Gas Price Projections for Eastern Australia, 2023 Update

Prepared for

Australian Energy Market Operator

by

Lewis Grey Advisory

LG021

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Contents

Disclaimer

This report has been prepared solely for the Australian Energy Market Operator, for the purpose of assessing gas prices in eastern Australia over the period 2022 to 2053. Lewis Grey Advisory bears no liability to any party (other than specifically provided for in contract) for any representations or information contained in or omissions from the report or any communications transmitted in the course of the project.

The price projections reported in this document were finalised in November 2022 and did not take into account the potential impacts of gas price caps announced by the Commenwealth.

1. Terms of reference

The Australian Energy Market Operator (AEMO) has engaged Lewis Grey Advisory (LGA) to update the Gas Price Projections for Eastern Australia published with the 2022 GSOO in March 2022 (the 2022 Price Projections). The update focuses on changes to gas price forecast parameters that are both material and are to parameters that have a significant impact on gas prices. Other parameters are as in the 2022 Price Projections, with CPI escalation, and the methodology is largely unchanged.

1) Gas price forecasts

AEMO requires forecasts of annual gas prices for the forecast period 2022 to 2053 for each of four scenarios defined by AEMO (see below) for each of the East Coast regions. More specifically:

- Forecasts of wholesale gas prices (industrial, residential and commercial and gas-powered generation) for each region/generator located within the East Coast gas markets of Australia. The data must be in a format agreed with AEMO based on the specific requirements set out below.

2) Scenarios to be applied to the Forecasts

The outcomes for each of the above Services should reflect the different drivers for each of four scenarios. The scenarios reflect alternative economic and technology settings affecting Australia's gas and electricity markets, including international commodity dynamics where appropriate. Background information for each scenario can be found in the current Inputs, Assumptions and Scenarios page on the AEMO website.

AEMO will confirm the appropriate settings for these scenarios at project commencement, indicative settings are provided in the following table. The Recipient is expected to provide forecasts that are consistent with the themes of the following scenarios.

1.1 This report

This report, together with an Excel workbook, "Lewis Grey Advisory 2023 Gas Price Projection Workbook", fulfill the reporting requirements outlined in the Terms of Reference above. The first draft report was provided on 12th October 2022 and the report was finalised following discussions with AEMO.

Table 1 Scenario Overview

	Scenarios			
Driver	**Progressive Change**	**Exploring Alternatives**	**Step Change**	**Hydrogen Export**
Economic Drivers	Assumes lower economic growth and ongoing disruptions affecting international energy markets and supply chains. Includes the greatest relative risk of industrial load closures.	Population and economic growth adopt best estimate forecasts.	Population and economic growth adopt best estimate forecasts. Technology breakthroughs in energy efficiency and fuel switching increase energy productivity, and high electrification occurs	Australia's economic growth is higher than the other scenarios, supported by exports of "green commodities" to global consumers at scale, including hydrogen and other energy-intensive products such as green steel. This stronger economy also drives a larger net migration.
Technology Drivers	Technology cost reductions are slower than in the other scenarios.	Technology cost reductions reflects best estimates meeting net zero emissions globally post 2050, though with a faster cost reduction assumed for green gasses (e.g. biomethane), which uptake is limiting the scale and pace of electrification relative to Step Change.	Technology cost reductions reflects best estimates meeting net zero emissions globally post 2050, though with a faster cost reduction assumed for distributed energy resources (DER), such as rooftop PV and battery storage. The transport sector rapidly transforms via zero emissions technology cost reductions, and withdrawal of internal combustion engine vehicles from production lines.	Technology cost reductions reflects best estimates meeting net zero emissions globally by 2050 and with rapid technology cost improvements for the hydrogen supply chain. Cheap local hydrogen drives competition between hydrogen fuel-cell vehicles and EV's.
Decarbon-isation ambition	Global decarbonisation progresses in line with currently announced policies and ambitions, including Australia's updated commitment to a 43% reduction of economy-wide emissions by 2030 and net zero emissions by 2050. .	This scenario reflects a strong commitment by state and federal governments to deliver not only net zero emissions by 2050, but also to limit global temperature rise to well below 2°C compared to pre-industrial levels (i.e. the Paris Agreement). Similar strong commitments are seen globally, but not all countries delivers on promises in the end.	This scenario reflects a strong commitment by state and federal governments to deliver not only net zero emissions by 2050, but also to limit global temperature rise to well below 2°C compared to pre-industrial levels (i.e. the Paris Agreement). Similar strong commitments and actions to deliver are seen globally.	Very strong international decarbonisation objectives limit global temperature rises to 1.5°C by 2100. Domestically, economy-wide net zero emissions are achieved before 2050.

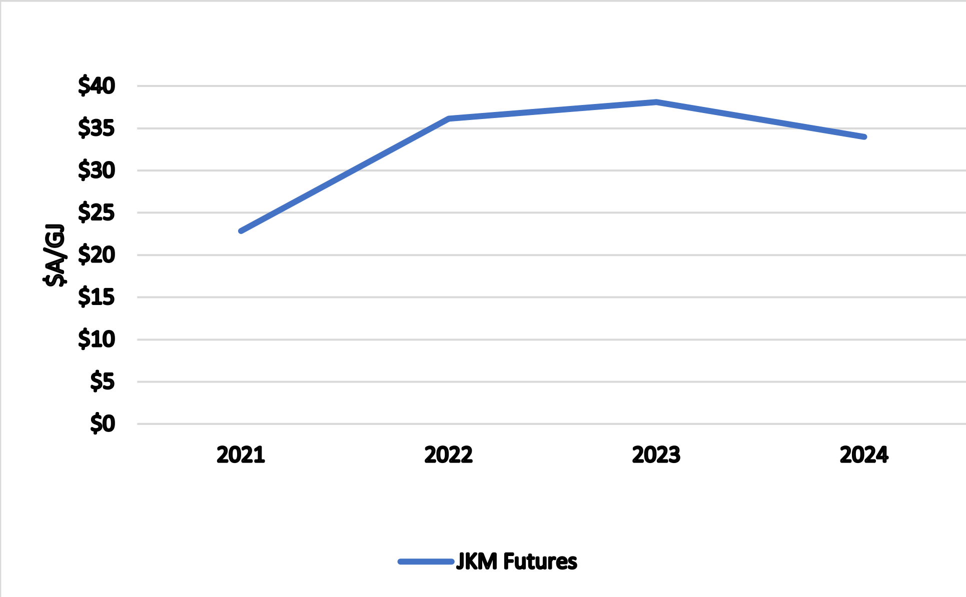
	Scenarios			
Driver	**Progressive Change**	**Exploring Alternatives**	**Step Change**	**Hydrogen Export**
DER Uptake	DER uptake is dampened due to supply chain issues. Renewable energy development continues to be driven by current market and policy settings, and coal capacity is relatively more likely to remain operational until announced closure timings.	Overall, this scenario has a higher proportion of utility-scale investments relative to the decentralised focussed Step Change, using moderate forecasts of DER, electric vehicles and energy efficiency.	Digital technologies expedite consumers' ability to use their DER assets efficiently and a large proportion is actively participating in the energy system.	The strong decarbonisation targets drive significant electrification and hydrogen production (for both export and domestic consumption). High electrification and energy efficiency investments occur across many sectors

2. Introduction

2.1 Gas Market Changes Since 2021

During 2022 global LNG prices have surged in response to Russia's invasion of Ukraine, the consequent sanctions on Russia, significant reductions in Russian gas supply to Europe and European gas buyers' scramble to secure alternate supplies, principally LNG. Global LNG prices doubled from already high levels, reflecting limited supply expansion options in the short term. The anticipated continuation of high prices is illustrated in Figure 1.

Figure 1 JKM Futures, late 2022



Source: LGA compiled from ACCC "LNG netback price series – Public Version – 17 October 2022"

Australian LNG exporters responded to high global prices by increasing spot export sales, offering short-term domestic (east coast) sales at high, export equivalent, prices. During winter 2022 high gas demand for power generation in the NEM, due to reduced coal plant output, led to supply/price crises in both electricity and gas markets. After the electricity market experienced very tight supply conditions, on June 15 AEMO suspended the market for seven days to ensure reliable supply. The Gas Supply Guarantee was also triggered to ensure gas supply for power generation. In the Victorian Gas Market persistently high prices led to the Administered Price Cap of $40/GJ being triggered. High energy prices also led to the financial failure of a number of energy retailers.

While domestic spot prices have recently retreated from the extreme levels reached during winter 2022, they remain well above previous benchmarks. Moreover Asian LNG spot and futures prices remain very high and are not expected to decline before 2024.

In its July 2022 Gas Inquiry Interim Report the ACCC reported that in the previous year the LNG exporters had exported most of their "excess gas" (gas available surplus to contractual commitments) and sold very little into the domestic market. The ACCC estimates that if this persists in 2023 there will be a shortfall of 56 PJ in the domestic market in that year.

2022 has not seen much resolution of future trajectory of gas demand in response to decarbonisation targets.

2.2 Study Improvements since 2021

LGA has made further improvements to the modelling methodology and data applied to estimate the price projections in 2022, in response to changes in the gas market and comments from stakeholders regarding the 2022 Price Projections. They are summarised here with details provided in section 3.

- Gas production costs for undeveloped 2P reserves and for 2C resources are indexed to foreign exchange rates (refer to section 3.5.6)
- The number of sellers per joint venture can be specified differently for domestic and export markets (refer to section 3.5.7). This structure was suggested by the ACCC in its July 2022 Gas Inquiry Interim Report
- JKM Futures are used as a short-term benchmark for modelled LNG New Contract Prices (refer to section 3.4.1.2.1)
- Gas producer reported average prices are used to benchmark Domestic Average Prices (refer to section 3.4.1.2.2)

2.3 Study Objective

The objective of this study is to project gas prices in the Eastern Australian natural gas market (NSW, VIC, QLD, SA and TAS) over the period 2022-2053, taking into account exports from Gladstone and the potential to import LNG to the domestic market, but the study does not consider the supply of biogases and hydrogen.

Eastern Australian gas market prices are largely determined by contract negotiation between producers and buyers, hence the projections' focus on delivered average annual contract prices, including transmission costs, applicable to Large Industrial Consumers, with high load factors. However with current high offer prices for new contracts it must be recognised that buyers may be reluctant to enter contracts at all, in the hope of price relief in the near term.

Wholesale prices for other consumer groups, excluding retail margins and distribution costs, are further estimated by adjusting the Industrial prices by applying the following formulas:

- Residential and Commercial (R&C) price = Industrial price + Load Factor Adjustment (Pipeline & Storage)
- Gas Powered Generation (GPG) price = Industrial price + Load Factor Adjustment (Pipeline only) + Site specific adjustments

3. Methodology and Data

3.1 Relevant Features of the eastern Australian Gas Market

Natural gas has been supplied to markets in Eastern Australia since the late 1960s[1]. A period of isolated state markets with monopoly-monopsony supply-demand arrangements was followed by domestic gas market liberalisation in 1997, with the commencement of third-party access to pipelines. By 2004 an interconnected pipeline grid had been established (refer to Figure 4 below), facilitating more competitive supply arrangements. Significant additional gas resources in the Bass, Otway and Surat basins were subsequently developed,[2] the last having sufficient gas reserves to support the construction of LNG export facilities at Gladstone, Queensland.

Since 1997 the Federal and State Governments have encouraged secondary trading of gas and pipeline capacity, using spot markets operated by AEMO. While liquidity in these markets has increased over time[3], longer term contracts between gas producers and buyers have remained the primary mechanism whereby additional gas supply enters the domestic market. Over the past 8 years buyers have reported material rises in the prices negotiated by producers for additional gas, coincident with a number of potential causes:

1) Development of LNG export facilities in Queensland.
2) The East Coast gas market opening up to supplying both domestic and international gas markets.
3) LNG exporters competing with domestic gas consumers to access gas supply to fill their LNG production facilities.
4) Declining resources in the Cooper and Gippsland Basins, which have supplied the majority of domestic gas to date.

Since the Covid-19 induced declines in global and local oil and gas prices in 2020, economic recovery has stimulated rapid energy price escalation, particularly in Northern hemisphere gas and LNG markets. In the lead-up, and subsequent to, the COP-26 climate conference in Glasgow in November 2021, the energy sector as a whole has become very focussed on Net Zero 2050/Decarbonisation, creating:

- Future domestic and global gas demand uncertainty
- Potential for increasing costs due to diseconomies of scale, and higher costs of capital for fossil fuels
- Potential constraints on hydrocarbon resource development on one hand or promotion of gas as transitional fuel on the other
- Globally, forecasts of long-term declines in Oil and LNG demand and prices, despite current price escalation

A new factor in Eastern Australia considered in this study is the assumption that Port Kembla and Adelaide Import Terminals will proceed to completion, which together with potentially declining global prices makes it possible that LNG imports at competitive prices will drive domestic prices in some scenarios.

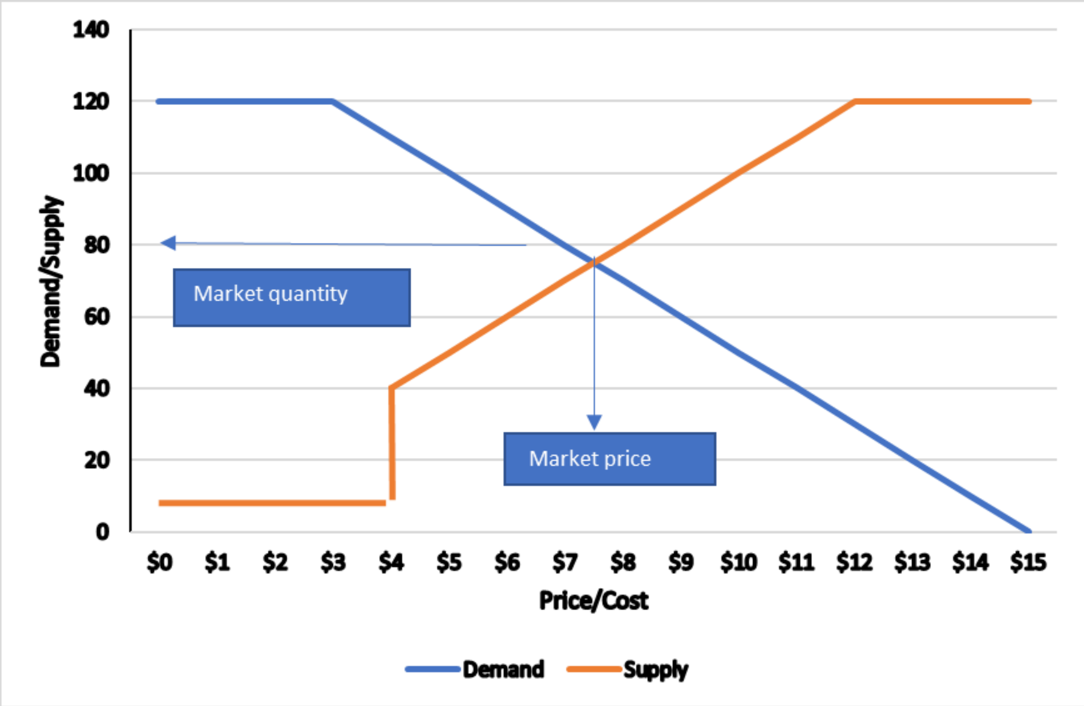
[1] Prior to this, many of the markets had been supplied with town gas manufactured from coal and waste refinery gases.
[2] The first two being conventional, offshore resources, the last being coal seam gas (CSG).

[3] Biennial review into liquidity in wholesale gas and pipeline trading markets, AEMC, 30/1/2020.

3.2 Model Outline

In most markets demand declines and supply increases with price, with the market price being set where the demand and supply curves intersect, as illustrated in Figure 2.

Figure 2 Market prices are set at the intersection of demand and supply curves



LGA bases its gas price forecasts on a demand-supply balancing methodology which captures the features of the Eastern Australian gas market outlined above. It is based on the assumption that suppliers try to maximise prices subject to competition with other suppliers and consumer price resistance[4]. The outcomes are equivalent to least cost supply plus a margin due to market power (less than fully effective competition.)

Interaction of Eastern Australian domestic prices with Global LNG prices is taken into account directly by modelling the two markets in parallel. Domestic and Global LNG demand are satisfied by domestic and Global LNG suppliers, with interchanges between the markets through exports by domestic suppliers via Gladstone and imports of LNG via Port Kembla[5] from 2024 and Adelaide from 2025. Although representation of the global market is approximate, global LNG price outcomes replicate the forecasts of reputable third-party forecasters (refer to section 3.5.3). By modelling the price linkages directly, arbitrary assumptions about LNG netback or oil-price indexation linkages are avoided.

The actual market modelled is that for new gas supply contracts, where the price of gas entering the domestic market is set. Average prices in the market are then calculated from the prices of contracts entered in all the years up to the year under consideration. The new contracts required in each year are set equal to the total demand less contracts up to the previous year, and available supply is equal to total production capacity less capacity reserved for contracts up to the previous year.

[4] This approach replicates full competition in the case of many suppliers and monopoly supply in the case of one supplier.
[5] For this study imports are assumed to be solely through Port Kembla and Adelaide. Viability of imports through other proposed import terminals has not been tested, owing to the multiplicity of scenarios this would create.

Total demand is based on domestic demand forecasts provided by AEMO and Global LNG forecasts are sourced by LGA. Existing contracts already in place between the producers and regions, sourced from LGA's and other contract data bases, are specified as data and define the new contract requirement in the first year. LNG exporters' committed contracts for LNG are treated as contracts for gas at the wellhead – exports after these contracts have expired are determined in the model by competition between the Queensland exporters and other exporters in the Global LNG market.

Production capacity is linked to remaining gas reserves. Potential gas supply for new contracts comes from uncontracted capacity. Development of undeveloped 2P reserves is assumed to be followed by development of 2C resources (separately for each producer) and supply costs are based on independent estimates of undeveloped 2P and 2C production costs. Transmission and shipping costs to each region are added to production costs, so that gas from different producers is competing in each region on a delivered basis.

This approach enables the model to reflect the fact that existing contracts, particularly for exports, can lock up much of the existing gas resource base.

