19 June 2023

Gas price forecasts

Draft results

ACIL ALLEN

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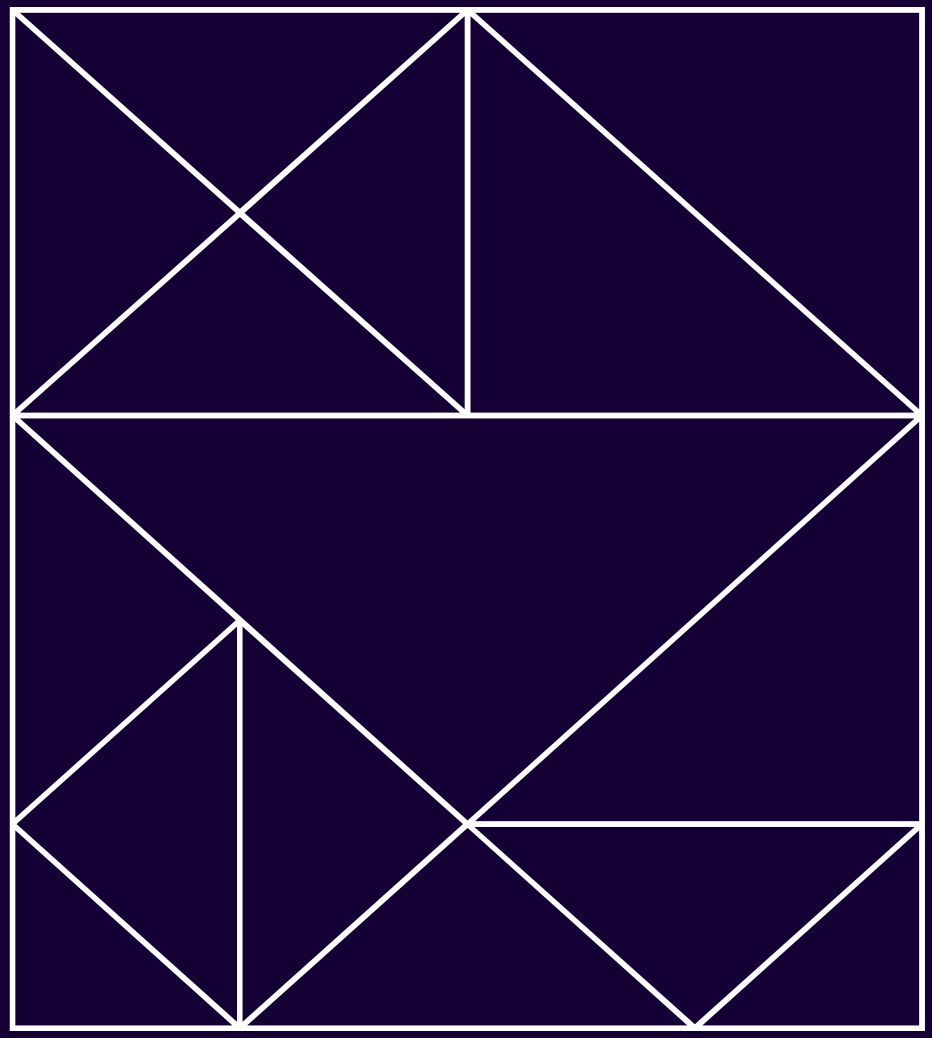


Our methodology

ACIL Allen developed a three-phase process for this project. These phases are described in more detail below. In the beginning we embarked on a data collection and high-level market analysis phase to ensure we were across all of the developments in the ECGM in detail. A model preparation phase then followed where we ensured the models were correctly specified and the assumptions have been confirmed. The final phase was undertaking the forecasts themselves.

Phase 1: Data collection and market analysis

The first step of the process was to complete a data collection exercise and review developments in the market. The data collection task involved collecting the necessary data and assumptions that fed our model which would produce the final forecasts.

The data requirements were required to calibrate our GasMark and PowerMark models and to ensure the assumptions and detail on market infrastructure were consistent with the assumptions contained in the Input, Assumptions and Scenarios (IASR) report and the 2023 Gas Statement of Opportunities (GSOO) report.

A supporting piece of work during this phase was reviewing the ECGM and the Northern Territory gas markets. This analysis is always an important task for these modelling exercises. It ensures our understanding of key market developments are fully understood, and we can plan for how these should be best captured in our model.

Some of these key developments included:

- Wholesale gas price caps recently introduced by the Commonwealth Government
- Trends in gas market consumption across the ECGM
- Developments in international energy markets which influence brent oil prices and Asian LNG prices
- Infrastructure investment in the ECGM
- New gas supply developments
- The role of hydrogen and how it might trend in the future.

Phase 2: Model preparation

GasMark has the flexibility to represent the unique characteristics of gas markets across Australia. The model now includes assumptions for over 200 gas fields and more than 250 individual demand nodes. As mentioned before, it was important to ensure the model remained consistent with the assumptions provided by AEMO for the various scenarios.

In some cases, our assumptions were simplified to broadly correspond with AEMOs assumptions (e.g. gas field production costs made consistent across a gas producing basin to align with the approach AEMO takes).

Specifically, our demand forecasts closely align with forecasts from the GSOO to ensure the price forecasts reflect the assumptions and broad demand scenarios that are defined in the GSOO. Beyond 2042, ACIL Allen extrapolated AEMOs forecasts all the way through to 2054 (as required by AEMO).

For supply we aligned our assumptions with AEMOs GSOO. In some cases, we may have differing assumptions on new projects and supply quantities from these projects. Some of these key assumptions are summarised on slide 6. These can be adjusted in subsequent iterations following feedback from AEMO. A full description of all assumptions will be provided in our draft report.

PowerMark was used by ACIL Allen to help with analysing GPG gas demand. PowerMark was run to estimate forecast GPG gas consumption by generator, and this was compared with AEMOs own GPG forecasts. The most appropriate forecasts in consultation with AEMO will then be fed into the GasMark model to forecast prices. ACIL Allen ended up using AEMOs demand forecasts based on a discussion of the results.

Phase 3: Undertaking forecasts

Following phases 1 and 2, ACIL Allen undertook the final forecasts. AEMO required various forecasts for eastern Australia and for the Northern Territory. The forecasts required relate to residential/commercial demand, industrial demand and GPG demand. The forecasts will be provided in Excel form.

In addition to supplying the forecasts in Excel spreadsheet form, ACIL Allen will provide detailed commentary of the results in the draft and final report and focus on which drivers are influencing prices over the short, medium and long term under the five different scenarios.

The following forecasts will be presented :

- Individual gas price forecasts (including transmission and storage) for each existing gas-fired generator within the National Electricity Market (NEM)
- Gas price forecasts (including transmission and storage) for generic new entry gas-fired generators, both open cycle gas turbines and combined cycle gas turbines, for each of the East Coast regions
- Annual wholesale contract price gas forecasts (excluding distribution and retail costs) for each region located in the East Coast of Australia, and specifically provided for
  - Industrial users consuming above 10 TJ per annum
  - Residential and commercial users.
- Annual gas price forecasts for Northern Territory gas-fired generators (for two scenarios ACIL Allen has undertaken previously).

Modelling framework

Our modelling framework is summarised on this slide. Our data collection and market analysis tasks feed into the preparation of our gas market model. We then undertake the forecasts using our GasMark model. The modelling produces results for three scenarios which have been defined by AEMO. We expect that this process will be an iterative process with AEMO.

Step 1

ACIL Allen will utilise its gas market model to produce the underlying forecasts. First created 20 years ago and extensively developed and enhanced over that period, it has been widely applied in analysing the dynamics of the gas markets in both eastern Australia (including the Northern Territory) and Western Australia

At its core, GasMark is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to 'arks' within a network model).

The model incorporates assumptions about gas supply (reserves, production rates, minimum selling prices etc.), gas demand at individual customer or customer group level (annual quantity, price tolerance, price elasticities, seasonal demand profiles etc.) as well as existing and possible future transmission pipelines (current capacity, future expansions, tariffs etc.), LNG terminals (import prices, annual and daily supply capacities etc.) and gas storage facilities (total storage capacity, maximum injection and withdrawal rates, cushion gas requirements, storage losses etc).

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. Or in other words, the model optimises the transmission of gas throughout the market from supply sources to demand markets in the most economically efficient way according to the assumptions for each object in the model (e.g. a demand market, gas field, transmission pipeline).

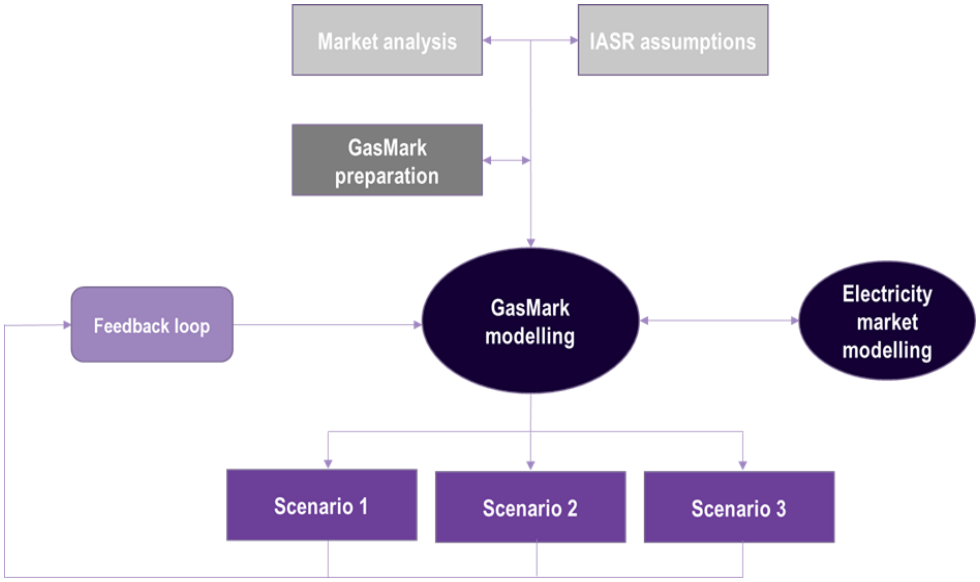
The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay.

