NESA – gas shock scenario

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Executive summary

The National Energy Security Assessment (NESA) identifies key strategic energy security issues in the liquid fuels, natural gas and electricity sectors in Australia. The Department of Resources, Energy and Tourism (DRET) released the inaugural NESA in March 2009. DRET has now developed the 2011 NESA.

DRET has included "shock scenarios" in the 2011 NESA. These shock scenarios are hypothetical physical or market-based disruptions to the liquid fuels, electricity and natural gas sectors that are designed to provide insights into the impacts that such disruptions may have on Australia's energy security. The shock scenarios analyse energy security impacts under current market conditions and in the longer term.

Frontier Economics was engaged to advise DRET on the impact of shock scenarios in the electricity and natural gas sectors. This report sets out Frontier Economics' advice to DRET on the impact of a shock scenario in the natural gas sector. The assessment of the gas shock scenario considers outcomes on the Roma to Brisbane Pipeline (RBP), broader gas market outcomes and outcomes for the electricity market.

The examination by DRET of shock scenarios in the gas sector is intended to provide insight into the effects that significant disruptions may have on Australia's energy markets. While specific pieces of infrastructure (in this case the Roma to Brisbane Pipeline) have been used to provide 'real world' information, this is neither a reflection on the reliability of that infrastructure nor a reflection on the mitigation options that exist to prevent loss of capacity of that infrastructure.

Shock scenarios analysed

The gas shock scenario analysed by Frontier Economics is defined to be a hypothetical supply interruption on the RBP of 14 days duration. The shock scenario includes cases in which the supply interruption affects 10 per cent, 50 per cent and 100 per cent of the capacity of the RBP and cases in which the supply interruption occurs during both peak and shoulder periods in both 2011/12 and 2015/16.

The gas shock scenario cases are not intended to represent the failure of particular infrastructure that is part of the RBP. Indeed, there are features of the RBP that would mitigate against loss of capacity (including that the RBP is looped for 403 kilometres of its 438 kilometre length, that the RBP has points along its length to allow the transfer of gas between the two pipelines and that the RBP has 10 gas receipt points in three distinct supply areas along its length). Rather, the gas shock scenario cases are designed to examine outcomes in an energy system under stress. For this reason, DRET has chosen to investigate shock scenario cases that do involve a major reduction in the capacity of the RBP.

Conclusion on outcomes on the RBP

Broadly speaking, irrespective of the timing of the interruption (peak or shoulder) or the year of the interruption (2011/2012 or 2015/16), Frontier Economics' analysis indicates that the following outcomes are likely to occur on the RBP:

- A 10% loss of RBP capacity will result in relatively modest curtailment of some gas-fired generators that draw gas from the RBP. Other customers will be largely unaffected.
- A 50% loss of RBP capacity will result in complete curtailment of all gas-fired generators that draw gas from the RBP as well as significant curtailment of other large customers. Smaller business and residential customers on the Allgas and Envestra distribution networks are likely to be unaffected.

Since Brisbane is supplied with gas only through the RBP (and is the only major city in eastern Australia to depend on a single pipeline for gas supply) there are few options available to manage the affects of a supply interruption on the RBP. Realistically, any significant reduction in capacity on the RBP will result in either voluntary or involuntary curtailment of gas load.

Voluntary curtailment will be facilitated through the introduction of the Short Term Trading Market (STTM) in Brisbane, which will commence operations by December 2011. This market will provide an opportunity for voluntary gas curtailment by those gas users who can curtail gas at least cost. Gas-fired generators – in particular Swanbank E – are likely to offer to voluntarily curtail through the STTM. This would provide an opportunity to manage relatively significant reductions in capacity on the RBP through price signals provided by the STTM rather than through involuntary curtailment. However, price signals provided by the STTM will almost certainly be incapable of managing large reductions in the capacity on the RBP. In this case, involuntary curtailment will be the only alternative.

Longer-term, security of gas supply to gas users along the RBP will only be significantly improved through further investment in infrastructure: either gas storage or a second gas pipeline. There is at least one proposal for a second gas pipeline to supply gas users in and around Brisbane – from gas fields in northern NSW – but so far no investment decision has been made.

It should be noted that these outcomes are based on Frontier Economics' forecasts of gas demand from gas-fired generators. These forecasts from Frontier Economics' are materially lower than the equivalent forecasts from the AEMO 2010 GSOO. In particular, the AEMO 2010 GSOO forecasts a substantial increase in peak gas demand from gas-fired generators. If the AEMO 2010 GSOO forecasts of GPG demand turn out to be accurate, then the supply interruption to the RBP is likely to have a more substantial impact on gas-fired generation than is estimated in this report. In particular, the supply interruption to the RBP will result in curtailment of greater gas-fired generation capacity. This could ultimately lead to more significant consequences for the electricity market.

Conclusions on broader gas market outcomes

While the consequences of a supply interruption to the RBP will be significant for customers drawing gas from the RBP, Frontier Economics' analysis indicates that there are unlikely to be any significant consequences for other markets.

Considered at an aggregate level, there is expected to be sufficient flexibility in gas production in the Bowen-Surat basins that there is no need to divert gas from the RBP to other gas demand centres. This conclusion is strengthened by the fact that there are a number of options available to gas producers for managing an interruption to the RBP. For instance, there may be storage capacity available to help manage the interruption and some CSM producers may be able to effectively swap production between basins.

This is not to suggest, however, that all individual gas production facilities in the Bowen-Surat basins are equally able to manage an interruption to the RBP. In particular, CSM production plant that do not have direct pipeline connections to the Wallumbilla hub – including Berwyndale South, Daandine, Kogan North, Peat, Scotia, Talinga and Tipton West – will not have the same ability to continue supplying gas through the Queensland Gas Pipeline and the South-West Queensland Pipeline that are available to other CSM production plant.

Some of these plant have other options to manage the impact of the interruption to the RBP, including supplying additional gas to gas-fired generators not supplied by the RBP. However, for those gas production facilities that are not connected to sources of gas demand other than through the RBP – which Frontier Economics understands to include Kogan North, Peat and Scotia – a complete loss of capacity on the RBP would likely require these plant to flare gas and/or shut down production during the 14-day interruption.

Conclusions on electricity market outcomes

Frontier Economics' analysis indicates that there are unlikely to be substantial impacts on electricity markets resulting from even a complete curtailment of gas supplies on the RBP. While our modelling shows Swanbank E would supply less electricity (or none in the case of complete curtailment), there are no issues for security of electricity supply caused by the curtailment of gas supplies on the RBP, and the overall impact on electricity prices is small (with the exception of the peak demand day in summer).

A key reason that electricity market price impacts are muted is an assumption that intraregional constraints do not block physical supply of electricity to Brisbane. Modelling all of the intraregional network constraints in the NEM is a substantial exercise and is beyond the scope of this project. If it is the case that intraregional network constraints in Queensland create issues for supply to Brisbane then the impact on the electricity market of the curtailment of gas to Swanbank E could be significantly greater. For partial supply interruptions of the RBP these circumstances may mean that the gas supplies to Swanbank E take precedence over gas supplies to other customers (either as a result of the higher opportunity cost of gas to Swanbank E or because the Minister directs that gas be supplied to Swanbank E as a priority). This would mitigate the consequences for the electricity market of the combination of supply interruptions of the RBP and electricity network constraints, but do so at the cost of greater consequences for other gas users.

1 Introduction

The National Energy Security Assessment (NESA) identifies key strategic energy security issues in the liquid fuels, natural gas and electricity sectors in Australia. The Department of Resources, Energy and Tourism (DRET) released the inaugural NESA in March 2009. DRET has now developed the 2011 NESA.

DRET has included "shock scenarios" in the 2011 NESA. These shock scenarios are hypothetical physical or market-based disruptions to the liquid fuels, electricity and natural gas sectors that are designed to provide insights into the impacts that such disruptions may have on Australia's energy security. The shock scenarios analyse energy security impacts under current market conditions and in the longer term.

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1.1 Frontier Economics' engagement

Frontier Economics was engaged to advise DRET on the impact of shock scenarios in the electricity and natural gas sectors.

Frontier Economics has undertaken modelling of the electricity sector and the natural gas sector in order to provide advice as to the likely impacts on security of supply in these sectors, including advice on energy security vulnerabilities and risks in these sectors.

1.2 This report

This report sets out Frontier Economics' advice to DRET on the impact of a shock scenario in the natural gas sector. Frontier Economics has separately provided a report that sets out its advice to DRET on the impact of a shock scenario in the electricity sector.

This report is structured as follows:

- Section 2 defines the gas shock scenario
- Section 3 describes Frontier Economics' modelling framework
- Section 4 sets out Frontier Economics' electricity market modelling assumptions

- Section 5 sets out Frontier Economics' gas market modelling assumptions
- Section 6 describes outcomes in the Reference Case
- Section 7 describes outcomes for gas users relying on the RBP in the various shock scenario cases
- Section 8 discusses the relevance of the STTM for outcomes for gas users relying on the RBP
- Section 9 describes broader gas market outcomes in the various shock scenario cases
- Section 10 describes electricity market outcomes in the various shock scenario cases.

2 Defining the gas shock scenario

The gas shock scenario is a major reduction in the capacity of a natural gas pipeline in Queensland.

2.1 Affected infrastructure

The gas shock scenario is defined to affect the Roma to Brisbane Pipeline (RBP), which transports gas from the Wallumbilla gas hub in Queensland to gas users in south-east Queensland, including Toowoomba and Brisbane.

There is a diverse mix of gas users that depend on the RBP for gas supplies, including:

- **Allgas distribution network**. APT's Allgas distribution network supplies gas to approximately 85,000 customers in Brisbane (south of the Brisbane River), in the Western region (Toowoomba and Oakey) and in the South Coast region (including Gold Coast and Tweed Heads). There are a mix of customers supplies with gas from the Allgas distribution network, including around 80,000 residential customers, around 5,000 small business customers and around 100 large business customers.[1]
- **Envestra distribution network**. Envestra's distribution network supplies gas to approximately 83,000 customers in Brisbane (north of the Brisbane River) and Ipswich.[2] There are a mix of customers supplied with gas from the Envestra distribution network, including around 80,000 residential customers, around 3,000 small business customers and around 70 large business customers.[3]
- **Dalby Council distribution**. Dalby Council is responsible for a gas distribution network located within the Dalby town boundary. Natural gas and LPG is supplied to around 2,500 customers in the town.
- **Commercial and industrial customers**. There are a number of large commercial and industrial customers in and around Brisbane that rely on agreements to transport gas on the RBP to meet their gas supply needs. These large customers include BP's Bulwer Island Refinery and Incitec-Pivot's Gibson Island plant.

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[1] AER, *APT Allgas, Access arrangement proposal for the Qld gas network*, Draft Decision, February 2011.

[2] Envestra's distribution network also supplies gas to Rockhampton and Gladstone, but those areas of Envestra's distribution network are not supplied through the RBP.

[3] AER, *Envestra Ltd, Access arrangement proposal for the Qld gas network*, Draft Decision, February 2011.

- **Gas-fired generators**. Swanbank E, Oakey and Braemar gas-fired generators all use gas shipped on the RBP in their operations.

One of the benefits of examining a gas shock scenario that affects the RBP is precisely this broad mix of gas users on the RBP. In comparison with the RBP, both the Queensland Gas Pipeline (from the Wallumbilla gas hub to Gladstone) and the Carpentaria Gas Pipeline (from Ballera to Mt Isa) primarily supply gas to large industrial customers and mining customers, with demand from residential customers, small business customers and market generators far less important.

Examining a gas shock scenario that affects the RBP has also been adopted for this NESA in order to assess the extent to which the introduction of the Short Term Trading Market for Gas (STTM) in Brisbane is likely to assist in managing gas supply shocks. The STTM is expected to be introduced by December 2011.

The RBP is located at the end of the interconnected gas transmission network and is the only option for physically supplying gas to customers in and around Brisbane. In a sense, therefore, the analysis of a supply interruption to the RBP is more straightforward than would be the case for other pipelines in eastern Australia: an interruption to the RBP does not create opportunities for supplying gas to Brisbane through alternative means and does not create any issues for gas markets downstream of Brisbane. The RBP is the same, in this regard, to each of the other gas transmission pipelines that supply gas demand centres in Queensland: the Queensland Gas Pipeline and Carpentaria Gas Pipeline are also located at the end of the interconnected gas transmission network. The only gas transmission pipeline in Queensland for which this is not the case is the South-West Queensland Pipeline, which transport gas to a number of different downstream gas markets. Examining a supply interruption to the South-West Queensland Pipeline would therefore have more material consequences for the broader gas market in eastern Australia than would a supply interruption to the RBP. However, since the South-West Queensland Pipeline is essentially used to transport CSM from the Bowen-Surat basins to South Australia, NSW and Queensland, examining a supply interruption to the South-West Queensland Pipeline would not provide insights into security of gas supply to Queensland.

2.2 Nature of the supply interruption

The gas shock scenario is defined to result in a temporary supply interruption on the RBP of 14 days duration. The temporary supply interruption includes three cases:

- a 10 per cent reduction in transport capacity on the RBP of 14 days duration
- a 50 per cent reduction in transport capacity on the RBP of 14 days duration
- a complete loss of transport capacity on the RBP of 14 days duration.

Each of these interruptions is assumed to be an immediate reduction in capacity in keeping with the intention of modelling a "shock" to the gas sector.

Note that the intention of this review is not to model a specific infrastructure outage and the consequent impacts on the operation of the RBP and the downstream distribution networks. Rather, the intention is to provide a high level understanding of the extent to which gas users in Brisbane and surrounding areas are likely to be affected by interruptions to the RBP. Given this, the supply interruptions analysed by Frontier Economics are purely hypothetical reductions in capacity assumed to affect the entire pipeline equally. Detailed modelling of pipeline operations along the length of the RBP on an hourly and daily basis, including pressure levels and linepack, is beyond the scope of this project.

It is also worth noting that there are features of the RBP designed to prevent and mitigate losses of pipeline capacity. The RBP is looped for 403 kilometres of its 438 kilometre length (effectively creating two parallel pipelines) with points along its length to allow the transfer of gas between the pipelines. The RBP has 10 gas receipt points in three distinct areas along the pipeline's length – Wallumbilla, Peat-Scotia and in the Kogan area – resulting in diversity of supply. These features reduce the likelihood that the RBP will experience a major reduction in capacity. However, the shock scenario cases are designed to examine outcomes in an energy system under stress. For this reason, DRET has chosen to investigate shock scenario cases that do involve a major reduction in the capacity of the RBP.

2.3 Timing of the temporary supply interruption

The supply interruption on the RBP is defined to occur at a number of different periods:

- a peak period in 2011/12
- a shoulder period in 2011/12
- a peak period in 2015/16
- a shoulder period in 2015/16.

In each case, the peak period is defined as a two-week period commencing at 4 AM Monday,[4] with the peak daily demand for the year occurring in the first week of the two-week period.

In each case, the shoulder period is defined as a two-week period commencing at 4 AM Monday, with the lowest average daily demand for the spring and autumn months occurring in the first week of the two-week period.

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[4] A commencement period of 4 AM Monday is chosen for consistency in modelling electricity days (which are defined to commence at 4 AM) and gas days.

Peak demand days on the RBP are driven primarily by demand from gas powered generation. Gas demand forecasts from AEMO's 2010 Gas Statement of Opportunities (AEMO 2010 GSOO)[5] indicate that this will become more evident over the next decade, with peak demand days driven primarily by gas demand from gas powered generation. The implication of this is that peak daily demand on the RBP is driven by, and will coincide with, peak daily electricity demand. As such, the peak gas and electricity interruptions are assumed to occur for the same two weeks. This assumption is also adopted for the shoulder months of the year.

2.4 Summary of cases

Given that the gas shock scenario includes supply interruptions of different magnitudes occurring at different times, the gas shock scenario in fact consists of a number of different cases. These cases are summarised in Table 1.

Table 1: Modelling cases for gas shock scenario

Case name	Affected pipeline	Type of interruption	Lost RBP capacity	Duration	Timing
RBP-10%Loss-2012-Peak	RBP	Forced outage	10 %	14 days	Peak 2011/12
RBP-10%Loss -2012-Shoulder	RBP	Forced outage	10 %	14 days	Shoulder 2011/12
RBP-10%Loss -2016-Peak	RBP	Forced outage	10 %	14 days	Peak 2015/16
RBP-10%Loss -2016-Shoulder	RBP	Forced outage	10 %	14 days	Shoulder 2015/16
RBP-50%Loss-2012-Peak	RBP	Forced outage	50 %	14 days	Peak 2011/12
RBP-50%Loss -2012-Shoulder	RBP	Forced outage	50 %	14 days	Shoulder 2011/12
RBP-50%Loss -2016-Peak	RBP	Forced outage	50 %	14 days	Peak 2015/16
RBP-50%Loss -2016-Shoulder	RBP	Forced outage	50 %	14 days	Shoulder 2015/16
RBP-FullLoss-2012-Peak	RBP	Forced outage	100 %	14 days	Peak 2011/12
RBP- FullLoss -2012-Shoulder	RBP	Forced outage	100 %	14 days	Shoulder 2011/12
RBP- FullLoss -2016-Peak	RBP	Forced outage	100 %	14 days	Peak 2015/16
RBP- FullLoss -2016-Shoulder	RBP	Forced outage	100 %	14 days	Shoulder 2015/16

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[5] AEMO, *Gas Statement of Opportunities for Eastern and South Eastern Australia*, 2010.

2.5 Defining energy security

DRET defines energy security as the adequate, reliable and competitive supply of energy to support the functioning of the economy and social development, where:

- adequacy is the provision of sufficient energy to support economic and social activity
- reliability is the provision of energy with minimal disruptions to supply
- competitiveness is the provision of energy at an affordable price that does not adversely impact on the competitiveness of the economy and which supports continued investment in the energy sector.[6]

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[6] DRET, *National Energy Security Assessment*, 2009, page 5.

3 Modelling framework

This section provides a brief overview of the modelling framework used by Frontier Economics to analyse the likely impact on energy security of the gas shock scenario.

3.1 Frontier Economics' relevant energy market models

In examining outcomes from the gas shock scenario, Frontier Economics has adopted a three-staged modelling approach, which makes use of three proprietary inter-related gas and electricity market models: *WHIRLYGAS*, *WHIRLYGIG* and *SPARK*. The key features of these models are as follows:

- *WHIRLYGAS* optimises total production and transmission cost in the gas market, calculating (among other things) the least cost operation of gas production and transmission assets to meet gas demand.
- *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least cost mix of existing plant and new plant options to meet load. *WHIRLYGIG* determines the least cost investment in, and operation of, generation plant to meet demand and to meet any regulatory obligations (such as renewable energy targets).
- *SPARK* uses game theoretic techniques to identify optimal and sustainable bidding behaviour by generators in the electricity market. *SPARK* determines the optimal pattern of bidding by having regard to the reactions by generators to discrete changes in bidding behaviour by other generators. The model determines profit outcomes from all possible actions (and reactions to these actions) and finds equilibrium bidding outcomes based on game theoretic techniques. An equilibrium is a point at which no generator has any incentive to deviate. The output of *SPARK* is a set of equilibrium dispatch and associated spot price outcomes.

WHIRLYGAS incorporates a representation of the physical gas infrastructure in the eastern States that includes all existing production plant, all existing transmission pipelines, demand forecasts for each region and options for new plant and pipelines.

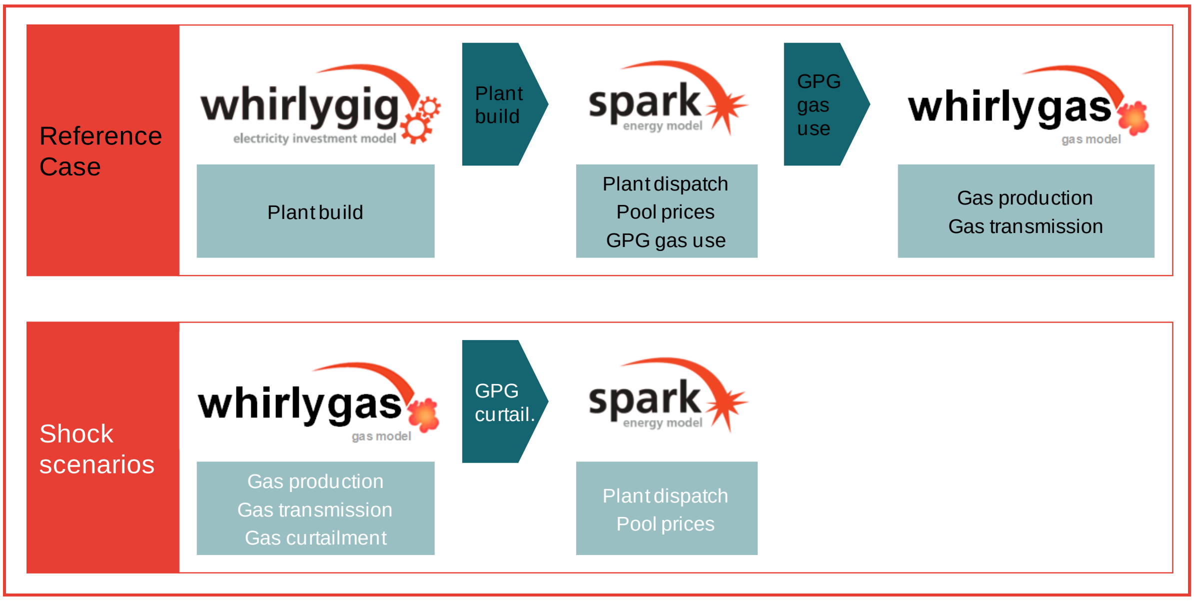
Both *WHIRLYGIG* and *SPARK* incorporate a representation of the physical infrastructure in the NEM that includes all existing generation plant in the NEM (including technical and cost information for those existing plant), all existing inter-regional interconnectors in the NEM, demand forecasts for each region in the NEM and options for new generation plant.

3.2 Modelling framework for the gas shock scenario

As discussed, the gas shock scenario includes a number of cases in which there is a temporary interruption to the RBP. For a temporary interruption to the RBP no investment response would be expected. The key question, therefore, is the extent to which existing gas producers and pipelines can respond to the interruption to the RBP, and the impact that the interruption has on gas market outcomes in south-east Queensland. Due to the presence of gas powered generation in south-east Queensland, interruptions to the gas supply to south-east Queensland are also likely to have implications for the electricity market.

Frontier Economics integrates its gas market modelling and electricity market modelling in order to reflect the interactions between gas markets and electricity markets. The framework that Frontier Economics has adopted is illustrated in Figure 1 and discussed in detail in the following sections.

Figure 1: Modelling framework



3.2.1 Modelling the Reference Case

The first step in Frontier Economics' modelling framework is to model outcomes in the Reference Case.

The Reference Case is intended as the most likely set of future outcomes, and does not include any interruption to the RBP. The Reference Case provides a set of outcomes against which the outcomes under the various shock scenario cases can be compared.

Modelling the Reference Case involves three integrated stages: *WHIRLYGIG* modelling, *SPARK* modelling and *WHIRLYGAS* modelling.

WHIRLYGIG

WHIRLYGIG modelling for the Reference Case provides a least cost investment path for the electricity sector. This least cost investment is an important input for *SPARK* modelling of both the Reference Case and the shock scenario cases in 2015/16: as electricity demand grows over the period to 2015/16, there will be a need for new investment simply to meet reserve constraints. Undertaking market modelling in 2015/16 without incorporating this new investment would be unrealistic.

In order to ensure that the modelling of least cost investment appropriately accounts for the impact of the rising carbon price and the LRET, *WHIRLYGIG* is run for a number of years past 2015/16.

SPARK

SPARK modelling for the Reference Case provides a set of optimal bidding patterns for generators in the NEM, and the power station dispatch outcomes, pool prices outcomes and gas-powered generation (GPG) gas use outcomes that correspond to these optimal bidding patterns.

