2018

YEAR	2009 FORECASTS (PJ)	2008 FORECASTS (PJ)	DIFFERENCE (%)
2010	208.2	208.8	-0.3%
2011	210.0	207.8	1.1%
2012	210.7	208.7	1.0%
2013	211.1	209.9	0.6%
2014	211.5	210.2	0.6%
2015	211.9	210.3	0.8%
2016	212.3	211.6	0.3%
2017	213.2	214.0	-0.4%
2018	213.9	215.1	-0.6%

Figure A5.2 Annual system demand forecasts, 2010-2018



In 2008, annual system gas consumption was 210.4 PJ on a weather normalised basis. This is 3.1 PJ higher than was anticipated by the 2008 VAPR Update.

Annual system gas consumption in the 2009 calendar year is anticipated to be 206.2 PJ, 4.2 PJ (or 2.0 percent) lower than its level in 2008. The changed consumption reflects a 0.7 per cent (or 0.9 PJ) decrease in tariff V gas consumption and a 3.3 per cent (or 3.9 PJ) reduction in tariff D gas consumption. The expected reduction in tariff D consumption reflects a number of factors including plant closures and downsizing in the manufacturing sector, temporary shutdowns for plant upgrades and changes in metering/tariff at a certain site.

Looking forward, annual system gas consumption in calendar year 2010 is projected to be 208.2 PJ, up 1.0 percent (or 2.0 PJ) on the levels anticipated for 2009 and 0.6 PJ lower than was projected by the 2008 VAPR Update. The growth reflects increases in tariff V consumption. Tariff V consumption is expected to grow by 1.7 per cent (or 2.1 PJ) in 2010, moderating slightly from recent historical growth rates. Tariff D consumption is expected to remain on the same consumption levels as 2009. This reflects recently announced manufacturing plant closures.

Annual system gas consumption in 2011 is projected to be 210.0 PJ, up 0.9 percent (or 1.8 PJ) on the levels projected for 2010 and 2.2 PJ lower than was projected for same period by the 2008 VAPR Update. Further forward, the 2009 projection profile is fairly consistent with the 2008 projection profile. In 2018, annual system gas consumption is projected to be 213.9 PJ, roughly 1.2 PJ lower than what was projected in 2008. The revised consumption level in 2019 reflects upward revisions to the projected consumption of tariff V and downward revision to the projected consumption of tariff D customers. Tariff D consumption in 2018 is now expected to be 4.5 PJ lower than the 2008 VAPR Update projections while tariff V consumption in 2018 now expected to be 3.3 PJ higher.

A5.3 Gas power generation comparison

In the 2008 VAPR Update GPG forecasts were presented on a Victoria wide basis rather than for the DTS. This was due to the high level of uncertainty regarding the location of new GPG projects. In the 2009 VAPR Update the GPG forecasts have been prepared for the DTS only due to increased certainty of the location of new GPG generators, particularly in the short term.

Table A5.4 presents the 2009 projections for gas consumption by GPG on Victoria's DTS. These projections are contrasted with the projections prepared for the 2008 VAPR Update. The 2009 forecasts are significantly lower because they do not include GPG demand located off the DTS.

In 2008 no attempt was made to differentiate between DTS and non-DTS connected GPG gas demand (see Section 1.1.6 of the 2008 VAPR Update).

Table A5.4 Projections for gas consumption by GPG (medium scenario)

YEAR	2009 FORECAST (PJ)	2008 FORECAST (PJ)	DIFFERENCE (%)
2009	14.9	27.8	-46%
2010	14.9	21.9	-32%
2011	14	23.8	-41%
2012	17.6	32.2	-45%
2013	22	41.9	-47%
2014	25.6	57.2	-55%
2015	27	75.2	-64%
2016	30.6	87.2	-65%
2017	34	93.3	-64%
2018	35.6	97.9	-64%

GPG consumption is estimated to be 14.9 PJ in 2009, down from 23.0 PJ in 2008. The 2009 estimate is based on partial year data, which has been grossed up to a full year estimate. GPG demand is forecast to be 14.9 PJ in 2010 and 14.0 PJ in 2011, significantly lower than in the 2008 forecasts. This is due to the expectation that new GPG plant, located off the DTS, will supply the majority of electricity demand growth.

