Gas Market Parameters Review 2018
Consultation Report

Report to the Australian Energy Market Operator

29 November 2017

EXECUTIVE SUMMARY

Introduction

The Australian Energy Market Operator (AEMO) has engaged Market Reform to conduct reviews of gas market parameters used in the Short Term Trading Market (STTM) for gas and in the Victorian Declared Wholesale Gas Market (DWGM) to ensure that they continue to be fit for purpose. The within scope gas market parameters and their values in the STTM are the market price cap (MPC) of $400/GJ, an administered price cap (APC) of $40/GJ and a cumulative price threshold (CPT) of $440/GJ, while the corresponding values in the DWGM are the value of lost load (VoLL) of $800/GJ, an APC of $40/GJ and a CPT of $1,800/GJ.

The STTM parameters are currently required by the National Gas Rules to be reviewed at least once every five years. While there is no similar requirement for the DWGM, AEMO is seeking to conduct reviews concurrently. The period studied in this review is 2019 to 2024, with any revised parameters to apply from 2020, or if there is a strong case for more immediate change, from 2019.

This report presents Market Reform's proposed methodology for the conduct of the review and presents the rationale for the approach. The proposed methodology will be the subject of an industry consultation, which will inform the final methodology used. AEMO is seeking to have the review completed by April 2018.

The review is to have regard to the links between the gas markets and other markets as well as to the industry structure today modified to reflect foreseeable changes in the future.

Market Situation

The study period aligns with a period during which the eastern Australian gas industry may face material shortfalls in gas supply assuming full supply of demand for LNG for export. While mechanisms such as the Australian Domestic Gas Security Mechanism (ADGSM) and the Gas Supply Guarantee (GSG) have been implemented to provide assurance that domestic gas demand and security of gas supply for the NEM, there will still be periods where the national gas market is operating at, or near, its limits. Projected falls in production of gas in Victoria combined with increased demand for gas powered generation are projected to mean that from 2021 the DWGM may not always be able meet peak DWGM consumption while also supplying gas to New South Wales and South Australia.

The Gas Market Parameters

The gas market parameters within scope define a maximum market price (VoLL in the DWGM or MPC in the STTM), CPT and APC. The key bounds on these parameters are that:

- The maximum market price should be high enough to avoid interfering with market clearing and should not restrict investment.
- CPT should be set so as not to undermine the recovery of investment costs over time, but also not to over-expose participants to risk.
- APC should be set to a level that provides a reasonable trade-off between impacting supply options (recognising that some supply options priced above APC may be impacted) and protecting participants from unmanageable risk, while also maintaining incentives for participants to hedge risk.

These considerations effectively place bounds on the acceptable range of gas market parameters.

Methodology

The methodology proposed in this report is based on assessing a range of gas market parameters – including the current ones – across a range of simulations of extreme price events. The performance of a choice of gas market parameters is assessed based on trying to maximise economic efficiency of the market while keeping risks acceptable to consumers of gas. By comparing simulation results against a set of parameters for which no administered pricing is applied it is possible to assess the loss in economic efficiency due to the application of more restrictive administered price caps. Market simulation solutions for extreme pricing events can be compared with simulations of that same period without the event occurring. The different profitability of market participants in these two situations allows assessment of the impact on risk for a range of hypothetical typical buyers from the market.

The simulation creates an event by combining a market context and a scenario. The market context reflects either the DWGM or an STTM hub, with the available supply and demand modified to reflect conditions for a particular year within the study period. A scenario includes a sequence of days in which an extreme pricing event occurs as well as the subsequent days. Scenarios are described in Appendix B. During such events VoLL or MPC might set the price and the cumulative price threshold may be triggered. The performance of the market can be assessed across the subsequent days. The scenarios include events specific to market – e.g. a break down at a production facility in the Gippsland for the DWGM or a high gas powered generation demand outside an STTM hub.

The market simulation will involve simulating schedules for a single market – the DWGM or an STTM hub - across a scenario. Interactions between markets will be reflected in the design of a scenario. A scenario may imply a particular set of data for an STTM hub and a particular set of data for the DWGM, but each market will be simulated independently. Each schedule will comprise a daily supply offer curve and daily demand curve, where these curves will reflect the market context and will be adjusted to reflect both events that arise from a scenario and the imposition of administered price caps when triggered. The offer curves and demand curves will be derived based on recent historic data but adjusted for future forecast levels of supply from geographic areas, market demand, changing levels of import and export, and consequential changes in potential contract positions. These simulations will not attempt to simulate individual participants.

Sensitivity analysis will be performed for all simulations so as to provide data to test the robustness of the performance of gas market parameters with slight changes in market outcome. This analysis will involve repeating simulations with varied levels of uncontrollable withdrawal and, separately, varied levels of offer prices in the supply curves. This will test alternative market clearing points in the vicinity of the base simulation solution.

The market efficiency for each simulation solution will be taken as the area under the demand curve relative to the demand cleared less the area under the supply curve utilised. A key consideration in this analysis is that once involuntary curtailment occurs, then an administered state will occur anyway. As a result, if involuntary curtailment occurs we will exclude those cases from the analysis. This means that effectively the value placed on uncontrollable withdrawal and the quantity of uncontrollable withdrawal can be treated as constant and invariant with respect to the choice of gas market parameters. The market efficiency loss for a case will just be the difference in the market efficiency between it and a reference case which is identical except that no administered price cap was applied.

The market simulations will provide information on prices and market imbalances that can then be applied to hypothetical representative market participants which buy from the market. The focus will be on direct market customers, small and medium retailers and gas powered generators. For each participant, a level of market exposure will be assumed based on the nature of the participant with this linked to the degree the overall market is long or short. Using established approaches from prior gas market parameter reviews an acceptable level of risk will be limited to 500 days of lost profit relative to the participant's position absent an extreme event.

This methodology will produce many sets of results for combinations of gas market parameters, extreme events (in different market contexts) and for different sensitivity factor settings. From the cases which conform to situations that avoid market administration for other reasons, we will identify a set of well performing and robust parameters. If these include current parameters then there may be no need for a change in parameters. However, if the methodology indicates that parameters should be changed then this will inform the final recommendations.

Data

The data used in this study is based on public historic market data and data from AEMO forecasts. Where possible established methodologies from prior reviews are used to estimate additional values.

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1 REVIEW OVERVIEW

1.1 Background

The Australian Energy Market Operator (AEMO) has engaged Market Reform to conduct the 2017 review of a number of parameters used in the Short Term Trading Market (STTM) for gas and in the Victorian Declared Wholesale Gas Market (DWGM) to ensure that they continue to be fit for purpose. The market parameters to be reviewed are collectively referred to as the gas market parameters and are described in Table 1.

Table 1 – The current gas market parameters

STTM			
Parameter	**Purpose**	**Documented in**	**Value**
Market Price Cap (MPC)	The maximum market price to apply for a gas day.	National Gas Rules	$400/GJ
Administered Price Cap (APC)	A cap that replaces MPC during an administered price cap state so as to mitigate the risk of high prices.	National Gas Rules	$40/GJ
Cumulative Price Threshold (CPT)	The threshold for automatic imposition of an administered price cap state.	National Gas Rules	$440 /GJ (110% of MPC)
DWGM			
Parameter	**Purpose**	**Documented in**	**Value**
VoLL	The maximum market price.	National Gas Rules	$800/GJ
Administered Price Cap (APC)	A cap that replaces VoLL during an administered price cap state so as to mitigate the risk of high prices.	Wholesale Market Administered Pricing Procedures (Victoria)	$40/GJ
Cumulative Price Threshold (CPT)	The threshold for automatic imposition of an administered price cap state.	Wholesale Market Administered Pricing Procedures (Victoria)	$1,800/GJ

STTM market parameters are currently required to be reviewed at least once every five years in accordance with rule 492 of the National Gas Rules (NGR). Following this review the requirement will be a four-yearly review. No similar requirement exists for a review of the parameters used in the DWGM. AEMO conducted its own review of the DWGM parameters in 2012 and is using the occasion of an STTM review have a third-party review the DWGM parameters also.

This report presents Market Reform's proposed methodology for the conduct of the review and presents the rationale for the approach. The proposed methodology will be the subject of an industry consultation, which will inform the final methodology used.

AEMO is seeking to have the review completed by April 2018.

1.2 Advice Sought

AEMO is seeking advice on the appropriate settings of the gas market parameters.

In developing recommendations, AEMO has asked for the review to have regard to the following:

1. Recognise links between markets

The analysis of the gas market parameters must recognise interactions between the STTM, DWGM and NEM, recent developments in each of these markets and the convergence of the gas and electricity markets. In particular, consideration of interactions between the STTM and DWGM and between each of these markets and the NEM should recognise the activities and operations of participants across markets.

2. Recognise industry structure and future developments

Any modelling of market outcomes should represent the broad industry structure as it exists today and include foreseeable changes to industry and market design in the future. Any changes to industry structure and market design since the previous review should be taken into consideration. Modelling need not attempt to represent actual industry players, it should represent the different distributions of participant size and roles in the contract and spot markets.

The modelling needs to be cognisant of the Review of the Victorian Declared Wholesale Gas Market recently conducted by the AEMC

3. Data to be used

The determination of the gas market parameters should be based on available public and market data or be reasonable and logically based estimates of data values which are not otherwise public or available. Where historic or market data does not exist, the Consultant will have to adequately justify the use of alternative information.

4. Determination of MPC / VoLL

MPC or VoLL is to be determined with the primary focus on economic price signalling as a market clearing incentive. It is to be a value greater than the maximum short run price expected to arise in the market, recognising that the STTM prices both the gas commodity and the cost of transmission in its prices whereas DWGM prices only include gas commodity costs. The value of MPC/VoLL is to be set with the aim of maximising the opportunity for an efficient market to clear in the short run. This objective implies that longer term investment costs will be recovered over time, but does not restrict short run prices to be constrained by long run average cost.

In the STTM the value of MPC should be common to all hubs and across the ex ante market price, contingency gas price and the ex post market price. In the DWGM the value of VoLL should be common to all schedules.

In considering the short run cost of demand side response in each market, the appropriate measure should be the greater of the cost incurred for a rare temporary supply interruption and the cost of responding to a long term loss of reliability due to supply side under-investment.

Whilst the setting of MPC/VoLL has fundamental implications for overall risk in the market and is a primary driver of that risk, the determination of its value is to focus on achieving economic price signals rather than to limit risk. Risk is addressed by the application of an administered price cap, and accordingly will be addressed when determining that price cap.

Market Reform is required to determine the appropriate settings of MPC and VoLL.

5. Determination of APC and CPT parameters

The purpose of the administered price cap (APC) is as a last resort to address unmanageable risk in the market by limiting the impact of extreme and prolonged events. Accordingly, the APC is a balance between providing limitation of overall risk whilst maintaining appropriate incentives on individuals for prudent risk management and minimising distortion of incentives for appropriate investment.

APC will be triggered by the cumulative price threshold (CPT) or triggered as a result of events that occur on a given day, primarily force majeure type conditions.

The intent of CPT is a means of addressing unmanageable risk and distortions arising from prolonged exposure to very high prices. CPT allows for a high MPC/VoLL that meets the objectives of ensuring voluntary market clearing and at the same time allows management of risk due to high price.

Market Reform is required to determine the appropriate settings of APC and CPT.

1.3 Study Period

The gas market parameters under review are intended to be applicable from 1 July 2020 to 30 June 2024. AEMO may seek to implement changes as early, applying from 1 July 2019 if this review identifies benefits in doing that. Gas market parameters implemented from the early date would apply through to 30th June 2024 when the recommendations of the next 4 year review would apply from.

To cover all eventualities, in this report the study period means the period from 1 July 2019 to 30 June 2024.

1.4 Timeline of Review

Submissions on this report are to be made by email to GWCF_Correspondence@aemo.com.au and are due by 24 January 2018.

A presentation of the draft recommendations of this review will be made to the Gas Wholesale Consultative Forum (GWCF) on 13 February 2018.

The final report is due for publication by 18 April 2018.

1.5 Report Outline

This report is structured as follows:

- Section 2 provides an overview of the markets relevant to this review, the trends in those markets, and the drivers of risks in those markets.
- Section 3 describes the role and relationships between the gas market parameters and also describes bounds on acceptable values.
- Section 4 provides a description of the parameter assessment problem to be solved in this review.
- Section 5 describes the proposed solution methodology to the problem posed in Section 4. While this section refers generally to the scenarios to be considered, more detail of the actual scenarios under consideration is provided in Appendix B.
- Section 6 provides a comparison of this review with previous gas market parameter reviews conducted for AEMO.
- Section 7 describes the key data and sources that are proposed to be used in the modelling.
- Section 8 provides detail of the next steps.

