Report to

Australian Energy Regulator

Public Version

Review of Ergon Energy's maximum demand forecasts for the 2011 to 2015 price review

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Ref: J1770 Ergon Energy

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1	25/09/2009	Draft to AER	MG, RL, MP
2	05/10/2009	Incorporating comments from AER	MG, RL, MP
3	09/10/2009	For Ergon comment on factual errors	MG, RL, MP
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EXECUTIVE SUMMARY

Review of maximum demand forecasts

The Australian Energy Regulator (AER) is required to determine the revenue requirements for services provided by electricity distribution network service providers (DNSPs) in Queensland from 1 July 2010 to 30 June 2015. The National Electricity Rules require the AER to accept the forecasts of operating and capital expenditures in the DNSPs' regulatory proposals if they reasonably reflect, amongst other things, realistic expectations of demand.

The AER has engaged McLennan Magasanik Associates (MMA) to assist it by reviewing the key demand forecasts used by the DNSPs in formulating their regulatory proposals. As the Queensland DNSPs will be regulated under a revenue cap the forecasts of most concern are the maximum demand forecasts which are key inputs into capital expenditure forecasts and annual revenue requirements. The focus of the review has, therefore, been on the maximum demand forecasts, at both the system and spatial levels.

Overview

In order to assess whether the demand forecasts included in regulatory proposals are reasonable and realistic MMA has initially considered the approach taken and methodologies adopted by the DNSP. MMA has then examined the key drivers of maximum demand and whether these are appropriately taken into account in the forecasts prepared by the DNSPs. To the extent they have not been appropriately incorporated this is addressed in the chapter on system maximum demand.

Preliminary review of approach and methodology

MMA has previously, with the cooperation of the DNSPs, carried out a preliminary review of the approaches, methodologies and data sources used by the DNSPs in their forecasting of maximum demand. This preliminary review was conducted prior to the lodgement of the regulatory proposals and did not involve an assessment of the DNSPs forecasts of demand.

Ergon Energy uses a bottom up approach to its maximum demand forecasting at the spatial level and does not reconcile this in any systematic way with any forecasts at the system level. The Ergon Energy methodology is based largely on a continuation of history as well as incorporation of spot load assessments.

MMA considers that while the approach taken by Ergon Energy may be reasonable in a period of stable growth, it is unlikely to be so given the significant changes in key drivers of maximum demand expected to take place over the coming period.

As a result of the preliminary assessment of approach and methodology, MMA has concerns regarding:

- the lack of responsiveness of the approach to changes to key drivers, such as the Global Financial Crisis (GFC)
- the absence of any systematic reconciliation of spatial forecasts to a system maximum demand which takes changes to such key drivers into account
- Ergon Energy's approach to weather correction
- use of an "organic growth" trend analysis which may incorporate spot loads
- how spot loads are calculated and their probability and timing assessed
- use of coincidence factors as a method of calculating 50%POE and 10% POE forecasts
- lack of documentation

Demand forecasts used to derive capex for the Regulatory Proposal

Ergon Energy has, because of timing issues, based its detailed capital expenditure programs within the Regulatory Proposal on its September 2007 maximum demand forecasts prepared following the summer of 2006/07. However, recognising the possible impact of changed drivers, Ergon Energy has compared the overall system forecasts with two subsequent forecasts it has prepared – in September 2008 and February 2009. The September 2008 forecast was prepared in the same way as its September 2007 forecast while the February 2009 forecast is essentially the same as the September 2008 forecast except that many of the larger spot loads included have been amended, mainly in terms of their timing.

Ergon Energy argues that as its 2008 and 2009 system maximum demand forecasts are, on average over the period 2011 to 2015, higher than its 2007 forecasts for the same period, then the use of the 2007 forecasts is conservative and reasonable. Ergon Energy also appears to be arguing that forecasts prepared by NIEIR in 2007 and 2008 and early 2009 validate the Ergon Energy forecasts and conclusions that the 2007 forecasts can be relied upon.

MMA has primarily reviewed Ergon Energy's September 2007 forecasts. However, it has also considered briefly the September 2008 and February 2009 forecasts and considered the arguments made by Ergon Energy:

- that its September 2007 forecasts are reasonable as they are, on average over the coming regulatory period, lower that the September 2008 and February 2009 forecasts
- that its forecasts have been validated by forecasts produced by the National Institute of Economic and Industry Research (NIEIR) and that this validation included consideration of the impact of the GFC

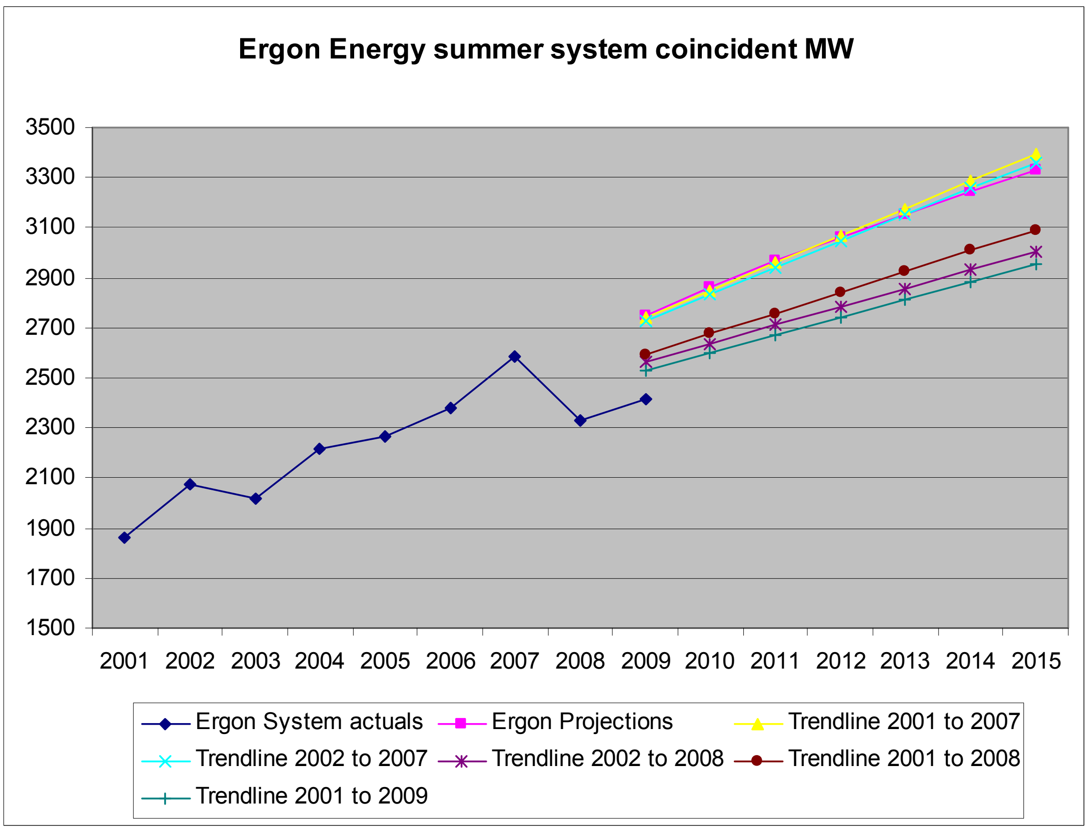
MMA has not been persuaded by the Ergon Energy argument that as its September 2007 forecasts are lower than its September 2008 and February 2009 forecasts they are both reasonable and also take into account the changes to key drivers resulting primarily from the GFC.

Nor does MMA consider that any NIEIR report that it has seen validates the Ergon Energy September 2007 maximum demand forecasts.

Regulatory Proposal

The recent history of Ergon Energy's summer network coincident maximum demand between 2001 and 2009[1] is shown in Figure E 1 together with the system maximum demands projected by Ergon Energy[2] over the period to 2015. Also included are trendline estimates based on trends from 2001 or 2002 to 2007, 2008 or 2009.

Figure E 1 Ergon Energy's network summer maximum demands, projections to 2015 and trendline projections



The top three lines are the Ergon Energy projection for the forthcoming regulatory period and the 2001 to 2007 and 2002 to 2007 trendlines. All the trendlines based on actual (i.e. not weather corrected) data incorporating the 2008 and 2009 years result in projections much lower than the Ergon Energy Regulatory Proposal projection. As can be seen, even if all drivers were the same as those experienced over the past five or six years, the range of projected outcomes could differ substantially, ranging from 2960 MW to almost 3400

[1] The 2002 to 2008 data are from the RINs. The 2001 and 2009 system MDs are from PL563c

[2] From the data provided in the RIN.

MW by 2015. Annual growth in these projections also differs substantially, from 70 to 110 MW pa. In its Regulatory Proposal projection Ergon Energy has projected average annual growth of about 100 MW p.a.

There are, therefore, two key issues to consider:

- if a historical trend approach is to be followed, which is the appropriate trend?
- what impact will any change to key drivers have?

Key drivers of maximum demand over the coming period

Over the period 2002 to 2007 system maximum demand grew strongly, driven largely by strong economic and population growth and very strong growth in air-conditioning penetration. Mild summers in 2008 and limited very hot days in 2009 are understood to have contributed to the lower than expected maximum demands in those years.

Over the period from 2008 to 2015 MMA forecasts a significant change in key drivers which would be expected to materially reduce maximum demand growth compared to the previous period:

- the GFC is expected to significantly reduce state economic growth, from about 5% pa between 2002 to 2008 to 2 to 3% pa between 2008 and 2015. This reduced economic growth will reduce growth in maximum demand, especially for business and industrial customers. By the year 2015 economic growth in Queensland is expected to be some 8% lower than it would have been without the GFC, and the proportion of maximum demand which relates to economic growth would be expected to similarly be lower.
- growth in air-conditioning penetration will slow markedly as penetration levels approach saturation. While most new homes will be air conditioned, there will be significantly less uptake of air-conditioning by existing homes
- population and customer number growth are expected to moderate.

MMA considers that the significant changes to key drivers, such as the impact of the GFC, need to be incorporated into demand forecasts.

Spatial maximum demand

MMA has reviewed the Ergon Energy methodology used to prepare the 2007 maximum demand forecasts on which the capex proposals are based and the application of the methodology to forecasts at eight selected ZSS.

The methodology used at a ZSS level has been to estimate starting point and baseline growth through trendline analysis of historical growth and then to add to this probability and diversity weighted spot loads.

In terms of the starting points and baseline growth, based on the trendline analysis, MMA considers that, for the ZSS it has reviewed, judgements have generally been applied reasonably by Ergon Energy.

However, MMA does have a number of significant concerns about the approach and methodology used by Ergon Energy and the resulting forecasts used for the Regulatory Proposal. These concerns are summarised in the following categories:

- lack of responsiveness to change in key drivers
- calculation and treatment of spot loads
- lack of weather correction

As such, MMA does not consider the approach and methodology used by Ergon Energy to constitute good maximum demand forecasting practice[3].

Unresponsive to recent major changes in key drivers

Ergon Energy uses a bottom up approach based largely on a continuation of history as well as spot load assessments which are based on customer-supplied information and then routinely moved back by a year if they did not eventuate. Ergon Energy does not prepare a top down, system-wide forecast based on broader economic, demographic and other key drivers of maximum demand. While we understand it makes some comparisons with the NIEIR top down approach[4], Ergon Energy has made it clear that the NIEIR forecasts are taken into account, but that Ergon Energy does not in any way systematically reconcile to the NIEIR forecasts nor document the differences.

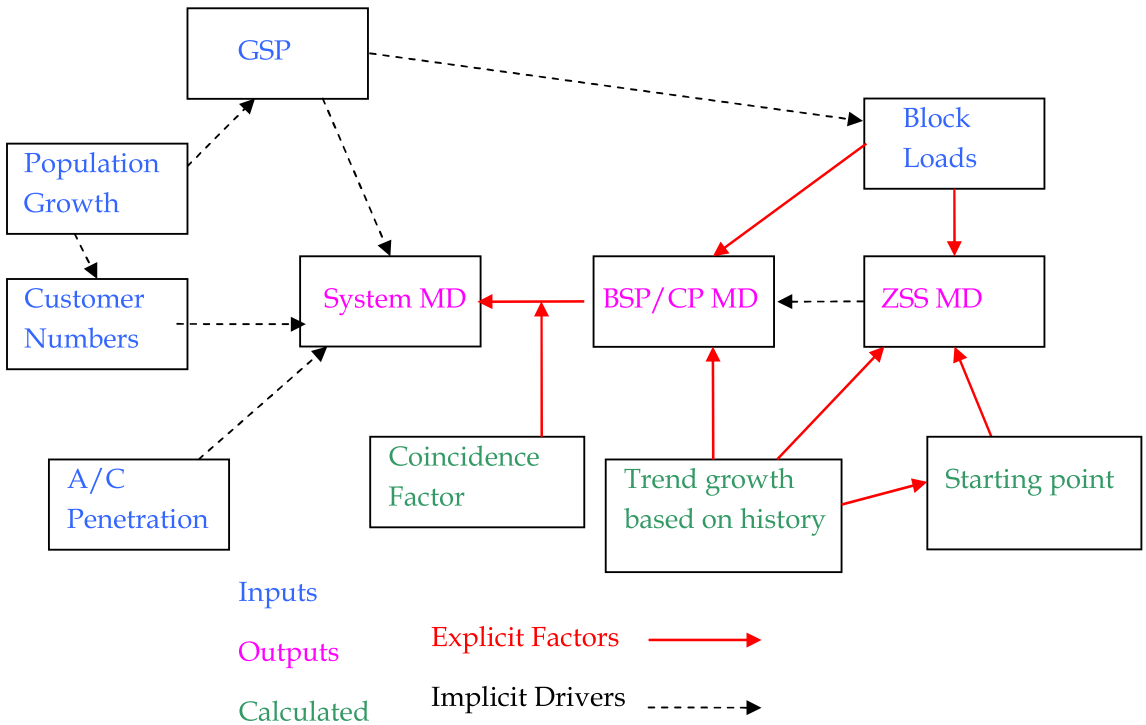
While Ergon Energy mentions a number of key drivers such as GSP, population growth and air conditioning penetration in its description of forecasting methodology[5], it does not appear that changes to any of these, apart from new spot loads, are actually taken into account in its methodology. Figure E 2 shows the relationship between these implicit drivers and the explicit factors used to derive the forecasts.

[3] MMA defines good maximum demand forecasting practice (referred to as good practice in this report) as an approach, methodology and the application of methodology which results in realistic and reasonable maximum demand forecasts. The criteria according to which good forecasting is assessed are based on MMA's experience in reviewing, for regulators and others, a number of demand forecasts made by electricity and other utilities and also draws on work and publications by H Lee Willis, in particular H Lee Willis, "Spatial electric load forecasting", Second edition,Marcel Dekker Inc, New York, 2002.

[4] Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd. , Section 21.3, P. 170

[5] Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd , Section 21.2, P.161

Figure E 2 Ergon Energy's drivers, inputs and outputs



Although factors such as GSP, customer number growth and air conditioning penetration are said by Ergon Energy to be important in maximum demand drivers the only inputs used are historical trends and spot load forecasts. The Ergon Energy approach implicitly assumes that the drivers of growth will remain similar to the historical period over which trends have been derived and explicitly includes changes to larger customers. While this may be reasonable in a period of stable growth, it is unlikely to be so over the coming period, given the significant changes in key maximum demand drivers expected to take place during that time. MMA considers that the use of only a bottom up approach against the background of the recent economic and minerals boom is likely to result in an unrealistic outcome.

Following its preliminary review of approach and methodology, MMA suggested that Ergon Energy incorporate a documented comparison with a recent top down analysis of maximum demand, such as that carried out by NIEIR for Ergon Energy in 2007 and 2008. This has not been incorporated in the Regulatory Submission.

This lack of consideration of changes to key drivers is a major concern for MMA. For the Energex region the difference between the system maximum demand forecasts in the Energex system maximum demand forecasts pre-GFC and the NIEIR April 2009 forecasts for Energex taking GFC into account averaged 6% over each year of the period 2011 to 2015[6]. The difference between the pre-GFC and post-GFC NIEIR forecasts was of the order of 4% across each year of the regulatory period. Yet the Ergon Energy methodology actually results in an increase in the forecasts after taking GFC into account. This is likely to be the result of ignoring changes to the trend growth as a result of major changes to key drivers and also potentially significant over-statement of spot load impacts (see below).

Treatment of spot loads

After assessing information provided by Ergon Energy, MMA considers that the Ergon Energy methodology both effectively double-counts small spot loads and also generally takes too optimistic a view of the timing, size and probability of the spot loads.

This is likely to result in forecasts which are over-optimistic. MMA has not been able to accurately quantify the impacts of these but provides an indicative assessment of 2.5% based on double-counting. In addition, many spot loads are likely to be delayed by at least a year.

Lack of weather correction

Ergon Energy has argued in its Regulatory Proposal[7] that weather correction requires a very significant amount of additional data and is not really required.

However, as seen in Figure E 1 , the weather can exert a very significant impact on trend-line assessments. MMA considers that appropriate weather correction is an important part of good maximum demand forecasting practice, and recommends that Ergon Energy work towards such weather correction in future.

Summary on spatial forecasts

In summary, MMA considers that the trend-line methodology applied by Ergon Energy is not realistic during times of significant change in key drivers, such as those due to the GFC, that the spot load methodology used is flawed as it allows double-counting of spot loads and that the spot load forecasts and probabilities actually applied by Ergon Energy are likely to be over-optimistic in terms of both magnitude and timing.

It is not possible to adjust these components using the bottom-up approach applied by Ergon Energy. In order to allow an indicative assessment of the likely magnitude of the GFC and other key driver changes to be assessed, MMA has considered the Ergon Energy system maximum demand.

System maximum demand

As noted earlier, Ergon Energy uses a "trendline plus spot load" approach to forecasting both spatial and system maximum demands and does not rely on its own system

[6] Energex Regulatory Proposal for the period 2010 - 2015. page 154.

[7] Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd, Page 176, Table 42.

maximum demand forecasts in deriving its capital expenditure. However, such an approach does not allow for any material changes to key drivers such as the GFC.

In order to make an indicative assessment of the likely impact of the GFC on the Ergon Energy network MMA has derived its own indicative 50% POE System MD forecasts based on a model that links the components of System MD to the key drivers as follows:

- C&I and SME components – MD grows in proportion to GSP growth or a percentage of GSP where the percentage represents demand-GSP elasticity
- Residential baseload component – MD grows in proportion to residential customer numbers
- Residential weather sensitive component – MD grows in proportion to residential customer numbers and air-conditioning penetration

MMA's indicative forecasts based on this model are some 230 MW or 7.5% on average below the Ergon Energy forecast and this is largely due to the assumed starting level in 2008/09. MMA acknowledges the uncertainty in estimates of weather corrected system MD for 2007/08 and 2008/09, caused by the generally milder weather over this period, and has also modelled the impact of increasing the estimated 2008/09 value by 50 MW. This reduces the difference between the MMA and EE forecasts in 2014/15 to 130MW – on average the MMA forecast is 5.5% lower. Use of alternative GSP projections in the MMA model reduces the differences between the MMA projections and the Ergon Energy projection to 6.3% and 4% respectively

The 130 to 230 MW difference between the Ergon Energy and MMA forecasts is approximately equivalent to one to two years of system MD growth. MMA's forecast takes into account post-GFC projections of economic growth that project Queensland GSP over the period 2011 to 2015 to be approximately 6 to 11% lower than the pre-GFC projections did i.e. the Queensland economy is not expected to recover the one to two years of growth lost due to the GFC. MMA's forecast reflects this loss of growth in the MD projection, whereas Ergon Energy's forecast appears to be based on the assumption that lost growth/developments will be recovered.