Glossary

1 IN 2 PEAK DAY	Most probable peak day gas demand forecast, with a 50% probability of exceedence. This is expected, on average, to be exceeded once in 2 years (also known as the 50% peak day).
1 IN 20 PEAK DAY	Peak day gas demand forecast for severe weather conditions, with a 5% probability of exceedence. This is expected, on average, to be exceeded once in 20 years (also known as the 95% peak day).
AEMC	Australian Energy Market Commission.
AEMO	Australian Energy Market Operator Ltd
AER	Australian Energy Regulator.
AEST	Australian Eastern Standard Time (see also EDST).
AMDQ	Authorised Maximum Daily Quantity.
ANNUAL PLANNING REPORT	An annual report providing forecasts of gas or electricity (or both) supply, capacity and demand and other planning information.
ANTS	Annual National Transmission Statement.
APD	Portland Aluminium (customer owned station).
APT	Australian Pipeline Trust (formerly Eastern Australian Pipeline Limited).
AUGMENTATION	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
AUSTRALIAN PIPELINE TRUST (FORMERLY EASTERN AUSTRALIAN PIPELINE LIMITED)	Owner and operator of the Moomba to Sydney pipeline (and laterals).
AUTHORISED MAXIMUM DAILY QUANTITY	In respect of a customer, the maximum daily quantity of gas, expressed in GJ/day, which is authorised by AEMO to be withdrawn by or on behalf of that customer from the transmission system, in accordance with the allocation of authorised MDQ under the NGR.
BACK-OFF	A forced reduction in gas injections.
BASSGAS	A new project, sourcing gas from the Bass Basin for supply to the DTS, and injected at Pakenham.
BEGINNING-OF-DAY LINEPACK	Beginning-of-day linepack (BoD LP) is equal to the end-of-day linepack from the previous gas day.
BID STACK	Incremental gas quantities by injection point offered by market participants and stacked in price order.
BOC	BOC Gases Australia Limited.
BOC GASES AUSTRALIA LIMITED.	The BOC plant, situated next to GasNet in Dandenong, liquefies natural gas for storage in GasNet's LNG tank.
BOD LP	Beginning-of-day linepack.
BOM	Bureau of Meteorology.
BROWNFIELD	A tract of land developed for industrial purposes, polluted, and then abandoned.
CAGR	Compound average growth rate.
CCGT	Combined Cycle Gas Turbine. A type of GPG
CENTRAL DISPATCH	The process managed by NEMMCO for the dispatch of scheduled generating units and other services in accordance with Clause 3.8 of the Rules.
COINCIDENT PEAK DAY DEMAND	Gas used by a given customer or a group of customers on the day of maximum system usage in a given year or month.
COMPOUND AVERAGE GROWTH RATE	The year-over-year growth rate over a specified period of time.
CPRS	Carbon Pollution Reduction Scheme.
CONNECTION ASSET	The electricity transmission or distribution network components used to provide connection services (for example, 220/66 kV transformers).
CONNECTION ASSET CONSTRAINT	A constraint applying to an asset connecting the electricity transmission network to the distribution network.
CONNECTION POINT	A gas delivery point, transfer point, or receipt point.
CONSTRAINT (ELECTRICITY)	Any limitation on the operation of the transmission system that will give rise to unserved energy (USE) or to generation re-dispatch costs.