A list of abbreviations is provided in Appendix A. The scenarios under consideration for inclusion in the review are presented in Appendix B.

2 OVERVIEW OF THE MARKETS AND DRIVERS OF RISK

2.1 The Context of the East Coast During the Study Period

The most recent Gas Statement of Opportunities (GSOO)[1] presents a broader view of the Australian east coast over coming decades.

Figure 1 – Eastern and south-eastern Australian domestic gas production (excluding LNG), 2017-36[2]

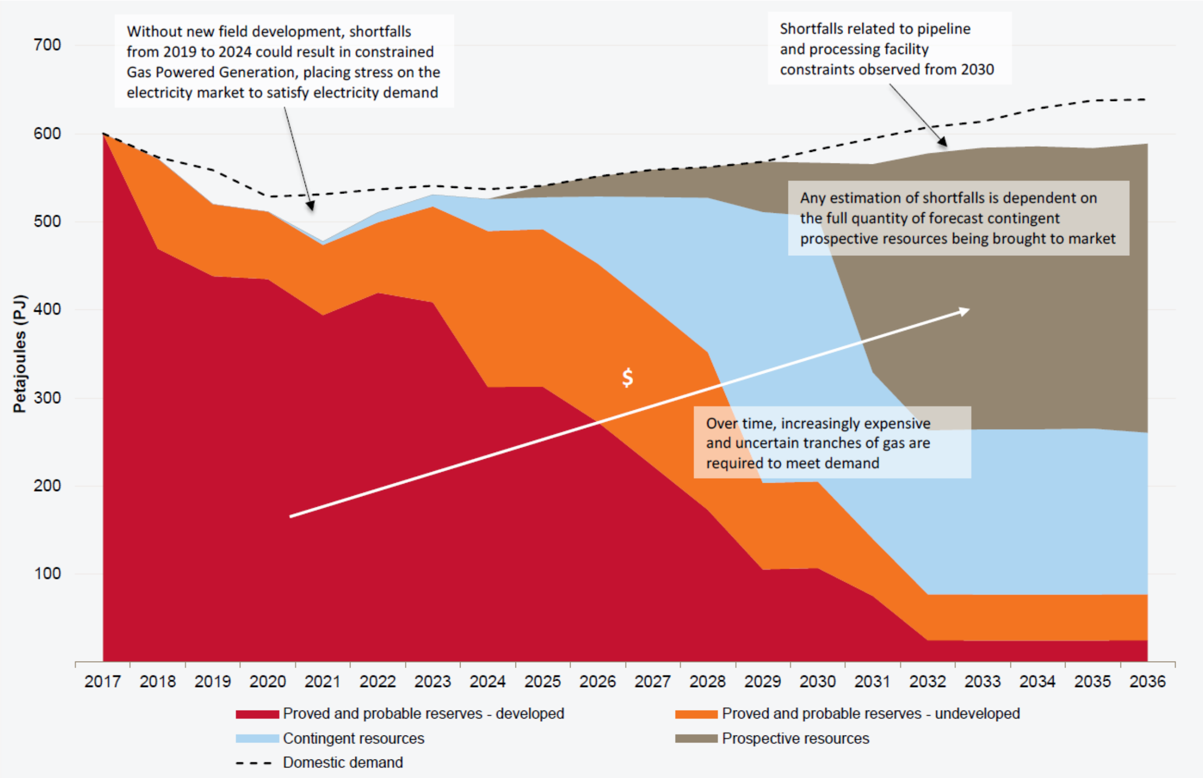


Figure 1 illustrates the supply and demand situation for domestic gas after netting supply and demand associated with LNG exports which have tightened the supply and demand balance in recent years. It shows that during the entire study period traditional supply sources are declining leading to a projected shortfall between east coast domestic gas production and demand. Left unchecked, this could give rise to significant changes in gas flows as usage changes and prices rise.

Measures already put in place to mitigate these risks include:

- The Australian Domestic Gas Security Mechanism (ADGSM) whereby the Federal Minister for Resources may, after a consultation process, impose LNG export restrictions for years in which a domestic gas shortfall is forecast.
- The Gas Supply Guarantee (GSG) is a separate mechanism developed between the Commonwealth Government and gas producers and pipeline operators to make gas supply available to electricity generators during peak NEM periods.

While these measures provide an assurance that supply and demand can be satisfied, during the study period there may be an increase in the frequency of periods where the national gas market is operating at, or near, its limits, increasing the potential for sustained periods at high price.

[1] Gas Statement of Opportunities for Eastern and South-Eastern Australia, AEMO, March 2017 and Update to Gas Statement of Opportunities, AEMO September 2017. The former document forecasts out to the mid-2030's while the latter document provides an update for the period to 2019.
[2] Reproduced from Figure 4 in the March 2017 GSOO.

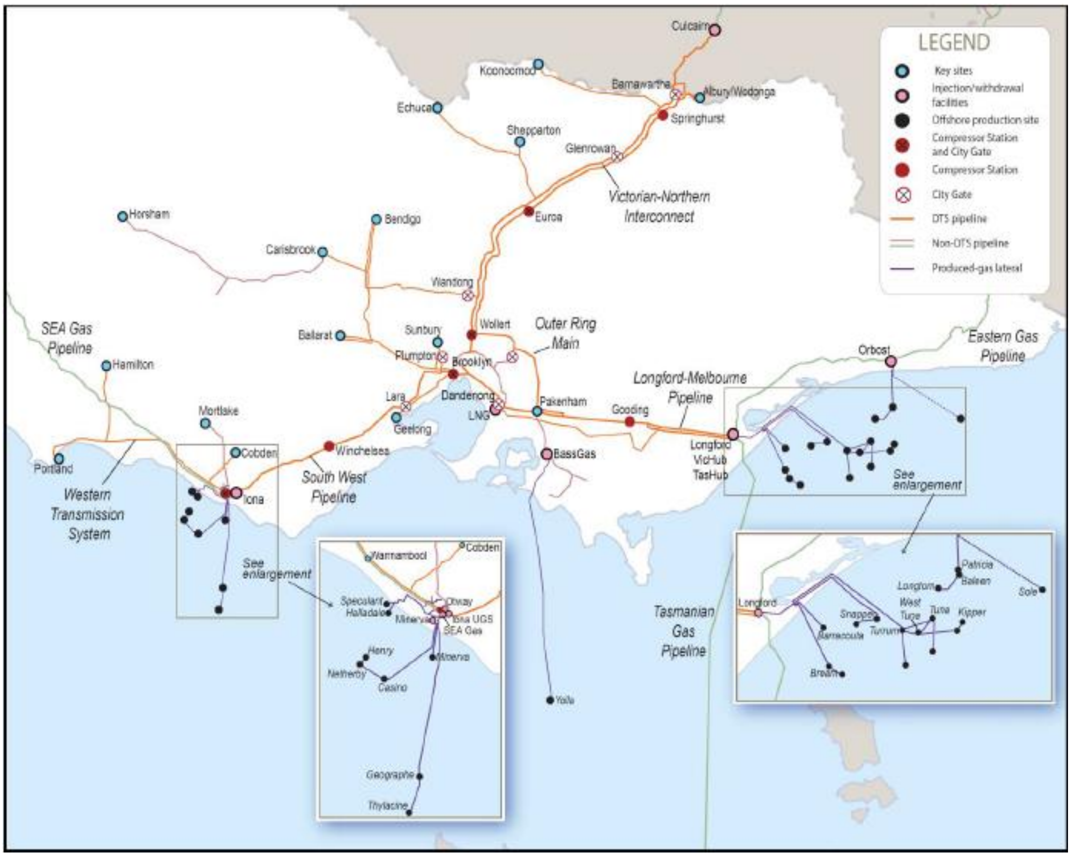
It must be noted that these estimates are based on current knowledge of likely available gas reserves and the rate at which they are expected to be developed. The situation could evolve quite differently if additional reserves became available and entered production.

2.2 Victorian Declared Wholesale Gas Market (DWGM)

2.2.1 Current Industry Structure

The DWGM is a market that operates across the Declared Transmission System (DTS) in Victoria. The extent of the DWGM is shown in Figure 2. This market is connected with New South Wales, South Australia and Tasmania via transmission pipelines that are not part of the market.

Figure 2 – The Victorian gas transmission system[3]



Consumers in Victoria are primarily supplied by retailers but large customers can purchase gas directly. Most participants can match their demand with their own supply and thereby limit exposure to the market. Heating load is the major demand with gas-powered generation second. Summer demand is typically in the region of 350 TJ/day but winter demand can significantly exceed 1000 TJ/day. The 1 in 20-year peak demand scenario for the DWGM is currently 1310 TJ/day. The 2017 forecast daily supply availability is 1,169 TJ from Gippsland, 647 TJ from the Port Campbell (Geelong) region (including under-ground gas storage) and 87 TJ from LNG sources in Melbourne. The pipelines to other states can act as supply or demand in the DWGM.[4]

2.2.2 DWGM Supply and Demand Trends

While the supply and demand situation in the DWGM has been relatively stable over the last decade, there are a number of significant supply and demand changes going forward. These changes are

[3] Victorian Gas Planning Report, AEMO, March 2017.
[4] Data in this paragraph is based on the Victorian Gas Planning Report, AEMO, March 2017.

factored into the broader east coast gas situation but are important to the DWGM context. The most recent Victorian Gas Planning Report (VGPR)[5] (which forecasts only to 2021):

- Estimates that the closure of the Hazelwood Power Station in 2017 will cause annual GPG consumption to reach 18 PJ in 2017 and 20 PJ in 2018. Consumption is forecast to decrease to 9.6 PJ in 2021 due to increased renewable generation.
- Forecasts annual consumption to fall, due to improved efficiency and fuel switching. Demand is forecast to fall from 214 PJ in 2017 to 205 PJ in 2019 and 197 PJ in 2021. The rate of decline is approximately 2% per year.
- States that based on producer forecasts, that Gippsland annual production could drop by 34% (off setting increases in 2016) with daily production reducing by 27% to 857 TJ/day by 2021. Supply from Port Campbell is estimated to decline by 81% over this period
- Concludes that while there is adequate Victorian supply through to 2021 to meet peak demand and GPG forecasts, but from 2021 it may not be possible to always also supply gas to New South Wales and South Australia.

2.2.3 System Operation

AEMO is the system operator for the DWGM. The primary operational consideration is managing linepack (stored gas) within day and between days. It can take in the region of 6 hours for gas to flow from Longford to Melbourne but demand in Melbourne can rise rapidly if temperature drops. Gas production facilities tend to supply gas at a constant rate, with that rate only changing at a few discrete intervals during the day.

The normal operational process is to schedule gas through the market to meet the forecast hourly demand. As demand changes, rescheduling of gas can increase supply as required but, once it becomes too late to deliver gas from distant (low cost) locations, AEMO must schedule higher cost LNG from Melbourne to serve demand locally. These events are called "surprise" events.

Network constraints can also prevent low cost gas from being delivered. In these situations, AEMO calls on the lowest cost gas that can serve the load, though this may mean constraining on some supply sources and constraining off others. These events are called "constraint" events.

AEMO must manage the linepack distribution across the system, through scheduling gas and operating compressors so as to maintain gas flows within the day. Between days, AEMO must manage end-of-day linepack to ensure that the system pressures at the end of the day are compatible with achieving required gas flows to satisfy forecast demand on the next gas day.

2.2.4 Market Design

The DWGM is designed to facilitate the efficient scheduling of gas.

Participants in the market are retailers and market customers and traders. Market participants will typically hold contracts for gas supply from gas producers, storage fields or other supply sources. The DWGM operates under a "market carriage" arrangement meaning that market participants have access to the DTS and are entitled to flow whatever they have scheduled. The DTS is funded by Transmission Use of System Charges so the cost of the accessing the network is not included in the gas market.

To schedule gas, market participants place bids to inject gas at injection points to the DTS or place bids to buy gas at controllable withdrawal points from the DTS, and forecast their uncontrollable demand that will be taken at any price. AEMO can modify the aggregate demand forecast and profiles that across the network. Gas powered generation (GPG) is treated as uncontrollable demand forecast.

AEMO determines a constrained operational schedule which endeavours to efficiently match supply with demand while accounting for operational and network constraints in the DTS. Separately AEMO solves an "infinite tank" version of the gas scheduling problem that ignores transmission constraints and defines an unconstrained pricing schedule that sets market prices. To the extent that

[5] Victorian Gas Planning Report, AEMO, March 2017.

operational constraints result in a different actual pattern of injections or off-takes, then those who are constrained on are compensated by an ancillary payment, with this funded through an uplift charge applied to those deemed to have caused it (if identifiable) or through an uplift on all consumption (if not identifiable). Authorised Maximum Daily Quantity (AMDQ) is a form of hedge available in the market that provides some protection against uplift charges for the holders.