The dispatch outcomes and pool price outcomes from the Reference Case provide the point of comparison against which electricity market outcomes in the various shock scenario cases can be compared.

The GPG gas use outcomes from the Reference Case are an important input into the *WHIRLYGAS* modelling of both the Reference Case and the shock scenario cases. The GPG gas use outcomes from the Reference Case will be combined with forecasts of non-GPG gas demand from the AEMO 2010 GSOO to provide total gas demand. The GPG gas use outcomes from the Reference Case are used in preference to the GPG gas demand forecasts from the AEMO 2010 GSOO for two reasons:

- The GPG gas use outcomes from the Reference Case will be at the power station level, rather than the regional level as in the AEMO 2010 GSOO. Given the impact of gas curtailment will depend, in part, on the fuel supply options of individual power stations, this level of detail is important.
- Using the GPG gas use outcomes from the Reference Case will ensure internal consistency within the modelling. If the GPG gas demand forecasts from the AEMO 2010 GSOO were used, then the level of gas curtailment to GPG under the shock scenario cases that is implied by these gas demand forecasts may not be consistent with the dispatch of these power stations in the Reference Case. This would create issues in comparing outcomes between the Reference Case and the various shock scenario cases.

WHIRLYGAS

WHIRLYGAS modelling for the Reference Case provides a set of least cost gas production and gas transmission outcomes to meet total gas demand. *WHIRLYGAS* modelling will also identify whether there is likely to be any gas curtailment under the Reference Case during peak periods.

3.2.2 Modelling the shock scenario

The second step in Frontier Economics' modelling framework is to model outcomes in each of the shock scenario cases.

Each of the shock scenario cases is based on the Reference Case and incorporates all of the same input assumptions as the Reference Case except for the assumptions relevant to the available supply of gas through the RBP (90, 50 or 0%).

WHIRLYGAS

WHIRLYGAS modelling of the shock scenario cases is used to assess likely gas market outcomes during the supply interruption to the RBP:

- For the supply interruption cases in 2011/12, *WHIRLYGAS* modelling includes only existing and committed gas production and gas transmission infrastructure. Because Brisbane and surrounding areas depend entirely on the RBP for gas supply, the modelled outcomes from *WHIRLYGAS* assess the likely extent of supply curtailment required under each case.
- For the supply interruption cases in 2015/16, *WHIRLYGAS* modelling also includes new gas production and gas transmission infrastructure. Relevantly for the supply interruption on the RBP, the cases in 2015/16 incorporate expansions in the capacity of the RBP to keep pace with forecast growth in gas demand on the RBP.

As with the *WHIRLYGAS* modelling for the Reference Case, *WHIRLYGAS* modelling for each of the shock scenario cases provides a set of least cost gas production and gas transmission outcomes to meet total gas demand. *WHIRLYGAS* modelling also identify the extent of any gas curtailment under the Reference Case during peak periods.

SPARK

Given the growing importance of GPG in south east Queensland to outcomes in the NEM, Frontier Economics explicitly models the flow on effects of the gas curtailment on these gas-fired generators and outcomes in the NEM.

As discussed above, for each of the various shock scenario cases the output from *WHIRLYGAS* includes an assessment of the extent of gas curtailment, which will allow an assessment of the extent of gas curtailment for gas-fired generators that rely on the RBP. *SPARK* modelling of the shock scenario cases is used to assess the likely electricity market outcomes resulting from any such curtailment:

- For the supply interruption cases in 2011/12, *SPARK* modelling includes only existing and committed generation plant, with the modelling outcomes reflecting changes in bidding behaviour of these generators in response to gas curtailment to gas-fired generators that rely on the RBP.
- For the supply interruption cases in 2015/16, *SPARK* modelling also includes all new generation plant in Queensland and the NEM that makes up the least-cost investment path from the *WHIRLYGIG* Reference Case. To the extent that the least-cost investment path includes new GPG in south east Queensland, we assume this plant connects directly to gas sources in the Bowen-Surat basins, rather than relying on the RBP for gas transportation.

As with the *SPARK* modelling for the Reference Case, *SPARK* modelling for each of the shock scenario cases provides a set of optimal bidding patterns for generators in the NEM, and the power station dispatch outcomes, pool prices outcomes and GPG gas use outcomes that correspond to these optimal bidding patterns.

4 Electricity market modelling assumptions

This section provides a brief overview of the key electricity market modelling assumptions used by Frontier Economics to analyse the likely impact on energy security of the gas shock scenario.

Frontier Economics has, where possible, used input assumptions developed by AEMO. Frontier Economics has adopted this approach on the basis that the input assumptions developed by AEMO are commonly used for modelling work of this type and, to varying extents, can be considered an industry standard. Adopting this approach, Frontier Economics has, to a large extent, relied on the following sources:

- AEMO, *Electricity Statement of Opportunities for the National Electricity Market*, 2010 (**AEMO 2010 ESOO**). This is the source for system demand forecasts used in Frontier Economics' modelling.
- AEMO, *National Transmission Network Development Plan*, 2010 (**AEMO 2010 NTNDP**). The **NTNDP Modelling Assumptions** (supplied by ACIL Tasman and EPRI) and the **NTNDP Input Tables**, both released with the AEMO 2010 NTNDP, are the source for most of the input assumptions for existing and potential new generation plant.

4.1 NTNDP scenarios

The National Transmission Network Development Plan (NTNDP) examines the future through five market development scenarios. These scenarios outline a range of plausible future outcomes for key issues and policy settings facing the energy industry and investors.

None of the NTNDP scenarios represents a base case forecast, or a forecast that reflects the most likely state of the world. The NTNDP scenarios are designed to reflect "different combinations of the principal energy sector and national transmission network development drivers".[7] AEMO makes clear that none of the five scenarios is a base case but neither does each scenario have an equal probability of occurring.[8]

While none of the five scenarios is a base case, for a number of input assumptions that will be important determinants of the outcomes from this modelling project (including capital costs for new generation plant and fuel costs) the Decentralised World scenario has input assumptions that fall within the range for the other scenarios. For these key input assumptions, therefore, the

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[7] AEMO, *National Transmission Network Development Plan*, 2010, page 22.

[8] AEMO, *National Transmission Network Development Plan*, 2010, page 23.

Decentralised World scenario provides as close to a mid-point as is available from the NTNDP. For this reason, for the purposes of this modelling project, Frontier Economics has largely adopted the input assumptions from the Decentralised World scenario. The key exceptions to this are the assumed carbon price and demand forecasts, which are discussed in more detail below.

4.2 Discount rate

WHIRLYGIG optimises the total system costs of meeting demand over the entire modelling period. Total system costs are calculated as a net present cost in a specified base year using an assumed discount rate. The objective to be minimised by the model is the net present cost.

For the purposes of all modelling, Frontier Economics has used the WACC of 9.79% from the Decentralised World scenario.

4.3 Inflation rate

For the purposes of all modelling, Frontier Economics has used an inflation rate of 2.75%.

4.4 Electricity demand forecasts

Given this modelling project is focused on the impact on system security of the loss of the RBP and subsequent impacts on GPG relying on the RBP, electricity demand forecasts are an important input assumption. In order to examine the impact of the shock scenario cases it is necessary to develop a set of electricity demand forecasts for each region in the NEM that reflect the variation of demand throughout the year. The approach and assumptions that Frontier Economics has used to develop the required demand forecasts are as follows:

- The starting point is a half-hourly load profile for each NEM region that reflects a representative year. Frontier Economics has used the historic half-hourly load profile for each NEM region from calendar year 2010 to provide this representative year. The advantage of using the load profile for calendar year 2010 is that we can get a load profile for both electricity and gas for 2010 (the gas data available from the National Gas Market Bulletin Board for 2010 is the most complete data set for gas) and thereby account for the correlations between electricity and gas demand in our analysis.
- Modelling every half-hourly demand point in a year is computationally very demanding. For this reason, in the interests of making the modelling problem more tractable, Frontier Economics models a representation of the load profile for each year, rather than the full half-hourly load profile for each year. The representative load profile is generated by averaging demand during

half hours where demand is relatively constant within each NEM region. This method allows us to best capture the correlation in demand between the different NEM regions in our forecasts.

- For each NEM region, this representative half-hourly load profile is then scaled to reflect forecast growth in both total demand and peak demand. Frontier Economics has used the medium growth, 50% probability of exceedence demand forecasts for summer and winter from the AEMO 2010 ESOO to scale the representative half-hourly load profile for each year of the modelling period. The modelling results for these representative load profiles can then be aggregated to provide annual results.
- Given that the focus on this project is on supply interruptions that occur over a period of 14 consecutive days, Frontier Economics has modelled these periods with a more detailed load profile to the other modelling periods. Each 14 day period has been modelled as a number of 'representative days', which include a Sunday/public holiday, a Saturday and a number of working weekdays that reflect different levels of demand.

  The modelling results for these representative days can then be aggregated (based on the frequency of occurrence of each representative day during the quarter) to provide annual results. The representative days can also be ordered in sequence to reflect a period of 14 consecutive days, allowing analysis of the day-to-day impact of a supply interruption during this period.

The same system demand forecasts are used as an input to both *WHIRLYGIG* and *SPARK*. Importantly, however, in addition to using the medium growth, 50% probability of exceedence demand forecasts to develop load profiles for each year, Frontier Economics also uses the medium growth, 10% probability of exceedence demand forecasts for summer and winter for the purpose of modelling reserve constraints. These 10% probability of exceedence demand forecasts are assumed to be 100% co-incident across NEM regions, implying that maximum demand occurs in each NEM region at the same time. This assumption of co-incidence is made to ensure consistency with AEMO's reported regional reserve margins in the reserve constraints.

4.5 Existing NEM generation plant

This section provides an overview of the key input assumptions for existing generation plant that Frontier Economics has adopted.

Capacity and ownership

Frontier Economics has used the latest information available from AEMO's website[9] on existing and committed scheduled and semi scheduled generation plant in each region of the NEM. This provides both the identity of existing and committed generation plant and the summer and winter capacity of these generation plant.

In addition, Frontier Economics' market modelling (using *SPARK*) also requires information on ownership of existing generation plant. Frontier Economics has used up-to-date publicly available information on plant ownership in its modelling.[10]

Outage rates

Frontier Economics has used information on equivalent forced outage rates and planned maintenance rates from the NTNDP Input Tables.[11]

Frontier Economics' typical modelling approach is to derate all generation plant at a flat outage rate throughout the year. The assumption is that while different plant will have outages at different times during the year, on average across the system outages will occur at a constant rate.

Auxiliary power requirements, heat rate and emissions intensity

Frontier Economics has used assumptions on auxiliary power requirements, heat rates and emissions intensities for each existing power station that are set out in the NTNDP Modelling Assumptions. The emissions intensity set out in the NTNDP Modelling Assumptions and used by Frontier Economics in its modelling accounts for both combustion emissions and fugitive emissions.

VOM

Frontier Economics has used assumptions on variable operating and maintenance (VOM) costs for each existing power station that are set out in NTNDP Modelling Assumptions.

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[9] AEMO, Tables of Existing and Committed Scheduled and Semi Scheduled Generation – by Region. Available from:

http://www.aemo.com.au/data/gendata.shtml

[10] Note that Frontier Economics' modelling incorporates the Queensland Government's proposed restructure of the three Government-owned generators in Queensland (CS Energy, Stanwell and Tarong Energy) into two Government-owned generators.

[11] The exception is the equivalent forced outage rate for OCGT plant which is in excess of 25% in the 2010 NTNDP Input Tables. This outage rate reflects the fact OCGT plant may be unavailable during shoulder periods. However, the forced outage rate of OCGT plant during peak periods (when their capacity is needed) is much lower. For this reason, Frontier Economics has used an equivalent forced outage rate of 3% for OCGT plant.

Fuel costs

Frontier Economics has used assumptions on fuel costs for each existing power station that are set out in NTNDP Modelling Assumptions.

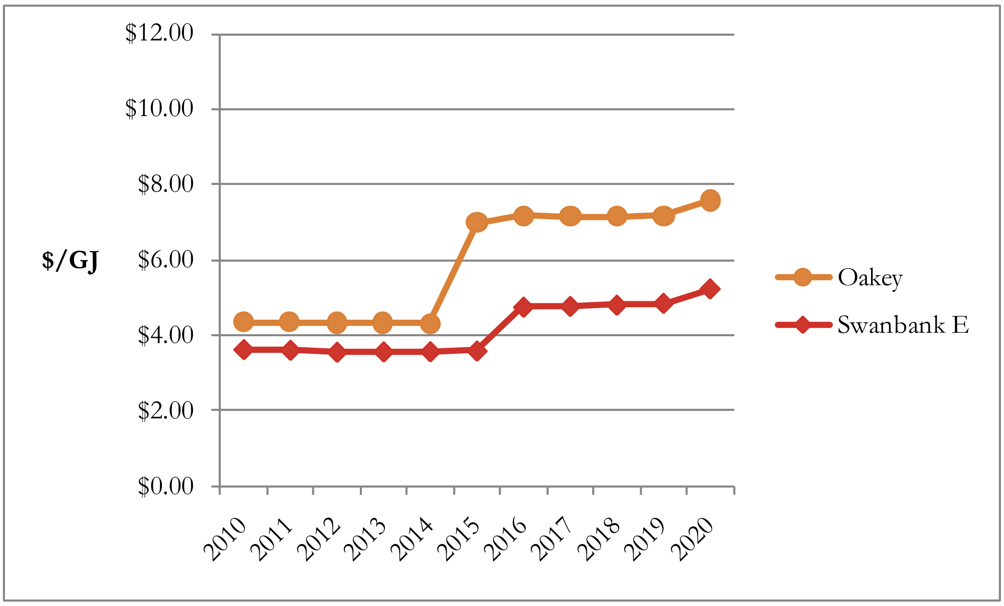
The gas costs for each of the gas-fired generators reliant on the RBP are shown in Figure 2. The NTNDP forecasts that:

- Swanbank E will have gas costs around $3.50/GJ up to 2014/15. In 2015/16 and beyond its gas costs are forecast to increase to around $4.75/GJ.
- Oakey will have gas costs around $4.30 up to 2013/14. In 2014/15 and beyond its gas costs are forecast to increase to around $7.00/GJ.

Frontier Economics understands that the reason that the NTNDP gas prices increase for Oakey in 2014/15 and for Swanbank E in 2015/16 is that this coincides with the term of existing contracts for gas supply to these power stations. Once the existing lower priced contracts expire, it is assumed that power stations face gas prices determined in the market.

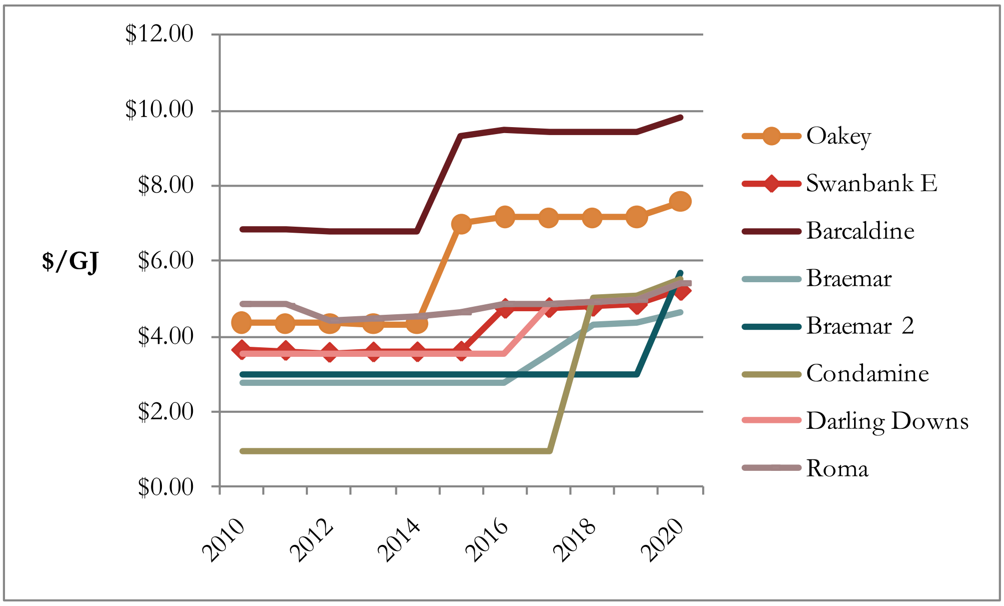
Figure 3 compares the gas costs for Swanbank E and Oakey with the gas costs for other gas-fired generators in south-east and south-west Queensland. This shows that the forecast gas costs for Swanbank E and Oakey tend to be relatively high compared to gas-fired generators located further west around the CSM fields in the Bowen and Surat basins.

Figure 2: Gas costs – gas-fired generators on the RBP



Source: NTNDP Modelling Assumptions

Figure 3: Gas costs – gas-fired generators in south-east and south-west Queensland



Source: NTNDP Modelling Assumptions

4.6 New generation plant

This section provides an overview of the key input assumptions for new generation plant that Frontier Economics has adopted.

Generation options

Frontier Economics has used assumptions on new generation options that are set out in the NTNDP Modelling Assumptions (however, given the timeframe for this modelling project, Frontier Economics has excluded those generation options that involve carbon capture and storage). Frontier Economics has also adopted constraints on construction times for new generation options and annual build limits that are set out in the NTNDP Modelling Assumptions.

The available thermal generation options, and key renewable generation options, are set out in Table 2.

Table 2: New generation options – thermal plant

Technology	Fuel Type	First Year Available for Construction	Lead time for development (years)
OCGT	Gas	2011	1
CCGT	Gas	2012	2
Supercritical PC - Black coal	Black Coal	2014	4
Supercritical PC - Brown coal	Brown Coal	2014	4
IGCC - Black coal	Black Coal	2015	4
IGCC - Brown coal	Brown Coal	2015	4
Wind - Small scale (50 MW)	Renewable	2012	2
Wind - Medium scale (200 MW)	Renewable	2012	2
Wind - Large scale (500 MW)	Renewable	2012	2
Geothermal - HSA	Renewable	2015	4
Biomass	Renewable	2012	2

Source: NTNDP Modelling Assumptions

Outage rates

As is the case for existing generation plant, Frontier Economics has used information on equivalent forced outage rates and planned maintenance rates from the NTNDP Input Tables.[12]

Auxiliary power requirements, heat rate and emissions intensity

As is the case for existing generation plant, Frontier Economics has used assumptions on auxiliary power requirements, heat rates and emissions intensities for new generation plant that are set out in NTNDP Modelling Assumptions. The emissions intensity set out in the NTNDP Modelling Assumptions and used by Frontier Economics in its modelling accounts for both combustion emissions and fugitive emissions.

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[12] As with existing generation plant, the exception is the equivalent forced outage rate for OCGT plant, for which Frontier Economics has used an equivalent forced outage rate of 3%.

Capital costs, FOM and VOM

For existing generation plant, the only cost information that is required for Frontier Economics' modelling is the variable costs of production: VOM and fuel costs (and carbon costs, once thermal generators are exposed to a carbon price).

For new entrant generation plant, Frontier Economics' modelling also requires information on the capital costs and the fixed operating and maintenance costs (FOM) of generation plant. This cost information is an important factor in least cost investment decisions.

Frontier Economics has drawn all required cost information for new entrant generation plant from the NTNDP Modelling Assumptions. Capital costs, FOM and VOM for important new generation options are set out in Table 2.

Table 3: New generation costs

Technology	Capital costs (Real 2009-10 $/kW)	FOM ($/MW/year) for 2009-10	VOM ($/MWh sent-out) for 2009-10
OCGT	985	9,000	2.50
CCGT	1,368	14,000	2.00
Supercritical PC - Black coal	2,676	33,000	4.60
Supercritical PC - Brown coal	3,571	41,000	5.10
IGCC - Black coal	4,201	73,000	12.80
IGCC - Brown coal	5,025	50,000	5.20
Wind - Small scale (50 MW)	3,178	42,000	0.00
Wind - Medium scale (200 MW)	2,886	39,000	0.00
Wind - Large scale (500 MW)	2,744	37,000	0.00
Geothermal - HSA	7,260	125,000	0.00
Biomass	5,000	40,000	2.25

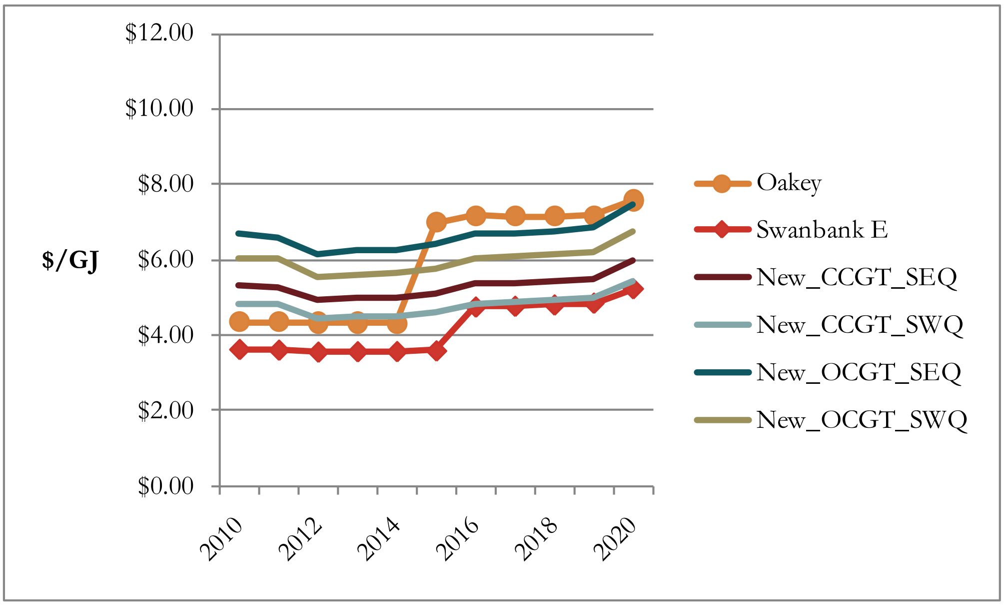
Source: NTNDP Modelling Assumptions

Fuel costs

As is the case for existing generation plant, Frontier Economics has used assumptions on fuel costs for new generation plant that are set out in NTNDP Modelling Assumptions.

Compared to new gas-fired generators, Swanbank E and Oakey initially have relatively low gas costs. Figure 4 compares the gas costs for Swanbank E and Oakey with the new entrant gas costs for CCGT and OCGT plant in both south-east Queensland and south-west Queensland.

Figure 4: Gas costs – Oakey and Swanbank compared with new entrant gas



Source: NTNDP Modelling Assumptions

4.7 Carbon price

Consistent with current policy, Frontier Economics' modelling is undertaken on the basis of an assumption that there will be a carbon price introduced from the beginning of 2012/13. The starting carbon price is assumed to be $20/tonne CO_2-e (in $2010/11), escalating thereafter at CPI + 4%.