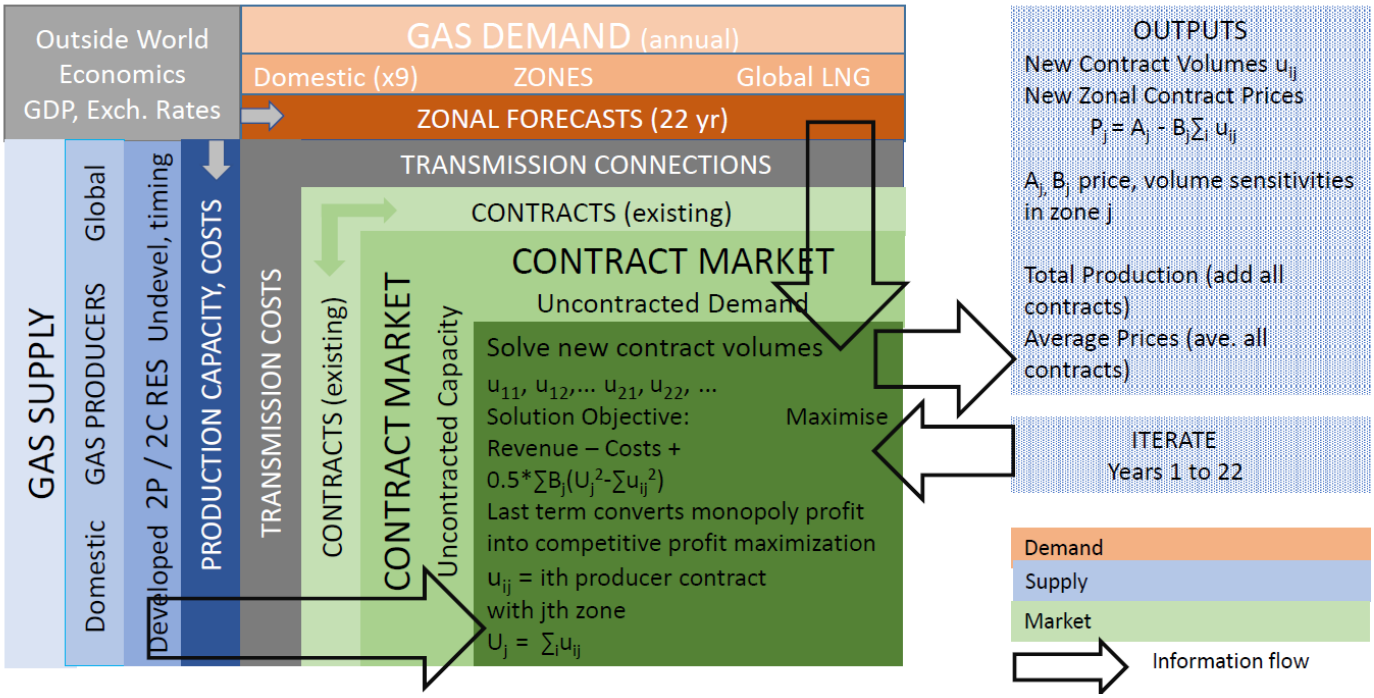
The methodology has been implemented in a generic Excel shell called the Resources Market Model (RMM), which is applicable to any resource-based market (gas, coal, oil) in which reserves and term-contracts are important features. In 2017 RMM was used to build a model of the Global LNG market, RMMLNG, and in 2019 it was used to build a model of the eastern Australian gas market, RMMEAU. RMMLNG was used to support LGA's projections of Queensland gas exports, which LGA prepared for the GSOO in 2017[6], and RMMEAU was used to derive gas prices for the 2021 and 2022 GSOOs.

RMMEAU currently provides for multiple producers to compete in up to 10 consuming markets. Parties sharing a resource, e.g. joint venture partners, can be represented as single or multiple sellers. Markets can be different regions or different markets in the same location, e.g. GPG and large industrial. Producers are linked to markets by a transportation network of pipelines, tankers and/or other modes of shipping.

A model schematic is shown in Figure 3, illustrating how demand and supply data is processed into new contract market format and then the market solution is obtained by maximising the market objective, which represents the market as a Nash-Cournot game. With sufficient competition the Nash-Cournot solution becomes a least cost solution.

[6] LGA's earlier export projections during the LNG construction phase (2014-2016) used a different methodology.

Figure 3 RMMEAU Model Schematic



3.2.1 Additional features of the methodology

1. Demand forecasts are accompanied by price elasticities and the prices at which the forecasts are projected to occur. This data is converted into a linear demand-price sensitivity used in the Nash-Cournot model. A dynamic elasticity function can be used to deal with changing sub-market composition in each region.

2. RMMEAU does standard gas accounting to keep track of both reserves remaining and reserves already committed to contracts, so that new gas production capacity and contracts are properly constrained.

3. Transmission is treated as a passive input to production costs i.e. the pipeline/shipping owners are not profit maximising agents like the producers are[7]. This choice has been made owing to the lower cost of transmission compared to production. Transmission routes are specified as data and it is assumed that each producer to zone route is unique (alternatively that the costs of different routes are very similar). Transmission capacity is not constrained. The impact of constraints can be estimated by varying pipeline tariffs to keep throughput below capacity.

4. In scenarios with declining domestic demand forecasts transmission costs are varied in proportion to the inverse of demand, to reflect the fixed cost nature of pipelines. This is not applied to LNG shipping, however.

5. The production solution engine is driven by a bespoke hill-climbing algorithm. Production constraints are dealt with by penalty functions – when a constraint is reached, the cost of production increases. Solution proceeds on an annual basis – alternative time periods are possible but require significant data re-organisation.

6. The duration of new contracts must be specified as input and 3-year contracts are currently assumed. All new contracts must be of the same duration so that the market is unambiguously defined.1-year contracts would be equivalent to annual competition for the whole market, once initial contracts had expired.

[7] The mathematics of competitive supply across multiple supply tiers, such as production and transmission or retail, are too complex for inclusion in RMMEAU. LGA currently has single year models of two-tier supply chains.

7. Oil indexation of existing contracts is applied ex-post. No indexation is applied to new contract prices as global price impacts are included in the model and further indexation would amount to double counting. LGA acknowledges that oil price indexation may continue to be used in the gas marketplace.

8. For the avoidance of doubt:

    a. RMMEAU works on annual intervals, it does not calculate daily prices or deal with peak demand[8], but peak supply costs are added ex-post to derive GPG and R&C wholesale prices.

    b. RMMEAU works on the assumption that supply can be developed in time to meet demand, apart from the initial global imbalance which is captured in the model. It cannot predict future imbalances, though they are almost certain to occur due to unforeseen events.

3.3 Market Representation

The eastern Australian gas resources, pipeline infrastructure and gas markets represented in RMMEAU are illustrated in Figure 4. In RMMEAU the eastern Australian gas market is represented as competition among multiple domestic gas producers (currently in nine basins) and one generic global LNG joint venture producer, supplying demand in 9 domestic regions and one generic global LNG market. The cost of gas supply (delivered to each market) is made up from two components, production and processing, plus a transmission component provided by third parties.

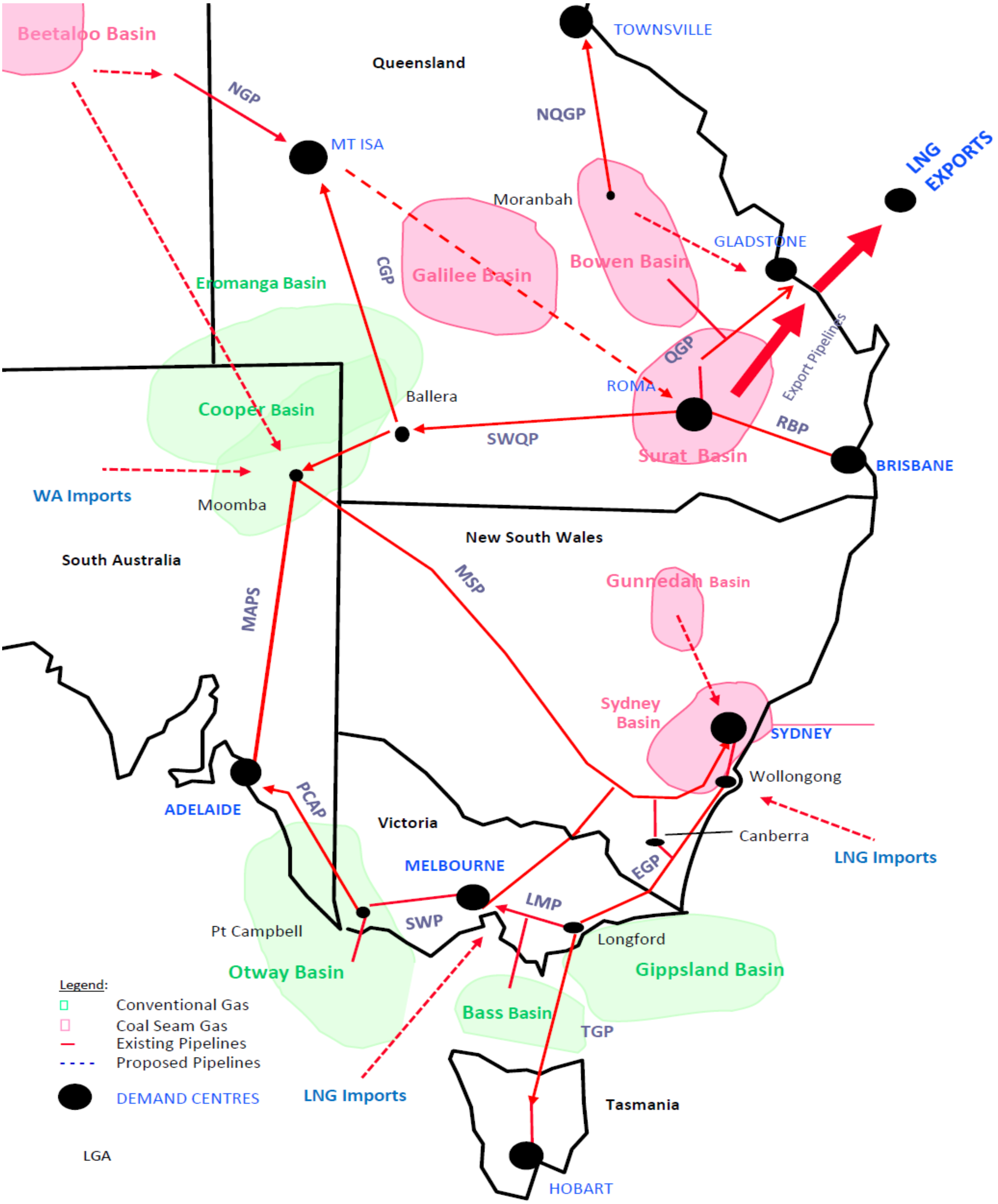
The producers cover all current production plus potential new sources such as the Beetaloo, Galilee, Gunnedah and North Bowen Basins and imports from Western Australia and/or global LNG producers. The Global LNG joint venture producer is assumed to comprise multiple identical partners.

The market regions are: NSW; Victoria; SA; Tasmania; Brisbane; Gladstone (domestic); Mt Isa; Townsville; Roma/Wallumbilla; and Global LNG. For the purposes of calculating pipeline costs all are represented as point loads, the first four being at Sydney, Melbourne, Adelaide and Hobart respectively. Northern Territory demand is not included in the current version. Market demand is the aggregate annual demand in each region. LNG demand includes gas used in liquefaction.

Costs of transporting gas from producers to markets are the sum of tariffs/costs of the pipelines/shipping used in transportation.

[8] LGA has derived a methodology for peak demand that has been developed up to a single year implementation.

Figure 4 Eastern Australian Gas Resources, Infrastructure and Markets Represented in RMMEAU



3.4 Model Validation and Price Sensitivity to Key Factors

3.4.1 Model Validation

3.4.1.1 Validation for the 2022 Price Projections

For the 2022 Price Projections the RMMEAU model used in this study was benchmarked against contract prices reported by the ACCC in the Gas Inquiry 2017-2025 Interim Report July 2021. In Appendix A of this report ACCC provides a consolidated picture of contract prices for 2021 (Chart A6). Table A6 shows prices of contracts direct from producers averaging \$8.54/GJ in Southern states and \$7.92/GJ in Queensland. This benchmarking has not been repeated for the 2023 Price Projections but has been replaced by other benchmarking reported below.

To replicate the conditions before these contracts were entered, the RMMEAU model was run without any prior domestic contracts in 2021 (but assuming export contracts were in place) and with contract durations of one year. Other parameters are as reported for the 2022 Net Zero 2050 Scenario. The prices estimated by RMMEAU under these conditions are shown in Table 2.

Table 2 2021 Wellhead Contract Price Benchmarking (\$2021/GJ)

	ACCC Average	RMMEAU Average	Difference
Southern States	\$8.54/GJ	\$8.58/GJ	\$0.04/GJ
Queensland	\$7.92/GJ	\$7.93/GJ	\$0.01GJ

3.4.1.2 Validation for the 2023 Price Projections

Additional validation has been undertaken for this study.

3.4.1.2.1 Short-Term LNG Price Forecasts

As noted in section 2.1, a critical change in the gas market in 2022 has been the surge in global LNG prices in response to Russia's invasion of Ukraine and flow on effects. Global LNG prices doubled from already high levels, reflecting limited supply expansion options in the short term. East coast gas prices responded to high global prices and domestic supply/price crises in both electricity and gas markets, with both spot prices and contract offers maintaining levels not seen previously.

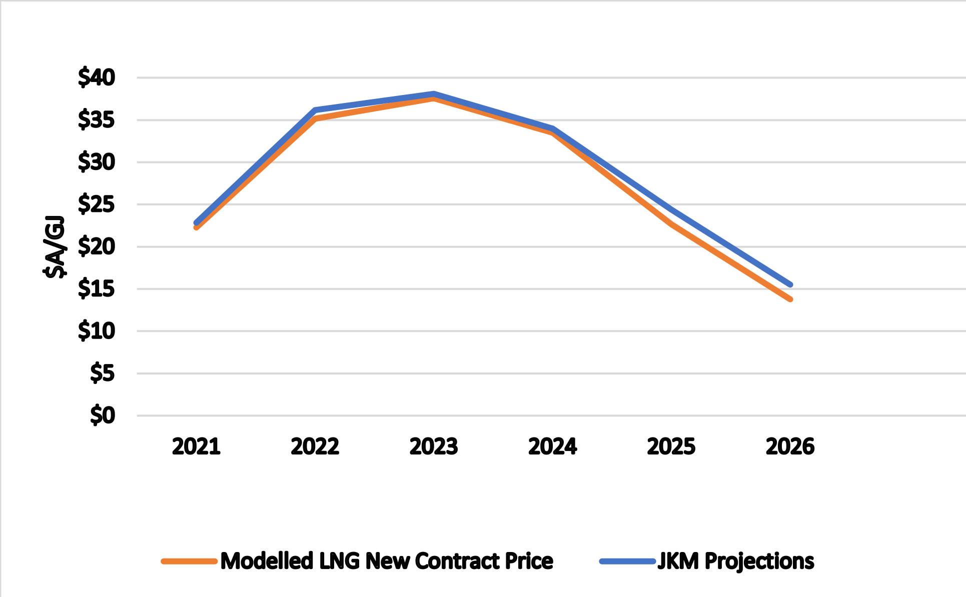
Global LNG prices have therefore become a critical determinant of east coast gas prices in the short-term. At this time (October 2022) all third-party projections of global LNG prices appear to be based directly on LNG futures. The JKM futures projection illustrated in Figure 1 has therefore been adopted as the benchmark/target for the RMMEAU Global LNG new contract price projections to 2024, taking into account the increase in global LNG demand due to the European push to reduce dependence on Russian gas exports following Russia's invasion of Ukraine. Prices are assumed to moderate after 2024 as shown in Figure 5.

These LNG prices have been modelled in RMMEAU using OIES[9] estimates of the increase in LNG demand - 32 bcm (1,390 PJ) in 2022 and 52 bcm (2260 PJ) in 2023 and beyond – IEA[10] has provided consistent estimates. The LNG demand projections used in RMMEAU to 2026 are therefore the demand projections used in 2022 plus the above increases.

[9] REPowerEU and the Short-Term Outlook for the European Gas Market, Oxford Institute for Energy Studies, July 2022
[10] Gas Market Report Q3 2022, International Energy Agency, July 2022

With these changes plus changes to the assumed Global LNG price elasticity in the years 2022 to 2026, reflecting less elastic demand in 2022 – 2024 with more elasticity after 2024 as gas buyers take up other fuel or conservation options or switch to new gas pipeline options, the new contract price for global LNG estimated by RMMEAU accurately tracks the IEA projections (Figure 5). The modelled impact of these on domestic prices is discussed in section 4.

Figure 5 Global LNG prices, RMMEAU Projection Step Change Scenario vs JKM Projections Benchmark ($A2022/GJ)



3.4.1.2.2 Reported Gas Producer Average Prices

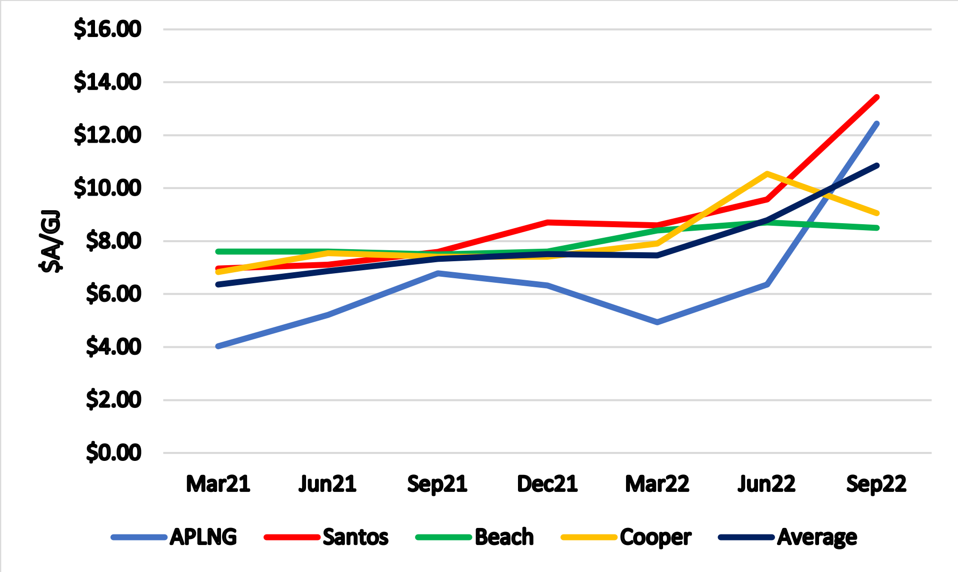
Share-market listed gas producers report their sales volumes, revenues and average prices on a quarterly basis. It is important to check that these are consistent with modelled average prices. Producers that report at a sufficient level of disaggregation to separate out Eastern Australian data include Beach Energy, Cooper Energy, Origin (including APLNG data) and Santos.

The average prices received by these producers in 2021 and 2022 to date are depicted in Figure 6. The price figures reported reflect varying mixes of gas sold under long and short-term contracts and spot sales. The proportion of the market represented by these figures cannot be estimated reliably.

It is noted that the average over all producers increased steadily through 2021 and then more significantly in June and September 2022, though it remained well below the high spot and new contract prices reported in 2022. The rise in average prices from 2021 to 2022 YTD is approximately $2/GJ. If it is assumed that December 2022 will be the same as September 2022, then the producer average will have increased from $7.01/GJ in 2021 to $9.49/GJ in 2022, an increase of $2.48/GJ or 35%.

LGA notes that this information would be more useful if the ACCC could use its data acquisition powers to acquire the data from all gas producers and report the aggregates in its Gas Inquiry reports.

Figure 6 Average Gas Prices Received by Gas Producers for East Coast Sales



Sources: Company Quarterly Reports

3.5 Data Sources and Assumed Values

3.5.1 Summary

3.5.1.1 Assumptions Common to all Scenarios

The following assumptions are common to all scenarios. Details are provided in sections 3.5.2 to 3.5.13.

