

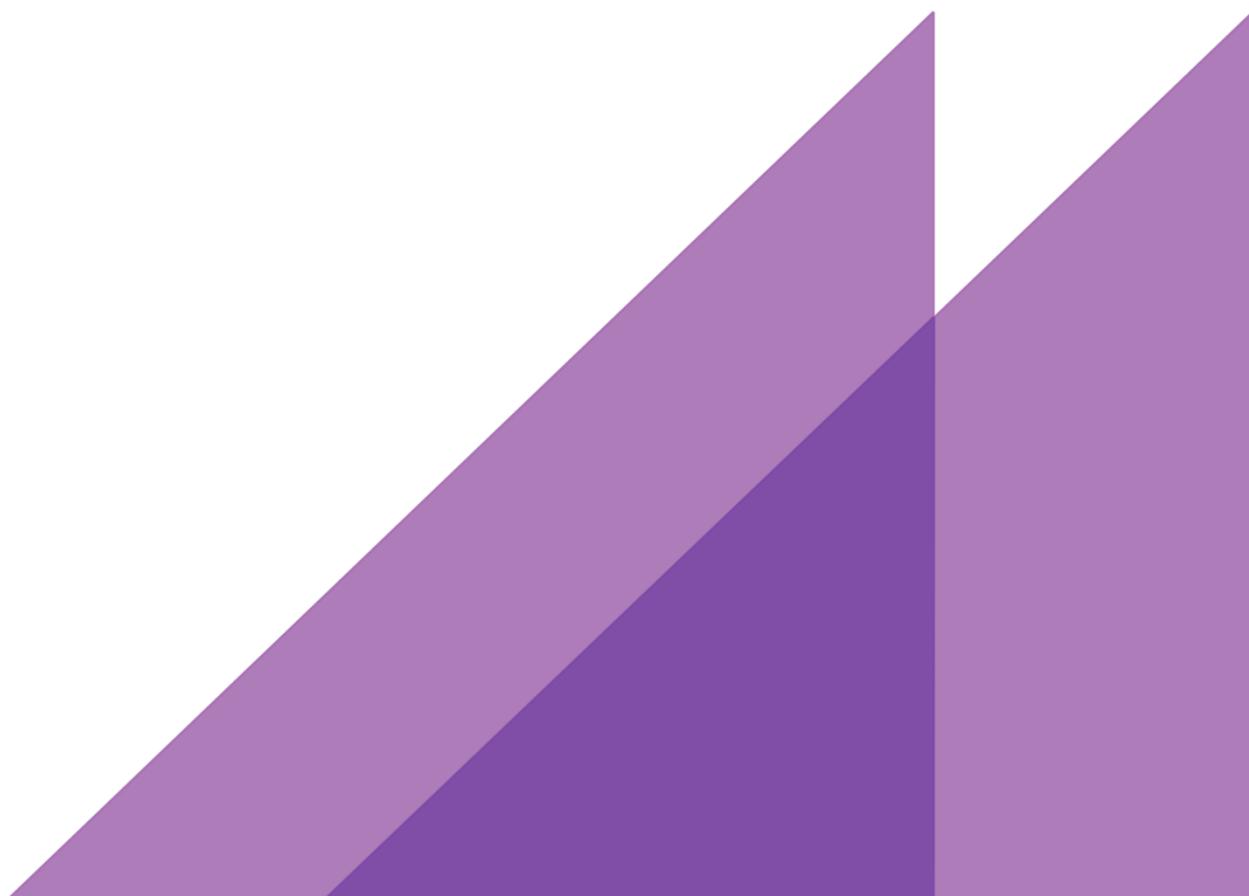
REPORT TO
AUSTRALIAN ENERGY MARKET OPERATOR

24 JUNE 2014

GAS CONSUMPTION FORECASTING



A METHODOLOGY





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Executive summary

The Australian Energy Market Operator (AEMO) has engaged ACIL Allen Consulting (ACIL Allen) to help it develop a methodology for forecasting gas consumption in eastern and south-eastern Australia. AEMO will apply the methodology during the second half of 2014 to produce forecasts that will be included in the inaugural National Gas Forecasting Report (NGFR).

ACIL Allen developed the methodology based on a review of past forecasting approaches and drawing on ACIL Allen's own experience with forecasting consumption in the energy and water industries. It consulted with industry stakeholders at the early stages of the review and when a draft methodology had been developed.

Following that process, ACIL Allen recommends the following methodology for forecasting gas consumption in eastern and south-eastern Australia.

1. specify and describe the forecast area to which forecasts will relate. This might be a state or a much smaller area. AEMO should prepare a schematic summarising key characteristics of each forecast area such as:
 - a) data sources
 - b) large customers
 - c) distribution networks
 - d) consumption sources that will be omitted and forecast independently
2. gather data from the sources identified in the forecast area
3. disaggregate data to the level at which forecasts are desired:
 - a) AEMO may wish to produce forecasts for the residential, business, small industrial and large industrial sectors separately, in which case aggregated data will usually need to be disaggregated
 - b) AEMO may wish to produce forecasts on a seasonal basis, in which case annual data series will usually need to be disaggregated
4. identify 'large industrial' customers, whose consumption will be forecast using the 'survey approach'
5. adjust the available data series to remove the consumption of 'large customers' and any other customers whose use is to be forecast separately (such as gas fired power stations connected to the National Electricity Market)
6. use the econometric approach to forecast consumption by residential, business and small industrial customers (i.e. all but large industrial) as follows:
 - a) identify likely drivers of gas consumption and obtain measures of these including projections
 - b) estimate regression models to explain historical consumption using the drivers (on a 'sector-by-sector' basis if required)
 - c) produce baseline forecasts by applying projections of the relevant drivers to the estimated models
 - d) make post-model adjustments as appropriate to account for anticipated, but unprecedented, changes in consumption

7. use the survey method to produce forecasts of consumption by large industrial users as follows:
 - a) identify consumption of large industrial customers on the most granular level at which data are available
 - b) survey individual users to identify plans and expectations to increase or reduce gas consumption
 - c) produce forecasts on the basis that consumption in future will be the same as it was in the past except where likely changes can be identified.

The independent forecasts produced by these methods would then be added together to produce total forecasts.

The same approach should be applied independently to each 'forecast area'.

The necessary data for these approaches are a significant consideration. AEMO's role in Australian gas markets is different to its role in the NEM. One result of this is that the data to which AEMO has access in the gas market 'capture' less of the gas that is bought and sold than is the case for electricity.

In some cases the inputs to the forecasting process will present a key source of uncertainty about consumption. A key part of the recommended methodology is that AEMO makes clear statements in the NGFR about the inputs to its forecasts. In some cases those statements may be somewhat controversial. For example, AEMO's forecasts will likely need to be based on expectations for future economic performance. However, there is no escaping the requirement for this to be incorporated in the forecasts. The alternative is to be unclear about the position that AEMO has taken in relation to these factors. This would create substantial uncertainty and a lack of transparency around the forecasts, and limit stakeholders' ability to use them.

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1 Introduction

The Australian Energy Market Operator (AEMO) has engaged ACIL Allen Consulting (ACIL Allen) to help it develop a methodology for forecasting gas consumption in eastern and south-eastern Australia.

In recent years, AEMO has published gas consumption forecasts in the Gas Statement of Opportunities (GSOO). It has also published forecasts relevant to the Victorian Declared Transmission System in the separate Victorian Gas Planning Report.

AEMO's aim is to produce energy forecasts, for both electricity and gas, that enable holistic and coordinated energy industry decision-making. Key aspects of AEMO's strategy for achieving this vision include publishing, in 2013–14, a methodology for forecasting gas consumption in eastern and south-eastern Australia at regional and bulk supply point levels.¹

AEMO intends to develop gas consumption forecasts with the intention that they will be published in the inaugural National Gas Forecasting Report (NGFR) in December 2014. These forecasts will also provide a key input into other AEMO publications, such as the AEMO GSOO and Victorian gas planning reports.

This report outlines a methodology that ACIL Allen has developed for this purpose.

ACIL Allen was engaged to recommend a methodology that AEMO could use to produce gas consumption forecasts for a range of different geographic areas disaggregated to the customer type level. The methodology excludes gas consumed by power stations that participate in the National Electricity Market (NEM) and in the production of liquefied natural gas (LNG). AEMO will address these sources of consumption separately.

The methodology recommended in this report was developed in consultation with industry stakeholders. This report was preceded by an options paper which outlined four broad approaches to forecasting gas consumption. Those four approaches, which are summarised in Appendix B, were referred to as the:

1. economic modelling approach
2. econometric approach
3. survey approach
4. panel and appliance model approach.

The options paper formed the basis of consultation. Consultation began with two workshops. Workshops were open to stakeholders to attend in person, in Sydney, Brisbane or Melbourne, or by video conference from AEMO's other offices.

Following a period of methodology development, a consultation draft of this report was developed and circulated to stakeholders for their feedback. This final report incorporates that feedback.

¹ The term "bulk supply point" refers to a regional location of concentrated gas consumption. See section 2.1.4 for a more detailed discussion.

A broad range of stakeholders were invited to participate in consultation. Participating stakeholders included gas network businesses and retailers, industry associations, gas-fired power station owners, large gas users and Commonwealth and State Governments.

Some stakeholders also provided input and commentary in written form, either formally or informally. Stakeholders were also invited to attend one-on-one meetings with ACIL Allen.

A key point that stakeholders raised during consultation was that it is important they can understand the basis of AEMO's forecasts. In other words, stakeholders value the transparency of the methodology highly. A second point raised was that the forecasting methodology should enable stakeholders to substitute their own views of key inputs for AEMO's views. This requires a degree of modularity in the forecasting methodology.

A summary of other points raised by stakeholders is in Appendix B, which also contains brief commentary on how stakeholder input has been addressed or incorporated into this methodology or the way that AEMO proposes to address it in future.

1.1 Report structure

This paper is structured as follows:

- chapter 2 provides an overview of the methodology
- chapter 3 discusses the collection and preparation of historical gas consumption data
- chapter 4 discusses the collection and preparation of other historical datasets (drivers) that will be used
- chapter 5 discusses the process for estimating the relationship between gas consumption and its drivers
- chapter 6 discusses the process for preparing, or assuming, future drivers
- chapter 7 describes the approach to post-model adjustments
- chapter 8 describes the approach to preparing forecasts for consumption by large industrial customers using the survey method
- chapter 9 describes the process for compiling forecasts and producing scenario forecasts
- chapter 10 describes three approaches to converting consumption forecasts to daily maximum flow forecasts. The recommendation is that AEMO tests each of these to determine which provides the best results in practice
- chapter 11 discusses the approach to tracking actual outcomes against forecasts and raises a number of factors that may be relevant to this process.

There are also a number of appendices.

- Appendix A discusses four broad approaches to modelling that were considered. This summarises the options paper that preceded this report
- Appendix B contains a summary of stakeholder feedback on the issues paper and of stakeholder discussion at the consultation sessions
- Appendix C provides background information to the eastern and south-eastern Australian gas market

1.2 Definitions and shortened forms

This section provides definitions of terms used in this report and, in Table 1, a list of shortened forms.

Gas is supplied to customers via a network of pipelines. Those pipelines are categorised as either transmission pipelines or distribution networks. Distribution networks are owned and operated by distribution network service providers (DNSPs).

DNSPs charge for their services using a distribution use of system (DUOS) tariff. Those tariffs are typically either:

- demand tariffs (tariff D) – where the price a customer pays their DNSP is determined, or partly determined, by the maximum demand they are permitted to, or expected to, place on the network
- volume tariffs (tariff V) – where the amount a customer pays their DNSP is determined by the quantity of gas they use over a defined period, usually three months
- DNSPs typically offer different volume tariffs for business and residential customers.

A summary of the tariffs currently in use in Australia is provided in Table C4 (in Appendix C).

There are two relevant types of customer meter:

- an accumulation meter is typically a basic device that is read manually approximately once every three months. Accumulation meters are not capable of recording consumption in more detail than the total quantity of gas used since they were last read
- an interval meter can measure the amount of gas used in a shorter time period, which can provide information regarding peak flow.

The following ‘types’ of gas customer are referred to in this report:

- industrial customers are customers that use gas for industrial purposes:
 - many, but not all, of these will be connected to gas transmission pipelines rather than to a distribution network
 - industrial customers are commonly placed on demand tariffs
- commercial customers are customers who use gas for commercial purposes (other than industrial purposes):
 - with a few exceptions, these customers are connected to the distribution network
 - commercial customers may be on either *volume* or *demand* tariffs
- residential customers are customers who use gas for domestic purposes:
 - these customers are on volume tariffs
- gas-fired power generators (GPG) are customers who use gas to generate electricity:
 - most GPG power stations are connected to the National Electricity Market (NEM), in which case they are excluded from this methodology. AEMO is currently developing its methodology for forecasting NEM GPG consumption and will publish it along with this report
 - a small number of GPG power stations are not connected to the NEM.

The purpose for which gas is used is less important than the historical consumption data that are available. The availability of data is linked to a customer’s tariff and the way their gas consumption is metered. Therefore, in this report, customers are referred to by reference to their tariff as follows:

- tariff D customers are customers on demand tariffs. These customers will use gas for either industrial or, in some cases, commercial purposes:
 - tariff D customers are further distinguished into ‘large’ and ‘small’ based on their gas consumption:

- › the threshold size above which a tariff D customer is considered 'large' should be determined after the forecast areas have been defined
- › generally, the intention will be to identify customers whose use is large *relative to* total consumption in the forecast area
- tariff D customers will generally have interval meters
- GPG customers that are not connected to the NEM are treated as tariff D customers and, if they use more than the relevant threshold amount of gas, as large industrial customers
- tariff V customers are customers on volume tariffs. These customers will include smaller commercial customers and all residential customers:
 - tariff V customers are distinguished as 'commercial' and 'residential' customers based on their distribution use of system tariff²
 - in this report:
 - › commercial customers on volume tariffs are referred to as 'V business' customers
 - › all other customers on volume tariffs are referred to as residential customers
- other customers are categorised based on the type of meter they use and therefore the data that is available regarding their consumption.

² As shown in Table C4, gas DNSPs typically offer different tariffs to commercial (business) customers than to residential customers. Note that the details of the categorisation and its veracity depend on local arrangements such as the DNSP's ability to change their customers' tariffs.

Table 1 Shortened forms

Shortened form	Definition
ABARES	Australian Bureau of Agricultural and Resource Economics and Sciences
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APPEA	Australian Petroleum Production and Exploration Association
BOM	Bureau of Meteorology
CDD	Cooling Degree Days
D Tariff	A gas DUOS tariff where the amount payable is determined by the maximum demand the customer is permitted to impose on the network.
DNSP	Distribution Network Service Provider
DTS	Declared Transmission System (in Victoria)
DUOS	Distribution Use of System tariff
DWGM	Declared Wholesale Gas Market (in Victoria)
EDD	Effective Degree Days
ENA	Energy Networks Association
EUAA	Energy Users Association of Australia
FEED	Front End Engineering Design
GBB	Gas Bulletin Board
GDP	Gross Domestic Product
GJ	Gigajoule
GPG	Gas-fired Power Generation
GSH	Gas Supply Hub
GSOO	Gas Statement of Opportunities
GSP	Gross State Product
HDD	Heating Degree Days
J	Joule
LNG	Liquefied Natural Gas
MJ	Megajoule
MOS	Market Operator Service
MW	Megawatt
NEM	National Electricity Market
NGFR	National Gas Forecasting Report
NGR	National Gas Rules
PJ	Petajoule
POE	Probability of Exceedence
STTM	Short Term Trading Market
TJ	Terajoule
UAFG	Unaccounted For Gas
V tariff	A gas DUOS tariff where the total amount payable is based on the volume of gas consumed.

2 Overview of methodology

Following consultation with stakeholders, a review of past forecasting approaches, and drawing on its own experience, ACIL Allen recommends that AEMO use the:

- econometric (time series) approach to forecasting gas consumption by residential and smaller business customers:
 - post-model adjustments would be made as appropriate to account for policy changes and other ‘new’ influences
- survey approach to forecasting consumption by large industrial customers.

The independent forecasts produced by these methods would then be added together to produce total forecasts.

The same approach should be applied independently to each ‘forecast area’. Forecast areas are to be defined by AEMO in the first instance.

The necessary data for these approaches are a significant consideration. AEMO’s role in Australian gas markets is different to its role in the NEM. One result of this is that the data to which AEMO has access in the gas market ‘capture’ less of the gas that is bought and sold than is the case for electricity.

At the time of writing AEMO is in the process of confirming the data to which it has access. For the purposes of this report our assumption is that AEMO will ultimately have access to data showing the consumption of:

- large industrial customers at the individual customer level
- other customers at the ‘tariff’ level (computed by subtracting tariff D usage from total flow), with no disaggregation to the individual customer level.

The data upon which forecasts would be based are discussed in chapter 3, which relates to usage data, and chapter 4, which relates to the drivers of consumption.

In some cases the inputs to the forecasting process will present a key source of uncertainty about consumption. A key part of the recommended methodology is that AEMO makes clear statements in the NGFR about the inputs to its forecasts. In some cases those statements may be somewhat controversial. For example, AEMO’s forecasts will likely need to be based on expectations for future economic performance. However, there is no escaping the requirement for this to be incorporated in the forecasts. The alternative is to be unclear about the position that AEMO has taken in relation to these factors. This would create substantial uncertainty and a lack of transparency around the forecasts, and limit stakeholders’ ability to use them.

The current approach used by AEMO to forecasting maximum load (flow) is to use a fixed ratio. Three alternatives to this approach are outlined in this report. ACIL Allen recommends that AEMO applies each of the alternatives to a sample of forecast areas to ascertain whether any of them outperforms the existing ratio-based approach and, if so, which of the four options performs best. This is discussed in chapter 10.

3 Preparing past consumption data

To prepare consumption forecasts using the methodology recommended in this report AEMO will require a time series of historical consumption data. These data must be at the level of (dis)aggregation for which forecasts are to be produced. Therefore, given AEMO's requirements, they would ideally be disaggregated:

- *spatially* to the 'forecast area'
- *functionally* to customer type
- *periodically* to monthly frequency.

The first step in preparing the historical data is to define carefully the area for which forecasts are to be prepared and, therefore, the area to which the data should relate. ACIL Allen recommends that AEMO does this by preparing logical schematics of each 'forecast area'. These are discussed in section 3.1.

As mentioned in chapter 2 this report has been prepared on the assumption that AEMO will have access to aggregated data for tariff V and tariff D customers, but that it will not have detailed data at a finer level than this (except for data for individual large industrial customers).

If it is to produce forecasts for commercial and residential customers separately AEMO will need to disaggregate the data further. The process for doing this is outlined in section 3.2.

The recommended approach to disaggregating the daily aggregate network level data will produce annual data pertaining to the consumption of commercial and residential customers.

This would not allow AEMO's forecasts to take account of differences in the monthly consumption profiles of these two different customer classes. However, for the reasons discussed in section 3.2, our conclusion is that this is likely to be the best approach available to AEMO in this context. On the other hand, if AEMO concludes that it need not produce forecasts for residential and commercial customers separately, it would be able to use the daily network level data, which would make analysis of seasonal patterns possible.

Where multiple data sources relating to the same quantity of gas are available it is recommended that AEMO prepare reconciliations of those data sources as discussed in section 3.3.

3.1 Specify 'forecast area'

The first step in assembling historical data is to specify the (spatial) area for which data are required. This may be a state, a particular distribution network, or a smaller area such as a system withdrawal zone. This is referred to in this report as the 'forecast area'.

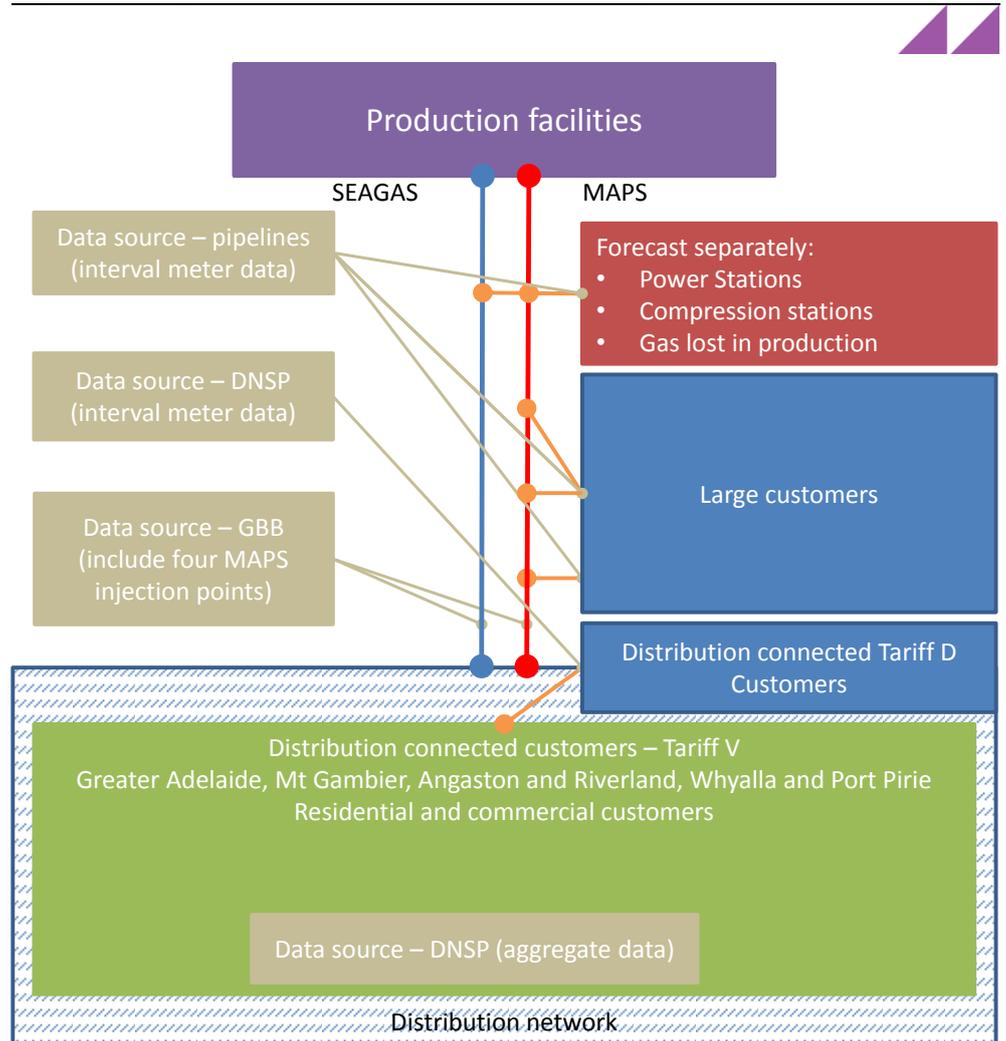
The forecast area should be described using a logical schematic of the gas network supplying it. The process required is illustrated in Figure 8 using the South Australian network as a working example. In this case the 'forecast area' is South Australia.

The logical schematic of the gas network should identify the different types of gas customer. It should identify as many individual large customers as possible, including any whose consumption is to be *excluded* from the forecasts.³ In doing this, though, AEMO will need to be sensitive to customers' willingness to be identified as large gas users. Some level of aggregation may be appropriate.

The logical schematic should also identify the points where historical consumption data have been measured and, therefore, potential sources from which data could be obtained.

The logical schematic should also identify other information about the forecast area that is either relevant to the forecasts, may become relevant in future or may be thought by others to be relevant.⁴ This will assist in enhancing the transparency of the forecasts and the ease with which stakeholders can understand them.

Figure 1 Logical schematic of South Australian gas network



Source: ACIL Allen Consulting

³ The reason it was excluded from the forecasts should be stated as well, though perhaps in the NGFR rather than on the schematic. In some cases exclusions will be by class, e.g. 'all NEM power stations'.

⁴ That is, even if AEMO does not use particular information it may be helpful to make this clear on the schematics.

The logical schematic should also partially reflect the actual location of different features. For example, the schematic should identify which large customers are connected to the distribution network and which are connected to a transmission pipeline. This is necessary to avoid either double counting these customers or overlooking them entirely. Beyond this, the logical schematic of the forecast area need not be geographically accurate.

AEMO should produce a logical schematic corresponding to that shown in Figure 1 for each forecast area individually. The schematics should capture as much detail around customers as possible, including:

- distinctions between customer types
- identifying unusual customer types, such as unregulated networks and small offtakes, such as farm gate offtakes.

When the schematics have been produced they should be discussed with network businesses and stakeholders, including those in the forecast area and those in other areas. The finished product should ultimately be published in the NGFR, though in doing this, AEMO should be sensitive to any confidentiality issues that may be relevant, for example to preserve asset security and by referring to large customers in groups in some cases.

Over time the logical schematics should be kept up-to-date to serve as a quick reference to the basis of AEMO's forecasts. If that basis changes in future, perhaps because AEMO decides to split one zone into two, the logical schematic should be changed to illustrate the change. Aside from changes in zone boundaries, changes to the forecast area schematics are likely to be very small from year to year.

As AEMO becomes more experienced with the forecasting methodology it may find it useful to add other information to the schematics. Alternatively it may choose to remove redundant information.

The schematics will identify the particular data series that are available to AEMO as well as their sources. They should show which data series will be used as the primary source and which data will be used for reconciliation.

3.2 Disaggregation process

To meet its objectives for gas consumption forecasts, AEMO will require consumption data that are disaggregated by customer type and location.⁵ While these data may exist (within DNSPs and/or AEMO's retail systems) ACIL Allen has not assumed that they would be available to AEMO.

Therefore, as noted in chapter 2, this report is based on the assumption that AEMO has access to a series of aggregate daily data for tariff D and tariff V customers separately. It is also based on the assumption that AEMO needs to produce forecasts of consumption at the customer type level, i.e. to distinguish between commercial and residential customers. To do this, AEMO would need to disaggregate the daily data into its constituent parts, namely residential and commercial customers.

⁵ They would also need to be disaggregated from annual data to monthly data. This issue is discussed in section 3.3.1.

To do this, ACIL Allen recommends that AEMO adopts a similar process to that used in the electricity market to produce net system load profiles. That is:

1. start with the sum of inflows from all network meters supplying gas to a particular forecast area
2. subtract all consumption that can be separately identified and attributed to customers, either individually or in aggregate. The extent to which this is possible will depend on the data supplied to AEMO. Ideally those data would provide separate identification of:
 - a) individual networks, including unregulated networks
 - b) standalone customers, including residential customers, such as farm gate deliveries
3. apportion the residual consumption, which will generally be aggregated tariff V consumption, to the remaining customer classes.

In the dataset we assume AEMO to have, the first steps will already have been completed. The remaining task is to allocate the total tariff V consumption between residential and commercial customers.

From a temporal point of view, the only way this apportionment can be made is at the annual level using total class-by-class consumption data such as those shown in Table 2, which Envestra submitted to the Australian Energy Regulator (AER) in 2010 in support of its current access arrangement.⁶

Table 2 **Gas consumption by South Australian distribution connected customers**

	Residential	Commercial (Tariff V)	Commercial (Tariff D)	Industrial (Tariff V)	Industrial (Tariff D)
	TJ	TJ	TJ	TJ	TJ
2006	7,875	1,049	1,716	1,890	13,732
2007	7,682	1,030	1,667	1,859	13,508
2008	7,425	1,071	1,644	1,930	13,106
2009	7,777	1,087	1,582	1,960	12,308

Source: National Institute of Economic and Industry Research, "Natural gas forecasts for the Envestra South Australian distribution region to 2019-20", September 2010, available from <http://www.aer.gov.au/node/20022> accessed 16 March 2014.

