NGFR Gas Price Assessment

October 2016

Final Report

CORE ENERGY GROUP

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Glossary

AEMO	Australian Energy Market Operator
AUD	Australian Dollar
AUD/t	Australian Dollar per tonne
CE	Core Energy Group
CSG	Coal Seam Gas
GPG	Gas Powered Generators
LNG	Liquefied Natural Gas
NGFR	National Gas Forecasting Report
PV	Photovoltaic Cell
RET	Renewable Energy Target
R&C	Residential & Commercial

1. Introduction

1.1. Introduction

Core Energy Group (“**CE**”) has been engaged by Australian Energy Market Operator (“**AEMO**”) to undertake an independent assessment of gas prices for the NGFR, having regard to 2016 AEMO Forecasting and Planning scenarios, defined NGFR projections and assessment of sensitivity of gas price to major variables.

1.2. Scope

The table below presents the scope of the engagement and references to the related sections of this report.

Scope	Section Reference
Undertake sensitivity analysis in relation to the 2016 AEMO Forecasting and Planning scenarios	4
Develop supply scenarios and associated cost of supply	5 & 6
Update upstream price forecasts | Core model outputs	8
Sensitivity and scenario analysis to consider the following factors: ▪ Pricing and tariff ▪ Fuel switching ▪ GPG role due to coal retirements (AEMO to provide list of coal plant closures) ▪ Solar PV impact ▪ RET, Carbon pricing (AUD25/t in 2020 and AUD50/t in 2030) and other emissions policies ▪ Technological advances including electrical vehicles and battery storage	4
Supply side price competition and strategy: ▪ Assessment and review of pricing strategies ▪ Cournot/game theoretic modelling approach	5, 6, & 7

2. Introduction and Methodology

2.1. Introduction

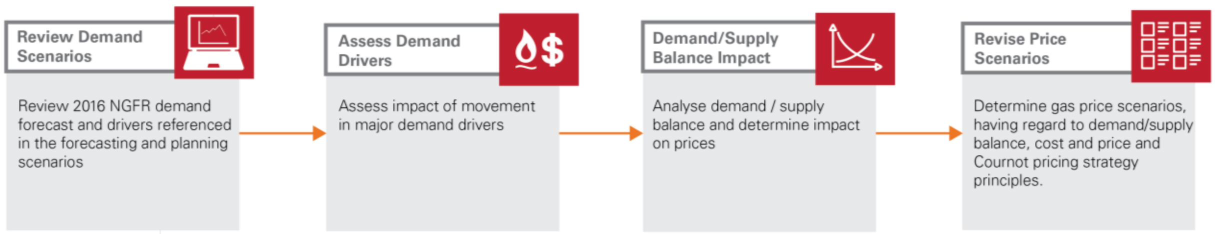
CE has derived future gas price scenarios having regard to:

- AEMO 2016 NGFR forecasting and planning scenarios, (see Section A.1)
- AEMO 2016 NGFR demand forecasts - including Tariff V, Tariff D, GPG and LNG
- CE assessment of major price drivers
- CE assessment of the future pricing strategy of EA producers – applying Cournot and other game theoretic principles

2.2. Approach

The following figure outlines the framework that CE has adopted to derive the gas price scenarios:

Figure 2.1 Framework | Gas Price Scenario Review



CORE has considered the following cost elements to derive scenarios of the delivered price:

- Wholesale contract market price
  - > Price at defined delivery point as extracted from CE Energyview system.
- Transmission cost
  - > Estimated transmission pipeline tariff as extracted from CE Energyview system.
- Peak supply cost
  - > Estimated cost of peak supply service as extracted from CE Energyview system.

It should be noted that this price represents the wholesale cost of gas to the retailer or GPG owner, not the marginal cost or opportunity cost, which may influence bidding behaviour. Costs are expressed in 2016 real terms unless stated otherwise.