CONSTRAINT (GAS)	Any limitation causing some defined gas property (such as minimum pressure) to fall outside its acceptable range.
CONSTRAINT VALUE ESTIMATE	An electricity transmission network constraint's expected cost to the community, weighted by the probability of a contingency event occurring. This cost comprises load shedding and generation rescheduling (for example increased fuel cost).
CONSUMER	See customer.
CONTESTABLE AUGMENTATION	An electricity transmission network augmentation for which the capital cost is reasonably expected to exceed $10M and that can be constructed as a separate augmentation (i.e. the assets forming that augmentation are distinct and definable).
CONTINGENCY	Either a forced or planned outage. An event affecting the power system that is likely to involve an electricity generating unit's or transmission element's failure or removal from service.
CPI	Consumer price index.
CREDIBLE CONTINGENCY	Any planned or forced outage that is reasonably likely to occur. Examples include the outage of a single electricity transmission line, transformer, generating unit, reactive plant, etc through one or two phase faults.
CRITICAL CONTINGENCY	The specific forced or planned outage that has the greatest potential to impact on the electricity transmission network at any given time.
CTM	Custody Transfer Meter.
CULCAIRN	The gas transmission network interconnection point between Victoria and New South Wales.
CURTAILMENT	The interruption of a customer's supply of gas at the customer's delivery point, which occurs when a system operator intervenes, or an emergency direction is issued.
CUSTODY TRANSFER METER	A meter installed at a connection point to measure gas withdrawn from or injected into a transmission system.
CUSTOMER	Any party who purchases gas and consumes gas at particular premises. Customers can deal through retailers or may choose to become market participants in their own right, and take on the retailing functions themselves.
DB	Distribution business.
DD	Degree Day.
DEGREE DAY	A commonly used temperature model for predicting gas demand for area/space heating.
DELIVERY POINT	The point on a pipeline gas is withdrawn from and delivered to a customer or injected into a storage facility.
DEMAND-SIDE MANAGEMENT	The act of administering electricity demand-side participants (possibly through a demand-side response aggregator).
DEMAND-SIDE PARTICIPATION	The act of voluntarily shedding electrical load by prior arrangement.
DEMAND-SIDE RESPONSE AGGREGATOR	An organisation or agency for the provision and administration of electricity demand-side responses/participation.
DISTRIBUTION	The transport of gas over a combination of high pressure and low pressure pipelines from a City Gate to customer delivery points.
DISTRIBUTION PIPELINE	Pipelines for the conveyance of gas that: • have a maximum allowable operating pressure of 515 kPa or less; or • where the maximum operating pressure is greater than 515 kPA, are uniquely identified as a distribution pipeline in a distributor's access arrangement.
DISTRIBUTOR	The owners of the distribution pipelines that transport gas from the transmission pipelines to the consumer or customer.
DNSP	Distribution network service provider.
DSP	Demand-side participation.
DTS	Declared Transmission System.
EAPL	East Australian Pipeline Limited.
EAPR	Electricity Annual Planning Report.
EAST AUSTRALIAN PIPELINE LIMITED	The former operator of the Moomba to Sydney pipeline.
EASTERN GAS PIPELINE	The east coast pipeline from Longford to Sydney.
EDD	Effective Degree Day.
EDST	Eastern Daylight Savings Time (see also AEST).
EFFECTIVE DEGREE DAY	A measure of coldness that includes temperature, sunshine hours, chill and seasonality. The higher the number, the colder it appears to be and the more energy that will be used for area heating purposes. EDD is used to model the daily gas demand-weather relationship.

EGP	Eastern Gas Pipeline.
EHV	Extra high voltage.
END-OF-DAY LINEPACK	End-of-day linepack (EoD LP) is measured at the end of a gas day at 6 am. EoD LP is equal to the beginning-of-day linepack (BoD LP) for the next gas day.
EOD LP	End-of-day linepack.
ESC	Essential Services Commission.
EX-ANTE	Before the event.
FCAS	Frequency control ancillary service.
FEED	Front-End Engineering and Design.
FIRM CAPACITY	Guaranteed or contracted capacity to supply gas.
FLOW PATH	Those elements of the electricity transmission networks used to transport significant amounts of electricity between generation centres and major load centres.
FORCED OUTAGE	An unplanned outage of an electricity transmission network element (transmission line, transformer, generator, reactive plant, etc).
FRONT-END ENGINEERING AND DESIGN	An engineering process commonly undertaken to determine the engineering parameters of a construction or development, in terms of engineering design, route selection, regulatory and financial viability assessments, and environmental and native title clearance processes.
GAS MARKET (MARKET)	A market administered by AEMO for the injection of gas into, and the withdrawal of gas from, the gas transmission system and the balancing of gas flows in or through the gas transmission system.
GAS QUALITY EXCURSION	Breach of gas quality limit (as determined by the Gas Quality Guidelines).
GENERATOR AUXILIARY LOAD	Load used to run a power station, including supplies to operate a coal mine (otherwise known as ‘used in station load’).
GENERATOR-TERMINAL BASIS	Refers to the demand for electricity as measured at the generator terminals. This measure includes generator auxiliary loads.
GJ	Gigajoule. An SI unit, 1 GJ equals $1x10^9$ Joules.
GPG	Gas power generation.
GREENFIELD	Land (as a potential industrial site) not previously developed or polluted.
GRP	Gross regional product.
GSP	Gross state product.
GWh	Gigawatt hours.
HDD	Heating Degree Day. See Degree Day.
HEATING DEGREE DAY	See Degree Day.
HVDC	High-voltage direct current.
INJECTION	The physical injection of gas into the transmission system.
INTERCONNECT (THE)	Refers to the pipeline from Barnawartha to Wagga Wagga connecting the Victoria and New South Wales transmission systems at Culcairn. This does not include the VicHub (Longford) and SEA Gas (Iona) interconnections.
k	Thousand.
km	Kilometres.
kPa	Kilopascal. A unit for measuring gas pressure.
KTS	Keilor Terminal Station.
kV	Kilovolts.
LATERAL	A pipeline branch.
LET-DOWN GAS	Gas released from the BOC plant (during the liquefaction processes) into the high pressure distribution system.
LIMITER	A regulator installed in a pipeline to reduce pressure and remove the need for heaters at downstream off-takes.
LINEPACK	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline network throughout each day, and is required as a buffer for within-day balancing.
LIQUEFIED NATURAL GAS	Natural gas that has been converted to liquid form for ease of storage or transport. The Melbourne LNG storage facility is located at Dandenong.
LNG	Liquefied Natural Gas.