⁶ In some cases a forecast area will include multiple distribution networks with different concentrations of commercial and residential customers. In these cases, the disaggregation would ideally be done on a 'network-by-network' basis in the forecast area if the necessary data are available. Therefore, in the South Australian example shown in Figure 2, the Adelaide metropolitan network would ideally be dealt with separately from the Mt Gambier and other non-metropolitan networks due to differences in the relative importance of residential consumption. If the necessary data are available, it may be appropriate to deal with the non-metropolitan networks separately from one another for the same reason. That is, Mt Gambier may be disaggregated using different proportions than Whyalla.

The actual data will not always correspond directly to the residual data. Discrepancies may arise due to:

- issues with metering such as revisions to account for estimated reads
- different customer bases, if for example some of the tariff V commercial customers whose consumption is shown in Table 5 have interval meters that would have been accounted for previously
- estimations made in the previous data (i.e. the data in table 2 may be based partly on estimates made at the time)
- differences in the way unusual customer types such as unregulated networks and farm gate users are accounted for
- gas which is unaccounted for.

Further, access arrangements are only refreshed every five years so there will not always be recent, publicly-available data at the customer-type level.

Therefore, actual data such as those shown in Table 5 should be converted to percentages and used as weights to apply to the daily tariff V data supplied by DNSPs.

Table 3 shows the data from Table 2 in percentage terms. The Tariff D data have been omitted as these have been accounted for separately in a previous step. If the weights are stable over time, such as may be the case here,⁷ it would also be sufficient to use the average of recent available years. On the other hand, in some cases trends may be evident, in which case it may be appropriate to extrapolate the weights using that trend.

Table 3 Gas consumption by South Australian distribution connected customers – proportion of Tariff V

	Residential	Commercial	Industrial
	%	%	%
2006	73	10	17
2007	71	10	18
2008	69	10	19
2009	72	10	18
Average	71	10	18

Note: Totals may not add due to rounding.

Source: ACIL Allen based on National Institute of Economic and Industry Research, "Natural gas forecasts for the Envestra South Australian distribution region to 2019-20", September 2010, available from <http://www.aer.gov.au/node/20022> accessed 16 March 2014.

This approach will produce annual data that are disaggregated by customer type. As discussed below, it would be difficult to disaggregate to a shorter time period than this.

⁷ Only four data points are shown here. More thorough examination would be required before a firm view was reached.

3.2.1 Disaggregating annual data — the problem of billing lag

As discussed above, the historical dataset would ideally be at monthly or seasonal (quarterly) resolution to allow the analyst to identify seasonal patterns.

Conceptually this could be done by obtaining individual customers' consumption data and either building these up to a total or, perhaps more pragmatically, using a sample to develop seasonal weights.⁸

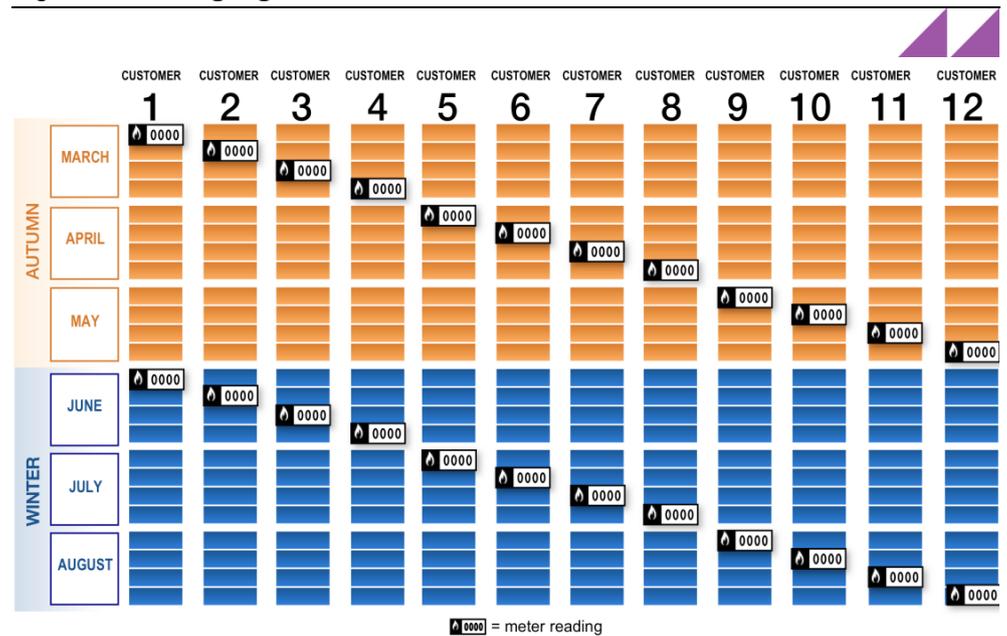
In ACIL Allen's view disaggregation of tariff V data to finer time periods than years is not likely to be reliable due to the way that gas consumption is measured.

At the time of writing, and for the foreseeable future, gas consumption of tariff V customers is measured using accumulation meters that are read manually and that provide no more information than how much gas has been used since they were last read.

Meter reading is an ongoing task for most gas distributors who employ (or outsource) teams of meter readers to visit each meter individually and read it. The result is that some meters are read every day, but any given meter is only read once each quarter. Therefore, meter readings that are taken during a particular quarter do not necessarily relate to gas consumption that occurred during that quarter.

This gives rise to a problem referred to here as 'billing lag'. Billing lag limits the analyst's ability to test for seasonal or similar patterns in gas consumption.

Figure 2 Billing lag



Source: ACIL Allen Consulting

To illustrate billing lag see Figure 9, which depicts the gas meters and meter readings of 12 individual customers. One of these meters is read each week beginning in the first week of March. Each meter is read once in every three-month period.⁹

⁸ The necessary data could be sourced from either DNSPs or AEMO's retail systems or they could be obtained by surveying a sample of customers. We note that they have not previously been taken from any of these sources for this purpose.

⁹ For simplicity in this illustration we have assumed that there are four weeks each month.

In the time period shown here every customer's meter was read twice, once each in autumn and winter. However, the time when the meter was read does not coincide with the time when the consumption occurred. Therefore, it is not correct to interpret meter readings that happened in winter as showing consumption that happened in winter. This is clearest for customer 1, whose meter was read in the first week of winter, showing consumption that occurred almost entirely in autumn. The problem is proportionately less important for customers as their number increases to the point where it is non-existent for customer 12, whose meter is read in the last week of the season.

In this example, only one of the 12 meter readings is truly a measure of winter consumption. All of the others are affected by billing lag to some greater or lesser extent.

In apportioning the data the key consideration is to avoid subjectivity. If, for example, the analyst has an expectation that gas consumption is higher in one season than another, this may lead them to assign the larger of two readings to the season where higher consumption is expected. The risk here is that the analyst will unintentionally manipulate the data to manufacture results that they expect to find even if they are not truly there.

It would be possible to assume that the seasonal pattern in the aggregate data is the same as the seasonal pattern at the customer-type level. However, this amounts to assuming that residential customers show the same seasonal pattern in their gas use as commercial customers in the same forecast area. While this may be true, it seems unlikely and cannot be verified. In our view this would not be a robust approach.

A preferable approach would be to identify those meter readings that occurred on or close to the last day of the season and assign the pattern shown in those readings to the totals drawn from the others. This would potentially work reasonably well for seasons that were strictly quarterly and could therefore be approximated using the quarterly meter reading data.

However, the formal definition of each seasons is, in itself, only an approximation of the variation in gas consumption that is to be analysed. For example, ACIL Allen understands, anecdotally, that it is commonplace for residents of the Australian Capital Territory to begin using space heating in May and keep using it until the end of September. This period includes the whole winter and a month each of autumn and spring.

This 'season' could not be reconstructed using quarterly data.

Another approach would be to redefine the cut-off dates for assigning meter readings to seasons. For example, AEMO could assign meter readings to the seasons with which they overlap the most. In the example in Figure 9 this would mean that the readings taken during winter for customers 7 to 13 (inclusive) would be assigned to winter, while the remaining customers' winter consumption would be taken from readings made in spring (not shown).

While this would improve the assignment of some readings, there is no avoiding the fact that meter readings taken in the middle of a season cannot be accurately assigned to one season or another.

In a project for the AER in 2011, ACIL Allen analysed electricity consumption data with billing lag and explored the possibility that redefining the cut-off dates would overcome the problem. On that occasion the results were mixed. Lagging meter reading data reduced the visibility of seasonal effects in some places. As discussed in that report, the conclusion reached at the time was that redefining cut-offs was not the correct approach.¹⁰ Therefore, it is not clear that this approach would improve matters for AEMO.

An alternative approach that may be available to AEMO relies on having individual data for a large number of customers in each region. If the dataset is sufficiently large, there will be, coincidentally, some customers whose meters are read within a week or two of the end of each season, such as customers 1, 2, 11, and 12 in Figure 2. It would be straightforward to identify the relative seasonal consumption for these customers and apply those weights to the remainder of the sample. That is:

1. identify customers whose meter readings align 'closely'¹¹ to the seasons
2. ascertain the seasonal consumption of these customers
3. divide consumption in each season (separately) by annual consumption for each customer to identify the proportion of annual consumption that occurs each season
4. take the average of each seasonal proportion
5. apply the averaged seasonal proportion to the annual consumption of other customers to produce estimated seasonal consumption while preserving annual totals.

In this report, we have assumed that the approaches described here are not sufficiently effective and that they would not be used. However, AEMO may reasonably reach an alternative view and apply them.

3.2.2 Average consumption data

The approach described here requires data pertaining to the average consumption of residential customers in a forecast area. This will need to be calculated based on the total consumption data series that AEMO will collect as described in chapter 3.

The necessary dataset for the gas consumption per customer above can be produced simply by dividing total consumption by total customers. However, care should be taken in doing so if the analysis is to be conducted at a higher frequency than either of the input data series. In particular, our expectation is that AEMO may be able to obtain customer numbers data on an annual basis, but not more frequently. If customer numbers change during the period in which data are collected (which is likely) this will be reflected in the consumption data. However, it would not be reflected in annual 'snapshot' customer numbers data.

The two main solutions to this problem are:

- to work at the frequency of the least frequent dataset, or
- to make an assumption about the 'shape' of customer numbers growth between observations, in which case it may be appropriate to assume that customer numbers growth is linear.

¹⁰ See <http://www.aer.gov.au/node/9751> for more detail.

¹¹ Note that 'close' will be an inherently arbitrary choice.

3.3 Reconciliation

When the above process is complete AEMO will have the following data:

- aggregate consumption by tariff D customers
- annual (or flat daily) apportioned consumption of tariff V residential customers
- annual (or flat daily) apportioned consumption of tariff V commercial customers
- consumption, aggregate or individual, of transmission-connected customers
- Gas Bulletin Board (GBB) data relating to total pipeline inflows and outflows.

Before moving on to analysing historical patterns and preparing forecasts, AEMO should ensure that these datasets are consistent by reconciling them to one another. In particular it should verify that the GBB data correspond to data from other sources. The results of the reconciliation should be included in the NGFR, or otherwise made available to accompany the forecasts.

Conceptually, the reconciliation process is no more complex than identifying which data series should logically sum to another and ensuring that they do.

While it is worthwhile to produce reconciliations such as this, AEMO should not expect that the data will match precisely. There are a number of reasons why a perfect match will not be achieved, not least of which is unaccounted for gas. This source of error is, by its very nature, not measured but deduced using a similar process to that described here.¹²

Part of this process should include identifying the extent of unaccounted for gas (UAFG) and ensuring that it is plausible. Conceptually, UAFG is gas that is lost in either a transmission pipeline or a distribution system. By definition it is not measured. It is the residual between what is injected into the system and what is delivered to customers.

The task that should be undertaken is to ‘account for’ as much as possible within practical limits and leave the residual as UAFG. Over time the amount of UAFG may have changed and the change should reflect the relevant pipeline or network business’ experience. For example, a business that has undertaken projects to minimise losses should exhibit reductions over time.

In practice, though, UAFG will be the gas that remains unaccounted for by the datasets AEMO can assemble. The measure of UAFG AEMO develops will depend on the accuracy and consistency of the available data.

When changes are observed in the historical level of UAFG, AEMO will need to decide how to treat them in future. Two basic options are available. It could either hold the level constant at a level observed recently or continue an observed trend.

The appropriate approach will vary with the circumstances and some consultation with the relevant network may be necessary. Consider the example described above where the network business has undertaken projects to reduce losses. If those projects are complete by the time the forecasts are to be prepared, the likelihood is that losses will have now reduced to a new (low) level, but will not continue to reduce in future. In this case, carrying losses forwards at the level observed recently would be appropriate.

If the ‘loss reduction’ projects are to continue, it may be more appropriate to carry forward a recent trend.

¹² The difference between what goes in and what is taken out is unaccounted for.

If no projects have been carried out but losses vary anyway, the likely cause is weather conditions (soil movement due to dryness) or a relationship between losses and consumption levels. In these cases it may be possible to forecast the level of losses econometrically—though this may not be possible—in which case the preferred approach would be to take an average over recent years to reflect the range of possibilities in the future.

ACIL Allen cannot provide AEMO with a firm statement at this stage of how close it can expect the correspondence between data series to be. AEMO will develop a sense of the accuracy that can be achieved over time as it applies this methodology. In the early stages the key diagnostic will be whether the correspondence in one forecast area is similar to the correspondence achieved in other forecast areas. If some forecast areas produce much better correspondence than others we would recommend that AEMO investigate reasons for the poorer fits.

Another key diagnostic will be whether the quantity of gas for which AEMO cannot account for is similar to the quantity of unaccounted for gas reported by others in the same forecast area. Therefore, AEMO should state the quantity for which it cannot account.

As time passes, AEMO will also be able to ensure that correspondences do not deteriorate significantly over time.

4 Other historical data

Aside from the historical consumption data discussed in the previous chapter, there are several other necessary data elements. Sources of these data are listed in Table 4 and discussed below.

It will also be necessary to prepare projections of the variables that are to be used to produce forecasts. This is discussed in chapter 6.

Table 4 Data requirements

Data	Description	Source
Number of customers	Number of customers to whom gas was supplied each year for which historical consumption data are available. These should be at the same level of (dis)aggregation as the consumption data.	DNSPs
Weather data	Either computed series of EDD or HDD, or necessary input data (temperature, wind speed, sunlight hours).	Input data from Bureau of Meteorology and AEMO computation
Economic drivers	Economic indicators for relevant areas including: <ul style="list-style-type: none"> ▪ economic activity ▪ population. 	AEMO annual economic outlook report, which is likely to draw on data from the Australian Bureau of Statistics, local government, state Departments of Treasury or Planning.
Retail gas price	Historical series of standing contract (or equivalent) price of gas.	Jurisdictional regulator
Policy data	Impact or nature of policies that may have influenced gas demand.	Commonwealth, state and local governments.
Large customers	Size and timing of very large usage changes, either increase or decrease, by forecast area.	NSPs, large customers, survey (future)
Housing completions	Number of new houses built in the forecast area.	ABS
Renovations	Number of major renovations conducted in the forecast area.	ABS
Metadata	Descriptive information relating to each forecast area.	Various, including DNSP, local governments, Australian Bureau of Statistics

Source: ACIL Allen Consulting

ACIL Allen also notes that AEMO's current practice is to commission an economic outlook study every year. This outlook, if it continues to be commissioned in future, could provide many of the necessary drivers.

The particular drivers to be used in AEMO's forecasting model should be chosen empirically through the forecasting process. At the methodology stage one cannot be definitive about which variables will be necessary. By necessity the process must be iterative, and is likely to involve a degree of trial and error. However our experience, and that of most gas network businesses to date, seems to have been that economic activity (measured using Gross State Product (GSP)) and population are typically the most relevant drivers. The discussion in this report focuses on these two 'candidate' drivers. However, this is not to say that other drivers should not be examined.

The theoretical link between these driving variables, and gas consumption, is clear. An increase (decrease) in either can reasonably be expected to cause an increase (decrease) in gas consumption holding all else equal. This warrants the inclusion of these variables in a forecasting model. However, the variables are likely to be very strongly correlated to each other. This means that including both may lead to non-convergence of the linear regression model. As the variables are likely to be highly correlated, it may also be difficult to determine the marginal effect of one holding the other constant. This means that, while the explanatory power of the variables will be high, caution should be taken before interpreting any individual coefficient. Provided AEMO is not looking to infer anything from the individual coefficients themselves, and that multicollinearity does not inhibit estimation of the regression model, then multicollinearity issues can be ignored.

In our experience these drivers will account for a large proportion of the variability in gas consumption by customers other than large customers (after the other factors discussed below have been taken into account). However, this is not to say that these are the only relevant variables or that AEMO should limit itself to these variables. ACIL Allen does not suggest that other variables must be considered, but cannot rule this out definitively. As with any forecasting process, the choice of predictive variables should be decided empirically through the modelling process.

The objective is to identify variables that:

1. have a theoretical relationship with gas consumption such that they can be incorporated into a properly specified econometric model
2. are measured and reported appropriately
3. are projected appropriately or are amenable to being projected by AEMO.

Economic activity, population, and other demographic factors have these characteristics, so they should be collected. As noted above, other variables may be identified in future that also have these characteristics. If so, these variables should also be considered for inclusion in the models.

4.1 Weather data

For the weather normalisation process, weather data must be collected for the area where the gas consumption in question occurred. The Bureau of Meteorology (BOM) collects and publishes historical weather data from hundreds of weather stations around Australia. There will typically be more than one data reading in a given forecast area so a choice must be made as to the most suitable.

ACIL Allen recommends that AEMO first identify the weather stations that currently operate in each forecast area and then narrow these down using the following factors:

1. prevalence of missing data at the station – if more than 10 per cent of data are missing, discard the station and move on
2. length of time series available:
 - a) must be at least as long as the historical consumption data series
 - b) should ideally be 30 years or more to allow projection, and to avoid overreliance on (relatively) short-term influences such as drought and issues around the choice of series start points/end points
3. availability of important weather variables such as humidity, rainfall, sunshine, and wind speed if these are to be used (see section 4.4 below).

The correlation between demand and weather should then be examined for each candidate weather station and a preferred option chosen based on the results. If multiple weather stations perform similarly, the choice will be relatively arbitrary. Generally, ACIL Allen recommends choosing a weather station that:

- has been well correlated with gas consumption over an extended period
- has been more closely correlated with gas consumption recently.

In some cases these criteria may be contradictory and some judgement may be required.

For example, if one weather station performed well for 10 years but has been less well correlated in the last two years, and an alternative has only been well correlated for a few years the choice will be difficult.

In such a case it would be important to try to understand why the relationship has changed. For example, the local population may have grown substantially in the area near the second weather station, which might support choosing it. It may also be possible to combine data from the two weather stations.

It should be noted, though, that data collected at nearby weather stations will be similar, as weather conditions are similar in places close to one another. Therefore, a stark difference such as this will be uncommon in practice unless forecast areas are aggregated to a very high level.

It should also be noted that the BOM maintains a network of around 100 reference climate stations which are chosen, in part, for the quality of the associated historical data. These may perform well in the analysis and should be considered in the above process. However, they should not be chosen automatically, and may not be chosen at all. The reason is that these stations are also chosen partly on the basis that they are away from built-up areas, which means they are away from where gas consumption occurs. This is valid for their intended purpose, which is long-term climate analysis, but may limit their usefulness for present purposes, as they may not be well correlated with gas consumption.

4.2 Retail price data

Retail gas prices impact gas consumption through the *price effect* as measured by the own price elasticity of demand.¹³ This should be accounted for in the forecasts.

Similarly, as discussed in section 7.3, it may be worthwhile examining the *substitution effect*, where consumption of gas is influenced by changes in the price of electricity through the cross price elasticity of demand for gas with respect to the price of electricity. This has not previously been found to be significant in gas forecasting models to ACIL Allen's knowledge, at least partly due to data issues.¹⁴ This is a factor that AEMO may wish to examine more closely in future.

¹³ The price effect is the extent to which consumers use less of a good when prices increase, and vice versa.

¹⁴ For practical reasons this may be better pursued in years to come rather than in the first NGFR given that it has not previously been found to be significant.

In practice, accounting for the impact of price on consumption will be an approximate process because the retail price of gas and electricity varies for individual customers depending on:¹⁵

- their retailer(s)
- when they signed their contract(s)
- whether they are on market or standing contract(s)
- which ‘block’ of their contract the customer is consuming at the time, which is related to their consumption (in areas where block tariffs are used).

It will not be practical for AEMO to obtain price data in sufficient detail to account for these factors individually.¹⁶ However, this is not a problem for the forecasting.

The price and substitution effects depend not so much on the *level* of price but the *change* in price. Therefore, the recommended approach is to assume that:

1. the rate of change of gas prices in the past has been similar for all customer types
2. the rate of change in those historic prices is reasonably approximated by the rate of change in the standing contract gas price(s) in each jurisdiction.

Both of these assumptions are consistent with what would be expected in Australian retail energy markets, most of which are characterised by price regulation and competition simultaneously. In the less regulated markets in South Australia and Victoria the standing contract prices are not set by government, but the same general relationship could reasonably be expected.

It remains then to measure the rate of change in the standing contract prices of energy in each forecast area. ACIL Allen recommends using either:

1. the calculated bill for a notional customer with constant consumption¹⁷
2. the percentage change in the volumetric charge of the block that is marginal for most customers.

ACIL Allen leans slightly towards the latter approach because it focuses most closely on the marginal price of consumption, making it a theoretically ‘purer’ approach. However, the difference in the rate of change in the two measures will be small unless there is a major restructure of tariffs or some other fundamental change, so the preference for one over the other is not strong.

In feedback on the consultation draft of this report, EnergyAustralia suggested that customers are more likely to think in terms of their overall gas bill rather than the marginal cost. This suggests that the first of the above approaches is preferred. ACIL Allen accepts that this is likely to reflect the reality for many customers. We make two points.

First, if the ‘bill’ approach is to be used it is important to hold consumption constant. Not doing this will tend to understate the true price change as the bill declines in response to

¹⁵ Conceptually customers could be treated as a panel and these issues could be dealt with. However, in practice this is unlikely to suit AEMO’s needs because it would be extremely data-intensive. Further, it is unclear that a panel approach is more accurate than the approach discussed here. See for example, ACIL Tasman’s review of gas consumption forecasts submitted to the AER by SP AusNet for its Gas Access Arrangement Review in 2012 available from www.aer.gov.au.

¹⁶ Also note that using this data would make this a panel model.

¹⁷ Note that consumption by the *average* customer should not be used as this would imply changing consumption levels and, therefore, confound the price effect.

rising prices. Therefore, if the bill approach is to be used, AEMO should *not* compute the bill for a customer with average consumption each year.

Second, from a modelling perspective it is the change in a variable relative to change in consumption that is most important. The relative changes in marginal price versus representative bill are likely to be very similar, so there is little to support one choice over another.

AEMO may choose its preferred approach based partly on the ease of presentation. For example, it may prefer to be able to publish the estimated 'typical residential gas bill', thus leaning towards the first approach.

Whichever approach is taken, the necessary data can typically be obtained from the jurisdictional regulator.¹⁸ Most of them are in the public domain. Useful sources of information include:

- in South Australia, retailer performance reports published by the Essential Services Commission of South Australia
- in Victoria, the Essential Services Commission's comparative performance reports (pricing)
- in New South Wales, the Independent Pricing and Regulatory Tribunal's retail price review reports
- in Queensland, the Queensland Competition Authority's statements of notified prices.

4.3 Data processing

The specific requirements at the data processing stage will depend on the data that are obtained. Broadly, it will be necessary to:

1. create time series that can be used to estimate the underlying econometric relationships and have appropriate frequency
2. check the continuity of those time series to identify any discrete jumps which may indicate system changes or changes in the way customers are classified. Any jumps that are identified could be corrected through the appropriate use of indicator variables in the specified models, or by clarifying with the data provider
3. check for measurement errors in the data and check for and impute missing data
4. compute heating degree day (HDD) and effective degree day (EDD) variables or other similar measures that may be used (see section 4.4 below)
5. convert (possibly) nominal price data into real terms.

4.4 Weather measures

Gas consumption will vary over time in response to variations in weather conditions driven primarily by the 'heating requirement'. Generally, the cooler a season is, the greater the heating requirement and, therefore, the greater gas consumption will be.

For present purposes it is necessary to 'remove' the effect of weather variations from the historical consumption data. Failure to do so will result in a model that is mis-specified and may falsely attribute the impact of weather variation to other factors.

¹⁸ An alternative would be to approach retailers for this information directly, though this would probably be more time consuming.

To do this requires a measure of the heating requirement in the same historical period as the historical consumption data. Two measures of the heating requirement are currently in use in Australia, namely HDD and EDD. These two approaches are similar, but differ in the input data they use. EDD is a richer measure that takes account of factors not included in HDD.

The underlying concept in both measures is the same. Both calculate the sum of the (absolute) differences between weather measures and a reference threshold. The difference is that HDD is based solely on temperature data while EDD also takes account of wind velocity, sunshine hours, and seasonal variations in propensity to use gas appliances.¹⁹

EDDs can be calculated on various bases by incorporating weather conditions at different times of day and changing the threshold level.²⁰ In its 2012 review of approaches to estimating the heating requirement in Victoria, AEMO concluded that the EDD₃₁₂ index performs better than EDD calculated over other time bases.²¹

4.5 Energy efficiency standards

In recent years the energy efficiency standards applicable to new buildings have been increased in various ways. The details and timing have varied between jurisdictions and a detailed review is not necessary for this report. It is sufficient to say that there have been changes in physical requirements for new houses and major renovations/additions. It is reasonable to expect that those changes may have created a situation where there is a cohort effect in gas consumption. That is, all else being equal, homes built or renovated more recently can reasonably be expected to use less gas than older homes. This cohort effect was discussed during consultation by several stakeholders, notably the Energy Networks Association (ENA). It was also raised in one-on-one meetings. It appears to be a particularly important issue for DNSPs as it can make a significant difference to the volume of gas they are called on to deliver.

The effect on gas consumption that is being addressed here is an aggregate of various factors, including increased energy efficiency of dwelling shells, through techniques such as double glazing and improved design, and shifts from electric to gas and solar-boosted hot water systems.

¹⁹ There are two seasonal influences in play here. The first is the general expectation that some seasons will be colder than others and, therefore, that gas consumption will be greater in some seasons than others. This is accounted for by using EDDs or HDDs, which both measure how cold it was during a particular season. The seasonal variation measure *within* the EDD calculation is intended to account for the fact that people will be quicker to use heating appliances in cold seasons (winter) than in warmer seasons (summer). This is accounted for in addition to the greater heating requirement, which means that, as this is modelled, a cold day in winter will add more to the measured heating requirement than an equally cold day in summer.

²⁰ The choice of the threshold is somewhat subjective. The intention is to screen out days when there is no weather-sensitive energy use.

²¹ EDD₃₁₂ is the number of EDD calculated using average of the eight 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. See <http://www.aemo.com.au/Gas/Planning/Victorian-EDD-Weather-Standards-Review> for further detail.

One approach that could potentially be used is to account for this effect explicitly using a measure of the size of the cohort of new and renovated homes. The underlying concept is as follows:

1. houses in a given forecast area that were built before a given date (base date) use, on average, a given quantity of gas each year – ‘A MJ’
2. houses in that forecast area that were built after the base data use a different quantity of gas each year – ‘B MJ’
3. until the base date the average gas consumption of all houses in the forecast area was ‘A MJ’
4. after the base date, the average household consumption of gas decreases over time as the proportion of ‘new’ houses increases. For each period, t , the average household consumption is as shown in equation (1):

$$\text{average household consumption} = \alpha_t A + (1 - \alpha_t) B \quad (1)$$

Where A and B are the average gas consumption old and new houses respectively and α is the proportion of old houses in the forecast area.