Conclusion

In conclusion, MMA considers that the 2007 forecasts relied upon by Ergon Energy to prepare its capex forecasts are not realistic. They do not take into account the impact of the GFC and we consider the spot loads are likely to be both over-optimistic and to some extent double-counted.

It is not possible to estimate the impacts of the changes to key drivers and over-estimation of spot loads on spatial forecasts using the Ergon Energy methodology. MMA's indicative system maximum demand assessment suggests that the Ergon Energy maximum demand forecasts are some 4% to 7% pa higher than they would be if the impacts of changed key drivers were properly taken into account and spot load assessments carried out more reliably.

To the extent these are reflected in growth capex forecasts, we consider that these are also likely to be overstated by a proportional amount.

MMA has concluded that the Ergon Energy demand forecasts prepared in 2007 are, on average over the period 2011 to 2015, some 4 to 7% too high and cannot, therefore, be considered realistic.

MMA has also reviewed the Ergon Energy customer number growth forecast of 1.6% pa. After taking into account recent history and expected changes in population and occupancy rates over the period, MMA considers these to be low and has used a growth rate of 1.8% pa for its indicative assessment of system maximum demand.

MMA also recommends that in future Ergon Energy adopt a top down methodology, which changes according to key economic, demographic, air-conditioning and weather drivers, as well as the bottom-up one currently used, and reconcile the two forecasts.

Finally, we note that the Australian and Queensland economies remain volatile. We have used economic forecasts for Queensland prepared in August 2009 as the basis of our analysis of system maximum demand. If there is a material change to the expected outlook then it may also materially impact on the forecasts.

1 INTRODUCTION

1.1 Background – review of revenues and prices

The Australian Energy Regulator (AER) is responsible, under the National Electricity Law (NEL) and National Electricity Rules (NER), for the economic regulation of electricity distribution services provided by distribution network service providers (DNSPs) in the National Electricity Market (NEM).

The AER, in accordance with the NER, is required to determine the revenue requirements for services provided by electricity distribution network service providers (DNSPs) in Queensland from 1 July 2010 to 30 June 2015 (the next regulatory control period). The relevant Queensland DNSPs are Energex and Ergon Energy.

The NER require the AER to accept the forecasts of operating and capital expenditures in the DNSPs' Regulatory Proposals if they reasonably reflect, amongst other things, realistic expectations of demand (refer to clauses 6.5.6(c) (3) and 6.5.7(c) (3) of the NER).

1.2 Role of demand forecasts

Demand forecasts potentially play a significant role in two components of a regulatory review:

- in determining the required capital (and to a lesser extent operating) expenditures applying to a DNSP. Capital and operating expenditures, in turn, are major inputs into the revenue required by the DNSPs over the 2010 to 2015 period
- in determining tariffs to apply under price cap regulation (pricing proposal). Here, in simple terms, tariffs are set by dividing the required revenue stream by the forecast demand

The two components require different but related demand forecasts. The forecasts of most relevance to capital expenditure requirements are those of maximum demand (MD) at both a system, or "global", level and more localised, "spatial", level. Forecasts of most relevance to determining tariffs are those related to energy and customer numbers.

The two Queensland DNSPs will be regulated under a revenue cap mechanism. As a result, the maximum demand forecasts are key inputs into capital expenditure forecasts and annual revenue requirements. Energy and customer number forecasts are significantly less important under a revenue cap. Prices are set each year to aim to recover the revenue cap; if the energy forecast is too high or low in one year, the prices are adjusted to compensate in the following year(s). The focus of the review is, therefore, on the maximum demand forecasts, at both system and spatial levels.

1.3 Review process undertaken

The AER has engaged McLennan Magasanik Associates (MMA) to assist it in its review of the key demand forecasts provided by the DNSPs with their Regulatory Proposals.

The review of demand forecasts undertaken by MMA has been a two-stage process:

- a preliminary review of approach, method and data sources
- a detailed review of system demand forecasts and review of forecasts at selected zone substations (ZSS) at the spatial level

1.3.1 Preliminary review of approach, methods and sources

In accordance with the NER, the DNSPs were required to submit their regulatory proposals by 1 July 2009. However, the Queensland DNSPs both agreed to a preliminary review which allowed them to describe the demand forecasting approach, methodology and data sources they proposed to use for their review and the AER (through MMA) to comment on these. This preliminary review was conducted prior to the lodgement of the regulatory proposals and did not involve an assessment of the DNSPs forecasts of demand.

The preliminary review served two key purposes:

- it provided the AER's consultants an opportunity to understand, in outline form, the forecasting methodology used by the DNSP prior to submission of the proposal. This facilitated the review of the forecasts after the proposals have been submitted.
- it allowed the DNSPs an early opportunity to identify whether significant issues are likely to exist with their approach to demand forecasting, and to work to address any identified issues at an early stage in the review process

As a preliminary review is not required under the NER, participation in such a review was a voluntary activity for the DNSPs. As a result, the preliminary review relied entirely on voluntary provision of information by, and cooperation from, the DNSPs.

Ergon Energy cooperated with the review but only limited documentation of approach and methodology was provided.

An outline of MMA's key comments from the preliminary review is provided in Section 3.4.

The preliminary review focused on the approach taken, methodology used and sources of data inputs rather than on specific forecasts at either the system or spatial levels. As a result, that review was general in nature and did not assess whether the approach and methodology had been appropriately applied. In addition, specific forecasts at either the system (global) or spatial levels were not assessed except as examples.

1.3.2 Detailed review of maximum demand forecasts

The detailed review of demand forecasts by MMA has been undertaken between July and October 2009, following the submission of the DNSPs Regulatory Proposals.

The review looks in some detail at the key drivers of maximum demand for the networks as a whole and the expected system wide impacts of significant changes to these drivers. It is to be expected that the system wide impacts will reflect the aggregate of the drivers that play out at the ZSS and spatial levels – which is a key driver of growth capital expenditure for the networks.

The preliminary review did not review the application of the methodology in any detail. Where judgement plays a very significant part in the forecasting process only limited understanding about methodology could be achieved prior to a review of actual history and forecasts. In order to more fully assess the methodology and whether judgements made are appropriate, a number of ZSS (including Malchi and Rockhampton South in the Carpentaria region, Garbutt, Hermit Park, Max Fulton and Neil Smith in the North Queensland region and Howard and Pialba in the Wide Bay region) were selected in consultation with the AER for more detailed review. They were based on the planned development of three new ZSS requiring significant capital expenditure over the coming regulatory period and a review of the forecasts at the ZSS which were expected to contribute load (contributing ZSS) to these new ZSS.

MMA received the Regulatory Proposal documentation in early July 2009. The new ZSS to be reviewed in detail were then identified and the DNSPs were asked to prepare a history and methodology description and provide supporting data in order to allow the forecasts for the contributing ZSS to be reviewed in detail.

MMA met with the two DNSPs on the 21st and 22nd July, 2009. At the meetings the DNSPs were asked to provide a detailed description of the methodology for the contributing ZSS. Following the meeting MMA prepared a list of questions and issues which required responses from the DNSPs. Further questions, issues and requests for clarification were raised over the period to mid September. Ergon Energy responded to all the questions and issues raised.

This report deals with the outcomes of the detailed review of demand forecasts submitted in the Regulatory Proposal. Ergon Energy has been provided with an opportunity to provide comment on the draft report about errors of fact and confidentiality and those comments have be taken into account in this final report.

1.4 Focus on summer maximum demand

The review has focused on summer maximum demand forecasts which are the most material for the regulatory proposals of the Queensland DNSPs.

1.5 Report layout

Chapter 2 outlines the key drivers MMA considers to be relevant to maximum demand forecasts for Queensland over the period to be covered by the regulatory review – essentially 2008 to 2015. It is against this background, of expected changes to key drivers, that the forecasts have been reviewed.

Chapter 3 commences by setting out the Ergon Energy system maximum demand history and forecasts for the coming review period. It then provides an overview of the Ergon Energy forecasting methodologies at both the system and spatial levels. It should be noted, however, that only the spatial forecasts were used in deriving the growth capex for the Regulatory Proposal. It then provides the key findings of the preliminary review of approach and methodology and follows these with commentary about other forecasts that Ergon Energy has used to support those it relied on for the capex forecasts.

The maximum demand forecasts at spatial level are considered in detail in Chapter 4, focusing on the contributing ZSS, while those at system level are considered in Chapter 5.

MMA's conclusions regarding the forecasts used by Ergon Energy are summarised in the Executive Summary.

1.6 Conventions adopted and glossary

Unless otherwise stated, all years referred to in the report are for financial years ending June 30 of the year stated. For example, unless otherwise stated, 2010 refers to the financial year ending June 30th 2010.

We refer throughout the text to system and spatial load forecasts. System in this context refers to forecasts at system-wide or network or regional level for the appropriate season, while spatial refers to the more local level, typically that of zone substations.

We provide a glossary of terms and abbreviations in Appendix A.

2 KEY DRIVERS OVER THE PERIOD TO 2015

2.1 Key drivers of maximum demand

In his reference text on spatial electric load forecasting, H Lee Willis has pointed out that peak demand in a utility grows for only two reasons[1]:

- new consumer additions. Load will increase if more consumers buy electricity.
- new uses of electricity by existing consumers. Existing consumers may add new appliances or replace existing equipment with appliances that require more power[2].

Similarly, any reduction of peak load growth is due to a reduction in either or both of these factors.

We consider below six key drivers of maximum demand change in Queensland and, where appropriate, the relevant Ergon Energy and Energex regions:

- economic growth
- population, dwelling and new customer growth
- growth of air-conditioning penetration and usage
- changes in climate
- energy efficiency and greenhouse gas reduction measures
- the Carbon Pollution Reduction Scheme and other price impacts.

The following sections of this Chapter compare expected changes expected in these drivers against recent history, typically the period 2002 to 2008. Unless there are significant changes to some or all of these drivers, the expectation of future growth is that it will be similar to recent growth.

In the following chapters we consider whether expected changes to key drivers have been appropriately taken into account in the forecasting methodologies used by Ergon Energy. To the extent we have considered this to not be the case we have provided an indicative assessment of the effect of incorporating these drivers on demand forecasts.

2.2 Economic growth

In assessing the general economic outlook over the next five to six years MMA has considered forecasts by the National Institute of Economic and Industry Research (NIEIR)[3] and KPMG Econtech[4].

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1 H Lee Willis, "Spatial Electric Load Forecasting" Second edition 2002, page 211.

2 To these might be added a power factor consideration although this is probably included within the second consideration and Willis only accords this a relatively low priority (Willis, page 33).

Over the past several years economic growth in Queensland has exceeded that for Australia as a whole. Between 2002 and 2008 the Queensland economy, as measured by Gross State Product (GSP), grew by 5% pa, significantly higher than the Australian economic growth rate of 3.3% pa.

In 2007 and 2008, when forecasts by the networks for the coming regulatory period were being prepared, the outlook for growth in Queensland was still strong. NIEIR's forecast of growth in Queensland GSP over the period to 2015 was some 3.9% pa in November 2007 and 4.2% pa in September 2008[5]. In October 2008 KPMG Econtech was forecasting Queensland GSP growth to average some 5% pa over the period 2008 to 2015, in line with recent growth[6].

However, as a result of the GFC, the outlook has changed substantially.

The most recent (August 2009) KPMG Econtech report[7] forecasts a very strong downturn, a contraction by 4.8%, for the Queensland economy in 2009. The three key components to this downturn were reduced consumer spending, the "demise" of the local property market and the decline in mining investment. Growth in 2010 is forecast to remain weak at 1.4%. Over the longer term from 2011 to 2015, stronger growth averaging over 3.5% pa is expected to resume with continued population growth and recoveries in the commodities and property markets. Even this is only some 70% of the growth rate experienced between 2002 and 2008. However, over the entire period of interest, 2008 to 2015, Queensland growth is expected by KPMG Econtech to average only 2% pa – less than half what it averaged over the earlier period. By comparison, the NIEIR April 2009 report for Energex forecast an annual growth rate of Queensland GSP of around 3% pa between 2008 and 2015.

Economic growth is considered to be a key driver of growth in maximum demand, especially in the business sector. It is, for example, often used as a predictor of non-residential energy consumption and is a key input in the global maximum demand models of a number of DNSPs. It clearly also has a significant impact on the system maximum demand forecasts for Energex, with the GFC resulting in a significant reduction in both GSP and a maximum demand forecast by NIEIR post GFC which is significantly less than the Energex forecast prior to the GFC[8].

MMA considers that the very significant expected reduction in Queensland economic growth, from 5% pa over the period 2002 to 2008 to a forecast 2-3% pa over the period of 2008 to 2015 needs to be taken into account when forecasting maximum demand growth over the period of interest.

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3 National Instiute for Economic and Industry Research in various reports to Energex and Ergon Energy from 2007 to 2009 including report to Energex, "Electricity consumption and maximum demand projections for the ENERGEX region to 2019", April 2009.

4 KPMG Econtech, "Australian National State and Industry Outlook" various issues.

5 NIEIR report to Ergon Energy, "Maximum demand forecasts for Ergon Energy connection points to 2017", November 2007 and later report in September 2008.

6 KPMG Econtech, "Australian National State and Industry Outlook" October 2008.

7 KPMG Econtech, "Australian National State and Industry Outlook" , August 2009.

8 Energex Regulatory Proposal for the period 2010 - 2015, page 154.

It must also be stressed that the economic impacts of the GFC are unlikely to be "recovered" over the period to 2015. By the year 2015 the April 2009 NIEIR GSP forecasts for Queensland are over 8% below those NIEIR made in September 2008. Similarly, it would be expected that components of maximum demand which rely on economic growth would be similarly affected. In other words, the GFC would not just delay projects. It would also be expected to result in significantly fewer (or smaller) projects than would have otherwise been the case.

2.3 New customer growth

Each additional new customer can be expected to add growth to both spatial and system peak demand, estimated by the peak demand of that customer multiplied by the appropriate coincidence factors[9].

Both the population and number of dwellings in Queensland have been growing strongly and these are also understood to have played a part in the growth in maximum demand.

While the rates of growth of population and household formation are still expected to remain reasonably strong, and stronger in Queensland than in most other states, these might be tempered by the slow-down due to reduced commodity prices and hence employment and expected reduction in overseas migration.

2.3.1 Queensland Population growth

Over the period 2002 to 2008 Queensland population grew at a rate of about 2.4% pa[10] due largely to growth in overseas migration. As with economic growth, this population increase is significantly greater than that for the Australian population as a whole (about 1.5% pa over that period) reflecting the high economic and employment growth experienced in Queensland over these years. It is also significantly stronger than the rate of growth seen in Queensland over the period 1996 to 2002 of 1.9%.

In September 2008 NIEIR[11] projected population growth in Queensland to moderate to about 2.1% pa over the period 2008 to 2015. The NIEIR population forecast for Queensland as a whole is shown in Table 2-1.

9 The coincidence factor needs to take into account the level of aggregation (eg zone substation, transmission substation or network) and the time of maximum demand (eg summer day or summer night) and associated levels of coincidence.

10 Australian Bureau of Statistics 3101, Demographic Statistics, December 2008

11 NIEIR report to Ergon Energy, "Maximum demand forecasts for Ergon Energy connection points to 2018", September 2008..

Table 2-1 NIEIR population projection growth rates for Queensland (% pa)

Year	Population ('000)	Annual Growth
2006	4202	2.4%
2007	4295	2.2%
2008	4393	2.3%
2009	4491	2.2%
2010	4587	2.1%
2011	4678	2.0%
2012	4770	2.0%
2013	4877	2.2%
2014	4983	2.2%
2015	5089	2.1%
2008-2015		2.1%

Source: NIEIR[12]

The forecast growth of 2.1% pa is in line with the middle population projection for Queensland produced by the Australian Bureau of Statistics (ABS) in September 2008 which forecast growth between 2008 and 2015 of 2.1% pa. The ABS projections are shown in Table 2-2. The ABS high growth scenario (Series A) and low growth scenario (Series C) projected population growth of 2.6% pa and 1.7% pa respectively.

12 NIEIR report to Ergon Energy, "Maximum demand forecasts for Ergon Energy connection points to 2018", September 2008.

Table 2-2 ABS population projection growth rates for Queensland (% pa)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2008-2015
Series A	2.2%	2.3%	2.5%	2.6%	2.6%	2.6%	2.6%	2.5%	2.5%	2.6%
Series B	2.2%	2.2%	2.2%	2.2%	2.2%	2.1%	2.1%	2.1%	2.0%	2.1%
Series C	2.2%	2.1%	2.0%	1.8%	1.7%	1.7%	1.7%	1.6%	1.6%	1.7%

Source: ABS, *Population Projections Australia*, 4 Sep 2008.

By contrast, the population growth projected by KPMG Econtech is significantly more bullish for Queensland. In its report to NEMMCO[13] as well as in the August 2009 issue of its quarterly *Australian National, State and Industry Outlook*,[14] KPMG Econtech noted that Queensland is a "rapid population growth state". In the latter publication KPMG Econtech forecast that over the three years to 2010/11, the Queensland population would grow by 2.8% pa[15]. This is well above the 2% growth rate expected of Australia as a whole and is significantly higher than the NIEIR and ABS projections. It is also higher than the forecast that KPMG Econtech provided to NEMMCO in March 2009 when it forecast a growth rate for Queensland of 2.2%[16].

In December 2008 NIEIR forecast population growth for Queensland to average 2.1% pa over the period 2008 – 2014[17] On balance we consider the NIEIR and middle ABS forecasts to be more likely outcomes.

2.3.2 Population growth in network regions

The NIEIR forecasts prepared for both Energex and Ergon Energy also allow comparison of population growth rates for populations in the regions served by the networks – essentially south east Queensland for the Energex network and the rest of Queensland for Ergon Energy. The population in the south east Queensland region covered by the Energex network has been growing at a rate materially greater than has population in the Ergon Energy region, some 2.6% pa versus 2.1% pa over the period 2002 to 2008. NIEIR projects the disparity in population growth rates to continue, with population in the Energex region forecast to grow at some 0.2% pa more than across the state as a whole and in the Ergon Energy region some 0.4% or 0.5% less than across the state as a whole. According to the September 2008 NIEIR forecasts[18], population growth in the south east Queensland region between 2008 and 2015 is forecast to be some 2.3% pa and in the rest of Queensland (Ergon Energy network area) some 1.7% pa. This is consistent with recent history.

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13 KPMG Econtech, *NEMMCO Ltd Stage 2: Economic Scenarios and Forecasts for the NEM Regions 2008-09 to 2028-29*, March 2009 .