The market is scheduled 5 times per day, based on bids and demand forecasts closing 1 hour before the schedule. It runs by 6 AM for the following 24 hours, by 10 AM for the scheduling horizon of the following 20 hours, by 2 PM for the following 16 hours, by 6 PM for the following 12 hours, and by 10 PM for the following 8 hours. The 6 AM schedule is the primary market schedule with all gas scheduled settled at the single market price applicable to that schedule (with constrained on ancillary payments funded separately). At each subsequent schedule, changes from the prior schedule are settled at the new market price. Actual deviations in gas flow during a scheduling interval from that scheduled are settled based on the price in the next scheduling horizon. Thus, if a participant over supplies at 9 AM then this will be priced at the price determined in the 10 AM schedule. The total uplift for the day required to fund constrained on ancillary payments is determined at the end of the day after the net ancillary payments take any successive positive and negative ancillary payments into account.

Most uplift in the market today is related to surprise events, though in the past there have been periods where congestion has dominated uplift (e.g. in 2007 just prior to an expansion of the gas network's storage capabilities).

2.2.5 Potential Market Design Changes

The AEMC has conducted a review of the DWGM.[6] The AEMC proposes:

- Incorporating common and congestion uplift costs into the market price.
- Establishing a forward trading exchange to allow participants to adjust their contract position ahead of the market running.
- Improved trading arrangements for AMDQ.
- A review of the performance of the market in 2020.

The AEMC review is the first step in developing rule change proposals. It is not possible to predict whether or how the rules will change at this point in time. Improved trading arrangements for contracts and AMDQ are not likely to increase risks that participant face. While the form of the clean price is not obvious, the AEMC goal is also for that to improve risk management options for participants.

There are also reviews underway of broader market arrangements across the east coast. These are focused primarily on improving access to pipeline capacity through trading mechanisms.

Given that the proposed changes should in theory improve risk management, but may not be implemented for several years (if at all) we do not propose to consider these changes in this review.

2.2.6 Price Caps and Triggers

The current market price cap – VoLL – in the DWGM is $800/GJ

The current administered price cap is $40/GJ.

Under the Administered Pricing Procedures,[7] AEMO will impose the administered price cap if any one of the following applies:

- The market is suspended
- Material curtailment has been ordered
- Retailer of last resort (ROLR) provisions are active following the suspension of retailer.
- AEMO is unable to publish a market price or pricing schedule as a result of a software failure.

[6] Final Report: Review of the Victorian Declared Wholesale Gas Market, 30 June 2017.
[7] Wholesale Market Administered, Pricing Procedures (Victoria) v3, AEMO, 28 July 2017.

- The cumulative price threshold (CPT) is exceeded

The cumulative price threshold is $1,800/GJ. The cumulative price period is 35 consecutive scheduling intervals (with 5 schedules per day this would be 7 days if the first period was at a 6 AM schedule). The marginal clearing price, or MCP, used in forming the cumulative price threshold is the greater of the ex ante market price from the unconstrained pricing schedule and the highest priced injection offer scheduled (from the operational schedule). Thus, if for a schedule, the unconstrained market price was $3/GJ but $10/GJ for (say) LNG was scheduled in the operational schedule then MCP would be $10/GJ. The imposition of APC is not considered in the calculation of MCP.

If the sum of the MCP values for 35 successive schedules exceeds $1,800/GJ, then from the first schedule for which occurs the maximum price in the market will drop from VoLL ($800/GJ) to APC ($40/GJ) and will remain there until the end of the gas day following the gas day on which the cumulative price last dropped below CPT and for which no other trigger for APC exists.

It should be apparent that two intervals at VoLL (whether as a result of high market prices or the cost of constrained on gas) plus 33 intervals at an average price of just over $6/GJ would trigger CPT. If the VoLL events happen in schedules one and two and all other prices are sufficiently over $6/GJ to trigger CPT in schedule two then the administered price will remain until schedule 36 when schedule one is no longer with the cumulative price period. By contrast, if the average value of MCP were to exceed 1800/35 =$51.43/GJ then CPT would be triggered for all periods and APC would apply in all periods.

2.2.7 Drivers of Unmanageable Risk in the DWGM

Some of the major short-run unmanageable risk factors in the DWGM which could lead to a high MCP – either through the market clearing price or high cost constrained on resources - include:

- Production failure on high demand day
- Pipeline compressor failure limiting ability to move gas
- Very high demand, e.g. due to:
    - Extreme cold weather
    - High rate of gas export to support other markets in stressed situation.
    - High GPG demand (e.g. surprise event during the day).
- Low reserves of stored gas (e.g. LNG to support Melbourne)
- VoLL triggered by bidding behaviour at a system withdrawal point (e.g. failure to schedule supply to hedge that position and drive price to VoLL).

Each of these events could take more than two scheduling intervals to resolve so could produce cumulative prices that could trigger APC. For each event, the extent of the event will determine whether the situation can be addressed by dispatchable resources. Once dispatchable resources are exhausted, the market will be in an emergency situation, for which APC is likely to apply anyway, independent of the CPT trigger. Accordingly, our focus is on eventualities that can be addressed by dispatchable resources.

There are also longer-term risks – such as the ability to secure contracted gas and the general supply and demand situation of gas – that can vary the level of exposure created by events in the short-run.

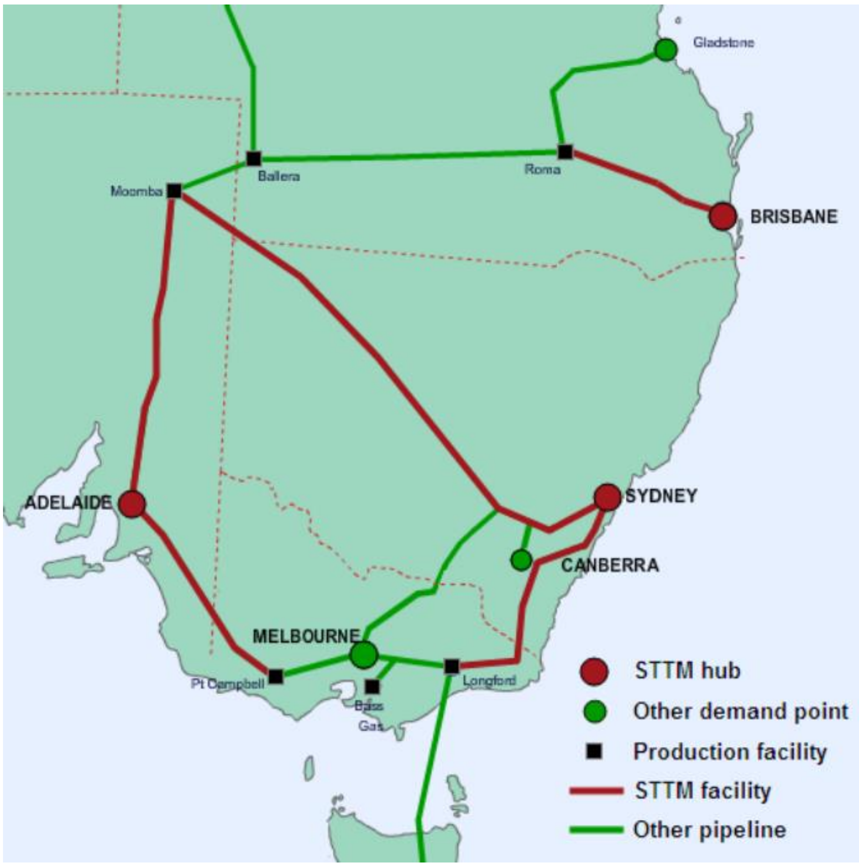
Specific scenarios under consideration for inclusion in this review are provided in Appendix B.

2.3 Short Term Trading Market (STTM)

2.3.1 The STTM Hubs and Industry Structure

The STTM includes three demand hubs – Adelaide, Brisbane and Sydney. Their location in the broader gas market is shown in Figure 3. The Wallumbilla gas supply hub, just to the east of Roma in Queensland, operates under different rules and is outside the scope of this review.

***Figure 3 – The three STTM supply and demand hubs*[8]**



Each of the three STTM hubs is a notional trading point between a distribution network and the delivery points of one or more transmission pipelines. Adelaide and Sydney are each served by two transmission pipelines while Brisbane is supplied by only one. Sydney also has one production facility and an LNG storage facility connected to the hub.

The demand within each hub is a mixture of residential, commercial, and industrial load. There is gas powered generation within the Brisbane and Sydney hubs and there is also GPG consumption on the transmission pipelines outside all hubs resulting in strong linkages with the electricity market.

The level of demand in the STTM hubs currently vary in the range of 40-100 TJ/day (Adelaide), 70-100 TJ/day (Brisbane), and 180 – 340 TJ/day (Sydney).

2.3.2 Supply and Demand Trends To 2025

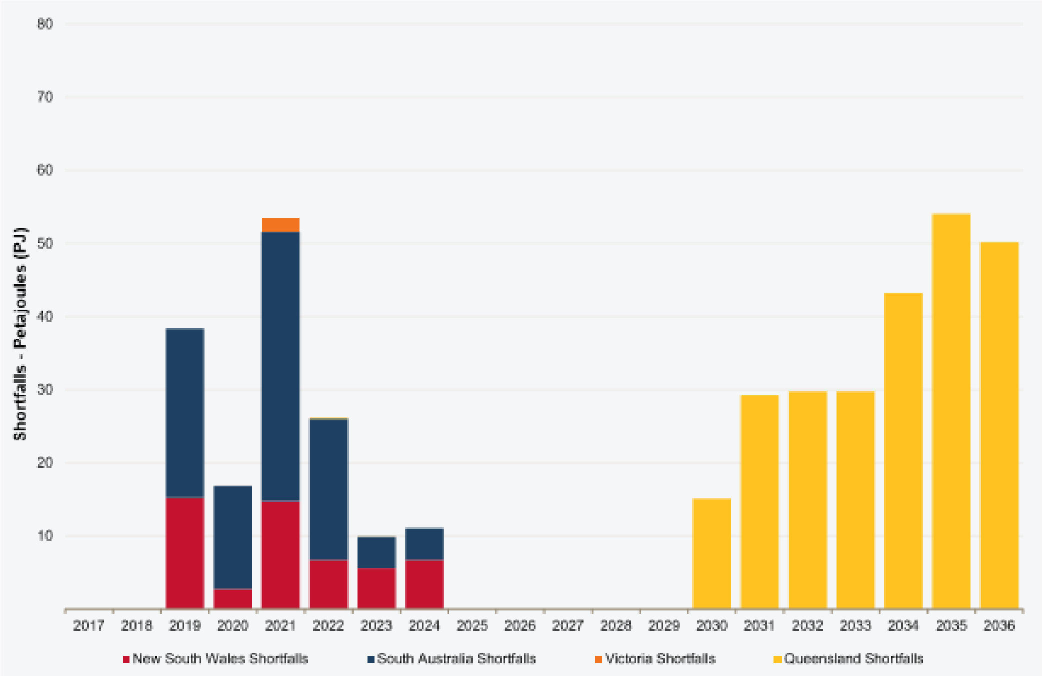
The discussion of trends in east coast gas supply and potential limitations on the DWGM to supply New South Wale and South Australia from 2021, as presented above, are very relevant to the STTM hubs. During the study period, it is possible that there will be periods where the supply options for STTM hubs will be limited, or at least will be expensive.

Figure 4 illustrates the projected gas shortfall on a regional basis as stated in the GSOO. From 2030, both pipeline and processing capacity is predicted to be insufficient to satisfy GPG demand in that region. This could be mitigated by the electricity industry moving away from gas or increased

[8] Overview of The Short Term Trading Market for Natural Gas, AEMO, 14 December 2011.

processing and pipeline capacity. While the extra capacity is required in inland Queensland, the Brisbane hub will be impacted by any shortfalls.

Figure 4 – Projected shortfalls in supply by region, 2017 - 2036[9]



The New South Wales and Adelaide situation shows similar trends and timings for those in the DWGM, and reflect the current state of projected near-term supply drop off. While the Adelaide and Sydney STTM hubs are only a component of demand in their respective states they will be impacted by any regional shortages and by limitations of the DWGM during the study period.

2.3.3 System Operation

The STTM hubs do not have a single system operator. Rather, each transmission pipeline operator is responsible for the operation of its pipeline while the distribution system operator manages its network.