- Current global price pressures are captured in via LNG prices. Short-term projections are benchmarked on Asian Futures.
- LNG imports are possible at Port Kembla from 2024 and Adelaide from 2025 – viability of terminals at other locations has not been tested
- No carbon prices are considered in the forecasts
- Production costs are fixed in United States dollars i.e. in Australian dollars production costs vary in line with $US/$A exchange rates. There is variation between producers and between 2P reserves and 2C resources for each producer.
- Transmission costs – current prices escalated by the inverse of aggregate demand
- Domestic Gas demand – AEMO's 2022 GSOO projections are used

- Global LNG demand – profiles compatible with domestic profiles have been selected
- Initial contracts – current estimates are used in all scenarios
- Heads of Agreement – All gas in excess of contract levels competes equally in all markets.
- Oil Indexation is applied only to initial contracts as the modelled prices fully reflect global prices.

3.5.1.2 Scenario Specific Assumptions

Scenario specific assumptions are summarised below, with details provided in sections 3.5.2 to 3.5.13.

Table 3 Scenario Definition Summary

Parameter	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Domestic Gas Demand	2022 GSOO Progressive Change	2022 GSOO Progressive Change	2022 GSOO Step Change	2022 GSOO Hydrogen Superpower
LNG Demand	IEA STEPS	IEA STEPS	IEA APS	IEA APS
Pipeline Tariffs	2021 escalated by CPI	2021 escalated by CPI	2021 escalated by CPI	2021 escalated by CPI
New Pipelines	None	Narrabri-Sydney	None	None
New Gas Sources	None	Gunnedah/Narrabri (2026)	None	None
Gas Reserves	Developed Fields + Approved	Developed Basins 2P, 2C + Gunnedah	Developed Basins 2P, 2C	Developed Basins 2P, 2C
Average Gas Production Costs Undevel 2P, in 2022.	$6.40	$4.36	$5.37	$5.37
Average Gas Production Costs 2C, in 2022	$9.19	$6.50	$7.52	$7.52

Parameter	Progressive Change	Exploring Alternatives	Step Change	Hydrogen Export
Number of Independent Domestic Sellers	11	24	16	16
Level of pre-contracted domestic demand (ACCC July 2021)	2022: 88% 2023: 79% 2024: 53%	Same as Progressive Change	Same as Progressive Change	Same as Progressive Change
Long-term Exchange Rates	1.243	1.333	1.243	1.115
Most Similar Oil Price Projection	25 % p.o.e. (High)	25% p.o.e. (High)	75% p.o.e. (Low)	75% p.o.e. (Low)

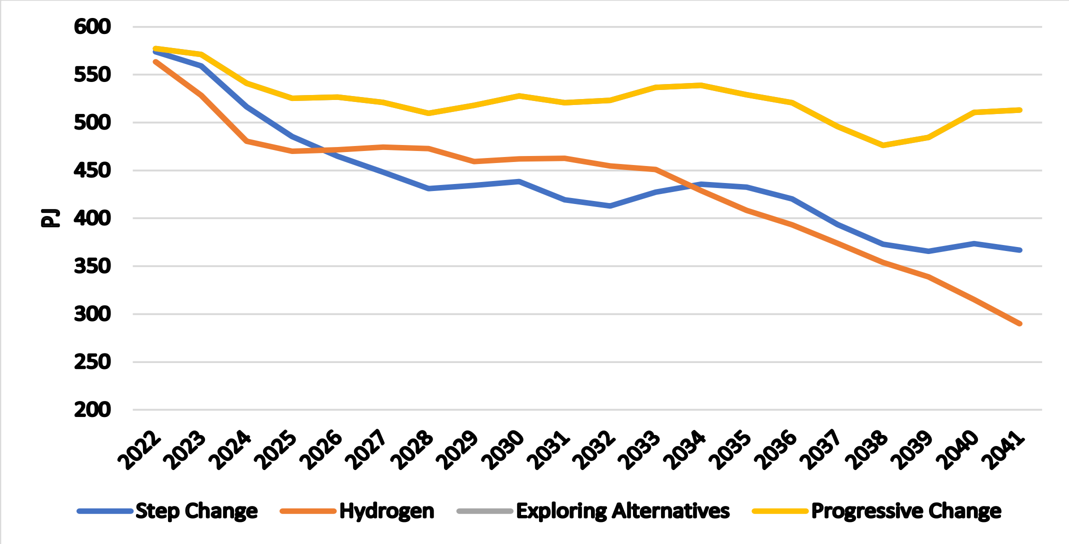
Data sources are discussed below. Values are documented in an accompanying workbook.

3.5.2 Gas Demand

3.5.2.1 Domestic

For this study, forecast domestic gas demand has been provided by AEMO's 2022 GSOO projections, aggregate versions of which are illustrated in Figure 7. Note that the Exploring Alternatives projection is assumed to be the same as the Progressive Change projection.

Figure 7 Domestic Gas Demand Forecasts (PJ)



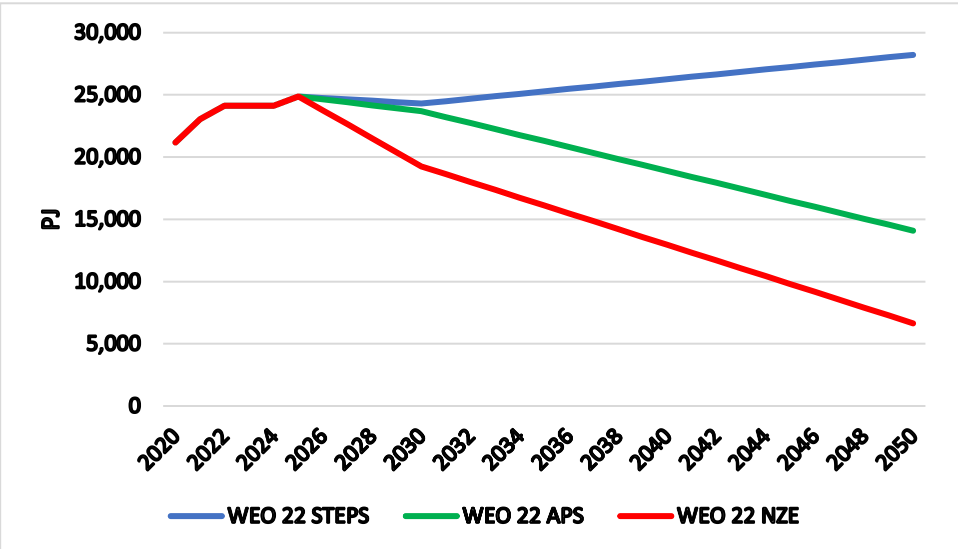
Demand projections are accompanied by underlying gas price projections. If sufficient supply is not available at that price, demand is reduced until supply matches demand. As such the model does not estimate supply shortfalls but the equivalent price induced demand reductions reflect the non-availability of sufficient supply at an affordable price.

3.5.2.2 Global LNG

Forecast Global LNG demand is derived by LGA from recent projections prepared by the International Energy Agency (IEA, World Energy Outlook 2022). Their scenarios are illustrated in Figure 8. The IEA scenarios are STEPS (Stated Policies Scenario), APS (Announced Pledges Scenario) and NZE (Net Zero Emissions Scenario).

Two of these scenarios envisage Global LNG demand falling after 2025 or 2030 and one envisages Global LNG demand continuing to grow, at a diminished rate, to 2050. The declining scenarios generally result in declining LNG prices, whereas the others do not (Figure 9).

Figure 8 IEA Global LNG Demand Projections (PJ)



Source: IEA WEO

The Global LNG demand forecasts appropriate for each AEMO scenario have been selected on the basis of their similarity of profile with the AEMO domestic demand scenarios. Thus WEO STEPS is associated with Progressive Change and Exploring Alternatives scenarios and WEO APS is associated with Step Change and Hydrogen Export scenarios. This ensures that the underlying market conditions in domestic and Global markets in each scenario are compatible. The more radical decline in WEO NZE is not associated with any AEMO scenarios. The allocations are shown in Table 3.

A key outcome of this allocation is that global LNG prices in the scenarios with declining domestic demand (Step Change and Hydrogen Export) are lower than in the remaining scenarios (refer to Figure 9 and Figure 10), which has a downward impact on domestic prices.

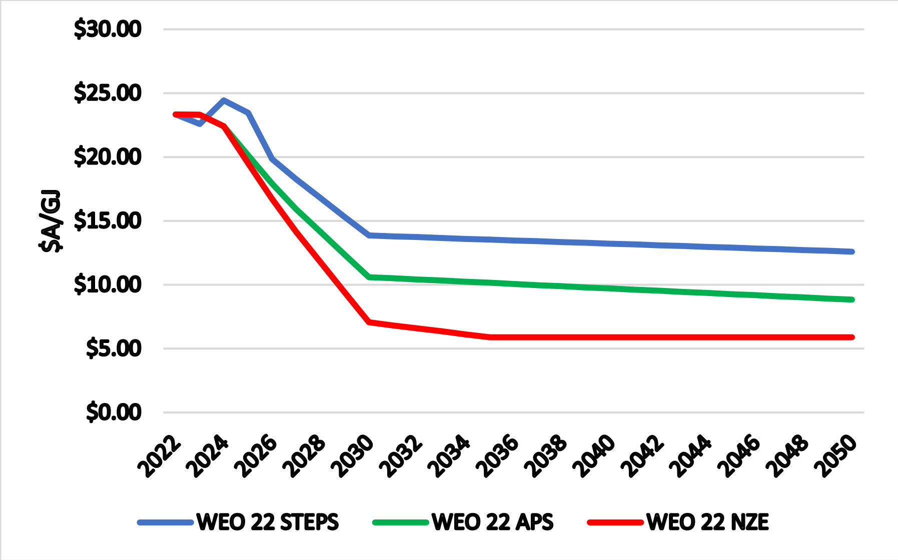
3.5.3 LNG Average Price Forecasts

LNG prices are calculated internally in RMMEAU, interactively with domestic prices. However in view of the relative size of the markets (the Global LNG market is some 40 times larger than the Eastern Australian domestic market), the impact is from Global LNG to domestic and not vice versa.

3.5.3.1 Long-Term LNG Price Forecasts for Comparison

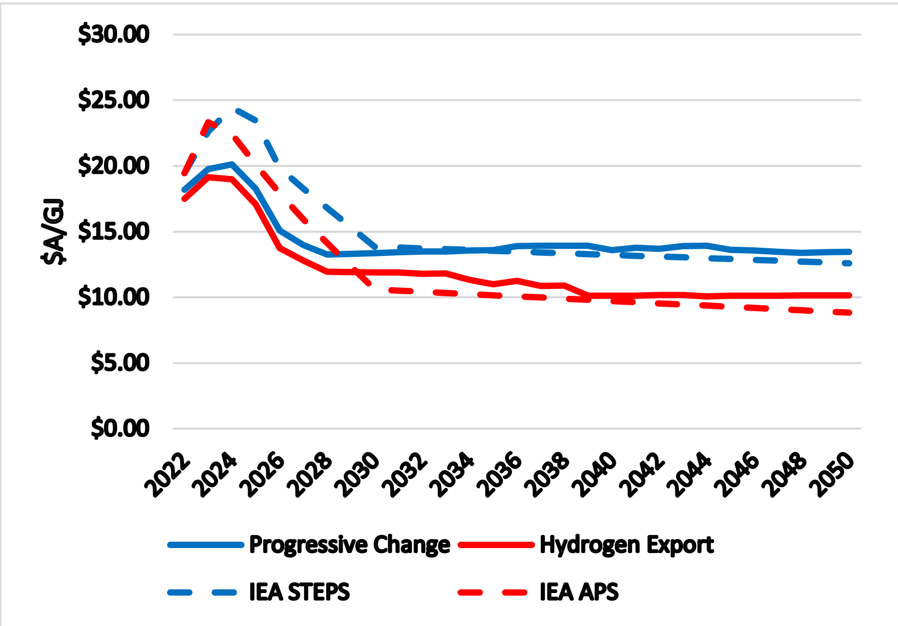
The WEO 2022 also presents updated LNG price projections. The high short-term prices reflect the current supply shortfall and the longer-term prices reflect IEA's views on LNG demand. In the declining demand scenarios prices are set at marginal production costs which exclude liquefaction capital costs and some production capital costs. The price projections are shown in Figure 9. They are generally low, particularly those associated with scenarios in which demand is declining due to decarbonisation (APS and NZE).

Figure 9 IEA Japan LNG Average Price Projections ($A/2022/GJ)



The RMMEAU Average Contract Price Projections for the Progressive Change and Hydrogen Export scenarios are compared with the WEA scenarios in Figure 10. There are some differences in the short-term (but RMMEAU tracks the spot futures accurately) and in the longer term the projections are consistent with the third-party projections.

Figure 10 RMMEAU and IES Japan LNG Average Price Projections ($A2022/GJ)



3.5.4 Pipeline Tariffs

Pipeline tariffs are as used in the 2022 Price Projections, escalated by CPI.

For scenarios in which demand is steady or increasing, tariffs are assumed to be static in real terms, i.e. to escalate at CPI, though no specific CPI has been assumed. For scenarios in which demand is decreasing, tariffs are assumed to increase in proportion to the inverse of aggregate demand, i.e. generate a steady revenue. (note that in each scenario demand in all regions declines at the same rate because this is how demand in each scenario was defined). LGA acknowledges that pipeline owners may choose alternative means of maintaining revenue in the face of declining demand but notes that discussion of alternatives is relatively immature and this method has therefore been selected.

Transmission costs from each producer to each market destination are the sum of individual pipeline tariffs for the pipelines making up the route. Backhaul is permitted and costed at 0.5 to 0.9 of forward haul, depending upon the expected relative volumes of backhaul and forward-haul. The same values have been used in each scenario.

Scenarios:

The same initial tariffs are used in all scenarios as their likely variation is considered limited relative to that of other parameters.

3.5.4.1 Pipeline Investment

In all except the Exploring Alternatives Scenario pipeline investment is limited to capacity expansion of existing pipelines.

In the Exploring Alternatives Scenario, in addition to the above it is assumed that the following pipeline is constructed, possibly with non-financial government incentives:

1. Narrabri to Sydney (from 2026), to facilitate development of the Gunnedah Basin. Assumed cost $0.90/GJ ($2021)

3.5.5 Gas Reserves

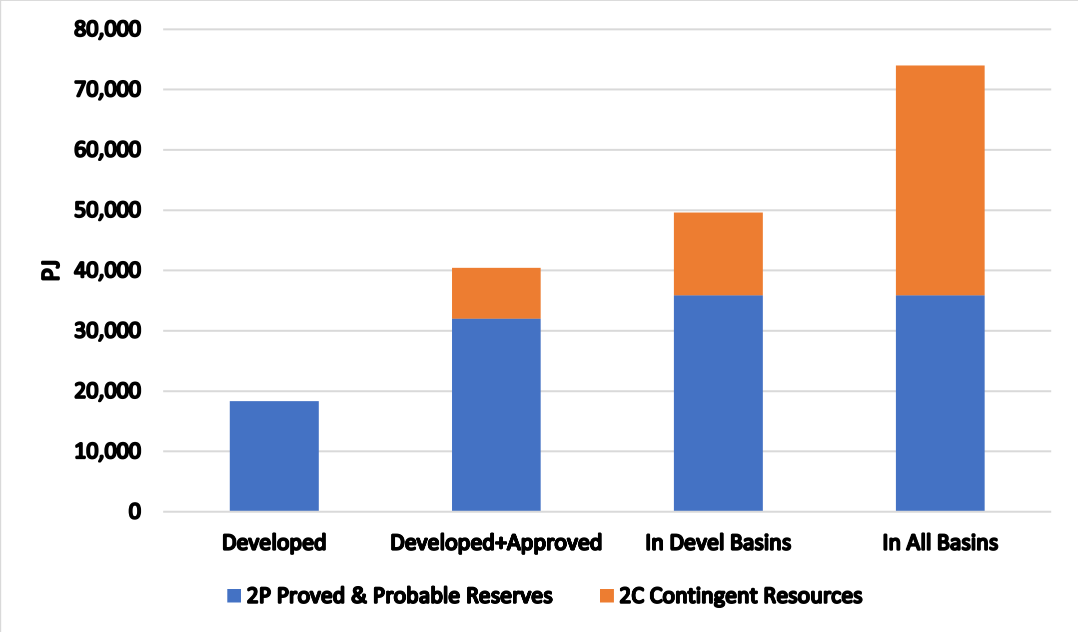
Estimated gas reserves/resources servicing the eastern Australian domestic and LNG export markets total 35,879 PJ of 2P reserves and 38,122 PJ of 2C resources on 31st December 2019 (ACCC Gas Inquiry Interim Report January 2022, Table A4, adjusted for production from 1/1/2020 to 30/6/2021).

Almost 90% of this is unconventional gas, most of which is Queensland coal seam gas. LNG exporters control over 90% of unconventional reserves and almost 50% of unconventional resources. The Gippsland Basin Joint Venture partners control over 50% of conventional reserves and resources. Definitions of reserves and resources are consistent with those published by the Society of Petroleum Engineers (SPE).

Since the publication of IEA's report "Net Zero by 2050 – a Roadmap for the Global Energy Sector" in June 2021, many reports have incorrectly claimed that IEA stated that further gas reserve development was inconsistent with net zero by 2050. What IEA actually said was that further development of already approved fields was consistent with net zero by 2050.

Figure 11 shows the volumes of reserves and resources by development status as estimated by the ACCC. Developed reserves are only 17,000 PJ and are unlikely to meet already committed exports. Developed + Approved reserves and resources are 40,000 PJ and are more likely to suffice to 2050. The majority of gas in developed basins is already in this category. Development of additional basins would release another 24,000 PJ of gas resources.

Figure 11 Eastern Australian Gas Reserves and Resources by Development Status (Projected back to 31/12/2019)



Source: ACCC, Gas Inquiry Interim Report January 2022, Table A4

Resource scenarios have been selected as follows:

1) The Progressive Change Scenario uses the Developed + Approved reserves/resources
2) The Step Change and Hydrogen Export Scenario use the In Developed Basins reserves/resources.
3) The Exploring Alternatives Scenario uses the Developed Basins reserves/resources plus Gunnedah Basin resources.

3.5.6 Gas Production Costs

3.5.6.1 Domestic

RMMEAU uses long-term new capacity development costs to set the price of gas for new contracts. New capacity development costs are based on Undeveloped 2P Reserves costs and 2C Resources costs, the latter being used when 2P reserves no longer set the marginal prices in the formula in the model schematic (Figure 3). Production costs are uncertain compared to other parameters used in the modelling, as they are not revealed by gas producers and even the producers cannot be certain about the costs of developing 2C resources.

AEMO has acquired updated production cost estimates for its own purposes and has provided LGA with estimates based on these. The costs applicable in each scenario are selected on the basis of both the scenario's economic strength (stronger implies lower costs) and gas market outlook (weaker outlook, i.e. lower demand implies higher costs). The scenarios allow for significant production cost variation as outlined below. Details are provided in the 2022 Gas Price Forecasts Databook accompanying this report. The production costs used in this study are assumed to escalate in line with changes in exchange rates.