The carbon price assumption used in Frontier Economics' modelling was adopted prior to the release of the Commonwealth Government's Clean Energy

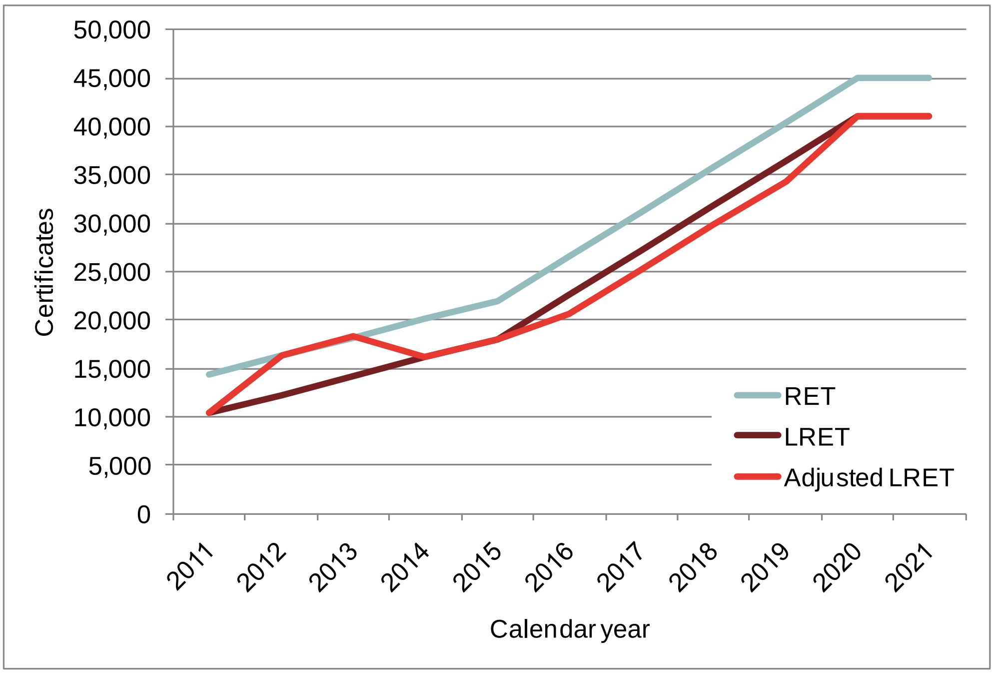
Plan. The Clean Energy Plan includes an initial carbon price of \$23/tonne CO_2-e commencing in 2012/13.[13]

The carbon price assumption used in Frontier Economics' modelling is also different from that assumed for Scenario 3 of the NTNDP. It is worth noting that the input cost assumptions developed for Scenario 3 of the NTNDP are based on the introduction of a carbon price. However, compared to the carbon price assumed by Frontier Economics, the carbon price assumed for the purposes of the NTNDP is introduced a year later and is higher.

4.8 LRET target

From 1 January 2011, the RET scheme has been split into the Large-scale Renewable Energy Target (LRET) and the Small-Scale Renewable Energy Scheme (SRES). As part of this process the RET target has been amended to come up with the LRET target and the adjusted LRET target (which accounts for the surplus of RECs available at the end of 2010). Figure 5 shows the RET target, the LRET target and the adjusted LRET target. Frontier Economics has used the adjusted LRET target in its modelling.

Figure 5: LRET target



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[13] Commonwealth Government, *Securing a clean energy future, The Australian Government's Climate Change Plan*, 2011.

Source: ORER, Frontier Economics.

5 Gas market modelling assumptions

This section provides a brief overview of the key modelling assumptions used by Frontier Economics to analyse the likely impact on energy security of the gas shock scenario.

Consistent with the approach for electricity market input assumptions, Frontier Economics has, where possible, adopted input assumptions developed by AEMO. Adopting this approach, Frontier Economics has, to a large extent, relied on the AEMO 2010 GSOO for key modelling assumptions relating to gas demand and transport capacity.

5.1 Gas demand forecasts

Given this modelling is focused on the impact on system security of an interruption to the RBP, demand forecasts are a key input assumption. In order to examine the impact of a 14 day interruption to the RBP during different periods of the year, it is necessary to develop a set of demand forecasts for the RBP region (and other demand regions) that reflect the variation of demand throughout the year. The approach and assumptions that Frontier Economics has used to develop the required demand forecasts are as follows:

- The starting point is a daily demand trace for the RBP region (and other demand regions) that reflects a representative year. Frontier Economics has used historic daily flow information available from the National Gas Market Bulletin Board (GasBB) from calendar year 2010 to provide this representative year. In Frontier Economics' view, calendar year 2010 provides by far the most complete set of flow data available from the GasBB.
- For the RBP region (and other demand regions) this representative daily demand trace is then scaled to reflect forecast growth in both total demand and peak demand. Frontier Economics has used the Decentralised World, 1-in-2[14] demand forecasts for summer and winter from the AEMO 2010 GSOO to scale the representative half-hourly load profile for each year of the modelling period.

  To ensure consistency between the electricity market modelling in the Reference Case and each of the shock scenario cases, Frontier Economics has forecast demand growth on the RBP by using the demand forecasts from the AEMO 2010 GSOO that exclude demand from GPG, and added to this demand Frontier Economics' own forecasts of demand from GPG that do

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[14] 1-in-2 peak demand forecasts are expected to be exceeded 50 per cent of the time, or once in every two years.

depend on the RBP for gas transport (Swanbank E, Oakey and, to a limited extent, Braemar 1).

- As gas market modelling is computationally much less demanding than electricity market modelling, we have been able to complete daily modelling, and have not needed to use 'representative days' as we have for the electricity market modelling.

Further details on Frontier Economics' approach to forecasting demand, particularly for the RBP, are set out in Section 6.3.

5.2 Existing gas reserves

Given that the AEMO 2010 GSOO does not contain information on remaining gas reserves by gas field, Frontier Economics has used information on remaining gas reserves by gas field from a range of sources, including company reports and other public information. For gas fields in Queensland, both conventional and coal seam methane (CSM), Frontier Economics has used information on gas reserves from the Queensland Department of Mines and Energy (DME). Information on the remaining reserves for gas fields in south-east Queensland is set out in Table 4.

This information on remaining gas reserves becomes of some relevance to this modelling project because a number of the conventional gas fields in Queensland may effectively be exhausted of recoverable gas reserves by 2015/16. Frontier Economics has used *WHIRLYGAS* to model each year to 2015/16 in order to ensure that the depletion of remaining gas reserves at existing fields is reflected in the modelling.

Table 4: Reserves in existing gas fields in south-east Queensland

Gas field	Type	Remaining 2P reserves (as of 30 June 2010) (PJ)
Roma	Conventional	51
Silver Springs	Conventional	76
Kincora	Conventional	18
Rolleston	Conventional	42
Yellowbank	Conventional	53
Dawson	CSM	172
Kogan North	CSM	165
Tipton West	CSM	675
Daandine Stratheden	CSM	583
SGP - Other	CSM	3,305
Don Juan	CSM	57
Spring Gully	CSM	1,705
Peat	CSM	134
Membrance Lonesome	CSM	15
Talinga Orana	CSM	1,342
APLNG - Other	CSM	4,612
Berwyndale	CSM	869
Kenya Argyle	CSM	3,824
Codie Lauren	CSM	1,022
QCLNG - Other	CSM	1,564
Cameron	CSM	992
Lacerta	CSM	111
Fairview	CSM	2,371
Scotia	CSM	179
Arcadia	CSM	356
Coxon Creek	CSM	1,336
ATP631	CSM	1,031

Source: QLD DME, Production and Reserves statistics.

Gas market modelling assumptions

5.3 Existing gas production facilities

Frontier Economics has used the AEMO 2010 GSOO as a source for information on existing gas production facilities. The AEMO 2010 GSOO provides information on the identity and capacity of each gas production facility in eastern Australia. Information on the gas production facilities in south-east Queensland is set out in Table 5.

Table 5: Capacity of existing gas production facilities in south-east Queensland

Production facility	Type	Capacity (TJ/d)
Roma Plant	Conventional	20
Silver Springs Plant	Conventional	8
Kincora Plant	Conventional	18
Rolleston Plant	Conventional	30
Yellowbank Plant	Conventional	30
Dawson Plant	CSM	30
Kogan North Plant	CSM	12
Tipton West Plant *	CSM	27
Daandine Plant *	CSM	59
Spring Gully Plant	CSM	60
Strathblane Plant	CSM	72
Taloona Plant	CSM	60
Peat	CSM	14
Talinga Orana	CSM	90
Berwyndale	CSM	140
Fairview	CSM	130
Scotia	CSM	29

Source: AEMO 2010 GSOO

** Not listed in AEMO 2010 GSOO. Capacity sourced from company reports.*

The available capacity from these gas production facilities will depend on the capacity of the gas production facility itself as well as the capacity of the upstream gas fields. In Queensland this is particularly relevant, with conventional gas fields in decline and typically producing at rates below the capacity of the associated production capacity. For these conventional gas fields, Frontier Economics has constrained annual production to levels not in excess of the highest annual production achieved in the previous two years (based on data available from the DME).

5.4 Existing gas transmission pipelines

Frontier Economics has used the AEMO 2010 GSOO as a source for information on existing gas transmission pipelines. The AEMO 2010 GSOO provides information on the identity and capacity of each major gas transmission pipeline in eastern Australia, a summary of which is provided in Table 6.

Table 6: Existing gas transmission pipelines in south-east Australia

Pipeline	**Capacity (TJ/d)**
Roma to Brisbane Pipeline	219
Queensland Gas Pipeline	134
South West Queensland Pipeline	181
South West Queensland Pipeline - Stage 3 *	380
Carpentaria Gas Pipeline	119
Moomba to Adelaide Pipeline System	253
Moomba to Sydney Pipeline	435
SEAGas Pipeline	314
South West Pipeline (SWP)	353
Longford to Melbourne Pipeline	1030
Culcairn-North	72
Culcairn-South	92
Eastern Gas Pipeline	268
Tasmanian Gas Pipeline	129
Roma to Brisbane Pipeline	219
Queensland Gas Pipeline	134
South West Queensland Pipeline	181

Source: AEMO 2010 GSOO

** Not listed in AEMO 2010 GSOO. Capacity sourced from company reports.*

Most relevantly for modelling the shock scenario cases, the current capacity of the RBP in the AEMO 2010 GSOO is 219 TJ/d. However, APA Group has announced a 10 per cent expansion to the capacity of the RBP, to be commissioned in the second half of 2012. Based on this, Frontier Economics has assumed that the capacity of the RBP will be 219 TJ/d for the 2011/12 interruptions, but will increase to 241 TJ/d from the beginning of 2012/13.

5.5 New gas production facilities and gas transmission pipelines

Typically, investment in new gas production facilities and gas transmission pipelines is an output from *WHIRLYGAS*. However, given the timeframe for this modelling project – the period from 2011/12 to 2015/16 – and the focus on gas market outcomes following an interruption to the RBP, there is little benefit to using modelled investment outcomes as an input into the analysis in 2015/16. First, given that there have been a number of final investment decisions to construct LNG export facilities in Queensland, gas market investment over the next five years in Queensland is going to be focused on ensuring that these committed investment decisions are fulfilled. Second, for the purpose of the analysis of the impact of supply interruptions on the RBP, the key investment consideration is whether there will be investment in new infrastructure to supply gas demand in Brisbane and surrounding areas. While there is at least one proposal to supply gas to Brisbane from a new source – from the Casino fields in northern NSW through the Lions Way Pipeline – DRET consider that the analysis of the shock scenario cases in 2015/16 will be more relevant to the NESA if it does not assume that a committed investment decision is made on this entirely new gas infrastructure.

For these reasons, Frontier Economics has assumed that any demand growth in Brisbane and surrounding areas in the period to 2015/16 will be met by incremental expansions in the capacity of the RBP. This is discussed in more detail in Section 6.4.

6 Reference Case outputs

This section provides the results from Frontier Economics' modelling of the Reference Case, out to 2015/16.

The focus of the Reference Case modelling is to develop a set of outcomes against which the outcomes under the various shock scenario cases can be compared. As discussed in Section 3, modelling of the Reference Case requires the following steps:

- **Power station investment modelling**. The outputs of this modelling include efficient generation investment (including any new investment in GPG in south-east Queensland). These investment results are an important input into market modelling (particularly in 2015/16, by which point new investment in electricity generation would be expected).
- **Electricity market modelling**. The outputs of this modelling include the following:
  - Power station dispatch, including dispatch of GPG in south-east Queensland. These dispatch results are an important input into developing gas demand forecasts for south-east Queensland.
  - Electricity pool prices.

  These Reference Case dispatch and price outcomes provide a basis for comparison of dispatch and price outcomes under the various shock scenario cases.
- **Gas infrastructure investment**. The results for investment in gas production and investment infrastructure are an important input into the assessment of the interruption to the RBP and its flow-on effects (particularly in 2015/16, by which point new investment in gas production and transmission infrastructure would be expected).
- **Outcomes on the RBP**. Analysis of RBP capacity under the Reference Case with RBP demand is used to establish whether there is any demand curtailment on the RBP under the Reference Case.

6.1 Power station investment modelling

Frontier Economics has modelled new investment going forward using our least-cost investment model, *WHIRLYGIG*. *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least cost mix of existing plant and new plant options to meet load. Based on capital and fuel cost assumptions from the AEMO 2010 NTNDP, there are eight entrant gas plant options in Queensland:

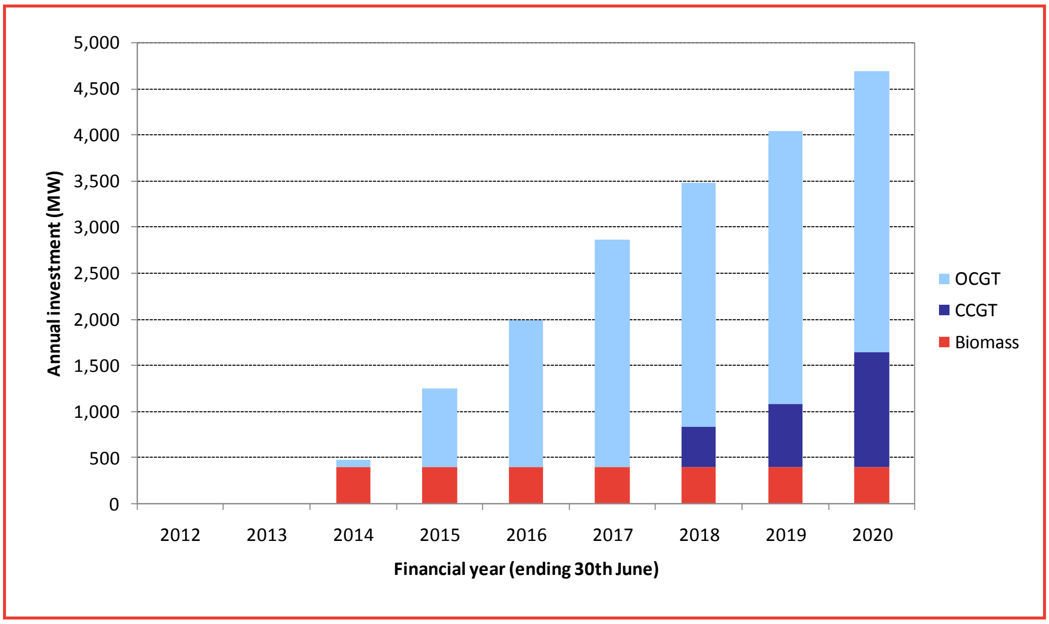
- CCGT and OCGT plant located in central Queensland
- CCGT and OCGT plant located in northern Queensland
- CCGT and OCGT plant located in south-eastern Queensland
- CCGT and OCGT plant located in south-western Queensland.

Based on the economics of generation investment and operation – driven primarily by the fuel cost assumptions in each sub-region – *WHIRLYGIG* forecasts investment in both OCGT and CCGT gas plant in south-western Queensland. Investment in this part of the region is driven primarily by assumed gas availability and prices available from surrounding CSM fields.

The quantity and timing of new investment in Queensland in the Reference Case is outlined in Figure 6:

- Biomass is being built from 2013/14 to meet the RET target
- OCGT is being built from 2013/14 to meet peak demand growth
- CCGT is being built from 2017/18 in response to carbon and to meet energy demand growth.

Figure 6: Queensland investment path – Reference Case



Source: Frontier Economics

6.2 Electricity market modelling

Frontier Economics has modelled plant dispatch and market prices going forward using our game-theoretic pool dispatch model, *SPARK*. *SPARK* uses game theoretic techniques to identify optimal and sustainable bidding behaviour by generators in the electricity market. The output of *SPARK* is a set of equilibrium dispatch and associated spot price outcomes.

6.2.1 Pool prices

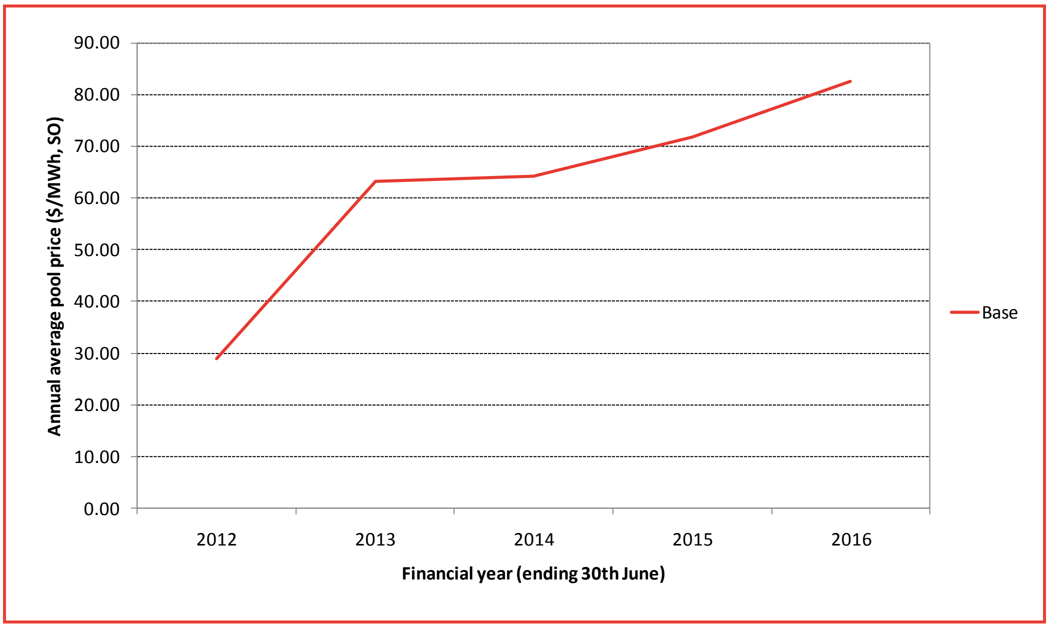
The annual time-weighted average forecast pool price for Queensland over the modelling period is shown in Figure 7.

It is clear from Figure 7 that prices increase markedly over the modelling period in all regions. This increase in pool prices over the modelling period is driven by:

- rising costs, since generators face increasing fuel prices and carbon prices over the forecast period
- growth in demand, which results in a tightening in the supply-demand balance and therefore an increase in output from higher cost plant.

The price forecasts shown in Figure 7 are broadly consistent with forward prices published by d-Cypha, suggesting that these key drivers are anticipated in the market.

Figure 7: Queensland annual pool prices – Reference Case



Source: Frontier Economics

The impact of these various factors on pool prices in Queensland is highlighted in Figure 8. These figures show the supply and demand curves in both 2011/12 and 2015/16 for Queensland.[15] Cumulative capacity is shown on the horizontal axis and cost in $/MWh is shown on the vertical axis. In *SPARK*, the ability of generators to bid strategically is captured by allowing strategic generators to choose how much of their capacity to bid into the market (where the generators are constrained to offer at least a defined minimum amount of capacity to the market, in order to make the modelling problem tractable). The extent to which generators can behave strategically in *SPARK* is illustrated by the two supply curves on each chart (the red and blue curves). The red curve is the supply curve corresponding to all generators in Queensland offering the maximum amount of capacity into the market. The blue curve is the supply curve corresponding to all generators in Queensland offering the minimum amount of capacity into the market. Between the blue curve and the red curve are many thousands of possible supply curves, each corresponding to a different combination of possible generator bids. *SPARK* models each of these different combinations of bids (and corresponding supply curves) for each demand level in the modelling, and determines equilibrium combinations of bidding strategies using Game Theory. For the purposes of comparison, the vertical lines in the figures represent key levels of demand used in the modelling – the peak, average and minimum demand level in the region. Each of these levels of demand, as well as a range of other demand levels that make up the representative demand curve, are modelled in *SPARK*.

In Queensland (and in other regions) there is significant structural change in the supply curve from 2011/12 to 2015/16. The supply curves shifts upwards as carbon prices and increasing fuel costs affect the cost of generation (the only exception being renewable generators, which do not face any increase in variable costs). This results in increased pool prices. An additional effect of carbon prices is to change the merit order of supply, because of the different extent to which the carbon price effects generators' costs. This is illustrated as a change in the shape of the supply curve over time. This effect does not necessarily result in increased pool prices.

The figures also illustrate the degree to which demand growth (as shown by the arrows) affects prices. Queensland sees considerable growth in average and peak demand over the period from 2011/12 to 2015/16, which can only be met with dispatch from higher cost generators and results in upward pressure on prices in Queensland. Although the figure for 2015/16 shows the peak demand level being higher than the red supply curve (representing maximum supply from

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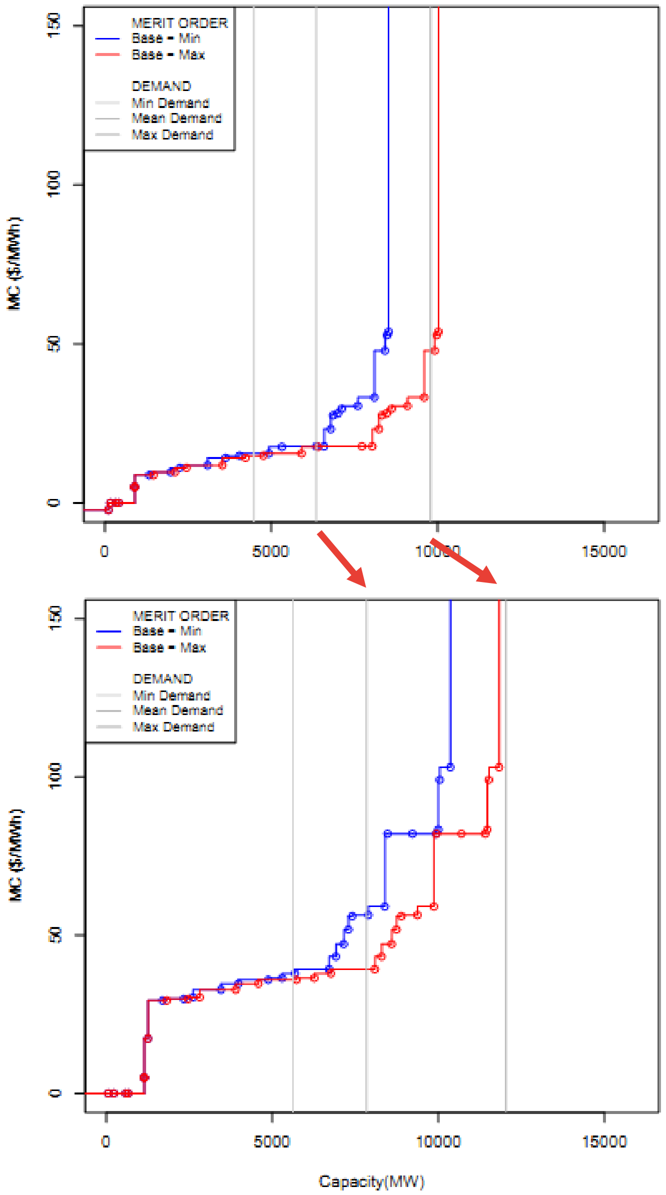
[15] Note that these figures are for illustrative purposes only. These curves show demand and supply in Queensland only, ignoring inter-regional interconnectors. Frontier Economics' modelling, however, models each region in the NEM and incorporates the inter-regional interconnectors.

Queensland generators), this does not necessarily imply loss of load: these illustrative figures do not show the capacity in other regions that is available to Queensland through inter-regional interconnectors.