Shippers source gas from contracts with producers (or buy from other markets such as the DWGM) and hold shipping contracts on the pipelines. These shipping contracts can be of different priority – e.g. firm or “as available”. A shipper without firm access may not be able to schedule gas on a pipeline if firm shippers are using it. Shippers must nominate to the pipeline operator the quantity of gas they want to flow on the pipeline to the hub under their contracts. This is influenced by the market processes discussed below. Within the distribution network the end consumers take delivery of shipped gas. While the STTM design assumes no constraints in the distribution network these can occur, limiting the ability of a gas to get to a customer.

Demand outside the hub – such as for gas powered generators – has the option to purchase gas from the hub and "back haul" it along a pipeline. Alternatively, they could have gas shipped to them via forward haulage on the pipeline without participating in the hub.

The STTM design includes the concept of Market Operator Service (MOS). Where the quantity of gas delivered on a pipeline differs from the pipeline schedule, the pipeline operator allocates this to shippers as MOS. The MOS providers have to pay the pipeline operator for this MOS service as well as replacing the gas that flowed. AEMO pays or charges the MOS provider for the MOS gas allocation on the gas day at the ex-ante market price for the gas day two days after the MOS gas flowed, which covers the cost of restoring its inventory of MOS gas. To procure replacement gas the MOS provider has the choice of trading it in the gas day two days after the MOS gas flowed (at no price risk but with quantity risk) or to run down its MOS gas allocation on the gas day.

[9] Reproduced from Figure 5 of the GSOO, AEMO, March 2017.

Pipelines operate in a flow control (constant flow) or pressure control (variable flow) mode. Where constraints occur in the distribution network then multiple pipelines, or multiple delivery points on the same pipeline, must operate in pressure control mode to ensure supply matches demand in different parts of the distribution network. This can result in increased MOS and decrease MOS occurring simultaneously on different pipelines in a hub.

2.3.4 Market Design

AEMO operates the STTM. To a large degree it can be thought of as an exchange which allows parties to trade gas with the actual scheduling of gas occurring through pipeline operator processes.

A day-ahead market determines a single daily quantity of gas for each shipper or user of gas. Shipper offers must be associated with shipper contracts they have on an STTM facility[10] or they may also bid on a transmission pipeline backhaul contract. Shipper offers at each hub must cover the cost of these arrangements. Users place priced or price taker bids for gas on distribution networks.

The facility operators must specify the capacity that they can deliver to the hub each day. This is a dynamic number as it depends on the level of demand upstream of the hub, which may not be known with certainty at the time the capacity is specified.

AEMO runs the market for each hub independently. The outcome of this market is a schedule for each shipper on each pipeline and for each user to take gas from the hub. An ex ante market price at the hub is determined, as well as a price on the capacity of each pipeline if the pipeline flows are at capacity.

Buyers and sellers of gas are settled at the ex-ante market price. The capacity price is not applied to ex ante trades – rather it is applied ex post to actual flows. Shipper with non-firm pipeline capacity pay the capacity price to firm shippers who did not get to flow gas.

The day-ahead schedules are used by shippers to nominate gas flows to pipeline operators under normal pipeline scheduling process under their contracts. There is no guarantee that they will necessarily secure that schedule on the pipeline.

On the day gas flows shippers are able to re-nominate increases or decreases under their contracts, or may trade with other shippers at a bilaterally determined price not seen by the market. Participants must notify AEMO of the volumes and counter parties for these bilateral trades via Market Schedule Variations (MSVs) if they are to be reflected correctly in STTM settlements. A small variation charge is imposed by the market on MSVs so as to encourage such trades to occur in the more transparent day-ahead market.

A contingency gas process also exists to handle events which could undermine the supply and demand situation in an STTM hub after the market has run. In situations where there is a trigger event, AEMO conducts a contingency gas conference to determine if additional gas flows are needed to manage the trigger event. Industry participants have an opportunity to accommodate the event triggering the conference but if required, AEMO can determine the need for contingency gas and can schedule contingency gas flows from offers submitted on the previous day and confirmed as available on the day. Offers can be either from pipelines or from sources (including demand side resources) in the hub. If contingency gas is scheduled then this also adjusts the positions of participants but is settled by AEMO at a contingency gas price.

The final schedule position of each participant is a function of its ex ante market position, any intraday re-nominations or trades (as reflected in MSVs) and any contingency gas schedules. In the event of a material involuntary curtailment of gas in a hub then those who consume less than scheduled will be settled at the ex-ante price, while those who consume more than scheduled will be settled at the Market Price Cap (or the Administered Price Cap if applicable).

To the extent that different volumes of gas actually flow on the pipeline, then the pipeline operators allocate these to MOS providers. AEMO tells the pipeline operators how to allocate MOS gas based on MOS offers provided to AEMO by competing MOS providers.

[10] A Shipper can bid on STTM facilities - pipeline, production facility and storage facility.

After the day, AEMO determines an ex post imbalance price which reflects what the price would have been given knowledge of actual deliveries to the hub.

- Deviations from the scheduled volumes of gas which improve the supply and demand situation (increased supply or decreased demand) are settled at a low deviation price based on the lesser of the ex post imbalance price, ex ante price, MOS costs for decreased flows, and the contingency gas price.
- Deviations from the scheduled volumes of gas which worsen the supply and demand situation (decreased supply or increased demand) are settled at high deviation price based on the greater of the ex post imbalance price, ex ante price, MOS costs for increased flows, and the contingency gas price.

To the extent that the market has any shortfall or surplus revenue over a billing period then surpluses are partly allocated back to those who funded deviations (subject to a $0.14 per GJ cap) while shortfalls and the balance of surpluses are recovered in proportion to withdrawals.

2.3.5 Potential Market Design Changes

We are not aware of any specific proposals that would materially change the design of the STTM hubs. As noted earlier, while there may be a number of reviews in progress on improving arrangements for accessing transmission pipeline capacity. We consider these reviews as unlikely to make the risk management situation worse and so do not propose to consider these changes in this review.

2.3.6 Price Caps and Triggers

The market price cap in the STTM is $400/GJ

The current administered price cap is $40/GJ.

The cumulative price threshold is 110% of the market price cap, or $440/GJ.

The CPT horizon is seven gas days.

The price to be accumulated is complex, as each day an ex ante price is determined for the next day, contingency gas prices may be determined for the current day, and deviation prices are determined for the prior day. Hence the new contribution to the cumulative price each day d is the sum of:

- The contribution of the (positive) ex ante price determined on day d *for day d+1*.
- The further (positive) increase in cost beyond the ex-ante price *for day d* determined on day d due to contingency gas scheduled in day d (5.5. hours into the gas day when the calculation is done[11]).
- The further (positive) increase in cost beyond the (positive) ex ante price fo*r day d-1* determined on day d-2 and the (positive) increase in that due to contingency gas *for day d-1* determined on d-1 due to the high deviation price (capped at the applicable market price cap) *for day d-1* determined on day d.

Each day, the cumulative price is formed by adding the term described above to the total and removing the corresponding term from 7 days prior from the total. In general, the prices used to accumulate prices are raw prices without the application of APC.[12] AEMO makes its determination of whether the CPT has been exceeded for a gas day during the prior gas day. It follows that APC will cease on the day following the last gas day for which CPT is exceeded.

For a period where no contingency gas occurs, the relevant price that gets accumulated is just the ex - ante price for tomorrow (d+1) plus the amount by which the (market price capped) high deviation price for yesterday (d-1) exceeds the ex-ante market price for that day.

[11] This is when the ex-ante price for the next day is determined.

[12] Exceptions apply if AEMO is unable to produce ex ante schedules or ex post prices in a timely manner, in which case the price used will be capped at APC.

2.3.7 Drivers of Unmanageable Risk in the STTM

Some of the major short-run unmanageable risk factors in the DWGM include:

- Production failure limits supply to the hub
- Pipeline compressor failure limits ability to move gas to the hub
- High GPG demand outside the hub reducing capacity to deliver to the hub
- Very high demand (including in broader gas market).
- Contingency gas scenarios resulting from the above risks

Each of these events could take more than two scheduling intervals to resolve. For each event, the extent of the event will determine whether the situation can be addressed by dispatchable resources. The multiple day nature of the STTM settlement processes also means that there may be linkages between gas days. For example, a MOS provider could be exposed to risks from the cost of replacing gas two days after a gas day.

As with the DWGM we focus these risks on situations which can be addressed by dispatchable resources without requiring involuntary curtailment (as such events will trigger APC anyway). Again, there are also longer-term risks that can vary the level of exposure created by events in the short-run.

Specific scenarios under consideration for inclusion in this review are provided in Appendix B.

2.4 Market Linkages

2.4.1 Linkages between DWGM, STTM and broader gas markets

The Adelaide and Sydney STTM hubs are connected via transmission pipelines to the DWGM and gas can be moved between these markets. Key considerations with these linkages are:

- The time frames for delivery mean that planned flows will tend to be driven by longer term (multiple day) issues rather than quick reactions to within day events.
- Multiple day issues could be relevant during the study period given concerns about the east coast gas supply and demand situation.
- When moving gas between the DWGM and an STTM hub the gas must be scheduled in each market as well as on the transmission pipeline connecting them, meaning that failure to get gas scheduled in one market can have flow-on costs and risks. Any mismatch in what is scheduled could leave a participant or shipper in the situation where it over-supplies in one market or one pipeline while under-supplying on another, effectively leaving it exposed to imbalance costs in each which are unlikely to offset each other.

Another consideration is that gas flows between markets may not always be driven purely by markets. In emergency events that span states the National Gas Emergency Response Advisory Committee (NGERAC) may become involved. NGERAC comprises officials from Commonwealth, state and territory governments, and representatives of AEMO, gas industry sectors and gas users. The Committee's responsibilities include ensuring consistent management of natural gas supply disruptions across jurisdictions and advising jurisdictions on responses to multi-jurisdictional natural gas supply shortages.

Conceptually, the linkages between gas markets can be simplified from a modelling perspective by focusing on each market individually but considering a range of import and export scenarios for each market.

2.4.2 Linkages with the National Electricity Market

Gas powered generation creates a link between the National Electricity Market (NEM) and the broader gas markets, including the STTM and DWGM. As demand from gas powered generation in the NEM goes up:

- Demand for gas in the DWGM and those STTM hubs with gas powered generation increases.
- Gas powered generation outside of STTM hubs can impact the quantity of gas that can be supplied to the hub.

- Purchase of gas in the STTM for backhaul to gas powered generators can increase the effective demand in a hub.
- Where NEM prices cause gas powered generation to come on at short notice, there is a risk that the market has inadequate linepack available to serve that generation.

There are also economic links between the markets. Generally, gas powered generators will only operate when the ratio of the electricity price to the gas price exceeds the heat rate of the gas powered generator (i.e. the rate at which it can convert gas to electricity). If gas prices are high due to some disruption in the gas market then electricity prices must be high in order to justify gas powered generation (ignoring any contractual considerations).

2.4.3 Risk Management in Gas and Electricity

There is divergence between the gas and the electricity markets when it comes to managing risk. Hedging in the NEM is predominately via financial instruments linked to market price. Markets exist for the trade of these hedging instruments and they are readily available. On the other hand, hedging in the gas industry is more physical, being linked to holding contracts with producers and with pipeline operators. While markets such as the DWGM and STTM facilitate trading around a contract position, the underlying contract is much less freely available. Securing a firm contract may entail making a very long-term financial commitment (multiple years) to pipeline operators and producers. While "as available" contracts can be procured at lower cost, these offer little benefit to the holder at times of peak flow on pipelines as holders of firm capacity are supplied first. Consequently, the risk of a participant wanting to consume gas being unable to secure a contract based hedge is greater in the gas industry than in the NEM.

The levels of aggregate contract coverage by participants in gas and electricity is similar. However, small players – such as new entrant retailers – will tend to have a lower level of contract coverage than in the electricity market.

During extended periods of system stress in the electricity industry, contract prices will tend to be high, though contracts will still tend to be available to protect against even more extreme events. In gas, meanwhile, a participant might have to secure capacity from others who already hold it, and there are potential barriers to such transactions due to a lack of a transparent market for pipeline access.

2.4.4 Implications of Linkages to Risks in Other Markets.

Short-run risks that arise between markets include:

- Gas supply disruptions in the broader gas markets exogenous to the markets under study causing increased competition for gas that would normally supply the STTM or DWGM. This could give rise to higher than usual flows between these markets.
- High electricity prices for a sustained period requiring long term running of gas powered generation at higher utilisation than normal.
- There may be coincident and cascading linked events across markets. E.g. an electricity shortfall in Adelaide might cause high gas prices in the Adelaide STTM hub, with this supplied from the DWGM causing high gas prices in the DWGM which in turn trigger a high electricity price event in the broader NEM.

Specific scenarios under consideration for inclusion in this review are provided in Appendix B.

