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FUTURE OF GAS REPORT

ATCO PLAN 2025-29

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Report to ATCO Gas Australia Pty Ltd

Future of gas

Scenario development and modelling for the ATCO gas distribution system

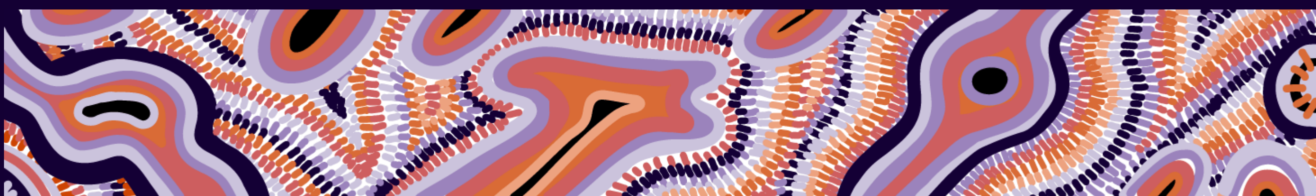
About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

ACIL Allen acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land and its waters. We pay our respects to Elders, past and present, and to the youth, for the future. We extend this to all Aboriginal and Torres Strait Islander peoples reading this report.



Goomup, by Jarni McGuire

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Background

ATCO Gas Australia Pty Ltd (ATCO) engaged ACIL Allen PTY Ltd (ACIL Allen) to develop scenarios and undertake modelling for the ATCO Mid-West and South-West Gas Distribution System (from now on referred to as the gas distribution system). The scenarios and modelling aim to recommend the appropriate asset lives for ATCO to adopt for the AA6 period, especially concerning taking 'No regrets' actions from the stakeholders' perspectives.

The purpose of the modelling was to assess the impact of each scenario on the gas distribution system. Where a scenario results in a substantial reduction in demand, or increases in capital expenditure to reconfigure or replace existing assets, the period over which existing assets are economically useful is shorter. Shorter asset lives result in depreciating the relevant assets sooner.

Making recommendations concerning shortening asset lives assumes linear acceleration of depreciation. Acceleration of depreciation is justified where future consumption is likely to fall substantially or where policy requires, or technology development drives, faster replacement of assets than previously expected, and the resulting future tariffs rise to such an extent that consumers are unwilling to pay them (switch to substitutes such as electricity where feasible or close operations and stop consuming).

As the scenarios were developed, it became clear that future demand, policy requirements and technology development may not be gradual and may not support the linear acceleration of depreciation. In some scenarios, demand is projected to fall away relatively quickly. In other scenarios, demand falls initially and then grows again later. In the Hydrogen Future scenario, demand falls away initially and then grows at a faster rate later. This growth in demand in the Hydrogen Future scenario relies on the significant replacement of assets to cope with distributing hydrogen.

Therefore, rather than recommending changes to asset lives, we recommend changes to the depreciation schedule, incorporating accelerated depreciation. In most cases, the recommended depreciation schedule is not linear, implying that the asset consumption is also not uniform. However, asset life shortening is implicit in the accelerated depreciation schedule.

Throughout the report, references to gas refer to gas generically (natural gas, hydrogen and other renewable gases). Where specific types of gas are discussed, they are referred to specifically (e.g., natural gas, hydrogen, bio-gas, etc.)

Scenarios

The future use of reticulated gas by households, businesses and industries is uncertain as Australia seeks to meet its 2030 and 2050 emissions reduction targets. The uncertainty primarily relates to unknowns such as the emergence and rate of development of zero-emission technologies and the Commonwealth and various state government policies that may be implemented to reduce emissions.

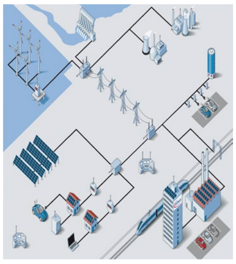
The scenarios aim to define plausible trajectories for the Western Australian gas sector for the potential market, policy, environmental, and industrial sensitivities. These scenarios generate model inputs concerning gas usage and cost, appliance switching, etc., beyond 2050

Four scenarios were developed in concert with ATCO and a group of ATCO's stakeholders, as shown in Figure ES 1 below.

Figure ES 1 Scenario summary

Hydrogen Future – Rapid learning rates relating to green hydrogen and renewable gas production enable these gases to displace natural gas domestically and internationally. The resulting green hydrogen industry mirrors the current natural gas and LNG industries with a broader high-volume export focus enabling the economic servicing of a smaller domestic market.

Electricity Dominates – Renewable electricity generation and storage experience a rapid reduction in cost through fast technological learning. Governments provide financial support to existing natural gas users to electrify their loads. As such, the relative cost of electricity against natural gas and renewable gases falls to such an extent that a broad-based electrification of industry and households occurs.



Energy Hybrid – Technical learning rates for renewable gases and electrification develop similarly, resulting in some customers electing to electrify and some remaining on the gas network. From an economic and environmental point of view, electricity and zero emissions gases become viable alternatives for natural gas. This results in a mixed response from residential/commercial and industrial consumers, with an even split electing to follow electrification or to stick with a gas-based energy supply chain.

Natural Gas Retained – global and local factors result in natural gas being retained in the ATCO network. Zero-emissions gases such as green hydrogen or renewable methane experience slow technological learning rates, which results in them generally remaining uneconomic at scale. As such, natural gas continues to be embraced as a 'transition fuel' used in large volumes globally to quickly and reliably reduce carbon emissions through coal-to-gas switching and to support/firm renewable generation. The carbon emissions intensity of natural gas and natural gas products such as LNG also reduce significantly through rapid technological learning relating to carbon capture and storage (CCS) and carbon capture utilisation and storage (CCUS) and improved access to adequate and affordable carbon offset options.

Source: ACIL Allen with ATCO and ATCO stakeholders

The scenarios were incorporated into the modelling by varying key uncertainties. The uncertainty settings for each scenario are shown in Table ES 1 below.

Table ES 1 Comparison of the four scenarios against each uncertainty

Uncertainty	Hydrogen Future	Electricity Dominates	Energy Hybrid	Natural Gas Retained
Global economic growth	Fast	Moderate	Moderate	Moderate
Domestic economic growth	Fast	Fast	Moderate	Moderate
Renewable gas / H_2 learning rate	Fast	Moderate	Moderate	Slow
Renewable electricity learning rate	Moderate	Fast	Moderate	Moderate
Global demand for renewable gas / H_2	Accelerated growth	Low growth	Moderate growth	Low growth
Electrification – households	Low demand	High demand	Moderate demand	Moderate demand
Electrification – industry	Low demand	Moderate demand	Moderate demand	Low demand
Carbon abatement policy (domestic)	Significant acceleration	Moderate acceleration	Current settings	Current settings
Carbon abatement policy (global)	Significant acceleration	Moderate acceleration	Current settings	Current settings
Fossil fuel technology development (i.e., CCS, CCUS, offsets)	Moderate	Slow	Moderate	Fast

Note: Darker shade = faster rate of change expected

Source: ACIL Allen

Methodology

The model produces a projection of gas demand and customer numbers to the year 2074 disaggregated to the local government area level. Customer numbers are split into new connections and disconnections as the economic decision for these two groups differs. Average consumption per connection is also forecast to 2074.

The 2074 end date was chosen as it provides a 50-year window for the modelling. In particular, it extends well beyond 2050, the target year for net zero emissions in Australia and the significant changes to the Australian and Western Australian economies achieving the net zero target will entail. In ACIL Allen's view, this window is sufficient to determine the different effects of each scenario on future asset utilisation and the need for acceleration of depreciation.

Forecasts are split between residential (Tariff B3) and commercial customers (Tariffs B1 and B2) and industrial customers (Tariffs A1 and A2).

The modelling approach forecasts the impact of relative energy prices between gas and electricity on the projected demand for gas to 2074 while accounting for the effects of changes in relative appliance costs and running costs between gas and electricity on total gas volumes over time.

The brought-forward depreciation is determined once the gas demand and customer forecasts are developed. The approach is to determine a constant annual average tariff (real dollars) for all years and then determine how depreciation must be adjusted yearly to maintain the tariff at that value in all years. This approach does not advantage or disadvantage any group of customers across time while allowing the revised depreciation schedule for each scenario to reflect the economic value of the gas distribution assets.

Modelling disconnections and connections

A fixed percentage of each Local Government Area's (LGA) customers consider switching annually. The default setting for the decision point is every 15 years. Given a uniform distribution, 1/15th of the residential customer base each year decides whether to remain connected to the gas network or switch to electric appliances.

The function that is used to determine the probability of switching is the logistic function. This function resembles an S curve characterised by a slow build-up, a ramp-up phase, and a mature phase where the take-up has reached a saturation point.

The logit model converts underlying drivers of choice to switch to electric appliances into a probability or market share of switching. The model values each attribute that drives the decision and applies an elasticity or weight to each factor. In our case, we are using a single factor, the NPV of switching, which incorporates the set of underlying drivers, such as relative prices and appliance costs, into a single measure.

The relative NPV of switching from gas to electricity is calculated, and the logistic curve estimates the market share of gas versus electricity over time. Separate calculations and projections are made for both disconnections and new connections. The S curve approach is used for residential customers (Tariff B3) and smaller commercial customers (Tariff B2).

Calculating bring forward depreciation

ACIL Allen's approach to calculating revised depreciation (brought-forward) schedules is as follows:

— Develop the projected annual gas demands from 2025 to 2074 for the four separate scenarios
– Extract the current asset base, the remaining asset lives, and the proposed new assets expenditure and lives and operating expenditures associated with each of the four scenarios.
– Replicate the revenue and depreciation schedules associated with the underlying demand and expenditures under the four separate scenarios.
— Determine the annual average tariffs for the depreciation schedules to 2074.
— Calculate the constant annual average tariff ($2023) that provides the same present value of revenues as the annual average tariff between 2026 and 2074.
— Sculpt regulatory depreciation to fit within the constant annual tariff constraint.