Figure 8: Queensland's supply and demand for FY2012 and FY2016 – Reference Case

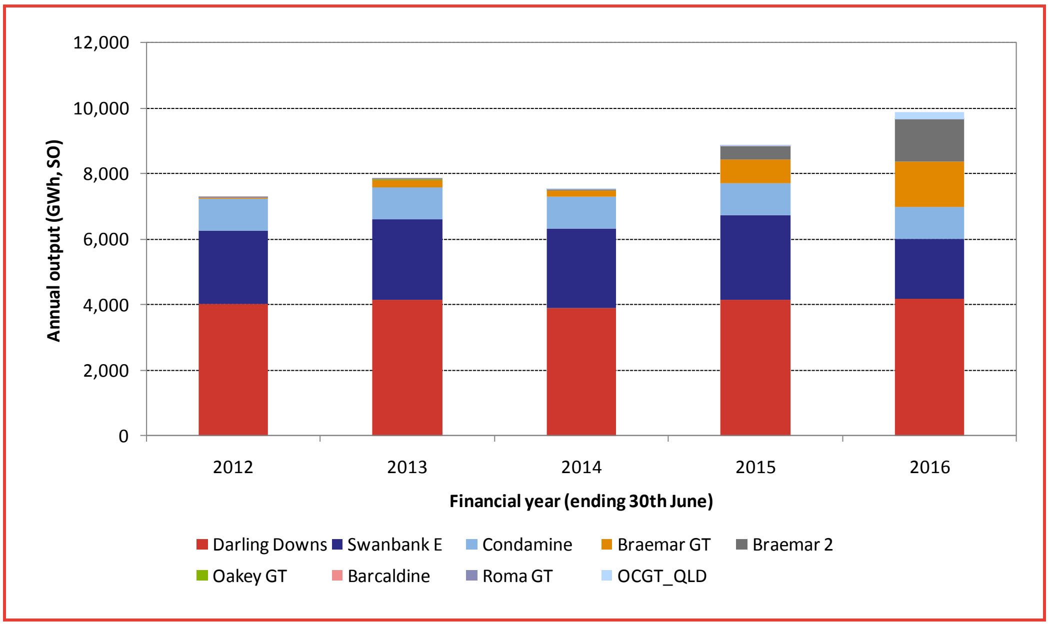


Source: Frontier Economics

6.2.2 Market Dispatch

SPARK provides dispatch results for each generator in the NEM. Given the focus of the gas shock scenario is gas-fired generation in Queensland, Figure 9 shows the annual dispatch of southern Queensland gas-fired generators in the Reference Case. The bulk of dispatch over the modelling period comes from Darling Downs and Swanbank E. Braemar 1 and 2 are dispatched to a larger degree in the later stages of the modelling as demand grows and carbon results in gas displacing coal plant on the margin. Oakey, Barcaldine, Roma and new OCGT run for only a small proportion of the year to meet peak demand.

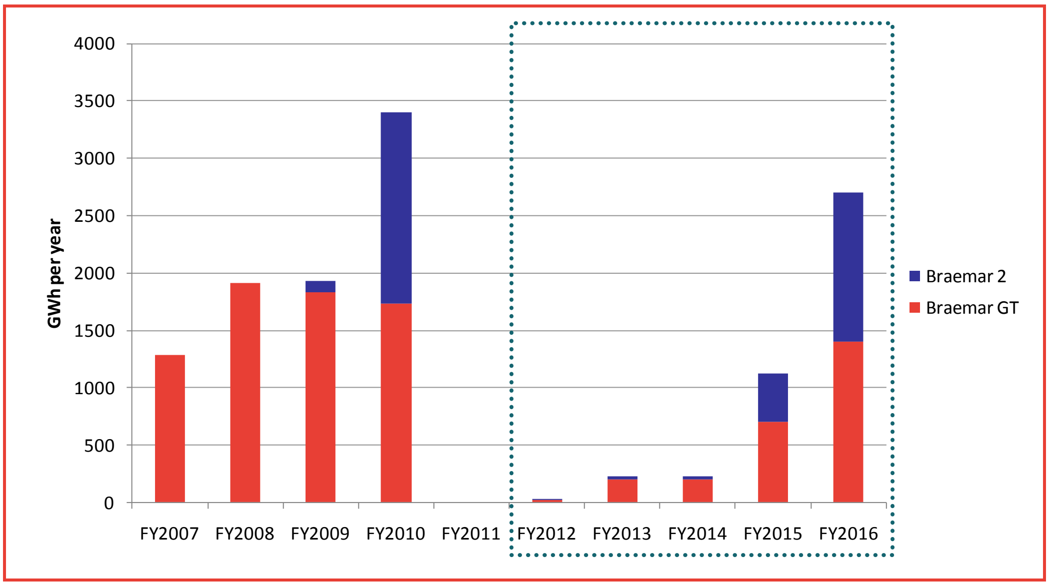
Figure 9: Annual output from Southern QLD gas-fired generators – Reference Case



Source: Frontier Economics

Frontier Economics has reconciled this forecast output pattern with historic output of these plant based on AEMO electricity market dispatch data. Frontier Economics' forecasts are generally consistent with historical output patterns for all gas plant in southern Queensland apart from Braemar 1 and 2. A comparison of Braemar 1 and 2's historical output and Frontier Economics' forecast output (highlighted by the dotted box) is outlined in Figure 10.

Figure 10: Historical and forecast output – Braemar 1 and 2



Source: Frontier Economics

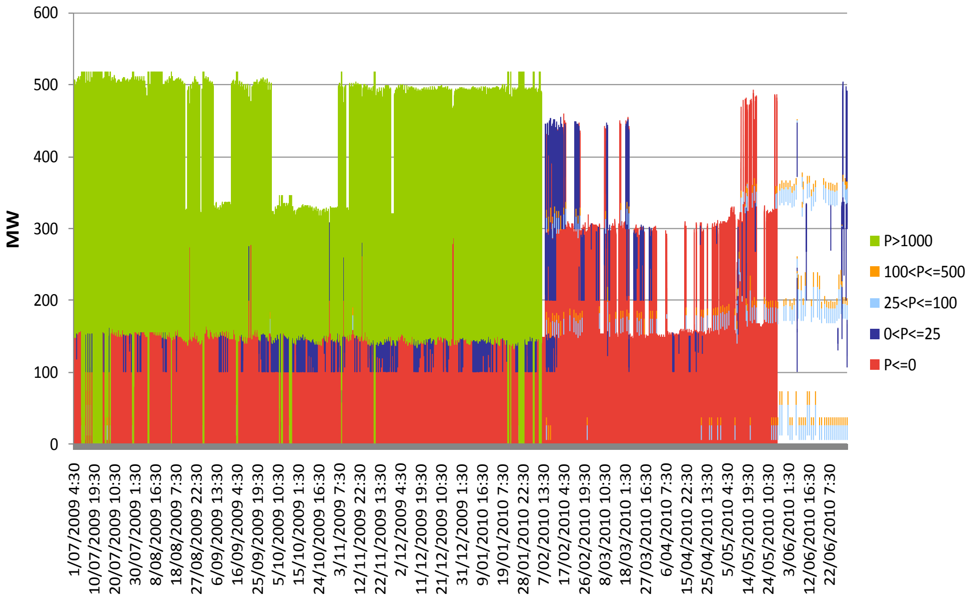
The historical output of Braemar 1 and 2 has been significantly greater than the forecast output suggested by Frontier Economics' modelling results (which are based on the fuel cost and operating parameters from the AEMO 2010 NTNDP).

The most likely cause of this discrepancy is due to an inconsistency between the gas price assumed for these plant (taken from the AEMO 2010 NTNDP) and the true opportunity cost of gas these plant face. In reality, due to the nature of CSM production in the region, there are likely to be quantities of "ramp-up gas" currently being produced but not exported due to the lead-times required to build up sufficient gas production capacity to match the capacity of planned liquefaction and export infrastructure.

The true opportunity cost of this gas, given it cannot currently be exported as LNG but must be produced in order to ramp-up gas production in anticipation of export in the future, is likely to be very low. This is confirmed by the bidding behaviour of Braemar 1 during 2009/10, outlined in Figure 11. Braemar 1 bid roughly 43% of its available capacity across the course of 2009/10 at prices below zero (generally close to the market price floor of -$1,000/MWh). This more-or-less ensures that Braemar 1 runs at close to a 43% capacity factor, which is significantly greater than a plant of its technological type and assumed fuel cost would be expected to run.

It is unclear how long Braemar 1 will continue to have access to gas at low opportunity cost. If it is the case that Braemar 1 has access to this gas as a result of the development of CSM production intended to support LNG exports, there is reason to expect that Braemar 1 will continue to have access to gas at low opportunity cost and continue to operate at output levels in excess of those forecast using *SPARK*. However, Frontier Economics has not adjusted Braemar 1's assumed gas cost because the output of Braemar 1 ultimately has little impact on the analysis of outcomes in the gas shock scenario. Since Braemar 1 secures a large proportion of its gas from local CSM fields, forecast output of Braemar 1 is not an important determinant of forecast gas demand from customers on the RBP (as discussed in more detail in the next section).

Figure 11: FY2010 bidding behaviour – Braemar 1



Source: Frontier Economics

6.3 Gas demand forecasts

Based on the approach discussed in Section 5.1, Frontier Economics has generated a daily forecast demand profile for each gas demand region over the period 2011/12 to 2015/16. We have forecast non-GPG demand to match summer and winter peak and total energy demand forecasts from the AEMO 2010 GSOO. We have forecast GPG demand to match summer and winter peak and total energy demand forecasts based on our *SPARK* modelling of forecast output of GPG in the NEM.

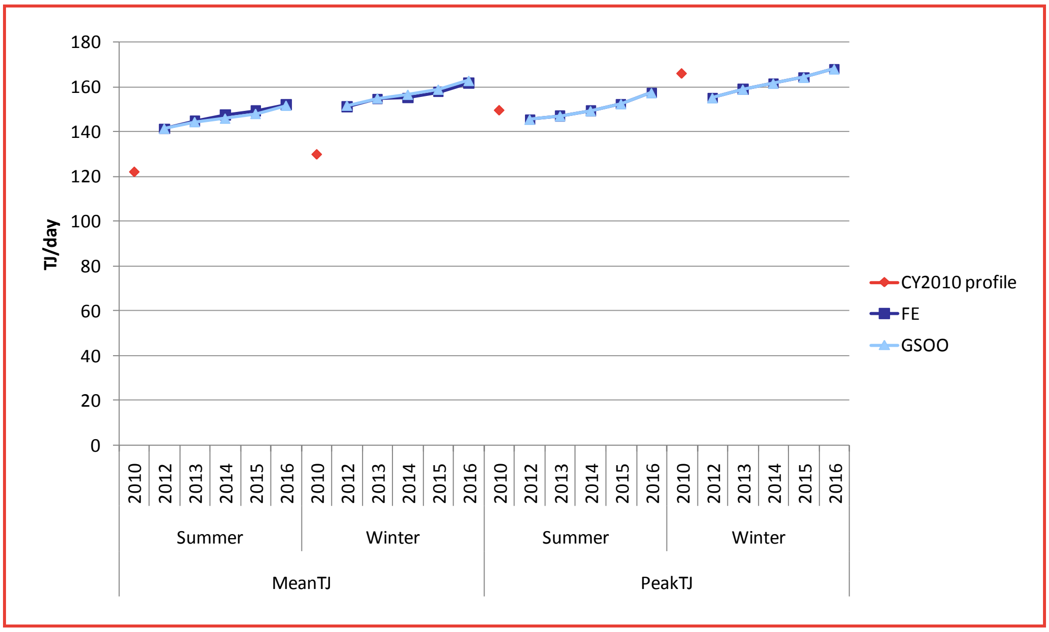
Outlined in Figure 12 and Figure 13 are comparison charts of summer and winter peak and total energy. Each chart compares actual CY2010 outcomes with the AEMO 2010 GSOO forecasts and Frontier Economics' forecasts for the RBP.

Figure 12 indicates that for non-GPG demand, the AEMO 2010 GSOO forecasts which Frontier Economics has adopted indicate a higher level of total energy ('MeanTJ') but a lower level of maximum demand ('PeakTJ') relative to what actually occurred in CY2010. In effect the AEMO 2010 GSOO is forecasting a much 'flatter' load shape on the RBP (i.e. higher average utilisation) than has occurred in the past.

Figure 13 indicates that for GPG demand, the AEMO 2010 GSOO forecasts of both total and peak demand tend to be considerably higher than recent historical outcomes – this is particularly the case for peak summer and winter demand. Since the AEMO 2010 GSOO is forecasting considerably higher peak GPG demand relative to total demand, the AEMO 2010 GSOO is in effect forecasting a much 'peakier' GPG demand shape (lower average utilisation) than has historically been the case. Frontier Economics' forecasts of GPG demand on the RBP are closer to historical outcomes than the AEMO 2010 GSOO.

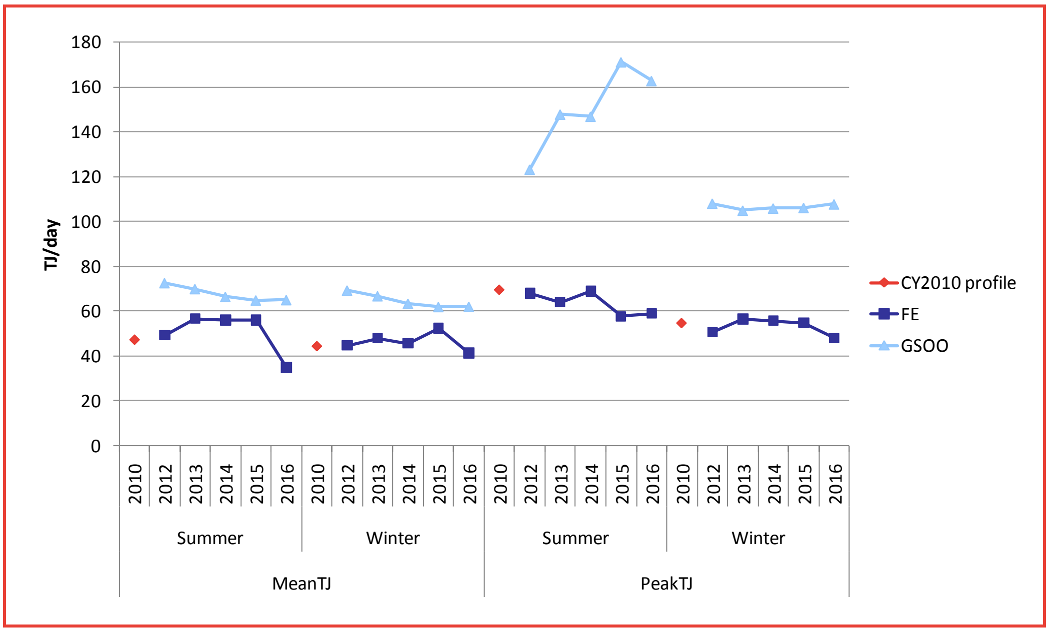
If the AEMO 2010 GSOO forecasts of GPG demand turn out to be accurate, then the supply interruption to the RBP is likely to have a more substantial impact on gas-fired generation than is estimated in this report. In particular, the supply interruption to the RBP will result in curtailment of greater gas-fired generation capacity. This could ultimately lead to more significant consequences for the electricity market.

Figure 12: Historical, GSOO and Frontier Economics non-GPG demand - RBP



Source: Frontier Economics

Figure 13: Historical, GSOO and Frontier Economics GPG demand - RBP



Source: Frontier Economics

6.4 Gas infrastructure investment

In order to model outcomes in the gas market in 2015/16 it is important to form a view on investment in new gas infrastructure by that point.

Frontier Economics' demand forecasts for the RBP, which are discussed in detail in the following section, indicate that there is no need for further investment in capacity on the RBP to meet demand growth by 2015/16. Given the forecast decline in generation from Swanbank E power station, and the 10% increase in capacity that has been committed for commissioning in late 2012, the capacity of the RBP is forecast to be sufficient.

There will undoubtedly be investment in other gas infrastructure in Queensland by 2015/16, particularly due to the commissioning of LNG export facilities in Gladstone. Frontier Economics has included in its modelling for 2015/16 those LNG facilities for which a final investment decision has been made – the QCLNG and GLNG projects. However, these projects do not have any direct consequences for the assessment of the affect of a supply interruption to the RBP.

6.5 Outcomes on the RBP

Frontier Economics has forecast two separate classes of demand on the RBP – demand from non-GPG and demand from GPG.

Total non-GPG forecast demand on the RBP has been broken-down into the following categories via the following approach:

- "V class" – distribution network customers with annual demand less than 10 TJ. Historical daily data for this customer class, aggregated across the Allgas and Envestra distribution networks, has been provided by AEMO. We have scaled historical daily data to forecast peak and energy growth estimates provided by ACIL Tasman to the AER[16] in order to generate a forecast daily demand profile for these customers.
- "D class" – distribution network customers with annual demand greater than 10 TJ. Historical daily data for this customer class, aggregated across the Allgas and Envestra distribution networks, has been provided by AEMO. We have scaled historical daily data to forecast peak and energy growth estimates provided by ACIL Tasman to the AER[17] in order to generate a forecast daily demand profile for these customers.
- "Directly connected load" – this is the remainder of total forecast non-GPG demand after accounting for both "V" and "D" class customers. These are loads of large commercial and industrial gas users that withdraw gas directly from the RBP, rather than withdrawing gas from one of the distribution networks. This will include large customers within the Brisbane gas market (including BP's Bulwer Island Refinery and Incitec-Pivot's Gibson Island plant) as well as any gas withdrawals upstream of the Brisbane gas market (including the load of small customers in Dalby).

Total GPG forecast demand on the RBP has been broken down by each generation station. The generators that draw gas from the RBP are Swanbank E, Braemar 1 and Oakey.

6.5.1 Outcomes in 2011/12

Forecast daily demand on the RBP for 2011/12 is outlined in Figure 14 below. A 10% and 50% loss of forecast capacity has also been illustrated. Apart from a few

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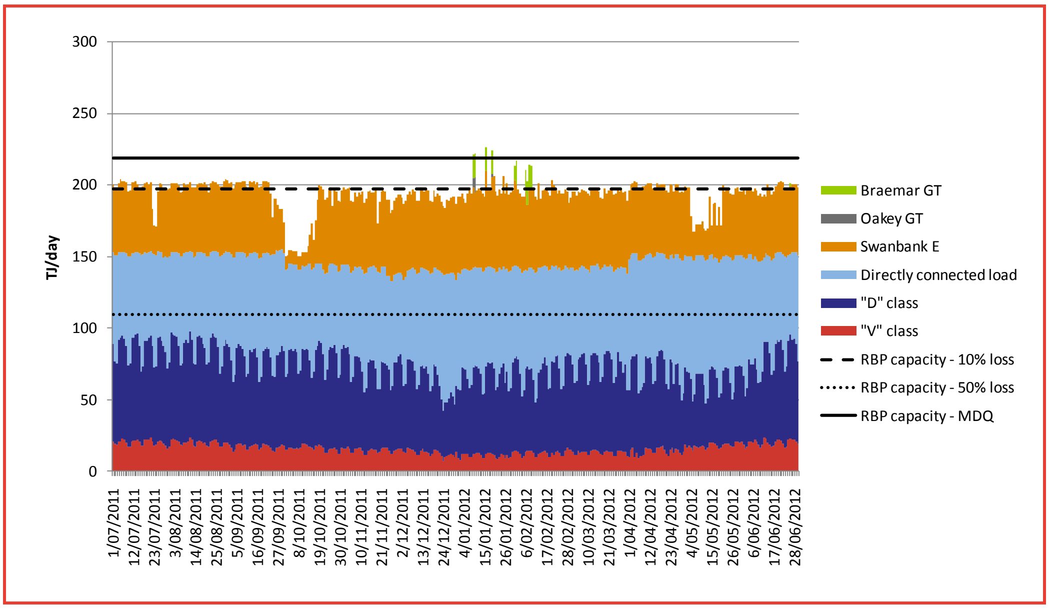
[16] ACIL Tasman, *Review of Demand Forecasts for APT Allgas Queensland*, Prepared for the Australian Energy Regulator, 31 December 2010; ACIL Tasman, *Review of Demand Forecasts for Envestra Queensland*, Prepared for the Australian Energy Regulator, 31 December 2010.

[17] ACIL Tasman, *Review of Demand Forecasts for APT Allgas Queensland*, Prepared for the Australian Energy Regulator, 31 December 2010; ACIL Tasman, *Review of Demand Forecasts for Envestra Queensland*, Prepared for the Australian Energy Regulator, 31 December 2010.

peak demand days in summer, forecast capacity on the RBP is sufficient to meet forecast demand.

Gas demand from GPG on the RBP in 2011/12 is dominated by Swanbank E. Oakey's gas demand is limited to peak demand days over summer. As discussed above, in the early years of the modelling the dispatch of Braemar 1 is lower than historically has been the case – this manifests itself as limited initial gas demand from Braemar.

Figure 14: RBP forecast demand and capacity – FY2012



Source: Frontier Economics

6.5.2 Outcomes in 2015/16

Forecast daily demand on the RBP for 2015/16 is outlined in Figure 15 below. A 10% and 50% loss of forecast capacity has also been illustrated. Due to the assumed increase in RBP capacity and reduced gas demand from GPG by 2015/16, forecast RBP capacity is sufficient to meet forecast demand.

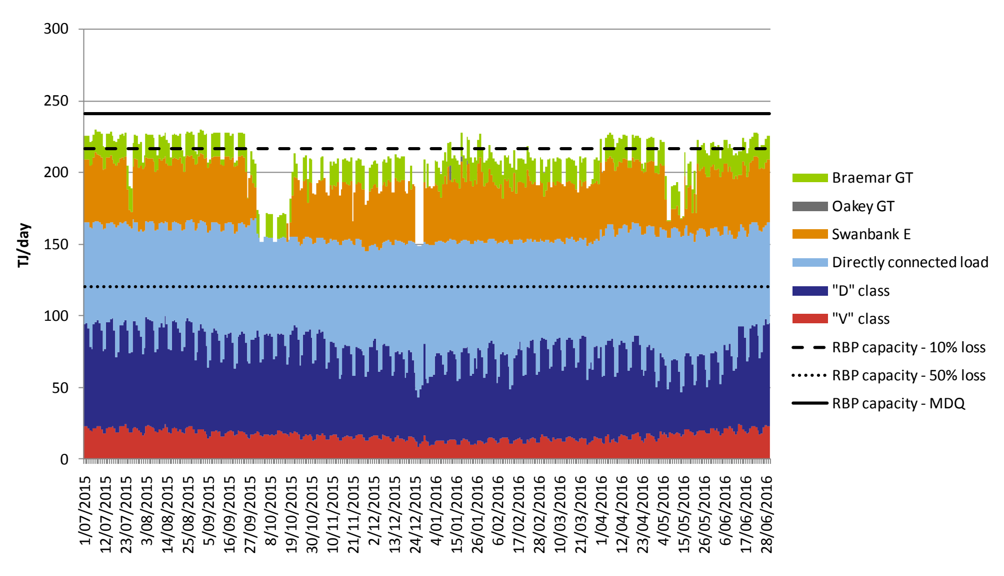
Forecast gas demand from GPG on the RBP in 2015/16 is considerably different to that in 2011/12. By 2015/16 Braemar 1's gas demand has increased in line with its forecast market dispatch. This is in large part due to the introduction of a carbon price in 2012/13, which results in gas plant displacing coal plant on the margin.

Increased gas demand from Braemar 1 is also driven by reduced gas demand from Swanbank E, which falls in line with its forecast market dispatch.

Swanbank E's forecast dispatch falls in 2015/16 due largely because the AEMO 2010 NTNDP forecasts an increase in its delivered gas price from $3.50/GJ in 2014/15 to $4.62/GJ in 2015/16. This increased gas price results in Swanbank E being displaced by lower-cost Wallumbilla GPG.

Finally, demand from Oakey has dropped off due to investment in new lower-cost OCGT peaking plant built to meet growth in peak demand.