3 ROLE AND BOUNDS OF GAS MARKET PARAMETERS

3.1 Introduction

It is important to appreciate the relationship between the maximum price in a market – such as VoLL in the DWGM and MPC in the STTM and administered pricing arrangements. This section provides an overview of the roles of the various gas market parameters and the important considerations in setting their values.

3.2 The Maximum Market Price (MPC/VoLL)

VoLL in the DWGM and MPC in the STTM are the maximum market prices in those markets. The maximum market price represents the price at which the market – as a matter of policy – is prepared to accept that it is not willing to pay more to supply demand. It should be set at a level high enough:

- To allow the market to clear in the short run, whether this be through demand response, redirecting supply from one use to another, or for additional high cost supply to come into the market on a short-term basis; and
- Encourage investment in capacity over time to support the ability for the market to clear.

It is common to try and justify the maximum market price based on some economic consideration of the "optimal" amount of peaking capacity in a long-run equilibrium. That is, over the long term the investment and operating costs of the gas system are perfectly aligned with the value of delivered gas. However, a long-run equilibrium view assumes perfect planning and will tend to imply lower prices in situations where the market is in disequilibrium – as most real markets are most of the time. In effect, a maximum market price based on an optimal long run equilibrium may actually cap prices at a level too low to allow a market to respond to situations arising from imperfections in forecasting, planning or investment.

It is appropriate to review the maximum market price from time to time to assure that it is high enough to accomplish its principal objectives but not so high as to cause other problems that are not best dealt with directly. It should be a stable market parameter that is not changed, and particularly not lowered, without a compelling argument that the current value is causing problems that are not best dealt with some other way. In particular, the maximum market price should not be lowered primarily because an inherently uncertain engineering/economic calculation suggests that a lower value might support a hypothetical long-run market equilibrium.

The view taken in this review is that the maximum market price should be high enough as not to interfere with the operation of markets.

The risks of extended periods of high prices should be managed with policies such as the administered price cap (APC) and cumulative price threshold (CPT), and other problems – such as market power for example - should be attacked directly by modifications in the market design or regulatory arrangements.

3.3 The Cumulative Price Threshold (CPT)

A cumulative price threshold (CPT) serves to limit the total amount of revenue suppliers in a market should be able to earn over a cumulative price period before an Administered Price Cap is imposed. The normal logic is to set CPT at level such that investors in peaking capacity can recover enough revenue to justify the investment prior to APC being applied. The cumulative price period is essentially seven days in both the DWGM and the STTM and the review of that value is outside the scope of this review. In theory if there were multiple CPT events a year then it would not be necessary for owners of peaking capacity to recover all of their costs in one cumulative price period. However, given that no CPT event has ever occurred in either the DWGM or STTM we will assume that investment costs must be recovered during a single a cumulative price period.

At $1,800/GJ the CPT in the DWGM would allow up to two schedules priced at the VoLL of $800/GJ within a cumulative price period but not three. At $440/GJ the CPT in the STTM would allow only one schedule at the MPC of $400/GJ but not two.

3.4 The Administered Price Cap

Once the CPT triggers APC then it can be assumed that investors have recovered an adequate return on their investment. APC is intended to be a price cap that – to a great extent – allows trade based on short run costs to continue while limiting profits on peaking capacity. This acts to limit the financial risk of consumers. The imposition of APC may require some interventions to ensure that supply and demand clear when APC is lower than the natural price that the market would otherwise clear at.

3.5 The Bounds on Parameter Settings

Here we summarise the logical bounds on the gas market parameters to be considered in this review.

- The maximum market price (VoLL or MPC) should be set at level no less than that which the market could be expected to clear at without requiring involuntary curtailment.
- The maximum market price (VoLL or MPC) should not be an impediment to efficient investment, but should not be so tightly defined by that criteria as to restrict investment to mitigate deficiencies in planning or forecasting.
- CPT should be set to a level that would allow reasonable opportunity to recover peak capacity investment costs over the cumulative pricing period (and allowing for revenues earned under normal market operation and subsequently under APC).
- APC should not be set so low as to remove the need for prudent risk management by the demand side.
- APC should not be set so low as to exacerbate issues by having supply withdrawn from the gas market or creating bigger issues in other markets (e.g. due to APC being too low for GPGs to be able to source gas).

In addition, the gas market parameters applied in the STTM and in the DGWM should avoid, where possible, inefficient outcomes between those markets or with the NEM and the broader gas market.

4 THE PARAMETER ASSESSMENT PROBLEM DEFINED

4.1 Introduction

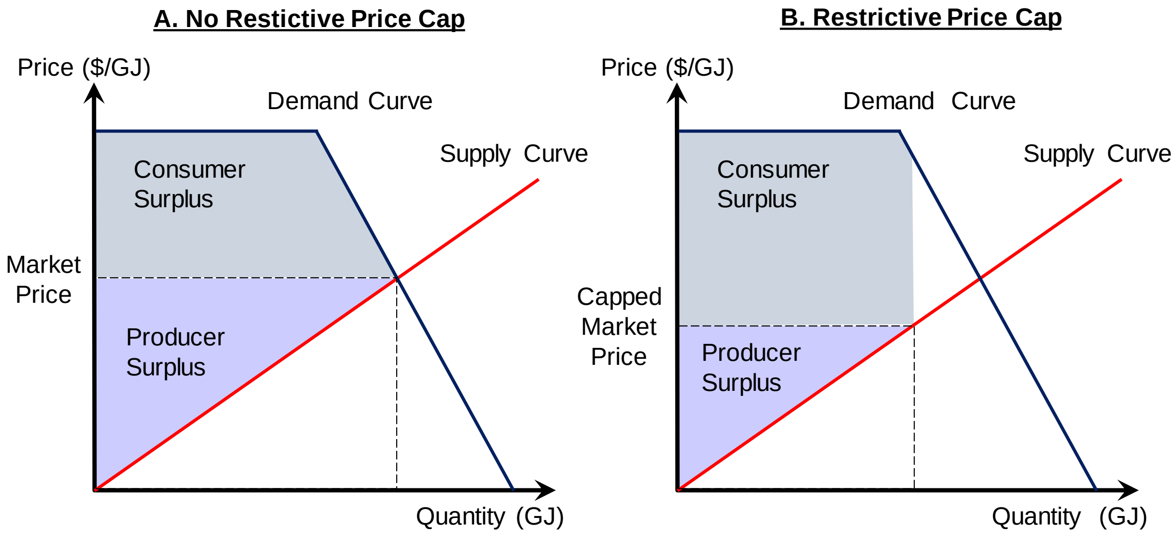
This section provides a summary of the problem that must be solved to test alternative parameter settings and provides the rationale for it. A parameter setting includes a value for VoLL or MPC, as applicable, a value for the CPT and a value for the APC.

4.2 Efficiency vs Market Risk

The core objective is to explore the trade-off between market efficiency and market risk. The primary measure of market efficiency is the sum of consumer and producer surplus.

Figure 5 illustrates the concept of market efficiency and the impact that price caps can have on it.

Figure 5 – Market efficiency, consumer and producer surplus, and the impact of price caps



Consumer surplus is the amount by which the total benefit consumers receive from gas exceeds what they must pay for it. Producer surplus reflects the total amount by which payments to suppliers exceed their costs. [13] Case A in Figure 5 shows a situation where the market clears without being restricted by a price cap. The market price is set at the point where the supply and demand curves cross. This is the point at which the sum of consumer surplus and producer surplus is maximised.

Case B illustrates the impact of capping the market price for the case where the market wants to clear at a point above the price cap. Suppliers have little incentive to supply gas which costs more to deliver than the capped market price allows or on which they cannot earn a profit[14], so the total quantity of gas made available may be restricted. While the consumers actually supplied benefit from a lower price, the reduced gas supply means that the sum of consumer and producer surplus is reduced. The efficiency of the market is reduced. Less restrictive applications of price caps will alleviate this problem and improve total economic surplus.

[13] Once involuntary curtailment occurs APC will apply anyway. Consequently, this assessment is limited to situations where involuntary curtailment is not required. As uncontrollable withdrawal will be unchanging with price, but the impact of varying price caps applied to uncontrollable withdrawals will dominate consumer surplus, we propose to exclude the fixed amount of uncontrollable withdrawals from the consumer surplus calculation. However, we will track any involuntary curtailment that occurs in our simulations as that will indicate that the situation represented by the scenario is too extreme.

[14] Under administered pricing the gas markets do offer cost-based compensation for suppliers scheduled with costs higher than APC. However, suppliers are not guaranteed to have their costs compensated fully and may prefer to move the gas to other markets or to other days (where they can get a profit). Suppliers also may not want to reveal their costs. In this study we assume that supply is withdrawn from the market.

Case B illustrates the impact of capping the market price for the case where the market wants to clear at a point above the price cap. The diagrams show suppliers withdrawing from the market due to the price caps.

On the other hand, less restrictive gas market parameters increase the risk exposure of participants in the market to the extent they are exposed to the market price. Exposed participants are required to buy expensive gas to either fulfil their obligations to retail gas consumers, or support their own industrial or commercial use of gas.

The measure of market risk of a firm (or participant) used in this study is the number of days it would take a firm of different sizes to recover the total lost profit from an event. It is defined as the ratio of the profit lost and the average daily profit, as defined by the total annual profit of the participant divided by 500 days, or:

$$\text{Days Lost Profit} = \frac{\text{Profit Lost}}{\text{Average Daily Profit}}$$

Each participant is assumed to consume an average of 1 TJ per day. For gas retailers, the application of an average price and a typical gas retail margin enables calculation of the average daily profit. For industrial users, the implications associated with the use of 1 TJ of gas are more complex. Using available ABS statistics, we can estimate the intensity of energy use by industry grouping, calculate the revenue associated with that gas use and determine the average daily profit. The calculation of lost profit is slightly more complicated. For each participant type the same calculation method applies in determining the profit from the base case and the profit available in the scenario case, except that the quantity and price in each case will be different according to the context/scenario. As a result, each of these profit estimates will differ from the average daily profit and each other.

In previous reviews of gas market parameters, the loss of more than 500 days' worth of profit as a result of an extreme pricing event was taken to represent the point where the risk exposure of a participant becomes unacceptable, creating the potential for participant insolvency. The same threshold is proposed for use in this study. This standard applies to all participants equally[15]. Some participants, such as industrial users, face a different risk relative to retailers when curtailment occurs, however the evaluation of curtailment costs is beyond the scope of this report. Therefore, the risk for all participants is the risk of obtaining potentially inflated quantities of gas, but at a greatly inflated price.

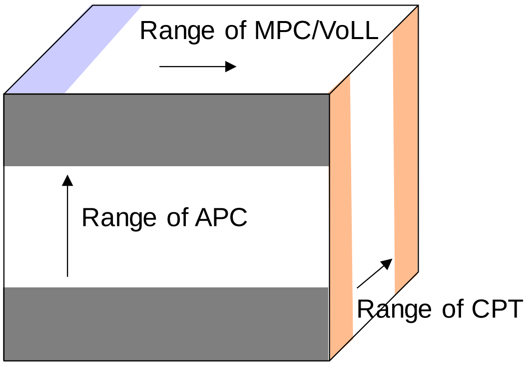
Question1: Do you have any comments on the appropriateness of the calculation of acceptable risk?

4.3 The Grid of Gas Market Parameters

Our methodology requires the assessment of both market efficiency and risk exposures for different gas market parameters. As we will only be considering discrete combinations of gas market parameters we refer to the set of considered gas market parameters as a forming a grid of gas market parameters. This grid, including the limits imposed by bounds, is illustrated in Figure 6.

[15] There are differences in balance sheet structure between the many participants in the gas market that may lead to different conclusions about the level of loss that could be sustained by each participant type.

Figure 6 – The grid of gas market parameters



For each parameter and combination of gas market parameters, the minimum and maximum value parameters in the grid are defined by the economic and logical bounds described in Section 3.5. Within the set of considered parameters we will include the current settings for each of the STTM and the DWGM[16]. It will be necessary to also consider sets of parameters with no CPT or APC applied for a given VoLL/MPC to provide a reference case of a market with no administered pricing and hence the maximum market efficiency achievable.

4.4 Assessing Gas Market Parameters

The performance of a given set of gas market parameters can be determined by simulating those gas market parameters across a range of situations. In each case the level of relative market efficiency and the degree to which risk exposures for a range of participant types can be assessed. By varying the key setting in the scenarios, the sensitivity of each parameter setting can be assessed.