Step 2

Step 2 will take the results of the modelling and add a further layer of analysis on top to produce the final forecasts. This step is required in order to ensure the forecasts account appropriately for developments in the market, particuarly in relation to how different users procure gas. For example, GPG facilities often rely on contract markets for a portion of their supply and then supplement their supply of gas through spot market purchases. These two different markets are priced differently, and this is especially the case as a result of the recently introduced price cap.

This layer of analysis will also be important for industrial users who also procure gas in different ways and have different demand characteristics which can influence the price they pay for gas. The impacts of vertical integration and competition issues will also be analysed (but are not explicitly includes in this version of the forecasts).

Figure 1: Modelling framework



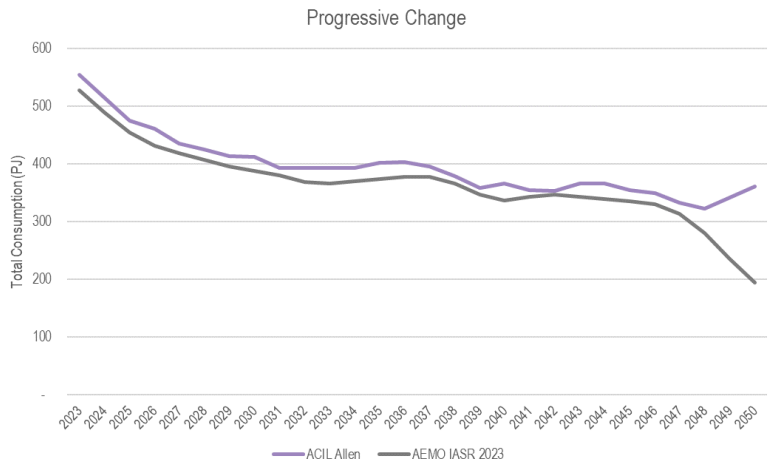
Scenario assumptions

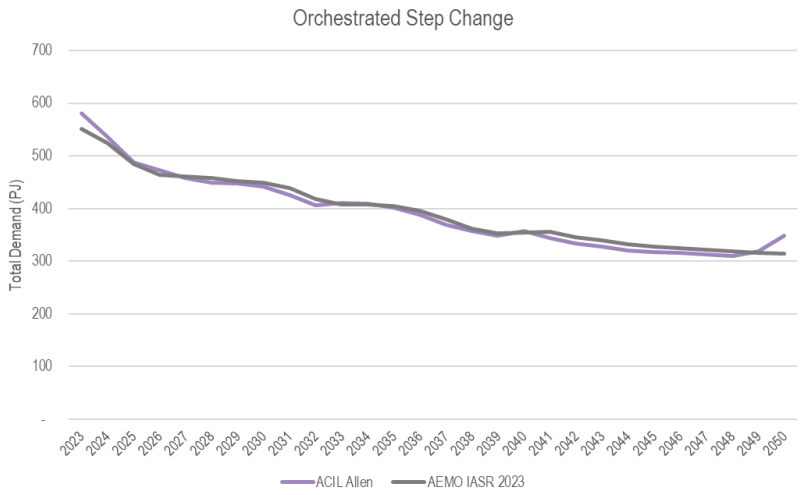
Assumption	Green energy	Orchestrated	Progressive
Demand	Green energy export scenario demand from 2023 GSOO	Orchestrated scenario demand from 2023 GSOO	Progressive scenario demand from 2023 GSOO
Reserves and resources	2P reserves + 2C resources	2P reserves + 2C resources	2P reserves + 2C resources
Production costs	Aligned with 2023 GSOO costs	Aligned with 2023 GSOO costs	Aligned with 2023 GSOO costs
New gas supply projects (NSW)	No Narrabri	Narrabri proceeds	Narrabri proceeds
New gas supply projects (VIC)	**Gippsland** - GBJV expansion (Kipper) **Otway** - Enterprise from 2024 and Thylacine in 2023 **Bass** - No further development	**Gippsland** - GBJV expansion (Kipper, Turrum); Manta and Longtom are developed **Otway** - Enterprise in 2024 and Thylacine from 2023 **Bass** - Trefoil is developed	**Gippsland** - GBJV expansion (Kipper, Turrum); Manta and Longtom are developed **Otway** - Enterprise in 2024 and Thylacine from 2023 **Bass** - Trefoil is developed
New gas supply projects (QLD)	No new projects	Bowen Basin – Mahalo project (Santos)	Bowen Basin – Mahalo project and expansion of Moranbah Gas Project
New gas supply projects (SA)	No new projects	No new projects	No new projects
New gas supply projects (NT)	Beetaloo – long term supply capacity of 20 PJ for ECGM	Beetaloo – long term supply capacity of 50 PJ for ECGM	Beetaloo – long term supply capacity of 100 PJ for ECGM
New storage	No new storage	Golden Beach storage project developed	Golden Beach storage project developed
Pipeline development (greenfield/brownfield)	According to 2023 GSOO	According to 2023 GSOO	Additional long term expansion of Carpentaria Pipeline, SWQP and MSP to cater for increased Beetaloo supply
Pipeline tariffs	According to 2023 GSOO	According to 2023 GSOO	According to 2023 GSOO
Global long term oil price	Long term US$45 per barrel	Long term US$65 per barrel	Long term US$85 per barrel
Queensland LNG exports	Green energy export scenario demand	Orchestrated scenario demand	Progressive scenario demand
LNG import terminals	No LNG import terminals	Port Kembla online from 2028	Port Kemba online from 2026

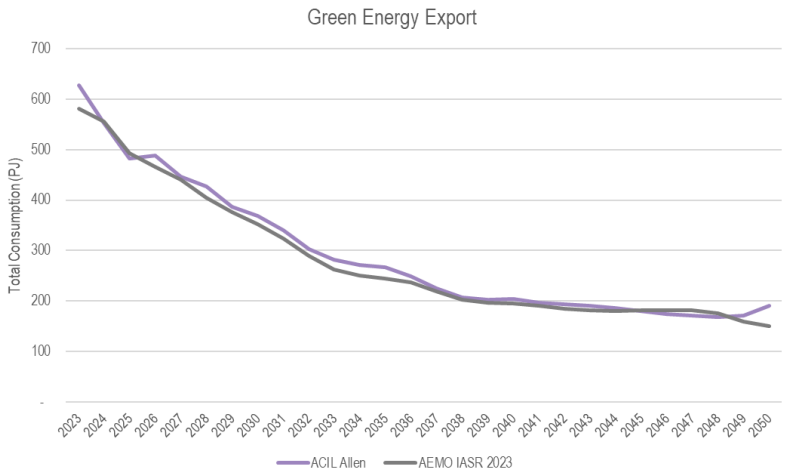
Forecast demand

Forecast demand in our model has been closely aligned with that of AEMO. AEMO have provided their latest demand forecasts for the Orchestrated, Progressive and Green energy export scenarios. The model will then ensure consumption is aligned with this demand curve and the effect on consumption from sensitivity to prices is essentially 'turned off'.

- Demand in all scenarios mirrors AEMOs forecast demand largely until the final few years in the Orchestrated and Green energy scenarios
- The only significant difference and departure from the AEMO assumptions is in the Progressive scenario, where demand from our modelling and AEMOs tracks in different directions. This is largely down to our extrapolation of GPG demand post 2042.
  - AEMOs GPG demand was supplied up until 2042 and ACIL Allen extrapolated demand based on guidance from the ISP forecasts beyond 2042 to the end of the forecast period. The extrapolation in the Progressive case resulted in large quantities of additional GPG capacity coming into the market post 2042, particuarly in the southern states (VIC and NSW predominantly).
  - This has meant total domestic natural gas demand increases, rather than falls.







Residential/commercial and industrial gas prices

Residential/commercial and industrial gas prices is largely based on the outputs from our GasMark model. Our model contains consumption details for all the key residential and commercial markets in the ECGM. For industrial users, we have details for several large individual industrial users (typically serviced by transmission pipelines) in the ECGM and then group all other industrial users together (which are typically serviced through the distribution network).

Residential and commercial gas prices

The key steps for modelling residential and commercial prices are as follows:

- Prepare demand forecasts and align with AEMO 2023 GSOO forecasts, per region, in the ECGM
- Finalise all other assumptions and ensure wholesale price cap is operating in the market
- Run our GasMark model and produce an average annual wholesale price for each region in the ECGM.

A key assumption we make in the residential/commercial modelling is that all wholesale gas to be delivered to residential and commercial customers is sourced via contracts that gas retailers directly have with gas producers. This means that gas being supplied to the mass market throughout the ECGM will be subject to the wholesale price cap. While there may be situations where procurement of gas is different for some markets, the predominant method is certainly retailers having direct supply contracts with gas producers.

The wholesale price cap is assumed to continue until our model assumes that long run LNG prices influence the LNG netback to fall below the price cap of $12/GJ. At that point, domestic prices are then using the LNG netback as the reference setting price and no longer the wholesale gas price cap. The price cap is operationalised in our model by essentially setting the LNG netback price (measured at Wallumbilla) to not move above a price of $12/GJ.

Currently, the gas price cap is intended to stay operational until 2025 per the most recent announcements by the Commonwealth Government.

The demand forecasts for each region are closely aligned with the 2023 GSOO results. The demand forecasts take into account the impact hydrogen and biomethane injection have on natural gas supply in the market. This impact is analysed outside of GasMark. The demand curves for natural gas are then inputted into the model and then run.