Figure 15: RBP forecast demand and capacity – FY2016



Source: Frontier Economics

7 Shock scenario – outcomes on the RBP

This section, and the sections that follow, provide the results from Frontier Economics' modelling of each of the shock scenario cases, in both 2011/12 and 2015/16.

The focus of the modelling of each of the shock scenario cases is to assess the impact on gas users relying on the RBP, and any flow-on impacts on other gas markets or electricity markets. As discussed in Section 3, modelling of the shock scenario cases requires the following steps:

- **Outcomes on the RBP**. Analysis of RBP capacity with RBP demand under each shock scenario case is used to establish the extent of any demand curtailment that is required. Any curtailment of GPG will then be used as an input into the electricity market modelling.
- **Broader gas market outcomes**. Curtailment of the RBP will mean that gas from Wallumbilla will not be able to be used to supply RBP demand. This may result in additional gas being available at Wallumbilla at low opportunity cost, with flow on affects for other gas markets in Queensland or southern States.
- **Electricity market outcomes**. Market outcomes under the shock scenario cases can be compared with market outcomes under the Reference Case to assess the impact of the RBP interruption on the electricity market.

This section focuses on the impact on gas users relying on the RBP. The possible role of the STTM in managing the impact on gas users relying on the RBP is discussed in Section 8. Broader gas market outcomes are discussed in Section 9 and electricity market outcomes are discussed in Section 10.

7.1 Assumed order of curtailment

In order to understand how curtailment of the RBP will affect different classes of customers it is first necessary to form a view on the likely order of curtailment on the RBP.

In the first instance, the operator of the RBP, APA Group, is responsible for the scheduling priority between users on the RBP in the event that there is insufficient capacity to transport all gas nominated by users. The RBP Access Agreement stipulates the scheduling priority to apply in these circumstances.[18] The scheduling priority is ultimately based on the contractual obligations that APA has to gas users; in particular, whether gas users have firm transportation agreements or interruptible transportation agreements. For gas users with

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[18] APT Petroleum Pipelines Limited, *Access Arrangement for Roma Brisbane Pipeline*, Approved by the ACCC 28 March 2007, Schedule 2, Principles for Terms and Conditions of Services.

equivalent transportation agreements, the allocation of capacity is on a pro rata basis. Given that the transportation agreements with individual gas users are confidential, it is not possible for Frontier Economics to determine with any certainty the scheduling priority that APA Group would implement in the event of a supply interruption to the RBP.

Despite the operation of the RBP Access Agreement, the *Gas Supply Act 2003* empowers the Minister for Energy to make directions regarding the curtailment of users and allocation of scarce gas. In the event of a significant reduction in transport capacity on RBP, it is likely that the Minister will exercise this power. In doing so, it is likely that the Minister would seek to minimise the impacts on small business and residential customers by first directing reductions in gas supply to GPG (where this does not threaten security of supply of electricity) and commercial and industrial customers (where this would not cause major damage to furnaces or plant).

Based on this, in what follows, Frontier Economics has assumed the following order of curtailment applies in respect of customers on the RBP:

- gas-fired generators (given that Frontier Economics' analysis indicates that curtailing this power stations does not threaten security of supply)
- customers that are directly connected to the RBP
- Tariff D customers on the Allgas and Envestra distribution networks (that is, customers with annual demand greater than 10 TJ)
- Tariff V customers on the Allgas and Envestra distribution networks (that is, customers with annual demand less than 10 TJ).

As between the gas-fired generators that are supplied from the RBP, Frontier Economics has assumed the following order of curtailment applies:

- Braemar power station
- Oakey power station
- Swanbank E power station.

This order of curtailment is based on the Frontier Economics' estimate of the relative opportunity cost to these power stations of a gas curtailment.

Braemar power station relies on gas from various sources including local CSM fields, Tipton West Processing Facility and the RBP. Frontier Economics has assumed that a reduction in gas supply to the power station from the RBP would cause Braemar power station to shift its gas demand away from RBP to local CSM fields without impacting on station output (the implicit assumption being that these CSM fields and the associated pipeline infrastructure have sufficient capacity to increase supplies to Braemar power station). Based on this, the opportunity cost to Braemar power station of a reduction in gas supply from the

RBP would be the cost differential between gas supplied from the RBP and additional gas supplied from local CSM fields.

Oakey power station relies on gas from the RBP in the first instance, but is capable of switching to distillate. The opportunity cost to Oakey power station of a reduction in gas supply from the RBP would, therefore, be the cost differential between operating on gas supplied from the RBP and operating on distillate. This is likely to be significantly greater than the equivalent opportunity cost for Braemar power station.

Swanbank E power station relies entirely on the RBP for gas supply, and cannot operate on distillate. For this reason, the opportunity cost to Swanbank E power station of a reduction in gas supply from the RBP would be its loss of operating profit. In those circumstances in which Oakey is operating this is likely to be greater than the equivalent opportunity cost for Oakey power station.

In practice, this assumed order of curtailment of power stations does not have a significant impact on the analysis – if the order of curtailment of power stations differs there will only be relatively minor consequences for the electricity market.

7.2 Outcomes in 2011/12

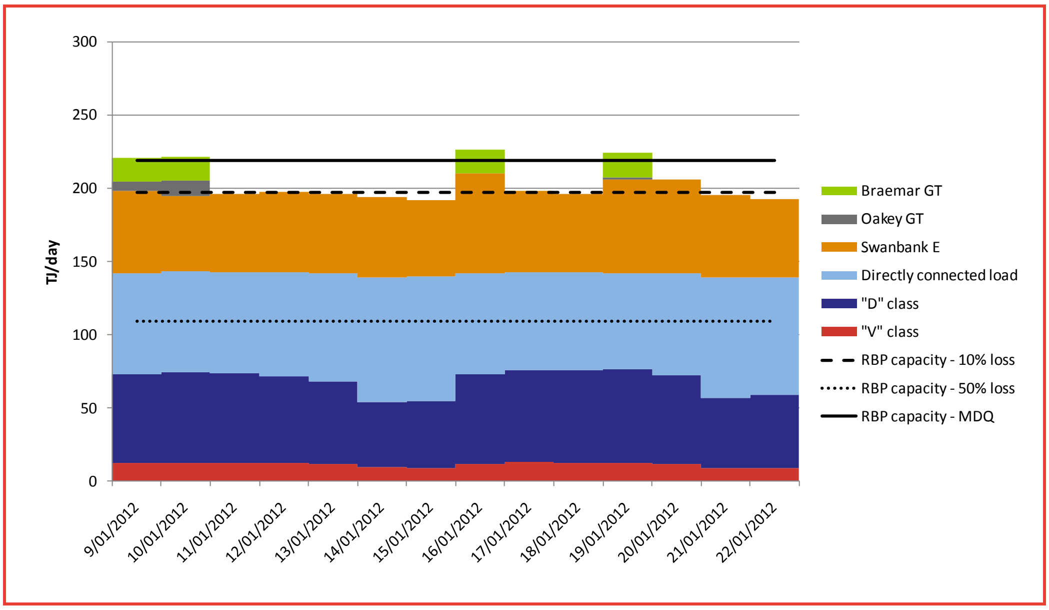
In order to assess the extent of any gas curtailment on the RBP under the shock scenario cases in 2011/12 it is first necessary to define demand on the RBP and capacity of the RBP during the specific 14 day shoulder and peak interruption periods considered. Using the forecast daily demand profiles for 2011/12 discussed in Section 6.3 we have determined the extent (if any) of curtailment that would be required assuming a 10%, 50% and 100% loss of RBP capacity during the following two periods:

- Peak period – 14 days from 9/1/2012 to 22/1/2012
- Shoulder period – 14 days from 30/4/2012 to 13/5/2012.

7.2.1 Outcomes on the RBP in 2011/12 peak periods

Forecast daily demand on the RBP for the peak period from 9/1/2012 to 22/1/2012 is shown in Figure 16. Forecast capacity on the RBP is shown by the solid black line, with a 10% and 50% loss of capacity shown by the dotted black lines.

Figure 16: Daily demand on RBP – 2011/12 peak period



Source: Frontier Economics

The extent of curtailment assuming a 10%, 50% and 100% loss of RBP capacity during the two week peak period from 9/1/2012 to 22/1/2012 is outlined in Table 7 below.

Table 7: Gas curtailment on the RBP (14 day peak period, FY2012) – Total TJ

Customer class	10 % loss	50 % loss	100% loss
"V" class	0.00	0.00	159.95
"D" class	0.00	0.00	797.23
Directly connected load	0.00	448.34	1024.15
Swanbank E	33.12	791.09	791.09
Oakey GT	16.59	18.99	18.99
Braemar GT	48.32	48.32	48.32
Total curtailment	**98.03**	**1306.74**	**2839.74**

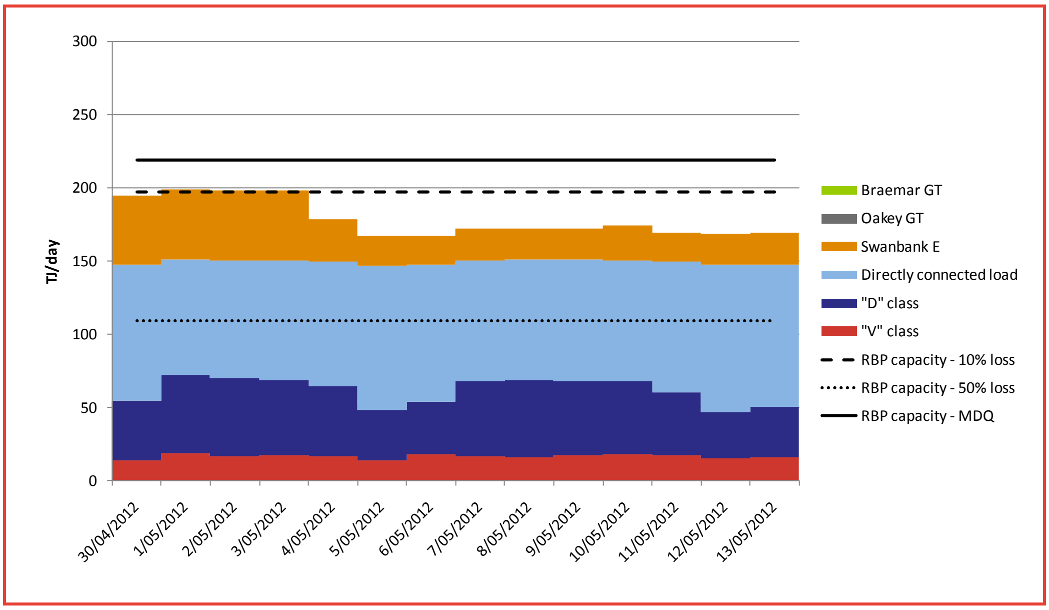
Source: Frontier Economics

Shock scenario – outcomes on the RBP

7.2.2 Outcomes on the RBP in 2011/12 shoulder periods

Forecast daily demand on the RBP for the shoulder period from 30/4/2012 to 13/5/2012 is shown in Figure 17. Forecast capacity on the RBP is shown by the solid black line, with a 10% and 50% loss of capacity shown by the dotted black lines.

Figure 17: Daily demand on RBP – 2011/12 shoulder period



Source: Frontier Economics

Note: Oakey is forecast not to generate during this shoulder period.

The extent of curtailment assuming a 10%, 50% and 100% loss of RBP capacity during the two-week shoulder period from 30/4/2012 to 13/5/2012 is outlined in Table 8 below.

Table 8: Gas curtailment on the RBP (14 day shoulder period, FY2012) – Total TJ

Customer class	10 % loss	50 % loss	100% loss
"V" class	0.00	0.00	232.72
"D" class	0.00	0.00	630.38
Directly connected load	0.00	558.24	1228.14
Swanbank E	4.18	410.67	410.67
Oakey GT	0.00	0.00	0.00
Braemar GT	0.00	0.00	0.00
Total curtailment	**4.18**	**968.91**	**2501.91**

Source: Frontier Economics

7.3 Outcomes in 2015/16

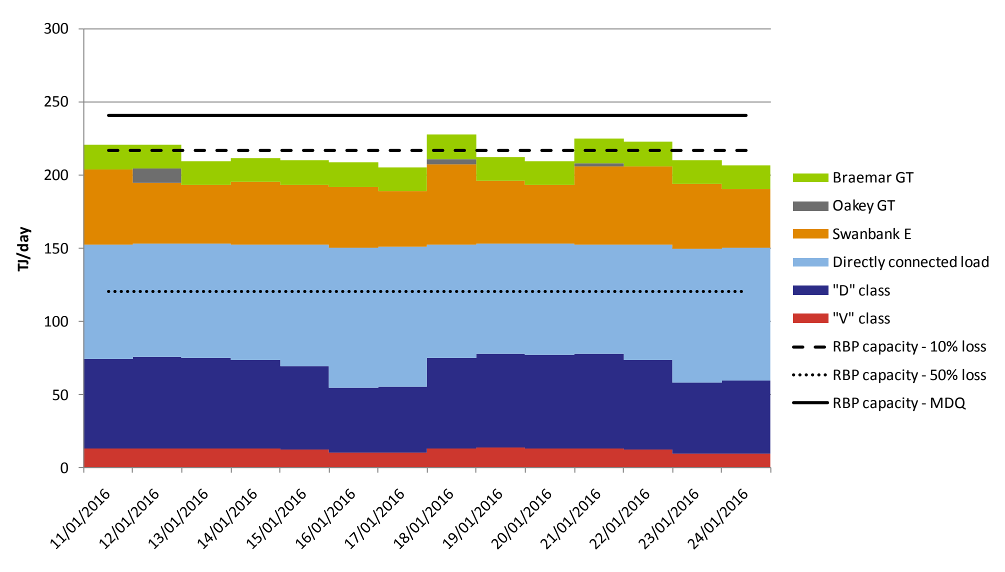
In order to assess the extent of any gas curtailment on the RBP under the shock scenario cases in 2015/16 it is first necessary to define demand on the RBP and capacity of the RBP during the specific 14 day shoulder and peak interruption periods considered. Using the forecast daily demand profiles for 2015/16 discussed in Section 6.3 above we have determined the extent (if any) of curtailment that would be required assuming a 10%, 50% and 100% loss of RBP capacity during the following two periods:

- Peak period – 14 days from 11/1/2016 to 24/1/2016
- Shoulder period – 14 days from 2/5/2016 to 15/5/2016.

7.3.1 Outcomes on the RBP in 2015/16 peak periods

Forecast daily demand on the RBP for the peak period from 11/1/2016 to 24/1/2016 is shown in Figure 17. Forecast capacity on the RBP is shown by the solid black line, with a 10% and 50% loss of capacity shown by the dotted black lines.

Figure 18: Daily demand on RBP – 2015/16 peak period



Source: Frontier Economics

The extent of curtailment assuming a 10%, 50% and 100% loss of RBP capacity during the two week peak period from 11/1/2016 to 24/1/2016 is outlined in Table 9 below.

Table 9: Gas curtailment on the RBP (14 day peak period, FY2016) – Total TJ

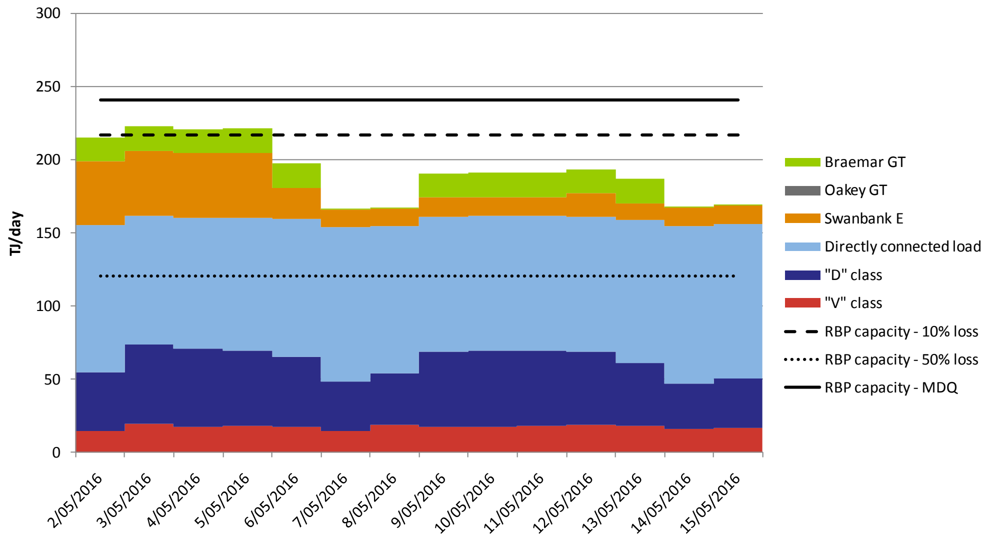
Customer class	10 % loss	50 % loss	100% loss
"V" class	0.00	0.00	171.86
"D" class	0.00	0.00	806.57
Directly connected load	0.00	443.06	1151.62
Swanbank E	0.00	625.52	625.52
Oakey GT	0.00	16.25	16.25
Braemar GT	32.72	230.14	230.14
Total curtailment	**32.72**	**1314.96**	**3001.96**

Source: Frontier Economics

7.3.2 Outcomes on the RBP in 2015/16 shoulder periods

Forecast daily demand on the RBP for the shoulder period from 2/5/2016 to 15/5/2016 is shown in Figure 19. Forecast capacity on the RBP is shown by the solid black line, with a 10% and 50% loss of capacity shown by the dotted black lines.

Figure 19: Daily demand on RBP – 2015/16 shoulder period



Source: Frontier Economics

The extent of curtailment assuming a 10%, 50% and 100% loss of RBP capacity during the two-week shoulder period from 2/5/2016 to 15/5/2016 is outlined in Table 10 below.

Table 10: Gas curtailment on the RBP (14 day shoulder period, FY2016) – Total TJ

Customer class	10 % loss	50 % loss	100% loss
"V" class	0.00	0.00	243.05
"D" class	0.00	0.00	629.12
Directly connected load	0.00	533.76	1348.59
Swanbank E	0.00	314.00	314.00
Oakey GT	0.00	0.00	0.00
Braemar GT	14.50	166.36	166.36
Total curtailment	**14.50**	**1014.11**	**2701.11**

Source: Frontier Economics

7.4 Summary of outcomes on the RBP

Because the RBP is the only option for physically supplying gas to customers in and around Brisbane, any material supply interruption to the RBP will almost certainly affect customers. In other major demand centres in eastern Australia – including Sydney, Adelaide and Melbourne – a supply interruption to a major transmission pipeline can be mitigated to some extent by increasing gas flows on other transmission pipelines or by drawing on gas from storage. In Brisbane, however, this is not currently an option.

Given this, the key question in analysing a supply interruption to the RBP is the extent to which customers are likely to be curtailed. Broadly speaking, irrespective of the timing of the interruption (peak or shoulder) or the year of the interruption (2011/2012 or 2015/16) the following is the case:

- A 10% loss of RBP capacity results in relatively modest curtailment of the "first-in-line" gas-fired generator that draws gas from the RBP. Due to its ability to source CSM gas from nearby fields Frontier Economics has assumed this first-in-line generator is Braemar 1.
- A 50% loss of RBP capacity results in complete curtailment of all GPG that draws gas from the RBP and a significant curtailment of directly-connected load such as large commercial and industrial customers.[19]

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[19] Where particular large commercial and industrial loads are not able to maintain their operation below some threshold gas supply level, these customers may need to entirely shut down their

- A loss of more than 50% of RBP capacity is required to result in load curtailment of customers connected to the Allgas and Envestra distribution networks.

7.4.1 Summary of outcomes in 2011/12

Due to the relatively high dependence on Swanbank E's output in 2011/12, the need for Oakey to run to meet peak demand during the peak period interruption and the lower RBP capacity prior to its assumed expansion in 2012/13, a 10% loss of RBP capacity results in some measure of curtailment for all of Braemar 1, Oakey and Swanbank E. The extent of curtailment in the shoulder period is less given that GPG demand is lower. During the shoulder interruption period only Swanbank E is very marginally curtailed, and only on days when gas demand is highest.

The pattern of demand is such that a 50% loss of RBP capacity results in complete curtailment of GPG and significant curtailment of directly connected commercial and industrial customers in both the peak and shoulder interruption periods.

A summary of load curtailment in both peak and shoulder interruption periods for all customer classes in 2011/12 is presented in Table 11.

Table 11: 2011/12 curtailment summary - TJ

Customer class	**10 % loss**		**50 % loss**		**100% loss**	
	Shoulder	Peak	Shoulder	Peak	Shoulder	Peak
"V" class	0.00	0.00	0.00	0.00	232.72	159.95
"D" class	0.00	0.00	0.00	0.00	630.38	797.23
Directly connected load	0.00	0.00	558.24	448.34	1228.14	1024.15
Swanbank E	4.18	33.12	410.67	791.09	410.67	791.09
Oakey GT	0.00	16.59	0.00	18.99	0.00	18.99
Braemar GT	0.00	48.32	0.00	48.32	0.00	48.32

Source: Frontier Economics

Note: curtailment of directly connected loads is higher during the shoulder period than the peak period because historic data suggests demand of directly connected load has been higher during shoulder periods with the result that curtailment is also greater.

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operations even with a 50% loss of RBP capacity. In this event, this gas would effectively be available to other large customers (including GPG).

While our analysis assumes that each customer class can be curtailed exactly in accordance with their forecast demand, it is important to note that pipeline operating constraints, particularly the need to maintain safe operating pressures throughout both the RBP and the distribution networks, may impose additional constraints on the priority of gas curtailment. These operating constraints will depend in part on the nature of the physical curtailment; in particular, what infrastructure is affected and the nature of the problem with that infrastructure. For those cases in which there is a partial interruption of the RBP – particularly the 50% interruption – this may result in actual curtailment for particular customer classes exceeding Frontier Economics' estimates.

7.4.2 Summary of outcomes in 2015/16

Due to the reduction in GPG demand in 2015/16 and the capacity increase on the RBP in 2012/13, the extent of GPG curtailment assuming a 10% loss of RBP capacity is considerably less than in 2011/12 in both the peak and shoulder period interruptions. This decreased reliance on RBP capacity to meet GPG demand is driven by:

- Reduced gas demand from Swanbank E, due to a higher assumed delivered gas price in 2015/16 and hence it being displaced by more efficient Wallumbilla generation (existing and entrant)
- Reduced gas demand from Oakey, due to being displaced by more efficient OCGT entrants that are built to meet growth in peak demand.

In both the peak and shoulder interruption periods, growth in non-GPG demand is insufficient to offset the relative fall in GPG demand. This, combined with a capacity expansion in 2012/13, results in additional spare capacity to meet demand on the RBP and hence a reduction in the severity of curtailment in the case of a loss of 10% of capacity.

As was the case in 2011/12, a 50% reduction in capacity continues to result in complete curtailment of all GPG and significant curtailment of directly-connected commercial and industrial customers.

A summary of load curtailment in both peak and shoulder interruption periods for all customer classes in 2011/12 is presented in Table 12.

Table 12: 2015/16 curtailment summary - TJ

Customer class	**10 % loss**		**50 % loss**		**100% loss**	
	Shoulder	Peak	Shoulder	Peak	Shoulder	Peak
"V" class	0.00	0.00	0.00	0.00	243.05	171.86
"D" class	0.00	0.00	0.00	0.00	629.12	806.57
Directly connected load	0.00	0.00	533.76	443.06	1348.59	1151.62
Swanbank E	0.00	0.00	314.00	625.52	314.00	625.52
Oakey GT	0.00	0.00	0.00	16.25	0.00	16.25
Braemar GT	14.50	32.72	166.36	230.14	166.36	230.14

Source: Frontier Economics

Note: curtailment of directly connected loads is higher during the shoulder period than the peak period because historic data suggests demand of directly connected load has been higher during shoulder periods with the result that curtailment is also greater.