A strongly performing set of gas market parameters would consistently produce higher market efficiency in different situations while maintaining an acceptable risk exposure for all represented participant types. If a set of gas market parameters were to perform very well in some cases but very poorly if the scenario was slightly change under a sensitivity analysis then that would make that parameter setting less attractive. If the current gas market parameters are found to be in the strongly performing set of possibilities that would suggest no need to change them. However, if the current gas market parameters perform noticeably less well than others than that would suggest grounds for change.

The proposed methodology for solving this problem is described in the next section.

[16] And to keep consistency between the markets in the modelling we will include the case where each market is simulated with the current parameters of the other.

5 PROPOSED SOLUTION METHODOLOGY

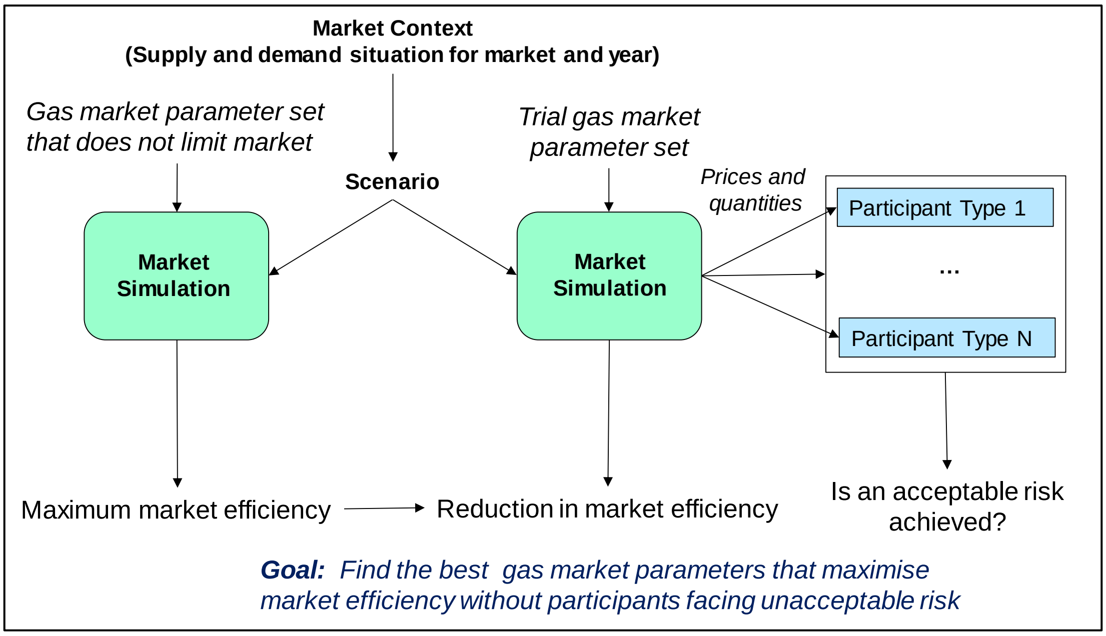
5.1 Introduction

The previous section described the structure of the parameter assessment problem. This section describes how it is proposed to solve that problem.

5.2 Overview of the Methodology and Model

Figure 7 provides an overview of the solution methodology for the parameter assessment problem defined in Section 4.

Figure 7 – Overview of the Methodology



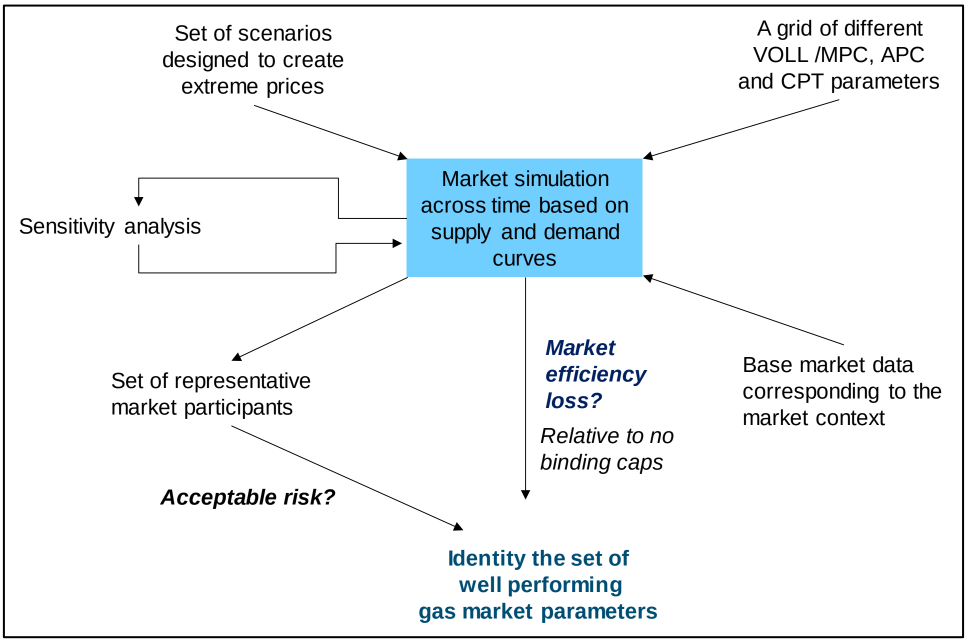
The key concepts in Figure 7 are:

- A market context describes a specific market, in a specific year with some specific supply and demand conditions. For example, this could be the DWGM in 2021 with the supply and demand figures as forecast by the Victorian Gas Planning Report.
- A scenario represents a specific event that happens in that a market – such as production problem or some the impact that a broader gas market issue has on the market under study.
- The range of gas market parameters from the grid of parameters includes:
    - A set of parameters that does not limit the market. This set will have different values of VoLL/MPC but no administered price cap will apply. This will correspond to the maximum market efficiency case, though the risks for participants may not be acceptable.
    - A broader range of alternative parameters with different levels of CPT and APC for a given setting of VoLL/MPC.
- By simulating the market context across the event represented in the scenario, and for enough time to work through the flow on effects of the cumulative pricing period, we can assess the market efficiency and participant risk exposures for the different parameter sets.
- For a given VoLL/MPC the set of gas market parameters that does not limit market efficiency will be used as a reference point to determine the loss in market efficiency for each parameter set with the same VoLL/MPC but with APC and CPT imposed.

- For each occurrence of APC, two variations of participant behaviour will be considered. One variation will be a "truncated variation" with market response modified to reflect the lack of willingness to offer into a capped market when cost is above the cap. The second variation is a "no-response" variation in which supply and demand curves are unchanged by the imposition of the APC.
- This analysis will also allow indicate if VoLL/MPC values are too low and interfering with the short run market.
- Given the parameters, and the resulting prices and quantities, we can assess the risk exposure for a range of hypothetical representative participants. This will be assessed relative to an estimate of their profits derived by simulating the market context without the scenario occurring (not shown).
- The goal is to find those parameter settings which perform best in terms of minimising the reduction in market efficiency while maintaining acceptable risk.

A range of different modelling components will be used to implement this methodology these are shown in Figure 8.

Figure 8 – Modelling components.



The key components are:

- The market context
- The scenarios
- The market simulation
- The representative market participants
- The sensitivity analysis
- The calculation of market efficiency loss
- The calculation of the acceptable risk

These components are described in the remainder of this section. We also discuss the relationship between investment and the bounds on the gas market parameters.

5.3 Market Context

The DWGM and STTM hubs during the study period will be different from today and will evolve across time. For this reason, it is necessary to recognise in this review that the markets will be in different states at different times. This concept is reflected in the market context.

It is important to simulate a market in different market contexts so as to ensure that the results of the review are robust for these different contexts.

A market context of a given market will created by starting with the current market and evolving it based on forecast change in the market. The simulations will be based on daily supply and demand curves so the practical realisation of market context is that that the shape, extent and prices in the supply and demand curves will change, reflecting:

- Underlying demand;
- Available supply capacities;
- Prevailing import and export levels;
- Injection and storage limits; and
- Levels of contracting (which will essentially be defined by the above considerations).

Each market context, without any extreme events occurring, will be simulated to provide a base reference point for what the profits of participants would be normally. This will be contrasted with cases where extreme events are imposed on the market context, in the form of the scenarios described in the next section.

5.4 Scenarios

Scenarios describe a sequence of days including some extreme event days that we anticipate will result in extreme pricing, such that MPC/VoLL may be achieved and/or APC triggered. A scenario will effectively be represented by a different set of market supply and demand curves from those that would normally apply. These will form input to the market simulation. During the simulation of the market these supply and demand curves may be further modified if APC applies.

The reference point for assessing the impact of a scenario will be a simulation of the base market context without any scenario imposed. This base market context simulation will allow the profitability of different participant types to be assessed. This will inform the analysis of acceptable risk.

Scenarios are defined relative to a specific market context – this allows the DWGM and all of the STTM hubs to be separately represented in event situations that are more tuned to the context of that market. The scenarios proposed to be explored are presented in Appendix B.

The first day of a scenario will be an event day. Prior to this it will be assumed that no administered price cap has been in place and that normal base market context conditions have prevailed. This will allow the CPT calculation to be initialised with data.

Two sets of day types will be considered within the period of the scenario.

- Generic base market context days. These will have normal base supply and demand curves. However, if APC is triggered then in the truncated variation of the simulation these curves will be modified to reflect the withdrawal of supply and demand response that is dependent on a price exceeding APC.
- Event days directly impacted by an event, e.g. reduced supply from a production facility or very high exports. For these days, the supply and demand curve will be modified to reflect the event and any market response that may occur. If an event lasts multiple days such that the administered price cap applies then within the simulation further modifications may be applied to account for the withdrawal of supply and demand response in the truncated variation.

A scenario will involve a mixture of these days.

Question 2: A range of scenarios to be studied are listed in Appendix B. Do you think any major scenarios are missing, or that any scenarios proposed are not relevant?

5.5 Market Simulation

The market simulation will comprise a model that determines schedules and prices given a daily supply and demand curve that reflects what can be delivered or withdrawn from the market on that day.

A similar simulation model will be used for both DWGM and STTM. Each market schedule will simply reflect a supply and demand curve.

A schedule produced by the model can represent a start of day or intraday schedule in the DWGM or a day-ahead, intraday (e.g. contingency gas, or ex post schedule) for an STTM hub. The MOS price can be based on deviations in the ex post schedule.

An event could occur at any schedule.

It is not proposed to explicitly model different conditions for every schedule across the day. Rather, *normally* no more than two schedules will be explicitly represented. One will the first schedule of the sequence (the ex-ante market in the STTM or the start of day scheduled in the DWGM) and this will by default be duplicated at each schedule for the entire day. This first schedule could be an event or a normal schedule. If the situation changes during the day – either an event ends or starts – then a second scheduled will apply for the remainder of the day. Thus, a surprise weather event in the DWGM could be represented as a normal schedule for the 6 AM, 10 AM and 2 PM schedules, then an event schedule – with increased demand but with no additional supply available from supplies distant from Melbourne.

The price for each schedule will be added to the cumulative price. An exception arises in the running of schedules if APC triggered. Once APC is applied during the gas day then in the truncated variation the base bids and offers applicable will be modified to account for withdrawal of supply and demand response due to the application of APC. This can lead to a third schedule type.

The supply and demand curves will be generated by combining bids and offers associated with different segments of the market.

The demand curve will be formed from bids for:

- Uncontrollable withdrawal (i.e. price taker demand) excluding GPG demand. This will be apportioned into industrial/commercial and domestic load;
- Gas powered generation demand (with a maximum price linked to what would be viable in the NEM);
- Exports;
- Contingency gas (in the STTM)
- Price sensitive load (including contingency gas). Where appropriate this will also be apportioned into industrial/commercial and domestic load.

The supply curve will be formed from offers for:

- Production facilities;
- Storage facilities (varying with the current level of storage);
- contingency gas (in the STTM);
- Imports

In the STTM, MOS curves will also be used to derive deviation prices.

There is assumed to be no net linepack change between the start and end of each schedule. The STTM hubs have little useable linepack. For the DWGM modelling of linepack has been dismissed because of the lack of locational and inter-temporal modelling within the day and there is no obvious basis for defining bids for linepack – in the real market it is scheduled to be at the same minimum level each day and this cannot be violated.

Each bid and offer from which the demand and supply curves are formed will in the first instance be based on current market data (see Section 7). In the STTM offers will be truncated at the hub capacity, while in the DWGM they will be limited based on pipeline point constraints that restrict the total volume deliverable over a day.

Export bids, GPG bids and import offers will be increased or decreased as required by the broader gas and electricity market context as required by scenario.

The level of hedging also has to be accounted for. Participants that are both suppliers and consumers tend to offer low (mostly near $0/GJ) and bid high (rising to near MPC/VoLL) to ensure that their supply is matched with their demand (though in practice the demand curve is not that price responsive). If that result is achieved then the participant has no exposure to the market price on the matched volume. The same effect can be achieved by independent participants who achieve that effect through contracting. Offer curves (and to the extent relevant, demand curves) can be modified into the future to maintain their general shape relative to the prevailing contract volume and expected gas market price.