LOAD SHEDDING	Disconnection of electricity customer load.
LONGFORD HUB	Interconnection hub for the EGP, DTS, TGP pipelines and Gippsland gas supplies.
LOR	Lack of Reserve.
LRA	Long-run average.
M	Million.
MAOP	Maximum allowable operating pressure.
MARKET CUSTOMER	A gas customer who is a market participant.
MARKET PARTICIPANT	A party who is eligible, by registration with AEMO, to trade gas on the spot market by submission of nominations and 'inc/dec' offers to AEMO in accordance with the NGR.
MAXIMUM ALLOWABLE OPERATING PRESSURE	The maximum pressure at which a pipeline is licensed to operate.
MAXIMUM DAILY QUANTITY	Maximum daily quantity of gas supply or demand.
MAXIMUM HOURLY QUANTITY	Maximum hourly quantity of gas supply or demand.
MD	Maximum demand.
MDQ	See Maximum daily quantity.
METER	A device that measures and records volumes and/or quantities of electricity or gas.
METER ID NUMBER	The number attaching to a daily metered site with annual gas consumption greater than 10,000 GJ or an MHQ greater than 10 GJ, which are assigned as Tariff D in the AEMO meter installation register. See also Tariff D.
METERING	The act of recording electricity and gas data (such as volume, peak, quality parameters etc) for the purpose of billing or monitoring quality of supply etc.
METERING DATA	The data obtained from a metering installation, including energy data.
METERING IDENTIFICATION REGISTRATION NUMBER (MIRN)	The unique gas supply withdrawal point identifier (daily metered sites and CTMs).
METROPOLITAN RING-MAIN	The 450 mm, distributor–owned pipeline from Dandenong to Keon Park to West Melbourne.
MHQ	Maximum hourly quantity.
MIRN	See meter ID number.
MMt/a	Million, million tonnes per annum.
Mt/a	Million tonnes per annum.
MVA	Megavolt amperes.
MVAr	Megavolt amperes reactive.
MW	Megawatts.
MWh	Megawatt hours.
NATIONAL ELECTRICITY MARKET	The wholesale market for electricity supply in the Australian Capital Territory and the states of Queensland, New South Wales, Victoria, Tasmania and South Australia.
NATIONAL INSTITUTE OF ECONOMIC AND INDUSTRY RESEARCH	A private economic research, consulting and training group.
NATURAL GAS	A naturally occurring hydrocarbon composed of between 95 and 99% methane (CH4), the remainder predominantly being ethane (C2H6).
NCAS	Network control ancillary service.
NEM	National Electricity Market.
NEMMCO	National Electricity Market Management Company.
NER	National Electricity Rules.
NGR	National Gas Rules
NIEIR	See National Institute of Economic and Industry Research.
NON-COINCIDENT PEAK DAY DEMAND	A given customer's (or group of customers') gas demand peak day. This does not necessarily occur at the same time as the system demand peak day.
NON-CONTESTABLE AUGMENTATION	Electricity transmission network augmentations that are not considered to be economically or practically classified as contestable augmentations.
NON-CREDIBLE CONTINGENCY	Any planned or forced outage for which the probability of occurrence is considered very low. For example, the coincident outages of many transmission lines and transformers, for different reasons, in different parts of the electricity transmission network.
NPV	Net present value.