Scenarios:

1) The Progressive Change Scenario uses High production cost estimates owing to its weak economic outlook.

2) The Exploring Alternatives Scenario uses Low production cost estimates, owing to its positive gas market outlook.

3) The other scenarios use Medium production cost estimates. These scenarios are a mix of medium/strong economic growth but weak gas market outlook, mixed signals as far as gas costs are concerned.

The average costs in each scenario, weighted by the relevant 2P reserves or 2C resources as of 31st December 2020, are presented in Table 3. The 2022 costs are higher than those used in the 2022 Price Projections but owing improving exchange rates are approximately the same in the long run.

3.5.6.2 Global LNG

Global LNG cost data have been sourced from McKinsey, “Setting the Bar for LNG Global Cost Competitiveness”. This report suggests 25 percentile, 50 percentile and 75 percentile total delivered costs to Asia at levels of $US6/mmbtu, $US7/mmbtu and $US8/mmbtu respectively. In each case the cost breakdown is approximately: gas production, 40%; liquefaction, 35%; and shipping, 25%.

Scenarios:

1) The Progressive Change Scenario uses the 75 percentile cost estimates, i.e. high costs consistent with the domestic costs.

2) The Exploring Alternatives Scenario use 25 percentile estimates consistent with lower domestic costs.

3) The other two scenarios use the 50 percentile estimates consistent with the medium domestic costs.

3.5.7 Number of Independent Sellers

Each production centre represented in RMMEAU can have multiple independent sellers, representing separate selling of their shares of output by members of a joint venture. The current situation, represented in the Step Change Scenario, sees two sellers in the Gippsland JV (by agreement with the ACCC) and 2 separate JVs in both the Cooper Unconventional and Surat Other production centres. The total number of independent domestic sellers in the Step Change Scenario is therefore 16 (the scenario excludes Narrabri and North Bowen, which remains isolated) plus importers from 2024. The Hydrogen Export Scenario has the same levels of competition.

In the Progressive Change Scenario this number is assumed to fall to 11 plus importers due to a single party purchasing 100% of the Gippsland JV (Woodside has recently purchased BHP’s gas division including its 50% of the Gippsland JV) and assumed mergers in the Cooper and Surat Basins. In the Exploring Alternatives Scenario, it is assumed to rise slowly to 24 by 2028 due to new entrants in the Cooper and Surat Basins and adoption of separate marketing to the domestic market in the Surat Basin. Separate marketing does not apply to LNG exports.

3.5.8 Initial Contracts

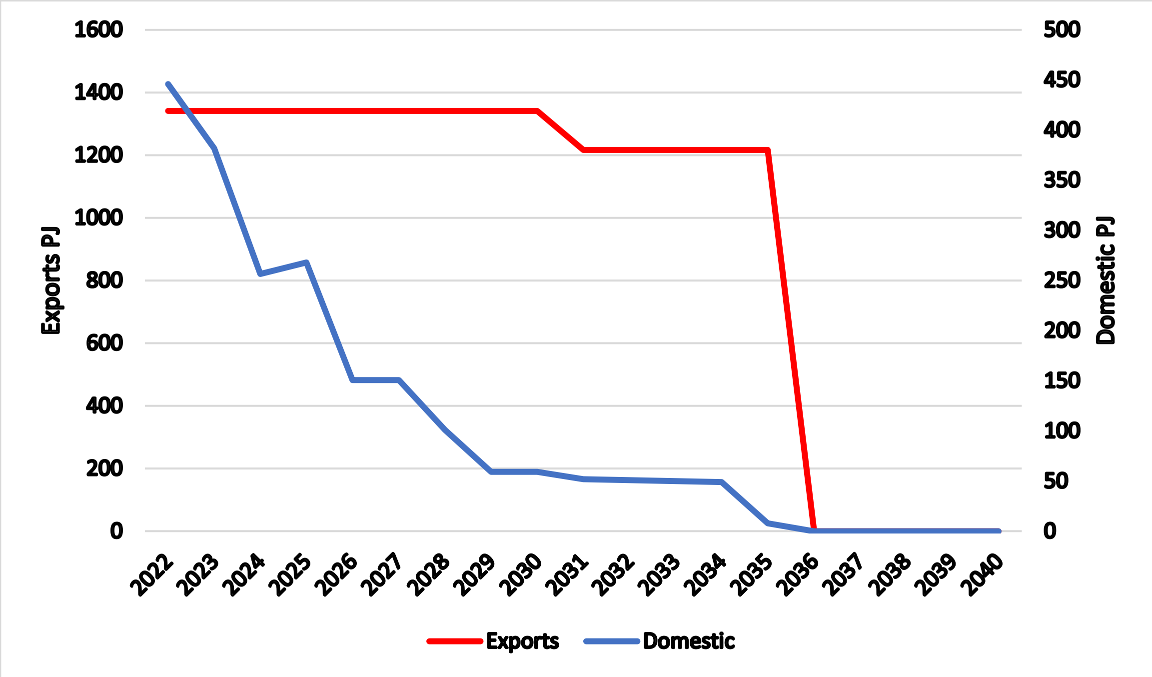
The aggregate volumes of gas known to be contracted to the domestic and export markets at the time of this study are illustrated in Figure 12. Export volumes include gas used in liquefaction. There are no known import contracts.

These contracts include only primary contracts between producers and buyers and generally exclude secondary contracts, except in the case of LNG, for which secondary contracts with buyers such as gas retailers are treated as primary contracts between the primary producer and the LNG market. The fall in LNG exports is due to termination of one exporter's contracts in 2031.

There are no known contracts beyond 2035. Export volumes are derived as part of the supply solution for Global LNG demand.

Scenarios: Contracts are the same in each scenario.

Figure 12 Aggregate Initial Contract Volumes (PJ)



3.5.8.1 Initial Domestic Contract Prices

Average prices for contracts in 2021 are as derived in section 3.4.1. Prices for contracts in 2022 and beyond are derived from the ACCC Gas Inquiry 2017-2025 Interim Report July 2022. Chart 2.5 of this report provides estimates of contract prices for 2022. Prices already negotiated for after 2022 are assumed to be slightly higher.

Table 4 Initial Domestic Contract Prices ($A/GJ, $2022)

	2022	2023+
Southern	$8.48	$9.25
Queensland	$7.46	$7.37

3.5.9 Federal Government Heads of Agreement with LNG Exporters

The Federal Government has entered a Heads of Agreement with the LNG producers under which uncontracted gas production in excess of their contractual obligations must be offered to the domestic market on 'competitive market terms' before it is offered to the international market. The HoA was extended to 2021 and 2022 on 21st January 2021.

LNG producers' excess gas was estimated at 100 PJ for 2021 and 101 PJ for 2022 (ACCC Gas Inquiry 2017-2025 Interim Report July 2021 Table 1.1). In all scenarios it is assumed to continue at this level in 2023 but cease thereafter owing to the establishment of import capacity at Port Kembla.

3.5.10 Potential New Sources of Supply

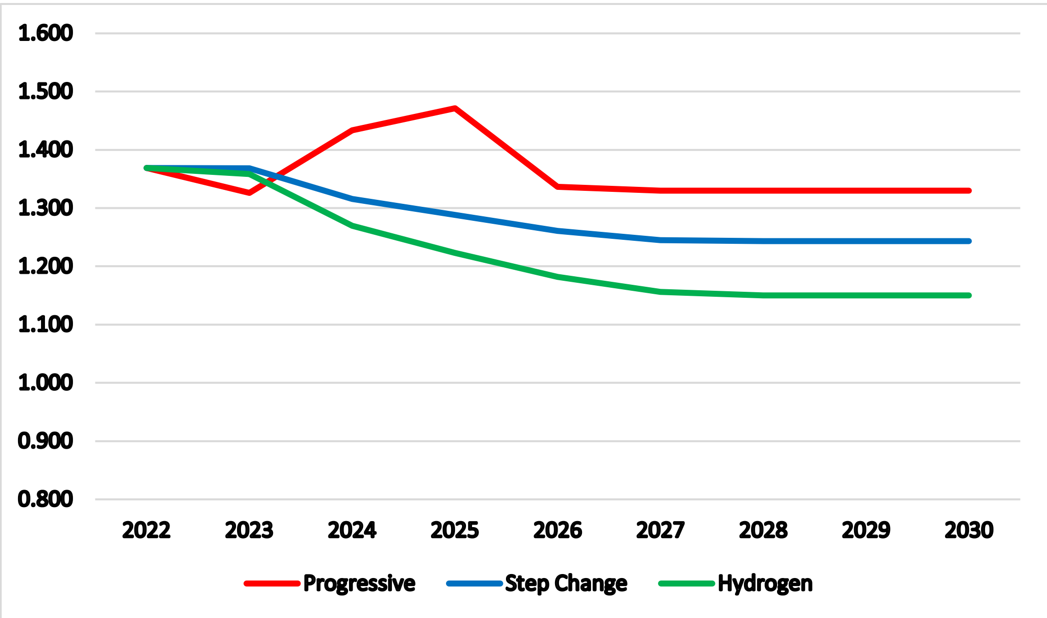
New Sources of Supply means gas resources that are not currently connected to the pipeline grid. In this study only the Gunnedah resources are considered, in the Exploring Alternatives Scenario. Their development is associated with pipeline development (refer to section 3.5.4.1).

All scenarios also potentially include imports, with volumes depending upon the competitiveness of Global LNG prices.

3.5.11 Exchange Rate Forecasts

Exchange rates directly affect the costs of gas production, both domestic and internationally, the value of LNG exports and imports imbedded in the modelling and the value of oil used to index a proportion of gas contracts. This study makes the conventional assumption that trade is denominated in $US and that the relevant exchange rate is $A/$US. The exchange rate forecasts used were provided to AEMO by BIS Oxford Economics. In all scenarios the forecasts foreshadow a strengthening of the $A against the $US (see Figure 13).

Figure 13 $A/$US Exchange Rate Forecasts



3.5.12 Oil Price Forecasts

A proportion of Eastern Australian domestic gas contracts are indexed to international oil prices. Oil prices have recently risen following the economic recovery from the initial impacts of COVID19 and in response to reductions in Western purchases from Russia following the latter's invasion of Ukraine.

LGA's longer term oil price projections are based on confidence interval projections of historical oil prices from 1968 to 2019. During this period the price has averaged $US55/bbl in $2021 terms, while alternating between 5-10-year highs and longer-term lows, and also trending upwards at 55c/bbl/year. The short-term projections are trended into the confidence interval projections over 2022-2026 (Figure 14). Please note that the meaning of confidence intervals, e.g. the 25% confidence projection, is that there is a 25% probability that the price of oil will be above this level for the duration of the projection.

IEA's latest oil price projections (in the WEO 2022) are illustrated in Figure 15. IEA's STEPS projection is most similar to LGA's 25%, the APS is most similar to the 75% and NZE is most similar to 95%. For consistency with the allocation of LNG demand the oil price projections for each scenario are allocated as follows.

Progressive Change and Exploring Alternatives: IEA STEPS – 25%

Step Change and Hydrogen Export: IEA APS – 75%

Figure 14 Confidence Interval Projections of Oil Prices ($US/bbl)

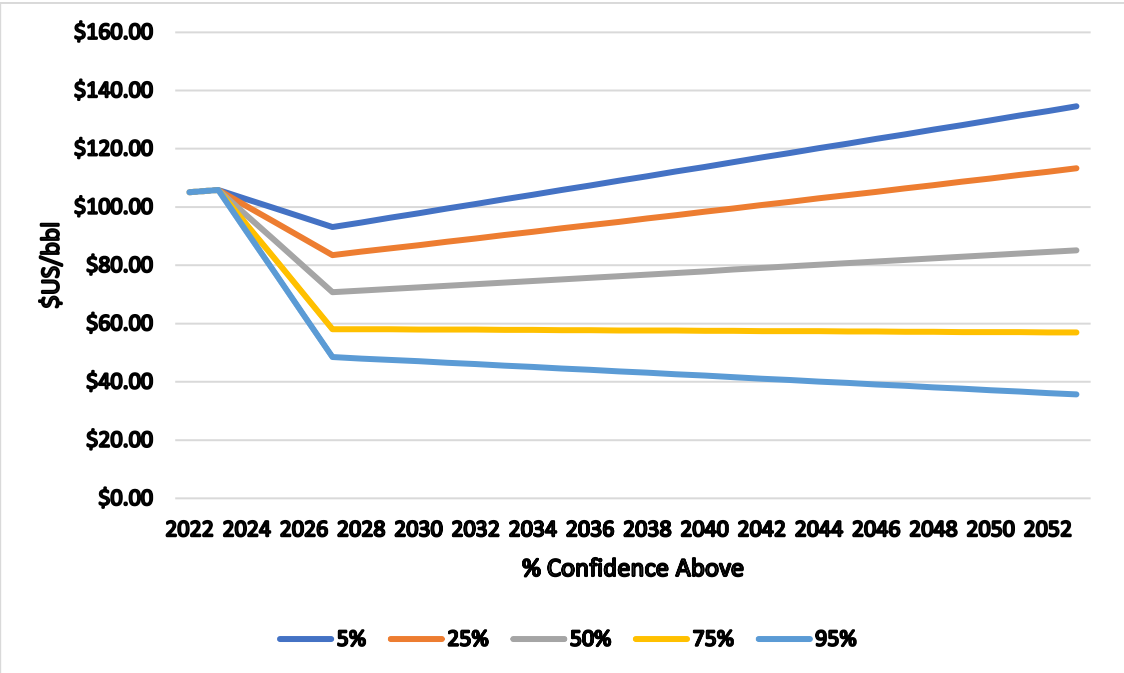
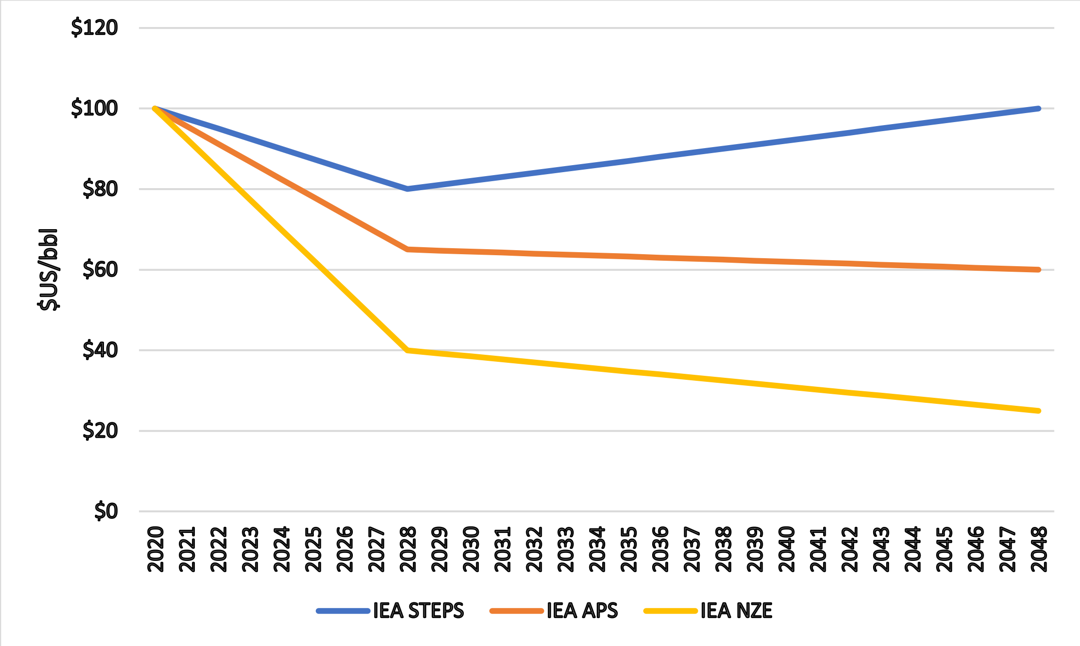


Figure 15 IEA Long Term Oil Price Projections



3.5.13 Proportion of Gas Contracts that are Oil Price Indexed

In 2020, the ACCC provided gas contract price data that enabled LGA to calculate the proportion of gas contracts for supply in 2021 that are oil price indexed, these being 55% in Queensland and 85% in southern states[11]. To the best of our knowledge no updates of this information have been published.

With the assumption that the Port Kembla import terminal will operate from 2024 and the use of multiple LNG price projections, the gas price projections derived in this study are fully indexed to global prices and further indexation or linking would amount to double counting. Consequently for this study it is assumed that only the contracts in place in 2021, illustrated in Figure 12, are oil-price indexed and so the proportion of oil-priced contracts declines from the 2021 levels as these initial contracts decline as a proportion of supply, reaching 0% by 2035.

This does not mean that we think oil indexation will cease to be used, only that it is not applicable to the prices that have been derived here.

3.5.13.1 Oil Price Indexation Mechanism

Oil price indexation varies from contract to contract. Typically, the gas price in the contract is specified as a percentage of an oil price index, for example Brent Crude price or Japanese Crude Cocktail (JCC, properly known as Japanese Customs Cleared Crude). The price paid is typically varied on a monthly basis. Some contracts have caps and floors or reduced slopes outside a set range of oil prices, to prevent excessive price variation, and longer-term contracts permit renegotiation from time to time.

Oil price indexation is a relatively new feature in the eastern Australian gas market and there is very little public domain information regarding oil price indexed contract parameters. For the 2021 Gas Price Forecast LGA estimated that the price of gas in those contracts can be expressed as:

Gas Price ($A/GJ) = 8.8% of Oil Price ($US/bbl) * Exchange rate ($A/$US)

[11] Gas Inquiry 2017-2025 Interim Report July 2020, Table2.6.

3.6 Data Sources

Data	Source
Economic Indicators	BIS Oxford Economics (from AEMO)
Gas Reserves/Resources	ACCC Gas Inquiry, January 2022
Gas Production Costs	Extracted from Rystad uCube Service and provided by AEMO.
Gas Transmission Costs	ACCC Gas Inquiry, July 2021
Global LNG production costs, incl shipping	McKinsey, Setting the Bar for Global LNG Cost Competitiveness
Domestic gas demand	AEMO scenarios applied in this study
Long Term Global LNG demand	International Energy Agency (IEA), World Energy Outlook 2022
Oil (Brent) and LNG (Japan spot) prices	IEA, Monthly Oil Prices Statistics

4. Large Industrial Gas Price Projections

4.1 Gas Prices Reported

The RMMEAU model calculates the following prices for all zonal markets for each year to 2053:

- New contract prices (a single price for new contracts in each market in each year)
- Annual average prices (averages over all contracts supplying that market in that year) are derived from the new contract prices for that year and previous year contracts that are still applicable.

These prices include wellhead prices and transmission tariffs. With respect to gas end users they represent the prices paid by large end users and retailers at the zonal centre.

It is noted that Canberra and Hobart prices are calculated by reference to Sydney and Melbourne respectively by adding/subtracting transmission costs. For Canberra the difference is frequently so small that Canberra cannot be differentiated from Sydney in the Figures.