3. NGFR Gas Demand Scenarios

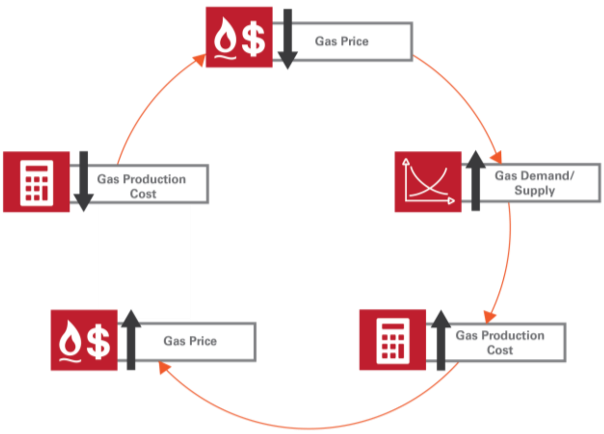
CE has considered AEMO's 2016 NGFR forecasting and planning scenarios as presented in Attachment A.1 and AEMO's 2016 NGFR future demand scenarios (including Tariff V, Tariff D, GPG and LNG), as a basis for deriving related gas price scenarios.

4. Gas Price Drivers

CE has analysed all major drivers of demand and has determined that movements in the drivers of LNG and GPG demand are expected to have the most material impact on gas price.

The sensitivity of gas prices to the drivers of the LNG and GPG demand segment are presented in the following table.

Table 4.1 Gas Price Sensitivity

Drivers	Gas Price Sensitivity
LNG Demand	
 Oil Prices/Exchange Rate/Gas Prices	▪ Eastern Australian domestic gas prices are influenced by LNG prices, which are linked to global oil prices and exchange rates ▪ In simple terms LNG prices are expected to set the upper limit of gas prices and the cost of gas extraction will set the lower limit. However high LNG prices can give rise to cost inflation which lifts the lower cost/price limit. ▪ The following diagram presents an illustration of the interaction between demand, cost and price forces. 
 Cost Competitiveness of Qld LNG	▪ The cost competitiveness of Qld LNG projects relative to foreign LNG projects is expected to have a material influence of ultimate demand e.g. low foreign prices and available supply could reduce demand for Queensland CSG if supply contracts are flexible or if buyers and sellers agree new terms. Conversely, if Qld LNG cost is lower than that of competing LNG export nations, spare capacity of the LNG projects will be used to fulfil contracts and fill spot cargoes and therefore LNG demand in EA will be higher.
 LNG Growth Outlook	▪ Queensland LNG demand growth is expected to be limited beyond the ramp-up period, until the end of the projects' initial contract period to ~2035. ▪ Key uncertainties in LNG demand include: • potential for reduction in LNG supply due to exercise of flexible contract terms or renegotiation between buyers and seller • recontracting risk around 2035 when existing contracts mature • potential for a seventh LNG train to come online, depending on global demand/supply balance and cost competitiveness of Qld LNG projects. ▪ The level of LNG demand has the potential to significantly impact the demand/supply balance and price of gas in Eastern Australia.

Drivers	Gas Price Sensitivity
	• Low LNG demand could make gas available to domestic market at lower prices • Strong LNG demand could result in higher demand for labour and services, placing upward pressure on costs, resulting in higher prices required to cover production costs. Further as high performance reserves are increasingly depleted, the development of low productivity acreage to fulfil LNG demand could result in higher upstream gas costs and prices.
GPG Demand	
 Electricity Wholesale Price	▪ The retirement of large scale coal generators is likely to drive an increase in average wholesale electricity prices as cheap coal-fired electricity supply will be removed from the National Electricity Market ("**NEM**") ▪ As wholesale electricity prices increase, GPG is likely to be more competitive in the intermediate to peak market, increasing gas consumption. ▪ Higher gas consumption could result in greater competitive tension in the gas market and higher gas prices.
 Electricity Demand/Technology Cost and Uptake Curve	▪ Uncertainty regarding the future growth of solar PV and battery storage translates to uncertainty regarding future GPG demand – volume and peak. High penetration in solar PV and battery storage could potentially reduce peak demand for GPG. ▪ A lower gas consumption could result in less competitive tension in the gas market and lower gas prices
 LREC/SRES/Climate Policy to 2030	▪ The growth in renewable capacity in the NEM has resulted in intermittent supply challenges. GPG is often required to fulfil demand when renewable capacity is unavailable. ▪ The expected increase in penetration of renewables to 2030 is likely to contribute to growth in intermittent supply, with GPG playing an increasingly important role to address energy security. ▪ Material retirement of coal could give rise to increased use of gas for intermediate generation capacity which could place some upward pressure on prices in a limited supply scenario. ▪ Higher gas consumption due to a combination of renewable penetration and coal retirements could result in greater competitive tension in the gas market and higher gas prices.

5. Gas Demand/Supply Balance

5.1. Demand/supply scenarios

To assess the extent of future demand/supply tension and implications for gas price, CE derived supply scenarios to meet the three NGFR demand scenarios, having regard to available 2P reserves, future field deliverability and relative production costs. The results are summarised in Figures 5.1 to 5.3.