Results

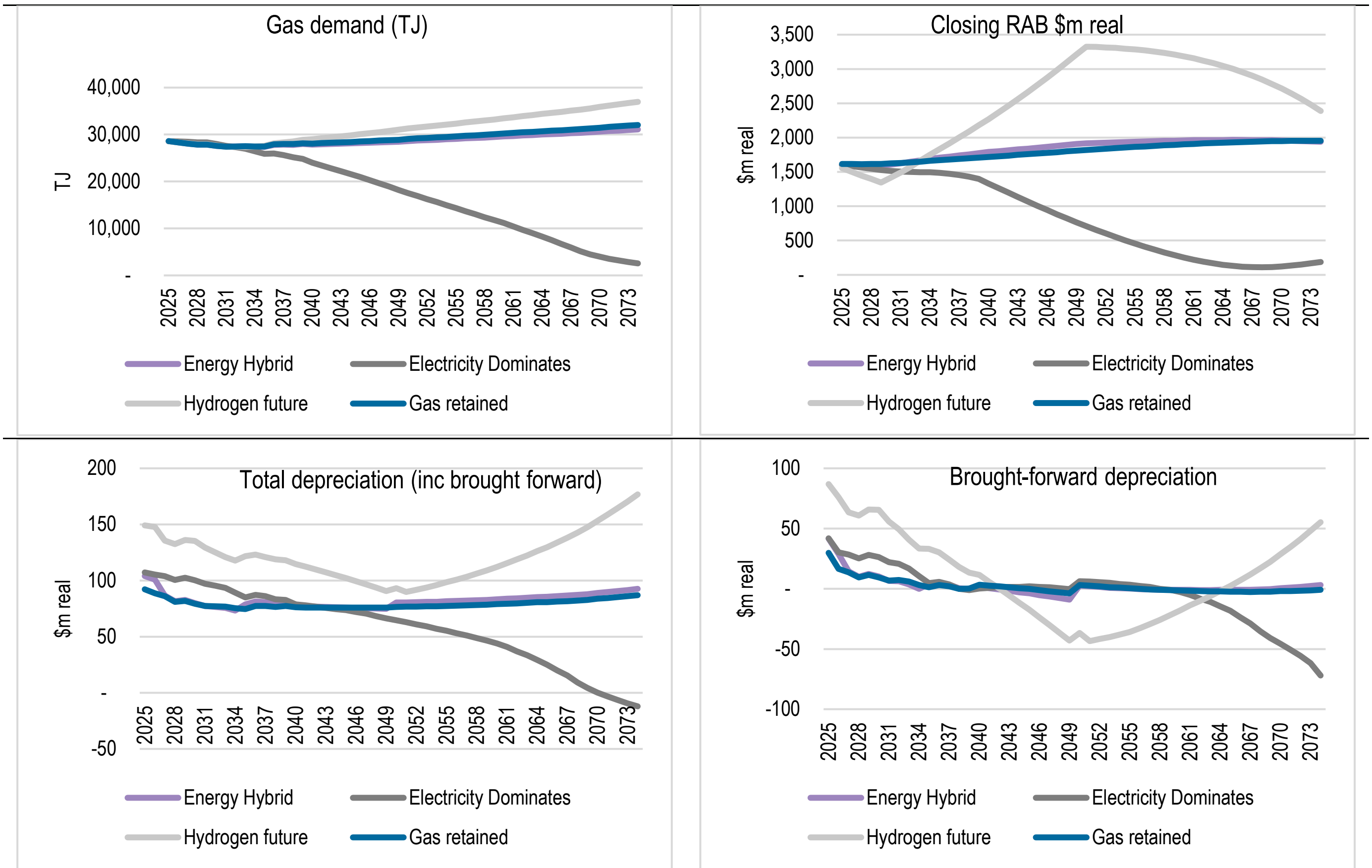
Figure ES 2 provides a summary of key results.

The Hydrogen Future scenario requires reconfiguration of the gas distribution network to support the switch to hydrogen gas as it becomes competitive compared with natural gas. Demand rises above all other cases in the long term. The increased capital expenditure drives significant growth in the regulated asset base (RAB). However, early asset replacement results in significant depreciation increases, including substantial amounts of brought-forward depreciation.

In the Electricity Dominates scenario, gas customers switch to electricity in large quantities starting in the early 2030s. More than 90 per cent of demand, including almost all domestic and small commercial demand, is projected to have switched to electricity by 2074. The loss of gas customers, and therefore, gas consumption, results in significant amounts of depreciation being brought forward until around 2060.

The Energy Hybrid and Gas Retained scenarios have slight contractions in demand to the mid-2030s and modest growth after that. Both scenarios result in a modest acceleration of depreciation (until 2041 for the Energy Hybrid scenario and 2045 for the Gas Retained scenario).

Figure ES 2 Projected gas demand, closing RAB, total depreciation and brought-forward depreciation by scenario



Source: ACIL Allen

Conclusions and recommendations

Figure ES 3 compares the brought-forward depreciation schedules by scenario for 2025-29. The depreciation schedules differ across the four scenarios. The calculated brought-forward depreciation drives this difference to ensure that tariff prices remain constant over the modelled period (2025-2074). The standard regulatory cycle is five years in length which allows flexibility in decisions relating to tariff pricing. Decisions made in the upcoming regulatory cycle (2025-2029) concerning accelerating depreciation in the regulatory cycle can be adjusted in the subsequent regulatory cycles as better information becomes available.

The Hydrogen Future scenario sits well above the other three scenarios, as substantial capital expenditures (compared with the other scenarios) are required to reconfigure the network to carry hydrogen gas. Therefore, there is significantly more capital to depreciate than in the other cases.

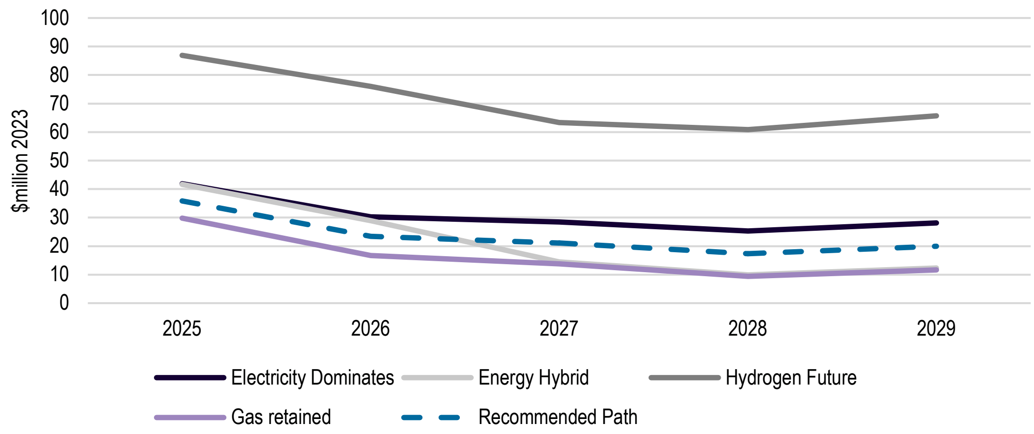
Electricity Dominates and Energy Hybrid start at similar levels in 2025 and 2026. The Gas Retained brought-forward depreciation is lower than all others in the first two years. From 2027 to 2029, the Energy Hybrid scenario shifts to track the Gas Retained scenario. The Energy Hybrid brought-forward depreciation decreases in 2027 because operating expenditure (as provided by ATCO) rises compared with the other scenarios. When operating expenditure increases, brought-forward depreciation must fall to maintain the constant average annual tariff assumption.

As shown in Figure ES 3 below, the potential range of brought-forward depreciation across the four scenarios from 2025 to 2029 is between $50 and $60 million annually (highest scenario, less lowest scenario each year). As each scenario is plausible, any brought-forward depreciation path could be considered reasonable. However, the least "no regrets" approach would be to choose a brought-forward depreciation path that follows or is close to the most significant number of scenarios possible.

The Hydrogen Future brought-forward depreciation is an outlier, whereas the other three cluster relatively closely over the five years. The Electricity Dominates, and the Gas Retained scenarios, bound the cluster. The Energy Hybrid brought-forward depreciation path sits within the bounds of the other two. Therefore, we recommend choosing a brought-forward depreciation path for 2025 to 2029 that is halfway between the Electricity Dominates and Gas Retained paths. We consider this to be the least "no regrets" option.

The recommended brought-forward depreciation path is included in Figure ES 3 below.

Figure ES 3 Recommended brought-forward depreciation path – 2025-29



Source: ACIL Allen

Introduction 1

ATCO Gas Australia Pty Ltd (ATCO) engaged ACIL Allen PTY Ltd (ACIL Allen) to develop scenarios and undertake modelling for the ATCO gas distribution system. The scenarios and modelling aim to recommend the appropriate asset lives for ATCO to adopt for the AA6 period, especially concerning taking 'No regrets' actions from the stakeholders' perspectives.

Making recommendations concerning shortening asset lives assumes linear acceleration of depreciation. Acceleration of depreciation is justified where future consumption is likely to fall substantially or where policy requires, or technology development drives, faster replacement of assets than previously expected, and the resulting future tariffs rise to such an extent that consumers are unwilling to pay them (switch to substitutes such as electricity where feasible or close operations and stop consuming).

As the scenarios were developed, it became clear that future demand, policy requirements and technology development may not be gradual and may not support the linear acceleration of depreciation. In some scenarios, demand is projected to fall away relatively quickly. In other scenarios, demand falls initially and then grows again later. In the Hydrogen Future scenario, demand falls away initially and then grows at a fast rate later. This growth in demand in the Hydrogen Future scenario relies on the significant replacement of assets to cope with distributing hydrogen.

Therefore, rather than recommending changes to asset lives, we have recommended changes to the depreciation schedule, incorporating accelerated depreciation. In most cases, the recommended depreciation schedule is not linear, implying that the asset consumption is also not uniform. However, asset life shortening is implicit in the accelerated depreciation schedule.

Throughout the report, references to gas refer to gas generically (natural gas, hydrogen and other renewable gases). Where specific types of gas are discussed, they are referred to specifically (e.g., natural gas, hydrogen, biogas, etc.).

The remainder of the report is structured as follows:

— Chapter 2 provides a profile of the Western Australian energy sector.
— Chapter 3 describes the four scenarios used in the analysis
— Chapter 4 sets out the modelling methodology and scenario input assumptions
— Chapter 5 provides the modelling results
— Chapter 6 sets out our conclusions and recommendations.

Western Australian Energy Sector Profile 2

The Western Australian energy sector is undergoing transformative change at most levels. Government action, policy, and gas project timing (supply and demand side) are key factors shaping the energy future in Western Australia. This section explores key themes of this energy future. It undertakes a high-level analysis of significant stakeholders and competitive dynamics in retail gas, explores technology developments within the sector, and assesses affordability, efficiency, and sustainability within the retail gas industry.