No additional load factor adjustment is required given GasMark accounts for the swing in residential/commercial demand throughout a year, for all markets in the ECGM. This is achieved by the model having daily demand profiles for each market based on historical demand. As we assume all residential/commercial demand is from contracted supply, the forecast will not reflect any influence from the spot market.

Industrial gas prices

The key steps for modelling industrial prices are as follows:

- Prepare demand forecasts and align with AEMO 2023 GSOO forecasts, per region, in the ECGM
- Ensure wholesale price cap is operating in the market
- **Run 1**: Run GasMark model and produce an average annual wholesale price for each region in the ECGM which is reflective of a contract price (and includes the operation of the price cap).
  - Adjust this price with any adjustment required to account for supply flexibility/load factor that many industrial users require in their gas supply contracts – we will make an assumption on this that will apply for all regions in the ECGM
- **Run 2**: Run GasMark and produce a monthly price series which is more reflective of the spot markets in the ECGM which are not subject to the price cap. This is achieved by removing the price cap and applying the short-term LNG netback as the price influencing mechanism in the market.
- Produce a weighted price that takes into account supply procured through contracts and supply procured through the spot market – we intend to make an assumption on the proportion of supply procured through contracts and via spot markets (which will apply to all regions)

We expect that the weighted price will only be applicable in the short to medium term. In the long-term prices will be fundamentally driven by demand and supply, and not by short term factors which spot markets reflect. Therefore, our forecasts long term will be more reflective of a long-term contract price and will not reflect a weighted price which accounts for short term factors.

Since the LNG export projects were commissioned in the ECGM, gas pricing and procurement has evolved. Gas prices have increased since these LNG projects were commissioned, and the demand/supply balance has also tightened. The way industrial users procure gas has subsequently changed, and industrial users are now more active in their procurement strategies. ACIL Allen intends to reflect this change in our industrial pricing.

We also account for the fact that industrial loads are much flatter loads than residential loads. Retailers typically will pay a premium to producers because of their significant load factor. Industrial users do not require this magnitude of flexibility and ACIL Allen will ensure the prices they paid are not influenced by the peakiness in market prices which are driven by residential and GPG loads.

Gas-fired power generation prices

The last consumer segment is GPG. This segment will require ACIL Allen to forecast prices for both existing generators and also new generators that are expected to enter the NEM. As mentioned previously I the slide deck, ACIL Allen has used AEMOs data on GPG gas demand instead of our own GPG forecasts.

Step 1: GPG demand forecasts

The first step for ACIL Allen in forecasting GPG prices was understanding demand for gas from GPG over the forecast period to 2054. ACIL Allen utilised its own electricity market model in the first instance to forecast gas-fired generation levels and gas consumption. These outputs (daily gas consumption volumes for each existing and new generator) were then analysed. However, during an initial task of comparing our latest results with AEMO's 2023 GSOO GPG forecasts, we found that there was a significant difference between our GPG gas consumption figures from the early 2030s compared with all scenarios in the GSOO.

For example, our current Reference case of the NEM indicates the potential need for 200-250 PJ per year by the mid 2030s to service GPG demand. This level of gas demand from GPG assumes a 'high electrification' electricity demand forecast. Therefore, this sort of GPG gas demand is an upper end estimate based on the level of electricity demand compared to the GSOO scenarios. We would expect that under the GSOO scenarios we wouldn't get as high as 250 PJ per year (although it would likely be notably higher still than the levels under the GSOO scenarios).

A reason for this might be the difference between the two models (i.e., PowerMark versus the model behind the GSOO GPG forecasts). Our model introduces new generation capacity on an iterative basis (usually annually), with the modelling taking into account the new capacity's impact on electricity spot prices before it builds any further capacity. The model introduces new capacity only if the new capacity is profitable as a generator entering and operating in the NEM (i.e., it earns the required return to debt and equity investors based on new entrant model parameters such as WACC, capex, economic life, other fixed and variable costs).

As a result of the anticipated differences in our forecasts if we model to 2054, it made the most sense from our perspective to use AEMOs forecasts to remain consistent with AEMOs scenarios on gas consumption in the ECGM. ACIL Allen agreed with AEMO that ACIL Allen will use data provided by AEMO on GPG gas consumption.

For the period 2043-2054, we extrapolated AEMO's GSOO forecasts based on GPG modelling done via the 2022 ISP process. The extrapolation was discussed with AEMO and revisions can be made if the extrapolation is not consistent with what AEMO broadly expects to happen. We understand that the 2022 ISP process and the GSOO GPG modelling is not completely consistent and can lead to results that are not completely aligned between the two processes.

Step 2: Gas market modelling and forecasting

The key steps for modelling GPG gas prices are as follows:

- Prepare demand forecasts (using AEMOs GPG data)
- Ensure wholesale price cap is operating in the market
- **Run 1**: Run GasMark model and produce an average annual wholesale price for each region in the ECGM which is reflective of a contract price and is subject to the price cap.
- **Run 2**: Run GasMark and produce a monthly price series which is more reflective of the spot markets in the ECGM which are not subject to the price cap. As described in the previous slide, the short-term LNG netback price becomes the price influencing mechanism in the spot market, and not the price cap.
- Produce a weighted price that takes into account supply procured through contracts and supply procured through the spot market
  - The proportion of supply via contracts and from spot markets will be based on the type of generator (e.g. OCGT vs CCGT), the location of the generator, and the expected dispatch profile within a year.

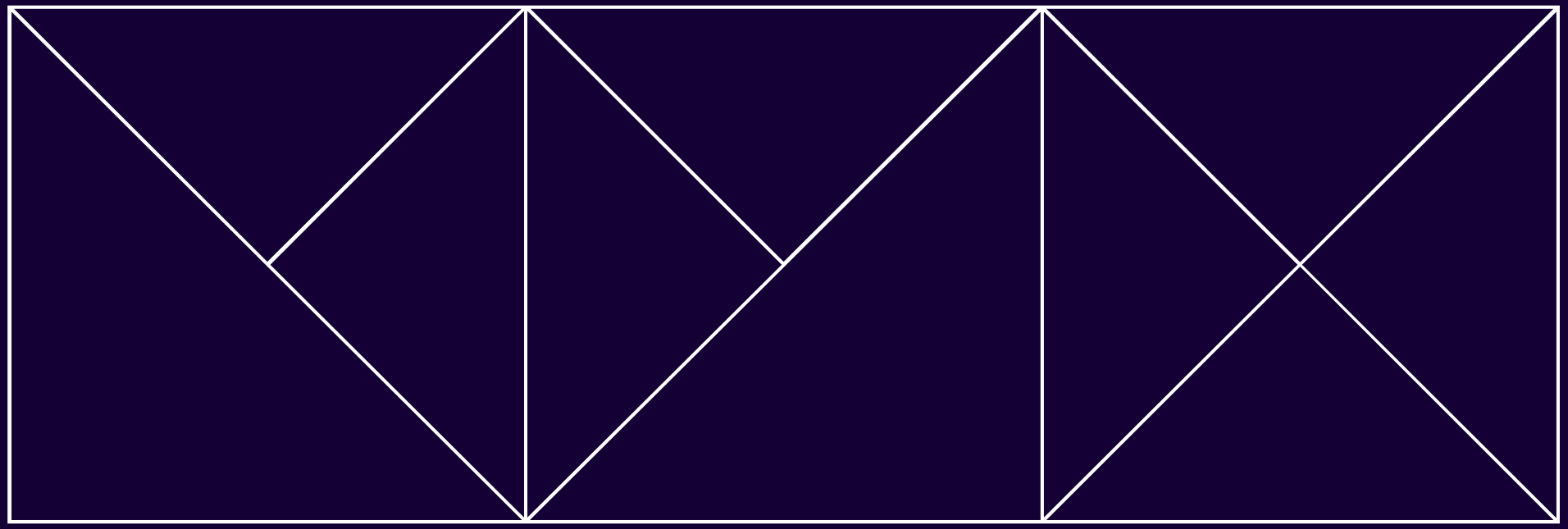
We expect the weighted price for each generator to be variable, with some generators being highly skewed towards contracted gas supply and other generators (such as stations with OCGTs who act in a 'peaking' role) who will be skewed much more the other way towards procuring gas via the spot market. This analysis is particuarly important given outcomes we are seeing in the market with respect to electricity market prices and how much we believe some generators are paying for gas. Short term prices are also likely to be well above capped prices, which is important to account for.

As we mentioned in respect to industrial prices, in the long-term our prices for generators will reflect a long-term price underpinned by demand and supply fundamentals, and not short-term factors. Therefore, forecasted prices in the long-term will be more reflective of contract prices.

A premium has been added to the price OCGTs pay in the long term to account for the additional costs they typically pay to source gas at short notice and at potentially high volumes. This is typically regarding pipeline capacity and the use of storage.

For generators in the NT, we also use AEMOs GPG forecasts to forecast prices.