Figure 5.1 Neutral Case | Demand/Supply | PJ

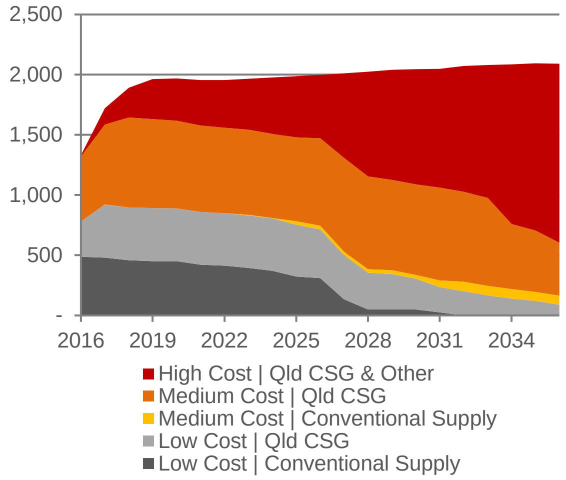


Figure 5.2 Weak Case | Demand/Supply | PJ

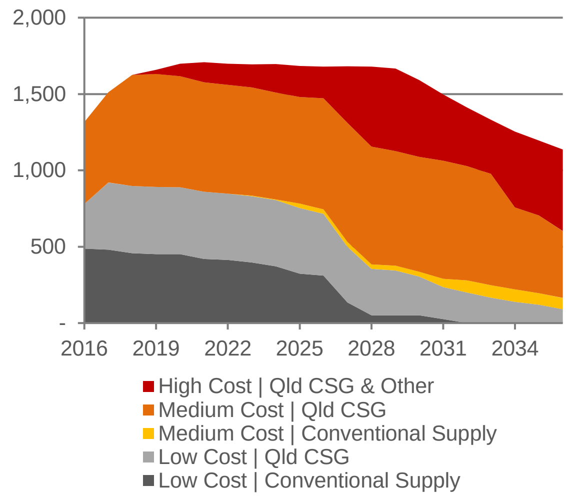
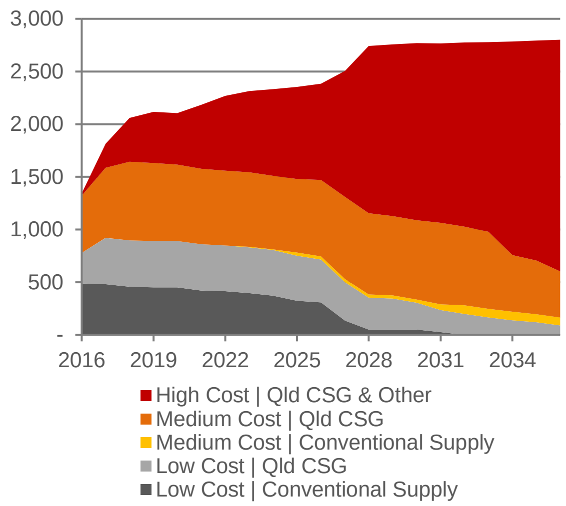


Figure 5.3 Strong Case | Demand/Supply | PJ



CE has made the following assumptions in relation to gas supply:

- Otway, Cooper and Bass projects supply southern markets until 2P reserves deplete in 2021/2022
- Gippsland is a major source of supply in southern markets until its 2P reserves deplete around 2026/2027
- Cooper Basin is supplied by Beach and Origin to southern markets until 2024 to meet domestic contracts and Santos is assumed to contribute to the GLNG Horizon contract beginning in 2016 and supplying for 15 years.
- Queensland CSG meets some domestic contracts and LNG to 2035.

6. LNG Price and Cost Scenarios

CE has derived estimates of cost and price under each AEMO NGFR scenario:

- Costs have been derived utilising a cash flow model, having regard to projected production, capital and operating expenditures, after royalties and tax
- LNG linked gas prices have been derived based on AEMO oil and exchange rate assumptions

Further detail regarding LNG price linkage follows:

1. Core has made the following assumptions to derive gas prices:
   > CBJV and Otway contract prices undergo price review in 2017 and GBJV in 2018. Gas prices are assumed to be oil-linked thereafter.