This concept can be incorporated into the forecasts by adding the cohort variable ‘ α_t ’ from equation (1) into the forecasting model for consumption per customer. Therefore, AEMO should gather data relating to the number of dwellings in each forecast area and the number of new dwellings constructed since the base date. The cohort variable is computed by dividing the latter by the former each year, which naturally accounts for the difference between new homes and replacements.

The cohort variable should also take account of the base year, therefore the numerator should reflect new houses built since the base year. This is illustrated in Table 5.

Table 5 Cohort variable with various base years

Variable	Index	2010	2011	2012	2013	2014
Houses in forecast area (total)	A	100	105	110	115	120
Housing completions (incremental)	B	10	10	10	10	10
New houses since 2010 (cumulative)	C	10	20	30	40	50
Cohort (base 2010) = C/A	D	10%	19%	27%	35%	42%
New houses since 2011 (cumulative)	E		10	20	30	40
Cohort (base 2011) = E/A	F		10%	18%	26%	33%
New houses since 2012 (cumulative)	G			10	20	30
Cohort (base 2012) = G/A	H			9%	17%	25%
New houses since 2013 (cumulative)	I				10	20
Cohort (base 2013) = I/A	J				9%	17%
New houses since 2014 (cumulative)	K					10
Cohort (base 2014) = K/A	L					8%

Source: ACIL Allen Consulting

The base year could be selected based on a policy review to support a conclusion as to when houses may have begun to be more efficient. However, in practice, the policy changes may not be sufficiently clear to support a clear choice, in which case the choice of base year should be empirical. That is, the base year should be chosen by varying it in regression models to ascertain which base year provides the best performing model. This should be done in models that include other drivers, which should not be changed while this question is tested.

One characteristic of the cohort variable as described here, which was raised during consultation, is that it does not allow for further improvements in energy consumption after the base data. That is, in equation (1), consumption cannot fall below B MJ per house (all else constant).

In practice, there may be multiple changes in the energy efficiency of dwellings in an area. For example, over the last 10 years many Australian jurisdictions had periods with a minimum 5-star energy efficiency standard and periods with a minimum of 6-stars. In future, the standard may be lifted higher still.

Multiple step changes in history could be addressed by including more than one cohort variable, though there are data limitations in doing so.²²

Another factor to consider, which is relevant to any approach that attempts to deal with energy efficiency explicitly, is that energy efficiency and price are closely related. This is discussed further in chapter 7.

²² it is not possible for a regression model to have more variables than observations in the historical dataset. Therefore, if there are 10 years of annual data it would be impossible to have more than 10 variables. It would also be highly preferable to have significantly fewer than 10.

5 Identify relationships

At this point in the process AEMO will have identified the forecast areas in which forecasts will be prepared and produced schematics for each of them. In doing that it will have identified suitable data sources and prepared separate series of past consumption for residential and commercial customers. The commercial customer series will consist of separate components, namely tariff V commercial and tariff D commercial.

Those series will have been reconciled with other measures of total consumption, where possible, to validate their accuracy.

The next step is to develop the econometric models that will drive the forecasts. The process that should be followed is to identify variables that have theoretical relationships with gas consumption, such as gas price, economic activity, and population. Econometric analysis should be used to quantify the direction and magnitude of these relationships.

Broadly, ACIL Allen recommends that the final specification of variables, lags, and functional forms be chosen empirically, by determining the combination of these that best fits the consumption data. It is beyond the scope of this report to attempt to cover all of the factors that must be considered in developing econometric models properly. For the most part we expect that AEMO will do this using multiple linear regression and ordinary least squares estimation. The remainder of this chapter reflects this expectation. AEMO should have regard to the various assumptions that underpin these methods and ensure that the analysis it conducts is appropriate in light of those assumptions.

There are many potential relationships that could be explored and quantified. For simplicity of presentation, this report focuses on the drivers that ACIL Allen's experience and a review of recent industry practice suggests are likely to be the most important. The fact that this report focuses on these drivers should not limit AEMO's willingness to examine other potential relationships.

Similarly, the actual final form for each of the models is determined only after assessing the various alternatives. In other words, an empirical approach should be adopted, guided by theory. The final form of the models may differ from that discussed here.

The relationships identified through this process are then used to produce 'baseline forecasts' based on projected drivers, which are discussed in chapter 6.

The baseline forecasts rely on an assumption that the relationships between gas consumption and its drivers will be consistent in future with what has been observed in the past. The possibility that this is not correct is dealt with using post-model adjustments, which are discussed in chapter 7.

This two-stage approach has the strength of being both transparent and modular, though this requires that each of the two steps discussed here are reported independently. This will give stakeholders the ability to substitute their own assumptions or estimates for those made by AEMO.

5.1 Residential customers

There is likely to be a high degree of homogeneity among residential customers. In this situation it may be most appropriate to analyse gas consumption in terms of:

1. the number of customers
2. gas consumption per customer.

That is, AEMO would estimate two regressions for residential customers in each forecast area.

This approach has the advantage of allowing individual customer-level analysis to be brought in at the post-model adjustment stage if desired.

Separate regressions would be performed for customer numbers and consumption per customer. This is appropriate because the different components could be expected to respond to different drivers. The outputs of the separate regressions are ultimately multiplied together to provide the forecast of gas consumption (possibly after post-model adjustments have been made).

The possible specification of each of these models is discussed below. This discussion is guided by our theoretical understanding of the likely driving forces behind gas consumption in this part of the market. However, as noted above, it will be important for AEMO to ensure that sound econometric practice is followed.

5.1.1 Number of residential customers

There are three potential sources of growth in the number of residential gas customers in a forecast area, namely:

1. growth due to population increase in new dwellings
2. growth due to the conversion (addition) of existing 'non-gas' dwellings to gas whether through urban infill (demolish and rebuild on site), or by converting existing dwellings
3. growth due to the reticulation of areas which are established, but where gas has not previously been available (reticulation schemes).

These different sources of growth should be treated separately in projecting customer numbers, and in analysing historical growth, though in practice the first two may be dealt with in the same model.

The three sources are discussed in turn below.

Growth due to population increase

Residential customers are generally households, so if the other two sources of growth in customer numbers are disregarded there would typically be a strong relationship between the number of customers in an area and the number of households in that area, or its population, or both.

These two variables, and in particular population, are good candidates for projecting gas customer numbers because projections of them are generally readily available, including from the ABS.

A possible drawback with using population or household numbers as the driver of residential customer growth is that a portion of residential customers may be non-residential in certain areas.

In these cases it may be worthwhile examining the relationship between economic activity and customer numbers. However, this can be difficult when the forecast area is small because data on economic activity are typically harder to obtain for small areas than population or household numbers. Further, projections of economic activity are difficult to obtain for small areas and economic product loses its relevance as areas become very small.²³

Therefore, the model for the number of residential customers could be as shown in equation (2).

$$\text{Residential customers}_t = \alpha + \beta_1 \times \text{Population}_t + \varepsilon_t \quad (2)$$

Alternatively the number of households may be substituted for population.

A consideration in choosing between these (or any other specification) will be the availability of forecasts of the driver(s). For example, a population projection may be more readily available for a given area than a projection of household numbers. This would support choosing a model using population as a driver.

Another factor may be the quality of competing projections. In ACIL Allen's experience there is sometimes significant disparity between population projections produced for different purposes. As a general proposition we recommend avoiding population projections where there is the possibility of a vested interest in the result and leaning toward Australian Bureau of Statistics (ABS) projections where they are available. However, it should also be noted that the ABS produces several population projections with varying input assumptions. These may be used to generate scenario projections (e.g. high, medium and low population growth) but otherwise it will usually be appropriate to choose the central or base case.

Growth due to dwelling conversions and urban infill

The appropriate treatment of this type of growth will vary depending on when it is thought to have commenced or accelerated, and the period for which historical data are available.

The rate of urban infill and dwelling conversion might be thought to have been constant throughout the period for which historical data are available. In this case a model similar to that in equation (2) with an additional trend term would potentially be suitable. The trend term would account for increases in customer numbers due to urban infill separately from the population term.

However, in this case the model in equation (2) would also potentially 'work'. The reason is that population series are typically trend-like in nature, particularly over short time periods. Therefore, the coefficient β_1 would reflect the combined impact of the conversions and population growth.

If the rate of infill and conversions is thought to have accelerated during the period covered by historical data, it would be appropriate to account for that acceleration separately. This could be done by adding an interaction term to 'turn it on' when the acceleration in urban infill is thought to have accelerated. The appropriate time to 'turn on' the interaction term could be observed in the data (i.e. when customer numbers accelerate) or be based on a general understanding of the area in question.

²³ For example, customers may work in a different small area than they live, yet it may be the economic product of the latter area that correlates with their income and, therefore, their consumption patterns. If forecast areas are too small this would be obscured even if data were available.

Growth due to reticulation schemes

Another source of growth in customer numbers in recent history, particularly in Victoria, has been gas reticulation schemes, where DNSPs have extended their network to areas which are already settled, but which have not previously had access to reticulated gas. Where such a scheme has occurred customer numbers growth will have changed significantly.

The recommended approach to dealing with these circumstances is to use interaction terms. These are dummy (dichotomous) variables that apply to other variables and have the effect of ‘turning on’ the other variable in the model when the dummy is set to ‘1’. In this case ACIL Allen anticipates that an interaction would be added to the model on the population variable. Therefore, the model would take the form shown in equation (3).

$$\begin{aligned} \text{Residential customers}_t & \\ &= \alpha + \beta_1 \times \text{Population}_t + \beta_2 \times I \\ &\quad \times \text{Population}_t + \varepsilon_t \end{aligned} \quad (3)$$

Where ‘I’ is the interaction term, set to one every year after the reticulation scheme was completed and zero otherwise.

An alternative would be to specify ‘I’ as a trend variable, set to zero until the reticulation scheme is completed and then increasing by one every period thereafter.

As with many aspects of the methodology, the best approach to modelling customer numbers in the presence of reticulation schemes will depend on the specifics and will be revealed empirically by the data.

5.1.2 Gas consumption of the average residential customer

Residential customers tend to use gas for three main reasons:

- space heating
- water heating
- cooking.

Given these uses, it is likely that the gas consumption of the average residential customer each year is likely to be related to:

1. the heating requirement that year
2. the age of the customer’s home and therefore its energy efficiency
3. the price of gas
4. household income.

As discussed in section 4.1 the heating requirement could be measured using HDD or EDD. Either of these should be considered candidate drivers.

The age of the customer’s home cannot be dealt with individually in the type of model proposed here. It would be dealt with in an aggregate fashion using the cohort variable described above.

Household income is also a candidate driver. However, household income is not measured regularly so GSP is used as a good proxy. Further, GSP is a fairly direct measure of the activity of small non-residential customers that may be included in the dataset.

However, to the extent that gas usage is non-discretionary, it may also be unresponsive to household income. This means that the driver may not prove to be statistically significant and may be omitted from the final model on empirical grounds, though this does not mean that it should not be tested.

Therefore, a potential specification of the model of gas consumption of the average residential customer is shown in equation (4):

$$\begin{aligned} \text{Consumption per customer} \\ = \alpha + \beta_1 \times HDD + \beta_2 \times CDD + \beta_3 \\ \times \text{cohort} + \beta_4 \times \text{price} + \beta_5 \times GSP + \varepsilon \end{aligned} \quad (4)$$

Evaluating the estimated price effect

The model shown in equation (4) is linear, so the coefficient on the price variable (β_4) reflects the estimated change in gas consumption, measured in MJ, associated with an increase in the retail price in gas, measured in cents.

This coefficient will provide a measure of the price effect, which is commonly discussed in terms of price elasticity. However, the coefficient cannot be interpreted directly as an elasticity because an elasticity is a measure of relative *percentage* changes. In other words, the units are different.

It would be useful to compare the price coefficient from equation (4) with other estimates of the price elasticity of demand for gas. This will help ensure that the modelled results are within reasonable bounds. This can be done in one of two ways:

1. estimate equation (4) in 'log/log form' by taking the natural logarithm of all variables (or of just consumption and price) and estimating the same regression using those transformed variables. In this case the coefficient on the price variable can be interpreted directly as an elasticity
2. compute the elasticity implied by β_4 manually by computing the implied consumption at a reference price and a second price one per cent higher (or lower) than the reference price.²⁴

In either case the implied elasticity should be reported along with the forecasts and compared with other estimates. If the implied elasticity is out of line with other estimates the first step would be to reconsider the model specification to determine whether there are more appropriate functional forms or additional variables that could be considered. If an acceptable output cannot be obtained in this manner, it may be appropriate to substitute the estimated value of β_4 with another value based on the expected price elasticity of demand. If this is done it should be made clear in the reporting.

²⁴ The elasticity would be calculated by computing the percentage change in consumption divided by the percentage change in price, which would be set to one. Therefore, the elasticity would be the consumption associated with the reference price, less the consumption associated with the second price divided by the consumption associated with the reference price.

Total consumption of residential customers

Total residential energy consumption is calculated as shown in equation (3):²⁵

$$\text{Total consumption} = \text{Consumption per customer} \times \text{No of customers} \quad (5)$$

Depending on the approach taken to post-model adjustments it may be necessary to take these into account before this step is completed. In effect, the 'consumption per customer' value in the equation above may be 'adjusted consumption per customer.'

5.2 Commercial customers

The recommended approach to forecasting gas consumption by commercial customers is to fit a model to *total* historical consumption by these customers to its drivers. Unlike residential customers, it is not recommended to model the number of customers and average consumption per customer separately. The reason is that while residential customers are likely to be homogeneous in the broad way they use gas, the same cannot be said for commercial customers.

The gas consumption of commercial customers is likely to be related to economic activity (measured using GSP), weather, and gas price. However, the nature of the relationships, and therefore the magnitude of the regression coefficients, is likely to be different. In particular, residential gas users will mainly use gas for space heating, so gas consumption by residential customers is likely to vary significantly with temperature. These customers also use gas for cooking and water heating, but the amounts involved in these uses are less variable with respect to weather. For example, the amount of gas used for cooking a given meal will be much the same regardless of the outside temperature, whereas the amount of gas used for space heating will not be.

In relation to GSP, it is important, as discussed in chapter 6, for AEMO to ensure consistency between its various forecasts. For example, it would use the same GSP outlook for gas forecasts as for electricity forecasts and other work. However, there may be cases where it is appropriate to alter the GSP forecast in a particular forecast area.

Economic forecasts are usually produced at a relatively high level. For example they may reflect the likely economic performance of a state. However, there will be parts of that state where the economic outlook is different than the state average. For example, with recent manufacturing plant closures there is discussion that the economic outlook for some parts of the country is worse than others. Similarly, with anticipated car factory closures, parts of South Australia and Victoria are likely to experience slow growth relative to other parts.

Depending on the details of AEMO's economic forecasts, these local characteristics may be 'averaged' into a state-wide economic outlook. If so, forecasts would be:

- overstated where local performance is weaker than state-wide performance
- understated where local performance will be stronger than state-wide performance.

AEMO could approach this by using disaggregated economic forecasts or by making post-model adjustments to forecast areas where economic performance is expected to be significantly different to state average levels. The latter approach is discussed in chapter 7. It may be informed by surveys of large industrial users as discussed in chapter 8.

²⁵ Note that multiplying the output of two regression models together in this fashion relies on an implicit assumption that the error terms (denoted ϵ) are not correlated with one another.

In relation to this the price of gas as paid by commercial customers, EnergyAustralia said that:

commercial gas customers are often on multiple year contracts and thus exposure to step price rises (rises independent of CPI and upstream contract repricing moments) may be delayed.

This will ideally be reflected in the way the price variable is structured for this class of customer. The challenge in doing so is that there are many customers in this class so some contracts will be rolled over every year. Therefore, while an individual customer might not experience a price rise every year, some customers will.

If no adjustment is made, the lagged effect of price changes would be expected to lead to a price elasticity (or coefficient) that is smaller than otherwise as, in a sense, not all customers will be responding to the price change.

If an appropriately detailed dataset was available this could be captured using cross sectional modelling techniques, which would allow the individual consumption of each customer to be modelled using their individual price. However, in this case that approach is likely to be impossible.

If customers in the commercial category in a particular forecast area are known to be 'quarantined' from price increases for a particular period of time, it would be appropriate for AEMO to reflect this in the way it lags the price variable in that forecast area or perhaps to model these customers separately, though this relies on the availability of consumption data for them.

In the commercial sector gas is still used for heating, but also for cooling, cooking, and for other purposes. While the heating requirement is still likely to be a significant contributor to explaining gas consumption in this sector, the extent to which gas consumption varies with temperature is likely to be smaller, at least in percentage terms.

Further, while gas air-conditioning equipment is very uncommon in the residential sector, it is quite standard in the commercial sector. This may also need to be reflected in the consumption models, for example by using CDD as well as HDD (or one instead of the other depending on the time period of the models).

Another factor that would influence gas consumption by individual customers is the installation of co- and tri-generation facilities. These forecasts are likely to be prepared at a level of aggregation where this type of change is not separately identifiable because, while it is of substantial importance for some customers, it is likely to be small relative to gas consumption for all customers as a group. In practice, this is not likely to be separately identifiable in a model.

Therefore, a potential specification for average consumption per commercial customer could be as shown in equation (4):

$$\ln(\text{Commercial gas consumption}) = \alpha + \beta_1 \times \ln(\text{GSP}) + \beta_2 \times \ln(\text{HDD}) + \beta_3 \times \ln(\text{CDD}) + \beta_4 \times \ln(\text{Price}) + \varepsilon \quad (6)$$

This implies that energy consumption is as per equation (5).

$$\text{Commercial gas consumption} = e^\alpha \times e^{\beta_1} \times \text{GSP} \times e^{\beta_2} \times \text{HDD} \times e^{\beta_3} \times \text{CDD} + e^{\beta_4} \times \text{Price} \times e^\varepsilon \quad (7)$$

If the model is seasonal, it is likely that HDD (in summer) and CDD (in winter) will be dropped due to being statistically insignificant. In colder jurisdictions such as Tasmania and parts of Victoria and New South Wales, we recommend that they be included in the initial specifications and that this decision be made based on the early modelling results.

As this model is based on total consumption by commercial customers, so are its outputs.

In this case the model is estimated in log/log form, which means that β_4 can be interpreted directly as an elasticity. As above, that elasticity value should be compared with other values in the literature. If the estimated value is out of line with those values, it may be appropriate to substitute it with another drawn from literature. As with the residential model, if this is done it should be made clear, and both the estimated and substituted value reported.

5.3 Model testing and validation

Once a model has been specified and estimated, it should be validated using standard statistical diagnostic tools.

The recommended approach is to use three main methods of model validation, namely assessing:

- coefficient size and sign against theoretical and empirical expectations
- the goodness of fit of the regression (R^2)
- the statistical significance of the individual explanatory variables.

The choice of model covariates will be based on theoretical considerations of the key drivers to explain the measured variation in gas consumption. As a consequence, AEMO should have prior expectations of the likely size and sign of model coefficients. The first test of any model is to ensure that the coefficients coincide with these expectations.

The second test of the models is the goodness of fit. The most commonly used measure of the goodness of fit is R^2 (coefficient of determination). In the model validation process, the R^2 is considered as part of a suite of available statistical tools. Emphasis is placed on the overall fit of the models as well as on the statistical significance of individual explanatory variables.

During consultation, EnergyAustralia emphasised the importance of ensuring that model performance is compared by reference to actual historical data. In effect this is what the R^2 value does, though AEMO may also want to produce 'back cast' series to illustrate year by year performance.

The third test is to ensure that each coefficient is statistically significant, that is, that changes in the variable associated with each coefficient have an effect on gas consumption that is statistically different to zero on average.

If sufficient data are available for out-of-sample testing this could also be considered, that is, a subset of the data could be withheld and the model used to 'forecast' that data using known drivers. However, with the relatively limited datasets that are typically available, this can be difficult to interpret because withholding data for this purpose will also reduce the precision of the model being tested.

6 Projected inputs

Having developed the econometric models described in chapter 5 above, the next step is to obtain forecasts of all the input variables used in the regressions and produce baseline forecasts. The main input variables which will be required are:

- GSP growth
- population growth by forecast area
- housing growth by forecast area
- real retail gas prices
- weather data.

A key message arising from consultation was that two characteristics of the projected drivers are important. The first characteristic was that the drivers should lead to forecasts that are reasonably accurate. This expectation was relatively unsurprising.

The second characteristic was less expected. Numerous stakeholders expressed the view that AEMO should make it very clear how its forecasts are developed. In some cases, stakeholders are less concerned that forecasts are accurate than that their basis is clear.

With the methodology recommended here, these two characteristics amount to a requirement that projected drivers are as accurate as possible, and that the drivers and their sources are clearly stated.²⁶

In some cases the appropriate source will be clear. For example, as a general proposition ACIL Allen recommends that AEMO rely on data obtained from the ABS wherever possible. However, in selecting the source for each driver AEMO should take care to ensure that both historical and projected values are available and that they are prepared on a consistent basis. The ABS publishes more in the way of historical data than it does projections, which may limit the extent to which AEMO can use ABS data for forecasts.

In some cases there will be no clear and obvious source of either historical data or future projections. In these cases AEMO may base the forecasts on relevant elements of the economic modelling it commissions each year.

Regardless of the source of the inputs, AEMO should ensure that the reporting of the forecasts makes clear statements regarding AEMO's expectations about:

- forward gas price levels(both wholesale and retail)
- price elasticity of demand, by customer type
- housing growth
- economic activity (GSP or similar)
- future weather conditions.

Those statements should be accompanied by statements of the source or basis of those expectations.

²⁶ Note that when drivers and regression coefficients are made clear, the process of replicating the forecasts themselves is a simple matter of arithmetic.

There may be some controversy attached to these statements. However, the alternative would create substantial uncertainty and lack of transparency around the forecasts and limit stakeholders' ability to use them.

The relevance of most of the factors noted above is self-evident, though weather conditions may be an exception. The issue here is whether future weather data should be adjusted from recent trends to account for climate change. In ACIL Allen's recent review of gas consumption forecasts prepared by Victorian gas DNSPs a discrepancy between the future expectations of AEMO and the Victorian gas DNSPs was apparent. As ACIL Allen reported to the AER at the time, the discrepancy was not about the rate of decline in HDD, but the 'starting point' from which that rate commenced. For the reasons set out in that earlier report ACIL Allen's recommendation is that AEMO should adopt its own analysis from 2012 as the basis for projecting weather data forward.

The projected drivers are also the logical basis for scenario forecasts. One way to resolve the uncertainty surrounding drivers will be to publish scenarios. For instance, AEMO may choose to publish forecasts of future gas consumption in a 'high' and 'low' economic growth scenario.

The key point is that scenario forecasts would be based on an underpinning logic. That is, rather than just being 'high' and 'low' forecasts, the forecasts are the direct result of uncertainty in the drivers.

In principle, AEMO should ensure that the input assumptions it makes in different forecasting exercises are the same. For example, the gas forecasts in the NGFR would ideally be based on the same economic projections as the electricity forecasts in the National Electricity Forecasting Report (NEFR).

In the past AEMO has commissioned economic outlook forecasts annually and relied on these in all forecasting. ACIL Allen understands that this practice will continue.

7 Post-model adjustments

A key part of the forecasting methodology is to make appropriate post-model adjustments. The purpose of these is to account for changes that are expected in future but are not reflected in the historical data.

This chapter is structured as follows:

- section 7.1 provides a conceptual discussion of when post-model adjustments are appropriate
- section 7.2 provides a general discussion of how post-model adjustments should be estimated and applied
- section 7.3 relates to specific post-model adjustments that may be necessary in this case.

It should be noted that the discussion in section 7.3 summarises ACIL Allen's expectations as to what might be appropriate. However, this section has been prepared without ACIL Allen having knowledge of the results of analysis yet to be conducted by AEMO. In particular, the post-model adjustments discussed here are based on ACIL Allen's expectations as to the efficacy of the 'cohort' approach, described in section 4.5, in dealing with historical changes in energy efficiency standards.

As with many aspects of the methodology described here, ACIL Allen recommends that AEMO allows the data to inform the appropriate approach. It is possible that a detailed data analysis will support different conclusions to those anticipated in section 7.3.

7.1 When a post-model adjustment is appropriate

The issue to address is that relationships estimated using econometrics are inherently fixed at some level. As an example, a simple model of residential gas consumption might be based on customer numbers only, as shown in equation (8):²⁷

$$\text{residential consumption}_t = \alpha + \beta_1 \times \text{number of customers}_t + \varepsilon_t \quad (8)$$

The model in equation (8) includes an assumption that, on average, every new customer who joins the network will use β_1 GJ of gas. This is the same amount that existing customers use, also on average.

²⁷ Note that this takes a different approach to residential consumption from that discussed earlier. This is for illustration purposes only.

In fact, though, the average gas consumption of residential customers may be declining.²⁸ If it is, the model in equation (8) would tend to overestimate the consumption of new customers and, therefore, overestimate total consumption. If the decline has occurred in the past this could be addressed by adding a trend variable to the simple model shown in equation (8). The model would now be as shown in equation (9).

$$\text{residential consumption}_t = \alpha + \beta_1 \times \text{number of customers}_t + \beta_2 \times \text{Trend}_t \times \text{number of customers}_t + \varepsilon_t \quad (9)$$

In this example, the average gas consumption of each residential customer declines by β_2 GJ each year. In other words, in the first year every new customer is assumed to use $(\beta_1 + \beta_2 \text{ GJ})$ of gas (β_2 could be negative). The year after, the model implies that they will use $(\beta_1 + (2 \times \beta_2) \text{ GJ})$, and so on.

The model in equation (9) is flexible in the sense that customers who join the network in future years are 'allowed' to use different quantities of gas compared to people who joined earlier. However, it is fixed in the sense that the amount of this difference is fixed. The way that this amount is fixed could be made more complex: for example by allowing it to adjust in a non-linear way, but ultimately the relationship will be constrained by a functional form, and estimation will only be able to be informed by empirical data.

Post-model adjustments are appropriate when the analyst has a reason to believe the relationship is likely to change from the empirics in the future. That is, when the analyst cannot be confident that future consumption will reflect historical experience, even after accounting for cohort (and other) effects.

For example, an energy efficiency policy might be implemented that will change the rate at which average residential gas consumption declines over time. A post-model adjustment would be appropriate in this case if either:

- the residential consumption model is similar to that in equation (8), with no trend component (or equivalent)
- the policy is expected to accelerate the reduction in gas consumption beyond the trend that has been observed. That is, if the policy could be considered an *increase* in effort to improve energy efficiency.

There is inevitably a degree of subjectivity in deciding whether to use a post-model adjustment in a particular case. Consider the possibility that a post-model adjustment should be used to 'account for' the phase-out of electric water heaters.

In 2010, when the phase-out of electric water heaters appeared likely to go ahead, it would have been reasonable to make a post-model adjustment to account for it. While there had been other policies in place to improve the energy efficiency of water heaters, such as star ratings and minimum energy performance standards, the phase-out was more substantial than past policies, and hence warranted an adjustment of its own.

²⁸ Theoretically it might also be increasing, though this seems less likely at the time of writing. If it was, the same approach would apply, though the signs would be reversed.