OCGT	Open Cycle Gas Turbine. A type of GPG
OTWAY HUB	The interconnection hub for the SWP, WTS and SEA Gas pipelines, the UGS, and the on-shore and offshore Otway Basin supplies.
PARTICIPANT	A person registered with AEMO in accordance with the NGR (Victorian gas industry).
PEAK DAY PROFILE	The hourly profile of injection or demand occurring on a peak day.
PEAK FLOW RATE	The highest hourly flow rate of gas or MHQ passing a particular point in the system under normal conditions (as determined by AEMO) in the immediately preceding 12-month period or, if gas has passed a particular point in the system for a period of less than 12 months, the highest hourly flow rate which in the reasonable opinion of AEMO is likely to occur in respect of that system point under normal conditions for the following 12-month period.
PEAK SHAVING	Meeting a demand peak using injections of vapourised LNG.
PETAJOULE	Petajoule (PJ), SI unit, 1 PJ equals $1x10^{15}$ Joules. Also PJ/yr or petajoules per year.
PIPELINE	A pipe or system of pipes for or incidental to the conveyance of gas and includes a part of such a pipe or system.
PIPELINE INJECTIONS	The injection of gas into a pipeline.
PIPELINE THROUGHPUT	The amount of gas that is transported through a pipeline.
PJ	Petajoule.
PLANNED OUTAGE	A controlled outage of a transmission element for maintenance and/or construction purposes, or due to anticipated failure of primary or secondary equipment for which there is greater than 24 hours notice.
POE	Probability of Exceedence.
POST-CONTINGENT	The timeframe after a power system contingency occurs.
PRE-CONTINGENT	The timeframe before a power system contingency occurs.
DECLAREDTRANSMISSION SYSTEM	Owned by GasNet and operated by AEMO, the Declared Transmission System serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, Geelong, and extending to Port Campbell.
DECLAREDTRANSMISSION SYSTEM CONSTRAINT	A constraint on the Declared Transmission System (DTS). See also Constraint (gas).
PRIOR OUTAGE CONDITIONS	A weakened electricity transmission network state where a transmission element is unavailable for service due to either a forced or planned outage.
PROBABILITY OF EXCEEDENCE	Refers to the probability that a forecast electricity maximum demand figure will be exceeded. For example, a forecast 10% POE maximum demand figure will, on average, be exceeded only 1 year in every 10.
RETAILER	Those selling the bundled product of energy services to the customer.
SATISFACTORY OPERATING STATE	Operation of the electricity transmission network such that all plant is operating at or below its rating (whether the continuous or (where applicable) short-term rating).
SCHEDULING	The process of scheduling nominations and increment/decrement offers, which AEMO is required to carry out in accordance with the NGR, for the purpose of balancing gas flows in the transmission system and maintaining the security of the transmission system.
SEA GAS INTERCONNECT	The interconnection between the SEA Gas pipeline and the DTS at Iona.
SEA GAS PIPELINE	The 680 km pipeline from Iona to Adelaide, principally constructed to ship gas to South Australia.
SECURE OPERATING STATE	Operation of the electricity transmission network such that should a credible contingency occur, the network will remain in a ‘satisfactory’ state.
SENT-OUT BASIS	A measure of demand and energy at the connection point between the generators and the electricity transmission network. The measure includes consumer load, and transmission and distribution losses.
SHOULDER SEASON	The period between low (summer) and high (winter) gas demand, it includes calendar months April, May, October and November.
SOO (NEMMCO)	Statement of Opportunities.
SOUTH WEST PIPELINE	The 500 mm pipeline from Lara (Geelong) to Iona.
SPIKE LOADS	A short duration peak in gas demand.
SRMC	Short-run marginal cost.
STATEMENT OF OPPORTUNITIES	The Statement of Opportunities published annually by NEMMCO.
STORAGE FACILITY	A facility for storing gas, including the LNG storage facility and the Iona UGS.
SUMMER	In terms of the electricity industry, December to February of a given fiscal year.