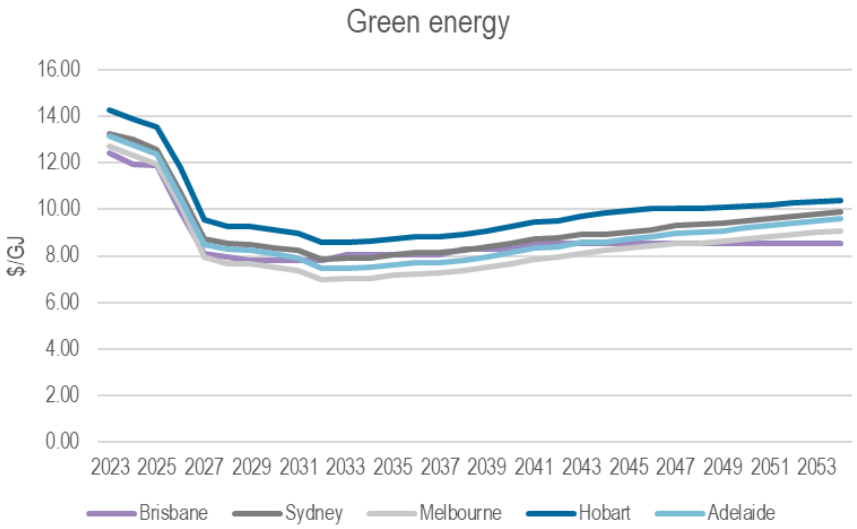
Draft forecasts

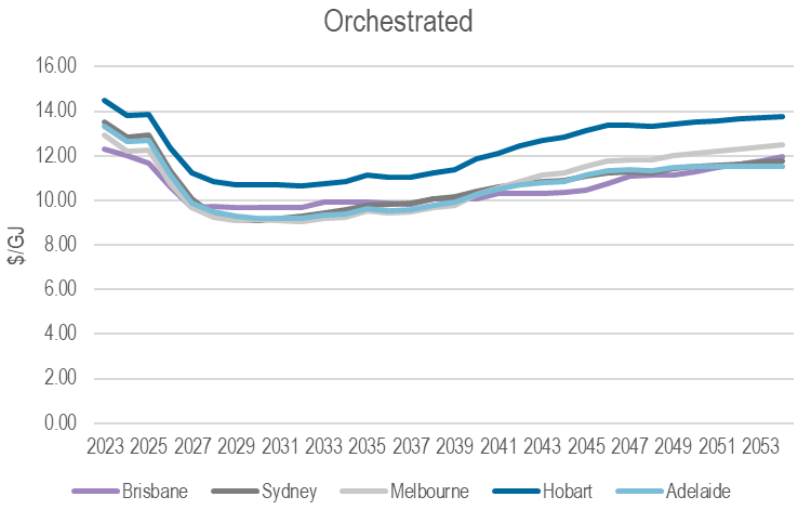


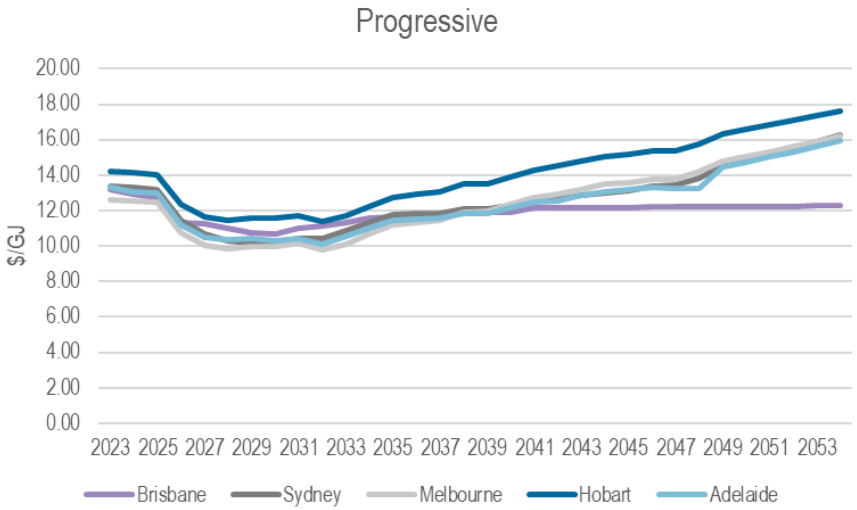
Residential and commercial prices

Our draft residential and commercial price forecasts are below. We present the forecasts for the three scenarios modelled – orchestrated, progressive and green energy exports. Detailed commentary will be provided in the draft report.

- Residential and commercial prices are expected in the short term to remain relatively steady before declining due to declining international LNG prices and the assumed removal of the wholesale price cap in 2025. We assume that supply for this market is 100% contracted.
- Over the period to 2025, wholesale prices will be largely influenced by the price cap of $12/GJ with transmission costs added on top. Most markets in all scenarios will hover between $12 and 14.50/GJ.
- Wholesale prices by the late 2020s are expected to 'bottom out' as international LNG prices cease their declines. The level at which prices fall to in each scenario is largely down to this assumption on how low international LNG prices fall to, and therefore the LNG netback.
- Prices are then expected to begin increasing for all scenarios and the rate at which they increase is largely down to long term demand and our assumptions on long term international LNG prices. Prices in the Progressive scenario beyond 2040 accelerate in the southern states due to significant GPG demand and constraints in supplying this demand via Queensland fields.







Industrial prices

Our draft industrial market price forecasts are below. We present the forecasts for the three scenarios modelled – orchestrated, progressive and green energy exports.

- Industrial prices are expected in the short term to remain relatively steady before declining due to declining international LNG prices and the assumed removal of the wholesale price cap in 2025 (much the same as the residential and commercial market).
- The key difference between our forecasts for industrial prices and residential and commercial prices is the influence of market seasonality and load factor.
  - Industrial prices are forecast fall to lower levels based on the assumption that they are much flatter loads then residential and commercial gas supply contracts, and therefore, pay less of a premium to producers to access their supply throughout a year
- As in the residential and commercial market, prices are expected to increase over time
- We have assumed that industrial user's source 90% of their supply via contracts and 10% from short term markets.

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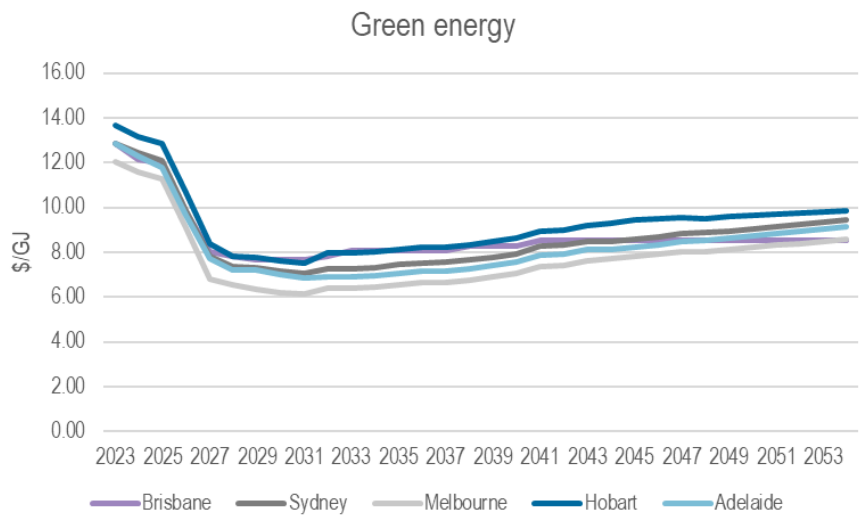
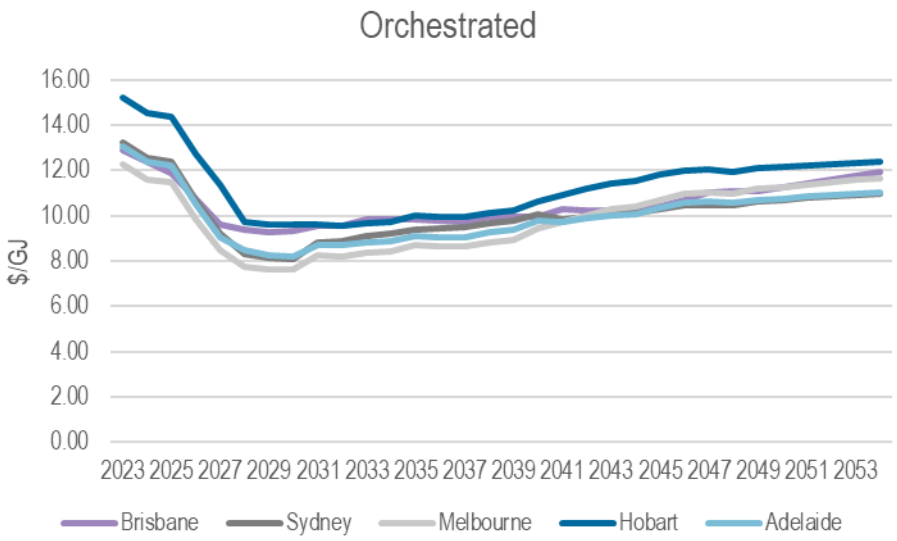
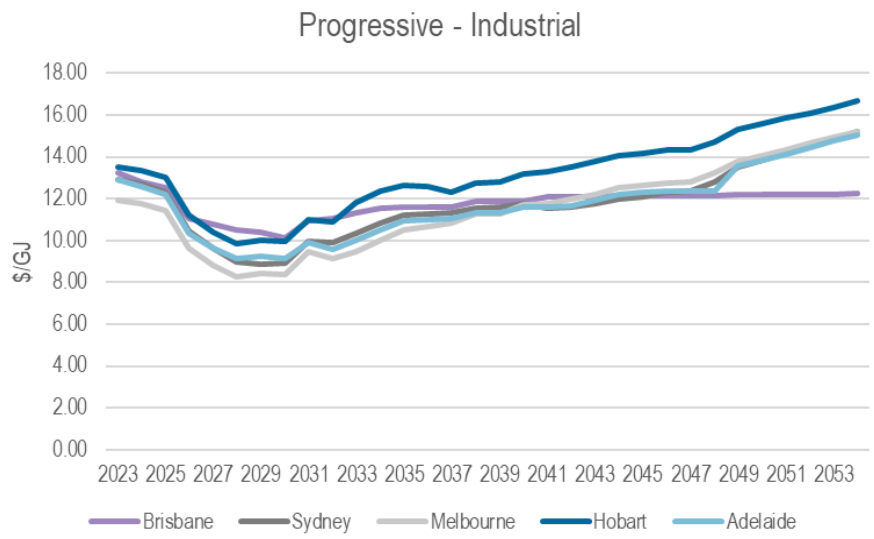