14 KPMG Econtech, "Australian National State and Industry Outlook" , August 2009.

15 KPMG Econtech, *Australian National, State and Industry Outlook 20 August* 2009.

16 KPMG Econtech, *NEMMCO Ltd Stage 2: Economic Scenarios and Forecasts for the NEM Regions 2008-09 to 2028-29*, March 2009.

17 NIEIR report to Ergon Energy, "Economic outlook for Australia and Queensland to 2018-19", December 2008.

18 NIEIR report to Ergon Energy, "Maximum demand forecasts for Ergon Energy connection points to 2018", September 2008

2.3.3 Dwelling numbers

Dwelling numbers in Queensland have been growing at about 2.3% pa between the 1996 and 2006 censuses. The census details for total and occupied private dwellings are provided in Table 2-3 as well as populations and a calculated number of persons per total dwellings (ppd) in each of the years.

Table 2-3 Total and occupied private dwellings, population and persons per dwelling in Queensland

Census	Total dwellings	Occupied dwellings	Population	Ppd
1996	1,325,559	1,204,072	3,355,031	2.53
2001	1,482,912	1,355,613	3,649,488	2.46
2006	1,660,750	1,508,522	4,114,858	2.48

Sources ABS Cat. No. 2068.0 - 2006 Census Tables.

Dwelling growth is a combination of population growth and changes in persons per dwelling known as the occupancy rate. The occupancy rate has been reducing over recent years across Australia and was generally expected to continue doing so. For example, between the 1996 and 2001 censuses the rate of growth of occupancy rate in Queensland was some -0.6% pa[19]. The combination of population growth of 1.7% pa and a reducing occupancy rate of -0.6%pa resulted in the observed dwelling growth rate of 2.3% pa.

However, between the 2001 and 2006 censuses the occupancy rate in Queensland actually increased. Thus the same observed dwelling growth rate (2.3% pa) was the result of a combination of a higher population growth rate (2.4% pa) together with an increasing occupancy rate (0.1% pa).

In the years 2007 and 2008 there has been a similar outcome to that seen between 2001 and 2006. The gross growth rate in dwelling completions[20] has been about 2.4% pa, while the estimated Queensland population growth rate between June 2006 and June 2008 has been about 2.5% pa.

A number of reasons have been suggested for the change in occupancy rate growth from negative to flat or positive between 1996 and 2006, including the high cost of accommodation, lower divorce rates and increase in fertility. However, the underlying causes and the direction of occupancy rate growth over the period to 2015 remain unclear.

NIEIR's September 2008 forecasts of dwellings and population for the Ergon Energy area provide an expectation that the occupancy rate will stay approximately constant over the period 2008 to 2015 for Queensland as a whole. MMA considers this to be a reasonable expectation. However, NIEIR does differentiate between the Energex and Ergon Energy regions. While the occupancy rate for Energex is expected to remain approximately flat, that for Ergon Energy is expected to reduce slightly, by some 0.2% pa.

19 Calculated as Queensland population divided by Queensland Total Private Dwellings.
20 ABS, 8752.0 Building Activity, Australia,

As a result, the September 2008 NIEIR forecasts over the period 2008 to 2015 were for dwellings in the Ergon Energy part of Queensland to grow at just under 2% pa, a little higher than population growth). However, this forecast was carried out before the impact of the GFC was felt. There is an expectation that the GFC will result in a slight reduction in population and dwelling growth over the period to 2015.

2.3.4 Customer number growth

Network customer numbers are dominated by residential customers. It is therefore to be expected that the rate of growth of network customer numbers would approximately equal the rate of growth of dwellings.

According to the Regulatory Information Notice (RIN) numbers provided by the DNSPs, over the period 2002 to 2008 total customer numbers grew by about 2.4% pa, approximately the same rate as the rate of growth of population (which is consistent with dwelling growth, given that the occupancy rate was approximately steady over the period).

However, as for population growth, the customer growth rates have been somewhat uneven across the state, with total customer numbers provided in the RIN growing by 2.2% pa for Ergon Energy. However, growth in Ergon Energy's active customer base, excluding street-lights, un-metered and watchman lights between 2004 and 2008 has been 1.9% pa, which is consistent with the NIEIR understanding of dwelling growth in that region over that period [21].

According to the RIN Ergon Energy is forecasting a customer growth rate of 1.6% pa. This growth rate is somewhat lower than the growth in dwellings forecast by NIEIR in September 2008 of 1.95% pa.

While MMA does not consider the Ergon Energy customer number forecasts to be unrealistic, they do appear a little low compared to NIEIR forecasts, even after some effect of the GFC is taken into account. MMA has therefore used a customer number growth forecast of 1.8% pa in its indicative assessment of Ergon Energy system maximum demand in Chapter 5.

2.3.5 Ramifications for customer number growth as a key driver

As stated above, each new customer can be considered to represent an additional new load for the network[22]. Based on the above analysis, the growth rate in customer numbers expected from 2008 to 2015 will be a little lower in percentage terms than the growth rate seen recently, some 1.8% pa for Ergon Energy against 1.9% seen in recent years.

[21] Data provided by Ergon Energy in PL780c has only allowed an estimate of active customers excluding streetlights and unmetered and watchlights from 2004 to 2008 because of data limitations within the legacy systems. We have used these numbers to estimate the active customer growth rates between 2004 and 2008.

[22] For example, at an indicative after diversity maximum demand (ADMD) of 2 kW at system level for a new customer, a residential customer growth rate of 2% pa will result in an average annual increase of 28 MW pa in system MD over the period 2008 to 2015 compared with an average annual increase of 22 MW for the Ergon Energy assumed growth rate of 1.6% pa. A difference of 6 MW is about 6% of the expected annual system MD growth rate.

While this is a reduction in percentage terms, in linear terms the growth rate in customer numbers is expected to remain reasonably steady.

Overall, the impact of additional customer numbers can be expected to remain about the same as, or slightly less than, the impact of customer number growth over recent years.

2.4 Air- conditioning growth

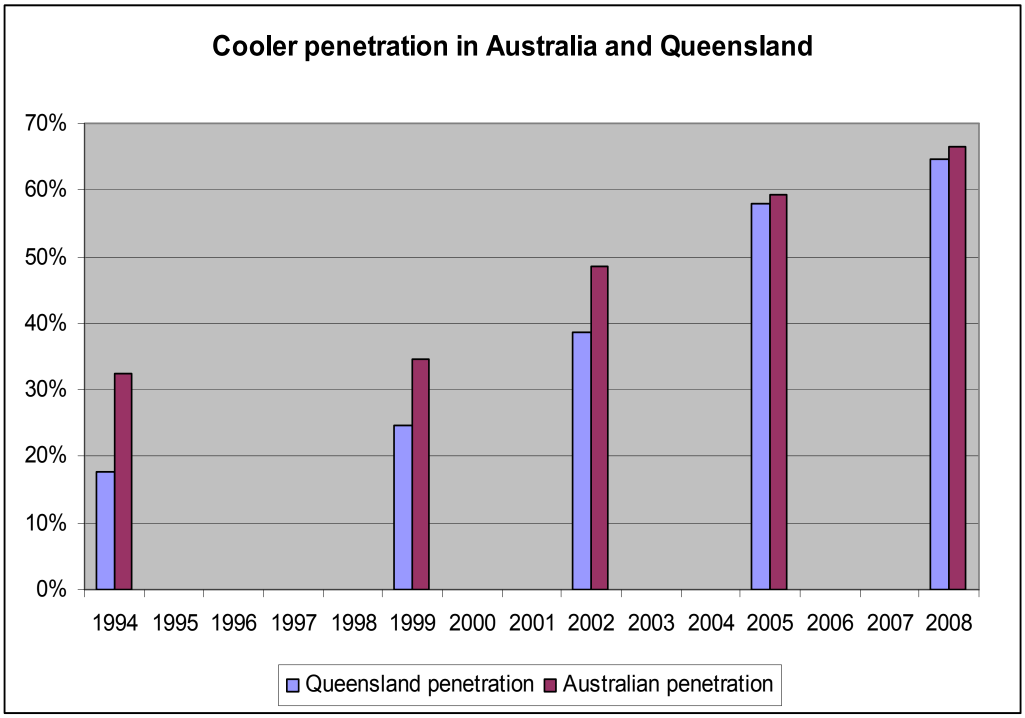
2.4.1 Penetration of air-conditioners in Queensland

The Australian Bureau of Statistics (ABS) has been collecting survey data on air-conditioner penetration across Australia since 1994 in its 4602 series, "Environmental issues: people's views and practices". The dates of the surveys with relevant air-conditioner data have been June 1994 and March 1999, 2002, 2005 and 2008. The most recent publication in the series, relating to the March 2008 survey, was published in November 2008[23].

The proportion of dwellings with coolers in Australia and Queensland is shown in Figure 2-1. Penetration of air-conditioning in Queensland and Australia has grown very strongly over the period 1994 to 2008. While the penetration rate in Queensland commenced at a lower level than that seen across the rest of Australia, since 2005 it reached approximately the same level as that seen across Australia. This means that the penetration rate of households with air-conditioners has increased more quickly in Queensland than it did in Australia as a whole over that period.

[23] Australian Bureau of Statistics, Publication 4602.0.55.001, "Environmental issues: energy use and conservation, March 2008" published November 2008.

Figure 2-1 Proportion of dwellings with coolers in Australia and Queensland, 1994 to 2008

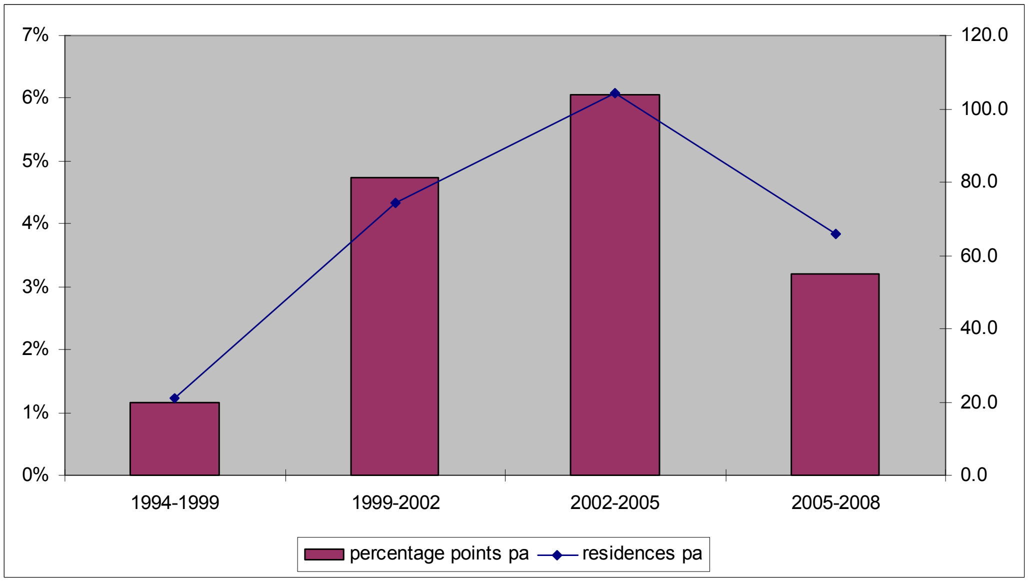


Source ABS 4602.0.055.001. Note that the series includes evaporative air coolers.

The above series includes evaporative air coolers. As evaporative coolers consume significantly less energy than do the reverse cycle and refrigerative air coolers, they are of less interest in terms of maximum demand than these other types of coolers. Over the past decade there has been a decline in evaporative air coolers, which means the rate of increase of non-evaporative air-conditioners is understated in the above Figure.

Figure 2-2 shows the average annual growth in penetration rate of non-evaporative air-conditioners in Queensland over the periods 1994 to 1999, 1999 to 2002, 2002 to 2005 and 2005 to 2008. The columns illustrate the average percentage point growth pa (growth in penetration rate over the period divided by the number of years) and use the left hand axis. The "residences pa" line shows on the right hand axis the average number of additional homes per year, in '000s, which installed air-conditioning for the first time over each survey period. This latter measure takes into account the growing number of dwellings in Queensland.

Figure 2-2 Average annual growth in penetration rate between survey periods (percentage points pa) and number of additional homes with non-evaporative air-conditioning each year ('000)



Source ABS 4602.0.055.001.

According to the ABS, the penetration rate of non-evaporative air-conditioning in Queensland increased slowly (by about 1 percentage point pa) between 1994 and 1999 but then grew very rapidly at around 5.5 percentage points pa between 1999 and 2005. This coincided with a strong increase in maximum demand. However, the growth slowed quite significantly over the period 2005 to 2008 as the penetration rate started to approach saturation level. Over the period 2005 to 2008 the average growth rate was 3.2 percentage points pa, about 60% of that seen over the previous two periods.

There has also been a significant reduction in the number of additional houses with air-conditioners, which is considered a key driver of maximum demand growth, although not as pronounced as the reduction in percentage point growth rates. Between 1999 and 2005 about 90,000 additional dwellings gained air-conditioning each year[24]. Between 2005 and 2008 this reduced to 66,000 pa, about three quarters of the growth seen over the previous periods.

A similar conclusion in terms of penetration rates can be drawn from the following diagram reproduced from the Powerlink Annual Planning Report 2009[25].

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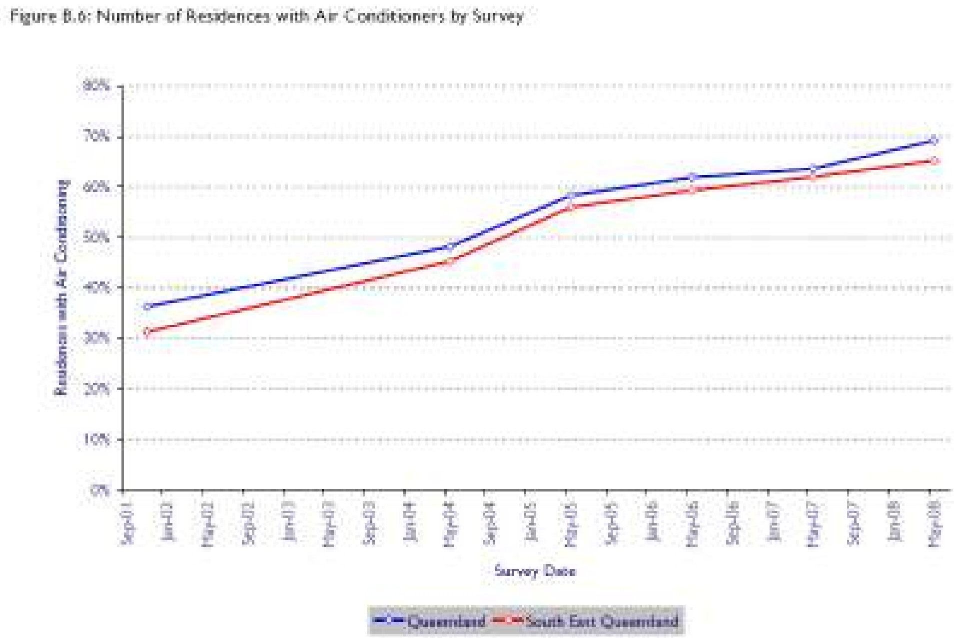
24 This is a combination of new homes and existing homes which install air-conditioning for the first time.

25 Powerlink Queensland, "Annual Planning Report", 2009, page 110

Figure 2-3 Number of residences with air-conditioners in Queensland and south east Queensland



Source: Powerlink APR 2009.

Reading from the graph, for Queensland as a whole, over the six years between May 2002 and May 2008 the penetration rate increased from about 38% to about 69% - an increase in penetration of about 5 percentage points pa. However, growth in penetration was definitely more rapid in the early years of the period. Between May 2002 and May 2005 penetration increased from about 38% to 59% (7 percentage points pa) while from May 2005 to May 2008 the rate grew at only just over 3percentage points pa. Very similar estimates are applicable to south east Queensland.

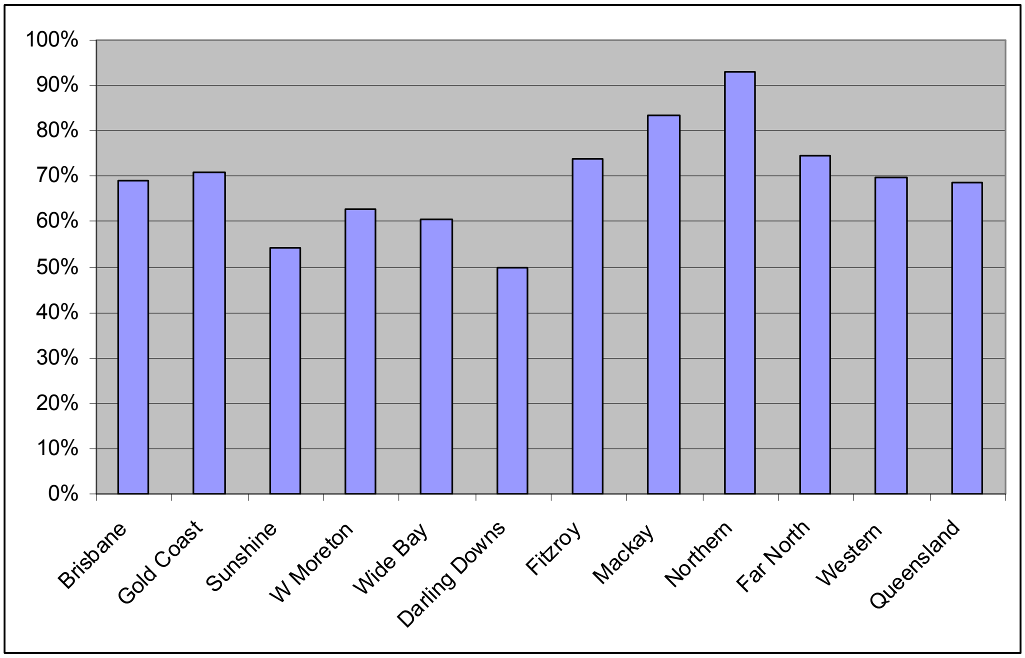
2.4.2 Regional distribution of air-conditioners

The Queensland Government through the Office of Economical and Statistical Research (OESR) has over the past few years carried out surveys of Queensland households which assess levels of air-conditioning and other appliances at a regional level. We believe the Powerlink figure shown in Figure 2-3 above is derived (at least in part) from these surveys.

The penetration of air-conditioning (excluding evaporative cooling) in May 2008, by region and for Queensland as a whole according to the May 2008 OESR survey[26] is shown in Figure 2-4.

[26] Queensland Office of the Government Statistician, "May 2008 Queensland Household Survey".

Figure 2-4 Air-conditioner penetration by statistical region, May 2008



Source: OESR May 2008.

As can be seen, the air-conditioner penetration rate for Queensland as a whole by May 2008 was approaching 70%. Air-conditioner penetration is highest in the Northern, Mackay, Fitzroy and Far North regions of Queensland, each with penetration of over 70% and lowest on the Sunshine Coast and Darling Downs.