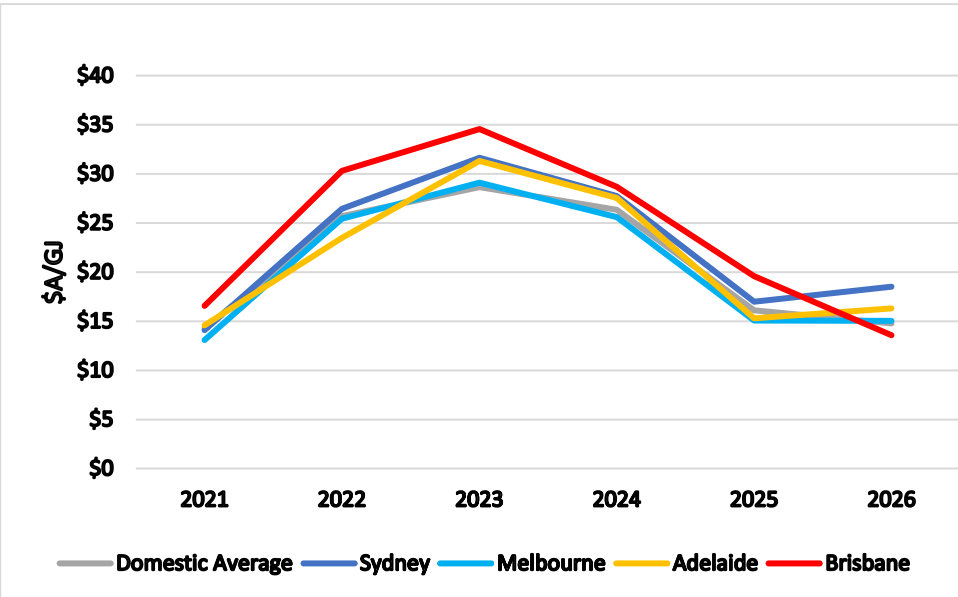
4.2 Summary of Modelling Outcomes

4.2.1 Short-Term Prices

All scenarios show a surge in prices over 2022-2026 due to high global LNG prices (refer to Figure 5).

- New Contract Prices reach levels between $25/GJ and $35/GJ in all capitals (refer to Figure 16), with Brisbane more affected than the others (it is closer to the LNG export terminals) and Melbourne least affected (furthest away from LNG export terminals). Essentially these prices are LNG netback prices with adjustment for the relative price elasticities of the global LNG and domestic markets. New Contract prices peak in 2023, in parallel with Global LNG prices

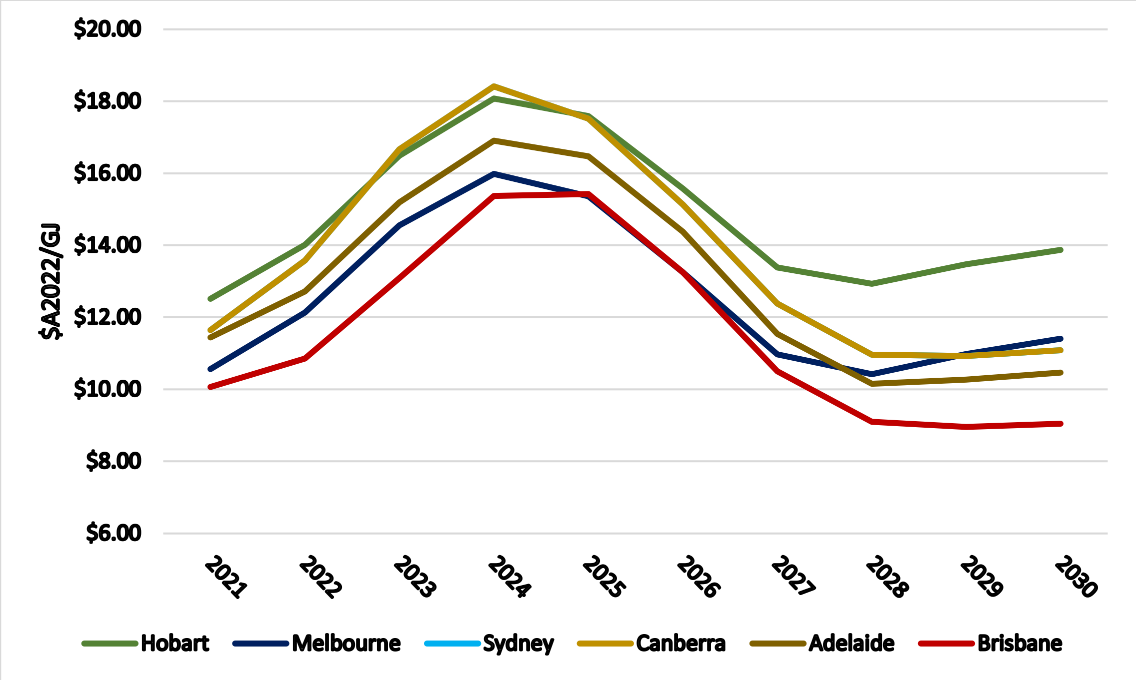
Figure 16 Projected Short-term East Coast New Contract Prices, Step Change Scenario ($A2022/GJ)



- Average Contract Price rises are less marked because the averages are also influenced by pre-existing contract prices (refer to Figure 17). Moreover, the high prices of New Contracts reduce the level of contracting during this period. Average prices reach levels between $15/GJ and $18/GJ. Average prices peak in 2024 or 2025 owing to the lag effect of older contracts.

- It is noted that the projected average price rise in 2022 over 2021 is $1.50/GJ (non-oil indexed) to $4/GJ (weighted oil Indexed) compared with an estimated actual rise of $2.00/GJ to $2.50/GJ for producers for whom average price data is available (refer to section 3.4.1.2.2).

Figure 17 Projected Short-term East Coast Average Prices, Non-Oil Indexed, Step Change Scenario ($A2022/GJ)



- As noted in section 3.2.1 RMMEAU cannot predict similar sharp price rise events in the future, though they are almost certain to occur from time to time.

4.2.2 Long-Term Prices

- The factors most strongly influencing longer term gas prices are:
    - Competitive LNG import prices in the scenarios with declining domestic demand (Step Change and Hydrogen Exports) matched by declining Global LNG demand
    - Initial gas production costs, low in the Exploring Alternatives Scenario, high in the Progressive Change Scenario and average in the Step Change and Hydrogen Export scenarios
    - Gas transmission costs, which increase in the scenarios with declining domestic demand

   - Exchange rates, via their impact on domestic production costs and LNG import prices.

- These factors impact prices in the regional markets differently
   - Sydney gas prices track LNG prices most closely, owing to the assumption that there is a sole East Coast LNG import terminal at Port Kembla, south of Sydney.
   - Brisbane gas prices are more affected by production costs
   - Melbourne and Adelaide gas prices are affected by both factors
   - The above cause scenario relativities to vary significantly from zone to zone e.g. in Sydney Strong Electrification has the lowest prices whereas in Brisbane Low Gas Price is lowest.
- All of the prices reported below are annual average delivered prices.

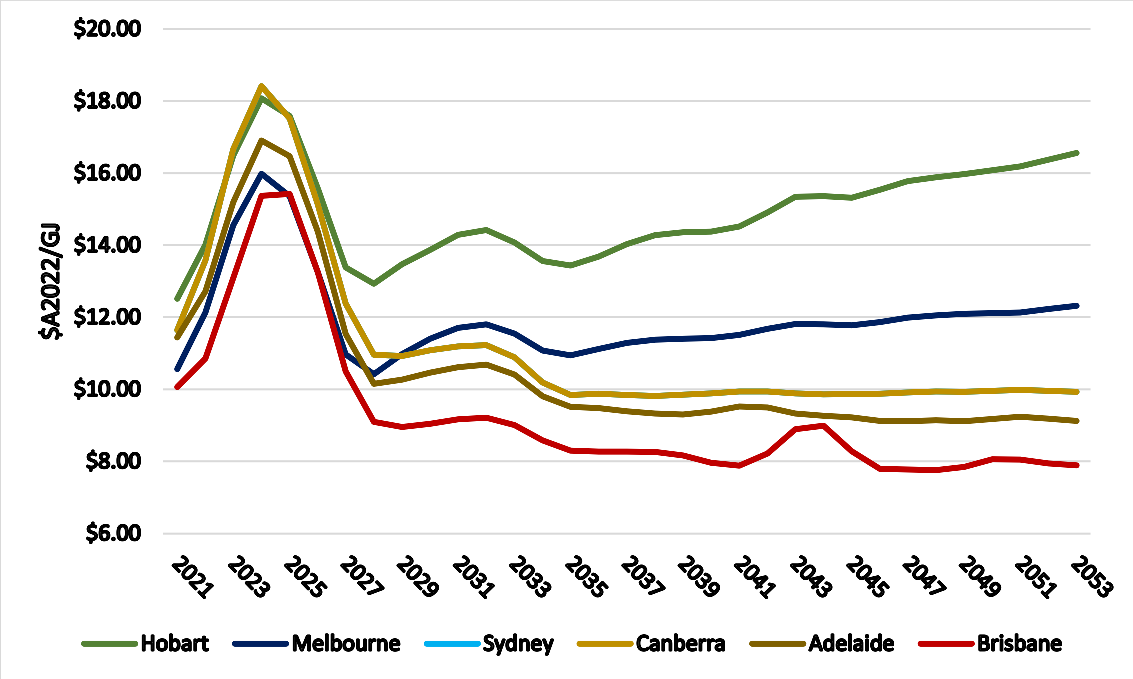
4.3 Step Change Scenario

4.3.1 Non-Oil Indexed Price Projections

Step Change Scenario non-oil indexed price projections for Large End Users in capital cities are depicted in Figure 18:

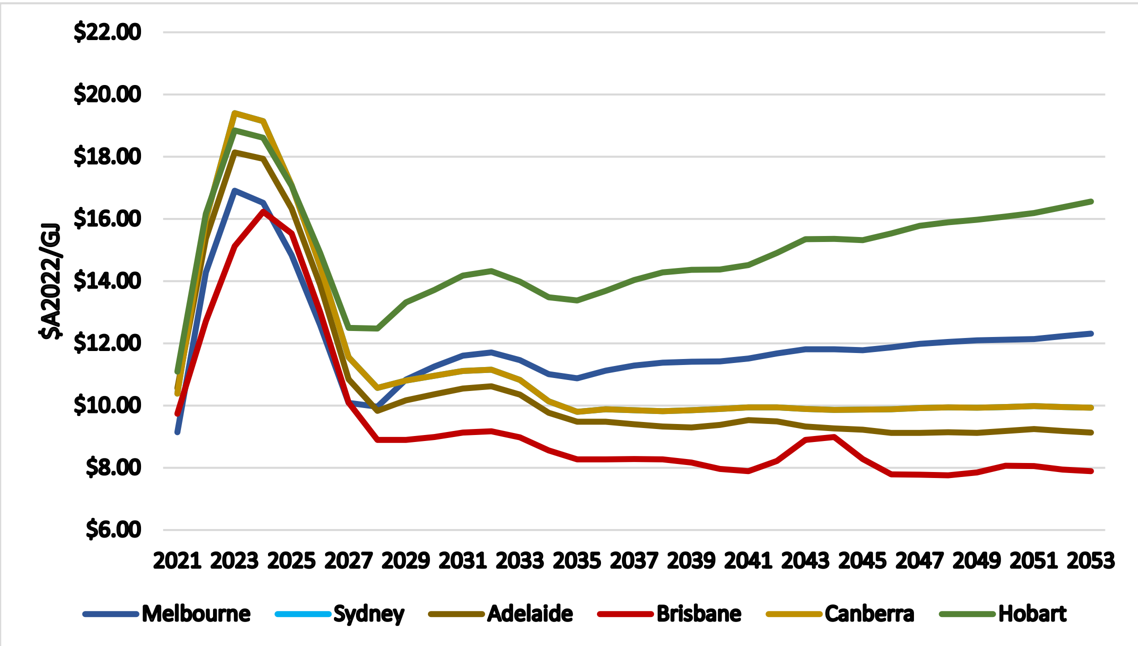
- After peaking in 2024 or 2025 Brisbane, Sydney/Canberra and Adelaide fall back to their 2022 levels and remain there for most of the period. Modest levels of imports start in 2028, rising to over 100 PJ pa by the late 2030s, mostly destined for Sydney/Canberra but also later for Adelaide and Melbourne.
- Melbourne and Hobart prices rise to higher levels as southern supply diminishes and is replaced by Queensland CSG, with associated higher transmission costs.

Figure 18 Step Change Scenario Non-Oil Indexed Price Projections for Large End Users ($A2022/GJ)



4.3.2 Weighted Oil Indexed Price Projections

Figure 19 Step Change Scenario Weighted Oil Indexed Price Projections for Large End Users ($A2022/GJ)



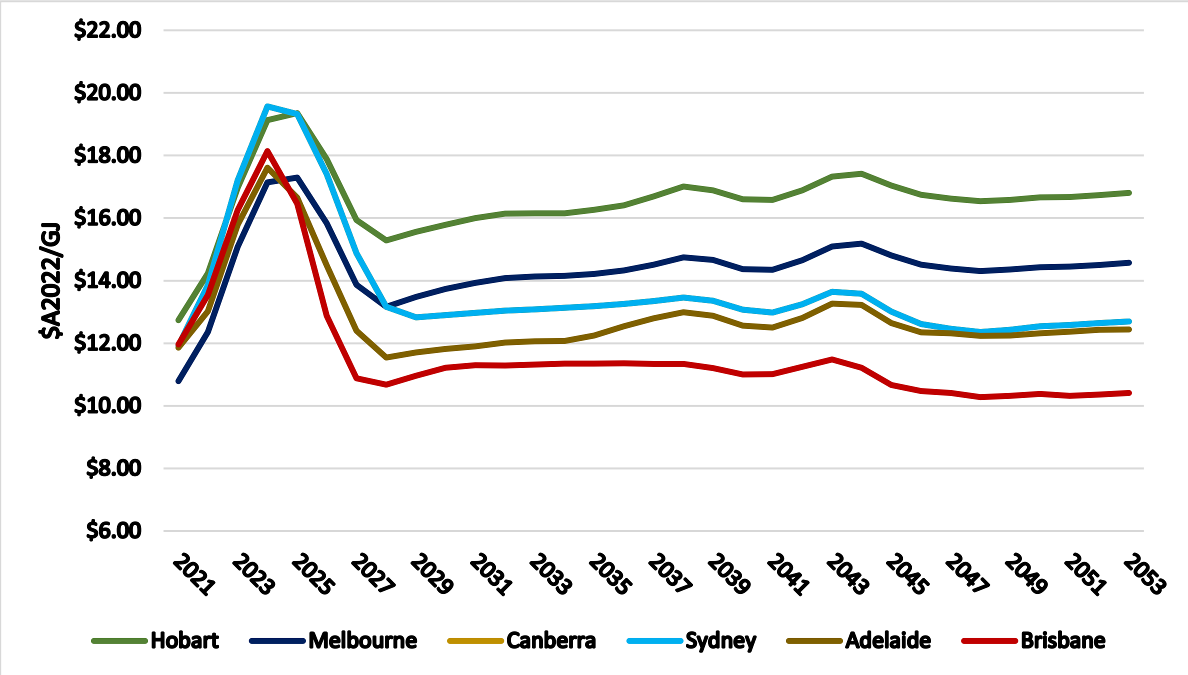
The most significant impact of oil indexation in the Step Change Scenario (and other scenarios) is the very significant increase in all prices in 2022 and 2023, owing to the increase in oil prices in those years (Figure 19).

4.4 Progressive Change Scenario

4.4.1 Non-Oil Indexed Price Projections

Progressive Change Scenario non-oil indexed price projections for Large End Users in capital cities are depicted in Figure 20. Key differences between this and the Step Change Scenario are that all prices are $1/GJ to $2/GJ higher in the long run, owing to higher costs of production and higher Global LNG Prices (also caused by higher LNG production costs), and rising over time, due to limited reserves. LNG imports are lower than in the Step Change Scenario until the late 2030s when domestic reserves accessed under this scenario become depleted.

Figure 20 Progressive Change Scenario Non-Oil Indexed Price Projections for Large End Users ($A2022/GJ)

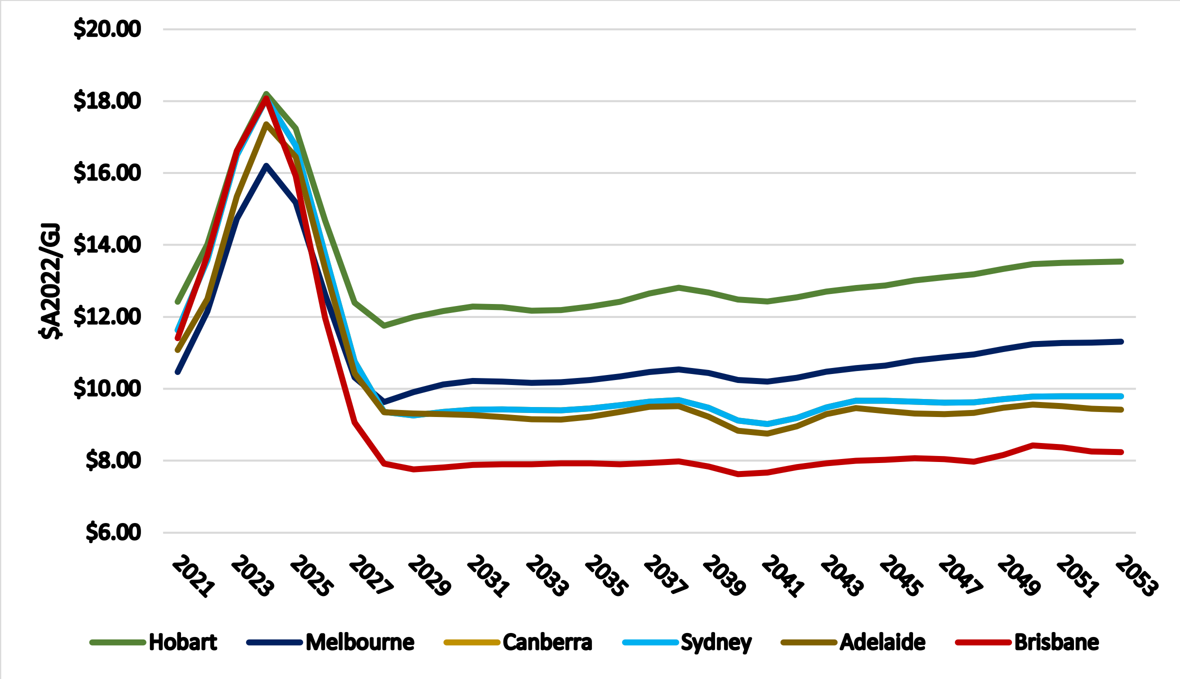


4.5 Exploring Alternatives Scenario

4.5.1 Non-Oil Indexed Price Projections

Exploring Alternatives Scenario non-oil indexed price projections for Large End Users in capital cities are depicted in Figure 21. Key differences between this and the Step Change Scenario are that all prices are approximately $1/GJ lower in the long run, owing to lower costs of production. LNG imports are considerably lower due to the development of Gunnedah Basin gas, which adds 70 PJ of domestic production by 2030.