The number of simulations run will be extensive – it will be necessary to run simulations for combinations of market context and scenarios, different gas market parameters, and for sensitivities. While this will generate a significant volume of data the execution should not be long as simulating a single market context and scenario is expected to take only a small fraction of a second. It is expected that many of the cases run will produce solutions that are far from acceptable in terms of risk or market efficiency, or will fail to be able to avoid more extreme involuntary curtailment events, so the number of options that are serious candidates will not be excessive.

5.6 Representative Market Participants

We will not specifically simulate individual participants within the market simulation. Instead we focus on the settlement outcomes of the market results for generic representative market participants from those consumers likely to have material risk exposure. For each participant we assume a level of market exposure aligned with the nature of the participant and the degree the overall market is long or short.

The participant types considered will include:

- A small market customer (who purchases directly from the wholesale market) who may have a less sophisticated approach to risk management than a retailer.
- A small gas retailer which due to its size can have disproportionately large imbalances and deviations;
- A medium sized gas and electricity retailer who could be impacted by events in both the NEM and the gas industry; and
- A gas powered generator;

Each generic participant type will have different behaviours in the spot market. For example, a GPG will be represented as bidding in the gas market to secure gas at a price consistent with economic operation in the electricity market and will operate whenever it can secure gas and profit from it. By contrast, small retailers will effectively be price takers in the gas market. Data for participant type will remain fixed with respect to the market context, with the exception of an adjustment to account for changes in contracting costs resulting from changes in the overall balance of supply and demand.

The level of contracting held by a participant of a specific type will be assumed fixed across all cases, though a number of different levels of contracting may be considered to give a range of results.

The CPT load factor employed in previous studies to evaluate the increase in demand during a CPT event is no longer a static feature of the market participant, and instead is determined by growth in the applicable demand category as defined by the scenario. To account for the influence on participant profitability of the incidence of growth in various demand components, each participant will have its demand apportioned between each demand category so, for example, a small retailer with a high percentage of domestic consumers will face increase in price and quantity on a very cold day, whereas an industrial user will only face price increases.

5.7 Sensitivity Analysis

Sensitivity analysis will be conducted to assess how much the results of the simulation change for a change in the inputs. We focus on simple changes around varying fixed demand and varying supply costs as these variations explore the region around the standard solution. The suggested sensitivity factors are described below, though the indicated percentages may need to be refined based on experience with the model:

- An increase in uncontrollable demand of [1%]. This reflects a tighter supply and demand situation.
- A decrease in uncontrollable demand of [1%]. This reflects a more relaxed supply and demand situation.
- An increase in all supply curve prices of [3%] but with no change in quantity. This reflects a high cost structure. The increases would be capped at the applicable price cap.
- A decrease in all supply curve prices of [3%] but with no change in quantity. This reflects a lower cost structure.

5.8 Calculating Market Efficiency Loss

The ideal measure of market efficiency would be based on the true costs and benefits of participants in the market. Actual bid and offer curves reflect that the market participants are trading relative to a contract or hedge position. It can be argued, however, that bids and offers formed relative to a contract position are a valid measure of participant costs and benefits simply because by submitting those bids and offers they are indicating what they would require to be paid or would be prepared to pay at the volumes associated with those bids and offers. The bids and offers effectively internalise all the costs and benefits associated with contract costs and hedging, making them more representative of the full range of costs and benefits applicable to a participant.

There are limits to this argument. The demand curve is by definition limited to VoLL/MPC. Some participants if allowed may bid at a higher price. Also, strategic behaviour could be reflected in bids and offers, distorting them. These effects may not be that significant in practice.

While individual solutions may contain inaccuracies through the use of market based bids and offers, these inaccuracies are common to all cases so the effect should be minimised given that the analysis is based on the difference between surpluses.

The market efficiency for each simulation solution will be taken as the area under the demand curve relative to the demand cleared less the area under the supply curve utilised. The market efficiency loss for a case will just be the difference in the market efficiency between it and a reference case which is identical except that no administered price cap was applied. An alternative measure of market efficiency loss can be determined by comparing market efficiency between cases with the same APC and CPT settings but different VoLL/MPC values. This will give insights into the impact of different VOLL/MPC values.

One special consideration is that uncontrollable withdrawal is conventionally priced at VoLL / MPC. For the purpose of assessing market efficiency we cannot just apply different VoLL / MPC values to the uncontrollable withdrawal as this will provide staggering changes in market surplus without demand changing. To mitigate this effect, we will assume a common value of uncontrollable demand across all cases. Further, as the involuntary curtailment of load will automatically trigger an administered pricing state we will identify any simulation outcome for which involuntary curtailment occurs and will simply exclude such outcomes from our analysis.[17]

5.9 Calculation of Acceptable Risk

The calculation of lost profit resulting from a scenario is measured by deducting the profit earned in a particular market context, from the profit that would have been earned absent the event. This portion of the calculation preserves factors related to the context of the scenario such as the season, for

[17] Though attempts will be made to tune the scenarios to avoid such outcomes.

example. This ensures that the amount of lost profit is assessed against the appropriate norm, and not a generic day.

Average normal daily profit is defined is an annual average of profitability, which varies between participants and industries. For example, large end-users of gas who are buying gas directly from the market have inherently different margins and cost structures than gas retailers.

Unlike for the calculation of lost profit, the average daily profit is not dependent on the seasonality or timing of a scenario, and an average measure is appropriate. For the purposes of this calculation it is also important to take an industry-wide and long-run perspective. This implicitly assumes that participant returns are close to long-run averages but to not do so will result in significantly different (and even nonsensical) parameter settings to restrict losses to a year's profit when profits are low (or negative).

In the previous CPT review[18], the acceptable level of risk was defined as 500 days lost profit. Although other factors are no doubt relevant, we assume that defining acceptable risk in this fashion is suitable for other market participants such as large commercial/industrial users.

5.10 Investment and the Grid of Gas Market Parameters

The incentivisation of investment is an important consideration when implementing price caps and often these models adopt a long run equilibrium analysis in which investment is part of the solution of the model. Section 3.2 explains the limitation of using long run equilibrium analysis and argues that VoLL and MPC must necessarily by higher than the values implied by such limits.

Here we focus on the investment cost relative to CPT. CPT should provide some ability to recover investment costs before the imposition of APC.

The normal process for estimating investment costs reflect consideration of the cost of constructing additional capacity, allowing for a required rate of return for similar investments. The analysis must reflect the full cost of investment as economies of scales mean that costs change with investment size.

We do not propose to explicitly model or calculate investment costs due to the complexity of this. Rather we propose instead to adopt an approach similar to that employed in other reviews:

- Using investment costs, required rates of return and an assumed event frequency such as the 1:10 years frequency adopted in previous studies, estimate the investment return that is required per event.
- Given the fixed and variable cost structure, and assumed utilisation, the profit requirement can be transformed into a revenue requirement that relates directly to prices and price caps.
- Use the revenue requirement as a lower bound on CPT to ensure investment is economically viable.

It should be noted that the use of CPT as a bound is only an approximation. The profit available in an event may be greater or less than the CPT, and is influenced by all three parameters under consideration. If a participant has a cost structure that allows significant profits while under APC then they may earn more than the CPT in each event. However, if APC is calibrated correctly, then there will be little opportunity for profit after Administered Pricing is activated and the CPT closely approximates the maximum amount of profit available in a single event.

In AEMO's 2013 review of CPT in the DWGM, a CPT value of approximately $800 was identified as being sufficient for these purposes. Adjusting the cost estimates to present day dollars, and adopting required rates of return within the 10%-15% range suggests a lower bound on CPT in the order of $1000, well below the current setting for CPT in the DWGM. In the last review of STTM parameters, conducted in 2012, AEMO did not perform a similar analysis for the STTM CPT setting, which is only $440. The STTM hubs are not directly comparable to the DWGM due to their different context. The original analysis of STTM settings[19] suggested that the lower MPC (and hence CPT) would not at that time be detrimental to investment in the context of the STTM. While our study will include the current STTM settings within the range of gas market parameter settings, during the course of the

[18] DWGM CPT Review, AEMO, 2013.
[19] STTM Market Settings Analysis, MMA, 2009.

review an assessment will be made of whether the current STTM parameters are still above a threshold for investment.

Question 3: Are there any artefacts of the modelling approach that need to be further considered or are causing concern?

6 COMPARISON WITH PREVIOUS STUDIES

6.1 Similarities with Previous Studies

There are many similarities between the methodology of this study and previous studies, particularly the most recent study[20], although the similarities tend to be high level rather than in detail. The overall philosophy of this review is aligned with prior reviews as is the requirement for revenue sufficiency for peaking investment and the limitation of risks on market participants.

The initial review of the DWGM gas market parameters[21] adopted as its objective the minimisation of risk subject to maintaining investment incentives. In subsequent reviews the objective was moved to provide maximum market efficiency subject to controlling unmanageable risk (and maintaining effective investment incentivisation). The bounds that guide the selection of the appropriate parameters in this study is aligned with the conventions of those subsequent reviews, though the modelling methodology differs.

Features of the proposed analysis which align with prior reviews include:

- Avoidance of gas market parameters that encroach upon the profitability of peaking investment to the extent that such investment is no longer capable of cost recovery.
- The use of models of participant risk exposure during events to assess appropriateness of risk exposure, although it is extended somewhat to consider non-retailer participants
- The inclusion in those models of recognition of the different customer bases and the impact this may have on quantity demanded during events

6.2 Differences from Previous Studies

The single biggest difference in approach is the underlying definition of scenarios. Previous studies have exclusively focused on an outcome based approach, which entails scenarios that are defined by specific outcome, like five days of application of APC, without considering the cause or the market machinations behind the scenario. By contrast the approach proposed for this review explicitly simulates periods in the future and extreme events that might occur. While more intensive, this modelling approach has the following advantages:

- It forces recognition that extreme events occur in different market contexts when the intrinsic supply and demand situations of a market may differ. This gives visibility of how the relative market efficiency and risk exposures change across the study period. Prior studies implicitly assume a static system throughout the study period,
- Given the infrequency of extreme events, it is impossible to tell if an outcome based result reflects a credible or unrealistic event. Describing scenarios explicitly makes it possible to understand how realistic an extreme outcome is. In particular, our approach requires analysis of which events are plausible in terms of the scope of the administered pricing mechanism, and which would trigger other interventions.

Each scenario is defined by a series of supply and demand curves. These are specified as composite curves, with underlying curves representing a variety of different supply and demand sources that are then aggregated. No such distinction was made in prior studies. Our approach enables consideration of how events and market context impact the bid and offers from different segments of the industry, including an allowance for changed contracting levels and import and exports. The ability to consider imports and exports explicitly provides a greater ability to simulate effects between gas markets and the electricity market.

To align with the evolving reality of the gas market the proposed methodology introduces market customers and gas powered generators into the range of market participants for whom a risk assessment is performed.

[20] DWGM CPT Review, AEMO, 2013.
[21] Settings for APC and CPT in the Victorian Wholesale Gas Market, MMA, 2008.

Question 4: A new feature of the Market Reform approach is a focus on simulating the drivers of high price rather than assuming a high price occurs. Do you see any limitations of this approach relative to prior methods?

7 KEY DATA TO BE USED IN REVIEW

7.1 Introduction

In this section we identify the data that we intend to use and map it to the inputs of the model. The principle documents referenced are:

- Gas Statement of Opportunities, (GSOO), AEMO, March/Sept 2017
- Victorian Gas Planning Report (VGPR), AEMO, March 2017
- National Gas Forecasting Report (NGFR), AEMO, 2016
- AEMO website: www.aemo.com.au
- State of the Energy Market, Australian Energy Regulator (AER), 2017
- ABS, Australian Bureau of Statistics

7.2 Base Supply and Demand Curve Data

The process of generating a demand or supply curve for use in the simulation begins with historical bid and offer curves. These are available by schedule for both the DWGM and the STTM (including MOS stacks), enabling selection of the appropriately daily/seasonal characteristics required for a particular scenario. This basic data is available directly from the AEMO website.

This data will be modified at the level of bid and offer data to reflect future conditions.

Gas powered generation projections will need to be converted to have some price sensitivity relative to the electricity market. This will be based on the heat rate conversion of gas to electricity.

Adjustments of supply and demand will be based on the GSOO, VGPR and NGFR. The AER also forecast future gas production by region along with assessment of future gas production by region which can be used as a further reference.