Although MMA does not have long-term historical information about the regional distribution of air-conditioning penetration of air-conditioners, from survey penetration information supplied by Ergon Energy[27] the growth rate over the period 2004 to 2008 has averaged around 5 percentage points pa in most parts of Queensland and somewhat lower, around 3 percentage points pa in the parts of Queensland with high existing penetration rates. The slower growth rates observed in areas with already high penetration is understandable as the air-conditioner levels in those regions start to approach saturation.

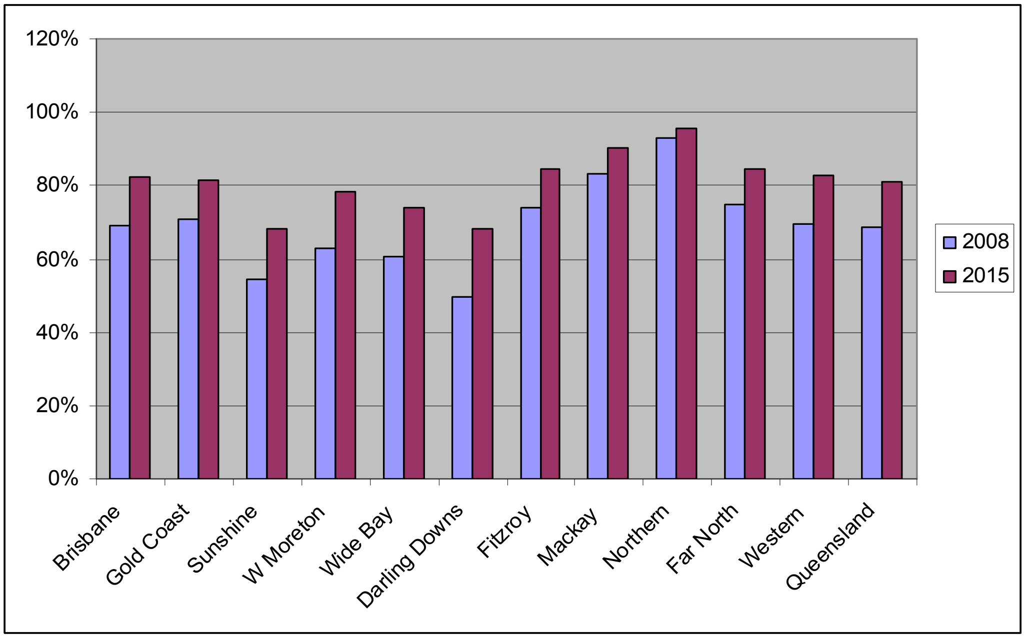
2.4.3 Indicative levels of penetration saturation

The OESR surveys asked respondents without air-conditioning about their intention to purchase air-conditioning and the time frame for any such purchase. By using the number who responded that they intend to never purchase air-conditioning together with expected new customer growth rates, an estimate can be made of the ultimate penetration rate for existing homes. These ultimate penetration rates for existing homes range from a high of 94% in the Northern statistical region to 58% on the Sunshine coast.

[27] Ergon Energy AR540, "Air-conditioning penetration trend QHS additional" provided with the public attachments to the Ergon regulatory proposal.

However, on the expectation that most new dwellings will have air-conditioning, and that the proportion of those who expect to never have air-conditioning will reduce over time[28], an estimate can be made of the expected ultimate penetration by region by the year 2015[29]. This estimate is illustrated in Figure 2-5.

Figure 2-5 Current level of air-conditioner penetration by region and expected saturation level in 2015



2.4.4 Estimated average annual growth rates in air-conditioner penetration and households with air-conditioning

MMA's projections of penetration of households with air-conditioning and number of air conditioned houses by 2015 in the Energex and Ergon Energy networks and for Queensland as a whole are provided in Table 2-4. The Table also provides estimates of comparable numbers in 2004 and 2008 and provides estimated growth in these parameters over the period 2004 to 2008 and 2008 to 2015.

28 Because householders change their minds or move home or the dwellings get demolished.

29 We have assumed household number growth by 2.2% in the Energex regions in line with the RIN forecasts but 1.8% pa in the Ergon Energy regions which is a little higher than the 1.6% pa in the Ergon Energy RIN forecasts. We have also assumed that almost all of the new customers have air-conditioning and that the number of customers who say they will "never" get air-conditioning reduces by 2% pa.

Table 2-4 Air conditioner penetration (%), number of air conditioned houses ('000), growth in penetration (percentage points pa) and number of air conditioned houses ('000)

	Energex			**Ergon Energy**			**Queensland**		
	2004	**2008**	**2015**	**2004**	**2008**	**2015**	**2004**	**2008**	**2015**
Air-conditioner penetration	47%	68%	81%	56%	71%	82%	50%	69%	81%
Houses with air-conditioning ('000)	454	715	992	266	365	470	720	1,080	1,462
Growth over the period		**2004-2008**	**2008-2015**		**2004-2008**	**2008-2015**		**2004-2008**	**2008-2015**
Penetration – percentage points pa		5	1.8		4	1.6		5	1.7
Air-conditioned houses ('000)		65	40		25	15		90	55

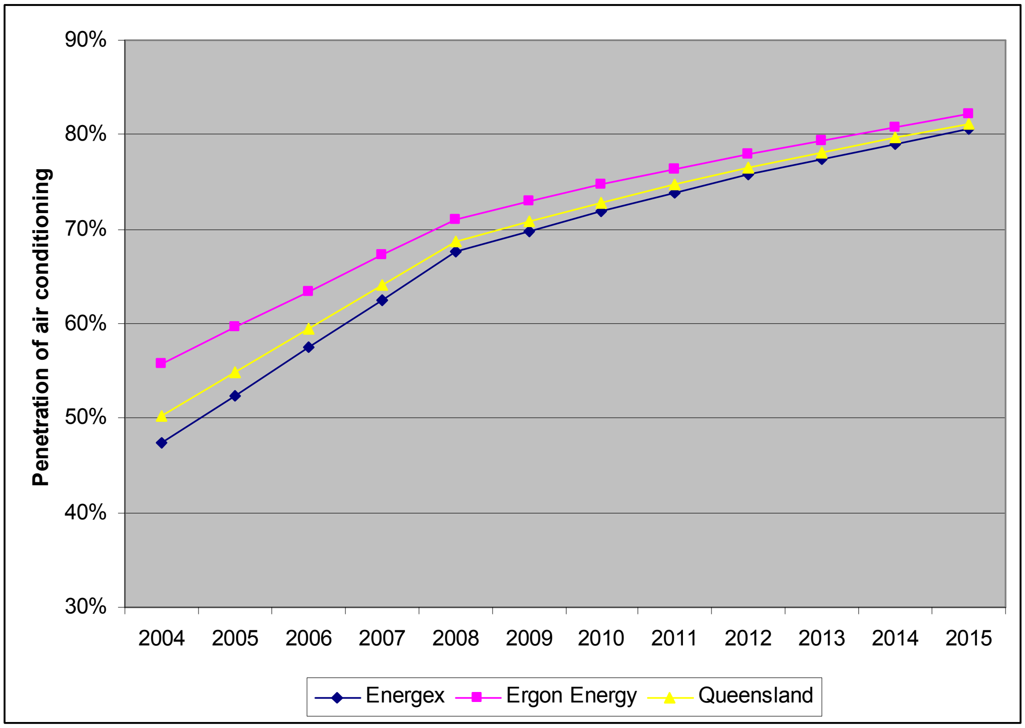
Over the period 2004 to 2008 air-conditioner penetration grew by an estimated 4 to 5 percentage points pa across Queensland, a little slower for Ergon Energy than for Energex. This is about the same rate of penetration growth as seen between 1999 and 2002 but slower than the rate from 2002 to 2005.

However, the level of penetration appears to be approaching saturation. We project saturation levels by 2015 to average about 81% to 82% of all homes across Queensland. Given that average penetration levels were about 69% in 2008 this means that the increase from 2008 to 2015 will only average about 1.5 to 2 percentage points pa over the entire period – significantly slower than the 4 - 6 percentage points average annual increase seen over the period 1999 to 2008.

In terms of absolute growth in houses with air-conditioning the expected reduction in new growth is a little less, with newly air conditioned houses across the state growing at about 55,000 pa over the period 2008 to 2015 compared to about 90,000 pa over the period 2004 to 2008 – a reduction of some 40%. Note, however, that in terms of the rate of growth of housing with air-conditioning this equates to an expected growth rate of 4% to 5% pa, down from about 8% to 12% over the previous period.

The average penetration growth rate for Energex is projected to be 1.85 percentage points pa over the period 2008 to 2015, while that for Ergon Energy is projected to be a little lower at 1.6 percentage points pa. We consider it reasonable to adopt a straight line approach to number of additional houses with air-conditioning over time, meaning that the growth in penetration rate declines over the period. The average penetration rates over the period 2004 to 2008 and MMA projections of penetration rate are illustrated in Figure 2-6.

Figure 2-6 Penetration rate of air-conditioning in Queensland and the network areas



Note: trend growth rates over the period 2004 to 2008 and MMA estimates from 2008 to 2015.

2.4.5 Impact of reduced growth in air-conditioning penetration

Given that the number of new homes being built is expected to remain about the same as it has over the past several years (see Section 2.3), and that most of these are expected to have air-conditioning, this means that the number of existing homes which become air conditioned for the first time is expected to drop very significantly when compared to the previous period. We estimate the reduction to be from over 42,000 existing homes in the Energex region taking on air-conditioning each year between 2004 to 2008 to only 16,500 existing homes doing so between 2008 and 2015 – a reduction of some 60%. The comparable numbers for Ergon Energy are an average of almost 16,000 existing homes taking air-conditioning each year for the first time between 2004 and 2008 compared to an average 5,100 pa between 2008 and 2015, a reduction of almost 70%.

If we indicatively assume that the fully diversified air-conditioning load is some 1 kW per household then it would reduce trend growth by of the order of 10 MW pa for Ergon Energy (about 10% of recent trend growth).

MMA has used the changes to customer number penetration assessed in Section 2.3 above in its indicative assessment of Ergon Energy system maximum demand in Chapter 5.

2.4.6 Considerations other than penetration

A multitude of other factors can be taken into account when trying to assess the likely contribution of cooling to maximum demand over the coming period, including:

- increasing size of air-conditioners
- increasing numbers of air-conditioners in households
- increasing house size
- increasing efficiency of air-conditioners
- improving thermal efficiency of houses (including additional insulation as part of the stimulus package)
- air-conditioner saturation effects
- increased price of electricity, including effect of the CPRS (see Sections 2.5 and 2.7)
- effect of the GFC and stimulus package on installation and use of air-conditioners
- climate impacts
- increased energy and greenhouse awareness

These, and other factors, are often included in an assessment of trend changes over time but are very difficult to model with any accuracy separately. On balance we consider that changes to these are likely to be similar to those experienced over recent periods and that these are secondary compared to the expected changes in air-conditioner penetration rate.

2.5 Climate change

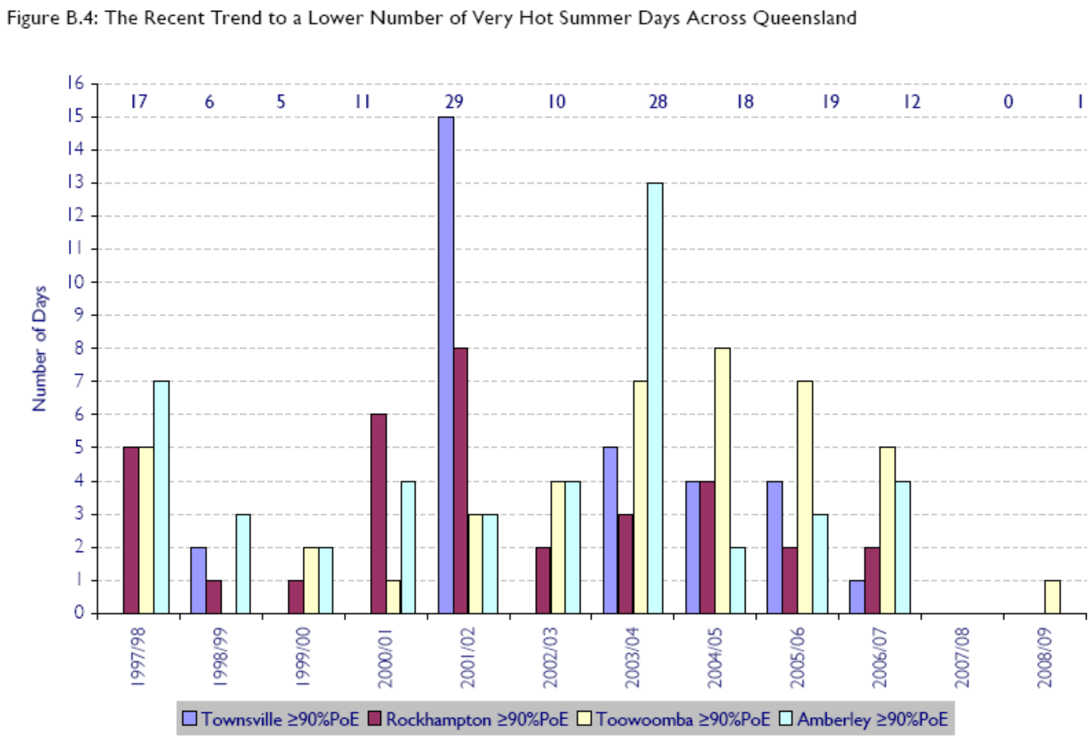
Weather, mainly temperature but also humidity, wind and other factors, has a strong influence on electricity demand variation from hour-to-hour and day-to-day. Peak summer demand is associated with high temperatures and a significant amount of variation in peak demand from year-to-year is due to differences in peak temperatures. To estimate underlying peak demand growth rates it is necessary to correct for the temperature differences, for example by calculating demand temperature sensitivity and estimating demand at a standardised peak temperature with a given probability of occurring.

Weather sensitivity also suggests that peak demand will change in response to global warming, though the global warming induced changes in peak temperatures are likely to be small in comparison to variations from year-to-year. More significant global warming induced changes to peak demand may result from changes in the duration of hot weather, such as the 16 consecutive days over 35 C experienced in Adelaide in March 2008, which resulted in new demand peaks in South Australia. However, the probability of such events is insufficiently quantifiable for inclusion in forecasts at present.

There is no evidence of any increase to peak temperatures in Queensland over recent years. Indeed, over the past 4 years since 2004/05 south east Queensland at least has experienced a range of summers[30] but, according to Powerlink, only a limited number of very hot days on working days - resulting in the maximum demand for the Energex network being lower than expected.

According to Powerlink, the number of days in summer which have achieved a greater than 90% POE temperatures (i.e. a temperature which would be expected to be exceeded in 9 out of 10 summers) is shown in Figure 2-7, reproduced from the Powerlink 2009 APR[31]. Although the label caption refers to a "recent trend to a lower number of very hot summer days across Queensland", it is not apparent from the Figure that such a trend exists. The 90% POE temperature is by definition expected to be exceeded in 9 years out of 10 – and from the Figure is exceeded in 10 years out of 12 for all stations reported, which is unexceptional[32]. While the last two years appear to have been mild in terms of less than average very hot days, especially on working days, this may well be by chance.

Figure 2-7 Number of hot summer days across Queensland



Source: Powerlink 2009 APR Figure B.4.

30 According to Powerlink, prevailing south east Queensland weather conditions were average in 2004/05, very hot in 2005/06 but with a lack of very hot working days and mild to average but with a limited number or lack of hot days in 2006/07, 2007/08 and 2008/09. Powerlink Annual Planning Report 2009, page 26.

31 Powerlink Annual Planning Report 2009, page 109.

32 In addition, Table 3.4 of the Powerlink Annual Planning Report 2009, page 26 provides details of working and non-working days which exceeded 30C , the 50% POE temperature at Amberley,the weather station used for south east Queensland weather correction. According to that Table this temperature was exceeded in 8 of 11 years and on working days in 6 of11 years. Both of these appear to be unexceptional for a temperature which should be exceeded only 1 year in 2.

The mild weather over the past two summers does, however, raise some potential difficulty with using 2007/08 and 2008/09 data, especially if trend analysis is used as a main forecast tool. In such a case the 2006/07 summer may be a more appropriate year to use as a starting point, although this risks losing information on any genuine change in the trend over the last two years.

2.6 Carbon Pollution Reduction Scheme

The Federal Government intends to introduce the Carbon Pollution Reduction Scheme (CPRS) from 1 July 2011. According to the Government's White Paper, the CPRS is expected to increase electricity prices to households by about 18 per cent and gas prices by about 12 per cent[33], although the full effect of this will likely not be felt until 2012/13 as the carbon price is capped at $10/t CO_2e until then.

While a significant increase in electricity prices is sometimes expected to impact almost exclusively on energy usage (and not on maximum demand), research in South Australia suggests this is not the case.

Over the past two years Monash University Business and Economic Forecasting Unit has created new approaches to forecasting peak demand for South Australia for ESIPC, including the use of summary econometric models to estimate the GSP and price sensitivity of energy and summer and winter 10% POE peak demands. The outcomes of this modelling are summarised in ESIPC's 2008 APR[34]:

"*Historic and forecast levels of customer sales and the summer and winter 10% POE levels have been used to identify summary econometric models and estimate the price and income elasticity of each electricity variable. Currently, back-cast peak demand POE levels have been used rather than the forecasts prepared in earlier years. These models are different from those used to develop the forecasts and should be regarded as part of a post-forecast review rather than forecasting models per se. Nevertheless, they provide a good basis to identify the sensitivity of the forecasts to the key assumptions about GSP and price. Regression results show a price elasticity of minus 0.28*[35] *for sales (with a lag of one year), minus 0.23 for the summer 10% POE peak (with a lag of two years), and minus 0.28 for the winter 10% POE peak. (The price elasticity shown here for customer sales is for combined residential and business sector sales. Our actual forecasting model treats each sector separately and identified a price elasticity of minus 0.31 for residential sales and minus 0.17 for business sales). The estimated income elasticity, which measures the relative change with respect to GSP, is 0.77 (with a lag of one year) for the summer peak, 0.98 for the winter peak, and 0.86 (with a lag of one year) for sales.*"

The above quote shows that, for South Australia at least, the price elasticity of peak demand is of similar order of magnitude to the price elasticity of annual energy demand.

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33 Australian Government White Paper, *Carbon Pollution Reduction Scheme, Australia's Low Pollution Future, Vol 2*, Dec 2008, page 17-3. In fact, the full sentence, in the section "Impact of the scheme on households" reads "Electricity prices are estimated to increase by around 18 per cent and gas prices by 12 per cent."

34 Annual Planning Report, ESIPC, June 2008.

35 Amended by ESIPC from -0.21 to -0.28. See letter from ESIPC to S Edwell dated 31 October 2008.

In other words, a price increase is expected to have a material impact on maximum demand as well as energy.

While there are uncertainties related to the CPRS[36], MMA considers that its impact should be given some consideration in forecasting of maximum demand over the medium-term. At the very least it would be expected to have a negative impact in energy and maximum demand, although the extent may be unclear.