Again, to the extent that there are additional pipeline operating constraints during the supply interruption, actual curtailment for particular customer classes may exceed Frontier Economics' estimates.

8 Options for managing gas curtailment

The analysis is Section 7 indicates that, because the RBP is the only option for physically supplying gas to customers in and around Brisbane, any material supply interruption to the RBP will almost certainly affect customers. This section considers the physical options and market-based options available for managing the curtailment of gas to customers.

8.1 Physical options for managing gas curtailment

The extent to which customers in and around Brisbane are affected by a supply curtailment to the RBP is due to the RBP being the only source of gas supply to these customers. The only physical options for managing gas curtailment resulting from an interruption to the RBP are:

- a second pipeline supplying gas to Brisbane and surrounding areas, or
- a gas storage facility capable of supplying Brisbane and surrounding areas.

8.1.1 Pipeline options

A second pipeline supplying gas to Brisbane and surrounding areas would mean that the gas customers in Brisbane would be less dependent on the RBP for gas supplies.

Frontier Economics is aware of one proposal for constructing a new gas pipeline to supply Brisbane and surrounding areas: Metgasco's Lions Way Pipeline, from the Casino gas fields in northern NSW. The proposed pipeline is intended to provide a route to market for gas from Metgasco's Casino gas fields, through gas sales to commercial and industrial customers and power generators around Brisbane and potentially through access to LNG exports through Gladstone.

The extent to which a second pipeline supplying gas to Brisbane would assist in managing an interruption to the RBP will depend on the capacity of the new pipeline and the effect that the new pipeline has on flows on the RBP. For instance, if the new pipeline is built simply to serve incremental demand in Brisbane and surrounding areas it is likely to be relatively small capacity and is unlikely to displace gas flows on the RBP. In this case, the second pipeline is likely to provide little in the way of spare pipeline capacity supplying Brisbane and surrounding areas. However, given the relatively low rate of growth in gas demand in Brisbane and surrounding areas that is forecast in the AEMO 2010 GSOO, the development of gas processing infrastructure at Casino and the Lions Way Pipeline is unlikely to proceed on the basis of simply providing incremental demand in Brisbane. If the new pipeline is built with the intention of supplying other gas markets, including through LNG export, then it is likely have a relatively large capacity and is likely to displace gas flows on the RBP (likely through gas swaps). In this case, the second pipeline is likely to provide significant spare pipeline capacity supplying Brisbane and surrounding areas and to mitigate the negative consequences of any RBP curtailment.

8.1.2 Storage options

Gas storage is currently used in a number of gas markets in Australia to manage volatility in gas demand and to provide security of supply. There are essentially two options for a large-scale gas storage:

- an LNG facility, which will withdraw gas from a pipeline and liquefy it for storage, before vaporising the gas and re-injecting it into the pipeline as required
- an underground storage facility, which will withdraw gas from a pipeline and re-inject it into an underground storage space (typically a depleted gas well), before withdrawing the gas from the well and re-injecting it into the pipeline as required.

An LNG facility, such as the Dandenong LNG Storage Facility in Victoria, is likely to assist in managing an interruption to the RBP only for a short period of time. For instance, the Dandenong LNG Storage Facility has a total storage capacity of 658 TJ and a maximum vaporising capacity of around 130 TJ/d. In the event of a total interruption to the RBP, a similar size facility in Brisbane would, at best, be able to provide ongoing gas supplies to priority customers for a period of days or weeks (depending on the degree of curtailment and gas demand of priority customers).

An underground storage facility, such as the Western Underground Storage Facility (WUGS) in Victoria could have a much greater total storage capacity than an LNG facility. For instance, WUGS has a total storage capacity of 12,000 TJ and a maximum withdrawal capacity of around 250 TJ/d. In the event of a total interruption to the RBP, a similar size facility supplying Brisbane would have sufficient capacity to avoid gas curtailment for a number of weeks. However, underground storage facilities can only be built where there is suitable geology, typically a depleted gas field. There are a number of depleted gas fields in the Bowen-Surat basins and the Denison Trough, and there are plans to develop at least one of these – the Silver Springs field – into a storage facility. However, gas from these fields could only be supplied to Brisbane through the RBP. Because of this, a gas storage facility in Queensland may be well-suited to managing interruptions at gas processing plant, but is not well suited to managing interruptions to gas pipelines. In contrast, in Western Australia the Mondarra gas storage facility north of Perth, which is currently being expanded to a total storage capacity of 15,000 TJ, can supply gas through two pipelines and is therefore well placed to assist in managing pipeline interruptions affecting Perth (as well as managing Perth's greater dependence on only a few gas processing plant).

In short, while the capacity of underground storage facilities could be sufficient to manage an interruption to the RBP for as long as several weeks, the likely sites for such storage facilities in Queensland would mean that these facilities would still rely on the RBP to supply gas to Brisbane and surrounding areas. There is more flexibility in locating LNG storage facilities; certainly, one could be located at an offtake point of the RBP so that it could continue to supply gas to Brisbane and surrounding areas in the event of an interruption to the RBP. However, the capacity of an LNG storage facility would only be able to mitigate curtailment in the event of a material interruption to the RBP, not avoid it altogether.

It is also important to bear in mind that storage facilities are typically used to manage peak demand and to arbitrage between high and low price periods, as well as providing some security of supply. As long as these facilities are used for a number of purposes they are likely to go through cycles of gas injections and gas withdrawal throughout the year. For instance, WUGS tends to be injected with gas throughout the summer, allowing that gas to be withdrawn during high demand and high price periods in winter. Under these circumstances, the ability of the storage facility to contribute to security of supply is compromised. However, the operators of these facilities earn a return on their investment by providing gas users with an opportunity to manage peak demand and to arbitrage between high and low price periods. Without the returns from arbitrage, investing in a gas storage facility purely for the purposes of supplying security of supply may not be economic. For example, APA Group's expansion of the capacity of their Mondarra facility from around 3,000 TJ to around 15,000 TJ is expected to cost $140 million.

8.2 Market-based options for managing gas curtailment

While there are some physical options to manage gas curtailment in Brisbane, none of these will be available in the short-term and it is unclear that investments in infrastructure will be profitable for the private sector even in the long term. This means that market-based options for managing gas curtailment will be important for managing the affects of a supply interruption to the RBP.

The extent to which different customer classes are likely to be curtailed under the various shock scenario cases (as discussed in Section 7) is based on an assumed order of priority of curtailment and on the assumption that there is no voluntary curtailment. In practice, actual curtailment is likely to vary as a result of variations in the opportunity cost of individual customers. This is particularly the case given that the Short Term Trading Market (STTM) – which provides a more liquid and transparent mechanism for trading gas – is due to commence in Brisbane towards the end of 2011.

This section considers the role that the STTM – and particularly the Contingency Gas mechanism – would play in the event of a supply interruption to the RBP.

8.2.1 Overview of the STTM

The Short Term Trading Market (STTM) is a market for the trading of natural gas at the wholesale level at defined hubs. The STTM currently operates at gas hubs in Sydney and Adelaide and is due to be introduced to the Brisbane hub towards the end of 2011.

The STTM provides for the exchange of gas at the gas hub. Sellers and buyers remain responsible for transporting gas to and from the hub, relying on supporting gas transportation agreements.

The ex ante market

The STTM is primarily a day-ahead market, with a number of mechanisms in place to manage variations between day-ahead schedules and actual outcomes.

The day-ahead market, known as the ex ante market, provides day-ahead schedules for supply of gas to the hub and withdrawal of gas from the hub, as well as a day-ahead market price. The ex ante schedules and ex ante price are based on bids and offers submitted by participants.

Shippers and users can submit bids and offers to the STTM up to 12 noon on the day ahead of a gas day. These bids and offers must be consistent with the contractual ability of shippers and users to flow gas to and from the hub. Bids and offers are scheduled by the Market Operator in price order, subject to any physical constraints of gas pipelines. This produces market schedules that set out the quantity of gas that each shipper and each user is expected to flow to and from the hub on the gas day.

Market schedule variations occur where shippers and users bilaterally agree a balanced variation to their market schedules. For instance, a shipper and a user could agree to flow one extra GJ, with the shipper flowing the extra GJ to the hub and the user flowing the extra GJ away from the hub. Market schedule variations are settled bilaterally between participants, rather than in the market.

Deviations occur where shippers and users flow quantities of gas to and from the hub that are different from their market schedules, and are not covered by a market schedule variation. For instance, shippers' market schedules may differ from their pipeline nominations for the gas day, resulting in a deviation between their pipeline nomination (which governs physical delivery) and their market schedule. One cause of deviations is that shippers with firm haulage contracts that are not scheduled in the ex ante market can nevertheless nominate quantities on their haulage contract and flow gas to the hub, displacing a shipper with a non-firm contract. In this case, both shippers will be determined to have deviated from their market schedules: the shipper with the firm capacity will have a positive deviation and the shipper with the non-firm capacity will have a negative deviation. Deviations are settled in the STTM. Payments for deviations are unfavourable relative to the ex ante price, with shippers flowing more gas than their market schedule receiving an unfavourably low deviation payment and shippers flowing less gas than their market schedule paying an unfavourably high deviation payment.

The Market Operator Service

The market schedules from the ex ante market, even taking account of variations and deviations, may not match the actual quantity of gas that flows from each pipeline to the hub on a gas day. Physical balancing on the gas day under the STTM is accounted for primarily through the Market Operator Service (MOS).

The Market Operator contracts for the supply of MOS through a tender process. MOS providers submit offers for MOS, which the Market Operator stacks according to price. Where MOS is required in order to physically balance gas supply on a gas day, the MOS that occurs on a pipeline is allocated to MOS providers on that pipeline according to their MOS offers.

Contingency Gas

Contingency Gas is a limited mechanism for balancing supply and withdrawals at a hub, or meeting operational requirements at a hub, when normal mechanisms are inadequate. Contingency Gas provides pipeline operators and distributors with a means of avoiding or minimising the need to involuntarily curtail shippers supplying the hub or users withdrawing from the hub.

The Contingency Gas mechanism under the STTM has the following attributes:

- The Contingency Gas mechanism allows participants to make offers each day to increase supply or decrease withdrawals at a hub (and also to make bids to decrease supply or increase withdrawals at a hub) for the following day.
- The Contingency Gas mechanism defines trigger events that commence an assessment process to determine whether Contingency Gas will be called.
- The Contingency Gas mechanism includes a mechanism for scheduling Contingency Gas offers and bids (as appropriate) and for determining the relevant Contingency Gas price.

The trigger events for Contingency Gas include pipeline pressure conditions that are outside acceptable operating levels, an STTM pipeline being unable to meet normal levels of daily delivery capacity to the hub, an event that could reasonably be expected to adversely affect the supply of gas to the hub or price taker bids not being fully scheduled.

In the event that one of the trigger events for Contingency Gas occurs, AEMO calls a Contingency Gas assessment conference with relevant pipeline operators (including the distributors) at which an assessment is made as to whether Contingency Gas is likely to be needed. Following the assessment conference, AEMO calls a wider industry conference that includes trading participants.

Following the conferences, AEMO must determine the requirement for Contingency Gas, confirm Contingency Gas bids and offers, and schedule Contingency Gas based on bids and offers from participants.

Typically, it is expected that one of the trigger events for Contingency Gas will occur at least a day ahead (based on demand and supply forecasts). If this is not the case – as is likely due to a sudden supply interruption of the RBP – then there may not be time to follow the usual process for Contingency Gas. In particular, AEMO may skip the industry conference if AEMO considers that Contingency Gas is urgently required. Regardless of whether AEMO holds an industry conference, in the event of a sudden supply interruption of the RBP it is likely that the response capability will be much reduced.

8.2.2 Operation of STTM during the shock scenario

In itself, the STTM cannot necessarily avoid involuntary curtailment in the event of supply interruptions. The price signals provided by the STTM create commercial incentives to shippers and gas users to make additional gas available during supply interruptions, but the STTM does not place an obligation upon shippers or end users to do so.

Given that Brisbane is supplied only by the RBP, the options for making additional gas supplies available are limited. Therefore, Contingency Gas can really only be provided by customers who are willing to voluntarily curtail. The extent of the supply interruption under the shock scenario cases in which 50 per cent of the capacity of the RBP is affected means that it is very unlikely that offers to supply Contingency Gas through voluntary curtailment will be sufficient to reduce demand to match capacity in these circumstances. In this case, and certainly in the shock scenario cases in which 100 per cent of the capacity of the RBP is affected, the Contingency Gas mechanism will be insufficient to manage the supply interruption and involuntary curtailment will occur.

However, in the shock scenario cases in which 10 per cent of the capacity of the RBP is affected, offers to supply Contingency Gas through voluntary curtailment are likely to be sufficient to reduce demand to match capacity. In these circumstances, it is worth thinking about the likely extent of offers to supply Contingency Gas and the likely prices at which Contingency Gas will be offered.

Contingency Gas offers

The obvious candidates to supply Contingency Gas in the event of a partial supply interruption to the RBP are gas-fired generators, particularly Braemar (whether directly, or indirectly through another gas shipper) and Swanbank E.

Voluntary curtailment by these generators effectively provides Brisbane with some ability to substitute alternate fuels in place of gas supplied on the RBP: with Swanbank E not operating, electricity can be supplied to the market by coal-fired generators, gas-fired generators not reliant on the RBP or renewable generators. As seen in Section 7, given the significant gas use by Braemar and Swanbank E, this source of Contingency Gas can potentially manage material supply interruptions to the RBP.

It is also possible that commercial and industrial customers would offer to supply Contingency Gas through voluntary curtailment (either directly or through agreement with their gas supply). The Market Price Cap under the STTM is $400/GJ, which is roughly 100 times the current gas price. This offers a significant incentive to supply Contingency Gas, particularly for those commercial and industrial customers with a low opportunity cost of lost gas supply.

Prices for Contingency Gas offers

In a competitive gas market, gas users would be expected to offer Contingency Gas into the STTM at the opportunity cost of not using that gas themselves.

For commercial and industrial customers, the opportunity cost of a gas curtailment is very difficult to measure. It will depend, among other things, on the nature of the gas users' operations, the extent to which they are able to substitute other fuels for gas, and the extent to which a gas curtailment has consequences for the safe and reliable operation of their equipment.

However, it is somewhat easier to estimate the opportunity cost of a gas curtailment to a gas-fired generator. For a gas-fired generator, the opportunity cost of a gas curtailment is effectively the change in operating profits resulting from the gas curtailment. Where the gas-fired generator has no other option for securing fuel, this equates to the loss of operating profits as a result of not generating. This can be calculated based on forecasts of electricity spot prices during the period of the gas curtailment and estimates of the short-run marginal cost of production of the generator. For Swanbank E, the maximum opportunity cost of a gas curtailment during 2011/12 is around $14/GJ in the peak period and around $6/GJ in the shoulder period. In 2015/16 the maximum opportunity cost is around $14/GJ in both peak periods and shoulder periods. This is not to say that Swanbank E will necessarily offer Contingency Gas at these prices; it may take the view that spot prices will be higher (implying a higher opportunity cost) or it may shadow price any offer of Contingency Gas at the expected opportunity cost of commercial and industrial customers.

For comparison, there have been offers to supply Contingency Gas at prices around this level in both the Adelaide hub and the Sydney hub. However, the majority of offers have been priced significantly higher than this – generally in excess of $100/GJ and frequently as high as the Market Price Cap.

9 Shock scenario – broader gas market outcomes

This section provides the results from Frontier Economics' modelling of the impact of each of the shock scenario cases on broader gas markets, in both 2011/12 and 2015/16.

9.1 Rationale for examining impacts on broader gas markets

Before discussing the results of Frontier Economics' modelling of the impact of each of the shock scenario cases on broader gas markets it is worth thinking about why an interruption to the RBP might be expected to have consequences for other regional gas markets.

It might be thought that, since the RBP is located at the end of the interconnected gas transmission network, an interruption on the RBP would affect gas customers along and at the end of the RBP but would not have consequences for broader gas markets. As can be seen in Figure 20, other than gas customers along the RBP, there are no gas markets further downstream of the RBP that would be affected by an interruption on the RBP. This compares with other pipelines, such as the South-West Queensland Pipeline, which transport gas to a number of different downstream gas markets.

Despite the fact that the RBP is located at the end of the interconnected gas transmission network, an interruption to the RBP could nevertheless have consequences for broader gas markets. The reason is that an interruption to the RBP will prevent gas producers from shipping gas along the RBP; these gas producers will, therefore, have to adjust their supply arrangements for this gas, which could include:

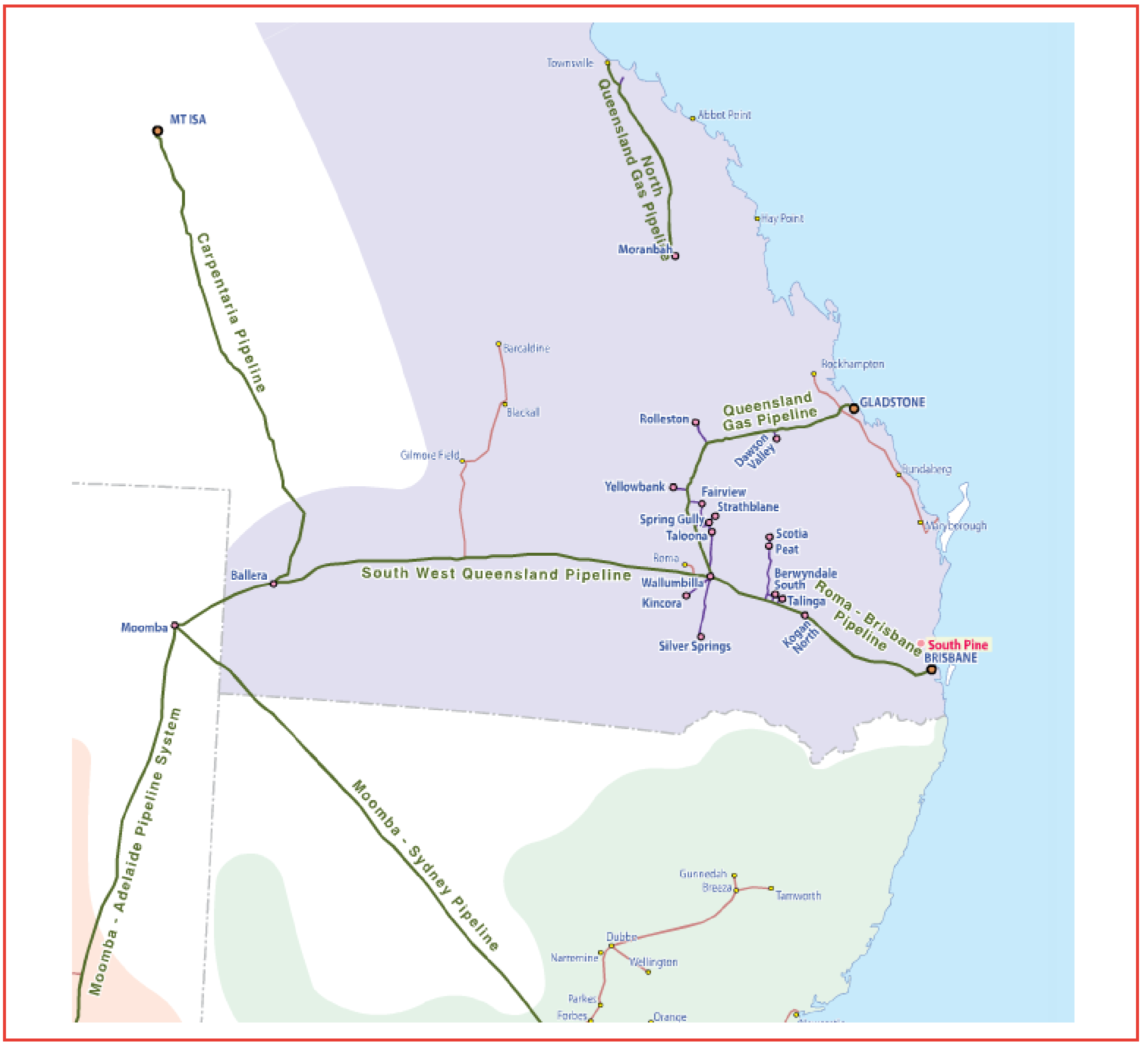
- reducing rates of gas production
- gas storage
- diverting gas to other supply sources
- flaring excess gas, as a last resort.

Reducing gas production or storing gas are likely to be preferred by gas producers to the extent that the costs of these strategies are small. If gas producers are able to pursue these strategies, there are likely to be no consequences for broader gas markets of the interruption to the RBP. However, reducing rates of gas production can be a particular issue for CSM producers due to issues associated with dewatering CSM wells.

In contrast to these strategies, diverting gas to other supply sources will have consequences for broader gas markets. In order to divert gas to other supply sources, gas producers will likely have to supply gas at a discount to currently prevailing prices – this might include supplying below the long run marginal cost of producing gas. Existing gas transportation agreements may also not be sufficient to manage the diversion of gas to other supply sources, meaning that gas producers or gas users will have to make arrangements with pipeline owners

Given that reduced production is likely to be the preferred option for managing an interruption to the RBP, the purpose of this section is to investigate the extent to which gas producers are likely to be able to the interruption by reducing rates of gas production. In the first instance, *WHIRLYGAS* is used to model outcomes in the market in aggregate. The implications of these modelling results are then considered.

Figure 20: Queensland gas transmission pipelines



Source: AEMO

Shock scenario – broader gas market outcomes

9.2 Modelling methodology

In order to assess the consequences for other regional gas markets of an interruption to the RBP, Frontier Economics uses *WHIRLYGAS*. As discussed, *WHIRLYGAS* incorporates a representation of the interconnected gas markets in eastern Australia, including all gas fields, gas production plants, gas transmission pipelines and gas demand centres.

To account for the interruption to the RBP, the first step is to run *WHIRLYGAS* under the Reference Case for both 2011/12 and 2015/16. This provides expected outcomes where there is no interruption to the RBP. The second step is to run *WHIRLYGAS* for each of the shock scenario cases. Three adjustments are made to the Reference Case in order to model the shock scenario cases:

- The capacity of the RBP is reduced (by 10%, 50% or 100%, depending on the scenario) for a 14 day period.
- To ensure that the model does not attempt to optimise for the RBP interruption prior to the interruption, outcomes in *WHIRLYGAS* for the shock scenario cases are fixed up to the period of the interruption to match outcomes in the Reference Case. This ensures that the interruption is indeed a "shock" to the system.
- The curtailment to the RBP has implications for demand by gas-fired generators around Wallumbilla. The curtailment of the RBP leads to reduced output from Swanbank E and Oakey, which is made up in part by increased production from gas-fired generators around Wallumbilla. The increase in demand by gas-fired generators that is implied by dispatch from *SPARK* is accounted for in *WHIRLYGAS*.

To account for the fact that CSM producers may be limited in the extent to which they can reduce rates of production without causing longer-term operational issues, Frontier Economics has included a constraint in its modelling to prevent production from CSM fields falling below 50% of maximum annual production. This is based on analysis of daily flow data from the GasBB, which shows that while daily production from CSM processing plants can vary quite significantly from day to day it does not often drop below 50% of maximum annual production.

In modelling the shock scenario cases, Frontier Economics assumes that gas storage is not available during the interruption to the RBP. While gas storage is available in Queensland (principally in the Cooper/Eromanga basin, although AGL is also developing the depleted Silver Springs gas field as a storage facility) and in other areas of eastern Australia, it is not clear that there would be capacity available during the period of the interruption to the RBP to store additional gas.