Figure 21 Exploring Alternatives Scenario Non-Oil Indexed Price Projections for Large End Users ($A2022/GJ)

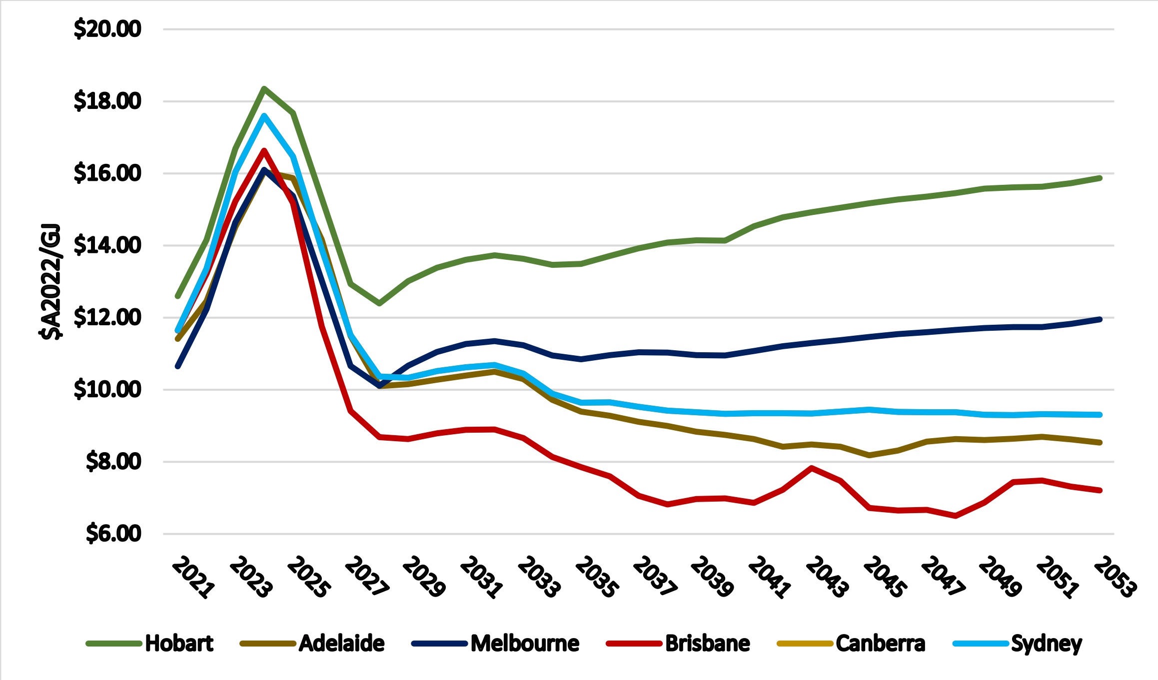


4.6 Hydrogen Exports Scenario

4.6.1 Non-Oil Indexed Price Projections

Hydrogen Exports Scenario non-oil indexed price projections for Large End Users in capital cities are depicted in Figure 22. Prices in this scenario are very similar to those in the Step Change Scenario, as the major scenario difference is lower exchange rates in Hydrogen Exports, which result in lower costs of production and prices. LNG imports are slightly higher than in the Step Change Scenario.

Figure 22 Hydrogen Exports Scenario Non-Oil Indexed Price Projections for Large End Users ($A2022/GJ)



4.7 Scenario Comparisons

It is informative to compare scenarios by investigating the changes at the major demand centres. Prices applicable to the 2021 Central Scenario and the 2022 Step Change Scenario, escalated to $2022, are included. Note that Canberra and Hobart are not discussed separately because their prices parallel those of Sydney and Melbourne respectively.

4.7.1 Melbourne

Melbourne non-oil indexed prices (Figure 23) run in parallel to 2024 under the influence of high Global LNG prices. Thereafter the Step Change and Hydrogen Export scenarios run broadly in parallel, with Hydrogen lower, with Progressive Change approximately $2/GJ higher and Exploring Alternatives approximately $1/GJ lower. Prices in all scenarios rise over time owing to the decline in Victorian gas production. The 2022 and 2023 Step Change scenarios are very similar.

4.7.2 Sydney

Sydney non-oil indexed prices (Figure 24) also run in parallel to 2024. The scenario pattern is then similar to Melbourne until 2035, after which prices reduce, This is due to lower Global LNG prices due to declining LNG demand in the Step Change and Hydrogen Export scenarios and lower production cost in Exploring Alternatives.

Figure 23 Melbourne Non-Oil Indexed Prices Scenario Comparison ($A2022/GJ)

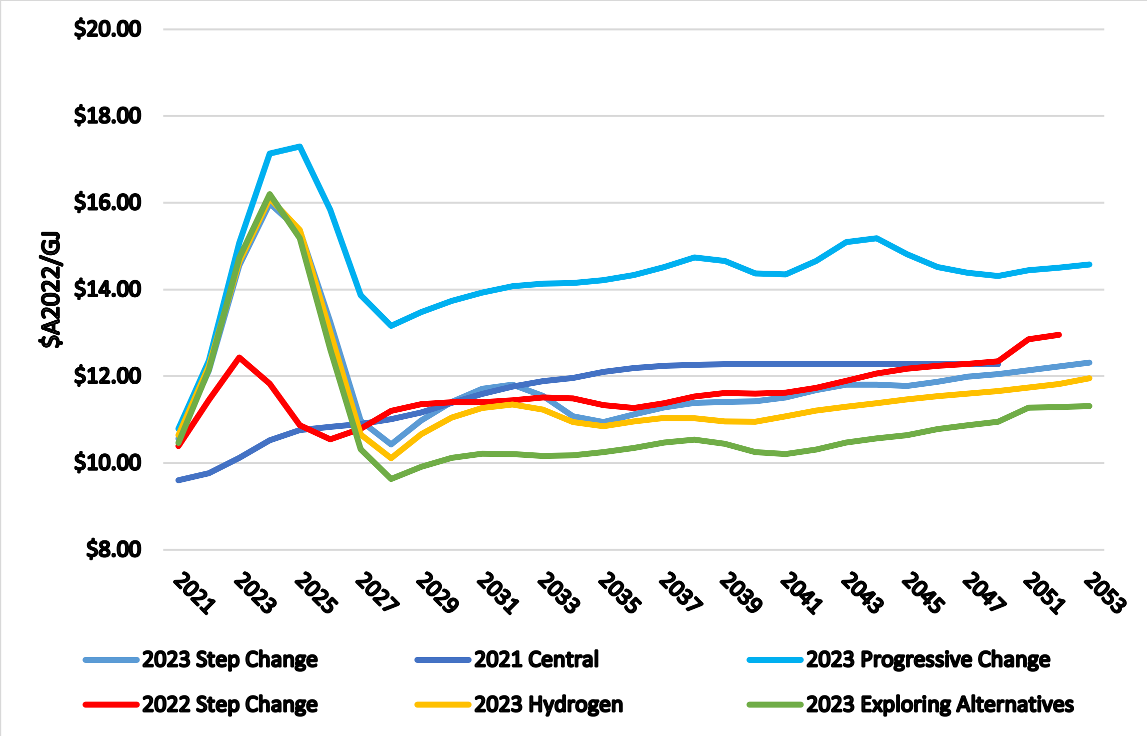
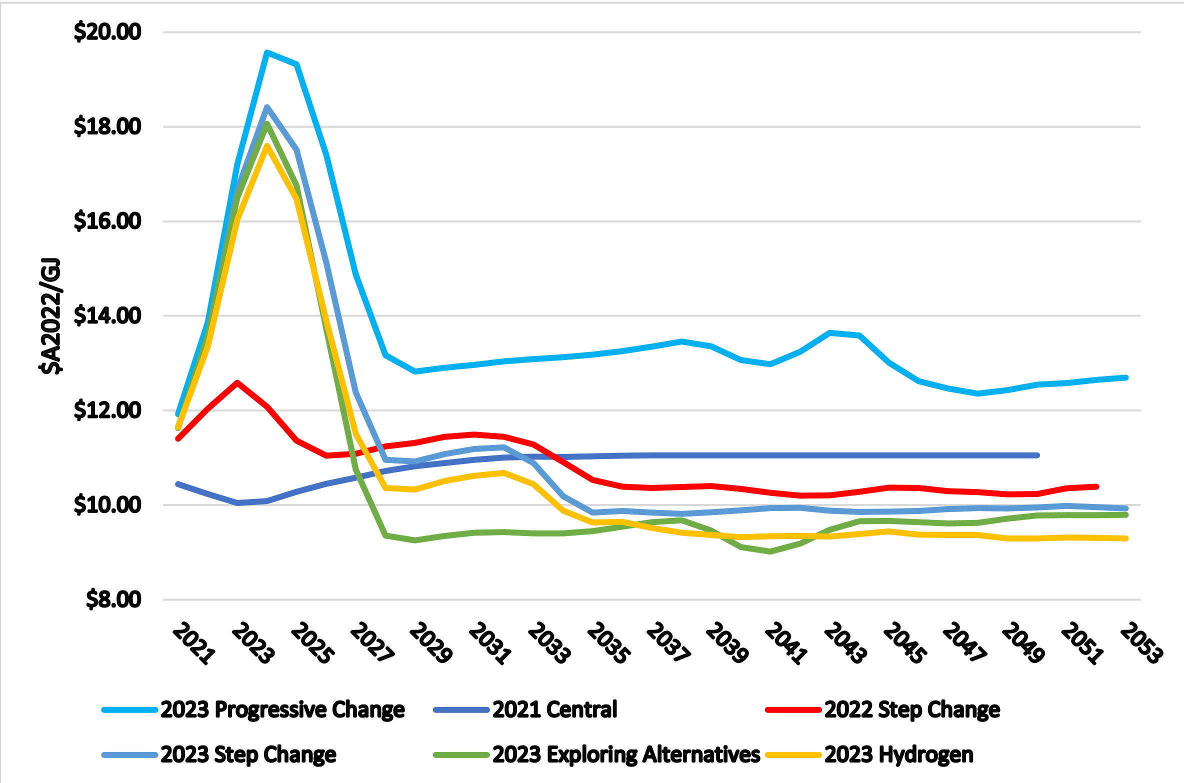


Figure 24 Sydney Non-Oil Indexed Prices Scenario Comparison ($A2022GJ)



4.7.3 Adelaide

The relativities between Adelaide non-oil indexed prices (Figure 25) are similar to those between Sydney prices, owing to the assumed construction of an import terminal in Adelaide in addition to Port Kembla, near Sydney.

4.7.4 Brisbane

The relativities between Brisbane non-oil indexed prices (Figure 26) are also similar to those of Adelaide and Sydney prices, though $1/GJ to $2/GJ lower.

Figure 25 Adelaide Non-Oil Indexed Prices Scenario Comparison ($A2022/GJ)

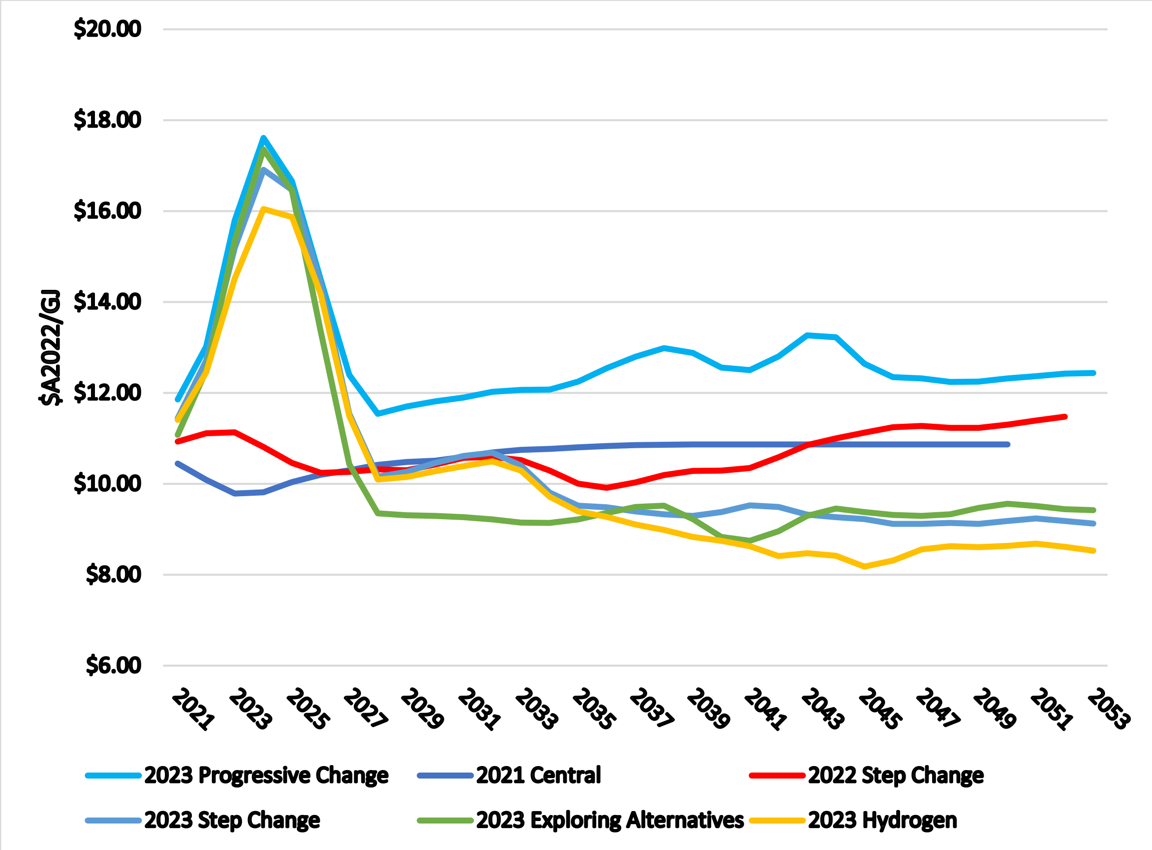
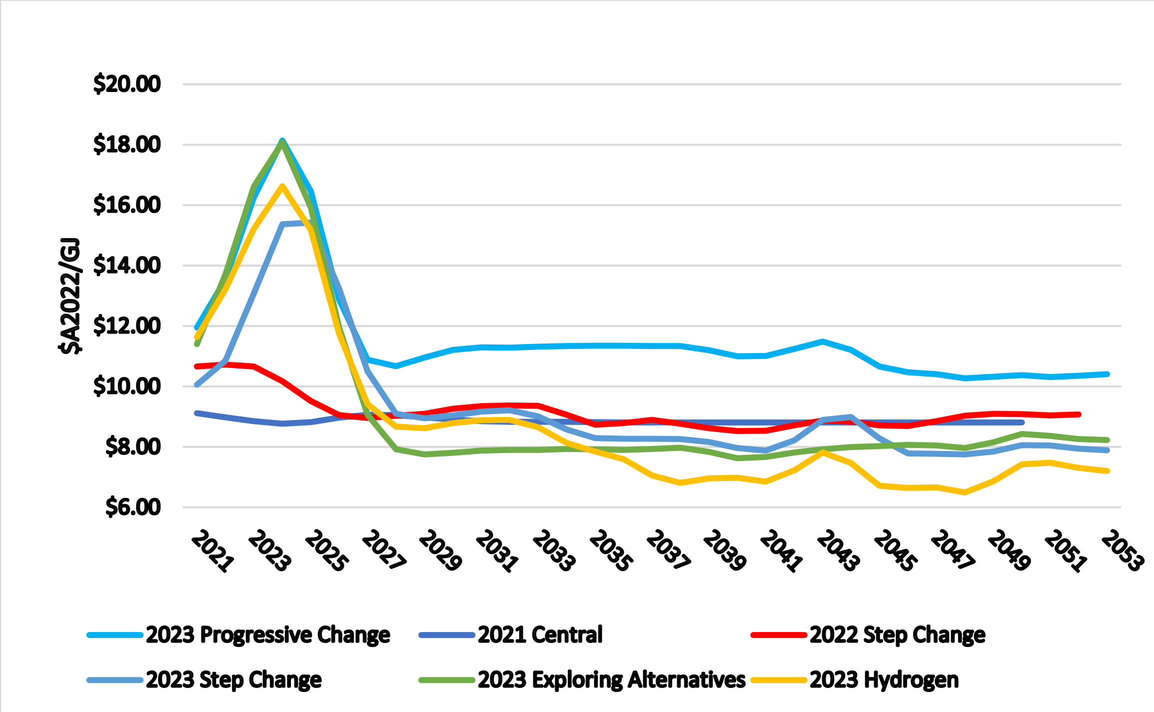


Figure 26 Brisbane Non-Oil Indexed Prices Scenario Comparison ($A2022/GJ)



5. Residential and Commercial Wholesale Gas Price Projections

Prices paid to retailers by Residential and Commercial (R&C) end users include distribution costs, a retail margin and adjustments to the wholesale price for load factor and security. R&C wholesale price forecasts are equal to Large Industrial Wellhead Prices plus Transmission Costs adjusted for load factor, plus a security component based on underground storage costs, presented in Table 5. The factors have been adjusted since the 2021 Price Projections by the removal of GPG demand from R&C demand in the current study, which has increased some of the load factor adjustments. **The Wholesale price forecasts do not include distribution costs or the retail margin**.

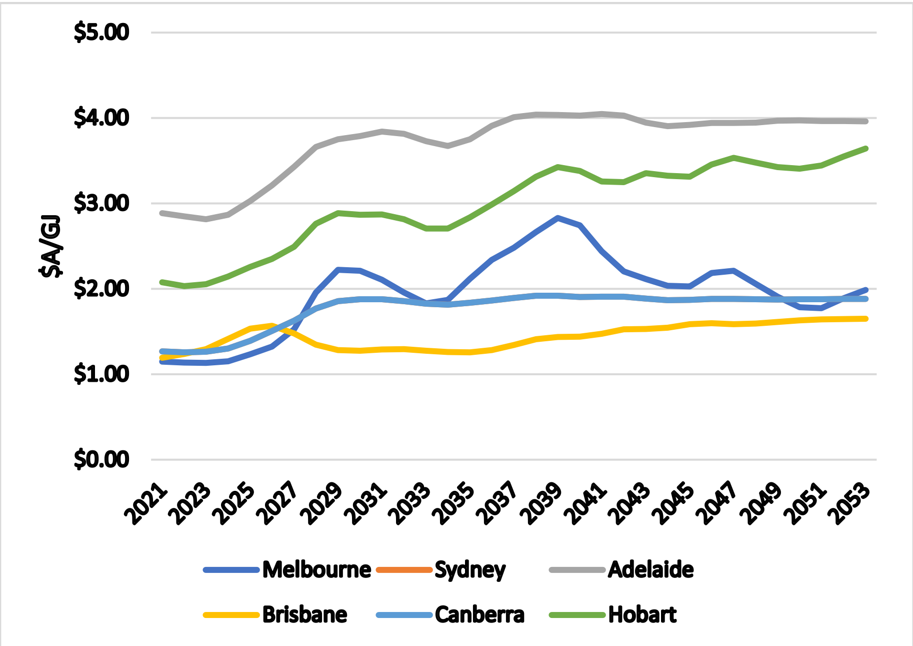
The differences between R&C wholesale prices and their Industrial counterparts in the Step Change Scenario resulting from the application of these parameters are shown in Figure 27. The progressive increase in the Melbourne value is due to changing gas sources, leading to increased transmission costs and the final increases in each capital are due to lower demand leading to transmission cost increases in all centres.