2.7 Impact of proposed network price increases

Within their regulatory proposals, Energex and Ergon Energy have both proposed very similar levels of revenue escalation through the X factors in a CPI-X tariff mechanism, Energex with X being -25.3% in 2010/11 followed by -8.4% thereafter[37] and Ergon Energy with X being -27.05% in 2010/11 followed by -7.69% thereafter[38]. This means very substantial expected real distribution price increases in the first year and still material price increases thereafter.

According to Ergon Energy, the result of its regulatory proposal would be to increase standard control services for Standard Access Customers from 8.475 c/kWh in 2009/10to 12.11 c/kWh in 2010/11 an increase of 43%[39]. This is followed by an annual decline of about 3.6% each year.

While the final price outcome is unclear, the expected delivered price increase would be additive to the CPRS increases discussed in Section 2.6 above and would be expected to also have an impact on both energy consumption and maximum demand. The proposal by the Queensland Competition Authority (QCA) to move towards cost reflective tariffs[40] may also result in further price increases.

2.8 Energy efficiency and other programs

Both households and the non-residential sector are expected to become more energy efficient over time due to a combination of, among other factors:

- attempts to reduce greenhouse gas emissions including the CPRS referred to in Section 2.6 above
- national reporting of greenhouse emissions by large commercial and industrial energy users from 1 July 2008
- minimum energy performance standards (MEPS) required on a range of appliances by the Federal Government

[36] Including the price and timing of introduction given the GFC, the price elasticity of maximum demand and the effect of substitute fuels such as gas also facing significant price increases.

[37] Energex Regulatory Proposal for the period 2010 - 2015,page 265.

[38] Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd page 30.

[39] Ergon Energy Regulatory Proposal for the period 2010-2015, Table 141 and Table 142

[40] Queensland Competition Authority final report, "Review of electricity pricing and tariff structures – Stage 1", September 2009.

- the banning of incandescent lighting by 2010 announced by the Federal Government in 2007
- improved house construction techniques and requirements leading to lower energy usage
- the wide-spread expansion of household insulation as part of the Federal Government's stimulus package
- time of use tariffs which would tend to reduce usage during times of peak pricing

While the impact of some of these measures on energy consumption can be estimated, it is much harder to assess the impact on maximum demand. To a certain extent the impact of such programs will be captured in any future trend analysis. However, this will take some time.

For the coming regulatory period, while it might be recognised that the combination of the measures and programs discussed above are likely to have some downward impact on maximum demand growth, the extent of the reduction is very difficult to quantify.

2.9 Summary of key driver changes

The period 2002 to 2008 saw significant increases in maximum demand on Queensland networks due to a combination of high economic growth, strong increases in air-conditioner penetration and power and high population growth.

Two of these key drivers are expected to undergo significant change over the period 2008 to 2015:

- state economic growth, which averaged 5% pa is forecast to reduce to less than 3% pa because of the GFC, some 50% to 60% of recent growth. This is expected to impact significantly on commercial and industrial growth and associated maximum demand
- air-conditioning penetration, which grew at about 5 percentage points pa between 2002 and 2008 is approaching saturation and is expected to increase at less than 2 percentage points pa. While most new homes are expected to still be air conditioned, this means significantly less existing homes which will convert to air-conditioning compared to the previous period, with resulting reductions in maximum demand growth. While the number of air-conditioners in houses and their power may continue to increase (although this may also be tempered by the economic downturn) there is no reason to believe that these increases will be greater than those seen in the 2002 to 2008 period.
- Population and customer number growth are also expected to reduce a little in percentage terms – although to stay approximately constant in terms of new customer connections each year.

Table 2-5 summarises recent history and projected growth in these factors.

Table 2-5 Summary of key driver assumptions

	GSP growth (%)	Residential customer growth (%)	Air-conditioner penetration (%)
2004			55.8%
2005	5.0%	2.0%	59.6%
2006	3.6%	1.5%	63.4%
2007	4.8%	1.8%	67.3%
2008	5.3%	2.2%	71.1%
2009	-4.8%	1.8%	72.9%
2010	1.4%	1.8%	74.7%
2011	3.0%	1.8%	76.3%
2012	4.5%	1.8%	77.9%
2013	4.2%	1.8%	79.4%
2014	3.4%	1.8%	80.8%
2015	2.7%	1.8%	82.2%

Sources: GSP – KPMG Econtech; residential customers and air-conditioner penetration – MMA.

These very significant changes in key drivers, together with difficult to quantify impacts of price increases and energy efficiency programs due to efforts to reduce greenhouse gas emissions, mean that maximum demand growth over the 2008 to 2015 period is expected to be less than it was over the 2002 to 2008 period. As a result, a simple extrapolation of growth from the current period is expected to provide an unrealistic expectation of maximum demand changes over the period to 2015.

The mild weather experienced in 2008 and lack of very hot days in 2008 and 2009 also serve to stress the importance of proper weather correction in forecasting.

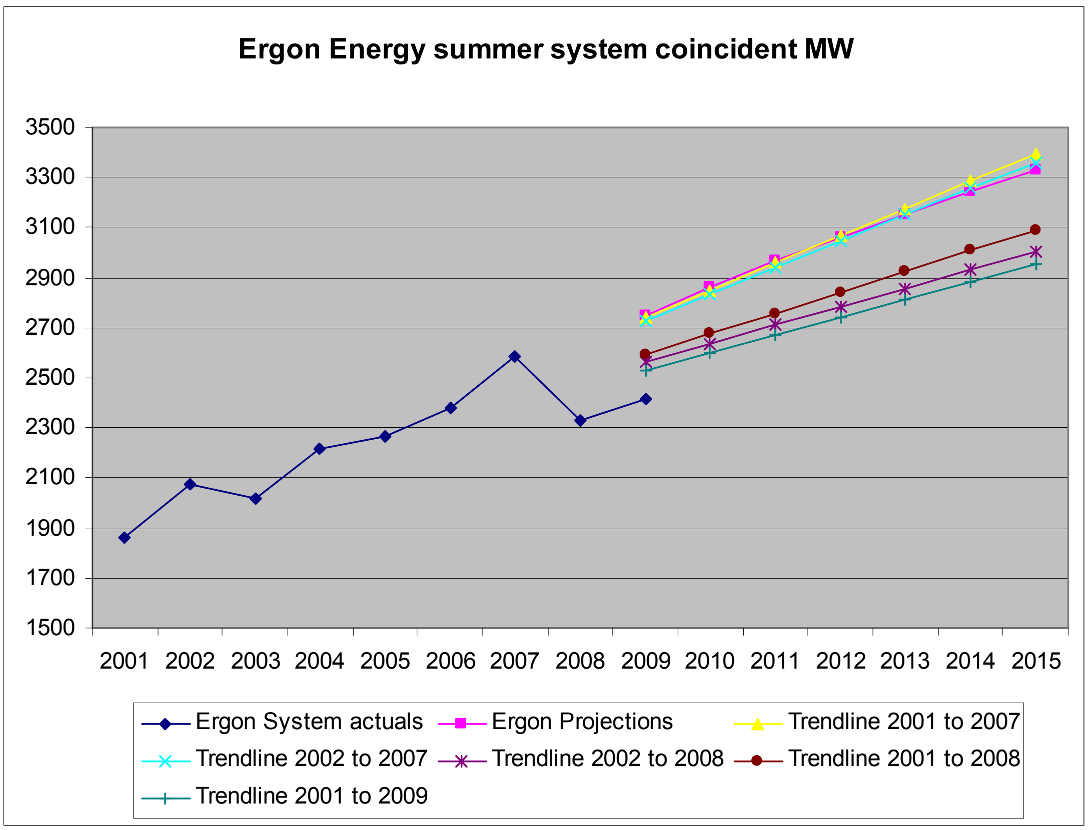
MMA considers that these significant changes to key drivers need to be taken into account by Ergon Energy in forecasting maximum demand. As shall be seen in Chapter 3, the Ergon Energy methodology does not take them into account. The MMA indicative assessment of their impact on system demand forecasts is provided in Chapter 5.

3 ERGON ENERGY FORECASTS AND FORECASTING APPROACH AND METHODOLOGY

3.1 Ergon Energy network summer maximum demand history and projections

The recent history of Ergon Energy's summer network coincident maximum demand between 2001 and 2009[41] is shown in Figure 3-1 together with the system maximum demands projected by Ergon Energy[42] over the period to 2015. Also included are trendline estimates based on trends from 2001 or 2002 to 2007, 2008 or 2009.

Figure 3-1 Ergon Energy's network summer maximum demands, projections to 2015 and trendline projections



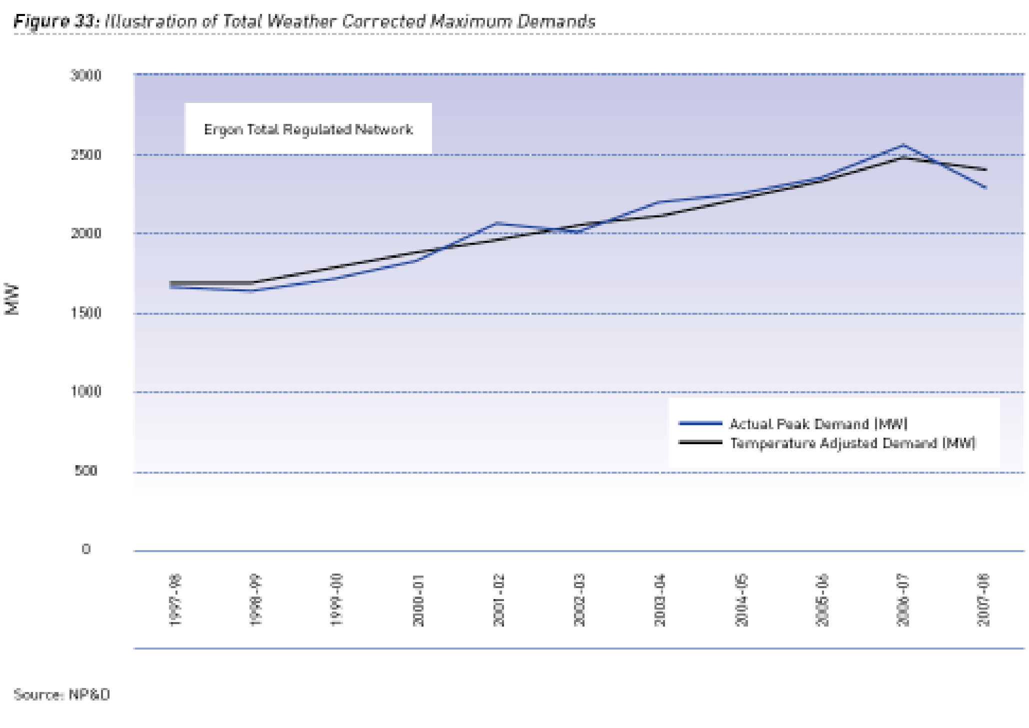
The top three projection lines are the Ergon Energy projection for the forthcoming regulatory period and the 2001 to 2007 and 2002 to 2007 trendlines. All the trendlines based on actual (i.e. not weather corrected) data incorporating the 2008 and 2009 years result in projections much lower than the Ergon Energy Regulatory Proposal projection. As can be seen, even if all drivers were the same as those experienced over the past five or six years, the range of projected outcomes could differ substantially, ranging from 2960

[41] The 2002 to 2008 data are from the RINs. The 2001 and 2009 system MDs are from PL563c.
[42] From the data provided in the RIN.

MW to almost 3400 MW by 2015. Annual growth from these projections also differs substantially, from 70 to 110 MW pa. In its Regulatory Proposal projection Ergon Energy has projected average annual growth of about 100 MW pa.

Ergon Energy has not provided any historical 50% POE values in the RIN, however, Figure 33 in the Regulatory Proposal (reproduced below) shows Ergon Energy's temperature (and presumably regional diversity) adjusted maximum demand. According to the Figure, in recent years the 2006/07 summer appears to have been hotter than average, while the 2007/08 summer was milder than average[43] [44].

Figure 3-2 Ergon Energy's weather corrected system maximum demand



Source: Ergon Energy Regulatory Proposal, page 173.

Thus, there are two key considerations in assessing the Ergon Energy forecasts at the system and spatial levels which are driven by trend analysis. The first is what is an appropriate starting point and trend to use in the absence of any significant change to key drivers. The second is whether the key drivers of maximum demand have changed significantly, or are likely to do so over the coming period, and if so, the likely impacts.

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[43] Although the Figure refers to "weather corrected" and "temperature adjusted" demand, it appears that the regional diversity considerations are also applied in weather corrections (Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd page 172). Ergon Energy points out that it does not use weather corrected numbers in its spatial forecasting but does correct at system level.

[44] The 2008/09 summer in south east Queensland is understood to have been average but wet and with no very hot days (see Section 2.5). It also had a regional diversity factor significantly higher than usual.

Chapters 4 and 5 discuss the first question while the previous Chapter assessed the key drivers which are likely to impact on maximum demand over the coming period, and how these differ from the previous period and Chapter 5 considers the likely impact.

3.2 Forecasts relied upon by Ergon Energy

3.2.1 The Regulatory Proposal

Ergon Energy prepared its capital expenditure forecasts based on its 2006/07 demand forecasts (prepared in November 2007) and has continued to rely on these forecasts.

According to the Ergon Energy Regulatory Proposal:

Due to the timing for the preparation of this Regulatory Proposal, Ergon Energy prepared its capital expenditure forecasts based on November 2007 demand forecast data validated against NIEIR's November 2007 report. Ergon Energy prepared further demand forecasts in 2008 and validated these against NIEIR's September 2008 report. Ergon Energy's 2008 demand forecasts were higher than the 2007 forecasts[45].

Subsequently:

"*However, in late 2008, the global financial crisis emerged and Ergon Energy considered it prudent to ask NIEIR to update its September 2008 report. In February/March 2009, NIEIR revised downwards its September 2008 demand forecasts for Ergon Energy however the updated forecasts remain higher, on average, than the 2007 forecasts. These are presented in NIEIR's April 2009 report.*

Ergon Energy considers it conservative to base its capital expenditure forecasts for the next regulatory control period on its 2007 demand forecasts.

Table 40 compares the maximum demand forecasts that were prepared in 2007, 2008 and 2009. It is evident that the 2007 average demand of the five year forecast period is lower (and therefore more conservative) than the average demand of both the 2008 and 2009 Ergon Energy forecasts."[46]

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[45] Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd, page 160.

[46] Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd, page 160.

Table 3-1 Ergon Energy's Coincident Peak Demand Forecasts

Table 40: Ergon Energy Coincident Peak (Maximum) Demand Forecasts for 2010-15 based on 2007 data and compared with 2008 data and 2009 data

	2010-11	2011-12	2012-13	2013-14	2014-15	Average of 5 Year Total
EE Coincident peak (maximum) demand – September 2007 (MW)	2,967	3,063	3,153	3,243	3,330	3,151
EE Coincident peak (maximum) demand – September 2008 (MW)	3,033	3,198	3,297	3,415	3,496	3,288
EE Coincident peak (maximum) demand – February 2009 Forecast (MW)	2,845	3,100	3,223	3,378	3,467	3,203

Source: Coincident peak (maximum demand) - Ergon Energy's Network Planning 2007, 2008 and 2009 forecasts (refer also NIEIR November 2007, September 2008 and April 2009).

"Ergon Energy's detailed analysis of the 2008 and updated 2009 forecasts compared with the 2007 forecasts used for this Regulatory Proposal indicates that:

- *A number of large customer projects, in particular connection of new coal mines, are likely to be deferred as a result of the global financial crisis;*
- *Any downturn as a result of the global financial crisis is likely to recover in 2012-13, after which the proposed projects have a high probability of proceeding;*
- *The revised forecasts show:*
  - *Reduced loads compared to the 2007 forecast for the period up to and including 2010-11; then*
  - *Similar loads for 2011-12 and 2012-13; followed by*
  - *Some acceleration of development during 2013-14 and 2014-15 as deferred projects are commissioned;*
- *The average peak demand during the 2010-11 to 2014-15 regulatory period remains reasonably similar in all three forecasts;*
- *Although the timing of projects has changed and been reflected in the capital expenditure forecasts, the overall amount of augmentation that needs to be completed during the entire regulatory period remains consistent with that developed from the 2007 forecasts.*

Ergon Energy believes that, despite a slowing of load growth at the beginning of the next regulatory control period, the projects that are deferred during that time will be connected during the latter stages of the same regulatory control period. This will result in the recommended augmentation program not being materially changed from that developed from the 2007 load *forecast. This means that it is reasonable for Ergon Energy to use its 2007 demand forecasts to prepare this Regulatory Proposal.*[47]"

Thus Ergon Energy argues that as its 2008 and 2009 system maximum demand forecasts are, on average over the period 2011 to 2015, higher than its 2007 forecasts for the same period, then the use of the 2007 forecasts is conservative and reasonable. Ergon Energy also appears to be arguing that forecasts prepared by NIEIR in 2007 and 2008 and early 2009 validate the Ergon Energy forecasts and conclusions that the 2007 forecasts can be relied upon. These arguments are considered in Section 3.6.

3.2.2 Forecasts used in capex calculations and "confirmation" from subsequent updates

Ergon Energy has pointed out on a number of occasions that it is only the spatial forecasts that are actually used in capex projections. The system-wide maximum demand forecasts have no actual bearing on the capex forecasts. It is, however, using its system forecasts, prepared essentially at Bulk Supply Point (BSP) and Connection Point (CP) level, to argue that overall demand forecasts at the spatial level will not have changed significantly since 2006/07. We discuss the BSP and CP forecasts in Section 4.3.6.

The Ergon Energy system maximum demand forecasts are initially derived at BSP and CP level and aggregated, after taking diversity factors into account, in 6 regions: Far North, North Queensland, Mackay, Capricornia, Wide Bay and South West.

3.3 Overview of Ergon Energy approach

Ergon Energy takes a bottom up approach to forecasting maximum demand based on linear trend analysis of (weather uncorrected) annual seasonal peak demands at the ZSS level combined with addition of spot or block loads. We understand that the forecasts are compared with the econometrically derived NIEIR forecasts in order to understand and reconcile significant differences in outputs.

While there are 14 stages described in the maximum demand forecasting methodology description included in the Regulatory Proposal[48], they can essentially be divided into 6 steps:

Step 1: Collect historical MW, MVAr and MVA MD data (separately) at the ZSS and BSP levels and cleanse these of anomalous values due to (for example) load switching. There is no weather correction done. Ergon assumes that the weather variability effect averages out over several years.

Step 2: Use linear regression analysis, utilising as much of the historic metering data as is considered relevant[49] to produce the forecast.

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[47] Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd, page 160.

[48] Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd, pages 168 to 171.

Step 3: Add spot loads and load transfers identified by Ergon Energy. The spot load forecast is done on a probabilistic basis and no size threshold is applied to exclude small loads at either the ZSS or BSP levels.

Step 4: Use the average power factor (uncompensated) over the past ten years to derive an uncompensated average power factor and then add in capacitor additions to forecast MVAs.

Step 5: Use the past ten years' history of coincidence factors to determine the 50% POE coincidence factors for each BSP/CP and region and 10% POE for the system.

Step 6: Compare against NIEIR's "top down" forecasts at the Connection Point level. Where there are significant differences we understand that Ergon Energy has a discussion with NIEIR to review the differences. However, the discussion does not appear to be documented[50]. Ergon Energy receives feedback from Powerlink as well.