Because the simulation does not model pipelines and storage capacity explicitly, restrictions that would normally appear in such a model must be incorporated in the supply and demand curves. Information on STTM hub capacity and DWGM pipeline injection limits can be sourced from AEMO. In the case of exports, the AER State of the Market Report provides information on gas pipeline transmission capacities which will provide the base reference data for limitations on transfers between markets. These will be updated based on current predictions of requirements as described in the GSOO.

7.3 Scenario Adjustments

Bids and offers will be adjusted for scenarios based on the following information:

- High demand days will typically be based on 1:20 forecasts based on data in the NGFR and modified based on the GSOO.
- Storage offers need to be revised based on the level of storage in the scenario. Historic data will inform the typical behaviour for high, medium and low storage scenarios, though some scaling may be required to reflect prevailing future market prices.
- Contract data adjustments will be based on maintaining patterns in historic data but moving the reference point in (primarily) the offer curves to account for changing contract position.

Aside from the data used to develop input supply and demand curves we have also used other historical data such as price and scheduled data to verify various modelling functions are accurate.

7.4 Curtailment Cost Data

Average revenue at risk data is available from the ABS by industry grouping. This measure may be employed when validating a potential VoLL setting as this should be high enough for the market to clear itself.

7.5 Participant Profitability Data

Participant profitability data is used to discern how many days profit is lost when an event occurs. In previous studies which only included retailers it was a relatively simple calculation based on the assessed average retail margin for retailers.

In considering industrial customers with profitability linked to production rather than just gas consumption, we require additional profitability data. The Australian Bureau of Statistics (ABS) has profit margins detailed by industry. We will cross-reference that with energy use by industry from the same source. Given both we can calculate the typical total revenue/GJ and hence the profit margin for industrial use of gas

Question 5: Earlier, in section 5.6, a set of representative Market Participants was described. New types of participants have been introduced relative to prior reviews requiring variation in the methodology for calculating average daily profit relative to prior reviews. Do you have any comments on the appropriateness of using ABS data estimating loss of profits?

7.6 Investment Cost Data

Previous gas market parameter reports are a primary source of data when it comes to estimating the cost structure of additional capacity.

Table 2 states costs for establishing an LNG facility (such as that in Dandenong in the DWSG).

Table 2 – LNG Investment & Operating Expense Assumptions[22]

Assumption	Input Value
Capital Cost	192,000/tonne
Fixed Costs	$0/GJ
Variable Costs	$0.50/GJ
Expected Life of Facility	30 years

Question 6: Are the investment costs and operating life reasonable estimates with respect to investment in an LNG facility such as that in Dandenong?

[22] Data taken from Table 4-2: LNG Cost Assumptions, DWGM CPT Review 2013 –Final Report, AEMO, 2013.

Error! Not a valid bookmark self-reference. shows a weighted average cost of capital (WACC) used previously.

Table 3 – Weighted Average Cost of Capital[23]

	Estimated Values
Average nominal risk free rate	3.50%
Inflation	2.00%
Debt margin	2.00%
Market risk premium	7.50%
Debt funding	40.00%
Equity funding	60.00%
Corporate tax rate	30.00%
Effective tax rate for equity	30.00%
Effective tax rate for debt	30.00%
Equity beta	1.00
Cost of equity (nominal post-tax)	11.0%
Cost of equity (real post-tax)	8.8%
Cost of debt (nominal pre-tax)	5.5%
Cost of debt (real pre-tax)	3.4%
Post-tax Nominal WACC	8.80%
Post-tax real WACC	6.67%

Efforts will be made to source more current data where possible though the same broad methods as applied in those previous studies will be used.

Question 7: Recognising that that the Investment Cost Data presented above must apply across a range of industries and participant types, and the investment under consideration is anticipated to be used infrequently:

a. Is the equity market risk premium for the sector (7.50%) reasonable?

b. Does the combination of the risk-free rate (3.50%) and the debt margin (2%) adequately reflect the cost of debt (5.50%)?

c. Is the overall estimate of post-tax real WACC (6.67%) reasonable bearing in mind it is applicable to a facility anticipated to be used infrequently?

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[23] Based on modelling data used in the IPART Review of Regulated Retail Prices in their August 2015 model.

7.7 The Grid of Gas Market Parameters

Table 4 describes the proposed gas market parameters to be reviewed.

Table 4 – Proposed gas market parameters.

Parameter	Current Value	Grid Points
Market Price Cap (MPC) Value of Lost Load (VoLL)	STTM $400/GJ DWGM $800/GJ	$400/GJ, $600/GJ, $800/GJ, $1000
Administered Price Cap (APC)	STTM $40/GJ DWGM $40/GJ	$40/GJ, $60/GJ, $80/GJ
Cumulative Price Threshold (CPT)	STTM $440 DWGM $1800	$440*, $600*, $1000, $1800, $2500 *These values are focused on the STTM and may be too low for the DWGM but will be simulated.

8 NEXT STEPS

During the period the period of consultation on this report, Market Reform will be implementing models and data required to support this study. To the extent that can reasonably be accommodated within the schedule and modelling constraints, efforts will be made to incorporate ideas provided in feedback to the review that would enhance the review. Similarly, through AEMO, Market Reform will also keep abreast of other reform proposals that may arise out of studies such as the AEMC's 'Reliability Standard and Settings Review 2018' for the National Electricity Market (the 'NEM review') which is work occurring in parallel to this study. To the extent that we are provided with proposals from those reviews that are relevant to this study then we will endeavour to explore their impact.

Our final report will be an extension of this report, providing commentary on the consultation feedback, and presenting our findings and conclusions.

APPENDIX A – ABBREVIATIONS

TERM	DEFINITION
ABS	Australian Bureau of Statistics
ADGSM	Australian Domestic Gas Security Mechanism
ADL	The Adelaide STTM hub
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	Authorised Maximum Daily Quantity (DWGM)
APC	Administered Price Cap
BRIS	The Brisbane STTM hub
CPT	Cumulative Price Threshold
DTS	Declared Transmission System (DWGM)
DWGM	Declared Wholesale Gas Market
GJ	Gigajoule
GPG	Gas Powered Generation
GSG	Gas Supply Guarantee
GSOO	Gas Statement of Opportunities
GWCF	Gas Wholesale Consultative Forum
LNG	Liquefied Natural Gas
MCP	Marginal Clearing Price (DWGM)
MOS	Market Operator Service (STTM)
MPC	Market Price Cap (STTM)
MSV	Market Schedule Variations (STTM)
NBB	National Gas Bulletin Board
NEM	National Electricity Market
NGERAC	National Gas Emergency Response Advisory Committee
NGR	National Gas Rules
NGFR	National Gas Forecasting Report
PJ	Petajoule (1,000,000 GJ)
ROLR	Retailer of Last Resort
STTM	Short Term Trading Market
SYD	The Sydney STTM hub.
TJ	Terajoule (1,000 GJ)
VGPR	Victorian Gas Planning Report (DWGM)
VoLL	Value of Lost Load (DWGM)

APPENDIX B – PROPOSED SCENARIOS

The following table describes the proposed scenarios. The years of focus are the tight supply year 2021 and years at the start and end of the horizon – 2019 and 2024. We have specifically included some scenarios based on 2019 to test the need for an earlier implementation of new market parameters.

Scenario	Market Context	Event	Detail
1A 1B	DWGM 2021[24] DWGM 2024[25]	Gippsland supply interruption	Unexpected reduction (or delay in return to service) of Longford production on a high demand weekday. It occurs at schedule 2 (before bid submission) creating exposure for participants at the injecting node relative to the beginning of day schedule, while creating challenges for serving the daily peak. Output is restored after midnight.
2A 2B	DWGM 2021 DWGM 2024	Compressor failure near Melbourne	Pipeline compressor failure near Melbourne on a high flow day from Iona, occurring early on a high demand gas day preventing management of pressure around Melbourne with impact on interconnected transmission pipelines.
3A 3B	DWGM 2021 DWGM 2024	Moomba supply interruption with a high rate of flow to SA and NSW on a peak day.	High rate of gas export from DWGM to address issues in other markets. This may occur for 3 successive days but is known at the start of the first day.
4A 4B	DWGM 2019 DWGM 2021	High forecast GPG demand	High expected GPG demand (due to forecast electricity market factors) at times of high gas demand. This would produce extra high demand going into the day. Flow of gas to SA (to manage increased GPG demand there) could limit Iona supplies. *This scenario would consider the impact of a participant trading in both gas and electricity. Electricity pricing levels would be set to a level as to make GPG participation attractive.*
5A 5B	DWGM 2021 DWGM 2024	High unforecasted GPG demand.	Victorian electricity prices suddenly rise across the peak causing GPGs to unexpectedly enter market within the gas day, causing increased demand on LNG. GPG demand would be at the limits of what can be supported. Demand for GPGs remains high to third gas day. *This scenario would consider the impact of a participant trading in both gas and electricity. Electricity pricing levels would be set to a level as to make GPG participation attractive.*

[24] 2021 indicates analysis over year ending June 2021. If the 2021 analysis suggests an urgent change in parameters is required, year ending June 2020 may also be considered allowing for the possibility of initiating the new parameters from July 2019.
[25] *Following a review of the GSOO and other forward-looking collateral, additional years may be added to coincide with any significant and expected market change.*

Scenario	Market Context	Event	Detail
6A 6B	DWGM 2019 DWGM 2021	Extremely high demand	Demand in excess of 1:20 year scenario – e.g. due to extremely cold weather. We might assume that effectively all available supply is required within their constraint limits. This is a situation where demand may also exceed normal contract / hedge limits.
7A 7B	DWGM 2021 DWGM 2024	High demand day requiring LNG while gas storage is low.	Peak winter week but with inflated LNG prices and low gas storage levels due to high demand earlier in the winter and/or as a consequence of previous events
8A 8B	SYD 2021 SYD 2024	Reduced supply to hub due to upstream reduction in production (or due to off-takes up stream but not back haul).	Due to unusual events upstream for a period of 3 days there is a 5% reduction of normal gas supply to the hub at a time of high demand but not enough to trigger APC for technical operating reasons. This is known before ex ante market runs.
9A 9B	ADL 2019 ADL 2024	Reduced supply to hub due to high GPG demand outside of the hub during ex ante market	GPG's buy high volume of back haul gas in ex ante market due to high electricity demand for 2 days.
10A 10B	BRIS 2021 BRIS 2024	Reduced supply to hub due to unexpected high GPG demand outside of the hub after ex ante market has run.	GPG's buy high volume of back haul gas in ex ante market due to high electricity demand for 2 consecutive days.
11A 11B	SYD 2019 SYD 2021	Contingency gas scenario	Contingency gas scenario due to a (some event) reducing gas supply to the hub in excess of 5% (but not so much as to cause an Administered Pricing State of itself)
12A 12B	ADL 2021 ADL 2024	Extreme MOS costs, including due to the cost of replacement gas.	Day 1 has a high deviation giving rise to the use of expensive MOS, but on day 3 when the MOS providers replace the commodity the ex ante price is high (due to some unrelated event) driving up deviation prices on day 1, as well as having high gas prices on day 3. MOS provider is left exposed due to note being able to secure all its gas required on day 3.
13A 13B 13C	DWGM 2021 SYD 2021 ADL 2021	DWGM supplying gas to SYD and ADL while electricity prices are high in VIC (and probably NSW)	Gas supply disruptions in the broader gas markets places increased demand on gas that would normally serve the STTM or DWGM (e.g. to supply LNG production). *This scenario would consider the impact of a participant trading in both gas and electricity. Electricity pricing levels would be set to a level as to make GPG participation attractive.*

Scenario	Market Context	Event	Detail
14A 14B 14C	DWGM 2021 ADL 2021 SYD 2021	High GPG demand in or around key markets.	High electricity prices for a sustained period required long term running of gas powered generation at higher utilisation than normal. This causes strong linkage between the DWGM and the ADL and SYD STTM hubs.
15A 15B 15C	DWGM 2021 SYD 2021 ADL 2021	High gas prices in the STTM makes the DWGM a critical supply source.	The DWGM becomes a major supplier for the STTM at a time of high prices in the STTM.
16A 16B 16C 16D	DWGM, SYD, ADL 2021	Four different linked scenarios	Scenarios which cause gas and electricity markets to become very inter related. • 16A: Electricity shortfall in South Australia, • 16B: High GPG demand in South Australia drives Adelaide STTM hub price. • 16C: High demand for gas in South Australia drives up gas prices in the DWGM. • 16C: High DWGM gas prices force GPG out of the market in the DWGM (limiting degree of price increase) but driving up prices in the NEM. *This scenario would consider the impact of a participant trading in both gas and electricity. Electricity pricing levels would be set to a level as to make GPG participation attractive.*