Other scenarios yield slightly different results owing to differences in transmission costs due to different gas sourcing and escalation. Oil indexation has no impact. Full details of R&C price projections for all scenarios are provided in the accompanying Excel workbook: “Lewis Grey Advisory 2023 Gas Price Projection Workbook”.

Table 5 R&C Wholesale Price Adjustments Relative to Large Industrial

	Melbourne	Sydney	Adelaide	Brisbane	Canberra	Hobart
Load Factor Adjustment	1.99	1.46	1.96	1.57	1.46	1.50
Security Factor ($A2022/GJ)	$1.00	$0.46	$0.96	$0.58	$0.46	$0.85

Figure 27 Differences between R&C Wholesale and Industrial Wholesale Prices, Step Change Scenario ($A/GJ, $2022)



6. GPG Wholesale Gas Price Projections

Gas-fired generators (GPGs) typically have very low load factors but much of their usage is outside of gas peak demand periods. Wholesale prices for generators are therefore based on their usage during winter peak periods, as forecast in the 2021 GSOO, Table 5.

GPG load factors calculated in this way are shown in Table 6. For New South Wales and Tasmania, which this calculation shows to have low load factors (high winter peak usage relative to annual usage), it is considered unlikely that that the generators incurred such high transmission costs hence the load factors have been adjusted up to the East Coast average of 43%.

The security factor adjustment used for R&C customers is not used for GPGs.

Table 6 GPG Load Factor Adjustments

	Victoria	New South Wales	South Australia	Queensland	Tasmania
GPG Load Factor	52%	18%	49%	50%	13%
Adjusted Load Factor	52%	43%	49%	50%	43%
Load Factor Adjustment	1.63	1.98	1.74	1.71	1.98

To approximate the range of usage patterns, the prices paid by most gas-fired generators are set equal to their industrial zonal centre price adjusted for the state average load factor plus a transmission adjustment based on their locations relative to that centre. One exception is Darling Downs PS which is understood to have a longer-term contract at sub-market prices. Table 7 lists the GPGs with non-zero adjustments.

Table 7 GPGs with Non-Zero Locational Adjustments ($A/GJ)

State	Power Station	Locational Adjustment
Victoria	Mortlake	-$0.30
New South Wales	Colongra	$0.25
New South Wales	Smithfield Energy Facility	$0.25
New South Wales	Tallawarra	-$0.20
New South Wales	Uranquinty	-$0.15

South Australia	Osborne	-$0.20
South Australia	Torrens Island A	-$0.20
South Australia	Torrens Island A	-$0.20
South Australia	BIPS	-$0.10
Queensland	Darling Downs[12]	-$1.30
Tasmania	Tamar Valley Peaking	-$1.17
Tasmania	Tamar Valley CCGT	-$1.17

In each state the prices applicable to new OCGTs and CCGTs are calculated assuming additional transmission costs of $1/GJ and $0.50/GJ in Victoria, New South Wales, South Australia and Tasmania and $0.75/GJ and $0.40/GJ in Queensland.

Full details of GPG price projections for all scenarios are provided in the accompanying Excel workbook: "Lewis Grey Advisory 2023 Gas Price Projection Workbook".

6.1 Step Change Scenario

GPG wholesale price projections for the Step Change Scenario are shown in Figure 28 to Figure 32, together with the relevant industrial wholesale price projections.

[12] The adjustment for Darling Downs is due to a lower priced contract and applies for a limited period.

Figure 28 GPG weighted oil indexed gas price projections, Victoria, Step Change Scenario ($A/GJ, $2022)

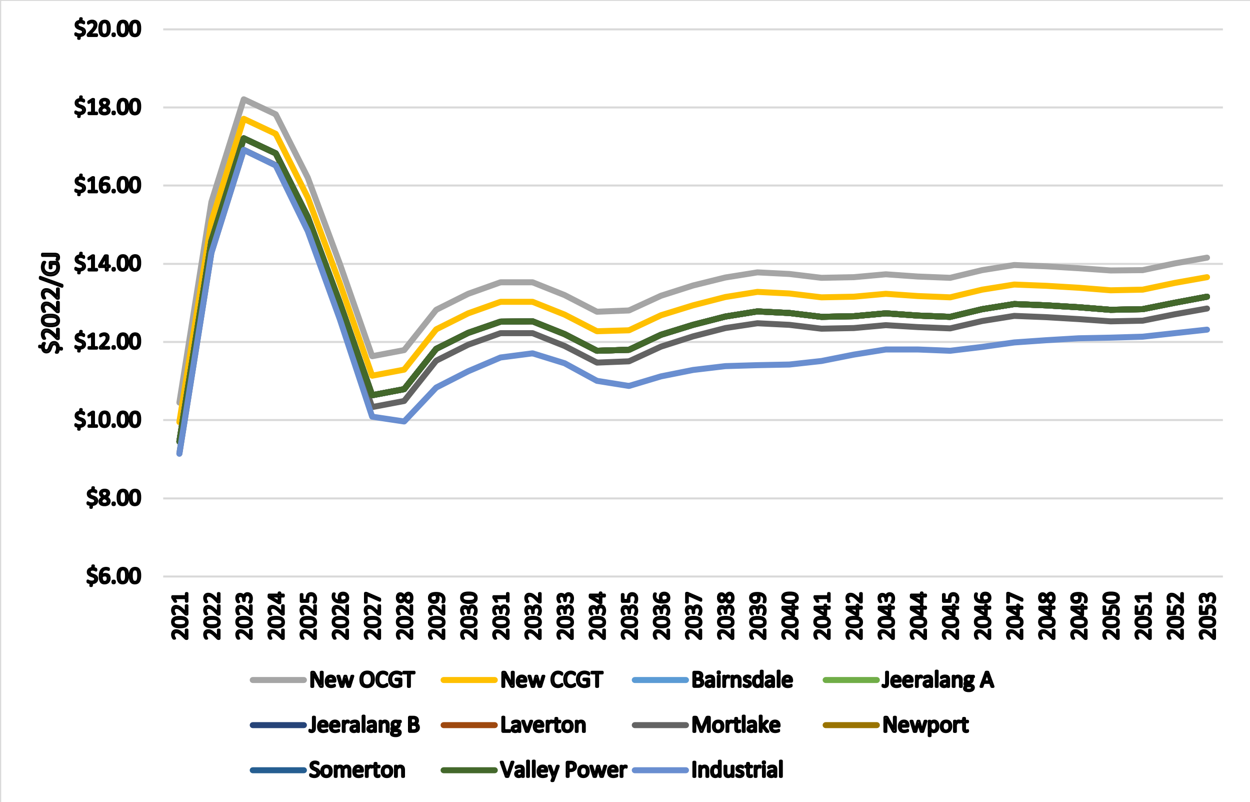


Figure 29 GPG weighted oil indexed gas price projections, New South Wales, Step Change Scenario ($A/GJ, $2022)

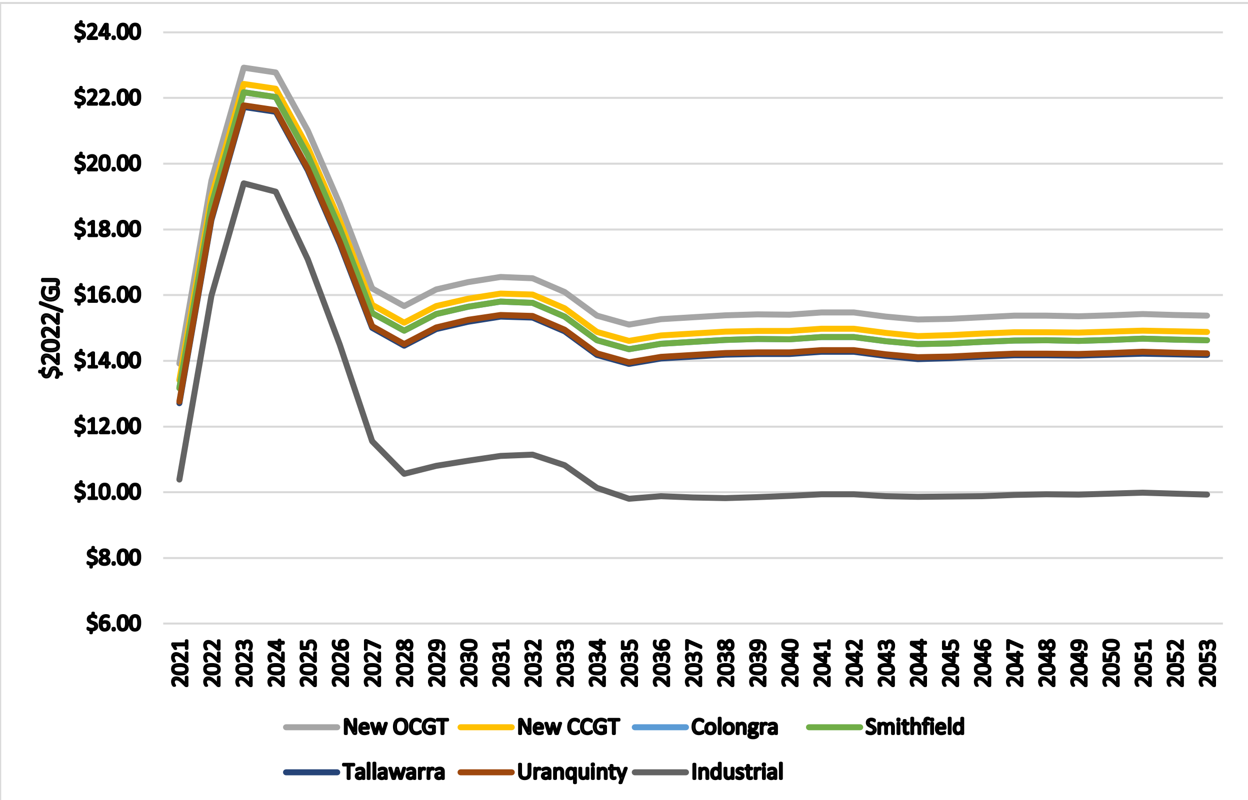


Figure 30 GPG weighted oil indexed gas price projections, South Australia, Step Change Scenario ($A/GJ, $2022)

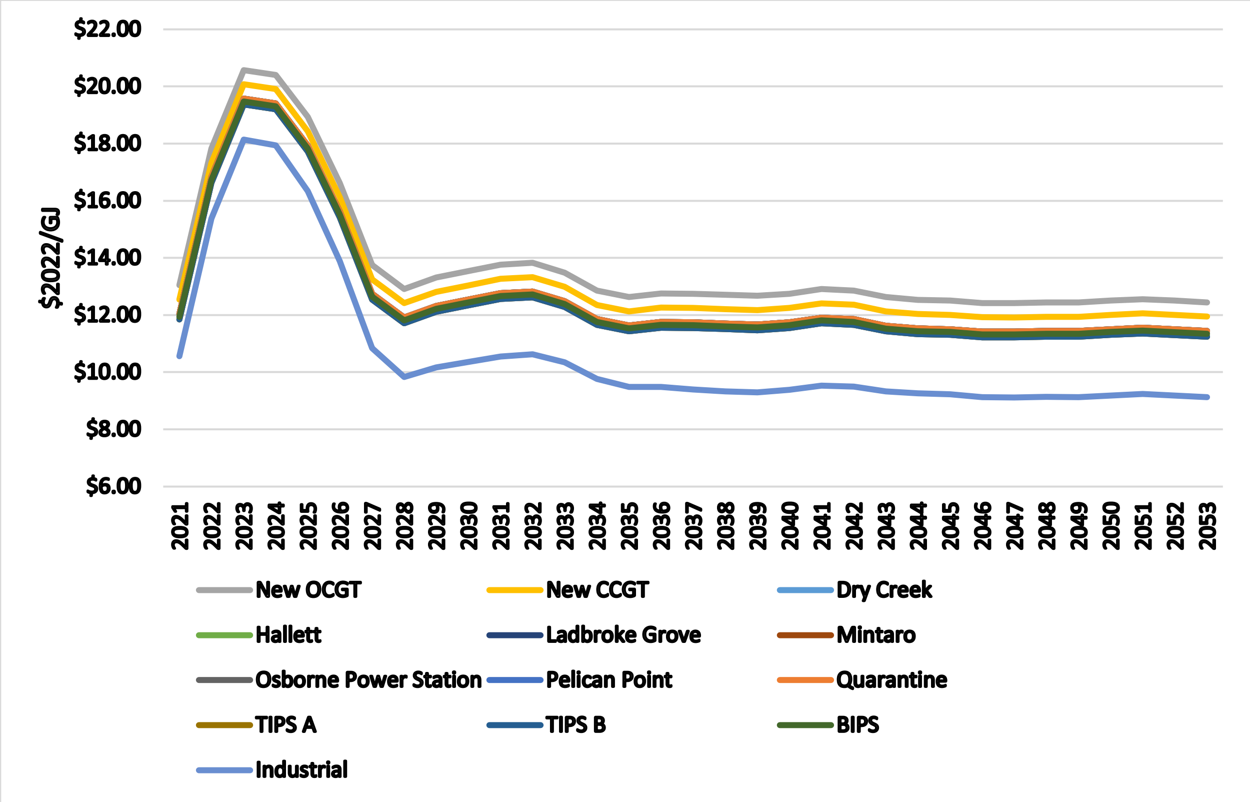


Figure 31 GPG weighted oil indexed gas price projections, Queensland, Step Change Scenario ($A/GJ, $2022)

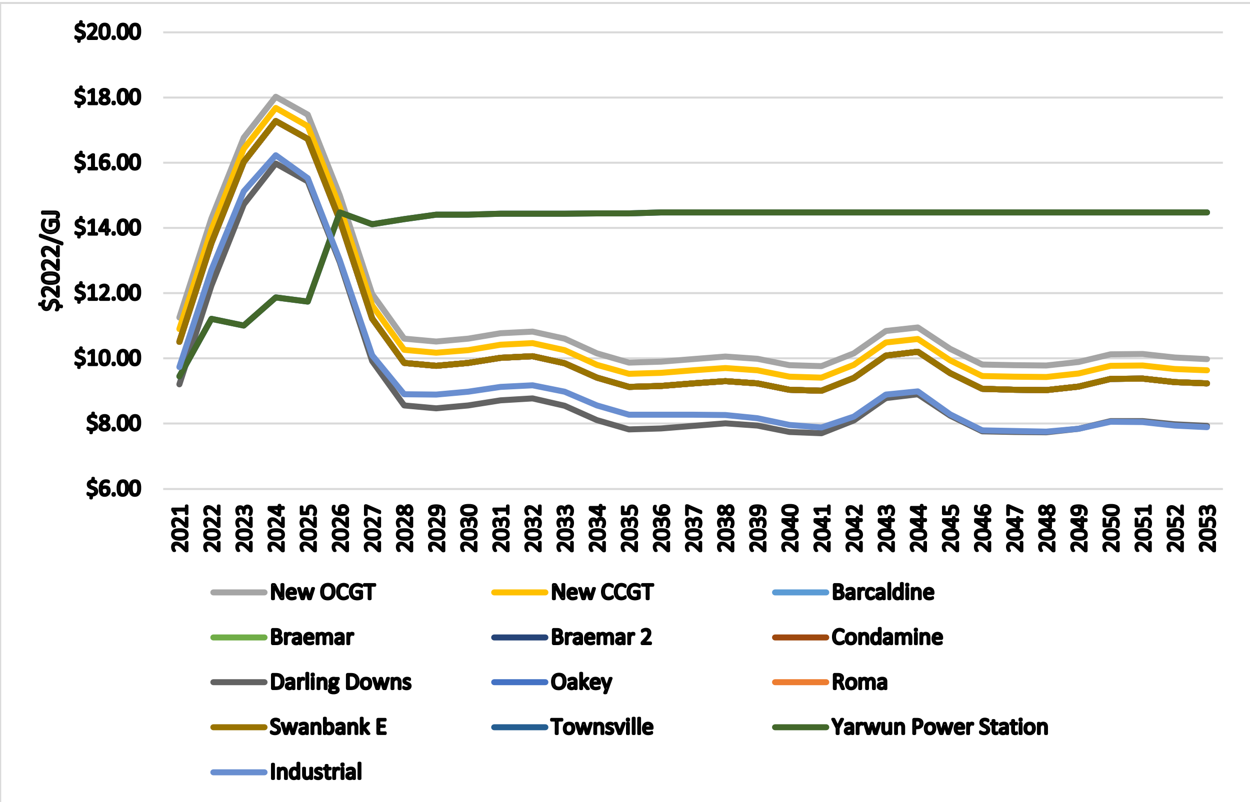
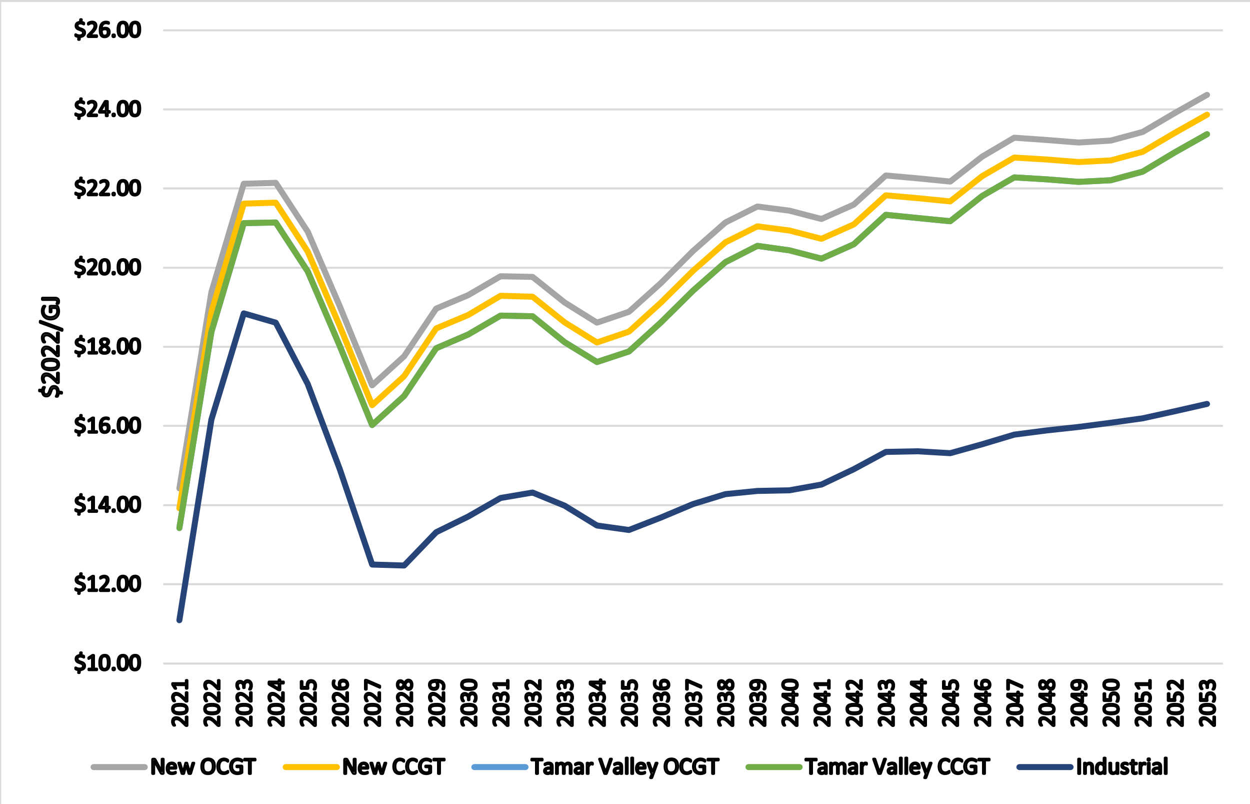


Figure 32 GPG weighted oil indexed gas price projections, Tasmania, Step Change Scenario ($A/GJ, $2022)



6.2 Scenario Comparisons

Scenario comparisons, including the 2021 Central Scenario and 2022 Step Change Scenario, are shown for Mortlake PS, Tallawarra PS, Pelican Point PS and Swanbank E PS in Figure 33 to Figure 36.