As we understand it, the only direct inputs into the Ergon Energy forecasts are historical maximum demand data and judgements by Ergon Energy network staff about spot loads and load transfers.

3.4 Preliminary review of approach and methodology

In its preliminary review MMA assessed the Ergon Energy approach and overview methodology against criteria relate to both key drivers of growth and the forecasting process itself.

3.4.1 Approach

Ergon Energy uses a bottom up approach, based largely on a continuation of history as well as incorporation of spot load assessments which may have been made several years previously.

MMA considers that the approach taken by Ergon Energy may be reasonable in a period of stable growth but it is unlikely to be so given the significant changes in key drivers of Maximum Demand expected to take place over the coming period. MMA considers that the use of only a bottom up approach may result in an unrealistic outcome.

MMA also notes that the Ergon Energy approach might incorporate a documented comparison with a recent top down analysis and a discussion of how the two are reconciled.

[49] Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd , page 169.

[50] In terms of the 2006/07 forecasts on which the capex is based, Ergon Energy has stated in response to MMA EE19: "NIEIR did have an error with the South West (SW) region Transmission Connection Points (TCPs). NIEIR agreed there was an error, and resubmitted their forecasts, after which a reasonable match existed between the NIEIR and EE forecasts."

3.4.2 Timeliness

MMA is concerned that the Ergon Energy capex forecasts are based on 2006/07 forecasts which significantly preceded the GFC.

MMA has suggested that Ergon Energy commission (or undertake or utilise) a current top down evaluation of the maximum demand for its network and regions against which to compare its bottom up methodology. In addition, MMA suggested that the size, timing and likelihood of all large spot loads should be reviewed in the current economic climate.

3.4.3 Methodological and other issues

MMA has concerns about some methodological issues including:

- Ergon Energy's approach to weather correction
- use of an "organic growth" trend analysis which may incorporate spot loads
- how spot loads are calculated and their probability and timing assessed.
- use of coincidence factors as a method of calculating 50 POE and 10 POE forecasts.
- lack of documentation.

3.5 Changes or comment since the preliminary review

Ergon Energy responded to MMA comments during the preliminary review stage t by:

- Reviewing point by point in Tables 42 and 43 of the Regulatory Proposal[51] the elements of good maximum demand forecasting practice raised by MMA and describing how Ergon Energy approaches these elements. According to Ergon Energy, it performs reasonably against all the relevant MMA criteria apart from documentation[52].
- For its 2009 update forecast, Ergon Energy re-evaluated a number of its spot loads and has found a significant number delayed by two or three years.
- Ergon Energy has commented on the economic outlook for Queensland as described by NIEIR in December 2008 and compared this to the outlook in 2007 and 2008.
- Ergon Energy has provided its own September 2008 and February 2009 forecasts for comparison. The February 2009 forecast is essentially the same as the September 2008 forecast except that many of the spot loads included have been amended, mainly in terms of their timing.

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51 Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd pages 176 to 179.

52 Regarding the element of documentation ,Ergon Energy commented that: "Ergon Energy recognises that the lower level detailed documentation may need to be more extensive. However, Ergon Energy believes that its forecasting method, and decisions made during the orecasting process, can be explained and audited using a spot-check random selection process." Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd, page 178.

3.6 MMA review of forecasts and arguments

As stated previously, Ergon Energy has based its capex on its September 2007 forecasts. It has also provided its September 2008 forecasts and February 2009 forecasts to demonstrate that by using the September 2007 forecasts it is being conservative.

MMA has primarily reviewed the September 2007 forecasts. However, it has also reviewed briefly the September 2008 and February 2009 forecasts and considered the arguments made by Ergon Energy:

- That its September 2007 forecasts are reasonable as they are, on average over the coming regulatory period, lower than the September 2008 and February 2009 forecasts
- That its forecasts have been validated by NIEIR and that this validation included consideration of the impact of the GFC.

3.6.1 Forecasts used are lower than subsequent forecasts

In assessing the argument made by Ergon Energy, it is instructive to consider the six regional forecasts made by Ergon Energy for each of its three forecasts referred to as the September 2007, September 2008 and February 2009 forecasts and the changes that have taken place. In order to simplify comparisons, only forecasts for the 2011 and 2015 years are provided in Table 3-2 and the differences between forecasts for these two years are provided in Table 3-3.

Table 3-2 Regional maximum demand in 2007 and forecasts made in September 2007, September 2008 and February 2009 for the years 2011 and 2015 (MW)

	Actual	Sep-07	Sep-08	Feb-09	Sep-07	Sep-08	Feb-09
Region	2007	2011	2011	2011	2015	2015	2015
Far North	368	440	441	433	505	514	526
North Queensland	494	560	561	559	631	625	632
Mackay	408	498	511	478	563	667	679
Capricornia	686	836	881	739	917	978	915
Wide Bay	340	371	394	378	415	439	441
South West	364	430	419	419	488	472	472
Sum (not diversified)	2,659	3,136	3,206	3,006	3,519	3,695	3,664

Source: Ergon Energy AR412 and AR436 demand forecasts summaries and PL758 BSP and CP summaries.

Table 3-3 Changes between regional maximum demand forecasts made in September 2008 and September 2007 (2008 – 2007), February 2009 and September 2008 (2009-2008) and February 2009 and September 2007 (2009-2007) for the years 2011 and 2015 (MW)

	2008-2007	2009-2008	2009-2007	2008-2007	2009-2008	2009-2007
Region/FC Year	**2011**	**2011**	**2011**	**2015**	**2015**	**2015**
Far North	1	-8	-7	8	12	20
North Queensland	1	-1	0	-5	6	1
Mackay	13	-33	-20	104	12	116
Capricornia	45	-142	-97	61	-63	-2
Wide Bay	22	-16	7	24	2	26
South West	-11	0	-11	-17	0	-16
Sum(not diversified)	70	-199	-129	175	-31	144

Ergon Energy's September 2008 regional forecasts were greater than its September 2007 regional forecasts by some 70 MW in 2011 and by 175 MW in 2015. Almost all of the additional growth occurred because of assumptions about major customer growth in Mackay, Capricornia and Wide Bay.

Between 2009 and 2008, largely as a result of the GFC, Ergon Energy has assessed a delay of around 2-3 years in a number of mines. This has had the result of reducing the forecast in 2011 by almost 200 MW (some 130 MW more than the increase between 2007 and 2008 forecasts). The largest impact is again expected in the Capricornia, Mackay and Wide Bay areas. However, most of the delayed projects are assumed to proceed; by the year 2015 the difference is only 31 MW – and all of this 31 MW and more can be attributed to a customer which will be served by Powerlink rather than Ergon Energy[53].

In other words, according to the Ergon Energy analysis the effect of the GFC is, by 2015, expected to be a net gain in expected growth (apart from the customer to be served by Powerlink). Growth is also some 144 MW higher than was expected to be the case in 2007.

This estimation raises concerns in a number of areas:

- Primarily, the Ergon Energy methodology focuses on trend analysis plus additions of block loads from "major customers". However, while many of the major customers are assumed to be deferred, no change is made to the underlying "trend" growth. Yet, as summarised in Section 2.9, the key drivers have changed substantially making the assumption of continued trend growth inappropriate. As discussed in Section 2.2, this results in a loss of economic growth (compared to recent history and expectations prior to the GFC) and hence a loss in expected maximum demand.

53 The customer was assumed to be supplied by Ergon Energy in the September 2007 and September 2008 forecasts and by Powerlink in the 2009 forecasts.

- Secondly, MMA is concerned that a proportion of the major customer load may be "double-counted", both historically through trend analysis and separately as major customers. One way of handling this concern is to treat large customers over a threshold size separately from the trend analysis. However, Ergon Energy includes even very small block customers (for instance 0.25 MW) both within trend analysis and as a separate block load.
- Thirdly, the timing of growth is likely to be important. If a project is deferred by two or three years then there is a saving in terms of timing of capex. This may appear as a change in growth capex or in the starting regulatory asset base.
- Finally, there is the consideration of the type and location of the growth capex. Between Ergon Energy's September 2007 and February 2009 forecasts there have been significant changes in Mackay, Capricornia and Wide Bay, less so in the other regions. And most of the changes have been due to deferral of very large projects as the trend growth has been assumed by Ergon Energy to continue. This may have an impact on the unit costs of the capex and on other regulatory considerations.

As a result, MMA is not persuaded by the Ergon Energy position that, as its September 2007 forecasts are lower than its September 2008 and February 2009 forecasts they are both reasonable and also take into account the changes to key drivers resulting primarily from the GFC.

3.6.2 Validation against NIEIR forecasts

MMA has been provided with copies of the NIEIR November 2007 and NIEIR September 2008 reports[54]. Although the Ergon Energy and NIEIR forecasts cannot be compared exactly, it appears that while the Ergon Energy forecasts may have increased between 2007 and 2008, the NIEIR forecasts did not. The sum of the totals forecast for coincident summer MD 50th in 2015[55] fell by 8.5% in the NIEIR 2008 forecasts compared to NIEIR's 2007 forecasts while the corresponding non-coincident summer MD 50th in 2015[56] fell by 4%. While Ergon Energy may have compared its forecasts to those of NIEIR, the increase seen by Ergon Energy in its 2008 forecasts compared to its 2007 forecasts does not appear to have been validated by the NIEIR forecasts.

In addition, Ergon Energy states that in February/March 2009 NIEIR revised downwards its September 2008 demand forecasts; however, the updated forecasts remained higher, on average, than the 2007 forecasts (see Section 3.2.2).

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[54] NIEIR report to Ergon Energy, "Maximum demand forecasts for Ergon Energy connection points to 2017", November 2007 and NIEIR report to Ergon Energy, "Maximum demand forecasts for Ergon Energy connection points to 2018", September 2008.

[55] Derived by adding NIEIR Tables 8.1 to 8.6 Coincident Summer MD 50th by Connection Point for Totals of Far North, North Queensland, Mackay, Capricornia, Wide Bay and South West.

[56] Derived by adding NIEIR Tables 7.2 to 7.7 Non-coincident Summer MD 50th by Connection Point for Totals of Far North, North Queensland, Mackay, Capricornia, Wide Bay and South West.

It appears that the updated NIEIR report referred to by Ergon Energy, and also called the NIEIR April 2009 report is the report by NIEIR entitled "Economic Outlook for Australia and Queensland to 2018-19" and dated December 2008. This is the document provided by Ergon Energy as AR374c with the Regulatory Proposal[57] [58].

However, despite the indications in the Regulatory Proposal referred to above, AR374c contains only updated economic forecasts, not demand forecasts. MMA has asked Ergon Energy to confirm that the report did not contain any updated maximum demand information and Ergon Energy has confirmed this[59].

Given that the NIEIR report referred to did not contain maximum demand forecasts MMA does not consider that this report validates the Ergon Energy maximum demand

3.6.3 Conclusion regarding Ergon Energy's arguments for use of 2007 forecasts

Ergon Energy has used two arguments to support its use of the 2007 forecasts for capex estimation purposes:

- that they are reasonable as they are lower than subsequent Ergon Energy forecasts
- that they have been validated by reference to NIEIR forecasts.

MMA is not persuaded by either argument. The later forecasts have not taken into account any changes to underlying trend caused by the changes to key drivers and will, as a result, overstate expected growth as well as having timing and geographical ramifications. The 2009 NIEIR forecasts referred to did not contain maximum demand forecasts and cannot, therefore, be considered to substantiate those of Ergon Energy.

[57] See Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd, page 67 where document AR374c is referred to as "NIEIR April 2009 report "Economic Outlook for Australia and Queensland to 2018-19 - December 2008".

[58] We note also that the NIEIR GSP forecasts for Queensland in the December 2008 report to Ergon Energy were materially higher than the more recent NIEIR forecast in April 2009 for Energex.

[59] Ergon Energy response to MMA EE 8 "Ergon Energy confirms information provided at our meeting on 22Jul09 that NIEIR's April 2009 report did not provide updates to the maximum demand forecasts - instead it provided updated econometric information as a result of the Global Financial Crises.

4 SPATIAL MAXIMUM DEMAND

4.1 Description of Ergon Energy Approach

Ergon Energy takes a bottom up approach to forecasting maximum demand based on linear trend analysis of (weather uncorrected) annual seasonal peak demands at the ZSS level combined with addition of probability and coincidence adjusted spot loads. We understand that the forecasts are checked (at an aggregated and diversified level) against those of NIEIR (which are econometrically derived) and the in-house strategic forecasts. However, Ergon Energy has stressed that this is a check only at a very gross level. This review appears to capture changes in significant block loads. However, it is not clear how this review translates to the ZSS level trends. As a result, any prospective changes to key drivers are not taken into account in forecasting.

4.1.1 Outline of Ergon Energy's spatial MD Forecast

While there are 14 stages described in the maximum demand forecasting methodology description included in the regulatory proposal[60], they can essentially be divided into 6 steps:

Step 1: Collect historical MW, MVAr and MVA MD data at the ZSS and BSP levels and cleanse this of anomalous values due to (for example) load switching. Ergon assumes that the weather variability effect averages out over several years.

Step 2: Use linear regression analysis with, "*As much of the available historic metering data is used in the regressions as is relevant*"[61] to produce the 50% POE forecast. The starting point for the forecast is understood to generally be the value derived by a linear trend of historic data, as it is often not the last actual recorded.

Step 3: Add spot loads and load transfers identified by Ergon Energy. The spot load forecast includes a size and assumed timing and diversity factor as well as the estimated probability of the project proceeding. The probability does not vary by year, meaning that it is applied equally to each year in which the project could proceed. No size threshold is applied to spot loads.

Step 4: Use the average power factor (uncompensated) over the past ten years to derive an uncompensated average power factor and then add in capacitors and capacitor additions to forecast MVAs.

60 Chapter 21 Demand Forecasts (System Only) of Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd, section 21.3.1.1 starting on page 168 describes the bottom-up methodology adopted by the Network Forecasting and Development Group at ZSS and BSP levels. The Ergon Energy analysis also included other components, for embeeded generation for example, but these have not been included in any of the ZSS we have reviewed in detail.

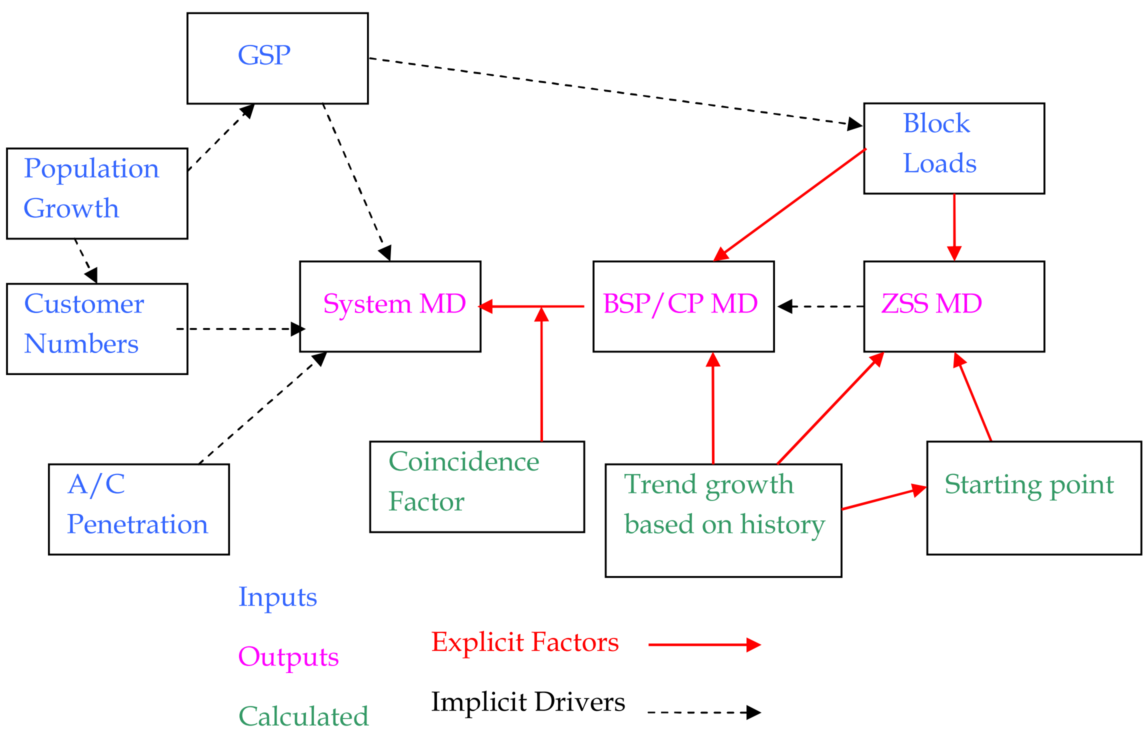
61 Chapter 21 Demand Forecasts (System Only) of Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd.P. 170

Step 5: Use the past ten years' history of coincidence factors to determine the 50% POE and 10% POE coincidence factors for each BSP to connection point, region and state. Co-incidence factors are not calculated for ZSS.

Step 6: Compare against NIEIR's "top down" forecasts at the Connection Point level. Where there are significant differences we understand that Ergon Energy has a discussion with NIEIR to review the differences. However, the discussion does not appear to be well documented enough for independent review. Ergon Energy receives feedback from Powerlink as well.

Figure 4-1 shows the relationships between the various inputs and outputs used by Ergon Energy. Although factors such as GSP, customer number growth and air conditioning penetration are said by Ergon Energy to be important in maximum demand forecasting, the only inputs used are historical trends and spot load forecasts.

Figure 4-1 Ergon Energy's drivers, inputs and outputs



4.1.2 Inputs into the forecasting process

As we understand it, the only direct inputs into the Ergon Energy forecasts are historical maximum demand data and judgements by Ergon Energy network staff about trends and starting values to use, spot loads and load transfers.

4.2 Examples of forecasting at ZSS level

As examples of the application of its methodology during the preliminary review, Ergon Energy provided information about the Frenchville and Glenmore ZSS in the Rockhampton area.

For the current review a further eight ZSS were selected for detailed review according to the process described in Section 1.3.2:

- Garbutt
- Hermit Park
- Neil Smith
- Max Fulton
- Malchi
- Rockhampton South
- Howard
- Pialba.

We refer to these as "contributing ZSS" throughout the report as they are expected to contribute load to the planned new ZSS.

The Gracemere area to the south west of Rockhampton is currently supplied from the zone substations of Malchi and Rockhampton South. Ergon Energy proposes to address load growth issues in the Gracemere and Stanwell areas by establishing a new Gracemere zone substation.

Ergon Energy proposes to develop the Townsville Central zone substation as a 2 x 32MVA substation. The Townsville Central substation is required to supply future city developments and to provide load relief to Hermit Park, Garbutt, Neil Smith and Max Fulton substations over the longer term.

The Wide Bay area around Howard and Pialba was an additional area to examine suggested by Ergon Energy. Ergon Energy proposes building a Toogoom substation to ease the load on Howard, Pialba and the Hervey Bay region. It will also reduce the length of the 11 kV feeders to the Toogoom area and surrounding Dundowran, Takura, Craignish and Burrum Heads.