SURPRISE EVENT	An event that can occur within the day for which, in order to operationally balance the system, AEMO may need to change the schedule of gas injections and/or withdrawals issued at the start of the gas day (due to a change in forecast weather, for example).
SVC	Static Var Compensator.
SWP	South West Pipeline.
SWZ	System withdrawal zone.
SYSTEM CAPACITY	The maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors and accordingly a set of conditions and assumptions must be understood in any system capacity assessment. These factors include: • load distribution across the system; • hourly load profiles throughout the day at each delivery point; • heating values and the specific gravity of injected gas at each injection point; • initial line pack and final line pack and its distribution throughout the system; • ground and ambient air temperatures; • minimum and maximum operating pressure limits at critical points throughout the system; and • powers and efficiencies of compressor stations.
SYSTEM COINCIDENT PEAK DAY	The day of highest system demand (gas). See also system demand.
SYSTEM CONSTRAINT	See Declared Transmission System (DTS) constraint.
SYSTEM DEMAND	Demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum). It excludes GPG demand, exports, and gas withdrawn at Iona.
SYSTEM INJECTION POINT	A gas transmission system network connection point designed to permit gas to flow through a single pipe into the transmission system, which may also be, in the case of a transfer point, a system withdrawal point.
SYSTEM NORMAL CONSTRAINT	A constraint that arises even when all electricity plant is available for service.
SYSTEM WITHDRAWAL POINT	A gas transmission network transmission system connection point designed to permit gas to flow through a single pipe out of the transmission system, which may also be, in the case of a transfer point, a system injection point.
SYSTEM WITHDRAWAL ZONE	Part of the gas transmission network that contains one or more system withdrawal point/s and in respect of which AEMO has determined that a single withdrawal nomination or a single withdrawal increment/decrement offer must be made.
t/d	Tonnes per day.
t/h	Tonnes per hour.
t/m	Tonnes per month.
TARIFF D	The gas transportation Tariff applying to daily metered sites with annual consumption > 10,000 GJ or MHQ > 10 GJ and that are assigned as Tariff D in the AEMO meter installation register. Each site has a unique meter ID number (MIRN).
TARIFF ORDER	The Tariffs and Charges Order made under section 48A of the Gas Industry Act and any Tariffs and charges that are approved under an access arrangement.
TARIFF V	The gas transportation Tariff applying to non-Tariff D load sites. This includes residential and small to medium-sized commercial and industrial gas users.
TASMANIAN GAS PIPELINE	The pipeline from VicHub (Longford) to Tasmania.
TERAJOULE	Terajoule (TJ). An SI unit, 1 TJ equals $1x10^{12}$ Joules.
TGP	Tasmanian Gas Pipeline.
TJ	Terajoule.
TJ/d	Terajoules per day. See also Terajoule.
TNSP	Transmission network service provider.
TOC	Transmission Operations Centre (formally VNSC).
TRANSMISSION	Long haul transportation of gas via high pressure pipelines.
TRANSMISSION CUSTOMER	A customer that withdraws gas from a transmission delivery point.
TRANSMISSION DELIVERY POINT	A point on the gas transmission system network at which gas is withdrawn from the transmission system and delivered to a transmission customer or injected into a storage facility.
TRANSMISSION PIPELINE	A pipeline that is not a distribution pipeline.
TRANSMISSION PIPELINE OWNER	A person who owns or holds under a lease a transmission pipeline which is being or is to be operated by AEMO.

TRANSMISSION SYSTEM	The transmission pipelines or system of transmission pipelines forming part of the 'gas transmission system' as defined under the Gas Industry Act.
UAFG	Unaccounted for gas.
UGS	Underground Gas Storage.
UNACCOUNTED FOR GAS	The difference between metered injected gas supply and metered and allocated gas at delivery points. UAFG comprises gas losses, metering errors, timing, heating value error, allocation error, and other factors.
UNDERGROUND GAS STORAGE	The Underground Gas Storage (UGS) facility at Iona.
UNSERVED ENERGY (USE)	The amount of energy that cannot be supplied because there is insufficient generation to meet demand.
USE	Unserved energy.
VALUE OF LOST LOAD	VoLL is a price cap applied to dispatch prices. The value of VoLL, which is set by the reliability panel, is currently $10,000 per MWh.
VCR	Value of Customer Reliability.
VICHUB	The interconnection between the EGP and the DTS at Longford, facilitating gas trading at the Longford hub.
VOLL	Value of Lost Load.
WESTERN TRANSMISSION SYSTEM (WTS)	Western Transmission System. The transmission pipelines serving the area from Port Campbell to Portland, and the Western District from Iona. Now integrated into the gas market and the DTS.
WINTER	In terms of the electricity industry, June to August of a given calendar year.

AEMO
15 William Street
Melbourne VIC 3000

INFORMATION CENTRE
T: 1300 361 011

www.aemo.com.au