2.1 Government action and policy

Several key government actions and policies strongly influence the future of Western Australia's energy sector. The announcement of the closure of all government-owned coal generator units by the end of 2029 is a crucial example. This action has placed enormous pressure on the electricity market, raising capacity and reliability concerns. It has also resulted in AEMO's 2022 Gas Statement of Opportunities (GSOO) projecting a significant shortfall in gas supply by the early to mid-2030s.

The 2022 AEMO Electricity Statement of Opportunities (ESOO) and GSOO anticipate replacement generation from gas-powered generation (GPG) through new entrant plants and increases in the capacity factor of the incumbent plant. AEMO also forecasts a capacity shortfall following the closure of Synergy's coal fleet without timely investment in new capacity. This further underlines the importance of the gas supply to incumbent and new-entrant GPGs concerning the electricity system's reliability and security.

Figure 2.1 GPG Gas Demand Forecast

Source: AEMO 2022 GSOO

Additional GPG utilisation within the Western Australian Wholesale Electricity market (WEM) will drive domestic gas demand considerably. Domestic demand is expected to increase by approximately 200 TJ per day over the coal retirement schedule compared to relatively flat projections before the retirement announcement. AEMO's 2022 GSOO expects this demand to peak when the domestic gas supply is likely to decline following the commissioning of the Waitsia Stage 2 and Scarborough gas projects in 2027 and 2029, respectively. These projects have the most distant start date of projects currently expected to contribute to domestic supply in Western Australia. As such, AEMO forecasts significant supply shortfalls after the start of these projects, as supply falls in line with field depletion and GPG demand continues to grow.

The Commonwealth Government's Safeguard Mechanism' will impact large emitters' gas and energy consumption. The mechanism aims to "reduce emissions limits, called baselines, predictably and gradually on a trajectory consistent with achieving net zero by 2050". Measures must be taken annually by all 'large emitters' to reach net zero by 2050, irrespective of individual company commitments. This policy is expected to encourage companies to invest in energy efficiency improvements and switch from gas to electricity or renewable energy where appropriate and cost-effective. However, with Western Australia's potential access to cost-effective CCS/CCUS and competitive offset options, these methods may be economically and practically favourable to cutting emissions directly.

The Western Australian Government has several policies and initiatives supporting renewable hydrogen. 'Diversify WA' focuses explicitly on renewable hydrogen and downstream processing of natural gas (petrochemicals including ammonia) to leverage the competitive price of delivered gas in Western Australia. The 'LNG Jobs Taskforce' is also keenly interested in downstream natural gas manufacturing opportunities in Western Australia, with recently commissioned work from ACIL Allen exploring urea, ammonia, and methanol projects. The Western Australian Government is also encouraging international support, signing a Memorandum of Understanding (MOU) with the Japanese Bank for International Cooperation (JBIC) to "progress opportunities for decarbonisation and low emissions technologies". This MOU is expected to focus on hydrogen, ammonia, low-emissions technology, and decarbonisation.

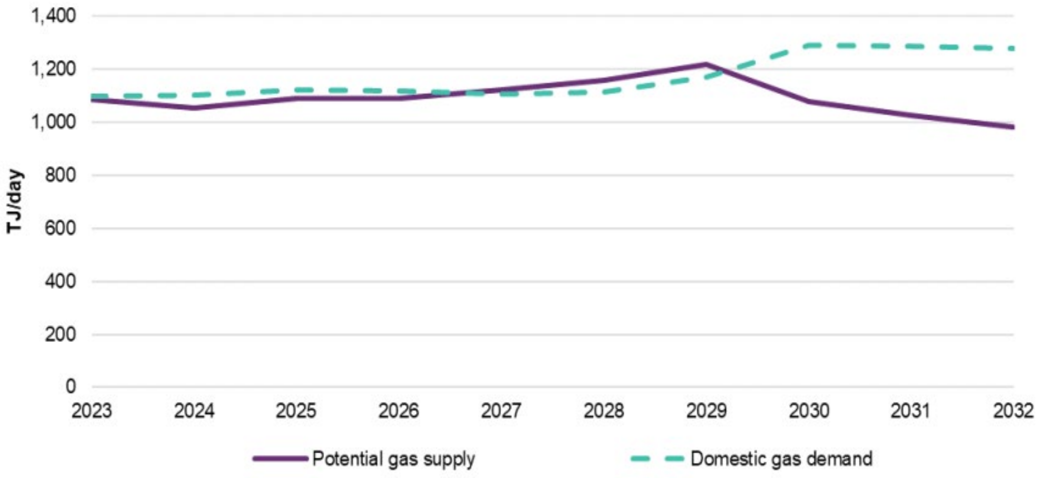
These government policies and the work surrounding them indicate a strong interest in developing future demand-side renewable and natural gas projects within Western Australia.

2.2 Gas Project Timing

The timing of supply and demand side projects within the Western Australian market is crucial to determining the balance within this market out to the mid-2030s.

Western Australian gas supply dynamics have generally been in surplus due to the gas reservation policy applicable to liquefaction plants operating within Western Australia. AEMO expects this surplus to give way to a tight supply, leading to potentially significant shortfalls once Synergy's coal plants are closed.

Figure 2.2 Base Scenario Gas Market Balance



Source: AEMO 2022 WA GSOO

During the period of tight supply (2023 to 2029), AEMO's 2022 GSOO expects the market to "*move into surplus with any delays to demand projects, or deficit if any supply projects do not progress according to current expectations*". These market dynamics place pressure on the timeline of the following major projects in the absence of new/additional domestic supply projects in the near to medium term.

Table 2.1 Assumed New Gas Supply

Project	Operator	Volume (TJ/day)	Available from
Scarborough	Woodside Energy	180	2027
Spartan	Santos	N/A (Backfill)	2023
Waitsia Stage 2	Mitsui E&P Australia	125	2029
Walyering	Strike Energy	30	2023
West Erregulla	Strike Energy	87	2025

Source: AEMO 2022 GSOO

A key feature missing from this 2022 GSOO is the industry response to the modelled shortfall. This response may be through new supply developments, such as within the Perth basin. These developments may offer significant quantities of natural gas to the domestic market, helping to manage the risk of the outlined shortfalls in supply.

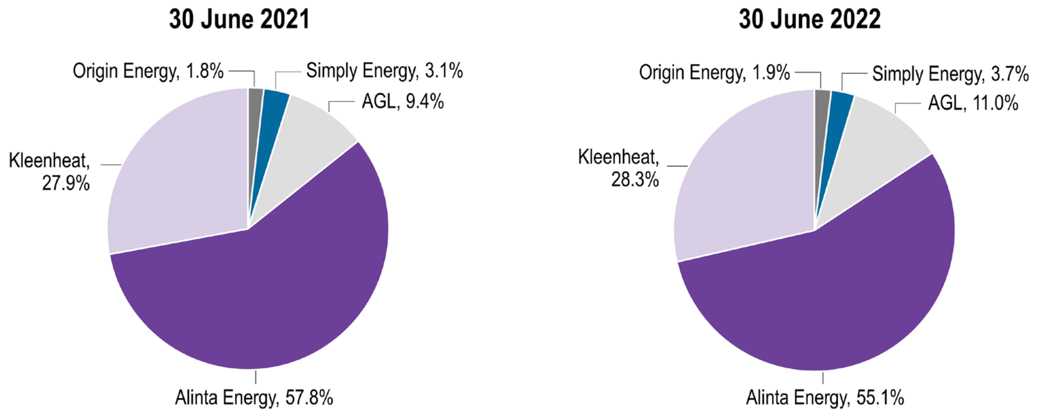
On the demand side, it is expected that continued strong demand for iron ore and base metals (Western Australia's largest export industry) will form the basis for continued growth in domestic gas demand. AEMO's 2022 GSOO analysis identifies an additional 43 TJ per day of demand from six committed resource projects to form the basis for short-term growth (out to 2026) and the coal closures to form the bulk of the medium-term growth in demand (out to 2030).

The potential market tightness, increased demand, and the increasing cost of production reflected in prospective supply projects are expected to increase wholesale gas prices in Western Australia. Gas prices are expected to escalate towards the mid-2030s, especially if additional projects, such as within the Perth basin, are not developed. This price escalation will encourage some users to develop and invest in energy efficiency. However, without specific policies promoting electrification, gas demand switching to electricity is less likely across this period because of the linkage between electricity and gas markets due to the large share of electricity produced from GPG.

2.3 Major Stakeholders and Competitive Dynamics

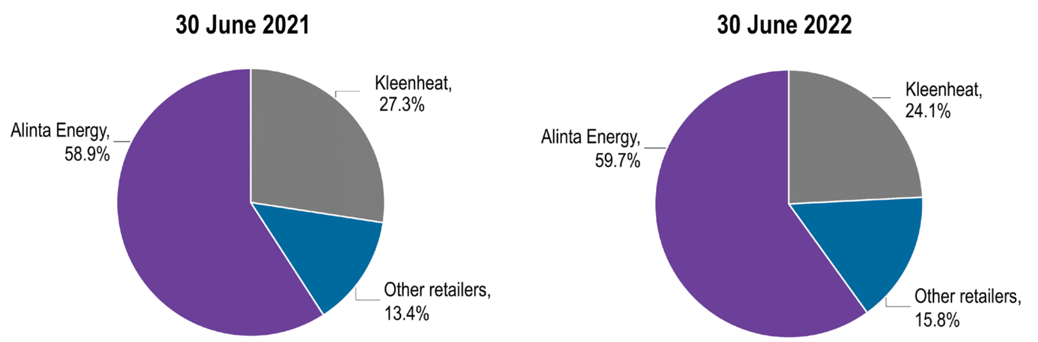
Retail gas has been fully contestable since 2004[1] and has transformed from one retailer (Alinta Energy) to nine authorised retailers at the end of 2022. These retailers compete for customers and face price competition leading to large conditional discounting. Despite this competition, the two longest-serving retailers (Alinta Energy and Kleenheat) comprise over 80 per cent of the total residential and business market share.