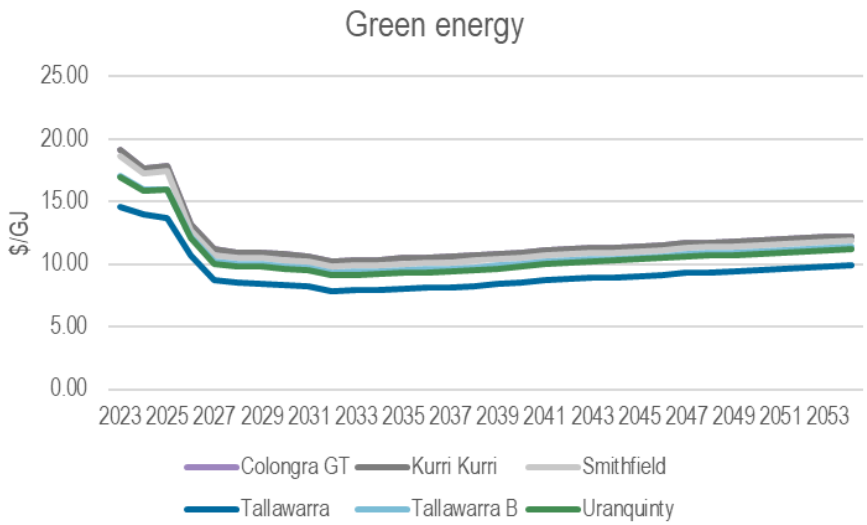


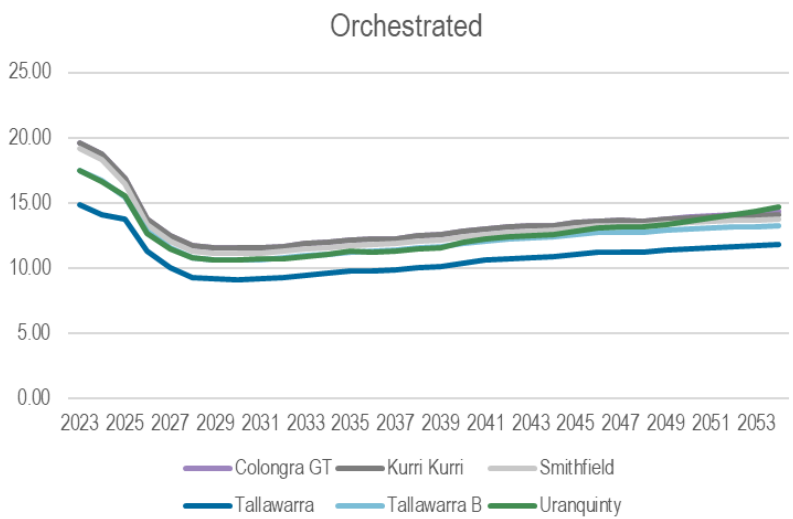


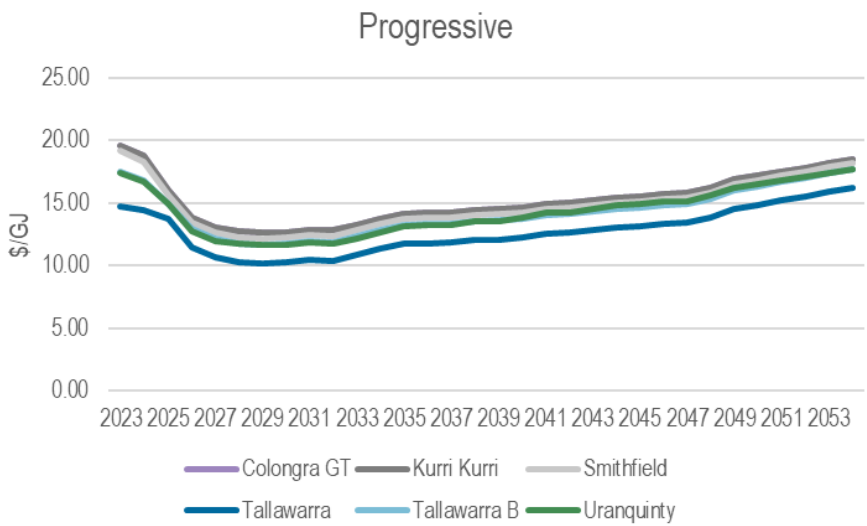
GPG prices - NSW

Our draft New South Wales GPG price forecasts are below for each individual generator. We present the forecasts for the three scenarios modelled – orchestrated, progressive and green energy exports.

- GPG prices in New South Wales are expected to follow the general trend in other markets across the forecast period.
- Our assumption is that OCGTs generally contract 20% of their supply and then source 80% of their gas via short term markets (some adjustment is made for OCGTs owned by larger gentailers such as AGL or Origin who have portfolios of supply that could result in less reliance on the spot market) based on their 'peaking' role and the intermittency at which they generate.
  - CCGTs on the other hand are assumed to be the opposite (80% contracted and 20% from short term market).
- As a result of this assumption, prices paid in the short term differ with OCGTs having to pay prices more similar to spot prices than lower contract prices contained by the wholesale price cap.
- In the long run, a premium is applied to OCGTs based on their intermittency in generating over CCGTs



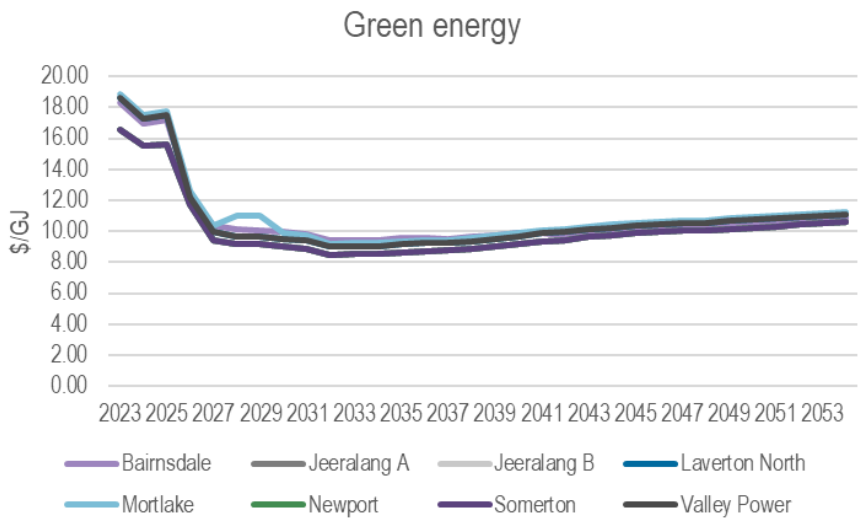


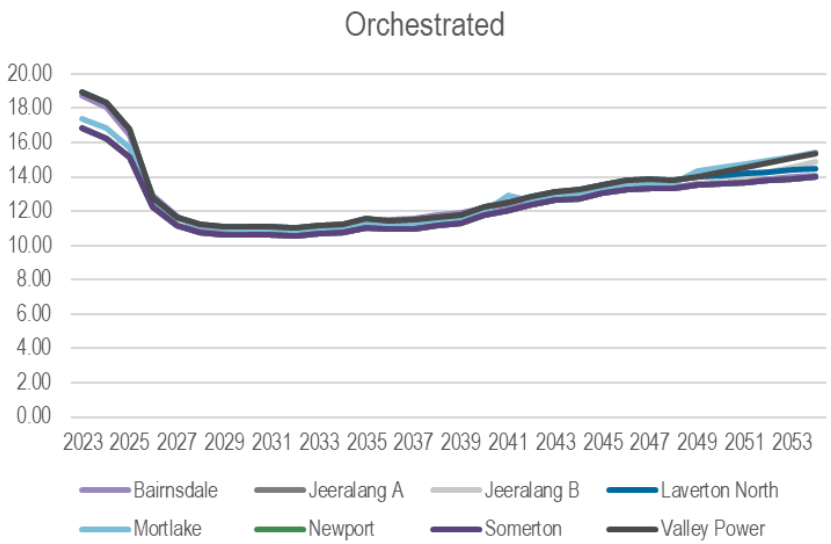


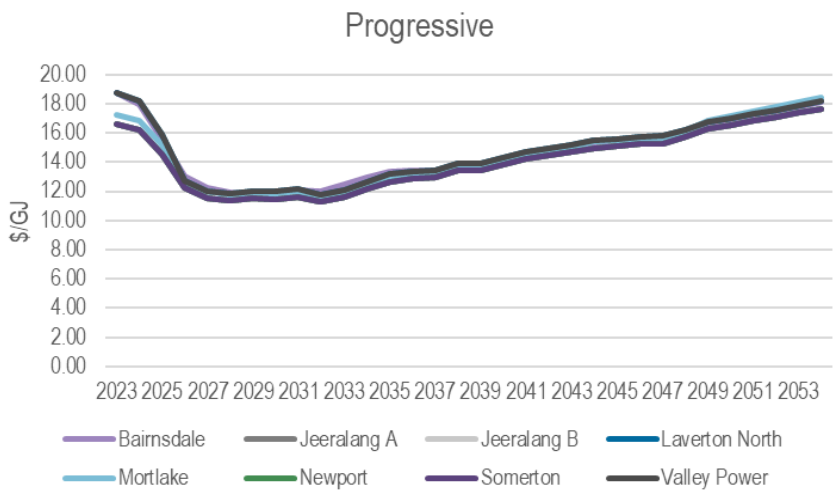
GPG prices - VIC

Our draft Victorian GPG price forecasts are below for each individual generator. We present the forecasts for the three scenarios modelled – orchestrated, progressive and green energy exports.