4.3 Review carried out

In the preliminary review it was seen that the Ergon Energy methodology required a significant number of judgements which would need to be critically reviewed following the submission of the Regulatory Proposal and forecasts. For the contributing ZSS and other areas where appropriate we have critically assessed:

- the starting points and base growth rates used by Ergon Energy
- the impact of not setting a minimum threshold size on spot loads
- the history of Ergon Energy spot load forecasts for major customers in the Capricornia region
- the amendments made to spot forecasts between September 2008 and February 2009
- history of load transfers
- comparison of ZSS against BSP forecasts

4.3.1 Starting points and base growth rates

The Ergon Energy default option for deriving the starting points is to use a linear trend. We generally consider this to be a reasonable approach as the "last actual" may be more vulnerable to weather variability. In some cases the forecasters make a judgment to use the last actual MD value rather than the trend value. While the reason for this decision is not always documented it appears to only take place when there has been a recent step change in demand or the recent history is not monotonic.

We have reviewed the starting points and growth rates for the eight ZSS. Of these six were reasonably straightforward and the starting points and growth rates were as expected.

The two unusual ZSS were Neil Smith, for which Ergon Energy used a limited data history, and Pialba, which appears to have had a step change in the final year of history.

When we examine Neil Smith, only data from 2003/04 to 2006/07 has been used, due to a step change increase in demand prior to this. It is not clear what caused this increase, the 2002/03 forecasts anticipate a block load due to Townville Centre Strand Unit Development, however this is still considered a new project in the 2003/04 and 2004/05 forecasts. Ergon Energy has then derived a base growth rate of 0.82 MW (4.5% in first year). For the sake of comparison we examined the 2007/08 forecast growth rates, which include an extra year of data. This has resulted in the base growth rates for Neil Smith reducing by 0.39 MW (to 0.43 MW) per year. This is summarised in Table 4-1. The difference in base demand by 2015 is more than 3 MW, with the 2006/07 forecast being 24.73 MW in 2015 and the 2007/08 forecast being 21.39 MW.

Table 4-1 Neil Smith growth rate forecasts from 2006/07 and 2007/08

Neil Smith growth rates	Summer MW pa	2014/15 Summer Base
06/07 Forecasts	0.82	24.73
07/08 Forecasts	0.43	21.39

Our comparison of the two sets of forecasts highlights the sensitivity of the inclusion of an extra year to a trend based on a small number of data points. The Garbutt, Hermit Park and Max Fulton forecast growth rates, based on a longer historic sequence, are only marginally different in the 2007/08 forecasts.

Pialba is a case where there was a drop in demand in the 2006/07 year (17.8 MW from 21.2 MW the previous year[62]) which is the last actual for the forecasts used. For this ZSS Ergon derived the trend growth from 1996/97 to 2005/06 and used the last recorded MD (15.7 MW[63]) as the starting point. It is not clear whether the change in demand was caused by a load transfer or a block load retirement (Ergon Energy could not give us a history of load transfers). If there was a load transfer of residential load equivalent to 20% of the ZSS demand, then presumably the derived growth when the removed load was still present should be 20% lower. If, however, it was a block retirement then using the same growth that existed previously may be appropriate. Without further information, it is not clear which is appropriate.

In general the starting points and base growth rates applied to the ZSS appear reasonable and the judgments applied in these areas generally appear appropriate. However, when a judgment is made about which years to include or exclude from the growth trend it is important to know whether a spot load or transfers is the cause. If there is no identifiable cause then the impact of weather variability cannot be discounted and the selection of data to include becomes arbitrary.

4.3.2 Spot loads – minimum size threshold

The ZSS forecasts involve a trend extrapolation of historic data and then the addition of spot loads as well. Ergon Energy does not apply a threshold limit (e.g. 1 MW or x% of ZSS MD) to the size of new block loads it treats explicitly in its forecasts. As a result, such loads are likely to be included both within the trend-line assessment and also separately – almost certainly leading to some double counting.

From discussion, we understand that Ergon Energy selects the historical years to use for its analysis by taking into account large step changes in demand due to load transfers or earlier spot loads. However, this is not documented, is made difficult by lack of information about load transfers (see Section 4.3.5) and still allows for potential double-counting due to the underlying trend demand growth being driven by a series of small to medium size block loads.

Although we consider it reasonable to take separate account of relatively large new spot loads, good practice requires that they then be excluded from the data used to derive the trend growth rate to ensure there is no double-counting, then added in later. If, as is often the case, records of spot loads included in trend analysis are inadequate to allow this to be done then a second-best alternative is to apply a reasonable minimum size threshold for explicitly recognised spot loads. This will likely reduce, although not eliminate, the double-counting.

[62] "PL641c_EE_SMDB DEMANDS 2007_11Aug09.xls", Ergon spreadsheet of historic MDs and diversity factors.
[63] "AR436c_EE_Wide Bay Zone Sub Forecast_06_07_final.xls", Ergon spreadsheet of ZSS forecsts incorporating 06/07 data.

We have estimated the impact of the removal of spot loads below a threshold set at 5% of the ZSS N-1 capacity on the eight ZSS we have reviewed in detail.

Following the filtering out of such spot loads, forecasts in Malchi, Rockhampton South, Howard and Pialba remain unchanged. There is a single 2 MW spot load at Pialba which is above the 5% threshold and a 0.7 MW spot load for Malchi also greater than the threshold. The impact on the four Townville ZSS studied in the years 2010 and 2015 is shown in Table 4-2.

Table 4-2 Townsville ZSS and the impact of small block loads

Ergon Original Forecast (MW)	2007	2010	2015	N-1 Rating
GARB Garbutt	35.6	30.9	34.7	35
HEPA Hermit Park	26.8	25.3	27.3	25
MAFU Max Fulton	26.6	23.7	29.3	35
NESM Neil Smith	16.9	19.2	21.7	25
Total	**105.9**	**99.2**	**113.1**	**120**
After 5% Block Filtering (MW)				
GARB Garbutt	35.6	30.9	34.7	35
HEPA Hermit Park	26.8	24.4	26.3	25
MAFU Max Fulton	26.6	20.3	25.8	35
NESM Neil Smith	16.9	17.6	19.5	25
Total	**105.9**	**93.2**	**106.3**	**120**
Percentage Change				
GARB Garbutt		0.0%	0.0%	
HEPA Hermit Park		-3.6%	-3.7%	
MAFU Max Fulton		-14.6%	-12.1%	
NESM Neil Smith		-8.3%	-10.1%	
Total		**-6.02%**	**-5.96%**	

Both Max Fulton and Neil Smith have a substantial decrease in forecast demand by 2015 if small block loads are not added separately. However, they both still have strong organic growth. The difference in MW terms for these two substations is 2-3 MW.

The unweighted average of the percentage reductions across the 8 ZSS examined is 2.6% in 2015. The distribution is very uneven with five of the eight ZSS unchanged and two with a greater than 10% reduction. While not intended to be a statistical analysis, this example shows that the absence of a threshold is likely to result in an exaggeration of future growth, which is variable across the ZSS but averaged about 2.6% by 2015 in the ZSS we have examined.

4.3.3 Spot loads methodology - how accurate have spot load forecasts been?

As a spot check of Ergon Energy's major customer forecasting process we have reviewed historical accuracy forecasts for customers (both existing and new) with additional load of 10 MW or more forecast from 2001 in the Capricornia region[64]. This has been possible because Ergon Energy has maintained a consistent forecasting methodology since 2000/01 which has allowed the loads of such customers to be followed. Note that we have not taken into account the coincidence factors which are, however, generally high and have in most cases not included consideration of negative forecasts.

Table 4-3 Review of forecasts of additional large major loads of size 10 MW or more in the Capricornia region – Confidential

Customer	Additional loads forecast	2008 Actual and comments
[redacted]	[redacted]	[redacted]

[64] We selected Capricornia as it was one of the regions with contributing ZSS we were evaluating and it had a significant number of spot loads. The 10 MW minimum cut-off size was selected to allow a manageable number of the largest loads to be examined.

Customer	Additional loads forecast	2008 Actual and comments
[redacted]	[redacted]	[redacted]

Customer	Additional loads forecast	2008 Actual and comments
[redacted]	[redacted]	[redacted]

Customer	Additional loads forecast	2008 Actual and comments
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Customer	**Additional loads forecast**	**2008 Actual and comments**
[redacted]	[redacted]	[redacted]

Source: Ergon Energy AR 412c, AR 436c, PL 758, EE.6. Note that the percentages are those allocated by Ergon Energy.

Although the above analysis covered fewer than 20 customers and may be a little inaccurate in some details[65] a number of observations can be made:

- There is almost inevitably a delay from when the project is first included into the planning schedule to when the load eventuates. This may only be a year but may also be significantly longer - up to say five years if the project eventuates.
- This delay was evident even before the GFC. The GFC has further set back projects by some 2 to 3 years.
- The contribution of the load increase, when it does eventuate, is often significantly smaller than expected[66].
- The probabilities assigned seem very high in many cases, especially when they relate to timing. There are numerous examples of very high probabilities being given to loads which do not eventuate. When loads do not eventuate in one year the identical forecasts are often (especially at smaller sizes) just shifted into the following year.

[65] As names may have changed,information has been abbreviated in order to fit into a table and some loads have been aggregated.
[66] As stated above, some of this may be due to not taking into account the diversity factor in the above Table.

In the preliminary review MMA commented that, while a probabilistic assessment of future spot loads sounds reasonable, it should be based on a set of assessment guidelines or judgements applied might vary significantly. We have seen no evidence of any such guidelines.

We note that GHD when reviewing the Ergon load forecasting methodology in 2002[67] made similar observations:

"The main concern is that many of these loads as proposed never eventuate, depending as they do on economic and financial vagaries. Also, many of them are largely mutually exclusive – several competing development applications may be lodged, but only one or two will actually proceed. This mutual exclusivity may apply across regions as well, especially as regards very large projects."

While MMA considers it good practice to take into account spot loads **which are not included in the trend analysis** (see Section 4.3.1), and considers that assigning probabilities is a reasonable approach to uncertain loads, as stated above such forecasting should be based on a set of assessment guidelines and also needs to be regularly reviewed.

Given the above observations about forecasts for major customers in Capricornia since 2001, MMA considers that the judgements applied by Ergon Energy to forecast spot loads appear biased. Based on the above evidence, we would expect that the size of large spot loads is over-stated and the timing forecast is almost invariably earlier than actually eventuates.

4.3.4 Spot loads – amendments made in 2008 and then 2009 as a result of the GFC

The 2007/08 year, possibly because it was very mild, saw reductions in maximum demand compared to the previous year across each region in the Ergon Energy network apart from the Far North (see Table 4-4). Using linear regression analysis from 2001 to 2008 would have resulted in a significant reduction to trendline estimates by 2015 compared to a trendline from 2001 to 2007 (as seen in Figure 3-1).

Table 4-4 Regional, summed regional and system maximum demand (MW)

	2007	2008	2009
Far North	368	374	387
North Queensland	494	455	494
Mackay	408	378	416
Capricornia	686	654	668
Wide Bay	340	282	330
South West	364	320	388
Sum of regions	2,659	2,463	2,682
System MD	2,584	2,332	2,418

[67] "PL723c_GHD_Load Forecasting Project Report_June 2002.pdf",

Source Ergon Energy AR436c, AR412c and PL758c.

While the 2009 regional maximum demands were all higher than those in 2008, they were on average only marginally higher than those in 2007. Inclusion of the 2009 actuals within the analysis does not materially increase the trendline outcomes (above those using 2008 actuals) by 2015[68].

As we have seen in Table 3-3, in 2008 Ergon Energy forecast combined regional maximum demand in 2015 some 175 MW above the amount forecast for that year in 2007. Given that the network as a whole is growing at some 70-100 MW pa, this is the equivalent of adding 2 years of network growth. As this growth was unlikely to have been derived from trend growth we conclude that it must all have been related to additional spot load. This additional spot load was distributed mainly in Mackay, Capricornia and Wide Bay.

The subsequent effect of the GFC on spot loads according to the 2009 Ergon Energy forecast was to shift a number of loads out by some 2-3 years. However, the net result by 2015 was a reduction compared to the 2008 forecast of only 31 MW. Given that one expected major customer addition was transferred to Powerlink, and was thus excluded from the 2009 forecast, Ergon Energy has forecast that the GFC would result in additional load by the year 2015 compared to what it had forecast a few months previously.

MMA does not consider this to be a realistic outcome of the impact of the GFC. We have previously mentioned our concerns that the trendline methodology does not take into account changes to key drivers. We have also mentioned our understanding that the spot load methodology is likely to result in a double-counting of load. This is likely to be significant at the BSP and regional levels. Finally we have provided evidence that the Ergon Energy spot forecasts over the period 2001 to 2007 in the Capricornia region were likely to be overstated in terms of magnitude and to be delayed in many cases. Certainly the high probability loading has in many cases been inaccurate in terms of timing if nothing else.

Another example of apparently high probability assessments is provided by the [redacted] This is not clear in the AR412c September 2008 forecasts we have seen for [redacted] as the mine is not included[69], however, a number approximating this difference appears to be included in the summary and is given 100% probability of proceeding in 2013/14 in the 2009 forecasts.

[68] If the trendlines start from 1996 or 1999 the conclusions are essentially the same.
[69] There is a disparity between the Wide Bay forecasts in the Wide Bay spreadsheet and the forecast summary.

However, according to the Tarong Energy website[70], and as recently confirmed by Tarong Energy personnel[71] there is still significant doubt about the timing of the Kunioon transition, which was initially planned for 2012. According to the website additional coal from the Meandu mine could be used well beyond 2012. While we consider the mine may well proceed, according a 100% probability to it taking place in 2013/14 appears very optimistic.

Taken in combination, the concerns about double-counting, over-optimistic spot load forecasts and ignoring the GFC in trend analysis results in MMA not placing a great deal of reliance on Ergon Energy's 2008 and 2009 system update forecasts.

4.3.5 Handling of load transfers

Within the forecasts of the contributing ZSS from 2001 a number of load transfers have been planned. For example, the 2005 forecasts produced by Ergon Energy expected there to be significant load transfers from Garbutt, Neil Smith, Max Fulton and Hermit Park to Townsville Port from 2007.

If these occurred then they would of necessity have an impact on the trend analysis carried out by Ergon Energy. We asked Ergon Energy to provide a history of which permanent transfers actually occurred, when and their size. Ergon Energy responded that it could not provide such a history[72].

Given the importance of trend analysis in the Ergon Energy methodology, MMA considers it very strange that histories of load transfers cannot be provided. It raises serious concerns about exactly how the forecasters could accurately produce trend forecasts if they are not provided with such fundamental information.

4.3.6 Comparison of ZSS against BSP forecasts

Ergon Energy separately, but using essentially the same process, produces forecasts at the ZSS level and the BSP/CP level. The ZSS forecasts are the main source of forecasts for capex calculations. The BSP/CP forecasts (referred to henceforth as CP forecasts) feed into the system maximum demand. However, Ergon Energy does not reconcile the ZSS and CP forecasts. It does calculate the diversity factors for the CPs (sum of the ZSS forecasts supplied by an individual connection point divided by that connection points forecast), but these are not used in the forecasts, nor are they critically reviewed.

MMA has a concern that the diversity factors calculated decline substantially over the forecast period for a number of locations, although there are some exceptions[73]. This indicates that for those regions the CP forecast is growing faster than the ZSS forecast. It is not clear to MMA why this should be the case.

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70 Tarong Energy, "Update on Meandu-Kunioon fuel strategy" available at http://www.tarongenergy.com.au/Portals/0/FUEL%20STRATEGY%20UPDATE.pdf

71 Email from J Todd, Tarong Energy 22 September 2009 stating that it is currently not possible to be more specific about the timing and that the website information remained current.

72 Ergon Energy response to MMA EE28, 14 September 2009.

73 Exceptions include T019 Gladstone South where the diversity factor increases.

We have reviewed the forecasts for the Townsville area ZSS, BSP and CPs. There is a substantial amount of growth expected in the area with several new ZSS being commissioned. Due to the transfers we show the aggregated forecasts for the connection points, referred to as T046/056/092/150/TransfieldGen Townsville Total, and the subsidiary zone substations in Table 4-5.

A 100% coincident new load would reduce the diversity factor, but would increase both ZSS and CP forecasts by an equal MW amount. The MW increase in the CP forecast is greater than the increase in the sum ZSS forecast for all years except 2008/09. This suggests that the new loads are adding more demand at the CP level than at the ZSS level and suggest an inconsistency between the two forecasts. From 2009/10 to 2014/15 the annual growth rate of the CP for this region is on average some 1% pa higher than that of the combined ZSS.

Table 4-5 Comparison of Townsville CP and ZSS forecasts

	Sum of CP Forecast (MW)	Sum of ZSS forecast (MW)	Diversity
2004/2005	273.61	305.77	1.12
2005/2006	278.84	310.80	1.11
2006/2007	308.39	337.17	1.09
2007/2008	328.10	352.87	1.08
2008/2009	327.72	368.19	1.12
2009/2010	340.51	380.13	1.12
2010/2011	353.15	390.96	1.11
2011/2012	366.50	401.90	1.10
2012/2013	381.04	413.56	1.09
2013/2014	395.60	424.21	1.07
2014/2015	410.70	434.55	1.06
2015/2016	428.11	447.04	1.04
2016/2017	444.83	457.27	1.03

We also compare the growth rate of the sum of all Ergon ZSS demands against the growth rate for all CP demands in Table 4-6. We find that historically from 2001-07 the growth rate was higher at ZSS level, but that in the forecasts a higher growth rate is expected at CP/BSP level. One possible cause would be if a significant number of new major customer loads were added directly at BSP/CP level rather than to a ZSS.

Table 4-6 Growth rate at ZSS and CP level

Growth p.a.	Historical 2000/01-06/07	Forecast 2007/08-2014/15
Total ZSS	4.4%	2.6%
Total CP/BSP	3.7%	3.2%

Based on our discussion of the double counting of block loads in Section 4.3.2 and the higher threshold size that would be required for CP/BSP than for ZSS, we consider it possible that the CP forecast growth rates are over-estimated relative to the ZSS. While not necessarily a crucial issue in terms of investment decisions this does highlight a weakness in the overall method and reduces confidence in the accuracy of the forecasts. It also raises a possibility that the ZSS forecasts, on which we understand much of the capex forecasts are based, may be somewhat more conservative than the system maximum demand forecasts which are derived from the CP forecasts.

4.3.7 Use of coincidence factors as a method of calculating 50% POE and 10% POE connection point and regional forecasts

Only the 50% POE demand forecast is required for almost all the ZSS forecasts made by Ergon Energy. A 10% POE forecast is required only for single radial line and transformer ZSS, these typically have loads below 5 MW. As such, these forecasts are relatively immaterial for the capex forecasts.

The method Ergon Energy employs at the system level for determining the 50% POE and 10% POE forecasts is to use the same region forecasts and to use a different regional to system coincidence factor for each probability of exceedance. For example in the 2006/07 system forecast calculations[74] the 10 and 50 POE forecasts differ only by the coincidence factor used.