9.3 Modelling outcomes in 2011/12

If there were to be consequences for other regional gas markets of an interruption to the RBP these would arise because gas producers currently supplying gas along the RBP would be unable to reduce their rate of production sufficiently to match the reduced flows on the RBP. With the South-West Queensland Pipeline now flowing west, from Wallumbilla to Ballera, gas supplied along the RBP is effectively produced by CSM producers in the Bowen-Surat basins and a small number of remaining conventional gas producers in the Bowen-Surat basins and the Denison Trough. For this reason, it is important to investigate the impact of the RBP interruption on these producers.

Figure 21 shows historic production from those producers in the Bowen-Surat basins and the Denison Trough whose daily flows are reported on the GasBB. Figure 21 also shows forecast production for these same producers in 2011/12 from *WHIRLYGAS*.[20] Figure 21 shows the RBP-FullLoss-2012-Peak shock scenario case, which is evident from the reduction in CSM production during the 14-day interruption to the RBP in January 2012.

Comparing historic patterns of production with forecast patterns of production, it is clear that the reduction in CSM production during the 14-day interruption to the RBP is somewhat more pronounced than observed historic variability in CSM production. However, it is certainly not substantially out of line with reductions in production that have been observed historically. Closer investigation reveals that historic variability in total CSM production tends to be somewhat lessened due to the fact that different fields tend to have reduced production at different periods during the year. During the 14-day interruption to the RBP, however, the reduction in flows on the RBP is forecast to cause all CSM producers to simultaneously decrease their rate of production. No individual producer, however, reduces its rate of production to below 50% of maximum annual production.

Figure 22 shows the same historic and forecast production, but for the RBP-FullLoss-2012-Shoulder shock scenario case. The basic conclusion is the same for this shock scenario case: the required reduction in CSM production to match the reduced flows on the RBP is somewhat more pronounced than historic variability in CSM production, but this is due to all CSM producers simultaneously reducing their rate of production during the interruption to the RBP. No individual producer, however, reduces its rate of production to below 50% of maximum annual production.

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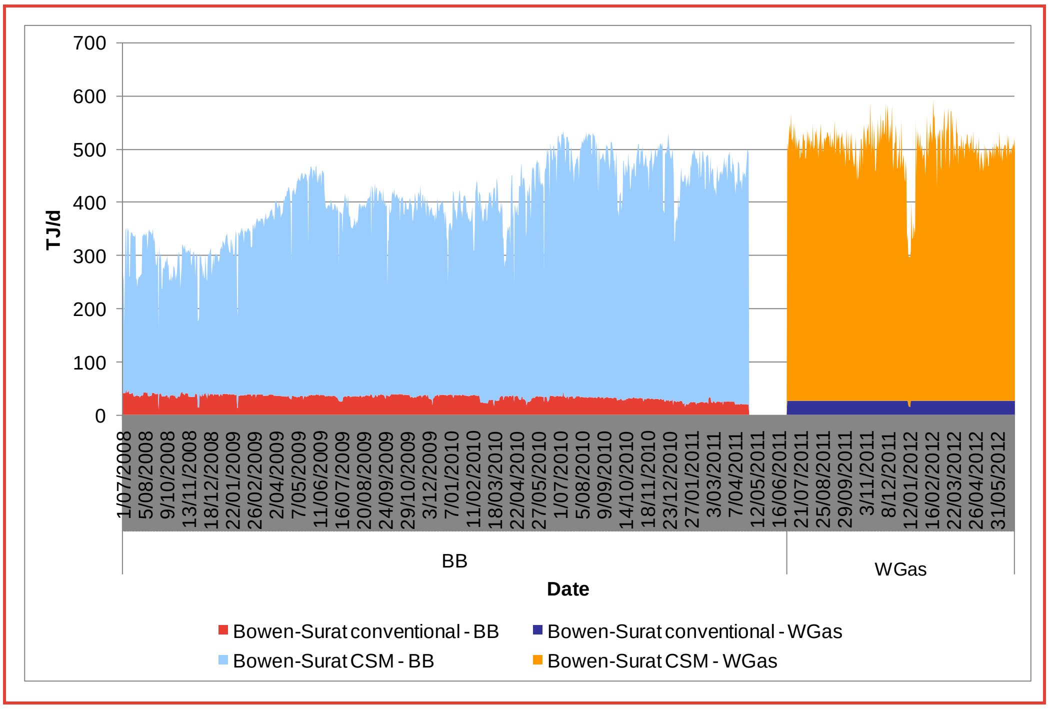
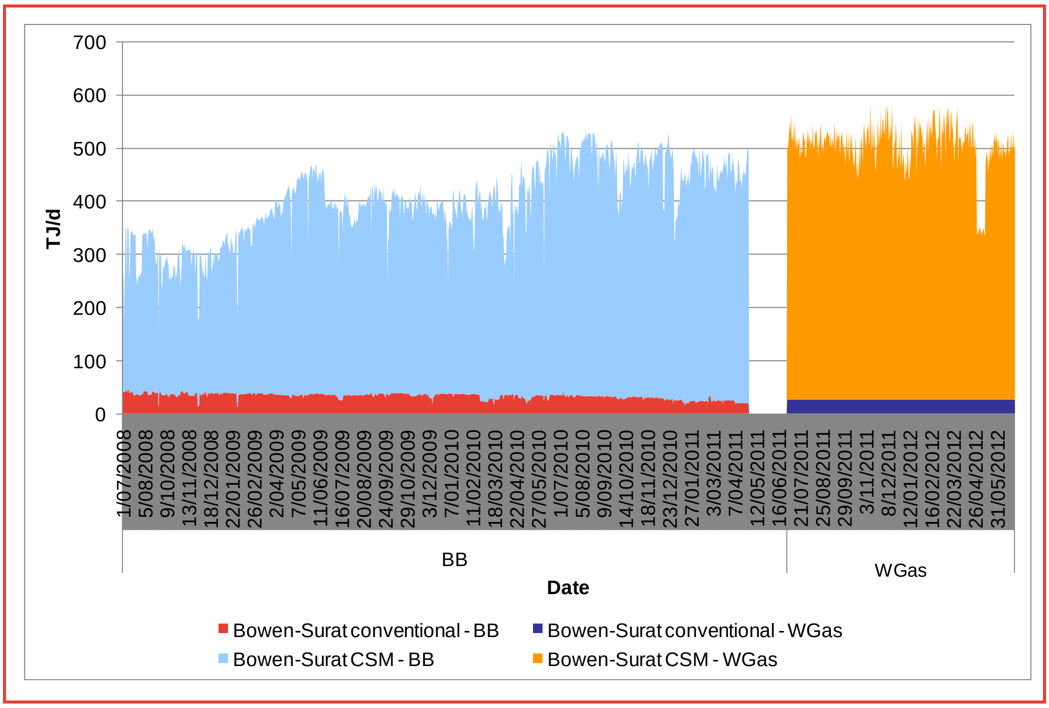
[20] Bowen-Surat gas production is higher in the *WHIRLYGAS* forecasts than has been observed historically in the GasBB data. A key reason for this is that the AEMO 2010 GSOO forecasts increased gas demand in Brisbane in 2011/12, which leads to increased Bowen-Surat gas production.

Figure 21: Bowen-Surat gas production – RBP-FullLoss-2012-Peak



Source: Frontier Economics

Figure 22: Bowen-Surat gas production – RBP-FullLoss-2012-Shoulder



Source: Frontier Economics

Shock scenario – broader gas market outcomes

Investigation of forecast flows on other pipelines flowing from the Wallumbilla hub – the Queensland Gas Pipeline and the South-West Queensland Pipeline – confirm that there is sufficient flexibility in CSM production in the Bowen-Surat basins to manage the reduced RBP flows under these two shock scenario cases. Despite the interruption to the RBP, there is no need to divert gas supplied from Wallumbilla along either of these pipelines, and therefore no consequences for other regional gas markets.

Given that there are no observed consequences for other regional gas markets in the shock scenario cases in which the entire capacity of the RBP is lost, there will also be no consequences for the shock scenario cases under which only part of the capacity of the RBP is lost.

9.4 Modelling outcomes in 2015/16

The same general observations that hold for the shock scenario cases in 2011/12 also hold for the shock scenario cases in 2015/16. That is, the reduced flows on the RBP can be managed by CSM producers in the Bowen-Surat basin without having to divert gas to other markets.

Figure 23 and Figure 24 show historic production from those producers in the Bowen-Surat basins and the Denison Trough whose daily flows are reported on the GasBB. These figures also show forecast domestic production for these same producers in 2015/16 from *WHIRLYGAS*.[21] Figure 23 shows the RBP-FullLoss-2016-Peak shock scenario case, which is evident from the reduction in CSM production during the 14-day interruption to the RBP in January 2016. Figure 24 shows the RBP-FullLoss-2016-Peak shock scenario case, which is evident from the reduction in CSM production during the 14-day interruption to the RBP in May 2016.

By 2015/16, reduced flows on the RBP are easier to manage through flexibility in CSM production in the Bowen-Surat basins because the RBP accounts for a smaller proportion of total CSM production. In 2011/12, flows on the RBP are forecast to account for around one third of CSM production. By 2015/16, flows on the RBP are forecast to account for around one quarter of CSM production that is directed to the domestic market. This is confirmed by the observation that in 2015/16 there is no need to divert gas supplied from Wallumbilla along other pipelines from that hub, and therefore no consequences for other regional gas markets.

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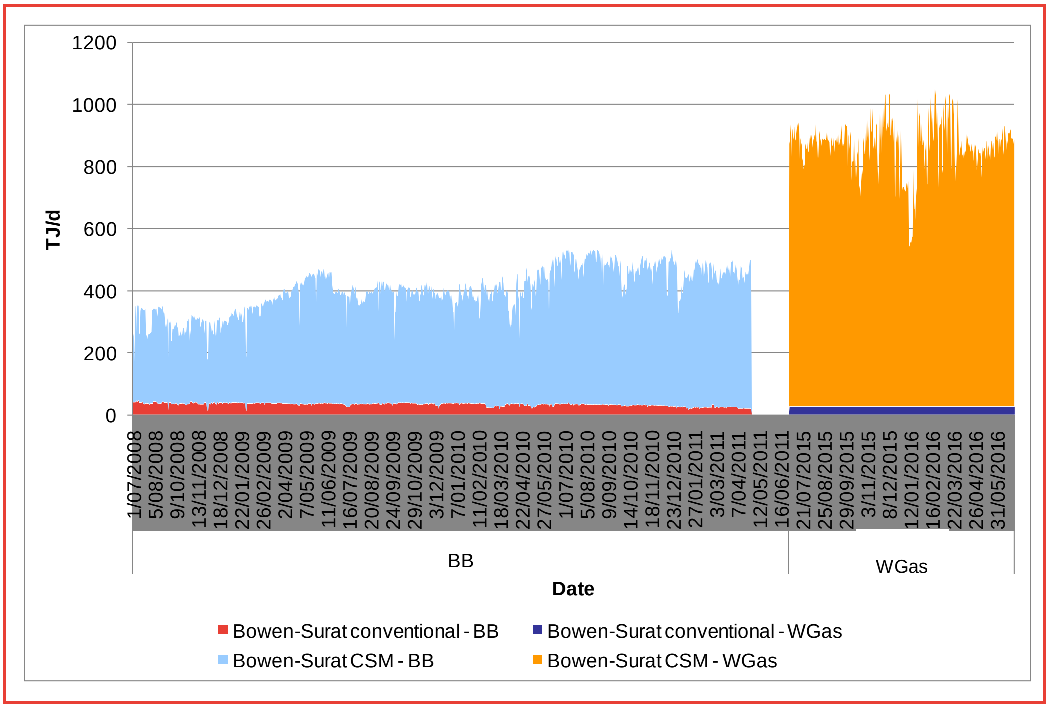
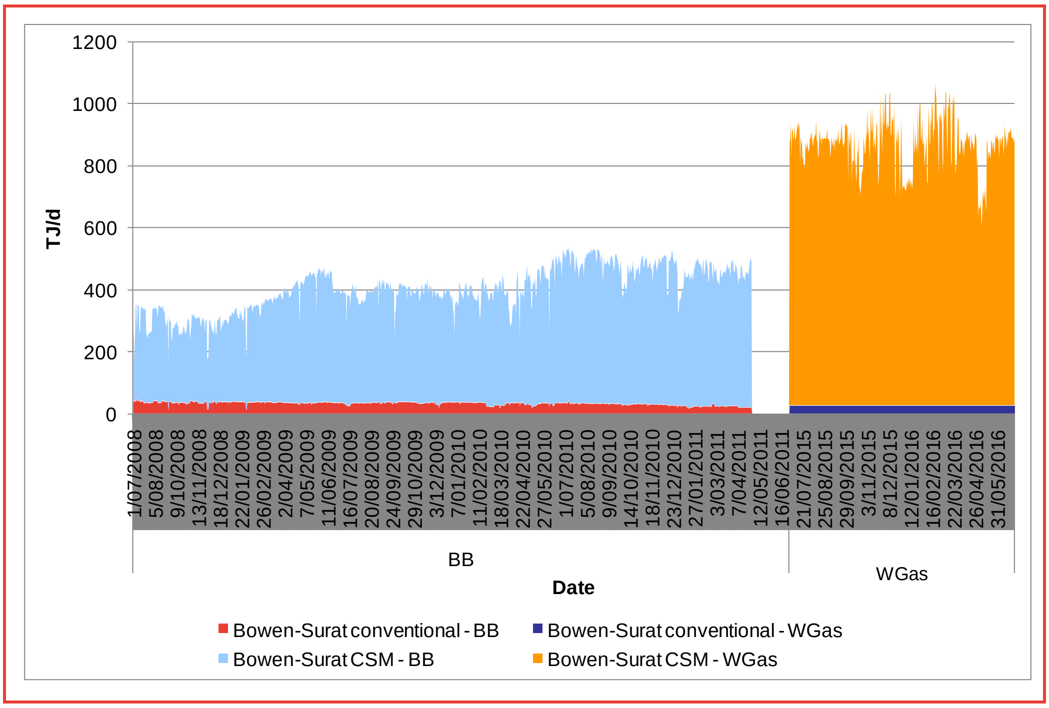
[21] Bowen-Surat gas production is higher in the *WHIRLYGAS* forecasts than has been observed historically in the GasBB data. The reason is both demand growth over the period to 2015/16 and increasing replacement of production from the Cooper-Eromanga basins with production from CSM from the Bowen-Surat basins.

Figure 23: Bowen-Surat gas production – RBP-FullLoss-2016-Peak



Source: Frontier Economics

Figure 24: Bowen-Surat gas production – RBP-FullLoss-2016-Shoulder



Source: Frontier Economics

Shock scenario – broader gas market outcomes

9.5 Conclusions on broader gas market outcomes

The *WHIRLYGAS* modelling discussed above indicates that, considered at an aggregate level, there is unlikely to be a need to divert gas to other markets as a result of an interruption to the RBP.

This conclusion is strengthened by the fact that *WHIRLYGAS* does not account for all options available to gas producers to manage an interruption to the RBP. For instance, as discussed, it has been assumed in the *WHIRLYGAS* modelling that there is no storage capacity available to help manage the interruption. Also, the modelling has not accounted for the options that some CSM producers have to effectively swap production between basins. For instance, Origin and Santos have interests in both CSM production in the Bowen-Surat basin and conventional gas production in the Cooper-Eromanga basin. These producers could use flexibility (including storage options) available at their processing plant in the Cooper-Eromanga basin to provide more options to manage the impact of the interruption to the RBP.

This is not to suggest, however, that all individual gas production facilities are equally able to manage an interruption to the RBP. In particular, CSM production plant that do not have direct pipeline connections to the Wallumbilla hub – including Berwyndale South, Daandine, Kogan North, Peat, Scotia, Talinga and Tipton West – will not have the same ability to continue supplying gas through the Queensland Gas Pipeline and the South-West Queensland Pipeline that are available to other CSM production plant.

Nevertheless there are other options for some of these plant to manage the impact of the interruption to the RBP. The most likely option is to supply additional gas to gas-fired generators:

- Berwyndale South can supply gas to the Condamine power station and also to the Braemar power station
- Daandine can supply gas to the Daandine power station
- Talinga can supply gas to the Darling Downs power station and is ultimately connected to the Wallumbilla hub through the Darling Downs pipeline
- Tipton West can supply gas to the Braemar power station.

Even during the various shock scenario cases, these power stations are not running at full capacity throughout the 14-day interruption. If necessary, these power stations could increase production to help these gas producers manage operational issues, but will presumably only do so if the terms on which the additional gas is supplied are sufficiently attractive to make additional dispatch profitable.

However, for those gas production facilities that are not connected to sources of gas demand other than through the RBP – which Frontier Economics understands to include Kogan North, Peat and Scotia – a complete loss of capacity on the RBP would likely require these plant to flare gas and/or shut down production during the 14-day interruption. Frontier Economics notes that these affected gas production facilities are among the smallest CSM plant in the Bowen-Surat basin.

Shock scenario – broader gas market outcomes

10 Shock scenario – electricity market outcomes

This section provides the results from Frontier Economics' modelling of the impact of each of the shock scenario cases on the electricity market, in both 2011/12 and 2015/16.

10.1 Rationale for examining impacts on electricity market

Before discussing the results of Frontier Economics' modelling of the impact of each of the shock scenario cases on the electricity market it is worth thinking about why an interruption to the RBP might be expected to have consequences for electricity markets.

As discussed in Section 7, an interruption to the RBP is likely to result in some degree of curtailment of gas supply to the gas-fired generators that rely on the RBP, particularly Swanbank E and Oakey. While Braemar 1's ability to source gas from the RBP will also be affected, its ability to source substitute gas from nearby CSM fields should enable it to continue operating in the event of a supply interruption on the RBP.

Given that Swanbank E does not have an alternative gas supply and is not a dual-fuel power station, curtailment of gas supply to Swanbank E will prevent it from running. Given that Oakey is a dual-fuel power station, curtailment of gas supply to Oakey will mean that Oakey will be able to continue to run, but only by using more expensive distillate. The overall effect is a change in the merit-order for Queensland: Swanbank E will completely drop out of the merit-order to the extent of its curtailment and Oakey will be pushed up to a higher price band in the merit order due to its higher cost fuel.

The purpose of Frontier Economics' modelling of the electricity market is to determine the impact of this on security of supply and prices in the electricity market. In the first instance, *SPARK* is used to model outcomes in the market in aggregate. The implications of these modelling results are then considered.

10.2 Modelling methodology

In order to assess the consequences for the electricity market of an interruption to the RBP, Frontier Economics uses *SPARK*. As discussed, *SPARK* incorporates a representation of the NEM, including all scheduled generators, interregional interconnectors and electricity demand centres.

To account for the interruption to the RBP, the first step is to run *SPARK* under the Reference Case for both 2011/12 and 2015/16. This provides expected outcomes where there is no interruption to the RBP. The second step is to run *SPARK* for each of the shock scenario cases. Two adjustments are made to the Reference Case in order to model the shock scenario cases:

- The output of Swanbank E is constrained on a daily basis to reflect the forecast extent that gas supply to the power station is curtailed (as discussed in Section 7).
- The fuel cost for Oakey is increased to reflect distillate prices to the extent that gas supply to the power station is curtailed (as discussed in Section 7).

As was discussed in Section 7, the extent of supply curtailment of gas-fired generators that draw gas from the RBP is the same under a 50% reduction in RBP capacity and a 100% reduction in RBP capacity. Consequently, the outcomes for the electricity market are the same under these two supply interruption cases – both result in Swanbank E being complete curtailed and Oakey being forced to run completely on distillate.

The implications under the 10% interruption case are different. Based on the assumed order of curtailment, the extent to which Swanbank E faces operational restrictions depends on the timing of the interruption and the year of the interruption. Given Frontier Economics' forecasts of gas demand on the RBP, Swanbank E will only face gas curtailment under the 10% interruption case in 2011/12.

Outlined in Table 13 is the extent of gas curtailment that Swanbank E faces on the nine days across both the peak and shoulder interruption periods in 2011/12 when RBP demand is forecast to exceed available capacity and hence Swanbank E's gas usage is expected to be affected. The extent of gas curtailment has been expressed both in TJ, as a proportion of total daily gas use and as a level of electrical energy based on Swanbank E's assumed heat rate (GJ required to generate a MWh of electricity).

Table 13 suggests that the maximum extent of curtailment that Swanbank E is expected to face is 13 TJ per day on 16/1/2012. Based on its assumed sent-out heat rate of 7.659GJ/MWh, this equates to 1,697 MWh of reduced output across the course of the day as a result of reduced gas supply.

Table 13: Swanbank E gas curtailment – 10% loss of RBP capacity

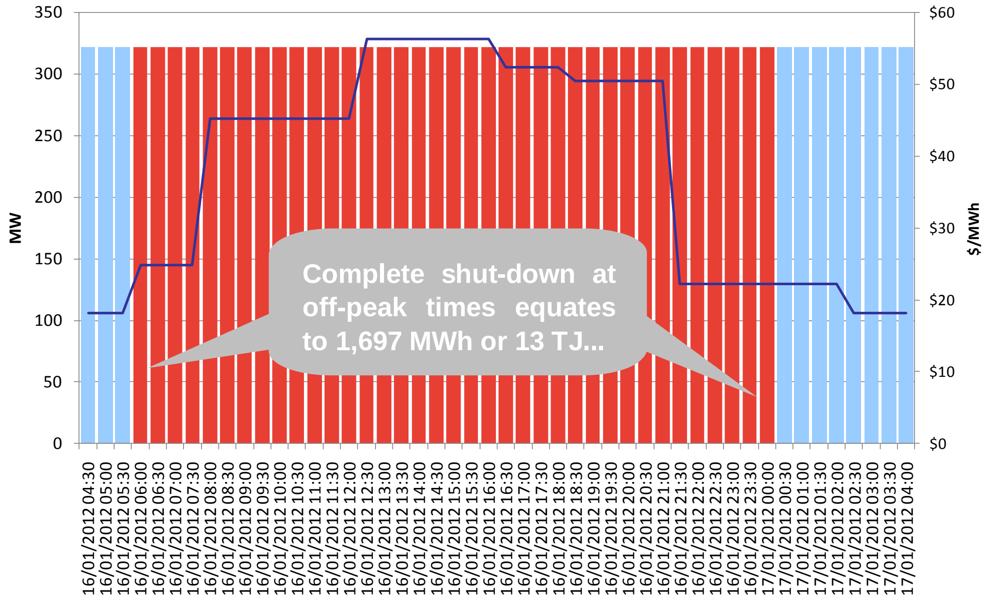
Interruption period	FinYear	GasDate	TJ	Proportion of daily gas use	MWh
Summer	2012	9/01/2012	1.05	1.87%	136.86
Summer	2012	12/01/2012	0.43	0.78%	56.48
Summer	2012	16/01/2012	13.00	19.12%	1697.05
Summer	2012	17/01/2012	1.09	1.97%	142.23
Summer	2012	19/01/2012	8.65	13.56%	1128.74
Summer	2012	20/01/2012	8.90	13.85%	1162.61
Shoulder	2012	1/05/2012	1.94	4.05%	253.56
Shoulder	2012	2/05/2012	1.02	2.12%	132.81
Shoulder	2012	3/05/2012	1.22	2.55%	159.75

Source: Frontier Economics

Figure 25 outlines Swanbank E's forecast half-hourly output and the half-hourly Queensland pool price on the 16 January 2012 when its gas curtailment is forecast to be greatest. The figure illustrates that in order for Swanbank E to curtail 13 TJ of gas relative to forecast gas usage, it must reduce its daily output by 1,697 MWh. To illustrate the extent of this reduction in output, based on its forecast output on the day, Swanbank E could curtail 1,770 MWh, or 13.56 TJ of gas, by entering a complete shut-down for 11 non-peak half-hour periods on the day (highlighted blue)

Given that on the day when Swanbank E's gas curtailment is expected to be at its greatest the station can ration its available daily gas effectively by enforcing a complete shut-down for 5.5 hours during non-peak times, the impact on wholesale spot market outcomes is likely to be negligible due to adequate supply from other generators during this time. Due to the likely negligible impact of Swanbank E's gas curtailment in the 10% interruption case, Frontier Economics has not used *SPARK* to model the impact of a 10% reduction in RBP capacity on the electricity market.