- GPG prices in Victoria are expected to follow the general trend in other markets across the forecast period.
- Our assumptions for Victorian generators are the same as applied to New South Wales which was described on the previous slide.
- The price for all generators is expected to be similar and no CCGTs currently exist in Victoria.
- Mortlake is the only generator on occasion which experiences noticeably different prices, and this is largely down to specific demand/supply interactions near Port Campbell.
- Any new CCGT or OCGT to be built over the forecast period in Victoria would have prices like existing generators (with CCGTs expected to have a lower price than forecast here for OCGTs)



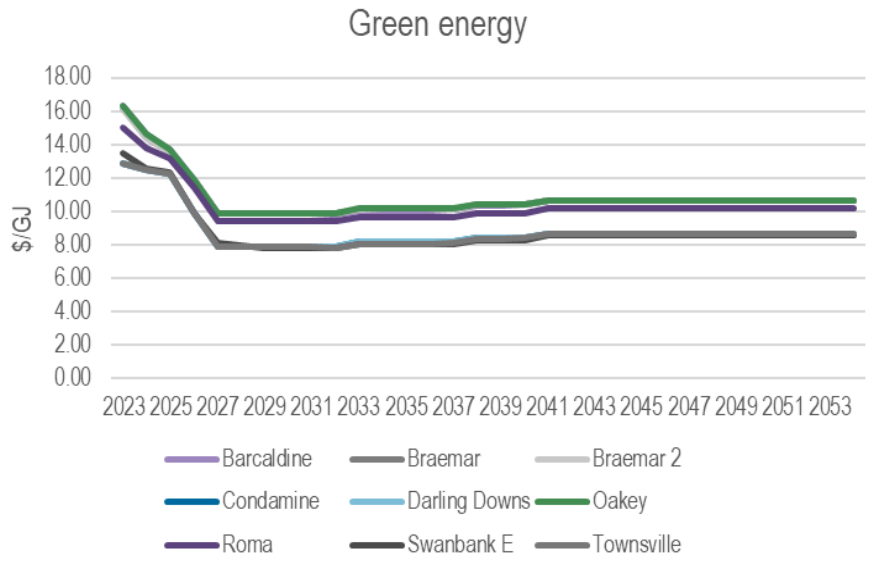


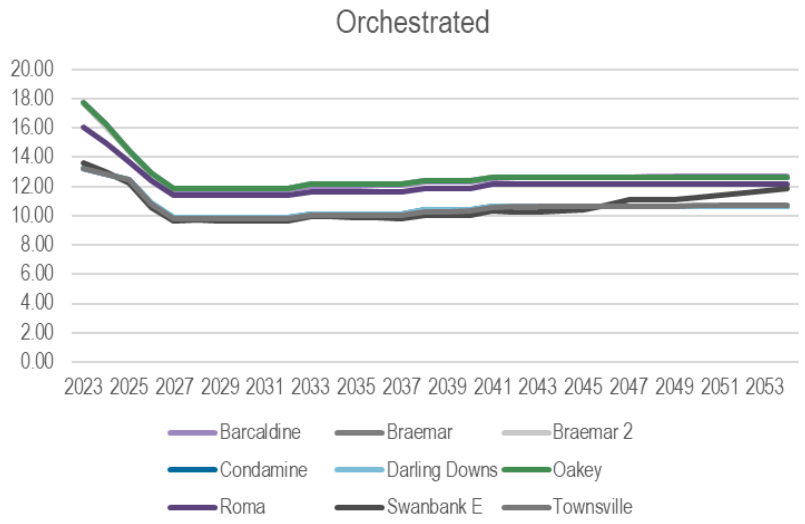


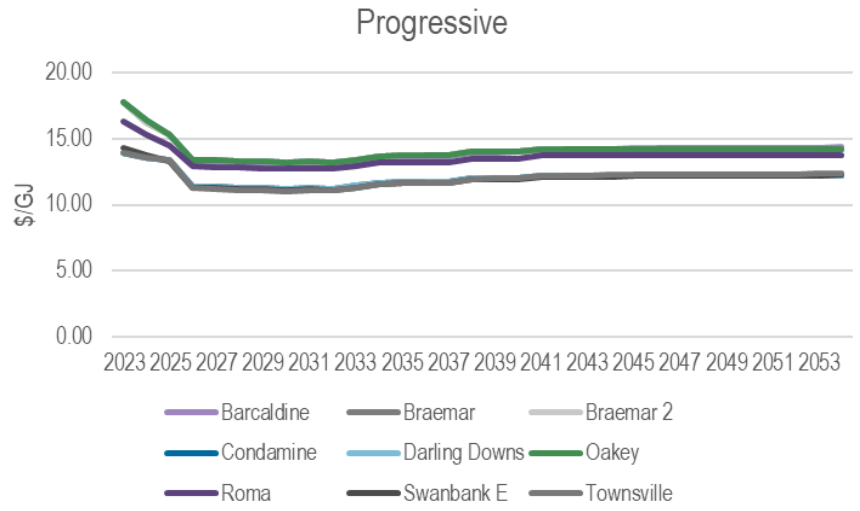
GPG prices - QLD

Our draft Queensland GPG price forecasts are below for each individual generator. We present the forecasts for the three scenarios modelled – orchestrated, progressive and green energy exports.

- GPG prices in Queensland are expected to follow the general trend in other markets across the forecast period.
- Our assumptions for Queensland generators are the same as applied to New South Wales and Victoria as described on previous slides.
- Prices paid by CCGTs are expected to be lower across the forecast period based on their role versus OCGTs
- The difference between most generators is small given most are located in the same area (around Roma, Condamine and Oakey etc). Our next version of the forecasts will more explicitly factor in differences that may occur as a result of ownership and vertical integration.
- Prices in the long term are expected to be significantly influenced by the long-term LNG netback price (and is relatively constant given our long-term assumption post 2030 is constant)



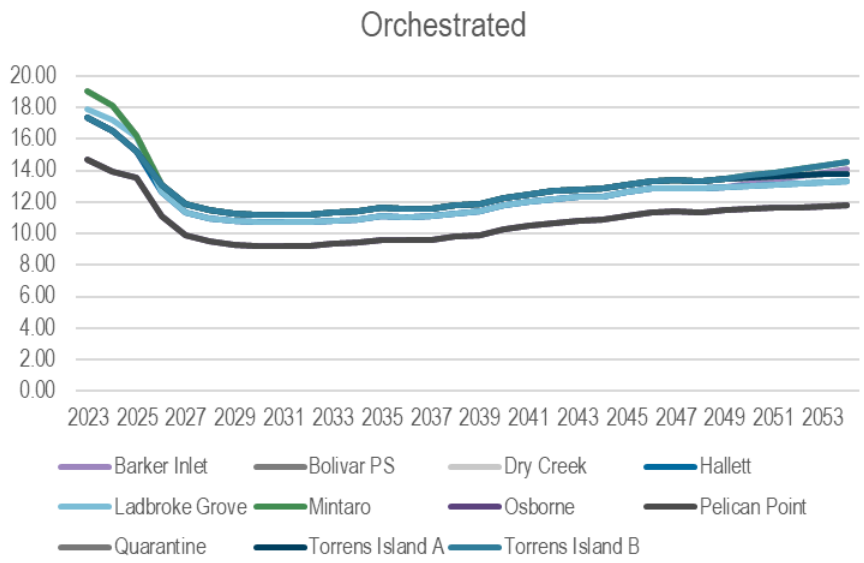


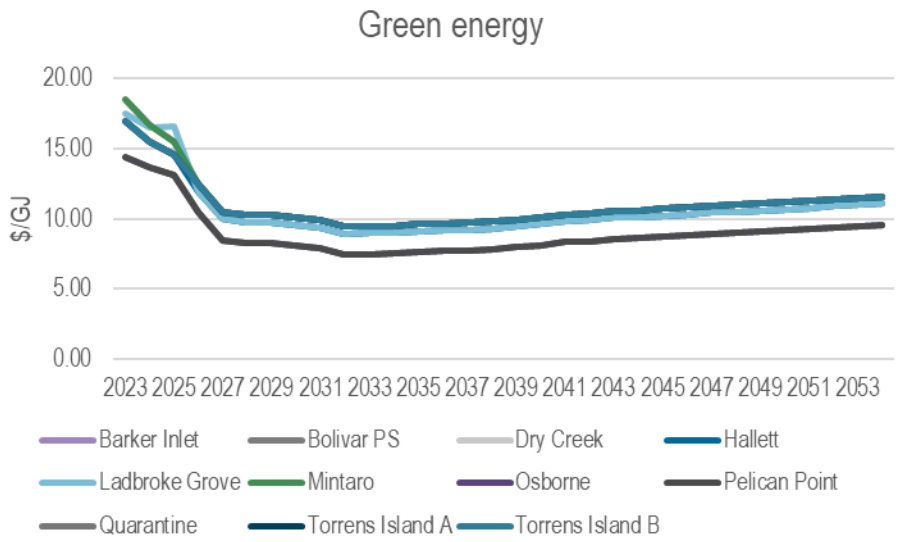


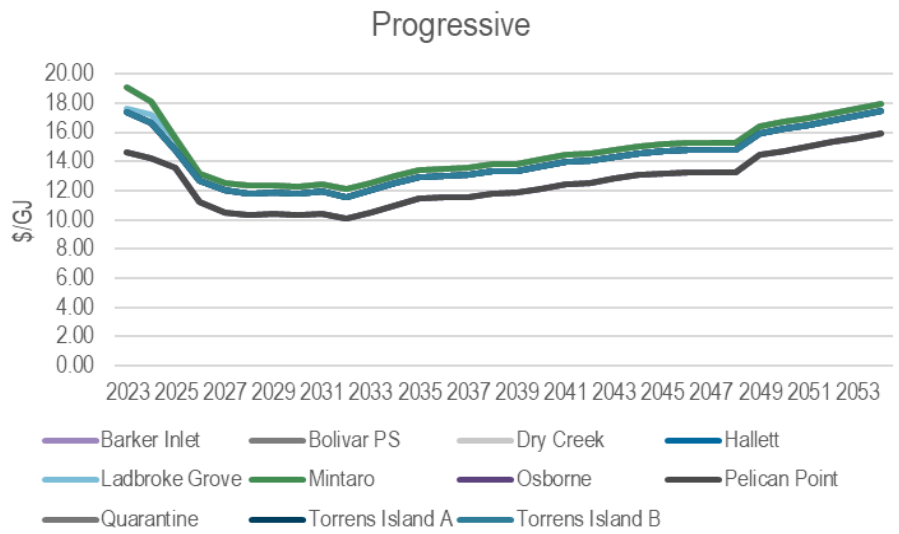
GPG prices - SA

Our draft South Australian GPG price forecasts are below for each individual generator. We present the forecasts for the three scenarios modelled – orchestrated, progressive and green energy exports.