For each power station the relativities among the scenarios in this study are very similar to those for industrial customers, with slight differences to transmission cost differences.

Figure 33 Mortlake weighted oil indexed gas price projections ($A/GJ, $2022)

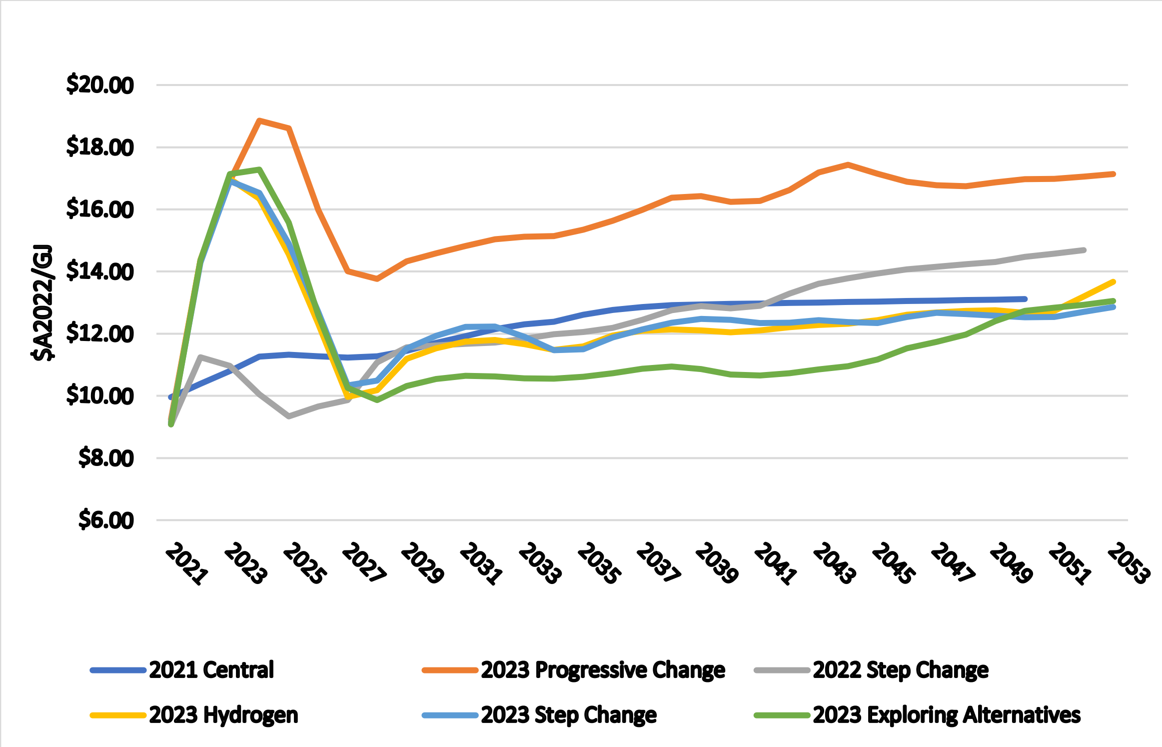


Figure 34 Tallawarra weighted oil indexed gas price projections ($A/GJ, $2022)

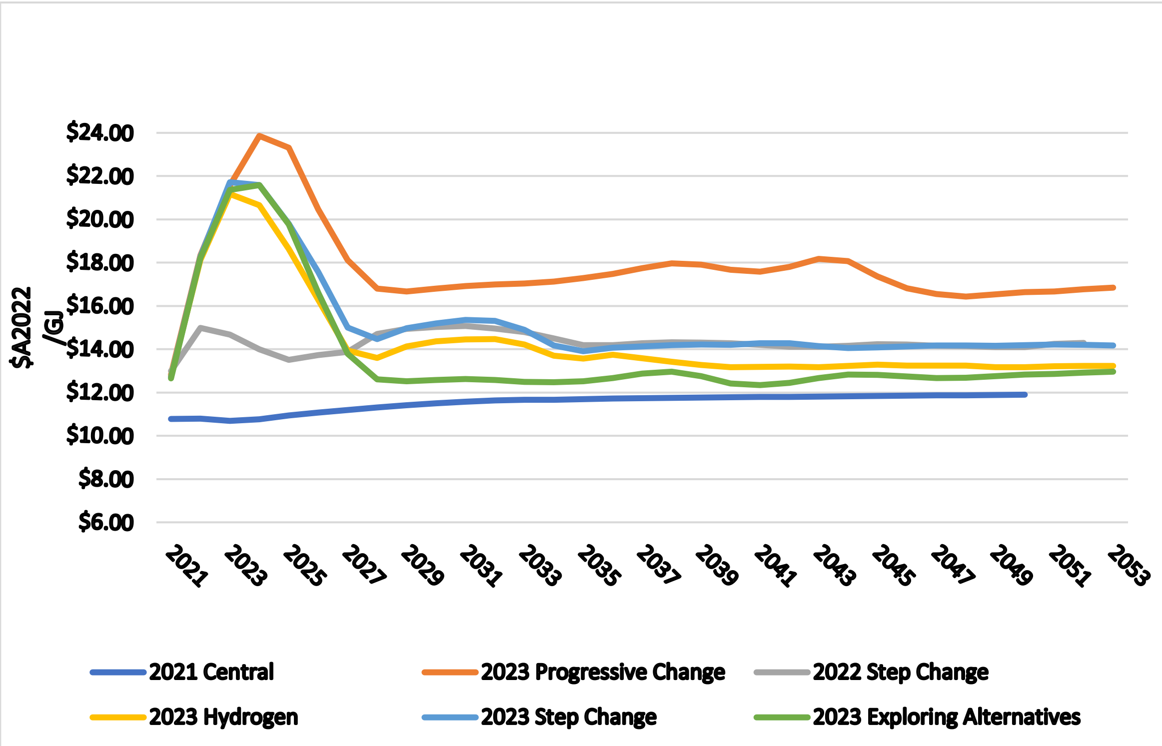


Figure 35 Pelican Point weighted oil indexed gas price projections ($A/GJ, $2022)

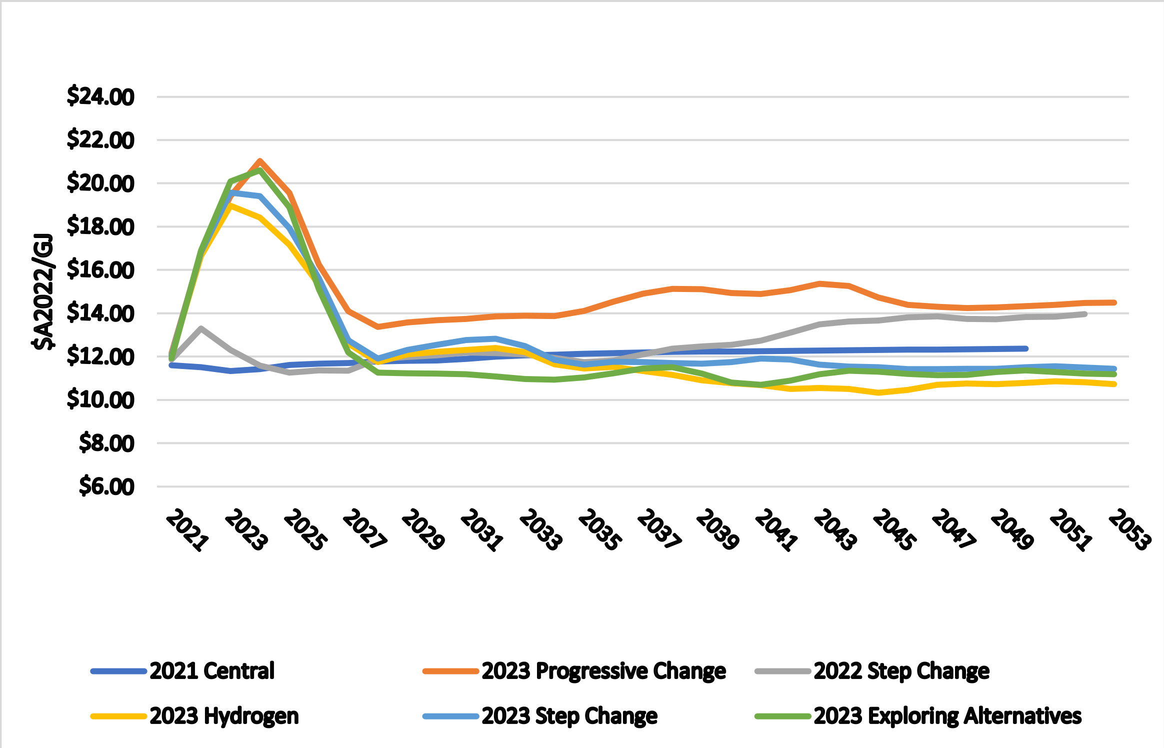
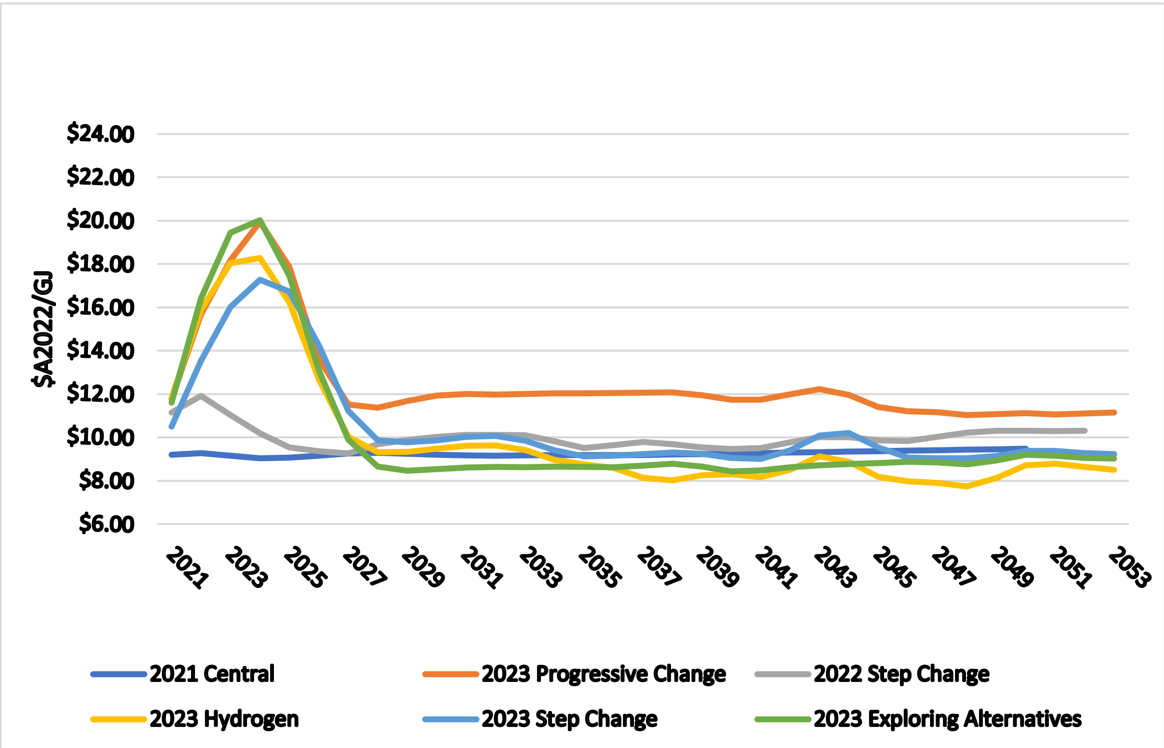


Figure 36 Swanbank E weighted oil indexed gas price projections ($A/GJ, $2022)

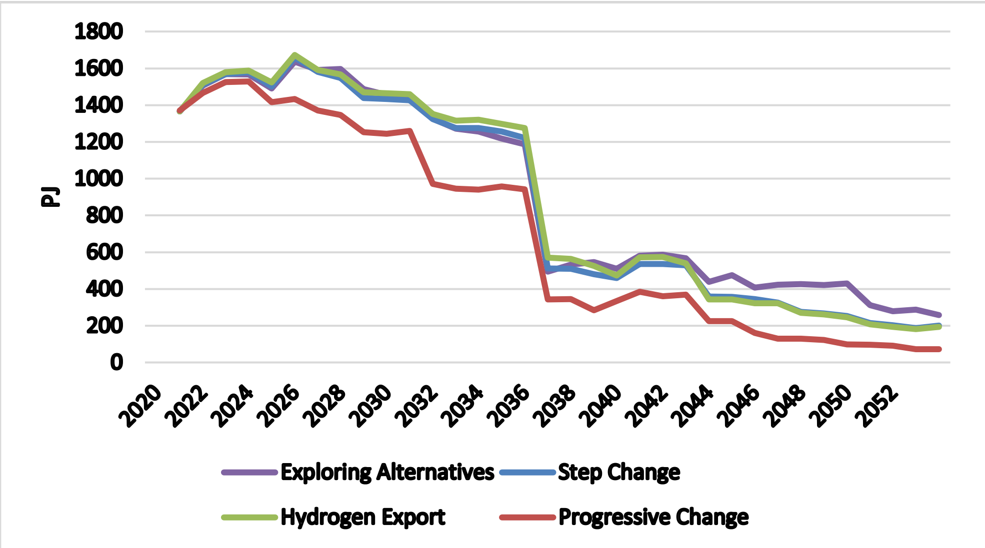


Appendix 1 LNG Exports and Imports

As noted in section 3.2, LNG exports from Gladstone are treated as committed contracts up to 2035, with variations up to that point, and after 2035 they are calculated entirely by RMMEAU, and depend upon the availability and competitiveness of supply and Global LNG demand. Projections of exports in each scenario are shown in Figure A 1.

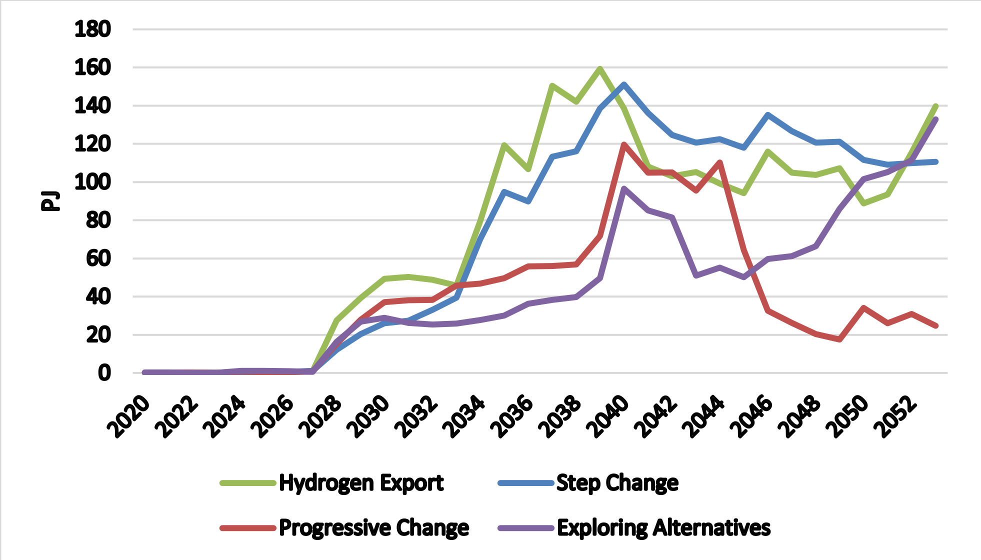
Until 2035 they are similar except for the Progressive Change Scenario, in which higher production costs lead to lower exports. After 2035 the Surat Basin has limited capacity for exports, which decline at that point and continue to decline thereafter.

Figure A 1 East Coast LNG Exports



The LNG import picture is more mixed, as shown in Figure A 2, except for the delay in imports until 2028 due to the prevailing high LNG prices. The scenarios in which LNG prices fall in line with declining Global LNG demand (Step Change and Hydrogen Export) show strong upturns in imports in the mid-1930s, reaching over 100 PJ/annum. Exploring Alternatives is generally lower because of the additional domestic production (Gunnedah Basin).

Figure A 2 LNG Import Volumes



Appendix 2 Glossary

2P (gas reserves)	Proved and Probable gas reserves (commercial/economic reserves with a 50% likelihood of being exceeded)
2C (gas resources)	Gas resources not yet commercial/economic, with 50% likelihood of being exceeded
$A	Australian dollar
$US	United States dollar
ACCC	Australian Consumer and Competition Commission
ADGSM	Australian Domestic Gas Security Mechanism
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	Authorised Maximum Daily Quantity
APA	Australian Pipeline Trust
bbl	Barrel (of oil)
COAG/NFRC	Council of Australian Governments
CPI	Consumer Price Index
GJ	Gigajoule = Joule * 10^9
GPG	Gas Powered Generator
GSOO	Gas Statement of Opportunities
HoA	Heads of Agreement
JCC	Japanese Crude Cocktail/Japanese Customs Cleared Crude
JV	Joint Venture
LGA	Lewis Grey Advisory

LNG	Liquefied Natural Gas
NGL	National Gas Law
NGR	National Gas Rules
PJ	Petajoule = Joule * 10^{15}
RMM	Resources Market Model
RMMEAU	Resources Market Model Eastern Australia
RMMLNG	Resources Market Model LNG
SPE	Society of Petroleum Engineers
STTM	Short Term Trading Market
VGPR	Victorian Gas Planning Report
VTS	Victorian Transmission System