Figure 2.3 Residential gas market share – coastal supply area – 2021-2022



Source: Economic Regulation Authority

Figure 2.4 Business gas market share – coastal supply area – 2021-2022



Source: Economic Regulation Authority

Data from the Economic Regulation Authority (ERA) indicates that "*AGL, Origin Energy, Perth Energy and Simply Energy increased their combined share of residential customers from 14.2 per cent to 16.5 per cent. Kleenheat's market share increased by 0.4 percentage points following a 3.0 per cent increase in Kleenheat's customer base*" over the past year. This shift in market share underlines the competitive market dynamics and, ultimately, the mobility of gas customers.

The ERA's report also indicated growth in residential gas customers consistent with preceding years. Residential customers total 764,040, up from 752,359 in 2021. Business gas customers are also up from 2021, totalling 9,449; however, they still fall short of 2016/17 levels of 9,765.

[1] Synergy is prohibited from supplying gas to customers that consume less than 0.18 TJ of gas per annum under the Gas Moratorium.

Observed competition within the retail gas market is expected to continue to serve customers with competitively priced gas as minor players continue to vie for market share.

Anticipated increases in wholesale gas prices are expected to be passed on to consumers. However, this is not anticipated to result in a measurable switch from gas to electricity among this consumer group in the short term because of the linkage between electricity and gas markets (gas is used to produce most electricity within Western Australia). Reticulated gas is expected to remain competitively priced with electricity in the short term. The linkage is expected to be broken as GPG is displaced with electricity produced by renewable energy.

2.4 Technology Development

Green hydrogen blending represents a pathway to partial gas network decarbonisation requiring limited network augmentation and relatively low capital investment. Various projects around Australia have started trialling blended hydrogen within gas distribution systems, including ATCOs own hydrogen blending project located in Cockburn. The project delivers a blend of up to 10 per cent hydrogen to 2,700 customers within the project area.

A wider hydrogen industry may develop within Western Australia over the long term, supported by the sustained interest and tailored policy from the Western Australian government (WA Renewable Hydrogen Roadmap). Within the next 10 years, this is expected to be limited to smaller projects within gas distribution networks, with larger scale injections into transmission infrastructure possible in the longer term (the late 2030s to mid-2040s) to pick up GPG, mining and minerals customers.

The development of hydrogen technology and other renewable gases will boost the environmental sustainability of gas, which will be necessary for promoting continued gas use over the following decades.

Decarbonisation of electricity networks will mainly be driven by replacing fossil fuel generators with renewable energy systems. As decarbonisation moves forward, the role of GPG in providing firming services to electrical systems is expected to become more critical. GPG firming is especially important for Western Australia, where establishing long-duration pumped hydro will be challenging. The availability of hydrogen or other renewable gases or greenhouse gas emission offsets will be required to achieve net zero emissions in electricity in Western Australia.

Most of the gas used in GPG will be during peak periods and periods when renewables have lower availability (e.g., periods of low light and night coinciding with low wind availability). Therefore, the capacity to swing large volumes of gas for short periods will be necessary, while the overall volume of gas consumed will be a small fraction of the gas used in GPG today.

2.5 Affordability, Efficiency and Sustainability

The affordability of natural gas is expected to remain relatively competitive with alternative forms of energy within Western Australia for the foreseeable future. The main alternative to gas use for many users is electricity. As discussed above, the linkage between gas and electricity prices due to GPG being a significant electricity supplier is expected to maintain price relativity between electricity and gas in the short to medium term. The Commonwealth Government's Safeguard Mechanism (applying to natural gas but not electricity) will likely impact this price dynamic for some more significant users. However, this is not expected to affect retail/commercial customers over the short to medium term.

From a market perspective, the competitive dynamics observed between gas retailers are expected to maintain a workably competitive retail market. As all market participants are contestable and the market has several retailers, competition for new and existing customers is expected to continue, with efficiency gains passed on to customers.

From an environmental sustainability perspective, the development and blending of hydrogen and other renewable gases blending, and the use of gas for renewable energy 'firming' is expected to strengthen the environmental prospects of gas as a fuel. The early adoption of renewable gas options/blending will support gas on a trajectory towards net zero emissions and may result in the retention of more customers long-term. However, blending hydrogen in proportions above 10-20 per cent will likely require significant gas distribution capital expenditure. This expenditure would only be justified where long-term delivered gas prices remained competitive with other forms of energy.

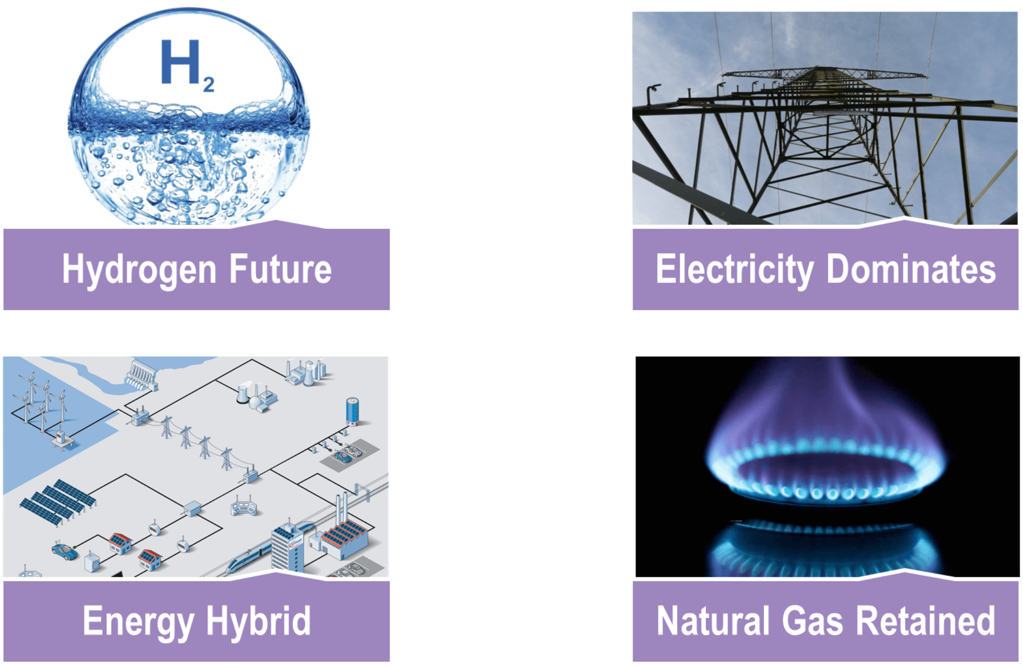
3 Scenarios

ATCO engaged ACIL Allen to undertake research and scenario development to define a set of plausible future scenarios for the Western Australian electricity and gas sectors. The specific focus is on reticulated gas in the ATCO distribution network. Reticulated gas could include natural gas, biomethane, hydrogen, or zero-emissions gases.

The future use of reticulated gas by households, businesses and industries is uncertain as Australia seeks to meet its 2030 and 2050 emissions reduction targets. The uncertainty primarily relates to unknowns such as the emergence and rate of development of zero-emission technologies and the Commonwealth and various state government policies that may be implemented to reduce emissions.

The scenarios aim to define plausible trajectories for the Western Australian gas sector for the potential market, policy, environmental, and industrial sensitivities. These scenarios generate model inputs concerning gas usage and cost, appliance switching, etc., beyond 2050.

Figure 3.1 Scenarios



Source: ACIL Allen

3.1 Hydrogen Future

Under the Hydrogen Future scenario, rapid learning rates relating to green hydrogen and renewable gas production enable these gases to displace natural gas domestically and internationally. The resulting green hydrogen industry mirrors the current natural gas and LNG industries with a broader high-volume export focus enabling the economic servicing of a smaller domestic market.

Internationally, green hydrogen and, in some cases, biomethane are used as a replacement fuel for natural gas, leveraging existing infrastructure and supply chains where possible. This creates a significant export opportunity for Australia, which comes at the expense of traditional exports such as LNG. Therefore, upstream natural gas developments and natural gas supply to the Western Australian domestic market are expected to be disrupted, as the world and gas suppliers move to produce and consume green hydrogen.

The Commonwealth and states under this scenario view green hydrogen as a cost-effective pathway to decarbonise industry, gas power generation and residential/commercial gas loads while maintaining Australia's role as a significant energy exporter. Government support for hydrogen infrastructure and other mechanisms designed to catalyse the green hydrogen and zero emissions gases industry are assumed under this scenario. Government programs include support for replacing appliances so they can operate on 100 per cent hydrogen.

Technologies that support reductions in carbon emissions from electricity and other stationary energy have moderate technological learning rates. These learning rates limit existing reticulated gas customers switching to electricity to lower emissions in the medium term.

Low-cost green hydrogen and renewable gas posed under this scenario will also significantly improve economic conditions within Western Australia, Australia and internationally, driving higher economic growth rates because of lower consumer energy bills and enhanced industrial operating margins. The growth of the hydrogen export industry also adds to economic growth. This improved economic outlook results in sustained growth in gas usage within all consumer groups, especially in the industrial sector. As a result, gas infrastructure continues to be utilised at existing levels, with expansion opportunities and green field projects likely in the medium to long term.

ATCO gas distribution system implications

From ATCO's gas distribution system perspective, this scenario will result in continued strong domestic demand gas, leading to modest growth in the volume of gas sold and the number of customers connected. Competitive pricing of the renewable gases under this scenario, including their lower carbon footprint, reduces the drive to electrify loads. However, the existing gas distribution network will likely need to be upgraded to carry a concentration greater than 10 per cent blended hydrogen and methane and placed on a pathway towards 100 per cent hydrogen carriage. The conversion of consumer facilities to run on higher concentrations of hydrogen will have a cost impact where facilities must be replaced before end-of-life. Under this scenario, it is assumed that government support is forthcoming to assist in this modification and that technical learning will bring this cost down over time.

Table 3.1 Hydrogen Future uncertainty setting matrix

Uncertainty	Substantial change	←	→	Insubstantial change
Global economic growth	**Fast**	Moderate	Slow	
Domestic economic growth	**Fast**	Moderate	Slow	
Renewable gas / H_2 learning rate	**Fast**	Moderate	Slow	
Renewable electricity learning rate	Fast	**Moderate**	Slow	
Global demand for renewable gas / H_2	**Accelerated growth**	Moderate growth	Low growth	No growth
Electrification – households	High demand	Moderate demand	**Low demand**	
Electrification – industry	High demand	Moderate demand	**Low demand**	
Carbon abatement policy (domestic)	**Significant acceleration**	Moderate acceleration	Step up	Current settings
Carbon abatement policy (global)	**Significant acceleration**	Moderate acceleration	Step up	Current settings
Fossil fuel technology development (i.e., CCS, CCUS, offsets)	Fast	**Moderate**	Slow	

Source: ACIL Allen

3.2 Electricity Dominates

Electricity Dominates

Under the Electricity Dominates scenario, renewable electricity generation and storage experience a rapid reduction in cost through fast technological learning. As such, the relative cost of electricity against natural gas and renewable gases falls to such an extent that a broad-based electrification of industry and households occurs.