   > The contract prices are assumed to comprise of 40% fixed cost-link component and 60% floating oil-price linked component.
2. Fixed Component
   > Core has assumed a fixed price of AUD5.00/GJ for GBJV and AUD6.00/GJ for CBJV.
3. Floating Component
   > Core has used the following Brent Oil price scenarios to derive the gas price projections. The Brent Oil scenarios were provided by AEMO as part of the engagement scope.

Table 6.1 Brent Oil Price forecast | USD/bbl

Year	Weak	Neutral	Strong
Brent Oil	30	60	90

Source: AEMO, 2016

> AUD to USD exchange rate under all scenarios are summarised below

Table 6.2 AUD to USD Exchange Rate

Year	Weak	Neutral	Strong
FOREX	0.65	0.75	0.95

> Gas price as a percentage of oil price, see Table 3.2

Table 6.3 Gas price as a percentage of oil price

Year	Weak	Neutral	Strong
GBJV/Otway	6.5%	7.0%	8.0%
CBJV	6.0%	6.5%	7.0%

4. Contract Prices
   > Contract prices are assumed to be the higher of cost based pricing and LNG linked pricing

   > The LNG linked pricing of GBJV and CBJV gas based on historical pricing structures are presented in the table below:

Table 6.4 LNG linked prices – legacy formula

Year	Low	Reference	High
GBJV	3.80	5.35	6.55
CBJV	4.05	5.50	6.40

However GBJV and CBJV are expected to contract at levels above those based on legacy formula, due primarily to underlying cost of production and minimum required rate of return. CE has assessed most likely prices to be as follows:

Table 6.5 GBJV Assumed Contract Prices

Year	Low	Reference	High
2017	5.75	6.25	7.91
2018	5.75	6.25	7.92
2019	5.75	6.25	7.93
2020-21	5.75	6.25	8.00

Table 6.6 CBJV Assumed Contract Prices

Year	Low	Reference	High
2017	5.80	6.00	7.57
2018	5.80	6.00	7.56
2019	5.80	6.00	7.59
2020-21	5.80	6.00	7.65

> Beyond 2022, Core projects that contract prices will be consistent with long term cost, as follows:

Table 6.7 Long term marginal cost

Year	Low	Reference	High
2022+	6.50	7.00	8.50

The results are summarised in the following table.

	Weak	Neutral	Strong
CE derived gas production cost	AUD6.50/GJ	AUD7.00/GJ	8.50/GJ
AEMO oil price & exchange rate assumptions	Oil Price: USD30/bbl FOREX: 0.65	Oil Price: USD60/bbl FOREX: 0.75	Oil Price: USD90/bbl FOREX: 0.95
Gas prices (Gippsland) based on above LNG linkage	Fixed: AUD2.00/GJ Floating: AUD1.80/GJ Total: AUD3.80/GJ	Fixed: AUD2.00/GJ Floating: AUD3.35/GJ Total: AUD5.35/GJ	Fixed: AUD2.00/GJ Floating: AUD4.55/GJ Total: AUD6.55/GJ
Higher of Cost and LNG legacy Price	**AUD6.50/GJ**	**AUD7.00/GJ**	**8.50/GJ**

CE assumes that new contract gas prices will be influenced primarily by LNG price linkage and cost of extraction. Under all scenarios marginal production costs are projected to exceed oil linked prices, based on AEMO assumptions, therefore new prices are assumed to be broadly in line with cost.

7. Competition

CE has undertaken analysis of the competitive dynamics between major producers, including consideration of pricing theories such as Cournot. This analysis indicates that two producing regions have scope to influence forward gas domestic prices:

- Gippsland Basin producers in the short to mid term
- Queensland CSG producers in the mid to longer term

7.1. Gippsland

CE has undertaken an analysis of all major southern market producers and determined that the only major party with potential supply side power, based on existing reserves and projected demand is the Gippsland producers. Key considerations are summarised in the following table.