7.2 Estimating a post-model adjustment

There are various ways that a post-model adjustment could be made. Staying with the example of the water heater phase-out, in their regulatory submissions for the 2010 to 2015 (current) regulatory period, the Victorian electricity DNSPs adopted an approach where they:

- assumed a 'stock' of electric resistance water heaters in their network area
- assumed the rate at which that stock of water heaters would fail
- calculated the number of electric resistance water heaters estimated to 'fail' each year
- multiplied this by an estimate of the average electricity consumption of relevant water heaters
- 'removed' electricity sales from their forecast of energy sales based on that calculation.²⁹

For gas consumption the same approach could be applied to estimating the number of additional gas water heaters to be installed in a region. That number could then be multiplied by an appropriate estimate of the gas consumption of a current technology replacement water heater.

The key characteristics of a post-model adjustment are that it should be based on objective estimates of key parameters and that it logically reflects the reason it is to be made.

In the case of the hot water phase-out, the parameters used are the initial stock of water heaters and the rate at which they would fail. The former could be drawn from a source such as the Regulatory Impact Statement that underpinned the government decision to phase out water heaters. Regulatory Impact Statements are often a useful source of parameter estimates for post-model adjustments relating to government policy as they are typically exposed to public comment and debate when they are developed.

The failure rate could be based on the useful life of a water heater, which can be drawn from Australian Taxation Office depreciation schedules.

In other cases the details will be different. The unifying concept is that the post-model adjustment should be estimated using a 'calculator', which is a forecasting model in itself. The same principles should apply to that calculator as to the overall forecasting model. In particular, the basis of the estimate should be clearly explained and transparent to allow analysis by others. The inputs to calculators should be clearly stated.

Post-model adjustments are forecasts in their own right and, as such, should be made transparently and based on robust methodologies. They should reflect actual practice and experience to the maximum extent possible. For example, while many post-model adjustments will be based on an 'appliance model' approach they would ideally be calibrated with observed practice rather than based on theoretical assumptions about what might happen.

The hot water example illustrates that the approach to a post-model adjustment will need to be tailored to the adjustment itself. The key methodological point is that, consistent with stakeholder feedback throughout this process, the post-model adjustments should be made in a way that is clear, transparent and modular. Stakeholders should be able to observe the effect of post-model adjustments separately. They should also be able to reverse or alter the effect for their own purposes if they choose to do so.

²⁹ A small adjustment was made to account for other forms of electric water heaters that may be used in place of those that failed, such as heat pumps, and to account for special cases such as apartments.

It is in the nature of post-model adjustments that the inputs will often be uncertain. In some cases they may be little more than 'best guesses'. Of course the inputs should be the best available, but the fact that there is substantial uncertainty should not prevent them from being stated clearly. As with driver projections, it may sometimes be useful to address this type of uncertainty by presenting scenarios, though in many cases the magnitude of uncertainty around gas consumption will not warrant this.³⁰

7.3 Post-model adjustments in this case

The previous two sections provide a general discussion of when a post-model adjustment might be required and how it would be estimated. This section provides a discussion of specific cases where post-model adjustments may be appropriate for the gas consumption forecasts.

As noted above, the decision to use a post-model adjustment is somewhat subjective. It would also ideally be based on analysis of specific data, which ACIL Allen has not been able to do in this case. Therefore, the statements in this section are somewhat general. It is quite plausible that, on examining the data, AEMO may reach different conclusions to those anticipated here.

The issue of post-model adjustments was discussed during consultation. For example, the ENA took the view that relevant forecasts should reflect changes in house building codes and increases in gas prices, which can motivate fuel switching to electricity for certain uses.³¹

At the time of writing this report, ACIL Allen considers that the two issues likely to be candidates for post-model adjustment are:

1. the shift from gas to electricity for space heating – the recommended approach for this depends on the efficacy of the cohort variable approach described in section 4.5 above, which is discussed further in section 7.3.3
2. forecast increases in the price of gas, in particular relative to the price of electricity – the recommended approach is to examine the price elasticities estimated in the models and consider substituting them for values taken from the literature if appropriate.

A discussion of these issues is below.

ACIL Allen does not anticipate that a post-model adjustment will be required to account for energy efficiency policies generally. As discussed in section 7.3.3, this expectation is based on an expectation that the cohort approach discussed in section 4.5 will account for changes in energy efficiency standards. In case it is not, section 7.3.3 provides alternative approaches that may be considered.

³⁰ That is, in many cases different scenarios of post-model adjustments will not lead to dramatically different consumption forecasts.

³¹ The ENA also emphasised the importance of weather normalisation, which is discussed in section 4.4.

There are various other factors that may be candidates for post-model adjustments, either now or in the future, but which appear too uncertain to address at this stage. AEMO may wish to incorporate these into future iterations of the NGFR. These include gas use for vehicles fuelled by compressed natural gas and the increased use of gas-fired air conditioning.

7.3.1 Accounting for increased use of electricity for space heating

A substantial portion of residential gas consumption is for space heating, especially in the residential segment. In this application gas and electricity are in close competition with one another. While there are various technologies that can be used for space heating, a key point is that this can be done using either gas or electricity.

Until recent changes (and anticipated changes) in the gas market there appeared to be a trend towards using gas for space heating where possible. However, more recently there has been evidence to suggest that this trend has reversed.

Evidence in this area is limited and difficult to obtain. ACIL Allen understands anecdotally that residential developments and new homes are increasingly choosing to use electric (reverse cycle) systems for cooling and, given that the systems are being installed, they are being relied on for heating as well. This allows the homeowner (or developer) to avoid the upfront capital cost of a separate heating unit. In the past, gas was cheaper than electricity by a sufficient margin that the capital cost was less of a barrier than it is now. More recently the 'balance' appears to have 'tipped' towards electricity. The convenience of having one appliance that both cools and heats also appears to have considerable attraction beyond simple cost relativities.

The recommended approach to dealing with this issue is *not to* make a post-model adjustment, but to deal with it by taking account of the age of houses in a given area using the 'cohort' variable described in section 4.5 above.

In the forecast period AEMO may choose to allow the model described above, with the cohort variable included, to provide the forecasts.

Conceptually, ACIL Allen identified two other ways that this effect could be included in AEMO's forecast models, which would avoid the need to make a post-model adjustment at all. AEMO could account for this effect:

- directly – by taking account of the number of houses with certain appliances, or combinations of appliances. In this approach AEMO would obtain data relating to the number of households with reverse cycle systems and/or gas heating systems in a given forecast area and incorporate these data into the relevant models
- indirectly – by taking account of the price of *electricity* in the gas consumption models.

In practice we are not convinced that either approach will be effective.

The direct approach would require data pertaining to the number of heating systems of different types in relevant forecast areas. ACIL Allen is not aware of up-to-date data regarding heater types in the public domain.³² ACIL Allen is aware that some DNSPs conduct periodic surveys to obtain this type of information in relation to their forecast areas, so AEMO may be able to obtain some of the necessary data through partnerships with those DNSPs. Alternatively, AEMO could conduct its own surveys or there may be other

³² A survey was conducted by the then Department of Environment, Water, Heritage and the Arts in 2008, based on data to 2005, and there are periodic ABS studies.

sources.³³ Furthermore, even if empirical data were available to some extent, forecasts would be difficult to obtain.

The indirect approach relies on an underlying assumption that changes in the current price of electricity drive changes in gas consumption. The *advantage* of this is that it is not limited to a single identified phenomenon, reducing the risk that AEMO will overlook a relevant factor in its forecasting.

The *disadvantage* is that it will be difficult, if not impossible, to fully capture the relevant price changes. In particular, while the current actual price of electricity and gas may be relevant to this issue, in practice, it seems likely that anticipated future prices are important as well. However, these are difficult to quantify, especially because different people will have different perceptions and expectations at the same time.

We note that the Centre for International Economics (CiE), working for SP AusNet, attempted to incorporate the effect of changing electricity prices in its forecasts of gas consumption in the context of the Victorian Gas Access Arrangement Review in 2012. SP AusNet concluded that “the most appropriate assumption for forecasting for residential gas use is to allow for no relationship between electricity prices and gas consumption.”³⁴

Insofar as history is concerned, ACIL Allen anticipates that the cohort variable approach described in section 4.5 will ‘capture’ the change from electricity to gas along with the general improvement in energy efficiency, though these would not be separately identified.

EnergyAustralia raised two concerns with this approach which are, in summary, that:

1. the cohort approach requires a forecast of the size of the ‘new’ cohort in the forecast period
2. by the time the forecasts are produced, the ‘new’ level of energy efficiency is in fact quite old. In future, customers may use even less gas than the more recent cohort of customers. If so, the cohort approach will tend to overstate future consumption.

Given that this approach is applicable to residential customers for the most part, the first of these concerns can be addressed by relying on a forecast of new housing starts. Ideally a separate historical measure and forecast of major renovations would be incorporated as well, as the housing starts data will not capture renovations directly. However, while housing starts data are tracked and reported quite widely, renovations data are more scarce. It is reasonable to expect that the two will be correlated, so the outcome will not be adversely affected by the absence of an explicit measure of renovations. In addition, renovations will be captured in part by economic activity, which ACIL Allen has noted as an explanatory variable that should be considered for inclusion in the baseline model.

The second concern is more difficult. It could be partly overcome by including multiple ‘cohorts’ in the historical data. However, it must be remembered that a regression model cannot have more variables than the number of historical data points (that is, some degrees of freedom must be retained). In practice, AEMO will probably have relatively few observations, especially if annual data are used, so it will be limited in the number of variables it can add to the models.

³³ For example, the ABS produces a range of statistical information on household energy consumption, appliance and conservation which may be of use in this regard.

³⁴ SP AusNet, “2013-17 Gas Access Arrangement Review - Access Arrangement Information, Appendix 4A: Gas demand Forecasting SP AusNet 2013-17”, 30 March 2012, available from www.aer.gov.au, accessed 13 December 2013.

EnergyAustralia's second concern could be rephrased by saying that, in their view, a post-model adjustment will be required *in addition* to applying the cohort approach.

This may be appropriate. The underlying question is how much energy to attribute to new connections in the forecast period. In equation (1), the coefficient 'B' provides an estimate of the gas consumption of a 'new;' house, but this is a house that was built after the 'base date'. New houses in the forecast period may be more efficient than this and, if so, a separate adjustment may be required. It may be appropriate, for example, to identify the average consumption of connections in the most recent year for which data are available (controlling for the other variables included in the baseline model) and assume that this will be typical of new connections thought the forecast period.

7.3.2 Adjustment for price changes via elasticity

Another area which was widely discussed during consultation, and which is likely to introduce substantial uncertainty to AEMO's forecasts, is the forward price of gas. It is worth remembering that at this point in the methodology only tariff V (residential and commercial) customers are being considered.

In microeconomics, the simple concept that customers typically use less of a good if its price increases, and vice versa, is known as the 'price effect'.³⁵ Formally, the magnitude of the price effect is measured by the own price elasticity of demand, that is, the percentage change in demand for a good that results from a given percentage change in its price. It should be noted that, technically, elasticity is estimated over a very small change in price and that in many cases the elasticity changes as price changes.³⁶

There is also the substitution effect where a change in the price of one product leads to a change in demand for another (cross price elasticity). In the context of gas consumption the substitution effect applies to the price of electricity, which is discussed in the previous section.

As shown in section 5.1.2, ACIL Allen's recommendation is that AEMO estimates the relationship between price and gas consumption directly in the baseline econometric models. The estimated coefficient on the price variables in the econometric model can be used to estimate the price elasticity of demand for gas in a given region.³⁷

Theoretically, the same approach could be used to estimate the cross price elasticity of demand for gas (with respect to the price of electricity). In the 2012 Victorian Gas Access Arrangement Review process SP AusNet submitted demand forecasts where this had been analysed. However, its advisor, the CiE, was unable to quantify this effect and concluded that the substitution effect should not be included in the forecasting models.

The elasticity as estimated in the models should be compared with values estimated in other studies. If the estimated elasticities do not correspond with expectations, either in sign or magnitude, it may be appropriate to substitute them with a value drawn from the literature.

³⁵ Theoretically, consumption of a 'Giffen [??] good' would increase if its price increases, but the existence of Giffen goods has been a matter of contention and can be practically ignored for most purposes.

³⁶ It is possible to construct a demand curve where elasticity is constant at one across all price levels (a unit elastic demand curve), but this is a special case.

³⁷ If the consumption models are in log-log form the coefficients can be interpreted directly as elasticities. Otherwise a transformation is required.

In ACIL Allen's review of the Victorian gas DNSPs' regulatory proposals in 2012 we noted that each DNSP had suggested that the price elasticity of demand for gas is approximately minus 0.3. This was accepted by the AER, and was consistent with its determination in a prior determination. It may also suggest that AEMO's analysis should reach a similar value.

However, it is important to consider the possibility of double counting. Price elasticity provides a measure of the extent to which gas users respond to changes (usually increases) in gas price. However, it provides no information about the way these responses occur.

Broadly, responsiveness can be thought of as comprising two components:

- a *behavioural* component – where consumers choose to use less gas as price rises. In practice this may manifest itself as a householder deciding to set their heater to a lower thermostat temperature and dress more warmly
- a *structural* (physical) component – where higher gas prices lead to different choices about appliances. For example, with higher gas prices, more efficient appliances may be financially justifiable.

Estimated values of price elasticity are invariably taken from models. In some cases, some of the physical components are accounted for separately and in others they are not. To illustrate, consider a simplified situation where:

1. gas prices rise over time
2. consumers respond to those increases by double glazing their homes, thereby reducing the amount of gas required to maintain a comfortable temperature.

If these are the only two factors influencing gas consumption in the relevant time period, and if a measure of the amount of double glazing installed is available, a model of gas consumption might be as shown in equation (10).

$$consumption_t = \alpha + \beta_1 \times price_t + \beta_2 \times glazing_t + \epsilon_t \quad (10)$$

where $price_t$ is the price of gas at time t and $glazing_t$ is a measure of how much double glazing has been installed.

In this model, β_1 represents the price elasticity of demand.³⁸ If the 'glazing' variable was omitted, it is likely that the estimate of this elasticity would be likely to be larger, as it would be the only variable in the model accounting for a gradual decrease in consumption per customer.

The point is that, in this simplified example, customers are installing double glazing because price is rising, so the reduction in consumption due to double glazing is, strictly speaking, part of the broader response to price. By accounting for double glazing separately in the model, the price coefficient β_1 is reduced to an estimate of the behavioural response to price.

In itself this may not be a problem for forecasting. However, if forecasts are to be accurate, the approach illustrated here relies on an accurate estimate of both gas price and the future uptake of double glazing.

³⁸ Note that as the model is shown here the coefficient β_1 is linear, not strictly speaking an elasticity. This is not important for illustrative purposes.

Timing must also be considered when accounting for the effect of price on consumption. Theoretically, the effect to be considered is that users may take time to respond to increases in price. There are two reasons:

1. it takes time to replace gas-using appliances, many of which are long lived with significant upfront capital cost
2. it may take time for a price change to impact an individual customer if, for example, a contract is in place.³⁹

This is an issue which has been examined in various past forecasting projects. It is partly an empirical question, so a definitive statement cannot be made here as to the correct lag structure to apply, or even whether the data support a lagged approach at all. It is likely to be worthwhile experimenting with different structures in the model fitting stage to find the combination of lags that best explains the historical data. In addition, the approach to modelling should reflect reality as closely as practical. As discussed in section 5.2, it may be necessary to structure the commercial price variable to reflect contract timing.

7.3.3 Energy efficiency policies

Another area that has required post-model adjustment is the recent rapid uptake of energy efficiency initiatives. Driven by various policy measures, including 'white certificate' schemes in New South Wales, Victoria, and South Australia, there has been substantial effort in recent years to introduce energy efficient appliances, which have reduced the amount of gas customers use.

The Victorian Government has recently announced that its white certificate scheme will cease from 2015. While other white certificate schemes appear likely to remain in place, the impetus for new measures is now quite low. Therefore, while energy efficient appliances might now continue to be taken up at similar rates to the recent past, it is unlikely that further policy-driven accelerations in their uptake will be observed.⁴⁰

The impact of energy efficiency schemes has been that the average consumption per customer has declined. However, from a forecasting perspective, this decline is now 'present' in the empirical data. In terms of the model of consumption per customer shown above, the response of energy consumption to changes in GSP is smaller than it would otherwise have been.

The question to consider in forecasting consumption is whether that coefficient will decline further in future, which would warrant a post-model adjustment, or whether no such adjustment is required.

This is not so much an empirical question as a policy question.

It amounts to asking whether the uptake of more energy efficient appliances during the forecast period will continue at a similar average rate to that which occurred during the period for which historical data are available. In most cases we expect that this will not happen because there are, currently, no proposed policy interventions of which we are aware that would drive such an increase. Therefore, we would expect that no post-model adjustment is required for energy efficiency policies.

³⁹ This is really a measurement issue arising from the fact that the measure of price will typically be an index or similar that changes annually. The individual price paid by users will reflect that index over time, but not immediately.

⁴⁰ Generally speaking this is because, while existing energy efficiency policies will remain, there are no new energy efficiency policies on the horizon.

8 Large industrial customers

The issues involved in forecasting gas consumption by 'large' customers are different from those involved in forecasting for other customers.

This chapter outlines the recommended approach to forecasting consumption by large customers.

First, section 8.1 provides a definition of large customers for these purposes.

Section 8.2 describes the recommended forecasting approach.

8.1 Identifying and defining large customers

'Small' customers are numerous and sufficiently homogeneous that their gas consumption can reasonably be forecast using econometric methods based on the behaviour of the average commercial or residential customer.

In contrast, there are relatively few large customers and, more importantly, they are anything but homogeneous, as evidenced by the brief description of the South Australian network in section C.3, which refers to a cement production facility, a glass manufacturing facility, and a steelworks.

For these purposes, large customers are customers that AEMO identifies at the forecast area schematic stage as those whose consumption it will forecast using the approach described in this chapter.

It is recommended that AEMO avoid defining large customers strictly. For example, a threshold-based approach such as 'large customers are all customers with consumption greater than x' is not recommended. Instead, ACIL Allen recommends that AEMO identify the customers whose consumption is large relative to their forecast area. In some forecast areas there will likely be customers who are defined as large, notwithstanding that they use less gas than customers in other areas who are not defined as large.

The recommended approach is that AEMO consider each forecast area separately and identify the customers whose consumption is sufficiently large that it should be considered separately. Those customers should be identified on the schematic as large customers. In practice, a rule of thumb such as 'top 10 customers in the region by consumption' may be helpful. AEMO should also consider the extent to which candidate large customers' consumption varies. It will be more helpful to the forecasting process to account for substantial variations in the consumption of smaller customers than for small variations in consumption off a larger base.

8.2 Forecasting consumption of large customers

Conceptually the methods described above could be applied to large customers as well. However, in practice they would be unreliable because of the widely differing characteristics of these customers. ACIL Allen does not recommend using an econometric approach to forecast gas consumption for large customers.

The recommended approach to forecasting the gas consumption of large customers is to use the survey method. ACIL Allen considers this method will lend itself reasonably well to forecasting gas consumption in this part of the market, at least in the short to medium term.

Conceptually, the preferred approach is first to determine the historical consumption levels for each individual user. Where these have been relatively stable, it is reasonable to assume (in the absence of contrary information such as announced plans for expansion, contraction, or closure) that those customers will continue to consume the same amount of gas in the future as they have used in the past. In cases where a reason can be identified to assume a change in consumption for a particular customer, this should be incorporated and the basis for the change recorded. The (Queensland) Department of Energy and Water Supply pointed to the Energy Efficiency Opportunities scheme as a source of potential data relating to historical changes in consumption.

This seems a simplistic approach, but at this very large end of the market (and excepting gas-fired power generators that are outside the scope of this exercise), gas is typically used for industrial production processes which are inherently quite stable. For the most part they are immune from weather effects and other short-term variability that characterises consumption by other customers. Of course, this is not to say that they never change, but when substantial changes occur they are generally due to long foreseen events such as expansion or closure of all or part of a facility. For example, in South Australia a case in point is the General Motors Holden facility in the northern suburbs of Adelaide. Another is the Ford factories in Melbourne and Geelong. It has recently been announced that these facilities will close. ACIL Allen has no specific knowledge of these facilities, but at least as an illustration it appears reasonable to expect that they will continue to use a fairly constant quantity of gas until they close when they will reduce their consumption substantially.

The data sources for this approach are surveys. Generally, ACIL Allen recommends that AEMO conducts surveys of the large customers identified in each forecast area at the forecast area schematic stage to identify expected changes in their gas consumption. This should be supplemented by active monitoring of the market to identify relevant changes. If this is coupled with the daily interval meter data we understand to be available to AEMO, a reasonable forecast of consumption could be produced.

The surveys themselves need not be complex. AEMO simply needs to know the size and timing of anticipated changes in the gas consumption of large users in each forecast area. In many cases large users will not anticipate changes, in which case AEMO would either project their consumption to be constant or perhaps make a small adjustment at the aggregate level to account for economic growth generally.

An addition to conducting surveys, which was raised during consultation by EnergyAustralia, is to consider the possibility that changes in one customer's consumption will impact the consumption of other customers. As noted above, the next few years will see the closure of car manufacturing plants in several parts of Australia. A survey-based approach should identify the extent to which those businesses will reduce their gas consumption. However, it may also provide information about the likely reduction in consumption by the firms that supply them. This may lead to direct post-model adjustments in the commercial customer category or to modifications to the economic outlook for certain forecast areas (see section 5.2).

It may also be worth considering the historical data for large customers in aggregate in each forecast area over time to identify any statistically significant long-term growth (or decline) trend or an aggregate relationship with a driver such as economic activity. This would involve estimating a simple regression model as illustrated in equation (11).

$$\text{large consumption} = \alpha + \beta_1 \times \text{trend} + \varepsilon \quad (11)$$

If the model suggests that a trend pattern exists, for example if the coefficient on the trend variable is statistically significant, there may be a reasonable basis for including an “unspecified industrial growth” component in the forecast. This would reflect the fact that there is typically a correlation between economic growth and growth in energy demand, but that with “lumpy” investment in new facilities and facility expansions it is often unclear just where the growth will occur.

In surveying large customers AEMO will need to be sensitive of confidentiality concerns associated with the data being sought. In particular, AEMO will likely need to publish data at an aggregated level to conceal the use of individual large customers. The level of aggregation should be balanced against the loss of transparency.

A further issue to consider is the appropriate treatment of new industrial loads and shutdown of existing loads. In particular, AEMO will need to take a position on new loads that have been announced but are not yet committed.

One possible approach is to use probability weights. AEMO would recognise all “announced” projects and apply individual probabilities to each based on an assessment of progress and prospects. This would also allow AEMO to produce high, medium and low forecasts in this segment. In the high case it would take an optimistic stance to growth projects and in the low case a pessimistic stance.

The problem with this approach is that it is inherently subjective. It assigns arbitrarily selected probabilities to projects for which the anticipated consumption is also not firm. The resulting forecast has little relationship to what the project could actually be expected to do. Another problem is that AEMO’s statement regarding the likelihood of a project proceeding may influence that likelihood as it may carry weight in financial markets, prejudicing the proponent’s chance of raising funds, attracting partners, or securing customers.

An alternative approach is to assign all projects at a particular stage the same probability, without considering the specifics of individual projects. For example, all projects that have not reached the Front End Engineering Design (FEED) stage would be treated as x per cent likely to proceed. Projects for which FEED has been completed have y per cent probability. By taking a more arm’s length approach AEMO may reduce the impact its views may have on investment markets.

Another approach would be to disregard projects entirely until they reach a certain point in the approval process. For example, AEMO may decide to include projects only *after* they have reached the Final Investment Decision stage or only after they have completed FEED and have the required environmental approvals in place.

9 Compiling forecasts and computing scenarios

9.1 Compiling forecasts

At this point in the process AEMO will have separate, independently prepared forecasts at each forecast area of gas consumption by:

- residential customers
- commercial and industrial tariff V customers
- large industrial customers.

The remaining step is to combine the forecasts together to produce a single forecast for each forecast area and for larger geographic areas as required. This is simply a matter of taking the sum of each component forecast to produce an aggregate.

Therefore, the total forecast for a forecast area is the sum of the component forecasts. In the residential and other customer category, other than large customers, each component forecast is the result of either a regression-based modelling process, perhaps involving two or more regression models. In the large space the forecasts are produced by assuming that consumption *tomorrow* will be as it was *today*, other than where surveys have revealed likely changes.

9.2 Scenario forecasts

A requirement of the methodology was that AEMO should be able to use it to produce forecasts under different scenarios.

In ACIL Allen's view it is not helpful to prepare scenario forecasts simply by increasing or decreasing the output variable for its own sake. Rather, ACIL Allen prefers a 'bottom up' approach to scenario forecasting.

That is, scenarios should not be simply a matter of increasing or decreasing projected gas consumption, but should be logically connected to differences in the driving assumptions.

Therefore, preparing different forecast scenarios is a two-step process. First, the driver of interest must be identified and altered to reflect the relevant scenario. Second, that altered driver is applied to the regression models developed earlier to produce different forecast scenarios.

For example, AEMO may produce gas consumption forecasts for 'base case' economic growth or 2.5 per cent per annum. It may also produce a 'low economic growth' scenario where it assumes 1.5 per cent annual economic growth and applies this to the model. The result would be lower forecast gas consumption (presumably), but the scenario is logically connected to uncertainty about economic growth. In effect, AEMO's forecasts become a series of conditional statements. That is, *on condition* that population growth (or another driver) is as expected, gas consumption is forecast to be XPJ. However, if population growth is different, then so too will be gas consumption.

Another way that different scenarios can be accounted for is through post-model adjustments. The details will vary in each case, but there are likely to be input parameters in the post-model adjustment calculators that will be uncertain and could be altered to reflect different possibilities. This would produce alternative consumption forecasts reflecting those uncertainties.

10 Maximum flow

The methodology above outlines a methodology for estimating total gas consumption in each forecast area AEMO would define. Another of AEMO's requirements is to be able to estimate maximum flow on 1 in 2 and 1 in 20-year bases and on a maximum hourly basis in Victoria.

It should be remembered that this relates to maximum daily and hourly flow *excluding* gas used for power generation, which is to be addressed separately. Based on ACIL Allen's experience, it is the GPG sector which provides most of the variation when looking at peak consumption levels period to period.

Conceptually, these forecasts could be based on the consumption forecasts or prepared independently of the consumption forecasts.

ACIL Allen's understanding, updated during the consultation process, is that most maximum daily loads are typically based on consumption forecasts. Broadly, our understanding is that forecasts of total gas consumption in an area are prepared and then multiplied by certain ratios to produce estimates of maximum daily flow. The ratios are based on historical data and were generally described as being well-established and fairly widely accepted.

As we understand it, the ratios are fixed and have been so for some time. Therefore, this approach relies on the assumption that the relationship between average and maximum flow will be the same in the future as it was when the ratio was established. It is beyond the scope of this project to test or verify this assumption, but it appears that it would be prudent for AEMO to do so if it intends to continue with this approach.

An alternative conceptual approach to using fixed ratios is to capture the variability in them. Two approaches to doing this are discussed below.

In principle, either of these approaches will outperform the ratio approach if the ratio is not well chosen.

ACIL Allen's recommendation is that AEMO examine the relative performance of the existing, ratio-based approach and the alternative approaches outlined below and adopt the approach that provides the optimal balance of resource requirements and accuracy.