The Commonwealth and the states provide financial support to existing natural gas users to electrify their loads, seeing this as a critical factor in meeting climate goals and bringing down the cost of living for the Australian population. Government support could include grants, subsidies and prohibitions on the sale or installation of new gas or other fossil space or water heating appliances. This would drive greenfield and brownfield appliance electrification, and government policy would be specifically tailored to ensure electricity price reductions.

The pace of renewable generation and storage cost reduction is assumed to start slow and ramp up by the mid-2030s, driven by faster learning rates as international adoption of renewable energy grows. As such, the most significant effect on gas distribution businesses will begin to be felt after the mid-2030s, with reduced but still economic gas volumes assumed to be sold beyond 2050. The gas sold within the network is taken to remain primarily natural gas, with hydrogen blending limited to 10 per cent.

As a result of the scenario's low electricity prices, the cost to produce green hydrogen and renewable gas will also fall, making these gases more affordable. However, the scale of electricity price reductions means more households and businesses will electrify their energy use. As such, there is limited scope for renewable gases within commercial/residential and many industrial customers. However, hydrogen and renewable gases play a role in hard-to-abate industries and exports in the longer term. Thanks to rapid reductions in electricity storage costs, gas power generation using hydrogen is also unlikely under this scenario due mainly to the significant energy round trip losses experienced during this process. Investments and technical learning in technologies such as CCS/CCUS are also assumed to be slow under this scenario.

Lower electricity prices and lower conversion costs faced by electrification under this scenario also significantly improve economic conditions within Western Australia and Australia. The economic conditions internationally are also expected to benefit under this scenario, with moderate growth rates projected based on lower energy input costs for all consumer groups.

ATCO gas distribution system implications

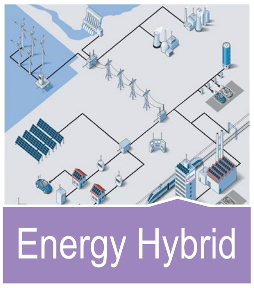
From the ATCO gas distribution system perspective, this scenario will see a substantial and sustained reduction in the volume of gas sold and the number of customers connected to the network. The strength of government policy will drive the pace of the decrease in volume and customers, and the rate of cost reduction experienced because of lower renewable electricity generation and storage costs. This scenario assumes that initially, the primary driving force is the reduction in energy costs and carbon emissions offered by a renewable-focused Western Australian grid, with government subsidies held off and used primarily to accelerate climate goal achievement.

Table 3.2 Electricity Dominates uncertainty setting matrix

Uncertainty	Substantial change	⟷		Insubstantial change
Global economic growth	Fast	**Moderate**	Slow	
Domestic economic growth	**Fast**	Moderate	Slow	
Renewable gas / H_2 learning rate	Fast	**Moderate**	Slow	
Renewable electricity learning rate	**Fast**	Moderate	Slow	
Global demand for renewable gas / H_2	Accelerated growth	Moderate growth	**Low growth**	No growth
Electrification – households	**High demand**	Moderate demand	Low demand	
Electrification – industry	High demand	**Moderate demand**	Low demand	
Carbon abatement policy (domestic)	Significant acceleration	**Moderate acceleration**	Step up	Current settings
Carbon abatement policy (global)	Significant acceleration	**Moderate acceleration**	Step up	Current settings
Fossil fuel technology development (i.e., CCS, CCUS, offsets)	Fast	Moderate	**Slow**	

Source: ACIL Allen

3.3 Energy Hybrid



Under the Energy Hybrid scenario, technical learning rates for renewable gases and electrification develop similarly, resulting in some customers electing to electrify and some remaining on the gas network. From an economic and environmental point of view, electricity and zero emissions gases become viable alternatives for natural gas. This results in a mixed response from residential/commercial and industrial consumers, with an even split electing to follow electrification or to stick with a gas-based energy supply chain.

From a government policy perspective, this scenario represents a 'market forces' approach, with government policy and support not favouring a particular technology or pathway to achieve government emission reduction targets.

Under the scenario settings, moderate electricity and renewable/zero emissions gases cost reductions engender moderate economic growth. This is because energy bill savings and improved industrial operating margins are more modest under this scenario than in the Electricity Dominates case. Hard-to-electrify industrial loads operate economically on natural gas and, later, hydrogen or other forms of renewable gas.

Technologies that support reductions in carbon emissions from electricity and other stationary energy have moderate technological learning rates. These learning rates limit existing reticulated gas customers switching to electricity to lower emissions in the medium term.

ATCO gas distribution system implications

From the ATCO gas distribution system perspective, this offers a mixed future. Due to the low prices and clear carbon benefits of electrification, some gas consumers electrify their loads. Concurrently, as the product sold via the gas network is decarbonised through the introduction of green hydrogen and renewable/zero-emissions gas, many customers do not electrify. This results in ATCO retaining much of its existing customer base and limits reductions in gas demand under this scenario.

Table 3.3 Energy Hybrid uncertainty setting matrix

Uncertainty	Substantial change	⟷		Insubstantial change
Global economic growth	Fast	**Moderate**	Slow	
Domestic economic growth	Fast	**Moderate**	Slow	
Renewable gas / H_2 learning rate	Fast	**Moderate**	Slow	
Renewable electricity learning rate	Fast	**Moderate**	Slow	
Global demand for renewable gas / H_2	Accelerated growth	**Moderate growth**	Low growth	No growth
Electrification – households	High demand	**Moderate demand**	Low demand	
Electrification – industry	High demand	**Moderate demand**	Low demand	
Carbon abatement policy (domestic)	Significant acceleration	Moderate acceleration	Step up	**Current settings**
Carbon abatement policy (global)	Significant acceleration	Moderate acceleration	Step up	**Current settings**
Fossil fuel technology development (i.e., CCS, CCUS, offsets)	Fast	**Moderate**	Slow	

Source: ACIL Allen

3.4 Natural Gas Retained

Under the Natural Gas Retained scenario, global and local factors result in natural gas being retained in the ATCO network, broadly in line with medium-term expectations as of the previous Access Arrangement process. Zero-emissions gases such as green hydrogen or renewable methane experience slow technological learning rates, which results in them generally remaining uneconomic at scale. This results in low local and international uptake of zero emissions gases. As such, natural gas continues to be embraced as a 'transition fuel' used in large volumes globally to quickly and reliably reduce carbon emissions through coal-to-gas switching and to support/firm renewable generation. The carbon emissions intensity of natural gas and natural gas products such as LNG also reduce significantly through rapid technological learning relating to carbon capture and storage CCS/CCUS and improved access to adequate and affordable carbon offset options.

The capture, transportation and storage of carbon dioxide are critical to this scenario. In this scenario, it is expected that CCS/CCUS will become widely used by carbon-intensive industrial customers who can easily capture their emissions. In addition, CCS/CCUS will become a significant industry internationally with the expected emergence of a regionally based price for carbon to reflect the cost of the industry's operation. This international cooperation on CCS/CCUS will enable natural gas emissions to be captured and stored when used in industrial applications and electricity generation. In the longer term, technologies that utilise the captured carbon emerge. This will enable the continued use of natural gas while avoiding emitting greenhouse gases.

The impact of CCS/CCUS on the gas distribution business is indirect insofar as it would not be expected that ATCO would play a role in this industry. However, the successful development of CCS/CCUS technology would allow for the continued development of Western Australia's natural gas reserves, which is critical to maintaining the domestic gas supply through the Domestic Gas Reservation Policy. Success in CCS/CCUS would also underpin the continued use of gas for gas-fired power generation in Western Australia. However, this gas is supplied outside the ATCO gas distribution network.

Hard-to-capture gas loads, such as residential and commercial consumption, have their emissions managed via a certified carbon offset crediting scheme at an economically viable price. Such schemes are fit for purpose and economical at the scale these loads represent.

Economic growth domestically and internationally is assumed to be moderate under this scenario. The wide adoption of CCS/CCUS and the availability of cost-effective offsets enables many gas users to continue mainly using unmodified appliances and industrial processes, avoiding costly upgrades for electrification or hydrogen compatibility. However, the cost to operate CCS/CCUS and provide offsets, coupled with the likely higher cost of gas production as more marginal reserves are exploited, increases energy bills and reduces industrial operating margins compared with other scenarios.

In this scenario, the gradual electrification of household appliances would be expected to occur, generally in line with appliance replacement cycles, as opposed to an acceleration in demand for switching. Industrial users would be expected to continue using carbon-neutralised natural gas or undertake CCS/CCUS where scale permits.

It is reasonable to characterise this scenario as contingent on developing CCS/CCUS technology and effective offset markets. Without them, the continued use of natural gas in all contexts is unlikely to be consistent with global or domestic government policy.

ATCO gas distribution system implications

From the ATCO gas distribution system perspective, this scenario results in little to no operational changes to the network. Low amounts of blended zero emissions gases such as H2 are expected, but these will not exceed the 10 per cent threshold within which the network can operate without significant capital expenditure. Natural gas prices in Western Australia are expected to increase by a small margin, resulting in gas volumes remaining primarily unchanged over the forecast horizon. Growth is expected in industrial and power generation applications proportional to economic growth rates. The assumed clean carbon credentials and stable natural gas prices limit the volume of gas demand switching to electricity and the development of renewable/zero emissions gases.