Gippsland Basin	
Overview	▪ The Gippsland Basin supplies approximately 40% of the domestic market and has a primary focus on supplying Vic, NSW and to a lesser extent SA
Estimated Supply Cost	▪ The medium to long term marginal cost is estimated to be approximately AUD 4.50/ GJ for legacy gas and higher for Kipper. This includes operational costs and maintenance/ SIB Capex only ▪ It is assumed that existing 2P reserves in the Gippsland Basin are depleted by 2026/2027.therefore the cost of production is expected to increase if further capital expenditure is required to develop additional 2P reserves.
Contracted Position & Uncontracted Potential Supply	▪ Significant contracts ending in 2017, 2020 and 2022. ▪ Additional ~150 PJ of volume available for recontracting from 2018 ▪ Additional ~50-100 PJ of volume available for recontracting between 2021 and 2023
Proximity to Key Demand Centres	▪ **LNG export and Queensland Domestic:** Not well placed to supply gas into the LNG export market and Queensland domestic market due to transmission challenges and tariffs. ▪ **Victorian DTS:** Gippsland Basin production is best placed to supply the Victorian market as Longford Plant is connected to the DTS/VTS. Gas can flow to Melbourne relatively cheaply via LMP. ▪ **Adelaide:** Moderate transportation costs incurred along the LMP, SWP and SEAGas ▪ **Sydney:** Moderate transportation costs incurred along the EGP (or potentially even a route running along the LMP, NVI and MSP)

As reserves currently stand, Gippsland Basin producers are exposed to limited direct gas supply competition in southern markets during the period to 2025 given constraints on Cooper Basin, Otway and Bass Gas and new NSW and Vic supply, with the only potential new supply associated with the proposed Sole development. Accordingly there is a potential for Gippsland suppliers to price gas at a level which is competitive with northern CSG supply, adjusted for related transmission costs.

7.2. Queensland CSG

CE has undertaken an analysis of all major Queensland CSG producers and determined that the only major party with potential supply side power, based on existing reserves and projected demand is APLNG and Origin Energy during the period beyond 2025. Factors considered are summarised in the following table.

Queensland CSG	
Overview	▪ Surat Bowen production supplies approximately 30% of the domestic market ▪ These producers will supply the 1,200 to 1,500PJ p.a. required to fulfill LNG contracts.
Supply Cost	▪ The medium to long term full lifecycle cost is estimated to be AUD 7.00/GJ at Wallumbilla under a neutral case. This includes drilling and tie-in capex, operational costs and maintenance/ SIB Capex.
Contracted Position & Uncontracted Potential Supply	▪ In 2015 and 2016 contracted to supply 125-160 PJ. The domestic contracts gradually mature through to 2031. ▪ The primary focus of these producers is the LNG export market which will generally require 1,200 to 1,500PJ per annum. ▪ Availability of future supply for domestic markets will
Proximity to Key Demand Centres	▪ **LNG export and Queensland Domestic:** The Queensland CSG producers are best placed to supply gas into the LNG export market and Queensland domestic market. ▪ **Victorian DTS:** Significant transportation costs required to supply into the Victorian market. This puts Queensland CSG supply at a significant disadvantage. ▪ **Adelaide:** Moderate transportation costs incurred along the SWQP (incl. QSN Link) and MAP. ▪ **Sydney:** Moderate transportation costs incurred along the SWQP (incl. QSN Link) and MSP.

Beyond 2025 GLNG, Santos and QCLNG reserves and production in the north are expected to be constrained and there is expected to be limited competitive pressure from southern sources unless new discoveries are made. Accordingly there is potential for APLNG and Origin to seek to increase prices due to limited competition.

8. Gas Price Scenarios

8.1. R&C Sector

The following figures present CE's projection of average delivered mass market gas prices at major demand centres.