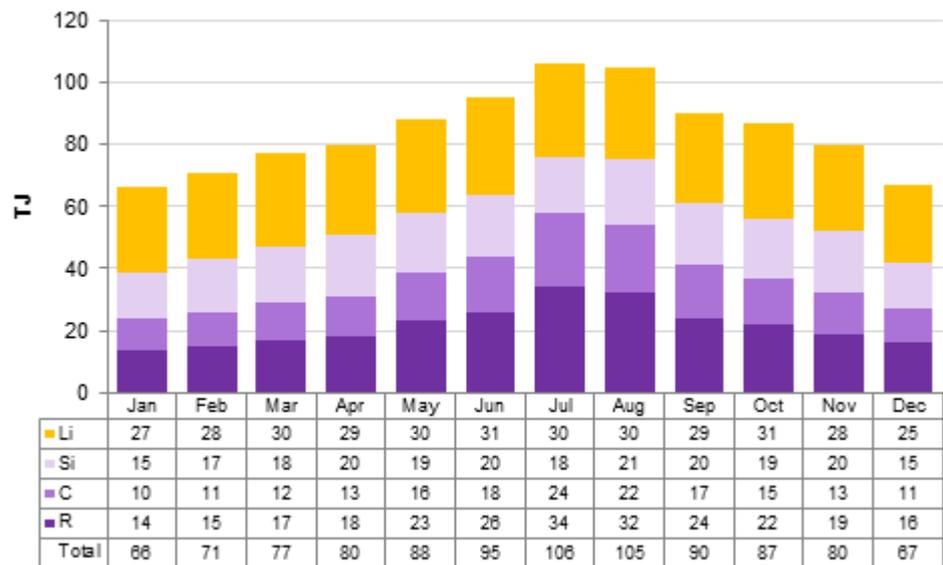
The following discussion focusses on forecasting peak daily consumption. The same methods can also be used to forecast maximum hourly consumption provided the underlying data is available at the required level of granularity. Should AEMO require, the same methods described below can also be used to forecast minimum flow.

10.1 Load factors and coincident peaks

A system load factor relates to the ratio between average consumption and the peak consumption level over a period. The concept in gas is exactly the same as it is for electricity.

To illustrate the challenges in forecasting peak daily consumption levels, consider the following hypothetical bulk supply point, which already has consumption forecasts by segment on a monthly basis over a year as shown in Figure 3. Let us assume that AEMO’s forecasting methodology has yielded results for forecast consumption by segment which in aggregate results in total consumption over the year of 1,012 TJ, broken down by residential 260 TJ (26 per cent); commercial 182 TJ (18 per cent); small industrial 222 TJ (22 per cent); and large industrial 348 TJ (34 per cent). The annual profile of consumption is skewed heavily toward winter gas consumption, driven largely by the residential and commercial segments.

Figure 3 Consumption forecasts for hypothetical bulk supply point

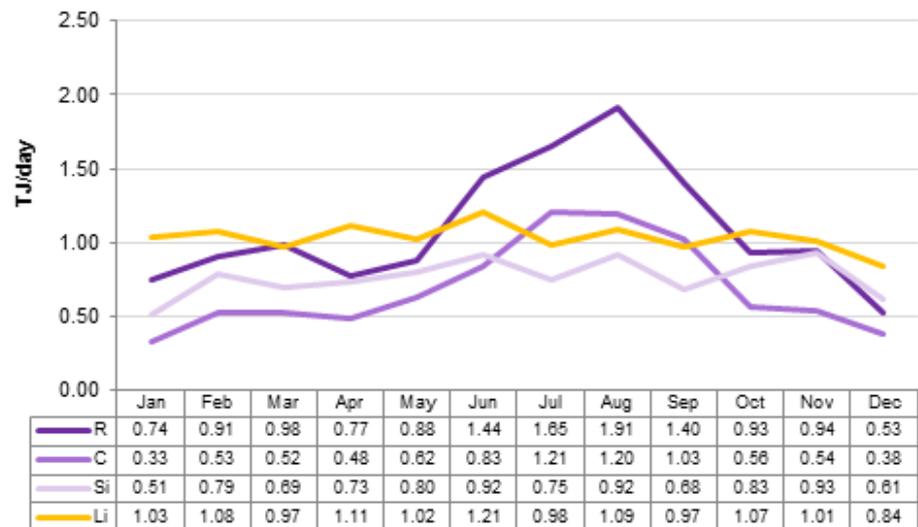


Note: R = residential; C = commercial; Si = small industrial; Li = large industrial

This forecast data does not provide any information in relation to peak daily consumption through this bulk supply point, either in aggregate or by segment.

If, in an ideal world, full historical daily data is available for each customer segment, then AEMO could undertake an historical analysis of peak daily consumption for each segment. This would likely include the weather effect on peak consumption and longer-term seasonal effects. Suppose AEMO’s analysis resulted in expectations of peak monthly demand by segment as shown in Figure 4.

Figure 4 Hypothetical bulk supply point: historical peak daily consumption by segment



Note: R = residential; C = commercial; Si = small industrial; Li = large industrial

The analysis would use monthly load factors to derive an expected peak daily consumption value, by month, by customer segment, noting that it is unlikely that the sum of the monthly peaks across segments would equal the peak daily consumption through the bulk supply point because the peaks are unlikely to be coincident. That is, they are unlikely to all occur on the same day within the month. Therefore by definition, the peak flow through the bulk supply point will be less than or equal to the sum of the components. Similarly, the peak daily consumption level for eastern and south-eastern Australia as a whole will be less than the sum of daily peak consumption levels for each of the bulk supply points which make up the market.

Armed with disaggregated daily data, AEMO could identify monthly peak consumption days and calculate the level of coincidence between the segments. Regressions could be undertaken on this historical data to arrive at a forecast of peak daily consumption levels by segment, based on the previously developed monthly consumption forecasts.

However, as discussed in previous sections, it is not clear that the required data to undertake this type of analysis will be available to AEMO. AEMO may only have access to aggregated daily data, with no way of breaking consumption down beyond large industrial and 'other' components (the sum of residential, commercial, and small industrial components). In some cases even this breakdown may not be possible, with only an aggregate daily consumption data being available for some bulk supply points.

In the absence of a meaningful way of breaking down historical data, AEMO will be unable to forecast peak daily consumption by segment, or even if it can, the forecast will not be able to be verified against actuals. AEMO will only be able to sensibly forecast peak daily consumption at the level to which daily data are available.

10.2 Regression and simulation

The regression and simulation approach is widely used in weather normalising maximum electricity demand. However, the approach is inherently one of dealing with randomness in a variable, so it need not be limited to weather normalisation.

Weather normalisation is based on an estimated (quantitative) relationship between maximum flow in a given forecast area and the variables that drive it. In this example it is assumed that the variability in maximum daily flow is driven by variability in weather. If this is not so in certain cases another variable would be substituted.

This section concludes with a description of the recommended approach when no alternative variable can be found, either because the source of the variability cannot be identified or because it is identified but cannot be measured.

The recommended approach is that weather normalisation is applied to each season individually. Given the objective is to forecast weather normalised maximum daily flow, it is only necessary to analyse seasons when maximum daily flow is likely to be observed. In this illustrative discussion it has been assumed that this will occur during the winter period.

Weather normalisation begins with data for an entire season in a single year. The necessary data are:

1. observed daily maximum flow
2. weather.

In this discussion we assume that the appropriate weather measure is HDD, though this should be tested by comparing correlations between daily maximum flow and HDD with other alternatives.

The first step is to compute a linear regression of the form of equation (12).

$$MF_d = m * HDD_d + c + \varepsilon \quad (12)$$

where MF_d is maximum flow observed on day d for all days in the dataset, HDD_d is the contribution made on day 'd' to the annual number of HDD, m and c are regression parameters, and ε is an error term. It may also be appropriate to incorporate multi-day effects by adding HDD from the days preceding the peak day to the model.

The regression coefficients (m and c) are used in the weather normalisation procedure by computing flow as it would have been every day of the relevant season in each year for which historical data are available.

The procedure is to:

1. use the estimated regression models for each season with all available weather data to produce estimates of what annual maximum daily flow *would have been* in each season under all of the weather conditions that have been observed given the relationship estimated in equation (12)
2. allow for the natural variability in daily maximum flow using the standard error of each fitted regression. This is done by adding an error taken as a draw from a normal distribution with a mean of zero and standard deviation equal to the standard error of the regression to each fitted value from the regression above.⁴¹

⁴¹ Assuming that the errors are normally distributed is an adequate starting point that should be used unless there is strong evidence to the contrary. If the analysis suggests that the errors follow another distribution, then it is reasonable to use it. It may be the case that the true distribution of the errors has 'fatter tails' than the normal distribution. In this case the simulated errors will be smaller than they should be and consequently the simulated maximum demands will be smaller. Weather corrected 10 and 50 POE demands will be lower than they should be in this case.

To illustrate, consider a forecast area for which there are 30 years of winter weather data at the weather station that has been identified as being most closely correlated with gas consumption. Assume that the chosen weather variable is HDD and that there were 75 days each winter that were neither 'mild', nor weekends or public holidays.⁴²

First, use the coefficients of the regression describing the weather relationship (equation (12)) and the weather data for the 75 working days in all available years (30) to produce estimates of what the daily maximum flow would have been in the most recent season under *all* weather conditions observed.

In this example there would now be 2,250 fitted daily maximum flow values (that is 75×30). Notionally these suggest what daily flow would have been in the year when equation (12) was estimated for each weather outcome that has been seen in the last 30 years.

Of these 2,250 values, 30 are annual maximum daily flow values, one maximum for each year of weather data. Record those 30 annual maximum flow values.

Then a random error is added to each of the initial 2,250 notional flow observations. This is done by taking a draw from a distribution with mean zero and standard deviation equal to the standard error of the estimate of the regression described in section 10.1.

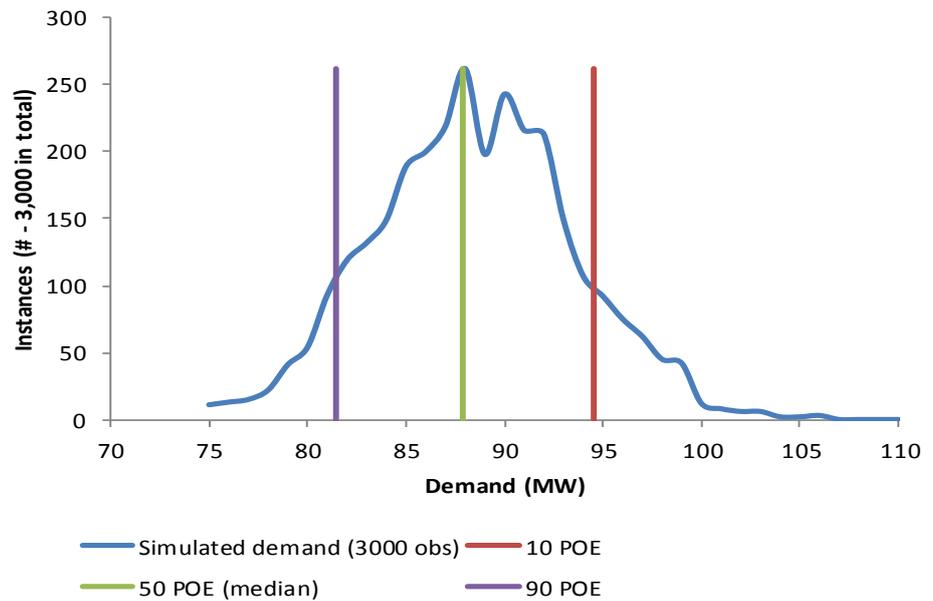
Every time this is done (i.e. every time a trial is conducted) another set of 30 annual maxima is produced. Therefore, if 100 trials are conducted, the result will be 225,000 daily maximum flows, of which 3,000 will be annual maxima.

The 10 and 50 POE flow values are taken from these 3,000 observations. That is, the 50 POE is the median of these 3,000 values and the 10 POE is the value that falls on the 90th percentile. This is illustrated in Figure 5. Any POE level can be taken by choosing the corresponding percentile.

Figure 5 illustrates the result of simulating 225,000 observations from a normal distribution with mean 88 MW and standard deviation 5 MW and taking the 3,000 simulated annual maxima. The 10, 50 and 90 POE values from the simulated data are shown in Table 6.

⁴² We have assumed for this illustration that gas consumption, and therefore maximum daily flow, is significantly lower on non-working days and on days when the weather is mild than at other times. These assumptions should be validated with the data before the procedure is commenced. If either assumption is not supported it should be omitted.

Figure 5 **Distribution of simulated maximum flows and POE (percentile) values – example**



Source: ACIL Allen Consulting

Table 6 **Weather-corrected flow at 10, 50 and 90 POE – example**

POE level	Flow (MW)
10	94.5
50	87.9
90	81.4

Source: ACIL Allen Consulting

This process is repeated for each historical season for which data are available and for which a relationship between maximum daily flow and weather has been estimated.

These can be used as the basis for estimating growth rates in maximum daily flow, which could be applied to the most recent normalised flow to produce projections of maximum daily flow.

The model in equation (12) will provide evidence as to whether the variability in maximum daily flow is attributable to weather conditions, in particular through the significance of the weather variable and the fit of the model.

If the model shows that maximum daily flow is not explained by weather, another explanatory variable should be used. This should be chosen to reflect the underlying driver of the variability in maximum daily flow.

If that driver cannot be identified or if it can be identified but no suitable measure can be found, the recommended approach is to treat the variability as being purely random by estimating a 'constant only' model and applying the procedure from there.

10.3 Ratio analysis

An alternative to the regression and simulation approach is to analyse the variability in the ratio of maximum to average daily demand itself. In this approach AEMO would compute the ratio for as many years as the data allow in the forecast area. The ratio would then be regressed on average daily flow to produce a model as shown in equation (13).

$$\frac{MF}{AF_t} = m * AF_t + c + \varepsilon \quad (13)$$

Where MF is annual maximum daily flow, AF is annual average daily flow, t is an index of years, m and c are regression coefficients, and ε is an error term.

AEMO would then conduct a simulation exercise using either the standard error of the regression in equation (13) or the residuals from that regression to produce a distribution of ratios. The 1 in 2 and 1 in 20 ratios would be drawn from that distribution and applied to the forecast of gas consumption to produce forecasts of daily maximum flow.

11 Tracking actuals against forecasts

When it has produced forecasts, AEMO will also compare actual gas consumption to its forecasts. The procedure for doing this is discussed in this chapter.

11.1 Comparing actuals and forecasts

At a high level the procedure for tracking actuals against forecasts is relatively straightforward. It is simply a matter of obtaining data from the same sources as were used to produce the historical data for the relevant forecast area and comparing them to the forecasts.

The complicating factor is that the forecasts will be on a weather normal basis whereas the actuals will not. Therefore, the actual data must be weather normalised. This is done using the coefficient from the original forecasting model and the same weather measure.

Therefore, in an example where the chosen weather measure was HDD and the coefficient on HDD in the forecasting model was β , AEMO would calculate the difference between the normalised level of HDD and the number of HDD that were observed and multiply this by β . This would produce an estimate of the change in consumption due to weather conditions being non-normal. This estimate would be subtracted from (or added to) the observed consumption to produce an estimate of weather normalised actual consumption.

That estimate would be compared to the original forecast for the corresponding time period.

The key aspects of this procedure are that:

- the comparison must be made on a *like for like* basis using data from the same source that was used to prepare the forecasts in the first instance. This prevents discrepancies in data capture and measurement biasing the comparison
- the comparison must be made on a weather normalised basis.

While this is the best basis on which forecast and actual outcomes can be prepared, we caution that it would be unreasonable to expect that AEMO's gas consumption forecasts will match precisely with actual data when compared on this basis. The reason for residual discrepancies, which is discussed in section 11.2, is that this process does not account for differences that might occur between forecast and actual drivers of consumption.

11.2 Describing variance using drivers

As noted above, AEMO can, and should, periodically compare its forecasts with actual weather adjusted gas consumption in each forecast area. However, it should not expect that there will be no differences between the two.

The following is a list of factors that would reasonably be expected to cause differences between forecast and actuals, each of which is discussed below:

1. differences between actual and forecast drivers
2. intra-period effects
3. billing lag
4. averaging and other simplifications in the forecasting method

5. stochastic (random) aspects of consumption
6. unanticipated influences.

When all these factors are considered an appropriate target cannot be specified without analysing the data. It is likely that the appropriate target would vary between forecast areas.

11.2.1 Driver effects

The first source of difference between actual and forecast consumption is the projected drivers. The details will vary between different models in different forecast areas, but the forecast in each forecast area should actually be thought of as a conditional forecast. That is, AEMO would provide a forecast of gas consumption *on condition* that the drivers are as it expects. It follows logically from this that if the drivers differ from AEMO's expectations, gas consumption will also.

In a simplified example, AEMO may conclude that gas consumption in a particular area depends only on economic activity. It would forecast consumption using a model similar to that in equation (14).

$$\text{Gas consumption} = \alpha + \beta_1 \times \text{GSP} \quad (14)$$

In other words, AEMO has concluded that for every unit increase in GDP, gas consumption will increase by β units. It then produces a forecast by assuming that GSP will be at a given level. To illustrate, assume that AEMO expects that, in the relevant period, GSP will be G units. Therefore, AEMO concludes that, *on condition* that GSP is ' G ' units, gas consumption will be ' $\alpha + \beta_1 G$ ' units.

When AEMO comes to assess its forecasts, the actual level of GSP may not yet be known, but it will already have occurred. If GSP actually differs from ' G ', then AEMO would expect gas consumption to be different than it forecast as a result of that difference.

In practice, AEMO's forecasts will likely be based on its expectations for a range of drivers including economic activity, gas price, and population. Any of these drivers could—and in all likelihood will—turn out to have different values from those assumed by AEMO in the first instance, leading to differences between forecast and actual gas consumption.

11.2.2 Intra-period effects

The next factor that may lead to differences between actual and forecast gas consumption is also concerned with driver projections. However, unlike the issue discussed in section 11.2.1, this section assumes that the driver projection is correct (e.g. GSP actually turns out to be ' G ' units). This issue relates to timing.

The economic drivers that are likely to form the basis of AEMO's consumption forecasts are typically forecast on an annual basis. For example, GSP and population are typically forecast as 'year on year' growth rates. However, those forecasts do not imply that growth will be linear during the year.

For example, at the time of writing the Victorian Treasury forecast for GSP growth was 2.75 per cent per annum each year from 2014-15 to 2016-17.⁴³ It may seem overly simplistic to say so, but this amounts to a prediction that between 1 July 2014 and 30 June 2015 total economic activity in Victoria will be 2.75 per cent greater than it was in the preceding 12 months.

Importantly, this is not necessarily the same as saying that economic activity will increase by 2.75 per cent from the previous year in every, or in fact, any of the 12 months in 2014-15. Nor is it the same as a forecast that economic activity will increase by any particular amount between corresponding quarters.

However, when this growth rate is used in a linear projection model such as that described in this report, this assumption is made. This gives rise to the possibility of intra-period effects. A forecast can be higher than actual in one period and lower in another period and still correspond to actuals when both periods are considered together. If AEMO compares actual outcomes with forecasts over a shorter timeframe than the period of the drivers that were used to prepare the forecasts there is a risk that intra-period effects will distort the outcome.

11.2.3 Billing lag

Billing lag is discussed in section 3.2.1. Simply put, the accumulation meters used in the gas industry (and in much of the electricity industry) mean that the meter readings collected in a particular season relate to gas consumption that occurs substantially before that season. The result is that seasonal effects in particular will be difficult to observe in data that are broken down to the customer-type level. At more aggregated levels meter reading is more frequent, so billing lag is not present.

ACIL Allen expects that billing lag will prevent AEMO from being able to compare actuals with forecasts at anything other than the aggregate level. For example, while it may be reasonable to compare total consumption in a forecast area, it may not be possible to compare consumption by commercial or residential customers separately.

11.2.4 Stochastic (random) aspects of consumption

In making any comparison of actual and forecast outcomes, AEMO should remain aware that gas consumption, as with many other variables, has random characteristics. By contrast, forecasts are inherently 'central' predictions. They are based on various simplifying assumptions including averaging out many small influences. The regression models AEMO uses to 'fit' historical gas consumption to drivers include an error term, denoted ' ϵ ' in this report.

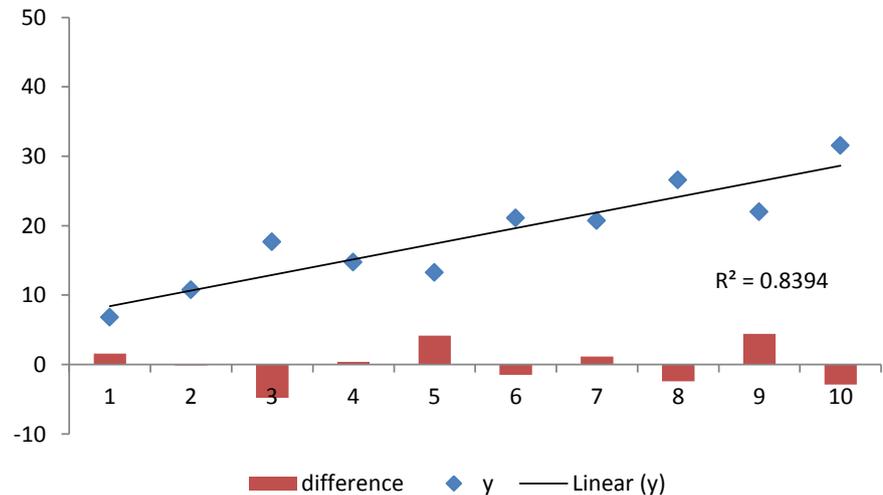
This term does not relate to error in the sense of mistakes made by the forecaster. Rather, it relates to error in the sense of a random (stochastic) disturbance.

It reflects the fact that actual gas consumption is the result of millions of small events. Some of those events are explained by variables that can be observed and measured, and these are accounted for in the regression models. However, other events are genuinely random.

⁴³ At the time of writing the 2014-15 Victorian Budget is imminent and the growth projection may change. This is noted, but is immaterial for present purposes.

In any regression model there are differences between the *actual* values and the fitted line, as illustrated in Figure 6, which uses simulated data that were created to illustrate the point that forecast accuracy can be strongly affected by pure randomness.

Figure 6 Illustrative regression model



Source: ACIL Allen Consulting

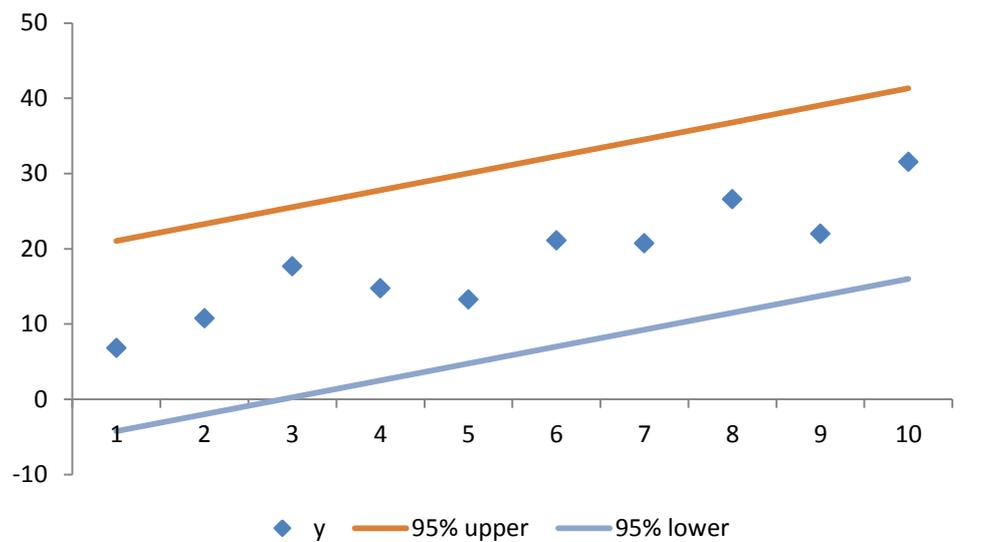
The basis of a regression model is that the *expected*, or most likely, value of the error term is zero. However, in any given case the actual value may not be zero. In fact the chances that the error will be zero are small.

In the example shown, the errors were generated randomly beginning with a linear function. Therefore, the model shown here is the best that can be used to forecast the results. The model shows a good fit, with the simple regression line explaining almost 84 per cent of variation in the blue data points. However, the errors range between -1 per cent (when $x=2$) and +31 per cent (when $x=5$).

A regression is accompanied by a standard error, which is a measure of how far the 'dots' fall from the 'line'. The standard error of the regression shown in Figure 6 is 3.16. This can be interpreted in a number of ways including that the analyst can be 95 per cent confident on the basis of this model that the actual value will fall within 6.32 units either side of the regression line.⁴⁴ This 95 per cent confidence interval is shown in Figure 7.

⁴⁴ That is, within plus or minus two standard errors of the regression line.

Figure 7 Illustrative 95 per cent confidence interval



Source: ACIL Allen Consulting

There is up to a 75 per cent difference between the outer limit of the confidence interval and the regression line.

11.2.5 Unanticipated influences

In addition to the sources of uncertainty listed above, the accuracy of AEMO's gas consumption forecasts will be limited by the effects of factors that were not known—and not knowable—at the time when the forecast was made. For example, if the government makes policy changes that have an effect within a given forecast period and those changes were unanticipated when the forecasts were prepared, the changes will cause discrepancies between the forecast and actual results. Similarly, if policies are known to be coming, but are not sufficiently well specified when forecasts are prepared to quantify their effect, the same result will be inevitable.

Other unanticipated influences may include the sudden closure of a large industrial facility resulting either directly or indirectly in a significant reduction in gas demand. For example, the decision by Penrice to close its South Australian soda ash operations in 2013 resulted in a reduced demand for steam from the associated Osborne co-generation plant, which in turn resulted in reduced gas demand at the Osborne facility.

Appendix A Alternative modelling approaches

This appendix provides a summary of each of the four different modelling approaches considered in this project and discussed in the options paper.

They are referred to as:⁴⁵

- the economic modelling approach – section A.1
- the econometric approach – section A.2
- the survey approach – section A.3
- the panel and appliance model approaches⁴⁶ – section A.4.

A.1 The economic modelling approach

The economic modelling approach to forecasting gas consumption has been used regularly to forecast gas demand by industrial customers. It is based on the fact that energy is an input to production and therefore energy demand is a function of economic activity.⁴⁷

Broadly, the approach is in two stages. First, a projection of economic activity in the region for which forecasts are required is prepared. Then, likely energy consumption is inferred from the economic projection using an output elasticity of demand for energy. This approach implicitly assumes that the energy intensity of economic activity in the future will be consistent with observations in the past.

This provides 'baseline' forecasts, which do not reflect changes in energy consumption attributable to policy factors. The baseline forecasts are adjusted to account for those factors as appropriate at a later stage.⁴⁸

The two stages are discussed in turn below.

A.1.1 Stage 1 – projection of economic activity

There are various methods for projecting economic activity, including input output analysis, computable general equilibrium modelling, and other approaches. A detailed comparison of these approaches is not necessary for present purposes.

The key issue in projecting energy demand using the economic modelling approach is that the economic projection needs to be suitably accurate and granular.

The importance of accuracy is self-evident. If the projection of economic activity is incorrect, then the forecast energy consumption will also be incorrect.

⁴⁵ It should be noted that the labels given to each approach are somewhat arbitrary. For example, the first three approaches could be described as econometric approaches and the first two (at least) could be described as economic modelling approaches. The labels are meant to simplify discussion and should not be interpreted as value judgements about one approach or another.

⁴⁶ The appliance model approach has not been used in recent regulatory proposals though it is widely discussed and is used for other purposes. It is included here for completeness.

⁴⁷ The economic modelling approach is equally applicable to modelling electricity consumption as gas consumption.