Table 3.4 Natural Gas Retained uncertainty setting matrix

Uncertainty	Substantial change	⟷		Insubstantial change
Global economic growth	Fast	**Moderate**	Slow	
Domestic economic growth	Fast	**Moderate**	Slow	
Renewable gas / H_2 learning rate	Fast	Moderate	**Slow**	
Renewable electricity learning rate	Fast	**Moderate**	Slow	
Global demand for renewable gas / H_2	Accelerated growth	Moderate growth	**Low growth**	No growth
Electrification – households	High demand	**Moderate demand**	Low demand	
Electrification – industry	High demand	Moderate demand	**Low demand**	
Carbon abatement policy (domestic)	Significant acceleration	Moderate acceleration	Step up	**Current settings**
Carbon abatement policy (global)	Significant acceleration	Moderate acceleration	Step up	**Current settings**
Fossil fuel technology development (i.e., CCS, CCUS, offsets)	**Fast**	Moderate	Slow	

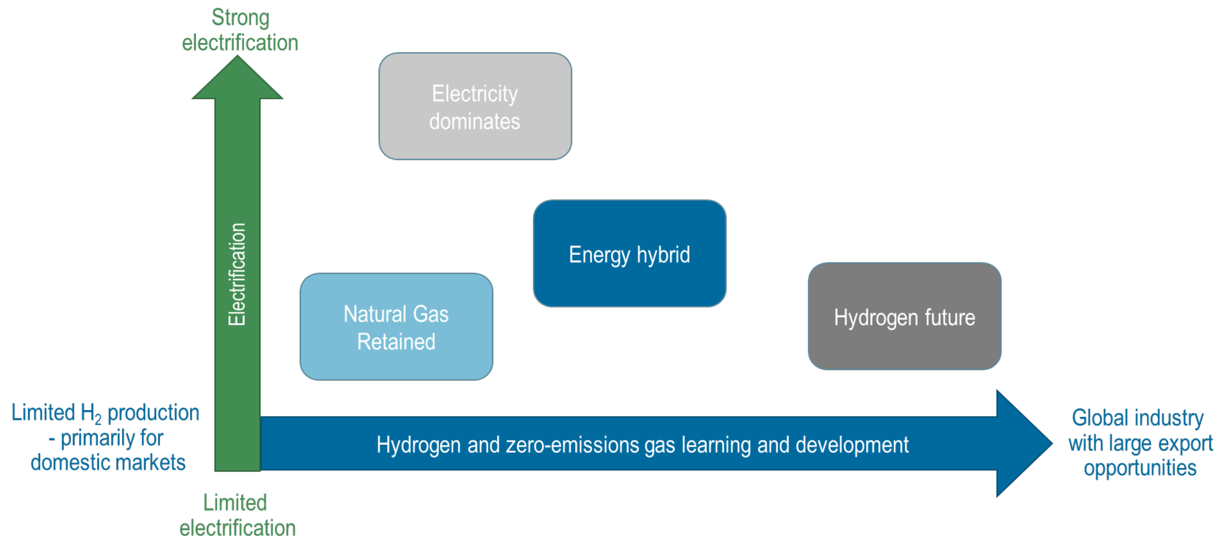
Source: ACIL Allen

3.5 Scenario comparison

This section briefly compares the scenarios regarding the two key factors, electrification and zero emissions gas development.

Hydrogen Future and Electricity Dominates represent the bookends in either electrification of natural gas heating demand or replacing natural gas with zero emissions gas. The Energy Hybrid scenario is a mid-range scenario. The Natural Gas Retained scenario is most like the status quo. However, it is contingent on the economic development of CCS/CCUS and the long-term availability of carbon credits to offset emissions produced by distribution system gas consumers.

Figure 3.2 Scenarios compared



Source: ACIL Allen

Table 3.5 Comparison of the four scenarios against each uncertainty

Uncertainty	Hydrogen Future	Electricity Dominates	Energy Hybrid	Natural Gas Retained
Global economic growth	Fast	Moderate	Moderate	Moderate
Domestic economic growth	Fast	Fast	Moderate	Moderate
Renewable gas / H_2 learning rate	Fast	Moderate	Moderate	Slow
Renewable electricity learning rate	Moderate	Fast	Moderate	Moderate
Global demand for renewable gas / H_2	Accelerated growth	Low growth	Moderate growth	Low growth
Electrification – households	Low demand	High demand	Moderate demand	Moderate demand
Electrification – industry	Low demand	Moderate demand	Moderate demand	Low demand
Carbon abatement policy (domestic)	Significant acceleration	Moderate acceleration	Current settings	Current settings
Carbon abatement policy (global)	Significant acceleration	Moderate acceleration	Current settings	Current settings
Fossil fuel technology development (i.e., CCS, CCUS, offsets)	Moderate	Slow	Moderate	Fast

Note: Darker shade = faster rate of change expected

Source: ACIL Allen

Modelling Methodology and Scenario Input Assumptions 4

This section describes the methodology adopted to model the demand for gas in the ATCO network up to 2074 and the method used to calculate brought-forward depreciation. The section also explores the key assumptions and inputs used in the model calculations. The key assumptions cover carbon, hydrogen, gas, and electricity prices determined by each scenario's characteristics.

4.1 Methodology

This section provides an overview of the modelling methodology adopted to forecast gas demand across ATCO's five tariff classes and calculate the brought-forward depreciation schedule for each scenario.

The model produces a projection of gas demand and customer numbers to the year 2074 at the LGA level. Customer numbers are split into new connections and disconnections, while average consumption per connection is also forecast to 2074.

Forecasts are split between residential (Tariff B3) and commercial customers (Tariffs B1 and B2) and industrial customers (Tariffs A1 and A2).

The modelling approach forecasts the impact of relative energy prices between gas and electricity on the projected demand for gas to 2074 while accounting for the effects of changes in relative appliance costs and running costs between gas and electricity on total gas volumes over time.

An S curve logistics function is used for residential customers (Tariff B3) and smaller commercial customers (Tariff B2). The relative NPV of switching from gas to electricity is calculated, and a logistic curve is used to estimate the market share of gas versus electricity over time. Separate calculations and projections are made for both disconnections and new connections.

For commercial (B1) and industrial (A1 and A2) customers, separate econometric models of total volume were constructed. These were also a function of gas and electricity prices, weather and economic activity (GSP).

The brought-forward depreciation is determined once the gas demand and customer forecasts are developed. The approach is to determine a constant annual average tariff (real dollars) for all years and then determine how depreciation must be adjusted yearly to maintain the tariff at that value in all years. This approach does not advantage or disadvantage any group of customers across time while allowing the revised depreciation schedule to reflect the economic value of the gas distribution assets.

As part of this study, the four separate scenarios discussed in the previous section are modelled:

— Hydrogen Future

— Electricity Dominates

— Energy Hybrid

— Natural Gas Retained

4.1.1 Logistic model of disconnecting or connecting

The model considers two groups of customers:

— Existing customers may choose to disconnect and switch to electricity

— New customers may choose to connect to the gas network.

The probability of disconnections is a function of the NPV of switching. As the NPV of switching to electricity from gas becomes progressively less negative or positive, the proportion of customers making the switch increases. The NPV is a function of relative appliance costs and usage charges driven by the relative costs associated with gas and electricity prices. The other main driver of the NPV calculation is the discount rate.

The key inputs into the NPV calculation for switching decisions are:

— Relative capital costs of the appliances

— Relative running costs

— Gas connection charges

— Electricity upgrade connection costs

A fixed percentage of each LGA's customers consider switching annually. The default setting for the decision point is every 15 years. Given a uniform distribution, 1/15th of the residential customer base each year decides whether to remain connected to the gas network or switch to electric appliances.

The function that is used to determine the probability of switching is the logistic function. This function resembles an S curve characterised by a slow build-up, a ramp-up phase, and a mature phase where the take-up has reached a saturation point.

The logit model converts underlying drivers of choice to switch to electric appliances into a probability or market share of switching. The model values each attribute that drives the decision and applies an elasticity or weight to each factor. In our case, we are using a single factor, the NPV of switching, which incorporates the set of underlying drivers, such as relative prices and appliance costs, into a single measure.

The function takes any value from zero to infinity as inputs and converts them to output between zero and 1.

The function takes the form of an S curve:

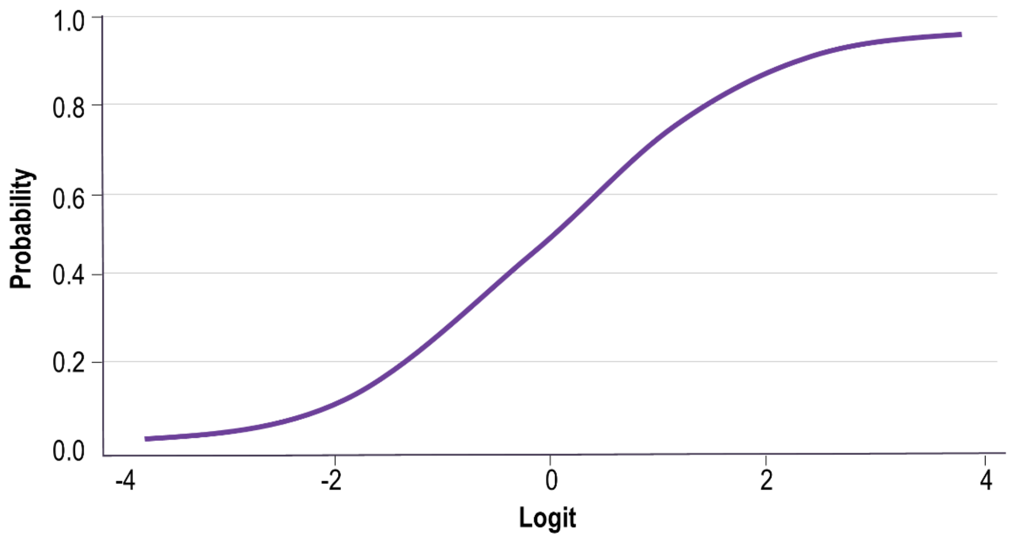
$\pi(x) = 1/(1 + \exp{(-y)})$ where:

$$y = \beta_0 + \beta_1 NPV$$

y is a linear utility function of the drivers denoted by the NPV.

The S curve is shown in Figure 4.1 below.

Figure 4.1 The logit S curve



For potential new customers, the NPV calculation for the connection decision is similar to that of the disconnection NPV, which includes the relative capital and running costs for electricity and gas. However, it excludes gas disconnection or electricity upgrade charges, as they only relate to the switching decision.

4.1.2 Econometric models of volume per customer

While the logistic function can model the number of connections and disconnections to the ATCO network for residential (B3) and commercial (B2) customers, the average volume consumed by B3 and B2 customers is modelled via separate econometric models. For B3 customers, the average volume consumed is a function of the retail gas price, the retail electricity price and the weather represented by the number of heating degree days. For commercial B2 customers, average consumption is a function of gas and electricity prices, weather, and GSP.