Figure 25: Swanbank E gas curtailment – 16/1/2012



Complete shut-down at off-peak times equates to 1,697 MWh or 13 TJ...

Source: Frontier Economics

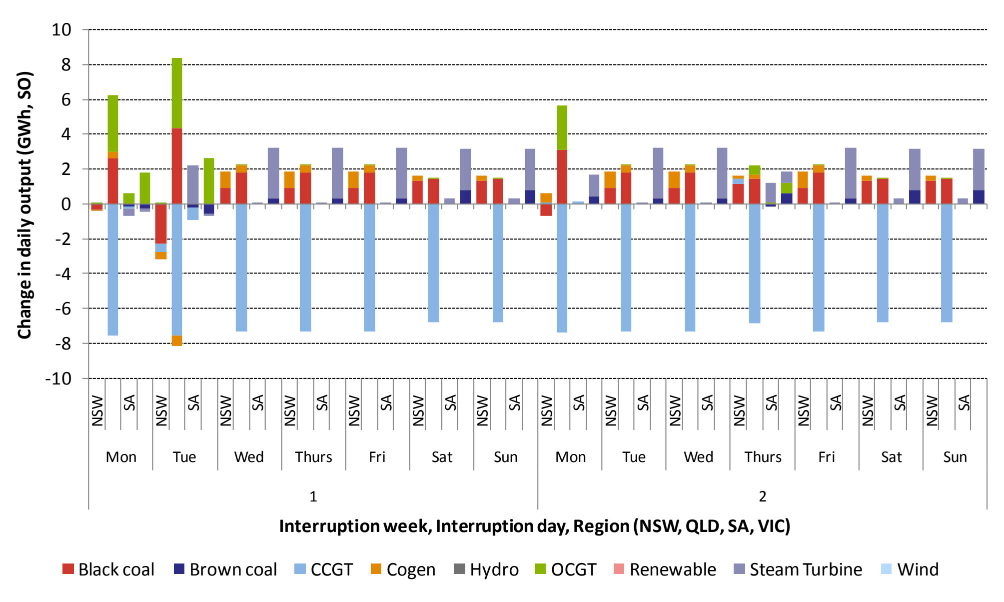
10.3 Modelling outcomes in 2011/12

Figure 26 and Figure 27 show the difference in daily electricity market dispatch, relative to the Reference Case, for the 50% reduction in RBP capacity and the 100% reduction in RBP capacity. Figure 26 shows outcomes for peak periods and Figure 27 shows outcomes for shoulder periods. Negative values on the charts represent the generation lost due to the supply interruption, and positive values on the chart represent the consequent increase in generation in each region.

For each of these cases there is sufficient capacity in the NEM to manage the gas curtailment to Swanbank E and Oakey. In each case, the curtailed capacity (largely from Swanbank E) is replaced by a mix of other generation, principally black coal, thermal gas and OCGT generation. Because these changes in output are derived from Frontier Economics' *SPARK* model the outcomes reflect strategic bidding. In most cases, cheaper black coal and OCGT plant can replace output from Swanbank E and, in the process, benefit from the higher spot prices. In some cases, however, particularly where electricity demand is high, the curtailment of Swanbank E changes bidding incentives for some plant in favour of less dispatch (in order to increase pool prices).

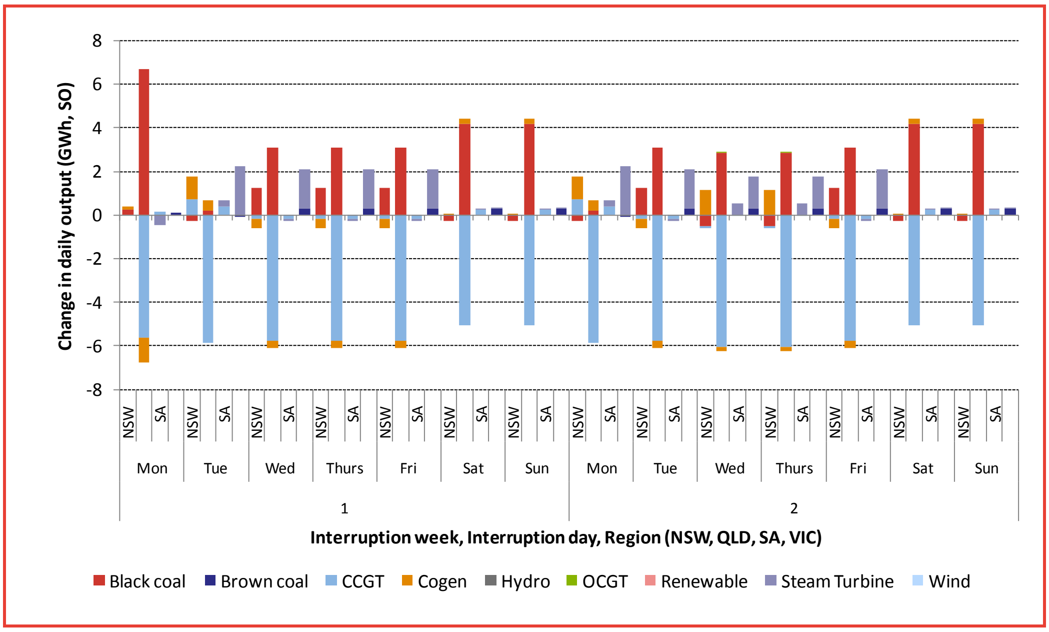
As well as reflecting strategic bidding, the type of replacement generation depends in part on the balance between supply and demand each day. Where there is sufficient supply, the replacement generation tends to be black coal and cogen, which are cheaper than OCGT. This is particularly clear when comparing outcomes during the weekends with outcomes during the week.

Figure 26: Change in daily NEM market output – RBP-FullLoss-2012-Peak and RBP-50%Loss-2012-Peak



Source: Frontier Economics

Figure 27: Change in daily NEM market output – RBP-FullLoss-2012-Shoulder and RBP-50%Loss-2012-Shoulder



Source: Frontier Economics

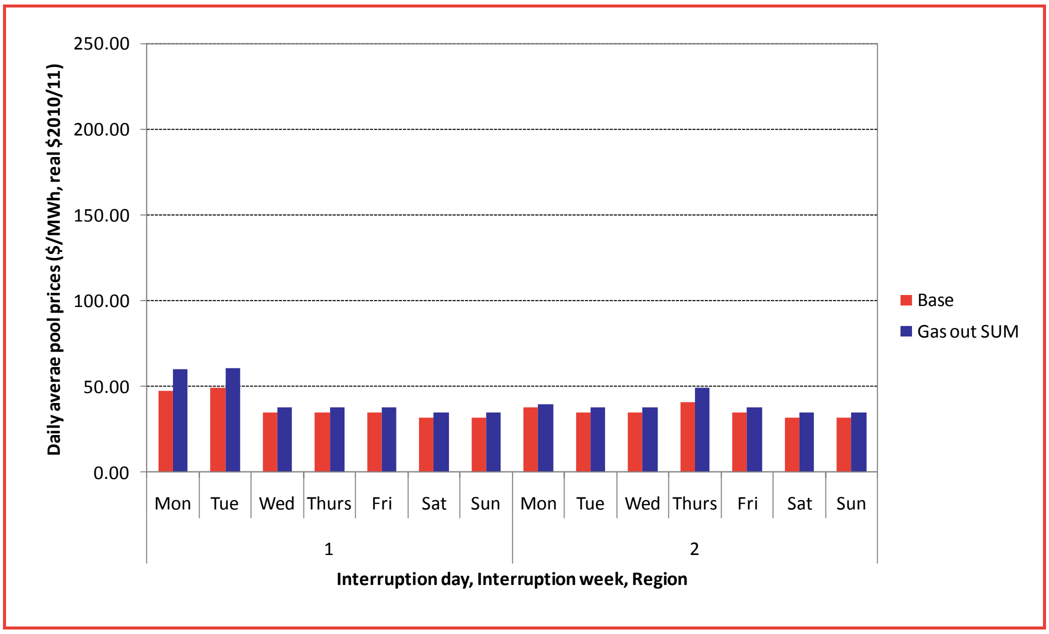
Figure 28 and Figure 29 show the difference in daily pool prices for Queensland, relative to the Reference Case, for the 50% reduction in RBP capacity and the 100% reduction in RBP capacity. Figure 28 shows outcomes for peak periods and Figure 29 shows outcomes for shoulder periods.

For each case the price impacts of the gas curtailment to Swanbank E and Oakey are relatively small. This makes sense, given both Swanbank E and Oakey are relatively small within the context of the NEM. However, during peak demand periods, even the removal of Swanbank E and Oakey can have impacts on the daily average pool price in Queensland. This is seen by the more significant price increases that are observed on several weekdays during the peak 14-day period.

Considered on an annual basis, however, the impact of the gas curtailment to Swanbank E and Oakey on the Queensland price is minimal. For the gas curtailment during peak periods the increase in annual average pool prices in Queensland in 2011/12 is around 15 cents, and for the gas curtailment during shoulder periods the increase is less than 5 cents.

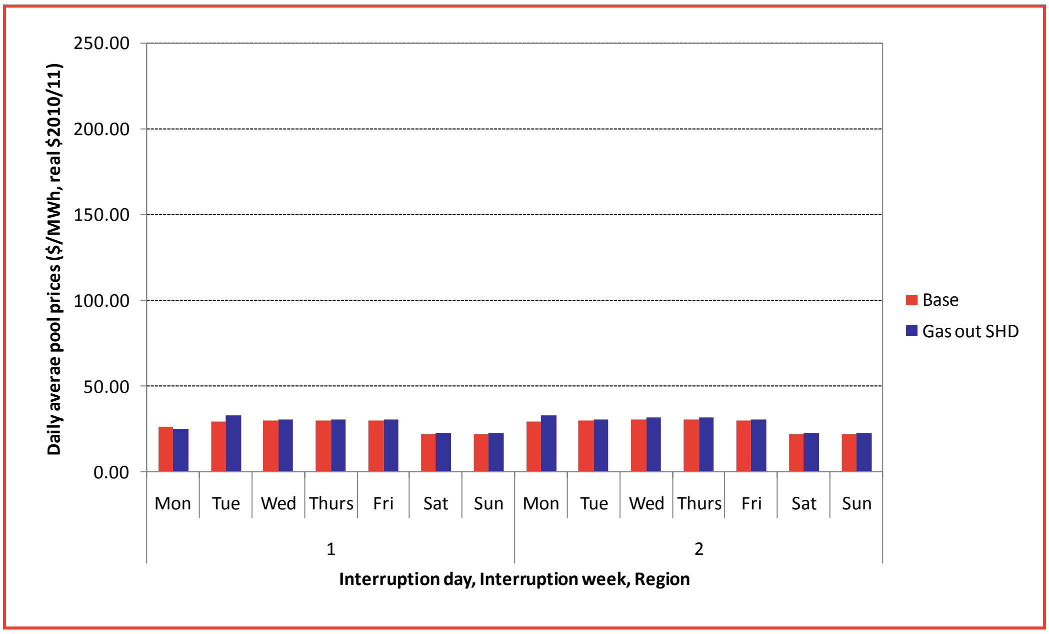
The gas curtailment to Swanbank E and Oakey has a very minor effect on prices in other regions in 2011/12.

Figure 28: Daily pool prices in Queensland – RBP-FullLoss-2012-Peak and RBP-50%Loss-2012-Peak



Source: Frontier Economics

Figure 29: Daily pool prices in Queensland – RBP-FullLoss-2012-Shoulder and RBP-50%Loss-2012-Shoulder



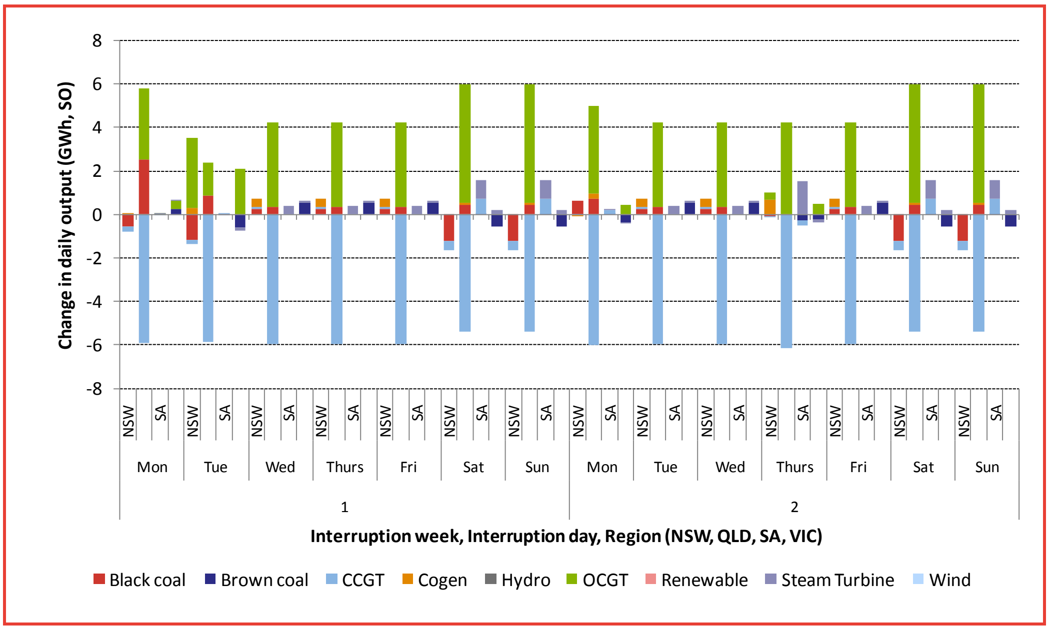
Source: Frontier Economics

10.4 Modelling outcomes in 2015/16

Figure 30 and Figure 31 show the difference in daily electricity market dispatch, relative to the Reference Case, for the 50% reduction in RBP capacity and the 100% reduction in RBP capacity. Figure 30 shows outcomes for peak periods and Figure 31 shows outcomes for shoulder periods. Again, negative values on the charts represent the generation lost due to the supply interruption, and positive values on the chart represent the consequent increase in generation in each region.

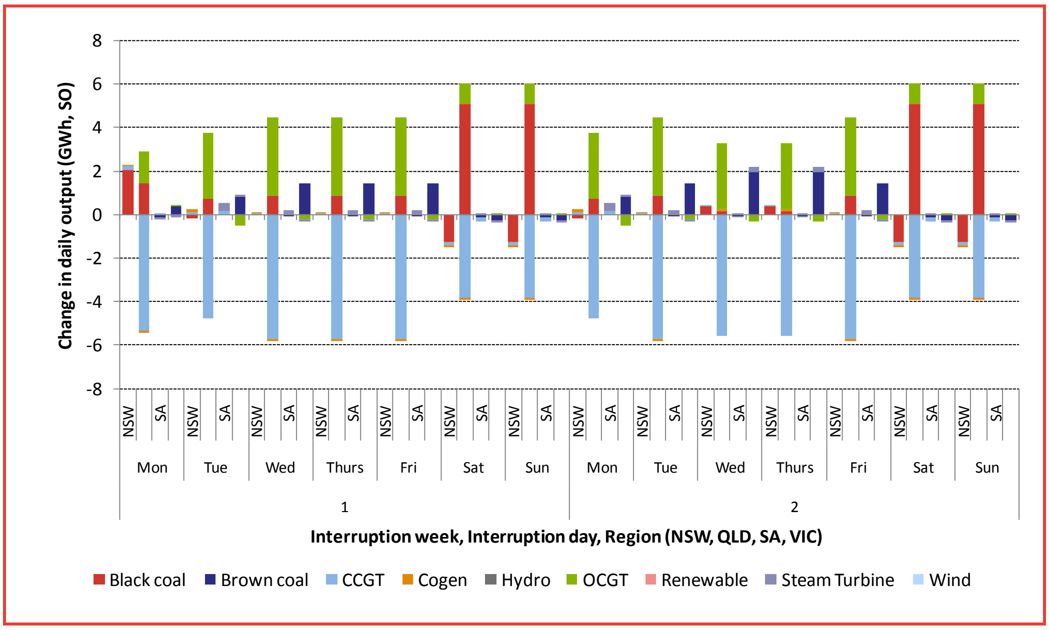
As with outcomes in 2011/12, for each of these cases there is sufficient capacity in the NEM to manage the gas curtailment to Swanbank E and Oakey. The clear difference from outcomes in 2011/12 is that replacement generation in 2015/16 is much more OCGT plant than black coal. This reflects the tightening of demand and supply in Queensland over time and the resulting reduction in 'spare' baseload generator slack in 2015/16 to replace lost supply.

Figure 30: Change in daily NEM market output – RBP-FullLoss-2016-Peak and RBP-50%Loss-2016-Peak



Source: Frontier Economics

Figure 31: Change in daily NEM market output – RBP-FullLoss-2016-Shoulder and RBP-50%Loss-2016-Shoulder



Source: Frontier Economics

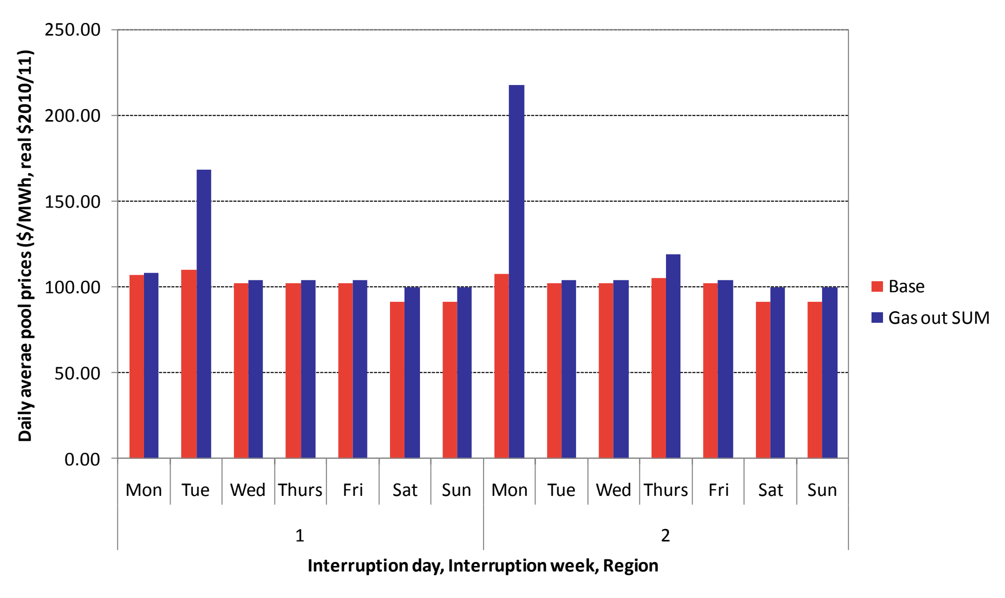
Figure 32 and Figure 33 show the difference in daily pool prices for Queensland, relative to the Reference Case, for the 50% reduction in RBP capacity and the 100% reduction in RBP capacity. Figure 32 shows outcomes for peak periods and Figure 33 shows outcomes for shoulder periods.

Unlike in 2011/12, when sufficient 'slack' exists in Queensland to prevent material price spikes in the event that Oakey and Swanbank E experience a gas supply interruption, there are some instances of significant price increases in 2015/16. This is due to the tightening demand-supply balance by 2015/16 in Queensland. On the first Monday of the second interruption week, when demand is highest, the daily pool price spikes to roughly $220/MWh. The general level of prices in 2015/16 is also higher as compared to 2011/12 due to the effect of a carbon price.

Considered on an annual basis, however, the impact of the gas curtailment to Swanbank E and Oakey on the Queensland price is minimal. For the gas curtailment during peak periods the increase in annual average pool prices in Queensland in 2011/12 is around 50 cents, and for the gas curtailment during shoulder periods the increase is less than 15 cents.

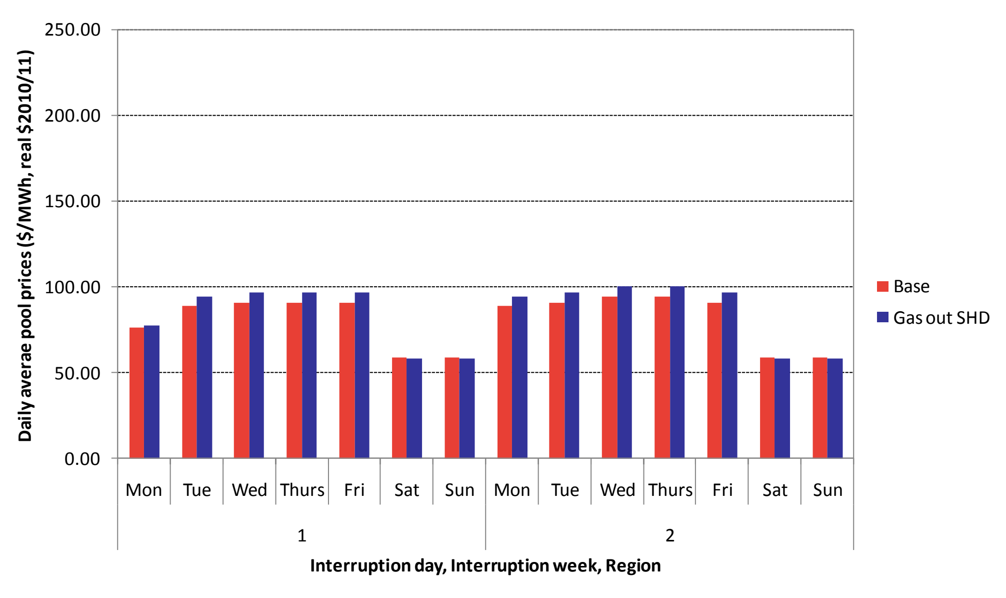
The gas curtailment to Swanbank E and Oakey has a very minor effect on prices in other regions in 2015-16.

Figure 32: Daily pool prices in Queensland – RBP-FullLoss-2016-Peak and RBP-50%Loss-2016-Peak



Source: Frontier Economics

Figure 33: Daily pool prices in Queensland – RBP-FullLoss-2016-Shoulder and RBP-50%Loss-2016-Shoulder



Source: Frontier Economics

10.5 Conclusions on electricity market outcomes

The results of the electricity market modelling show that there is little impact on electricity markets of even a complete curtailment of gas supplies on the RBP. There are no issues for security of electricity supply caused by the curtailment of gas supplies on the RBP, and the overall impact on electricity prices is small (with the exception of the peak demand day in summer).

It is important to note that modelling all of the intraregional network constraints in the NEM is a substantial exercise and is beyond the scope of this project. However, if it is the case that intraregional network constraints in Queensland create issues for the physical supply of electricity to Brisbane then the impact on the electricity market of the curtailment of gas to Swanbank E could be significantly greater. For partial supply interruptions of the RBP these circumstances may mean that the gas supplies to Swanbank E take precedence over gas supplies to other customers (either as a result of the higher opportunity cost of gas to Swanbank E or because the Minister directs that gas be supplied to Swanbank E as a priority). This would mitigate the consequences for the electricity market of the combination of supply interruptions of the RBP and electricity network constraints, but do so at the cost of greater consequences for gas users.

FRONTIER ECONOMICS NETWORK
BRISBANE | MELBOURNE | SYDNEY | BRUSSELS | COLOGNE | LONDON | MADRID
Frontier Economics Pty Ltd 395 Collins Street Melbourne Victoria 3000
Tel: +61 (0)3 9620 4488 Fax: +61 (0)3 9620 4499 www.frontier-economics.com
ACN: 087 553 124 ABN: 13 087 553 124