⁴⁸ Only policy impacts that are applicable to industrial energy users should be taken into account.

The reason that the economic projection must be granular is that it must capture differences in the energy requirement of different industries. To illustrate, consider an area where the economic activity consists (only) of financial services and cement manufacturing. In an area such as this an increase in economic activity might be due to growth in either:

- the financial services sector – in which case growth in energy consumption would be small
- the cement manufacturing sector, in which case growth in energy consumption would be substantial
- growth in both sectors, in which case growth in energy consumption would be moderate.

It is important that the economic projection is sufficiently granular to capture the different energy intensities of different industry sectors. It may also be appropriate to assign industries to tariff classes, though this depends on the detailed application.

A.1.2 Stage 2 – selecting the output elasticity

When a suitably granular projection of economic activity has been prepared, the next step is to select and apply output elasticities of demand for energy.

Conceptually, these are simply coefficients or weightings that convert economic activity (measured in dollars) into energy requirements (measured in joules).

However, in practice, estimating the output elasticity of demand for energy is a challenging and data-intensive process, especially if it is to be done at a localised level.

Conceptually there are two possible sources:

1. estimates based on data from the region for which forecasts are to be prepared
2. ABARES estimates (or similar), which are produced at a higher level.

A key issue in selecting the output elasticity of demand is that it must reflect the reality of the area for which forecasts are being prepared. Consider the example in the previous section of the two sector region. The cement manufacturing plant in the region in question might be fired either by coal or gas. Obviously if it was fired by coal, the output elasticity of demand for gas would be zero (or very low). The reverse is also true. While this is a simple example, the point is that the fuel that is actually in use must be reflected by the output elasticity of demand that is chosen.

A.1.3 Pros and cons of the economic modelling approach

The key advantage of the economic modelling approach is that the vast majority of the data required to implement it can be obtained from public sources. Economic models are extremely complex and require a large quantity of input data. That data is broadly in two categories, namely:

1. input output tables
2. elasticities.

Most of the data necessary to produce input output tables is readily available from public sources such as the ABS. This is a significant point in favour of this approach. However, this is partly offset by the fact that the necessary elasticities are typically very difficult to observe. In practice they are strongly exposed to the judgement of the individual forecaster.

However, in our view there are a number of disadvantages associated with the economic modelling approach. Several of these relate to the very complex nature of the models.

The first disadvantage is that developing and maintaining an economic model is a substantial task in itself requiring highly specialised knowledge and expertise. Several models are in use in Australia.⁴⁹ However, it would be a very large and costly task for AEMO to develop and maintain its own economic modelling capability in-house. Therefore, if AEMO was to adopt an economic modelling approach it would most likely have to outsource a substantial part of the modelling.

The need to outsource modelling is not, in itself, a reason to avoid the economic modelling approach. If this approach was the best way to forecast gas consumption, then the need to outsource should not stand in the way. However, adopting the economic modelling approach through outsourcing would tend to make the forecasting process substantially less transparent, which is contrary to AEMO's objective to establish a transparent methodology that allows the impact of each driver on consumption to be understood.

As noted above, economic models are complex and represent a substantial amount of intellectual property. For these reasons, forecasts that are prepared using economic models are often accompanied by very limited information regarding the forecasting methodology and inputs. This is in contrast to the first of the principles for best practice forecasting identified in section E.2.2 and as such is a negative of this approach. This is especially significant to the extent that the output elasticities are withheld from scrutiny as these are critical to the projection.

A second consideration of using this approach, as alluded to at the start of the section, is the implicit assumption that output elasticities, which are derived from historical relationships, will remain the same for the projection period. Whilst this assumption may have been valid in the past, increasingly in Australia with rising energy costs, the ways in which energy is being used, and business drivers for energy efficiency, is resulting in changes to relationships. The changes can occur at various levels:

- intensity of overall economic activity (e.g. gas use per \$m of GSP/GDP)
- intensity of industry sectors (e.g. gas use per unit output in cement manufacturing)
- intensity of specific activities within sectors (e.g. industrial boiler efficiencies or household appliance efficiencies).

Increasing gas costs to businesses over the next few years—the likes of which have not been experienced before—are likely to reveal the underlying elasticity of demand for gas and also the cross-elasticity of substitute products (such as coal for steam raising in industrial settings or reverse cycle air conditioning for heating purposes within households). Forecasts which rely on historical relationships are likely to over-estimate gas consumption as households and businesses make consumption and equipment decisions based on substantially altered financial trade-offs.⁵⁰ To account for these changing dynamics the output elasticities themselves must be projected forward on some basis.

A.2 Econometric approach

The econometric approach attempts to identify the key economic and demographic parameters that drive energy consumption and to establish a statistical relationship between these parameters and energy consumption.

⁴⁹ One is operated by Monash University's Centre of Policy Studies. Others are maintained by various private sector consultancies including ACIL Allen.

⁵⁰ Note that these effects are quite different to the artificial effects resulting from policy decisions.

In doing this, the forecaster can incorporate their views (or the views of other experts) on the future course of these drivers into the forecasts. The economic modelling approach also does this, though different methods are used.

A.2.1 Overview of the econometric approach

The econometric approach is in four steps (to the baseline forecast stage), namely:

1. collect and process the necessary data
2. specify and estimate models
3. test and validate models
4. produce baseline forecasts.

As with the economic modelling approach, the baseline forecasts are then adjusted to account for policy changes.

The four steps are discussed in turn below.

Data collection and preparation

The econometric approach draws on the following two categories of data:⁵¹

1. historical consumption data, disaggregated:
 - a) spatially, to the level at which forecasts are to be prepared
 - b) functionally to relevant customer types, e.g. residential, commercial, industrial, power generator.
2. Data pertaining to historical drivers, which must also be disaggregated spatially to the level at which forecasts are to be prepared. Selecting the drivers to use is an empirical question that is addressed at a later stage. Drivers are likely to include:
 - a) economic activity
 - b) population
 - c) gas price
 - d) appliance uptake.

Appropriate steps must be taken to ensure the veracity of the data to be used. For example, data should be collected from published and verified sources where possible.

Some data processing may be required. For example it may be necessary to account for changes in network configuration if spatial forecasts are to be prepared. In other cases it may be necessary to impute missing data.

Model specification and estimation

When suitable data sources have been identified and the data collected and processed, the next step is to identify the econometric models that will drive the forecasts.

This is an empirical process of hypothesising the relationship between energy consumption and its drivers, and testing that relationship using regression techniques. In general terms, regression models are run with each candidate driver to find the combination of variables, lags, and functional forms that provides the best fit to the consumption data.

⁵¹ Historical weather data is also required.

This approach is typically done with data that have been disaggregated functionally. This allows different drivers to be used for different types of customer. For example, it is common to see residential consumption models that incorporate population, and commercial models that incorporate economic activity.

Regressions would normally be estimated using the ordinary least squares method which minimises the sum of squared vertical distances between the observed responses in the dataset and the responses predicted by the regression equation.

Produce baseline forecasts

The econometric models that have been specified and statistically validated in the previous steps in the forecasting process will form the basis of the baseline energy demand forecasts.

To generate the baseline forecasts from the calibrated models, it will be necessary to obtain forecasts of all the input variables used in the regressions.

The baseline forecasts are later adjusted to account for policy changes.

A.2.2 Pros and cons of econometric approach

The pros and cons of the econometric approach are approximately the reverse of the economic modelling approach.

The most important input for the econometric approach is a historical time series of the quantity to be forecast, in this case gas consumption. The length of the time series required depends on the complexity of the model and other factors, but at least five or 10 years of history would be required in most cases.

Collecting the required data may be a significant practical challenge for this approach. While AEMO has access to detailed historical consumption data in Victoria, we understand it has much more limited data for other regions. While the necessary data have most likely been collected, we expect that they are held by network businesses. It may be impossible for AEMO to apply the econometric approach without the cooperation of network businesses in providing the necessary data.

On the other hand, the econometric approach to forecasting gas consumption has the advantage that it can be made highly transparent. Modelling can be done using spreadsheet software such as Microsoft Excel and assumptions can be made explicit. This also makes sensitivity testing relatively straightforward.

Econometric techniques suffer from some of the same flaws as highlighted with economic models in the previous section in that they rely upon historical relationships. In situations where these relationships may change due to a step change in the price of gas, prices of substitute products, or other 'shock', such models will likely fail to accurately predict gas consumption until sufficient historical data becomes available under the altered environment.

A.3 Survey approach

In many situations a relatively large proportion of gas is used by a relatively small number of customers.

These are often industrial customers with relatively stable consumption profiles and with detailed knowledge of their future plans to expand or contract and, therefore, to increase or reduce their gas consumption. The lumpy nature of this type of consumption makes it difficult to forecast accurately using any of the methods described above.

Typically, forecasts of gas consumption by customers in this segment are based on analysis of the individual customers (both existing and proposed). That analysis may be based on surveys or on monitoring media and other sources for information about expansion or contraction plans.

Methodologically the forecasting approach is simple. It involves identifying major gas users and prospective gas users, and asking them for their expectations regarding their gas consumption in the forecast period. Of course there are challenges with securing responses as well as with the uncertainty and/or reliability of the answers that are received.⁵² For prospective users, one needs to determine the likelihood of plans coming to fruition.

The survey approach has been used widely as a supplement to other approaches. It is not presented here as more than this. However, in our view it can potentially be a useful supplement that should not be overlooked. In some cases, such as for very large users, and small power stations⁵³, it may prove to be the only viable method.

A.4 Panel and appliance model approaches

A.4.1 Panel approach

The panel approach to forecasting gas consumption is conceptually similar to the econometric approach. Both approaches:

- rely on actual historical data concerning gas consumption
- identify drivers of gas consumption
- estimate statistical relationships between consumption and those drivers
- use projections of the drivers and estimated relationships to produce forecasts.

Both methods could be used in the form of a single model of consumption by a class of customers, or as separate models of customer numbers and average consumption.

The key difference between the two approaches is in the level of aggregation. The econometric approach uses data that relate to all customers in a class, for example all residential customers. By contrast, the panel approach uses data that relate to individual customers where appropriate.

⁵² Regardless of customers' willingness to respond to surveys, there will always be uncertainty as to whether their expectations are correct. This may be because they simply cannot be sure or for other reasons, such as their unwillingness to offer pessimistic forecasts which might be interpreted and applied to their business for other purposes, such as by potential investors.

⁵³ Note that power stations generally are outside the scope of the methodology discussed here. AEMO will continue to forecast gas requirements for power generation as it has done in the past.

Therefore, a panel model of gas consumption by residential customers might take account of the following factors, each of which could change over time:

1. the size of each household, which could be measured as number of residents, number of rooms, or house area
2. the type of each dwelling, for example whether it is detached, semi-detached or an apartment
3. the retailer from which each household buys gas
4. the price each household pays for gas
5. the timing of when each household connected its gas supply (i.e. the household's cohort)
6. the income of each household
7. economic activity in the household's area
8. temperature conditions in the household's area.

Therefore, the panel approach can take account of drivers of consumption that apply differently to individual households. In contrast, the econometric approach cannot; in effect it treats all customers as the same, at least on average.

Appliance model approach

The appliance model approach begins with the various appliances for which gas is used. Essentially the approach is to estimate the number of appliances that will be in place during the forecast period and their average gas use. This is usually done on a household-by-household basis, and is used to assemble a forecast of total gas consumption.

The appliance model approach has the advantage that it allows changes in gas consumption that might be achieved by changing appliances. Therefore, it is often used to estimate the impact of energy efficiency and similar policies. However, it is a highly data-intensive exercise that would need to be calibrated to a total consumption level before it would be suitable for the type of forecasting required of AEMO.

A.4.2 Pros and cons of panel and appliance model approaches

The panel approach is a particular form of the econometric approach. The key difference between the two is the detailed level at which the data must be collected. In our view it is very unlikely that AEMO would be able to assemble a sufficiently detailed dataset (at least initially) to conduct a panel-based approach to modelling gas consumption in any significant part of the network.

Similarly, the appliance model approach is extremely data-intensive, requiring data regarding the stock of appliances in use in certain areas, which must be collected by surveying or similar approaches.

In our view neither of these approaches is likely to meet AEMO's requirements in forecasting gas consumption at the network or whole market level.

Appendix B Summary of stakeholder feedback

Stakeholder Comment	Stakeholders	AEMO Comment
Why are forecasts being brought in-house?		
<p>Why is AEMO looking to bring this capability in-house and why were stakeholders not consulted on this decision?</p> <p>Forecasting industrial gas consumption and maintaining Computable General Equilibrium (CGE) models is not easily done or capability easily acquired. There is concern over impact on market fees to participants.</p>	AGL, Lumo Energy	<p>Forecasts are being brought in-house to increase transparency and to better service the industry. AEMO's cost-benefit analysis showed that engaging a consultancy firm to provide dynamic and responsive forecasts would incur a greater cost in the long-term than bringing modelling in-house.</p> <p>AEMO considered various options prior to the decision to bring forecasts in-house. A cost-benefit analysis was undertaken on each option. This analysis indicates that estimates of the long-term cost of developing in-house forecasts is comparable to the cost of the current approach of outsourcing, but that bringing forecasts in-house would result in additional benefits such as dynamism, increased transparency and responsiveness.</p> <p>Economic assumptions will continue to be outsourced, as they have been in the past, giving rise to consistent assumptions across gas and electricity forecasting and reducing the need to acquire capability in this area.</p>
Forecast purpose – why is AEMO undertaking this work?		
<p>What is the purpose of the forecasts – particularly the point on “enabling decision making” – what decisions are AEMO looking to make? Is there evidence that industry lacks the information or the ability to gather the information themselves?</p> <p>Ensure that the purpose of the forecasts is clearly stated.</p>	DEWS, Envestra, ENA	<p>AEMO is required under the National Gas Law (NGL) to complete gas forecasts for the Gas Statement of Opportunities (GSOO). AEMO's reliance on third-party consultants for these forecasts creates issues in responding to questions promptly, investigating sensitivities and building understanding.</p> <p>In order to overcome these issues, AEMO is seeking to produce transparent modular forecasts in which market participants can pick and choose components they are confident in, and use for their own forecasts where they believe the AEMO approach is inferior to internally developed forecasts.</p>
AEMO has no input on gas market operation, therefore why is AEMO undertaking this task?	TasGas Networks	

Stakeholder Comment	Stakeholders	AEMO Comment
Is AEMO attempting to get into matters associated with economic regulation of networks?	Envestra	<p>AEMO's objective is to increase transparency and provide better information for industry decision making and reference.</p> <p>AEMO already publishes forecasts of gas demand in the GSOO. This process relates to improving these forecasts.</p> <p>ACTION: AEMO to ensure that the purpose and basis for the forecasts are clearly stated in the methodology paper.</p>
How does industry use AEMO's forecasts?		
<p>There are benefits in having an agreed common, transparent and respected view as a basis for forecasting, giving a better foundation for policy formulation etc.</p> <p>AEMO has a reputation for being independent and reputable. Once forecasts are published they will be used for applications for which they were not necessarily intended.</p> <p>AEMO forecasts are often used by networks as a cross-check against their bottom up forecasts (marker for reconciliation of growth rates).</p>	Various	Noted and these points will be considered as part of our preferred approach to forecasting.
<p>Forecasts of gas consumption are used to support decision making on gas and capacity procurement, access arrangements, strategy and pricing and asset development.</p> <p>Having information available allows for easier market entry.</p>	Lumo Energy	
<p>Transmission businesses are primarily concerned with the contracted volumes as opposed to actual flow and therefore do not greatly rely upon AEMO forecasts. The current aggregated forecasts provided in the GSOO are adequate.</p>	Jemena	

Stakeholder Comment	Stakeholders	AEMO Comment
Forecast components, timeliness and bias		
Why are forecasts for Gas Power Generation (GPG) and Liquefied Natural Gas (LNG) not part of this process? Are interactions between market sectors not being considered?	EUAA	AEMO develops forecasts of GPG and LNG and these forecasts will be presented in the National Gas Forecasting Report (NGFR). Supply to meet all demand segments will be modelled in the GSOO. The approach for forecasting GPG and LNG will be published in mid-2014.
Unaccounted for gas (UAFG) should be included in forecasts.	Various	ACTION: Forecasts to include UAFG.
Will industry get a chance to review LNG forecasts prior to finalisation?	APPEA	<p>Forecasts of LNG production and associated gas and electricity consumption are being developed by a consultant in 2014. These forecasts, and associated assumptions and methodology, are released in the NEFR in June 2014, with updated forecasts released in the NGFR (December 2014).</p> <p>AEMO is currently giving LNG project proponents the chance to give feedback on forecasts and discuss commercial sensitivity of these forecasts.</p> <p>Any comments on the forecasts released in the NEFR will be considered as part of the update for the NGFR.</p> <p>ACTION: A report detailing LNG forecasts will be released with the NEFR in June 2014. Stakeholders can review these forecasts and provide feedback to AEMO before the update of forecasts for the NGFR.</p>
LNG forecasts should be provided in quarterly (or even monthly granularity) due to the large rate of change in the segment expected over the next few years.	EnergyAustralia	ACTION: AEMO to consider developing and publishing LNG related forecasts on a quarterly or monthly basis during the ramp-up phase, having consideration for any confidentiality concerns.
The GSOO is out of date upon release. Forecasts would preferably be live and dynamic. Ideally a methodology would support a 5-year outlook updated weekly.	EUAA	<p>AEMO acknowledges the limitations of an annual release of long-term forecasts. AEMO's primary objective this year is the development and external validation of its models and forecasts.</p> <p>ACTION: In 2015, AEMO will consider release of periodic updates to its medium-term forecasts and the development and release of short-term forecasts for gas.</p>
Are AEMO's forecasts likely to have an upward bias as a result of the GSOO having a focus on supply adequacy? This bias could have significant flow on impacts to economic regulation if AEMO's forecasts are relied upon by the Australian Energy	Envestra	AEMO is assessed by its Board on the performance/accuracy of the forecasts it releases across gas and electricity.

Stakeholder Comment	Stakeholders	AEMO Comment
Regulator.		The objective of the GSOO is to enable efficient investment decision making.
Tasmania is not a regulated network and therefore potentially did not need to be part of this process/approach.	TasGas Networks	Whilst Tasmania is not regulated, it is part of the interconnected network and therefore it is important to consider Tasmania in the forecasts.
A consumption range may be superior to just offering a single forecast trajectory. Producing an indicative range will highlight the uncertainty.	Various	In 2014 AEMO intends to produce three scenarios for gas consumption. ACTION: AEMO to investigate the development of confidence intervals.
Preferred segmentation for forecasts is: Residential, 10 terajoules per annum, tariff V, commercial and industrial and large industrial. Data available at an average site size level with forecasts of population (household/business number) available.	Lumo Energy	Segmentation of forecasts will be determined by stakeholder requirements as well as the resolution of underlying data available. ACTION: Segmentation may depend on data availability and confidentiality concerns. This will be discussed further at the data session (see pages 4 and 5).
The forecast must be presented in such a way as to allow it to be assessed against actual current and historical data. (Noting that the Gas Bulletin Board (GBB) is currently being reviewed, it is sufficient for the NGFR forecasts to be comparable against historical GBB data on a somewhat aggregated basis).	EnergyAustralia	AEMO agrees that it is paramount to be able to track forecast performance and balance this with the amount of data requested from participants. ACTION: AEMO to clearly state how GBB data fits with the NGFR forecasts and how this data can be used to track forecast performance.
Data input		
<p>Several comments were made referencing input data requirements. More specifically:</p> <ul style="list-style-type: none"> • What data would AEMO need and would this be an additional cost to businesses? • Data may be commercially sensitive. • What data does AEMO already have access to? • Could AEMO complete the work in stages, starting with using data from the main gas 'capillaries'? • Will AEMO source data from upstream producers? • Could a rule change be implemented forcing companies to report to AEMO when demand is expected to be different to forecast demand? 	Various, including ENA, APA, EUAA, Jemena	<p>AEMO is very mindful of the burden of data collection and will work with industry to establish a balance between confidentiality, practicality and needs.</p> <p>AEMO will coordinate a separate session with stakeholders to address:</p> <ul style="list-style-type: none"> • What AEMO already has access to. • What can be obtained through other agencies. • What additional data can be obtained from businesses. • What data gaps exist and how can these be filled. <p>Work done to date indicates that AEMO will likely have to continue to source data from stakeholders, as per previous years.</p>

Stakeholder Comment	Stakeholders	AEMO Comment
<p>Note that there are constant corrections and adjustments to end-user accounts and some data may not be available.</p> <p>Data would be available for Transmission Network Service Provider connection points along main transmission pipelines. Some investment may be required for AEMO to hook into network business systems to facilitate automatic acquisition of data; may be confidentiality issues with acquiring this data.</p>		<p>There may be a difference between the data AEMO acquires and uses to develop the forecasts versus the level of detail which is published in order to protect confidentiality.</p> <p>ACTION: AEMO to coordinate a separate session on data.</p>
<p>It was noted during the workshop that the Standing Council on Energy and Resources is looking at issues of information disclosure by energy companies and noted that State Governments have wide ranging information gathering powers already.</p>	DEWS	
<p>The data requirements for each of the proposed approaches should be made available for review to assist in determining the approach.</p>	ENA	<p>Data requirements to be discussed at the data session with stakeholders.</p>
Demand drivers and assumptions		
<p>Forecast should be accompanied by drivers (both upward and downward) which would result in material changes to any central case to assist with forecast longevity and reputation.</p> <p>AEMO should focus on the big impact drivers first: e.g. climate change is not a big factor, yet is sometimes overrepresented in forecasts.</p> <p>Assumptions need to be clearly thought through, researched and stated.</p>	Various	<p>Noted and these points will be considered as part of our preferred approach to forecasting.</p>
<p>Gas prices are a key input into demand forecasts. How are these assumptions derived and can stakeholders have the opportunity to review?</p> <p>There are a range of prices in play at any one time – how will AEMO deal with this uncertainty?</p> <p>Expected large price rises in the market are likely to change the market relative to historic gas consumption patterns. History is not going to be a good guide.</p>	Various, including DEWS, ENA	<p>Assumptions of gas price are developed by a consultancy firm (Frontier Economics this year). Frontier is developing three price scenarios for various customers in each region, in order to capture the uncertainty associated with gas price trajectory.</p> <p>Price elasticity, in particular customer responses to large increases in price unlike those seen historically, is currently being researched by AEMO.</p>

Stakeholder Comment	Stakeholders	AEMO Comment
A key changing trend in the market is cross-price elasticity effects (for example reverse cycle air conditioning).		ACTION: A report detailing the assumed economic outlook including gas price will be released with the NEFR in June 2014. Stakeholders can review and provide feedback to AEMO.
<p>We request that AEMO consult with the public on the methodology used to develop the gas prices. This should occur prior to the gas prices being modelled so that focus is on the methodology rather than the final price outcomes and would ideally include the consultant undertaking the gas price modelling. We believe this consultation is important within the NGFR process as gas prices will be pivotal to both gas and electricity demand outturns in the next few years.</p> <p>Consistency between the underlying gas prices and gas demand forecasts is necessary for forecast integrity. We understand that this may not be fully achieved due to time limitations within the first NGFR, but should be actioned for following NGFRs.</p>	EnergyAustralia	<p>ACTION: The development of gas price forecasts for 2014 has already been completed. The consultant has agreed to provide interested stakeholders with a workshop on the methodology. AEMO will be in contact in the near term to gauge interest in the workshop and suggest timing. Additionally, the approach will be published in the Economic Outlook in June 2014. Any feedback on the methodology will be incorporated in the 2014 NGFR (where possible) or in the 2015 process.</p> <p>AEMO agrees that consistency between the underlying gas prices and gas demand is important and will look at implementing this in future NGFRs.</p>
Equivalent Effective Degree Day (EDD) factors for other regions aside from Victoria would be useful to some although not all that critical for consumption forecasts (more a factor for maximum demand).	Various	<p>AEMO will look at developing EDDs for regions other than Victoria for the 2015 NGFR.</p> <p>ACTION: AEMO to consider developing and publishing EDDs for other regions in 2015.</p>
Residential demand is also driven by policy impacts such as building codes and a shift to solar hot water systems.	Various including DEWS, ENA	<p>AEMO's objective is to identify changing trends and the impact of policy and implement these into forecasts. This may need to occur via post-model adjustments.</p> <p>As part of the NEFR work, AEMO is already developing solar and energy efficiency models. Learnings and results from this work will be implemented in the NGFR.</p> <p>ACTION: AEMO to ensure that policy impacts are considered in forecasts.</p>
All terms and assumptions must be unambiguously defined for the forecasts. In particular, clarity is required concerning pipelines where there are major suppliers/demands located along the pipeline and not just at end points of the pipeline.	EnergyAustralia	ACTION: AEMO to ensure that terms and assumptions are clearly defined in the NGFR.

Stakeholder Comment	Stakeholders	AEMO Comment
Comments on the forecasting approach		
<p>Forecasting techniques should:</p> <ul style="list-style-type: none"> • Match the purpose of the study: GSOO purpose is to identify constraints for pipelines and production. • Be transparent and relatively simple. • Be able to be tracked. • Rely upon data and assumptions that are made available to participants. 	Various including Lumo Energy	Noted and these points will be considered as part of our preferred approach to forecasting.
<p>A robust forecasting process must take into account the major demand drivers, noting that these vary according to segment and/or industry type. To achieve this, finer segmentation of the commercial and industrial market may be required in some specific cases (for instance, smelting, the automotive industry etc.), perhaps based on Australia New Zealand Standard Industrial Code (ANZSIC). In addition, this may allow a high level appliance/panel approach to be applied to some segments of commercial and industrial demand.</p>	EnergyAustralia	Noted and these points will be considered as part of our preferred approach to forecasting.
<p>Comments relating to the survey approach:</p> <ul style="list-style-type: none"> • EUAA has experience in surveying its own membership regarding gas use and had found it proved difficult in some cases to get specific company energy data due to commercial sensitivity. Commercial sensitivity of information and data in the survey approach may limit its success. • Need to be clear on questions when surveying users. • Industrial load closures will results in big changes in the near future. Need to engage with business one-on-one, however some are quite small. For example, car part manufacturers that are individually quite small, but that in aggregate represent a significant level of demand. 	Various including the EUAA, DEWS	<p>AEMO already holds one-on-one interviews with large industrial customers for the NEFR.</p> <p>AEMO agrees that questions need to be framed appropriately to glean meaningful information and that particular at-risk sectors may need to be targeted.</p>

Stakeholder Comment	Stakeholders	AEMO Comment
<p>Comments relating to the appliance/panel approach:</p> <ul style="list-style-type: none"> • Has the ability to pick up changes in technology and efficiency of key products as well as changes in consumer behaviour and policy interactions. • Can work at the residential level, however assumptions need to be clearly stated and regularly reviewed. In situations where data is scarce, assumptions are even more critical. • Targeted application of panel/appliance approach could work, however care would need to be taken to correctly back out from historical figures. 	<p>Various including Origin, ENA</p>	<p>Noted and these points will be considered as part of our preferred approach to forecasting.</p>
<p>Comments on the econometric approach:</p> <ul style="list-style-type: none"> • This approach is used extensively throughout industry, and is generally transparent, however post-model adjustments can reduce transparency and simplicity. • Major market adjustment occurring at present in relation to price: history is not going to be a good guide. 	<p>Various</p>	<p>Noted and these points will be considered as part of our preferred approach to forecasting.</p>
<p>Comments on the economic approach:</p> <ul style="list-style-type: none"> • Generally very complex and lacks transparency. • Forecasting industrial consumption and maintaining CGE models is not easily done or capability easily acquired. • Can be useful for measuring the impact of a change in a variable as opposed to a specific trajectory. 	<p>Various</p>	<p>Noted and these points will be considered as part of our preferred approach to forecasting.</p>
<p>Recommended approach:</p> <ul style="list-style-type: none"> • Gas consumption forecasting is a challenging and involved process. No single methodology will provide a high quality forecasts. For this reason it supports a multi-faceted approach. • Forecast horizon is important with respect to choice of approach. Longer terms will not be well described by any method which relies on time series analysis/extrapolation. • Combination of econometric, survey and appliance may be appropriate. 	<p>Various including ACIL Allen, Lumo Energy, EnergyAustralia</p>	<p>The NEFR incorporates a staged approach, with learnings to improve the forecasts noted and implemented in subsequent reports. A similar approach will be used for the NGFR.</p> <p>AEMO will seek to appoint a peer reviewer on the forecast model once complete and take peer review comments/advice into account for subsequent year's efforts. Peer review likely every 2-3 years rather than every year.</p> <p>ACTION: AEMO to ensure that assumptions are clearly stated.</p>

Stakeholder Comment	Stakeholders	AEMO Comment
<ul style="list-style-type: none"> • Post-model adjustments are important and are likely to be required, however too much adjustment can invalidate the primary model and render it useless. • A staged approach where improvements are implemented each year is understood and accepted. 		
Next steps		
What are the next steps with regards to the methodology development?	Various	<p>AEMO will publish the full methodology by 30 June 2014. AEMO to set up a workshop with stakeholders before publication.</p> <p>ACTION: AEMO to set up methodology workshop with stakeholders.</p>

Appendix C Background – the eastern and south-eastern Australian gas market

This chapter provides an overview of the eastern and south-eastern Australian gas market, its structure, and operations. The overview includes the role of long-term bilateral contracts and short-term and spot trading markets.