For commercial (B1) and industrial (A1 and A2) customers, separate econometric models of total volume were constructed. These were also a function of gas and electricity prices, weather and economic activity (GSP).

4.1.3 Calculating bring forward depreciation

ACIL Allen's approach to calculating revised depreciation (brought-forward) schedules was as follows:

- Develop the projected annual gas demands from 2025 to 2074 for the four separate scenarios
- Extract the current asset base, the remaining asset lives, and the proposed new assets expenditure and lives and operating expenditures associated with each of the four scenarios.
- Replicate the revenue and depreciation schedules associated with the underlying demand and expenditures under the four separate scenarios.
- Determine the annual average tariffs for the depreciation schedules to 2074.
- Calculate the constant annual average tariff ($2023) that provides the same present value of revenues as the annual average tariff between 2025 and 2074.
- Sculpt regulatory depreciation to fit within the constant annual tariff constraint.

The methodology is explained in more detail below.

Revenue and depreciation

The starting point for the assessment was the current asset base and the proposed new asset expenditure under each of the four scenarios. ACIL Allen collected all of the necessary data from ATCO to replicate the revenue and depreciation schedules, including:

- Asset values and asset lives
- New asset investment profile and lives
- Assumed inflation, cost of equity, cost of debt and WACC

This information replicates the PTRM results under the four separate scenarios.

Annual average tariff

Next, the annual average tariffs were calculated by dividing the total revenue by the projected gas demand each year (for each scenario).

Constant annual average tariffs

The next step in the process was to determine the constant annual average tariff (in real terms), where the present value of the revenues for the ATCO network between 2025 and 2074 was the same as the PV of the revenues calculated using the annual average tariffs from the original PTRM results.

The constant annual average tariff was calculated using the solver function in Excel as follows:

- A set of constant annual average tariffs were inserted into the model with an initial value set at an arbitrary positive value.
- The difference between the original PTRM annual average tariff and the constant annual average tariff was calculated each year.
- These differences were then multiplied by each year's gas demand to calculate each year's initial regulatory depreciation adjustment.
- The solver function was then used to find the constant annual average tariff, where the present value of the initial regulatory depreciation adjustments was zero. This calculation maintains the present value of revenues for the network between 2025 and 2074, the same as those calculated under the original PTRM annual average tariffs.

Sculpt regulatory depreciation

Adjusting the regulatory depreciation also changes the residual capital base used to calculate the returns to capital. Increases in regulatory depreciation reduce the residual capital base and return to capital in subsequent years (and vice versa). Therefore, the final step adjusts the regulatory depreciation to maintain the constant annual average tariff each year. This further adjustment compensates for changes in returns to capital from the changed residual capital base.

The final tariff sculpting was a straightforward process of making an additional adjustment each year to regulatory depreciation to maintain the constant annual average tariff constraint (reflected each year in real terms). The adjustment was made one year at a time, from the earliest to the latest year. The adjustment in each year flowed forward to subsequent years (changes to the real residual capital base). Once completed, the present value of the revised revenues was the same as the present value of the revenues before the bringing forward of depreciation.

4.2 Model input assumptions

This section describes the main input assumptions used in the modelling process. All dollars are real 2023 dollars unless otherwise stated.

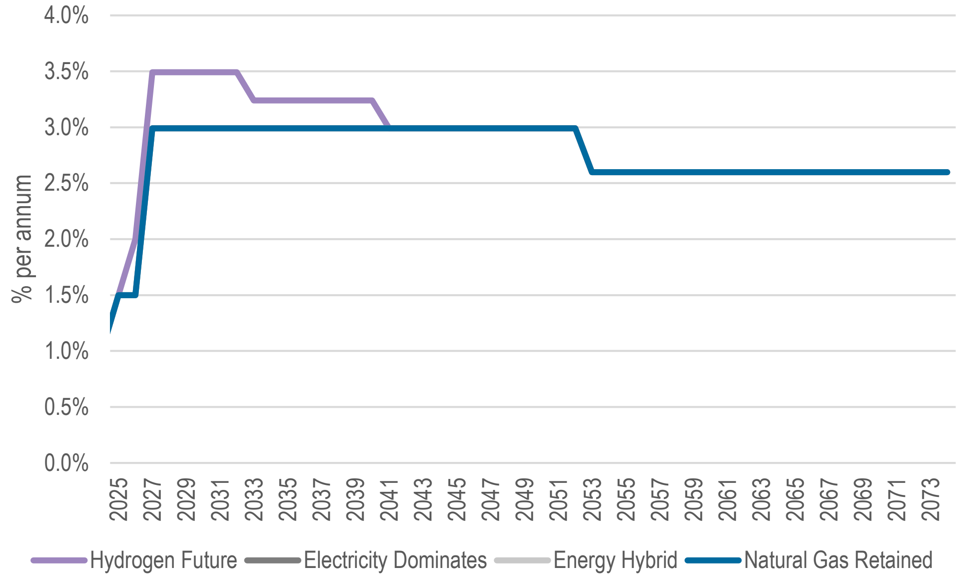
4.2.1 Gross State Product (GSP)

Growth in economic activity is a significant driver of rising incomes. Higher disposable incomes partly drive gas consumption, the subsequent demand for new gas appliances and equipment, and increasing commercial and industrial activity. There is a strong relationship between economic activity and gas consumption, given that gas is essential for many households and industries.

Figure 4.2 below shows the projected rate of GSP up to 2074 under the four separate scenarios.

The only scenario which differs in terms of the projected GSP over time is the Hydrogen Future scenario. Under this scenario, economic activity is expected to increase faster up to 2040. This faster rate is essentially a result of the large-scale investment required to integrate hydrogen into the existing energy system. The projected rate of GSP converges to 3.0 per cent per annum after 2040 for all four scenarios before falling to 2.6 per cent per annum from 2053 onwards.

Figure 4.2 Projected Gross State Product (GSP)



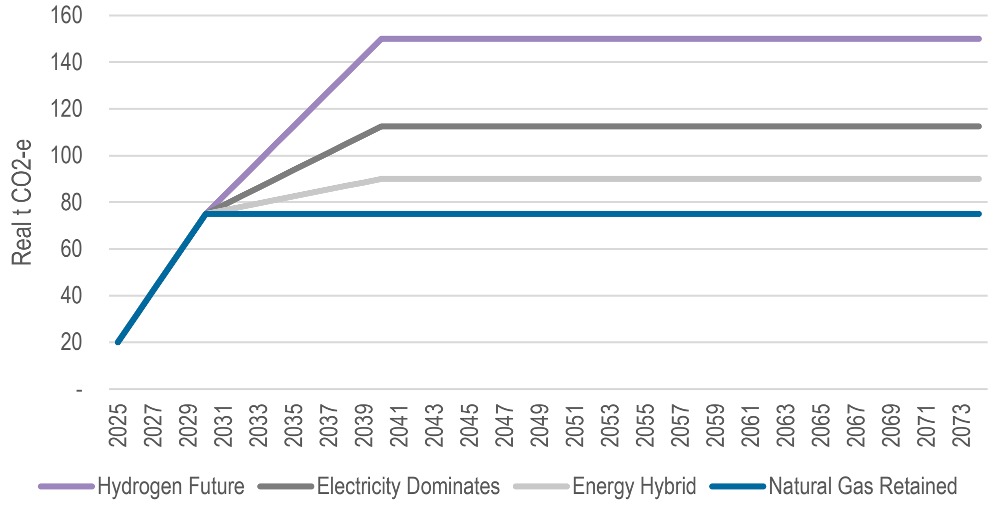
Source: ACIL Allen

4.2.2 Carbon price

The carbon price assumptions are contained in Figure 4.3. Carbon pricing starts at AUD 20 per tonne CO_2-e and linearly escalates to AUD 75 per tonne CO_2-e for all four scenarios. Under the Hydrogen Future scenario, this linear escalation continues to AUD 150 per tonne CO_2-e by 2040. This carbon price is the highest assumed price for the four scenarios and thus provides the highest uplift to gas prices. This high price assumption represents the 'significant acceleration in carbon abatement policy' domestically and internationally that is also assumed under this scenario.

The next most aggressive scenario in terms of the carbon price is the Electricity Dominates scenario, where the price of carbon peaks at AUD 113 per tonne CO_2-e by 2040. This is followed by the Energy Hybrid scenario, which peaks at AUD per tonne CO_2-e. The Natural Gas scenario shows no increase in the carbon price post the 2030 level of AUD 75 per tonne CO_2-e.

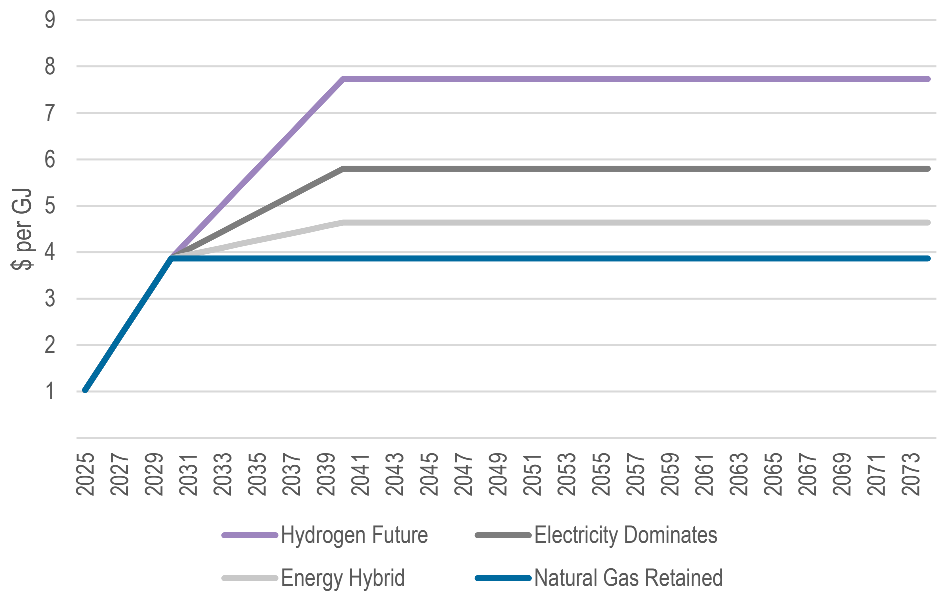
Figure 4.3 Projected carbon price, real AUD per tonne CO_2-e



Source: ACIL Allen

The impact of the projected carbon prices on the projected uplift in gas prices is shown in Figure 4.4 below. Under the Hydrogen Future scenario, the gas price will increase by $7.73 per GJ by 2040. This increase is followed by $5.80 per GJ for Electricity Dominates, $4.64 per GJ for Energy Hybrid and $3.86 per GJ for Natural Gas Retained.