- GPG prices in South Australia are expected to follow the general trend in other markets across the forecast period.
- Our assumptions for South Australian generators on contracting are the same as applied to the other states.
- Little variation is forecast between each generator in this initial version of our forecasts given most are located largely in Adelaide.
  - We expect this might change in our next version of forecasts once we take into account the possible differences between contracting by large gentailers versus smaller players in the GPG market.
- Ladbroke Grove experiences a slightly different price to other markets given its location in South Australia and that it relies on the SEA Gas pipeline for supply, while others in Adelaide and source supply also from the Moomba to Adelaide Pipeline.



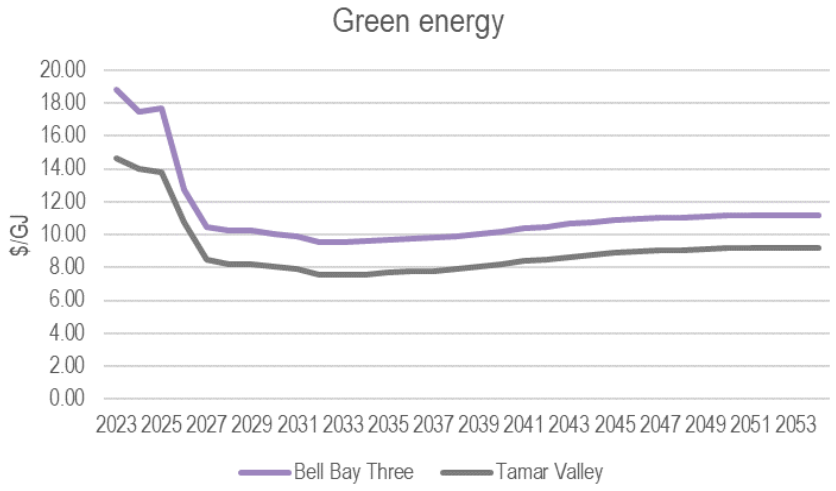


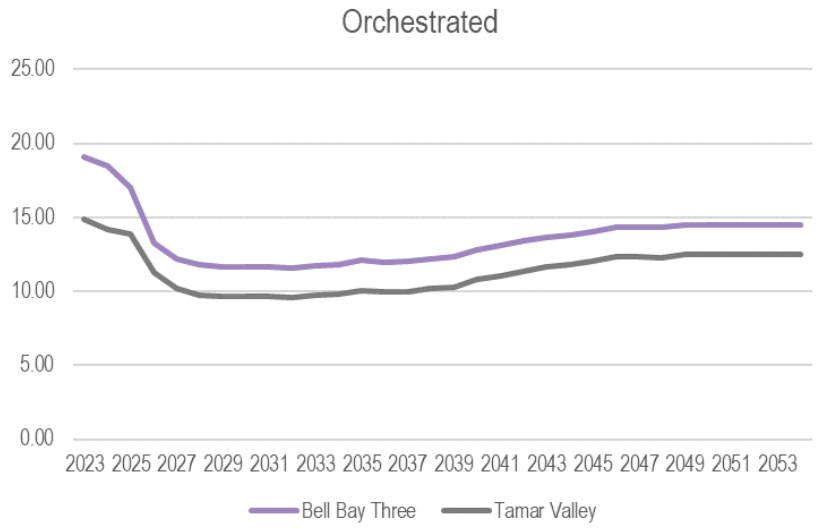


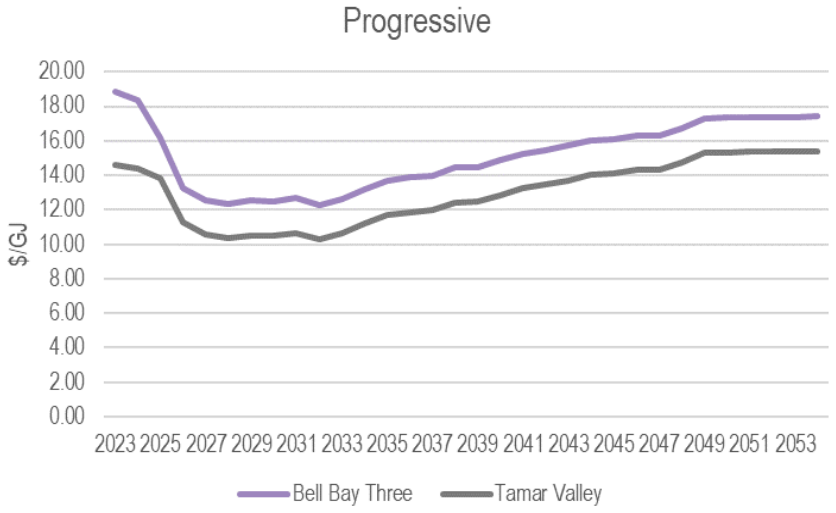
GPG prices - TAS

Our draft Tasmanian GPG price forecasts are below for each individual generator. We present the forecasts for the three scenarios modelled – orchestrated, progressive and green energy exports.

- GPG prices in Tasmania are expected to follow the general trend in other markets across the forecast period.
- Our assumptions for Tasmanian generators on contracting are the same as applied to the other states.
- The difference in price between the two generators is down to the different technology (CCGT vs OCGT)
- The higher price paid by Tasmanian generators compared to generators on the mainland is largely down to higher transmission costs to transport gas from Victoria.







Key findings

Residential and commercial

The key findings for forecast residential and commercial prices are:

- Over the period to 2025, wholesale gas prices are contained to a large degree by the wholesale gas price cap in all scenarios. The cap works as a substitute for the LNG netback in contract negotiations and prices should be $12/GJ plus transport.
  - Wholesale gas prices delivered to the major capital cities will hover between $12 and $15/GJ depending on location from 2023 to 2025
- During this period to 2025 we also expect Asian LNG prices to continue to retreat from the peak prices experienced in 2022. By 2026, we expect that LNG prices will have retreated to levels below the wholesale price cap level. Therefore, the LNG netback will take over as the price reference for domestic contracts from 2026 (assume the price cap is lifted).
- Prices in the **Orchestrated scenario** decline to levels around $9-10/GJ in the late 2020s and early 2030s before rising steadily to levels around $11-12/GJ by the end of the outlook period.
- Prices in the **Progressive scenario** decline to levels around $10-11/GJ in the late 2020s and early 2030s before most cities see prices rising to levels around $14/GJ by the end of the forecast period (except for Brisbane).
- Prices in the **Green energy export scenario** decline to levels around $7-8/GJ in the late 2020s and early 2030s and increase marginally over the outlook period.
- The sharpness in the decline in prices in each scenario in the 2020s is mainly down to what level international LNG prices are expected to fall to, and then trend at long term.
- The pace and level at which prices increase over the long term is mainly influenced by forecast demand levels – larger declines in demand place more downward pressure on prices.

Industrial

The key findings for forecast industrial prices are:

- Like the residential and commercial market, wholesale gas prices are contained to a large degree by the wholesale gas price cap in all scenarios. The cap limits the cost of wholesale gas for industrial users over the period from 2023 to 2025.
  - Wholesale gas prices delivered large industrial users will generally hover between $11.50 and $15/GJ depending on location from 2023 to 2025
- Prices in the **Orchestrated scenario** decline to levels around $9-10/GJ in the late 2020s and early 2030s before rising steadily to levels around $11-12/GJ by the end of the outlook period.
- Prices in the **Progressive scenario** decline to levels around $8-10/GJ in the late 2020s and early 2030s before most cities see prices rising to levels around $13-14/GJ by the end of the forecast period (except for Brisbane).
- Prices in the **Green energy export scenario** decline to levels around $6-8/GJ in the late 2020s and early 2030s and increase marginally over the outlook period.
- The key difference between the prices forecast for industrial users in comparison to residential and commercial markets is the assumption that their load factors are much flatter over a year. The ultimate price paid by industrial users for gas is typically lower due to this flat load factor, and this is reflected in the price forecasts.
- Prices over the medium and long term are mainly down to expected levels of demand. In some states such as Victoria, larger forecast reductions in demand over the next 10-15 years results in forecast prices being marginally lower than other states during this period. Then as larger declines are eventually made in other states towards the back end of the outlook period, prices then merge narrower for most locations.