The functions and operation of the Gas Bulletin Board (GGB) are summarised, and the proposed definition and treatment of regional bulk supply points is discussed. Further background information is provided on the different categories of gas customer, the layout and operation of gas networks, gas metering, and the tariffs charged by transmission and network service providers for providing gas transport and delivery services.

C.1 Overview of the eastern and south-eastern Australian gas market

C.1.1 Market definition

The eastern and south-eastern Australian gas industry is taken to encompass all natural gas suppliers and users in:

- the Australian Capital Territory
- New South Wales (NSW)
- Queensland
- South Australia
- Tasmania
- Victoria.

Western Australia and the Northern Territory are not included in the eastern and south-eastern Australian gas market.

C.1.2 History

The natural gas market in eastern and south-eastern Australia began to emerge during the 1960s and 1970s with the construction of transmission pipelines linking major cities to gas fields:

- Brisbane to the Roma/Wallumbilla fields in the Surat Basin (1969)
- Melbourne to Gippsland Basin fields (1970)
- Adelaide to Cooper Basin/Moomba (1970)
- Sydney to Cooper Basin/Moomba (1975).

These cities already had established distribution systems for reticulation of artificial 'town gas', which is manufactured from coal. Town gas was replaced by natural gas once the pipelines were built.

Through the 1980s and 1990s these remained physically separated 'point to point' systems, although new pipelines were built to supply gas to established industrial centres such as Mount Isa and Gladstone.

From the late 1990s, interconnecting pipelines began to link the separate systems together forming an interconnected network system (Victoria – NSW Interconnector 1998; Longford – Sydney 2000; Longford – Hobart 2002; Iona – Adelaide 2004).

The final ‘missing link’ joining the Queensland system in the north with the South Australian and New South Wales systems in the south was made with the construction of the QSNLink pipeline, from Ballera to Moomba, which was commissioned in 2008.

The evolution of the eastern and south-eastern Australian gas market was facilitated by changes in the regulatory environment through the 1990s which saw the removal of barriers to interstate trade in gas, and competition policy reforms that provided for third-party access to gas transmission and distribution systems on non-discriminatory terms.

C.1.3 Market operation

Upstream gas exploration and production

Natural gas exploration and production in Australia is a private sector activity. Australian governments are not directly involved in upstream petroleum exploration or production.

Petroleum exploration and production activities, both onshore and offshore, are undertaken by Australian and foreign companies.

Midstream

Australia has over 25,000 km of high pressure steel gas transmission pipelines transporting almost 1,300 PJ of gas every year. Under Australian gas law, transmission pipelines may be subject to economic regulation because they have natural monopoly characteristics. However, the major demand hubs in eastern and south-eastern Australia are now supplied by competing pipelines. As a result, most gas transmission pipelines in eastern and south-eastern Australia are no longer subject to economic regulation.

Downstream

A total of approximately 81,000 km of distribution pipelines supplies natural gas to more than 3.9 million households and businesses across eastern and south-eastern Australia.

These gas distribution networks are owned and operated by several different distribution businesses, some of which also have electricity network assets and operate in multiple jurisdictions. Gas distribution systems in Australia are generally subject to economic regulation.

The size of retail gas markets relative to the total market varies greatly from state to state. In Victoria and NSW, most gas is sold at a retail level with only small quantities sold at wholesale level to large industrial consumers and electricity generators. On the other hand, Queensland—and to a lesser extent South Australia—have more large mining, industrial, and electricity generation customers, and relatively small retail sectors.

Wholesale contract market

Most gas is sold under long-term, bilateral, wholesale contracts between gas producers and retailers/aggregators or directly to large end-users (industrial facilities such as fertiliser manufacturers and minerals processing plants, and electricity generators).

Historically, Gas Sales Agreements (GSAs) were often long-term arrangements with 20-year contracts being the norm. More recently there has been a trend to shorter-term contracts of three to five-year duration. However, financing of large gas-consuming facilities may still require security of supply under a long-term GSA.

Detailed terms of GSAs are typically commercial-in-confidence. Governments (state and Federal) typically have no access to contract terms.

Gas pricing under long-term contracts

Gas prices under long-term GSAs are determined by commercial negotiation between parties and reflect market circumstances. Governments have no role in setting or approving wholesale gas prices.

For the past 40 years gas prices in Australia have been low by international standards, reflecting regionally isolated markets and the availability of low-cost alternative energy sources, particularly cheap coal. Nevertheless, prices vary widely from contract to contract, reflecting market circumstances at the time the contract is made as well as different risk allocations, rights, and obligations of the buyer and seller.

Between now and 2020, more than half of the current long-term GSAs in eastern and south-eastern Australia will expire. With the establishment of large LNG export facilities in Queensland, the availability of gas to enable these contracts to be renewed is coming under considerable competitive pressure. LNG projects are now entering the market, buying large volumes of third-party gas to bolster their own sources. As a result domestic gas buyers are finding that producers are demanding higher prices for new long-term supply contracts—up to LNG netback⁵⁴—with prices directly linked to the price of oil. This represents a major shift from the pricing mechanisms that were prevalent under older GSAs, which were linked to consumer prices.

Spot and short-term trading markets

Spot markets currently play a limited role in the Australian gas industry. ACIL Allen's understanding is that the spot markets that do exist have limited liquidity, with most gas sales still underpinned by GSAs. However, the importance of spot and short-term trading markets is increasing. The evolving role of spot and short-term trading markets is discussed further below.

Victorian DWGM and DTS

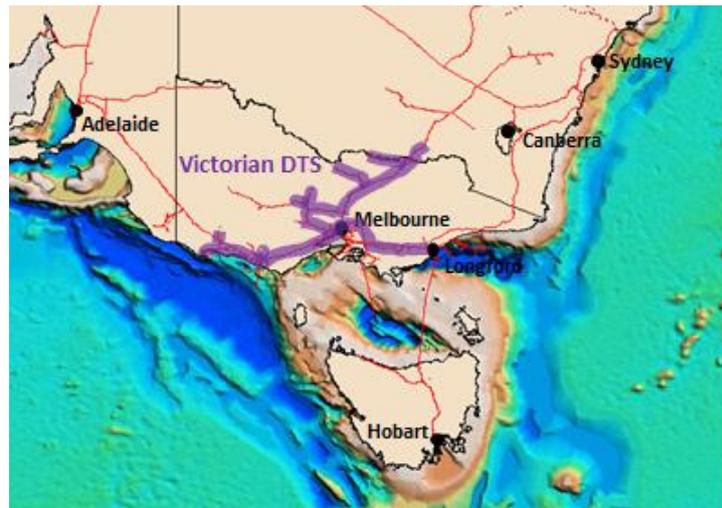
In Victoria there are two notable sub-sectors of the wholesale gas market.

The Declared Wholesale Gas Market (DWGM) has operated since 1999. Operation of the DWGM is governed by a set of processes, responsibilities, and obligations in Chapter 19 of the National Gas Rules (NGR).

The area within which the DWGM operates is shown in Figure C1.

⁵⁴ That is, the price of liquefied natural gas (LNG) minus the costs of shipping, liquefaction and pipeline transport incurred between the LNG customer and the gas producer.

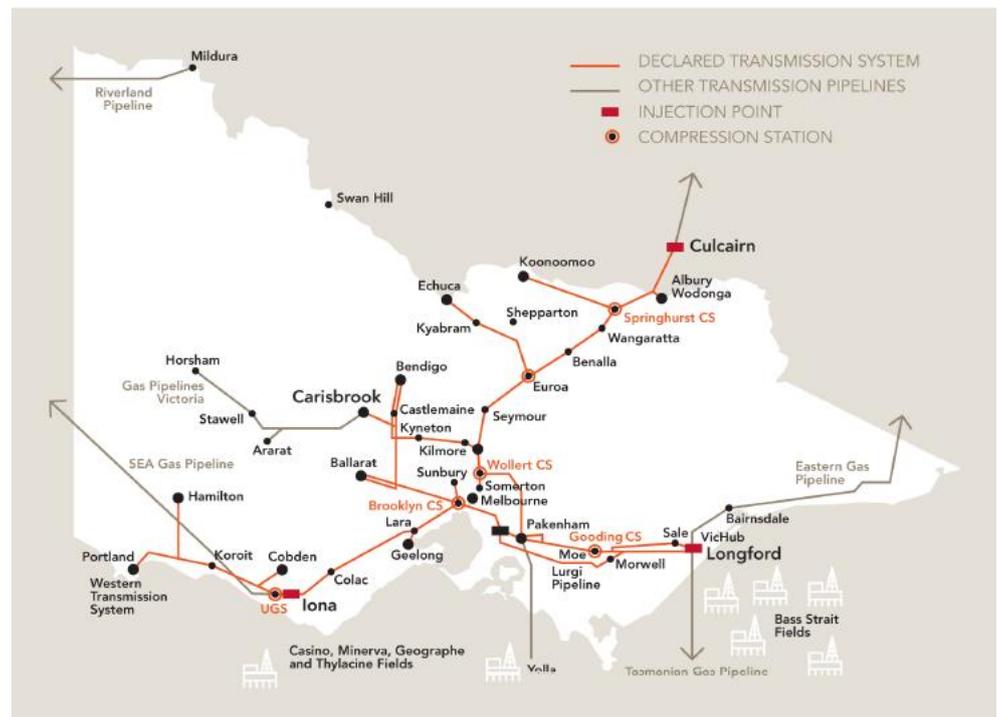
Figure C1 Location of the Victorian Declared Transmission System



Source: ACIL Allen Consulting; base layer from GPInfo.

The Victorian Declared Transmission System (DTS) is the system of high-pressure gas transmission pipelines that supports the operation of the DWGM. The pipelines and associated facilities that form the DTS are shown in Figure C2.

Figure C2 Victorian gas pipelines



Source: (AEMO, 2012)

The major DTS pipelines are:

- Longford to Melbourne pipeline
- South West Pipeline from Iona to Brooklyn (SWP)
- New South Wales Interconnect
- Western Transmission System.

The DWGM is different to other Australian gas markets in that it operates under what is referred to as an open access, or market carriage model, rather than the “contract carriage model” which dominates gas market operations elsewhere in eastern and south-eastern Australia.

The market carriage model means that users can access transmission capacity within the DTS under market-based arrangements set out in Part 19 of the NGR and administered by AEMO. Unlike other parts of eastern and south-eastern Australia, they do not need to have a gas transportation agreement with the pipeline owner in order to transport gas through the system.

The DWGM enables competitive, dynamic trading based on injections into and withdrawals from the transmission system that links multiple producers, major users, and retailers. AEMO as the market operator manages the trading functions of the spot market and also provides system balancing functions which, in other jurisdictions, are undertaken principally by transmission and distribution system operators.

The DWGM provides a clearing house in which gas can be bought and sold on an intra-daily basis with prices reflecting the short-term supply-demand balance, while underlying long-term supply contracts insulate major buyers and sellers from price volatility in much the same way that hedge contracts operate to manage price risk for electricity generators and retailers in the NEM. The DWGM is essentially a “balancing market” in which participants can sell marginal excess supply or purchase extra gas as required to balance bids and offers with actual injections and withdrawals.

Further details of the operation of the DWGM are set out in a “Guide to Victoria’s Declared Wholesale Gas Market” published by the Australian Energy Market Operator (AEMO, 2012).

Short Term Trading Market

The Short Term Trading Market (STTM) is a market for the trading of natural gas at the wholesale level at defined hubs between pipelines and distribution systems. The STTM currently operates hubs in Sydney, Adelaide, and Brisbane, as shown in Figure C3. It should be noted that the STTM is not a ‘gross pool’ market. A significant part of the gas that is supplied in these jurisdictions is not traded through the STTM.

In late March 2014, a new gas supply hub was also established at Wallumbilla in Queensland. The Wallumbilla Gas Supply Hub is not a part of the STTM but offers an alternative trading mechanism for STTM participants. The Wallumbilla Gas Supply Hub is discussed further below.

The STTM is designed as a wholesale market overlaid on existing contractual arrangements for supplying gas from multiple facilities to defined hubs.

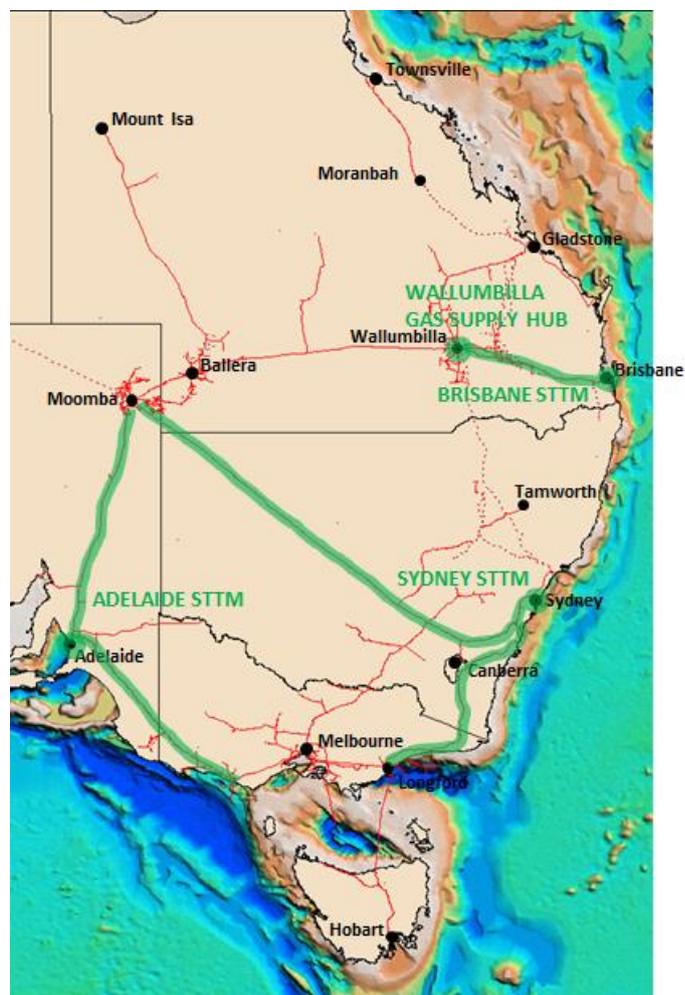
The STTM provides a single ex-ante market price for each hub which is applied for a whole gas day. This price is published approximately 18 hours ahead of time so shippers can use it to determine their shipping nominations to the relevant facility operators.

The STTM includes a pipeline balancing service to supply demand in excess of the schedule, or to absorb any gas scheduled for delivery that is not required on the day. This service is known as market operator service (MOS). Each hub is scheduled and settled separately, but the Sydney, Adelaide, and Brisbane STTM hubs all operate under the same rules. At any hub, there can be multiple facilities that deliver gas (such as transmission pipelines, storage facilities, and production facilities) and multiple distribution systems that deliver the gas from the hub to consumers.

Anyone with the necessary agreements and authorities is able to buy and sell gas in the STTM. With the STTM, “shippers” deliver gas to be sold in the market, and “users” buy gas for delivery to consumers. The same organisation can sell gas into the market and purchase gas from the market, but it does so at the daily market price. It offers gas for sale under the same terms as any other shipper and buys gas under the same terms as any other user. If an organisation has gas that is excess to requirements, it can sell the gas the next day on the open market. Alternatively, if demand is higher than expected, it can bid to purchase extra gas, when and if it needs to. This gives participants more choice in purchasing gas supplies.

Price transparency ensures that the price of gas set daily by the market properly reflects the true supply-and-demand situation. In turn, this provides a more reliable price indicator for future investment in production, transmission, and distribution infrastructure.

Figure C3 Location of Short Term Trading Market hubs



Source: ACIL Allen Consulting; base layer from GPInfo.

Wallumbilla Gas Supply Hub

A voluntary gas supply hub (GSH) at Wallumbilla, near Roma in Queensland, commenced trading operations in March 2014. The Wallumbilla GSH, operated by AEMO, is the next step in energy market reforms aimed at increasing transparency and competition in east coast gas markets. The hub is expected to support the efficient trade and movement of gas between regions, enhance the transparency of gas trading, and set a reference price for gas so participants can manage portfolio risk.

The GSH provides a centralised trading, settlement and clearing facility through an online portal, and enables generators, users, producers, and retailers to manage their daily and future gas requirements.

— the 1 TJ contract size allows for trading flexibility

— it provides another trading mechanism for participants already operating in the STTM.

AEMO offers spot and forward-dated products for participants to trade at the hub. The spot transactions include a core 'day-ahead' product and a 'balance-of-day' product that enables parties to adjust their portfolio closer to real-time and to manage imbalances within the gas day.

Pipeline capacity is also offered as a trading opportunity, allowing more efficient use of pipelines, and is designed to create increased opportunities to trade gas.

Gas Bulletin Board

The GBB is a website managed by AEMO that provides information about major interconnected gas processing facilities, gas transmission pipelines, gas storage facilities, and demand centres in eastern and south-eastern Australia.⁵⁵ The GBB covers major gas transmission pipelines, gas production facilities and underground storage facilities (see Table C1 and Figure C4).

According to AEMO, the GBB:⁵⁶

delivers a range of near-term gas market information to increase market transparency. In March 2014, the Standing Council on Energy and Resources (SCER) directed AEMO to improve GBB accessibility, coverage, and data quality.

AEMO is redeveloping the GBB in consultation with industry, and will deliver a scoping document to the SCER by mid-June 2014. Key milestones include an improved GBB interface by the end of 2014, implementation of a capacity listing service by early 2015, and any additional data collection and publications to be in place by early 2016.

⁵⁵ See www.gasbb.com.au.

⁵⁶ AEMO, "Gas Statement Of Opportunities Update", May 2014, p. 6, available from www.aemo.com.au.

Table C1 Gas Bulletin Board facilities

Transmission Pipelines	Gas Plants	Storage Facilities
Carpentaria Pipeline	Ballera Gas Plant	Iona Underground Gas Storage
Eastern Gas Pipeline	Berwyndale South	LNG Storage Dandenong
Longford to Melbourne	Camden CSM	Silver Springs
Moomba to Adelaide Pipeline System	Dawson Valley	
Moomba to Sydney Pipeline System	Fairview	
NSW-Victoria Interconnect	Kenya Gas Plant	
Queensland Gas Pipeline	Kogan North	
Roma - Brisbane Pipeline	Lang Lang Gas Plant	
SEA Gas Pipeline	Longford Gas Plant	
South West Pipeline	Minerva Gas Plant	
South West Queensland Pipeline	Moomba Gas Plant	
Tasmania Gas Pipeline	Orbost Gas Plant	
	Otway Gas Plant	
	Peat	
	Rolleston	
	Scotia	
	Spring Gully	
	Strathblane	
	Talinga Gas Plant	
	Taloona	
	Wungoona	
	Yellowbank	

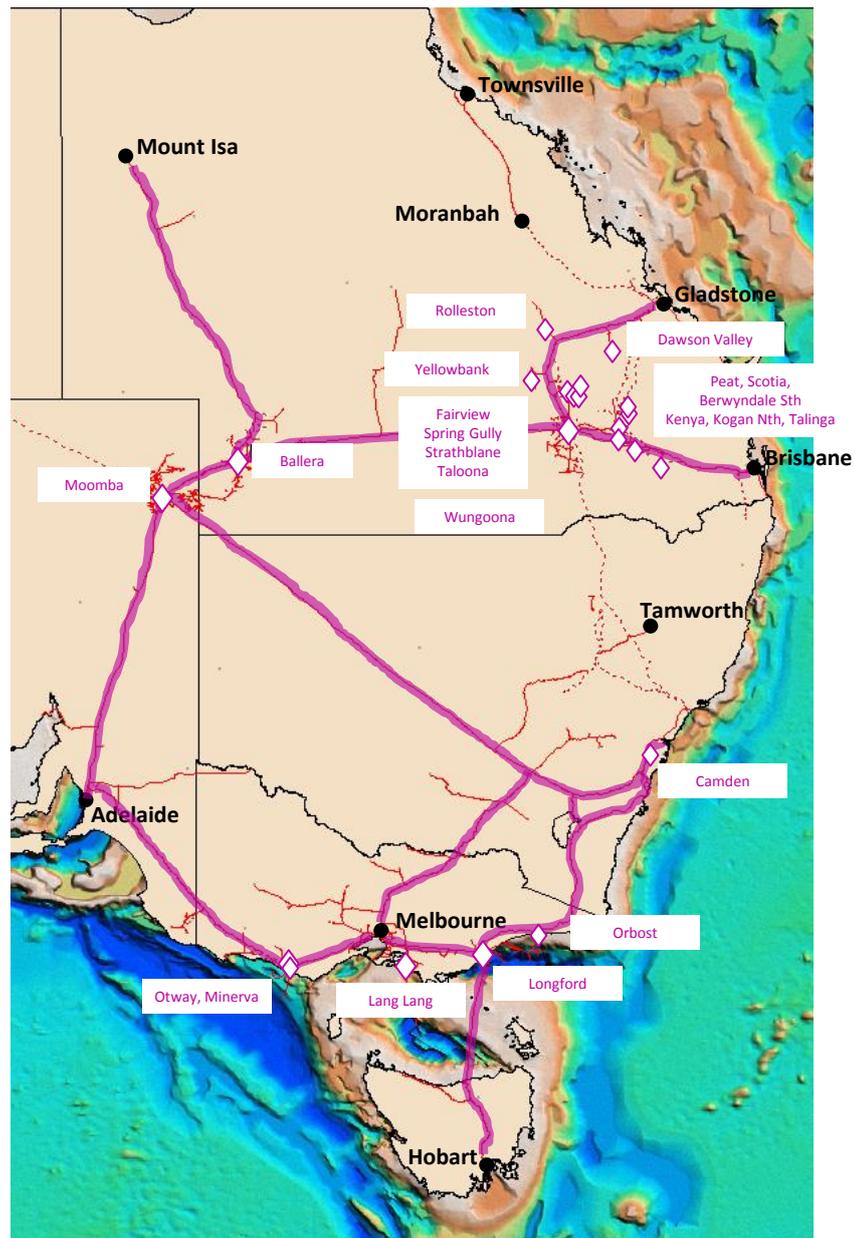
Source: Gas Bulletin Board

While the GBB coverage includes most major facilities in eastern and south-eastern Australia, it is not comprehensive. For example, the GBB does not cover the gas production facilities at Moranbah, gas demand in the Townsville area, or the North Queensland Gas Pipeline between Moranbah and Townsville. Nor does it cover other “on-field” facilities, such as the Daandine gas plant and power station in southern Queensland, which are also excluded.

The objective of the GBB is to facilitate trade in gas and capacity over the relevant pipeline systems by providing system and market information that is readily available to all GBB users. To that end, the GBB gathers and makes available to the public data on available pipeline and production facility capacity, daily capacity nominations, pipeline flows, production plant system injections, and gas storage status.

The GBB also supports the function of the National Gas Emergency Response Advisory Committee (NGERAC) and jurisdictions in the event of major gas emergencies.

Figure C4 Gas Bulletin Board pipeline and production facilities



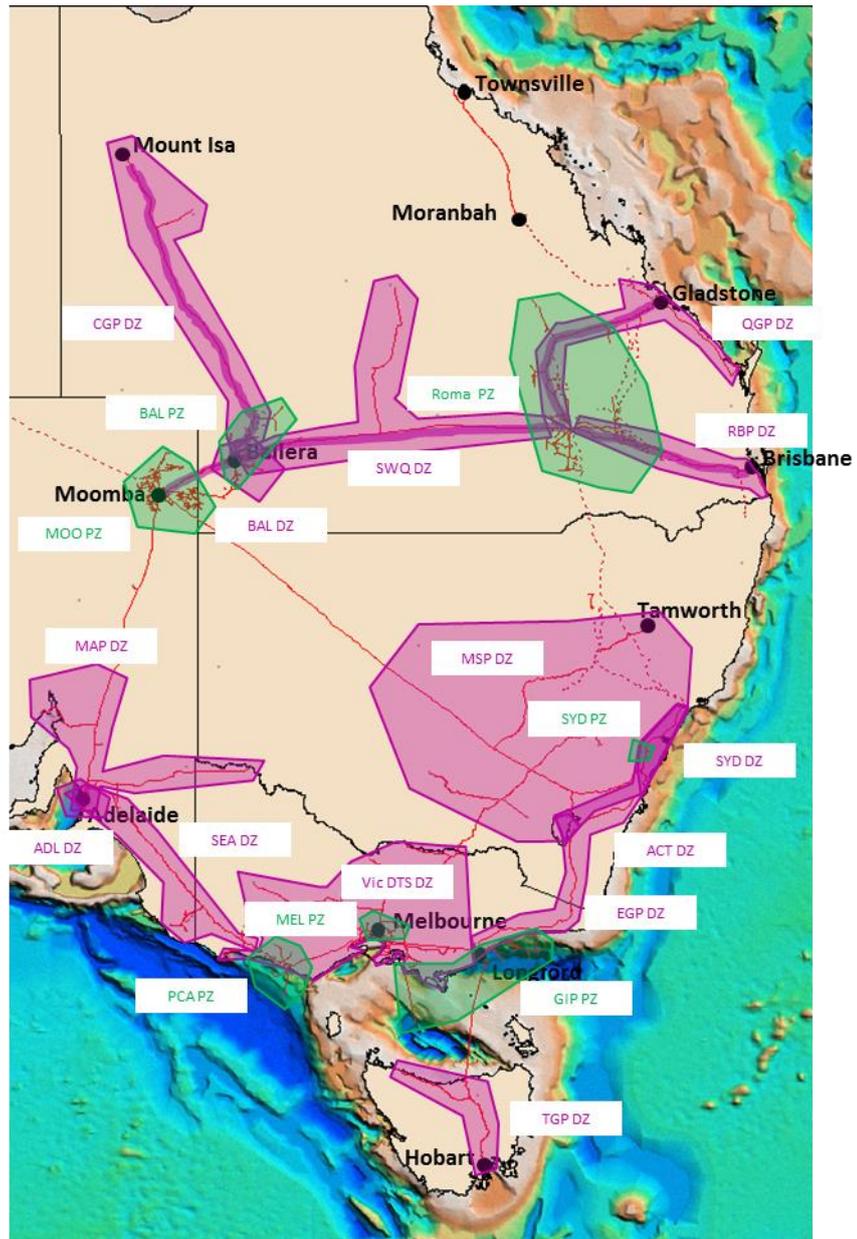
Source: ACIL Allen Consulting; base layer from GPIInfo.