Figure 8.1 Neutral Case, real 2016 | AUD/GJ

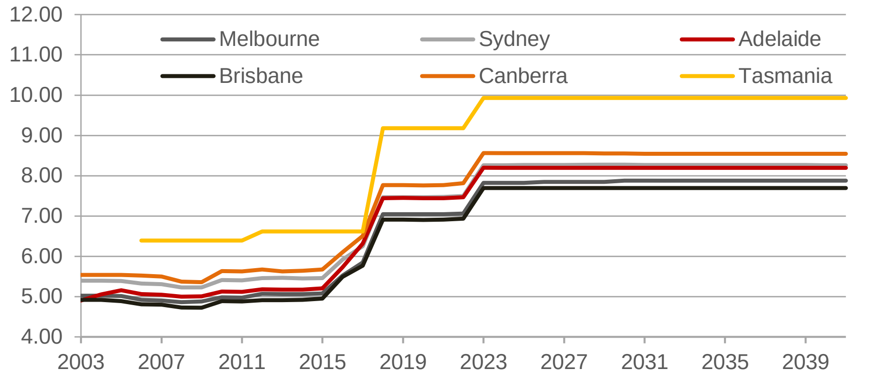


Figure 8.2 Weak Case, real 2016 | AUD/GJ

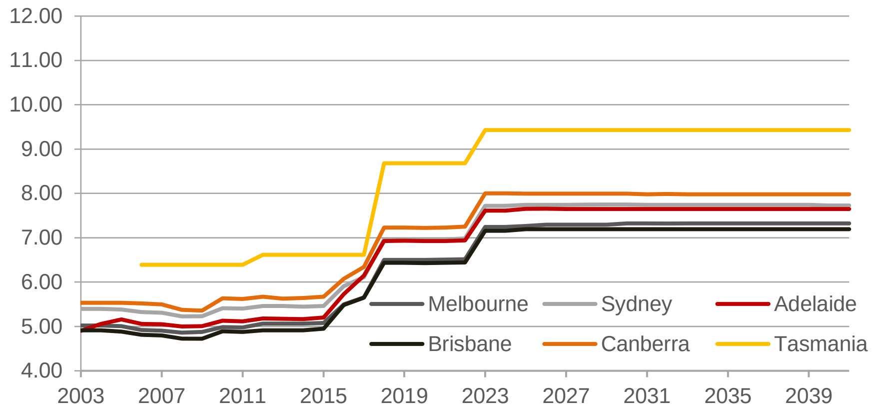
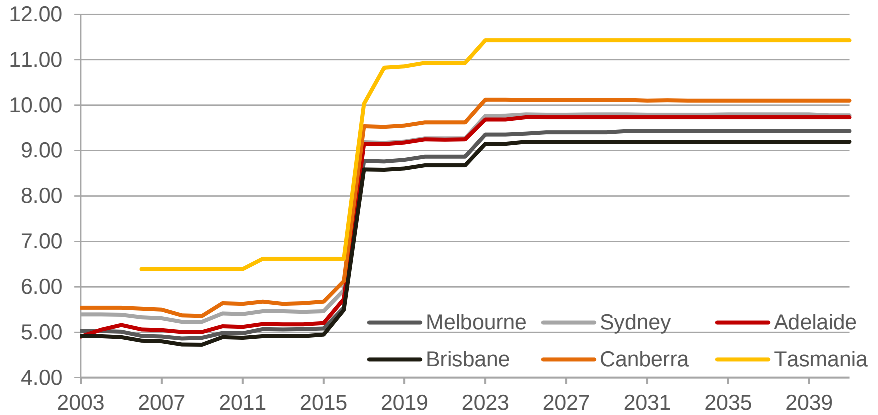


Figure 8.3 Strong Case, real 2016 | AUD/GJ



8.2. GPG

The following figures present CE's projection of average GPG gas prices for each NEM state (at transmission pipeline delivery point).