Gas fired power generation

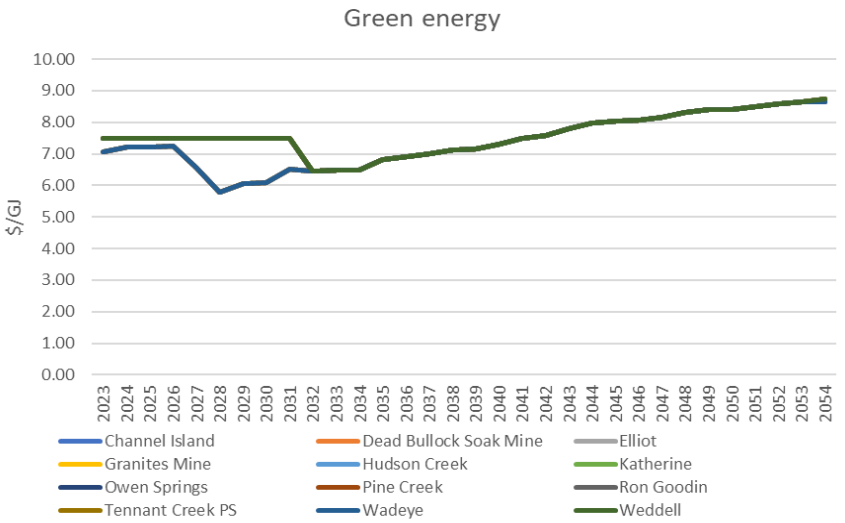
The key findings for forecast GPG prices are:

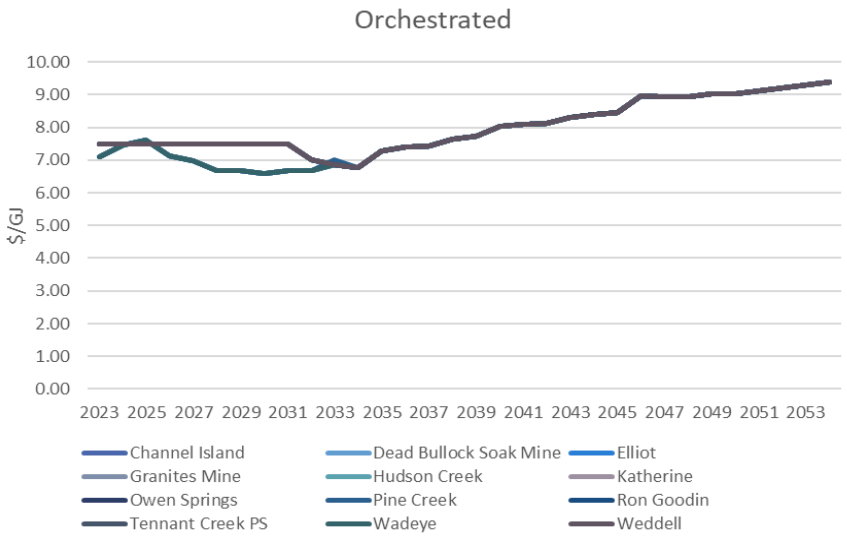
- Like the residential and commercial market, wholesale gas prices are contained to a large degree by the wholesale gas price cap in all scenarios. The cap limits the cost of wholesale gas for GPG over the period from 2023 to 2025.
  - Wholesale gas prices delivered to GPG stations will generally hover between $13/GJ and $20/GJ depending on location and generation technology from 2023 to 2025
- Prices in the **Orchestrated scenario** decline to levels around $9-12/GJ in the late 2020s and early 2030s before rising steadily to levels around $12-15/GJ by the end of the outlook period.
- Prices in the **Progressive scenario** decline to levels around $10-13/GJ in the late 2020s and early 2030s before most cities see prices rising to levels around $13-18/GJ by the end of the forecast period.
- Prices in the **Green energy export scenario** decline to levels around $7-10/GJ in the late 2020s and early 2030s and increase to levels around $9-12/GJ in the long run.
- The key difference between OCGTs and CCGTs is the impact in the short term from the divergence in contract and spot market prices. OCGTs that rely heavily on the spot market are forecast to pay higher prices for gas in the short term while wholesale price caps limit contract prices.
- In some scenarios, particularly the Progressive scenario, significant additional GPG capacity is brought online in the later years in the southern states. This results in higher prices for generators in these states to procure gas compared with generators in Queensland for example where limited new GPG capacity is needed and gas supply from Queensland suppliers is more readily accessible compared with limited southern supply.

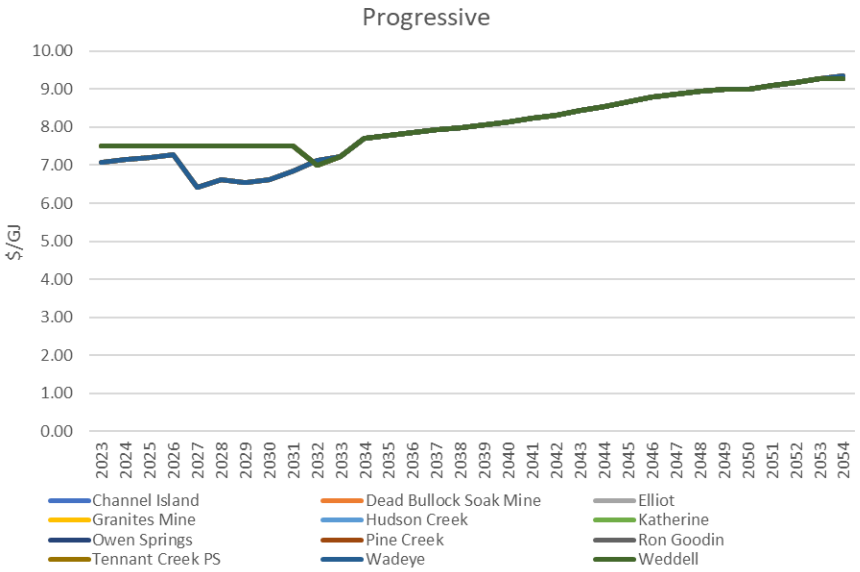
GPG prices - NT

Our draft Northern Territory GPG price forecasts are below for each individual generator. We present the forecasts for the three scenarios modelled – orchestrated, progressive and green energy exports.

- Our assumption is that currently many of Territory Generation's GPG stations are on long term contracts which are anticipated to retire around 2030. The price of gas we estimate to be between $7 and $8/GJ in 2023 dollars. After these contracts expire, the price they pay is forecast by our gas market modelling results.
- The generators outside of the Territory Generation portfolio are largely providing power for mining operations. We do not have visibility on what these generators might be paying.
  - As we do not know what their gas procurement details are, we have estimated their price for the full forecast period on our gas market model results.
- Over the forecast period prices are expected to increase. A dip in prices is demonstrated in the late 2020s and this is mainly as a result of increased Beetaloo production starting to enter the market. This suppresses prices in the market in the short term before prices continue their upward trajectory as production costs increase and more gas is directed over time to the ECGM and Darwin LNG.







Appendices

Appendix A: GasMark model

ACIL Allen has developed an Australian gas market supply/demand model. The platform has been developed by ACIL Allen over the past 20 years to analyse gas demand and supply dynamics in the east coast gas market and the Western Australian gas market. The model allows projection of future gas supply, demand and price outcomes at annual, quarterly, monthly or daily resolutions with a maximum time horizon of 30 years. It is therefore a useful tool for looking at the implications of short-term supply & demand variability over long time periods.

GasMark Global (GMG) is a generic gas modelling platform developed by ACIL Allen. GMG has the flexibility to represent the unique characteristics of gas markets across the globe, including both pipeline gas and LNG. Its potential applications cover a broad scope — from global LNG trade, through to intra-country and regional market analysis. GasMark Global Australia (GMG Australia) is an Australian version of the model which focuses specifically on the Australian market (including both Eastern Australia and Western Australia), but which has the capacity to interface with international LNG markets.

The model can be specified to run at daily, monthly, quarterly or annual resolution over periods up to 30 years.

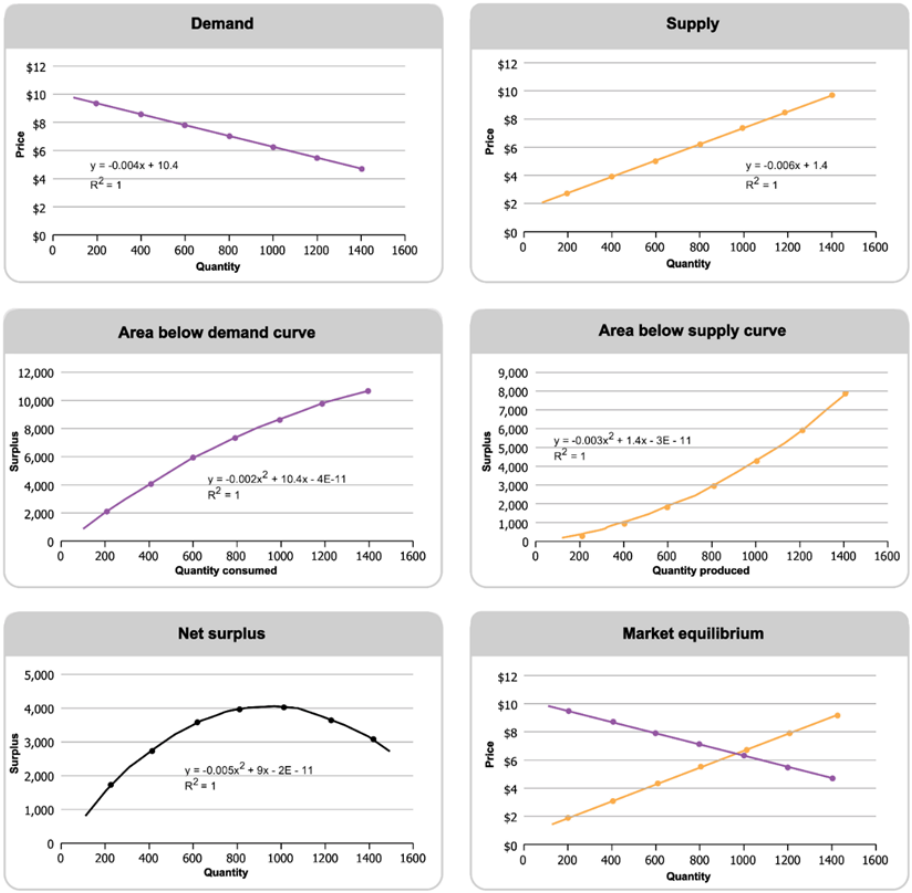
Settlement

At its core, GasMark is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to 'arcs' within a network model).

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. The objective function of this solution, which is well established in economic theory, consists of three terms:

- the integral of the demand price function over demand; minus
- the integral of the supply price function over supply; minus
- the sum of the transportation, conversion and storage costs.

The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised, and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price.



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