The GBB recognises 14 demand zones, which are regions where the natural gas load is delivered by one or more GBB pipelines. Those with two or more pipelines may be referred to as demand hubs. The GBB also recognises seven production zones, which are regions in which natural gas is produced from one or more facilities and is injected into one or more GBB pipelines that transport the gas to other production or demand zones. Those production zones supplying two or more pipelines may be referred to as production hubs.

The locations of the GBB demand zones and production zones are illustrated in Figure C4.

Table C2 sets out details of the GBB demand zones and production zones, and shows the relationship between the GBB demand zones and the demand groups upon which the GSOO is based.

Figure C5 Gas Bulletin Board Demand and Production Zones



Source: ACIL Allen Consulting; base layer from GPIInfo.

Table C2 Gas Bulletin Board demand and production zones

Zone Name	Zone Type	Zone Description	GSOO Demand Group
Sydney (SYD)	DZONE	Demand supplied through the MSP CG at Wilton and the EGP CG at Horsley Park CG and EGP CG at Wollongong CG.	4
Australian Capital Territory (ACT)	DZONE	Demand supplied through either the EGP CG at Hoskinstown or the MSP-Canberra CG at Watson.	4
Moomba to Sydney Pipeline System (MSP)	DZONE	Demand supplied through the MSP, including its laterals through Wilton CG and Canberra CG (Watson) but excluding any export flows to Victoria via the Interconnect.	4
Eastern Gas Pipeline (EGP)	DZONE	Demand supplied through the EGP including to the ACT and Sydney zones.	4
Sydney (SYD)	PZONE	Sydney Basin	4
Victoria	JURI		
Victorian Principal Transmission System (PTS)	DZONE	Demand supplied off the Victorian PTS includes demand on Western Transmission system, the Carisbrook to Horsham pipeline, and on laterals that may extend into NSW.	2
Gippsland (GIP)	PZONE	Production within the Gippsland Basin and the Bass Basin including gas sourced from the Gippsland and Bass Basins with gas currently injected at Longford Orbost (Patricia Baleen) and Pakenham (Bass Gas/Lang Lang).	
Port Campbell (PCA)	PZONE	Production of gas in the Port Campbell region generally sourced from the Otway Basin on-shore and off-shore gas fields and Iona UGS storage.	
Melbourne (Mel)	PZONE	Greater Melbourne Region. Only used for allocation of Dandenong LNG storage facility to a zone.	2
Roma to Brisbane Pipeline (RBP)	DZONE	Demand supplied via RBP downstream of Wallumbilla to Brisbane, including the Brisbane load and demand on laterals to the RBP and any other connecting pipeline loads supplied via the RBP.	5
Queensland Gas Pipeline (QGP)	DZONE	Demand supplied via QGP downstream of Wallumbilla and to Gladstone extending to Rockhampton and Maryborough and loads on all laterals to the QGP or connecting pipelines.	5
Carpentaria Gas Pipeline (CGP)	DZONE	Demand downstream of Ballera, including Mt Isa and demand on Cannington line or other laterals or connecting pipelines to the CGP north of Ballera.	5
South West Queensland Pipeline (SWQ)	DZONE	Demand on the SWQP west of Wallumbilla and to Ballera, including that from the Cheepie to Barcardine pipeline, and any other laterals or connecting systems including any net deliveries to the Ballera zone on the day.	5
Ballera (BAL)	PZONE	Ballera locale sourcing gas from Eromanga Basin; includes connections in the locale to the Carpentaria SWQ pipeline, the QSN Link and any bypasses between these pipelines.	

Zone Name	Zone Type	Zone Description	GSOO Demand Group
Roma (ROM)	PZONE	Large region covering the Bowen/Surat Basin where gas is sourced processed and directly or indirectly supplied into the QGP RBP or SWQ Pipeline.	
Ballera (BAL)	DZONE	Deliveries to the Ballera locale including (any bypasses to the proposed QSN Link or to the CGP from the SWQP).	5
Adelaide (ADL)	DZONE	Demand supplied through SEA Gas CG (Cavan) and the MAP CG (Gepps Cross) including demand from the Torrens Island and Pelican Point gas-fired generators and any other direct connected loads in the Adelaide area.	1
Moomba (MOO)	PZONE	Moomba locale sourced from Cooper Basin and with some raw gas transported from Ballera. Includes connections to the MSP MAP (proposed QSN link when it is commissioned) and any bypasses between any of these pipelines.	
Moomba to Adelaide Pipeline System (MAP)	DZONE	Demand supplied through the MAP system, including all laterals and including the Adelaide demand zone.	1
SEA Gas (SEA)	DZONE	Demand supplied through SEA Gas and its laterals or connecting pipelines, including the ADL zone.	1
Tasmanian Gas Pipeline (TGP)	DZONE	Demand supplied off the TGP within Tasmania.	3

Source: Gas Market Bulletin Board "Zones List" data file int902_v1_zone_1~20121017102956

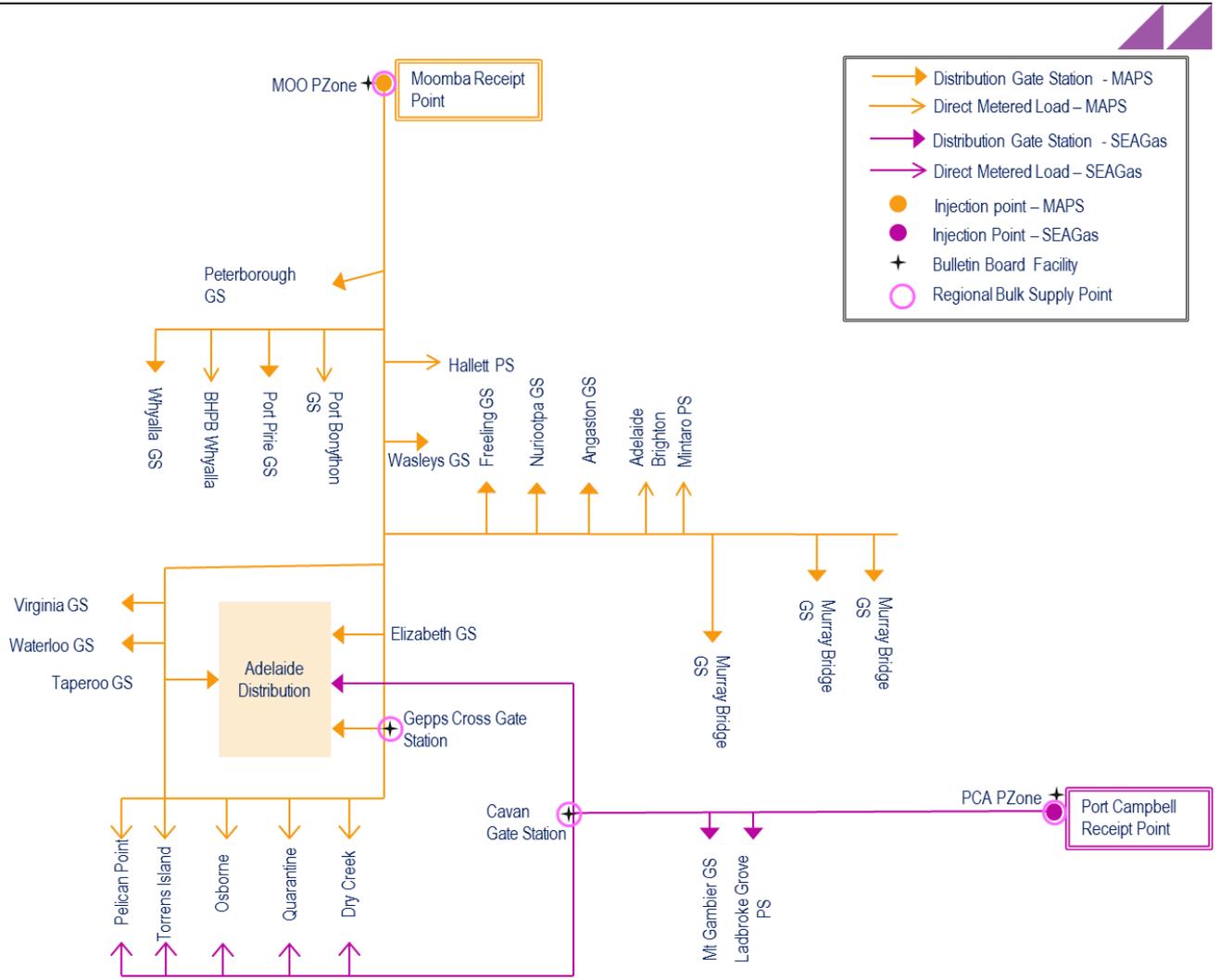
C.1.4 Regional bulk supply points

We take the term Regional Bulk Supply Point to refer to the following:

- any point where gas from a production facility or a group of production facilities is injected into a transmission pipeline and the quantities injected are metered on a regular basis (that is, a Production Zone as defined for the purpose of the GBB)
 - for example, the Moomba production facility injection point into the Moomba to Adelaide Pipeline System
- any point where gas is delivered from a transmission pipeline into a gas distribution network (that is, a gate station) or to a direct metered load and the quantities injected are metered on a regular basis
 - for example, the SEAGas City Gate station at Cavan in Adelaide, or the customer meter at the Pelican Point Power Station
- any point where gas from a production facility is delivered directly into a gas-using facility
 - for example, the delivery point for gas from the Daandine coal seam gas field in southern Queensland into the Daandine Power Station, or previously (prior to field depletion) the delivery point for gas from the Katnook field in south-eastern South Australia into the Ladbroke Grove power station
- any point where gas is injected into or withdrawn from a storage facility (underground storage or LNG storage)
 - for example, the Iona underground storage facility or the Dandenong LNG peak shaving facility.

Figure C6 is a schematic diagram representing the regional bulk supply points in South Australia. The purpose of this diagram is to illustrate the level at which we consider it should be feasible and would be appropriate to gather daily gas supply data. Capturing data and projecting consumption at the level of each distribution network gate station would allow reconciliation, at an aggregate level, between AEMO’s forecasts and the actual and projected consumption for regulated distribution businesses as reflected in their access arrangements.

Figure C6 South Australia Regional Bulk Supply Point schematic



Source: ACIL Allen Consulting compilation of public domain data.

Figure C6 is presented as an example only. In order to develop a comprehensive basis for modelling gas supply across the eastern and south-eastern Australian market, similar information will need to be compiled and collated for other jurisdictions or on the basis of Demand Groups as defined in the annual GSOO.

C.2 Customer categories

We take the term “gas customers” to refer to individuals or entities that are physically supplied with natural gas from production facilities, generally via transmission or distribution pipeline systems, and who directly consume that gas through combustion or as a chemical feedstock. Not all gas buyers are gas customers. For example, a gas retail business may purchase gas not for its own direct consumption but for the purpose of on-sale to its retail customers. In this example, the retail business is not a “gas customer” but those to whom it on-sells the gas are “gas customers”.

Gas customers can be broadly categorised as follows:

- wholesale customers:
 - arrange own gas supply direct from producer under long-term contract.
 - typically take large volumes of gas with direct metered connection to a high-pressure transmission pipeline system:
 - › large industrial users (for example, mineral processing facilities, chemical plants, refineries)
 - › gas-fired power generators
 - › large co-generation facilities
- retail customers:
 - purchase gas via a retailer or aggregator acting as an intermediary between the seller gas producer and gas customer.
 - are divided into the following categories:
 - › medium to large industrial users. Typically consume >10 TJ/year. Often referred to as Tariff D or Demand/Contract customers (see section 2.5)
 - › residential customers. Typically consume <10 TJ/year. Often referred to as Tariff V or Volume customers (see section 2.5). This group is further sub-divided into:
 - ... small industrial customers: for example small metal fabrication works
 - ... commercial customers: for example restaurants, hotels
 - ... residential/household customers.

C.3 The layout of a gas network

Before undertaking any gas consumption forecasts, it is important to understand the nature of current gas consumption, where this is physically occurring, and by what customer types. Building up a historical picture of gas consumption and how it has changed over time is a critical first step in undertaking a consumption forecast.

The gas industry is characterised by a relatively small number of gas producers selling wholesale gas to a relatively small number of retailers and large users. Retailers then on-sell gas to small industrial, commercial, and residential users.

Physically, raw gas extracted from petroleum reservoirs is typically processed at plants to remove liquids and impurities and to bring the gas to the natural gas standard specification in order for transport and sale.

Gas is lost in the production process through venting (the direct release of methane to the atmosphere), compression into pipelines, flaring, and gas consumed for on-field electricity generation and processing.

For conventional petroleum deposits, natural gas can also be reinjected into the reservoir to assist the production of liquids and other higher hydrocarbons or where there is no ready market or pipeline connection to market for the gas produced. The accounting of gas production is further complicated by the treatment of raw gas versus processed gas and by some agencies including other products (for example ethane) in production statistics.

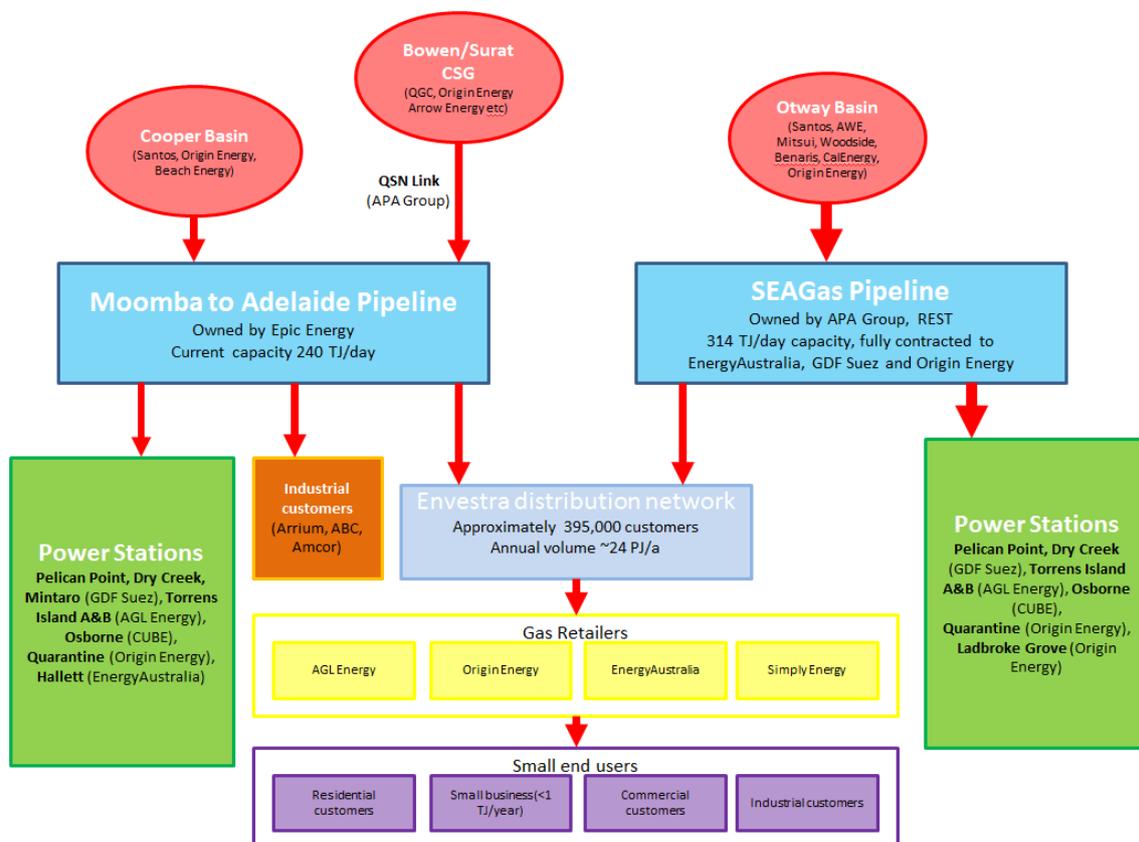
Large high pressure transmission pipelines transport the gas over long distances to industrial users, power generators, and to distribution network receipt points (typically referred to as city gates). Gas then enters lower pressure distribution networks for delivery to residential customers.

As an illustrative example, consider the South Australian gas industry structure, depicted in Figure C7. The state is serviced by two transmissions pipelines:

- Moomba to Adelaide Pipeline System (MAPS) which transports gas sourced from the Cooper/Eromanga Basins and Queensland CSG
- the SEAGas pipeline which delivers gas sourced from the Otway and Gippsland Basins in Victoria.

Gas consumption in South Australia consists of three main categories: power generation, major industrial loads, and commercial/residential customers serviced via the Envestra distribution networks. There are currently four main gas retailers active in South Australia, with Origin Energy accounting for over 50 per cent of residential customers as the incumbent retailer.

Figure C7 South Australian gas industry structure



Source: ACIL Allen.

Figure C7 also shows the routes of the two major transmission pipelines, their laterals, and points of connection with the regional distribution networks.

The boundary between natural gas transmission and distribution is generally taken to be the city gate regulator stations at which gas pressures are reduced from transmission pressures to sub-transmission pressures.

Both MAPS and SEAGas have multiple connection points to the main Adelaide distribution network. Other regional distribution networks include Waterloo Corner; Virginia; Wasleys; Freeling; Nuriootpa; Angaston; Murray Bridge; Berri; Mount Gambier; Riverland; Whyalla; Peterborough; Port Pirie; and Mount Gambier.

There is a large number of gas users on the South Australian gas network, presently comprising around 400,000 customers. Each of the distribution networks supplies gas to many small and medium customers.

In addition, while Figure 6 does not show them, there are also large customers that connect directly to one or other of the transmission pipelines. In South Australia these include the following:

- Adelaide Brighton Cement, located at Birkenhead
- Orora Glass (formerly Amcor), located at Nuriootpa
- OneSteel, located at Whyalla.

There are also power stations, such as Torrens Island Power Station and Pelican Point Power Station, both located just to the north of Adelaide. For the most part gas-fired power stations are market scheduled generators, visible to AEMO as the market operator. Gas consumption can be estimated based on historical generator volumes and assumed thermal efficiencies.

AEMO will also have good visibility of smaller generators below AEMO's 30 MW cut-off, provided they are still market-based generators. However, AEMO may have less visibility of non-scheduled, non-market generators, particularly if they are remote (i.e. do not physically connect with the NEM).

Gas is also 'consumed' by transmission pipelines themselves, at various compressor stations along the route. Compressor stations increase transmission pipeline pressure at points along the route, thereby increasing the delivery capability of the pipeline.

In the distribution network some gas is lost from the system due to pipeline leaks and for various other reasons. Within the industry this is commonly referred to as Unaccounted for Gas (UAG). UAG occurs primarily for two reasons:

- fugitive emissions: physical gas losses from distribution pipelines (in some cases distribution networks are quite old and leakages are common)
- measurement-based: end-user meter are typically biased to slightly under-record deliveries, to avoid potential over-charging.

Estimates of UAG for gas distribution networks in each state are presented in Table C3. For large networks, UAG typically ranges from 2.5 per cent to 4 per cent.

Table C3 NGA factor workbook – natural gas leakage factors

State	Unaccounted for gas (per cent UAG)	Natural gas composition factor (tonnes CO ₂ -e/TJ)	UAG CO ₂ CH ₄
NSW and ACT	2.4	0.8	328
Vic	2.75	0.9	326
Qld	2.63	0.8	317
SA	4	0.8	328
WA	2.55	1.1	306
NT	0.1	0	264
Tas	0.4	0.9	326

Source: Department of Industry, Innovation, Climate Change, Science, Research and Tertiary Education, Australian National Greenhouse Accounts, National Greenhouse Accounts Factors, July 2013.

Unlike electricity which is a homogenous product, natural gas represents a mix of gases. There may be slight variations in the energy content of natural gas depending upon the product composition within the gas stream. The Australian natural gas specification for pipelines provides for a range of compositions which make up 'natural gas'. In some cases, government departments may measure gas production on a volumetric basis and conversion to an energy basis is necessary. For example, it should be noted that conventional gas will typically have a slightly higher energy content (due to traces of higher hydrocarbons) compared with CSG which is almost exclusively methane with a small percentage of inert gases. However, for the most part energy differentials in eastern and south-eastern Australia are relatively minor.

C.4 Gas metering

For present purposes we identify two categories of meters, namely network and customer meters.

Network meters measure the quantity of gas travelling through or between networks. These include the meters that measure flow from a transmission pipeline to a distribution network. For the most part these are sophisticated, accurate meters that record gas flows frequently (hourly). These meters are owned and read by the network businesses themselves. In some instances network meters represent the source data for figures presented on the GBB.

Customer meters measure the quantity of gas leaving a network and flowing to a customer's premises. There are several types of customer meter. The most common is an *accumulation meter*, which is typically a fairly basic device that is read manually approximately once every three months. Most residential customers with gas connections have this type of meter. These meters are incapable of recording more than the total quantity of gas used since they were last read.

Customer meters are owned and read by distribution network service operators. The readings are transferred via AEMO's retail systems to the appropriate retailer.

Larger customers may have more sophisticated meters that can be read remotely and produce data frequently, e.g. hourly. The meters used to supply very large customers may resemble the network meters described above. These meters can provide information about how much gas was used in a given time period, or interval. Any meter with this capability is referred to in this report as an *interval meter*.

C.5 Tariff structures

The way that customers pay for their gas is also relevant to the data that are available and, therefore, to forecasting gas consumption. Tariffs are in three parts: distribution, transmission, and retail. These are discussed separately below.

C.5.1 Distribution

Most gas distribution businesses are subject to economic regulation by the AER. Access arrangement reviews are generally undertaken every five years, with the regulator using a 'building blocks' approach to determine a revenue requirement for the business, for each year of the forthcoming access arrangement period.

The network business then develops annually a set of tariffs designed to recover the approved revenue requirement.⁵⁷ Within a distribution network there are typically three tariff types: one for residential customers, one for small commercial and industrial customers, and one for large customers (mainly industrial). The rates payable for each service type may vary for different locations or zones within the distribution system, reflecting differences in the cost of service.

The residential and small commercial/industrial tariffs are *volume* tariffs, comprising:

- a fixed charge in dollars per day
- a consumption charge in dollars per gigajoule of gas used.

The consumption charge typically has a declining block structure. That is, customers pay less per GJ the more gas they use.

The large industrial/commercial tariffs are termed *demand* tariffs. That is, customers pay a fixed amount per month based on the maximum quantity they are permitted to withdraw from the network. They must pay this amount regardless of whether they actually use that quantity.⁵⁸

The tariff structures reflect the meters that are used. That is, accumulation meters are used for volume tariffs, while interval meters are used for demand tariffs.

In this report we refer to these tariffs as follows:

- tariff R – residential tariffs
- tariff C – small commercial/industrial (volume) tariffs
- tariff D – large industrial/commercial (demand) tariffs.

For the most part, gas DNSPs use this nomenclature for their tariffs. To avoid confusion, Table C4 summarises at the time of writing the network tariffs available on regulated distribution networks in eastern and south-eastern Australia using this nomenclature.

⁵⁷ A more detailed summary of this process is contained in Appendix E.

⁵⁸ Note this relates to the network component, the retail component is a different matter. [CHECK OK?]

Table C4 Eastern Australian gas distribution tariffs

DNSP	DNSP's Tariff Name	Our Classification	Description
Queensland			
APT Allgas	Tariff V	R + C	Residential and Commercial – up to approximately 10 GJ per day.
	Tariff D	D	Between 50 GJ and 525 GJ of MDQ* per day.
Envestra (Brisbane, Riverview and Northern)	Tariff R	R	Residential – less than 0.2 GJ per day.
	Tariff C	C	Commercial – up to approximately 5 GJ per day.
	Tariff D	D	Between 50 GJ and 10,000 GJ of MDQ per day.
New South Wales			
Envestra (Albury)	Tariff V	R + C	Residential and Commercial – between 0.02 GJ and 1 GJ per day.
	Tariff D	D	Between 10 GJ and 40 GJ per day.
Envestra (Country Energy Gas Networks) (Wagga Wagga)	Tariff V	R + C	Residential and Commercial – less than 10 TJ per annum.
	Contract Customers	D	More than 10 TJ per annum.
Jemena	Tariff V	R + C	Residential and Commercial - less than 10 TJ annum.
	Tariff D (5 subsections)	D	More than 10 TJ per annum.
Australian Capital Territory			
Actew AGL	Tariff Customers	R + C	Residential and Commercial - less than 10 TJ per annum.
	Contract Customers	D	More than 10 TJ per annum.
Victoria			
Multinet	Tariff V	R + C	Residential and Commercial – less than 10,000 GJ per annum, and less than 10 GJ of MHQ*.
	Tariff D	C	Commercial – more than 10,000 GJ per annum and more than 10 GJ of MHQ.
	Tariff L	D	More than 1 TJ per annum, or less than 10 TJ per annum, and MHQ demand is less than 10 GJ per hour.
SP Ausnet	Tariff V	R	Residential – less than 10,000 GJ per 12 month period, and less than 10 GJ per hour.
	Tariff V	C	Commercial – less than 10,000 GJ per 12 month period, and less than 10 GJ per hour.
	Tariff M	D	More than 10,000 GJ per 12 month period, or more than 10 GJ per hour.
	Tariff D	D	More than 10,000 GJ per 12 month period or more than 10 GJ per hour. Required to pay an Operating and Maintenance charge.
Envestra	Tariff V	R + C	Residential and Commercial – between 0.02 GJ and 1 GJ per day.
	Tariff D	D	More than 10 TJ per annum.
APA Gasnet	Tariff V	D + C	Residential and Commercial – less than 10 TJ per annum.
	Tariff D	D	More than 10 TJ per annum or more than 10 GJ per hour.

DNSP	DNSP's Tariff Name	Our Classification	Description
South Australia			
Envestra	Tariff R	R	Residential – between 0.02 GJ and 0.9 GJ per day.
	Tariff C	C	Commercial – between 0.9 GJ and 12 GJ per day.
	Tariff D	D	Between 50 GJ of MDQ and 900 GJ of MDQ per day.

Note: * Maximum Daily Quantity (MDQ), Maximum Hourly Quantity (MHQ).
Source: ACIL Allen analysis of regulatory documents submitted by DNSPs.

C.5.2 Transmission

In eastern and south-eastern Australian gas markets, transmission services are primarily provided by unregulated pipelines. Some unregulated transmission pipelines post publicly-available standing offer tariffs. However, for the most part the tariffs paid for transmission services are not separately identifiable as they are subject to commercial negotiation between the pipelines and shippers. For the few remaining regulated pipelines, regulated tariff caps for standardised reference services are set by the AER and are publicly available.

C.5.3 Retail

There are numerous gas retailers in eastern and south-eastern Australia, with each setting its own tariffs for small and medium customers. In South Australia and Victoria this is done without government regulation. In other jurisdictions, a regulator sets the standing contract price (which typically operates as a price cap), and other retailers are able to compete. Retailers are not obliged to follow the distribution tariff structure in the prices they charge their customers, but for the most part they do.

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