Figure 8.4 Neutral Case, real 2016 | AUD/GJ

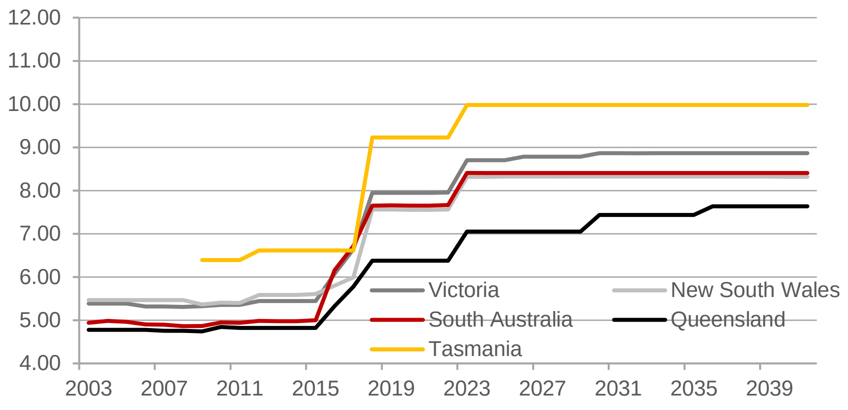


Figure 8.5 Weak Case, real 2016 | AUD/GJ

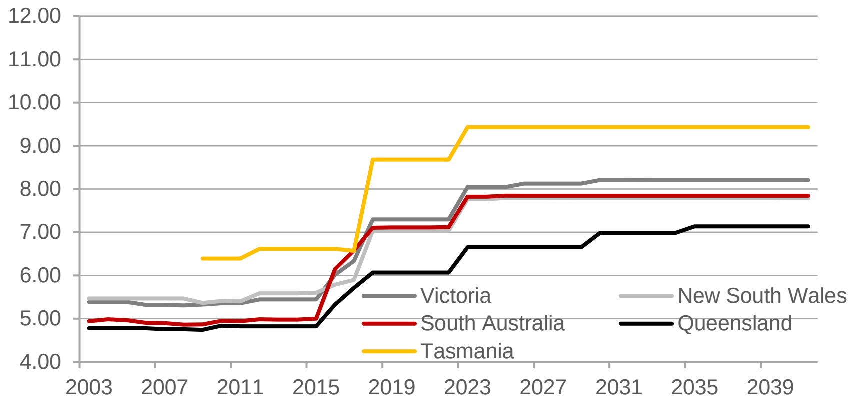
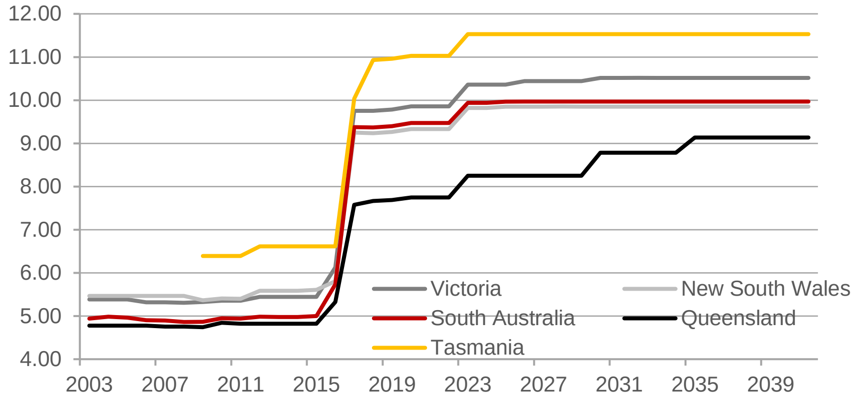


Figure 8.6 Strong Case, real 2016 | AUD/GJ



A1. AEMO 2016 NGFR Forecasting and Planning Scenarios

	Dimension	Impact area	Type	Weak	Neutral (most probable) estimate	Strong
Economy	Economy	Aus Business Conditions	Variable	Weak	Neutral	Strong
Consumer	Economy	Aus Business Conditions	Variable	Low confidence, less engaged.	Average confidence and engagement	High confidence, more engaged.
Population/Population Growth	Economy	Aus Business Conditions	Variable	ABS Population trajectory low	ABS Population trajectory med	ABS Population trajectory high
Elec Network Charges-5 years	Energy prices	Electricity Prices	Fixed	Current AER determinations, fixed after 5 years	Current AER determinations, fixed after 5 years	Current AER determinations, fixed after 5 years
Gas Network Charges-5 years	Energy prices	Gas/Oil Price	Fixed	Current AER determinations, fixed after 5 years	Current AER determinations, fixed after 5 years	Current AER determinations, fixed after 5 years
Elec Network Charges-long run	Energy prices	Electricity Prices	Fixed	Constant real	Constant real	Constant real
Gas Network Charges-long run	Energy prices	Gas/Oil Price	Fixed	Constant real	Constant real	Constant real
Retail costs and margins	Energy prices	Electricity Prices	Fixed	Assume current margins throughout	Assume current margins throughout	Assume current margins throughout
Tariff structure	Energy prices	Electricity Prices	Fixed	Same as current	Same as current	Same as current