Such an approach is unorthodox. The correlation of weather condition with coincidence factor would need to be substantiated before such a methodology was considered reasonable. We are also unsure how valid a calculation of 1 in 10 year coincidence is when it is based on very limited data points (e.g. fewer than 10 years data).

We understand the primary use of the 10% POE BSP, CP and Regional forecasts is as an input to Powerlink's forecasting process. As these forecasts are not of material relevance to the capex proposal they are not further considered here.

4.4 Demand Management

Ergon's demand management programs, with an annual budget of over $10M, at this stage are trials intended to test different approaches. The demand management section of the Regulatory Proposal[75] does not refer to any specific MW reductions expected. Much of the activity is centred on the Townsville region, however, the demand forecasts do not seem to be impacted by the currently planned activities[76].

Ergon Energy has through its forecast methodology assumed that the impact of the DM programs will not materially affect the forecasts, except to the extent that the program

74 Ergon Energy, "AR436c_EE_Demand Load Forecast Summary 2007.xls"

75 Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd , Section 30.

76 As stated elsewhere, the demand forecast methodologies of trendline plus spot growth do not allow this except where it is already included as a trend or possibly through using a negative spot load.

outcomes are included within trend growth. We note that the Energex has estimated an impact of 144 MW (about 2.2%) by 2015 in its Regulatory Proposal[77].

While the Ergon Energy outcome may be lower than Energex's, given that Energex appears further advanced in its program, the lack of any specific consideration again suggests that the Ergon Energy overall demand forecasts may be somewhat optimistic.

4.5 Concerns about methodology and forecasts

MMA has a number of concerns about the approach and methodology used by Ergon Energy and the resulting forecasts used for the Regulatory Proposal. These concerns are summarised in the following categories:

- lack of responsiveness to change in key drivers
- calculation and treatment of spot loads
- lack of weather correction

4.5.1 Unresponsive to recent major changes in key drivers

Ergon Energy uses a bottom up approach based largely on a continuation of history as well as spot load assessments to forecast at the ZSS, BSP and system levels. Ergon Energy does not prepare a top down, system-wide forecast based on broader economic, demographic and other drivers. While we understand it makes some comparison with the NIEIR top down approach[78], Ergon Energy has made it clear that it investigates significant differences, however it does not systematically reconcile ZSS forecasts to the NIEIR forecasts nor document the differences.

While Ergon Energy mentions a number of key drivers (such as GSP, population growth and air conditioning penetration) in its description of forecasting methodology[79], it does not appear that changes to any of these, apart from new spot loads, are actually taken into account in its methodology.

The Ergon Energy approach implicitly assumes that the drivers of growth will remain similar to the historical period over which trends have been derived. While this may be reasonable in a period of stability, it is unlikely to be so given the significant changes in key maximum demand drivers expected to take place over the coming period. MMA considers that the use of only a bottom up approach against the background of the recent economic and mineral boom in Queensland is likely to result in an unrealistic outcome.

In its preliminary review MMA recommended that Ergon Energy incorporate a documented comparison with a recent top down analysis of maximum demand, such as

[77] Energex Regulatory Proposal for the period 2010 - 2015, Chapter 5.

[78] Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd, Section 21.3, P. 170

[79] Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd, Section 21.2, P.161

that carried out by NIEIR for Ergon Energy in 2007 and 2008. Ergon Energy has not done this.

This is a major concern for MMA. For the Energex region the difference between the system maximum demand forecasts prepared by NIEIR for Energex before and after taking into account the impact of the GFC was of the order of 4% across the coming regulatory period. In other words, the impact of the GFC in the Energex region was expected to be an average reduction of maximum demand by about 4% in each year across the period. Yet the Ergon Energy methodology actually results in an increase in forecasts after taking GFC into account. This is likely to be the result of ignoring changes to the trend growth as a result of major changes to key drivers and also potentially significant over-statement of spot load impacts (see below).

An indicative assessment of the impact of varying these key drivers on the system maximum demand is described in Chapter 5. The result is an outcome about 4% - 7% below the system maximum demand forecast by Ergon Energy.

MMA considers this a reasonable estimate of the extent to which the current forecasts will be affected by the key drivers and considers it reasonable to apply these numbers at the ZSS level. This will act to "correct" the forecasts to the changed key drivers, while retaining the relative growth rates in ZSS forecast by Ergon Energy.

MMA also recommends that in future Ergon Energy adopt a top down methodology, which changes according to key economic, demographic, air-conditioning and weather drivers, as well as the bottom-up one currently used, and reconcile the two forecasts.

4.5.2 Treatment of spot loads

As described in Sections 4.3.2 to 4.3.4, MMA considers that the Ergon Energy methodology both double-counts spot loads and also generally takes too optimistic a view of the timing, size and probability of these loads. This is likely to have contributed to the outcome described above.

We are especially concerned that forecast block load timings are generally premature. A probability of proceeding by a given year could be a more informative figure than the single probability of proceeding number currently employed.

MMA has not been able to accurately quantify the impacts of these across all the ZSS but provides an indicative assessment of 2.6% based on double-counting alone. In addition MMA considers it reasonable to assume that many spot loads will be delayed by at least a year.

We note that these considerations have not been taken into account in Chapter 5 below which has been based purely on changes to key drivers on system-wide maximum demand. They do, however, help to explain the findings.

4.5.3 Lack of weather correction

Ergon Energy has argued in its Regulatory Proposal[80] that weather correction requires a very significant amount of additional data and is not really required.

However, as seen in Section 3.1, the weather can exert a very significant impact on trend-line assessments. MMA re-states its conviction that appropriate weather correction is an important part of maximum demand forecasting, and recommends that Ergon Energy work towards such weather correction in future. We note that a similar comment was made by GHD in its 2002 review of Ergon Energy's forecast methodology[81].

4.6 Summary of spatial forecasts

Having reviewed the methodology, application of judgment and forecasts submitted by Ergon Energy we do not consider the forecasts to be realistic or reasonable.

In summary, MMA considers that the trend-line methodology applied by Ergon Energy is not realistic during times of significant change in key drivers, such as those due to the GFC, that the spot load methodology used is flawed as it allows double-counting of spot loads and that the spot load forecasts and probabilities actually applied by Ergon Energy are likely to be over-optimistic in terms of both magnitude and timing.

It is not possible to adjust these components using the bottom-up approach applied by Ergon Energy. In order to allow an indicative assessment of the likely magnitude of the GFC and other key driver changes to be assessed, MMA has considered the effect of the changed key drivers on Ergon Energy system maximum demand in Chapter 5.

[80] Regulatory Proposal to the AER. Distribution Services for the Period 1 July 2010 to 30 June 2015. Ergon Energy Corporation Ltd, Page 176, Table 42.

[81] "PL732c_GHD_Load Forecasting Project Report_June 2002.pdf", Section 5.2.12, Page 13.

5 SYSTEM MAXIMUM DEMAND

Ergon Energy's System MD projections are derived from Bulk Supply Point and Connection Point MD projections aggregated at regional and then system level. Ergon Energy does not prepare System MD projections independently of the zonal and BSP MD projections and consequently does not expend much effort on preparing and analysing system MD data. MMA nevertheless believes that important insights can be gained by analysing and projecting MDs at the system level and has sought to do so. We have split the system MD projection task into two components:

- determining suitable historical 50% PoE system MDs
- decomposing system MD into components that relate to the major MD drivers on a logical basis.

5.1 Historical 50% POE system MDs

As noted in Section 3.1, Ergon Energy has provided weather normalised 50% PoE system MDs in Figure 33 of its Regulatory Proposal[82]. MMA's estimates of these values from 2003/04 to 2007/08 are shown in Table 5-1, along with actual MDs. Figure 33 does not extend to 2008/09 consequently we have included Ergon Energy's most recent forecast value, which we believe is the best estimate to use for 2008/09. The value 2,595 MW for 2008/09 is sourced from an Ergon Energy document[83]. The values for 2010/11 to 2014/15 in this document are referred to as the 2009 forecast in the Regulatory Proposal.

Table 5-1 also contains undiversified MDs (actual and 50% POE) for three regions that make up Ergon, South West, Central non-industrial and Northern non-industrial, as defined by Powerlink in Appendix B of its 2009 APR. The undiversified MDs are of course higher than the diversified system MDs but the weather corrections between actual and 50% POE are consistent with the weather corrections for the system MDs between 2003/04 and 2007/08. The Powerlink 50% POE MD data therefore corroborates the Ergon Energy data over this period.

Unfortunately, the Powerlink data for 2008/09 does not corroborate the Ergon Energy data, suggesting a negative weather correction even though the Powerlink APR notes that the 90% POE temperature was exceeded only in Toowoomba and a positive correction would be expected. Consequently there remains some uncertainty as to the exact weather correction to apply in 2008/09.

[82] Ergon Energy presents weather corrected data at the system level but not (apart from use of trendlines) at the spatial level, as noted in the previous section.

[83] Ergon Energy document "PL655c, EE Ergon Forecast 2008 Final Rev 2 Mar 09 GSM final.

Table 5-1 50% POE System MD Estimates (MW)

	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09
System actual MD	2,213	2,268	2,380	2,584	2,332	2,418
System 50% POE MD	2,127	2,242	2,357	2,502	2,422	N/a
Ergon 50% POE 2009 FC						2,595
Weather correction	-86	-25	-23	-81	90	177
Sum of regions actual	2,291	2,375	2,536	2,659	2,463	2,682
Sum of regions 50% POE	2,226	2,349	2,511	2,596	2,574	2,607
Weather correction	-65	-26	-25	-63	111	-75

5.2 50% POE MD Projections

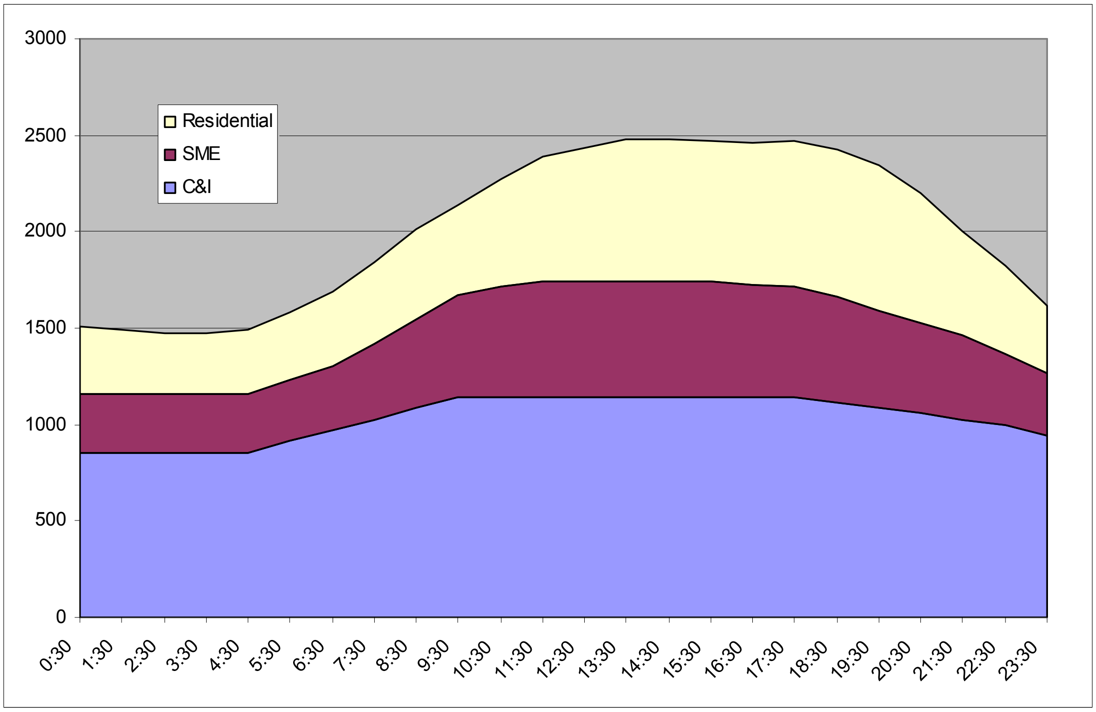
Three factors, customer numbers, air-conditioning penetration and GSP, are expected to drive growth at the system MD level. In the absence of Ergon Energy system MD models or suitable data for deriving a model combining these factors by statistical analysis of MD sensitivity to each factor, MMA has constructed a simple model by replicating the 2007 system demand profile presented in Figure 30 of Ergon Energy's Regulatory Proposal, using our estimates of the likely split between weather sensitive and non-weather sensitive components of the residential and SME loads. The peak contributions in the profile in Figure 5-1 are approximately: C&I – 1,140 MW; SME base load - 300 MW; SME weather sensitive - 300 MW; residential base load - 300 MW; and residential weather sensitive – 440 MW.

The model assumes that growth in the components of MD is related to the key drivers as follows:

- C&I and SME – MD grows in proportion to GSP growth or a percentage of GSP where the percentage represents demand-GSP elasticity
- Residential baseload – MD grows in proportion to residential customer numbers
- Residential weather sensitive – MD grows in proportion to residential customer numbers and air-conditioning penetration.

As noted above, these relationships are not determined by regression analysis.

Figure 5-1 Ergon Energy peak day indicative demand profile (MW)



The overall scale of each component and the GSP elasticity have been estimated by fitting the model to the historical 50% PoE estimates. The GSP and residential customer number growth rates and air-conditioning penetration used in the model are set out in Table 2-5. The GSP elasticity estimated in fitting the model to the 2003/04, 2006/07 and 2008/09 50% POE MDs in Table 5-1 is 1.11, which is consistent with many econometric estimates.

MMA's indicative forecast prepared using the model with the above data is tabled below. The MMA projections are some 230 MW or 7.4% on average below the Ergon Energy forecast and this is largely due to the assumed starting level in 2008/09 and 2009/10, based on the estimated negative GSP growth, because the subsequent growth is similar in the different projections.

Table 5-2 50% POE MD forecast comparisons (MW)

	2010	2011	2012	2013	2014	2015	2010-2015
Ergon Regulatory Proposal Forecast	2,861	2,967	3,063	3,153	3,243	3,330	469
2002 to 2007 Trend	2,835	2,940	3,046	3,151	3,256	3,361	526
MMA indicative forecast	2,607	2,693	2,811	2,928	3,031	3,121	514
MMA/EE	0.91	0.91	0.92	0.93	0.93	0.94	
MMA/Trend	0.92	0.92	0.92	0.93	0.93	0.93	

Given the degree of weather correction (177 MW) in the 2008/09 starting point that we have used, we believe that the starting point in the MMA forecast is considerably more realistic. If the 2008/09 starting point in the MMA forecast were increased by 50 MW to 2,645 MW, the 2014/15 value would increase by 83 MW to 3,204 MW, still approximately 130MW below the Ergon estimate. On average this projection would be 5.5% below the Ergon Energy forecast.

MMA also notes that using the NIEIR GSP forecast discussed in section 2.2, instead of the KPMG Econtech GSP forecast, reduces the differences between the MMA projections and the Ergon Energy projection to 6.3% and 4% respectively.

The 230 MW difference between the Ergon Energy and MMA forecasts is approximately equivalent to two years of MD growth. MMA's forecast is based on post-GFC projections of economic growth that project Queensland GSP over the period 2010/11 to 2014/15 to be approximately 8% lower than the pre-GFC projections did ie the Queensland economy is not expected to recover the two years of growth lost due to the GFC. MMA's forecast reflects this loss of growth in the MD projection, whereas Ergon Energy's forecast appears to be based on the assumption that lost growth/developments will be recovered.

5.3 Conclusion

MMA's indicative system maximum demand assessment highlights the need for Ergon Energy to consider system MD forecasts as part its forecasting process. The assessment suggests that the Ergon Energy maximum demand forecasts are some 4% to 7% pa higher than they would be if the impacts of changed key drivers were properly taken into account.

APPENDIX A GLOSSARY

2010 – 2015 regulatory period	The next regulatory period for DNSPs from 1 July 2010 to 30 June 2015
ac	Air-conditioning
ABS	Australian Bureau of Statistics
ADMD	After Diversity Maximum Demand
AER	Australian Energy Regulator
APR	Powerlink's Annual Planning Report.
BSP	Bulk Supply Point
Capex	Capital Expenditures
Contributing ZSS	Zone substations which are expected to contribute load through a load transfer to a new ZSS
CP	Connection Point
DM	Demand Management
DNSP	Distribution Network Service Provider
Global or system maximum demand	Summer coincident maximum demand for the network as a whole. Typically projected on a "top-down" basis based on assessment of key drivers.
GFC	Global Financial Crisis
GSP	Gross State Product – a measure of the goods and services produced in the state in $ terms.
HIA	Housing Industry Association
Maximum Demand (MD)	Single highest measurement of half-hourly average of instantaneous demand over a period, typically winter or summer.
MEPS	Minimum Efficiency Performance Standards
MMA	McLennan Magasanik Associates

MVA , MW	Measures of electricity demand and maximum demand. MVA (Mega Volt Ampere) is a measure of the "apparent" power or demand. MW or Mega Watt is a measure of the real power or demand. The two measures are required because of the reactive power (MVAR) which is a measure of "losses" due to the effects of capacitance and inductance. MVA and MW are related through the Power Factor (PF).
N-1 Security Standard	The requirement that a zone substation (or other critical infrastructure) meets stipulated requirements after the failure of 1 critical element. For example, many ZSS have the requirement that they meet the 50% POE forecast on an N-1 basis, that is with one piece of critical equipment (typically a transformer) not operating.
NEM and NEMMCO	National Electricity Market and National Electricity Market Management Company Limited
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
Opex	Operating Expenditures
Power Factor (PF)	The ratio of true power to apparent power in a circuit. PF = MW/MVA.
pa	Per annum
ppd	Persons per dwelling, calculated as the population divide by the total number of dwellings.
Probability of Exceedence (POE)	MD projections for each season and year are typically represented by a statistical distribution which takes into account key factors such as temperature and day type (e.g. whether a working or non-working day). An MD at a specified POE level is the estimated MD which is likely to be equalled or exceeded at that probability level. For example, a summer MD specified as 10% POE means that the probability of this MD being equalled or exceeded in the summer of that year is estimated to be 10% or 1 year in 10. A 50% POE MD is expected to be equalled or exceeded, on average, 1 year in 2. Distribution network planning in NSW is typically based on 50% POE forecasts.

Regulatory Proposals	Regulatory proposals submitted by the DNSPs to the AER in July 2009 relating to appropriate revenues and prices for DNSPs in Queensland from 1 July 2010 to 30 June 2015.
RC	Reverse Cycle Air-conditioning (capable also of heating)
RIN	Regulatory Information Notice
Spatial maximum demand	Summer or winter maximum demand for a small part of the network such as a transmission or zone substation. Typically projected on a "bottom-up" basis based on assessment of recent growth and spot loads.
System or global maximum demand	Summer coincident maximum demand for the network as a whole. Typically projected on a "top-down" basis based on assessment of key drivers.
Templates	Spreadsheet templates submitted as a response to the RIN in the Proposals.
Trim Factor	Factor used to reconcile the spatial forecast to the system demand forecast.
ZSS	Zone substation