LREC/SRES	Energy prices	Electricity Prices	Fixed	Assume current to 2020, with LGCs/SSTC deemable to 2030	Assume current to 2020, with LGCs/SSTC deemable to 2030	Assume current to 2020, with LGCs/SSTC deemable to 2030
Weather	Energy prices	Electricity Prices	Fixed	Neutral weather assumption for consumption forecasts, probabilistic weather settings for peak demand	Neutral weather assumption for consumption forecasts, probabilistic weather settings for peak demand	Neutral weather assumption for consumption forecasts, probabilistic weather settings for peak demand
Rainfall - Hydro gen	Energy prices	Electricity Prices	Fixed	Medium value for water availability (last 15 years)	Medium value for water availability (last 15 years)	Medium value for water availability (last 15 years)
LNG growth	Energy prices	Gas/Oil Price	Fixed	Australian LNG export growth per Oil price projections	Australian LNG export growth per Oil price projections	Australian LNG export growth per Oil price projections
Oil Prices/ Gas Prices	Energy prices	Gas/Oil Price	Variable	USD30/bbl (BR) with pricing affecting the industry as existing contracts expire	USD60/bbl (BR) with pricing affecting the industry as existing contracts expire	USD90/bbl (BR) with pricing affecting the industry as existing contracts expire
Exchange rate	Energy prices	Gas/Oil Price, business conditions for trade exposed businesses	Variable	AUD/USD 0.65 Five-year linear glide-path from current value	AUD/USD 0.75 Five-year linear glide-path from current value	AUD/USD 0.95 Five-year linear glide-path from current value
Elec Wholesale Price	Energy prices	Electricity Prices	Variable	As per the supply-side impact of this scenario. Assumes some abatement cost affecting end-user prices.	As per the supply-side impact of this scenario. Assumes some abatement cost affecting end-user prices.	As per the supply-side impact of this scenario. Assumes some abatement cost affecting end-user prices.
Electricity Demand	Energy prices	Electricity Prices	Variable	Based on end-point consumption (behind the meter), translated back to the grid.	Based on end-point consumption (behind the meter), translated back to the grid.	Based on end-point consumption (behind the meter), translated back to the grid.
Other policy and regulatory settings affecting electricity prices	Energy prices	Electricity Prices	Fixed	Status quo	Status quo	Status quo
Technology uptake	Technology	End use and energy efficiency measures/technologies	Variable	Hesitant consumer, weak economy.	Neutral consumer, neutral economy	Confident consumer, strong economy
Energy Efficiency	Technology	End use and energy efficiency measures/technologies	Variable	Policy measures deliver lower uptake of EE	Policy measures deliver med uptake of EE	Policy measures deliver high uptake of EE
Technology cost and uptake curve	Technology	End use and energy efficiency measures/technologies	Variable	Technology cost and uptake curve assumptions for weak economy, low consumer confidence/engagement.	Median technology cost and uptake curve assumptions	Technology cost and uptake curve assumptions for strong economy, high consumer confidence/engagement.
Climate Policy up to 2030	Climate Policy	Prices, plant-shut-downs, renewables and energy efficiency	Fixed	Assume Australia's Paris commitment is achieved	Assume Australia's Paris commitment is achieved	Assume Australia's Paris commitment is achieved

Climate Policy post 2030	Climate Policy	Prices, plant-shut-downs, renewables and energy efficiency	Fixed	2030 status quo maintained to 2040, but including announced coal plant closures post 2030.	2030 status quo maintained to 2040, but including announced coal plant closures post 2030.	2030 status quo maintained to 2040, but including announced coal plant closures post 2030.
Climate Policy impacts	Climate Policy	Energy prices	Fixed	**Scenario assumes most abatement cost hits the pricing mechanisms of the industry.** Proxy emissions abatement price of **$25/tonne in 2020 rising to $50/tonne by 2030**. Emissions Intensive Trade Exposed Industry pays only 20% of this cost in 2020, rising to 100% in 2030.	**Scenario assumes most abatement cost hits the pricing mechanisms of the industry.** Proxy emissions abatement price of **$25/tonne in 2020 rising to $50/tonne by 2030.** Emissions Intensive Trade Exposed Industry pays only 20% of this cost in 2020, rising to 100% in 2030.	**Scenario assumes most abatement cost hits the pricing mechanisms of the industry.** Proxy emissions abatement price of **$25/tonne in 2020 rising to $50/tonne by 2030.** Emissions Intensive Trade Exposed Industry pays only 20% of this cost in 2020, rising to 100% in 2030.
Climate Policy impacts	Climate Policy	Plant-shut-downs and generation replacement.	Fixed	Fossil fuel plant shut-down list informs scenario, assumes 2030 targets are achieved. Announced shutdowns beyond 2030 assumed in scenario. Technology replacement options do not include coal and are least cost.	Fossil fuel plant shut-down list informs scenario, assumes 2030 targets are achieved. Announced shutdowns beyond 2030 assumed in scenario. Technology replacement options do not include coal and are least cost.	Fossil fuel plant shut-down list informs scenario, assumes 2030 targets are achieved. Announced shutdowns beyond 2030 assumed in scenario. Technology replacement options do not include coal and are least cost.
Climate Policy impacts	Climate Policy	Other	Fixed	Energy efficiency initiatives consistent with National Energy Productivity Plan	Energy efficiency initiatives consistent with National Energy Productivity Plan	Energy efficiency initiatives consistent with National Energy Productivity Plan

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