Figure 4.4 Projected gas price uplift, real $ per GJ

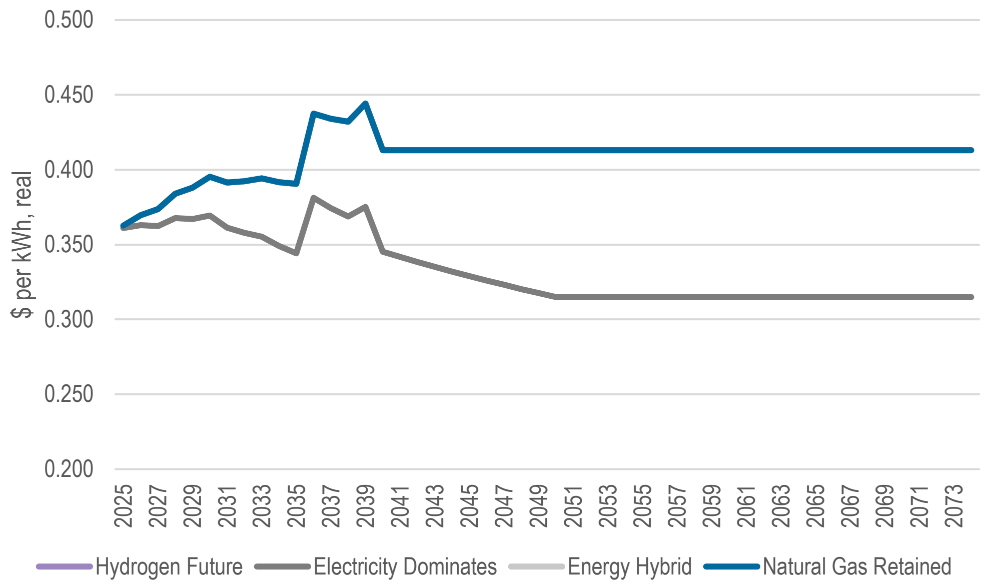


Source: ACIL Allen

4.2.3 Electricity prices

Projected retail electricity prices are shown in Figure 4.5 below. The path of electricity prices is the same for all scenarios except the Electricity Dominates scenario. Under the other three scenarios, electricity prices rise consistently from 2025 onwards before peaking at $0.44 per kWh in 2039. Prices then stabilise at $0.413 per kWh after 2040. Under the Electricity Dominates scenario, electricity prices peak at $0.381 per kWh in 2036 before declining to $0.315 per kWh by 2050. They remain at this level for the remainder of the forecast period.

Figure 4.5 Projected electricity prices, residential and commercial, real $ per kWh



Source: ACIL Allen

4.2.4 Gas prices

The gas price is a likely driver of gas consumption. The responsiveness of consumption to changes in price is known as the price elasticity of demand. The degree of responsiveness is thought to differ considerably across customer classes. Residential customers are generally less responsive to price changes than non-residential customers because energy costs comprise a more significant proportion of the total expenditures for non-residential customers. Therefore, price increases might lead to adaptive behaviour designed to reduce consumption/demand and hence costs.

For example, higher gas prices would be expected to reduce gas consumption by incentivising customers to become more energy efficient or switching appliances away from gas to electricity.

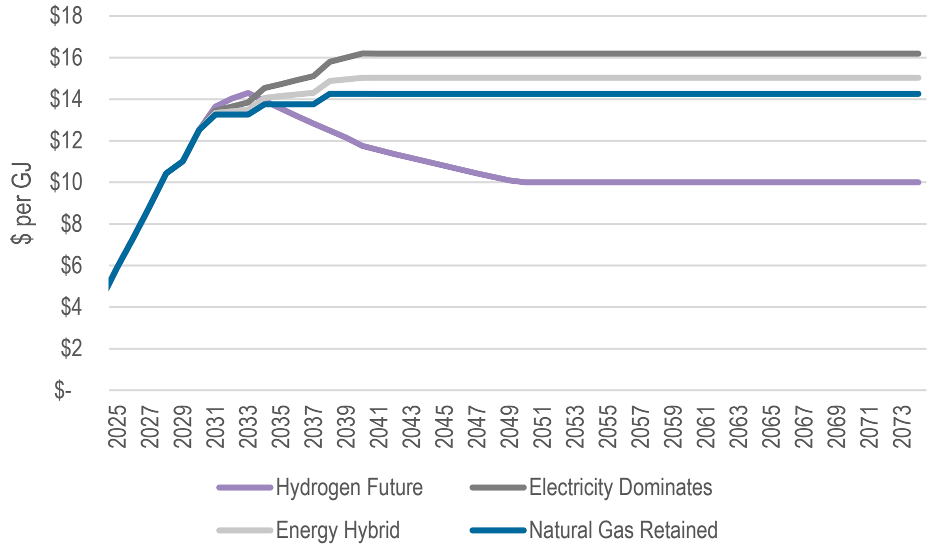
ACIL Allen forecasts gas prices using a bottom-up approach. Gas prices are broken into five components:

1. Wholesale market prices using ACIL Allen's proprietary GasMark model
2. Transmission costs
3. Distribution costs
4. Environmental policy
5. Retail margins

Our projections of wholesale gas prices are shown in Figure 4.6 below.

The wholesale price of gas follows a similar upward trajectory for all 4 scenarios, reaching $12.52 per GJ by 2030. After 2030, wholesale gas prices diverge across the 4 scenarios. Under the Electricity Dominates scenario, the wholesale price of gas peaks at $16.19 per GJ after 2040. Under the Energy Hybrid and Natural Gas Retained scenarios, the price peaks at $15.03 per GJ and $14.25 per GJ, respectively. Under the Hydrogen Future scenario, wholesale gas prices take a different path, declining consistently up to 2050, stabilising at $10.00 per GJ. Gas prices under this scenario are assumed to escalate initially due to the carbon price uplift and then moderate through the shift to competitively priced green hydrogen.

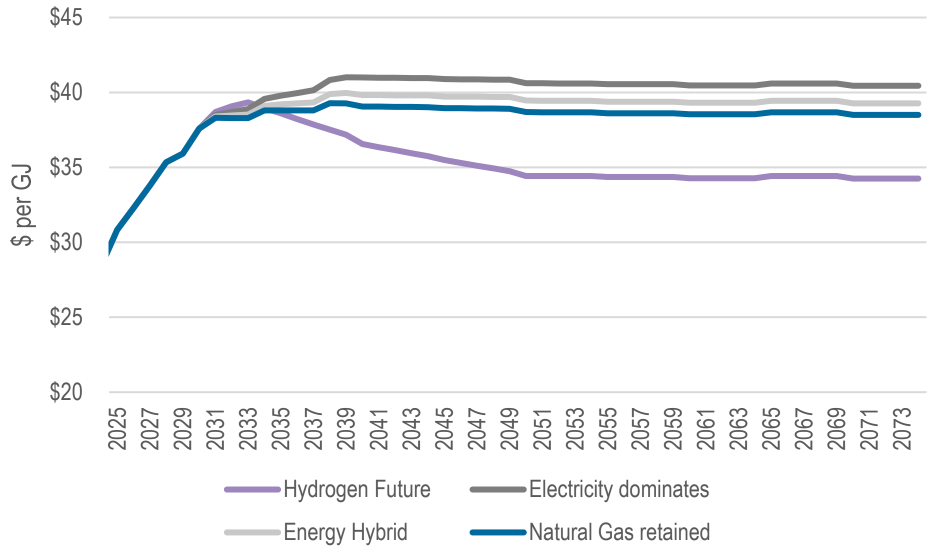
Figure 4.6 Wholesale price of gas, real $ per GJ



Source: ACIL Allen

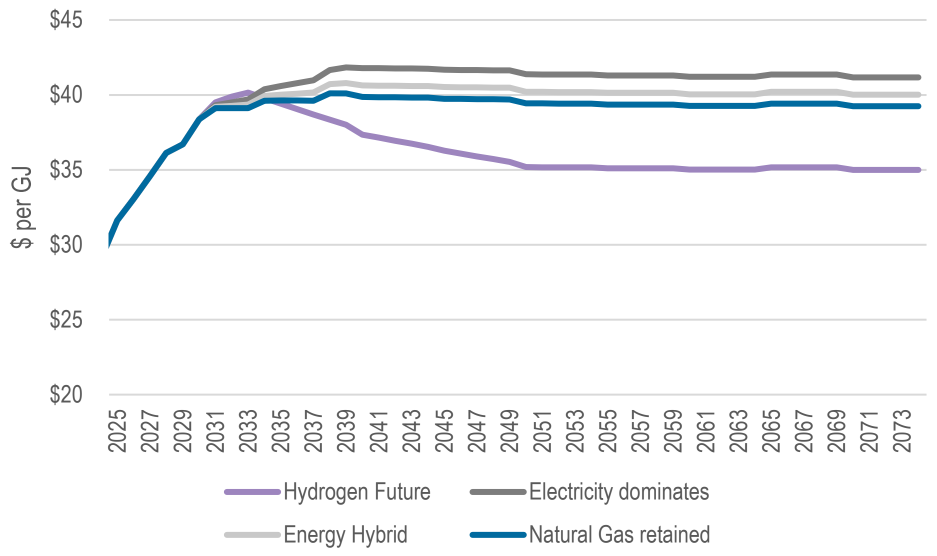
Projected retail gas prices for the four scenarios are presented in Figure 4.7 and Figure 4.8. Figure 4.7 shows the residential price, while Figure 4.8 illustrates commercial retail gas prices. The figures closely resemble the wholesale price figure shown above, as the main driver of the differences in the retail gas price across the 4 scenarios is the wholesale gas price.

Figure 4.7 Retail price of gas, residential, real $ per GJ



Source: ACIL Allen

Figure 4.8 Retail price of gas, commercial, real $ per GJ

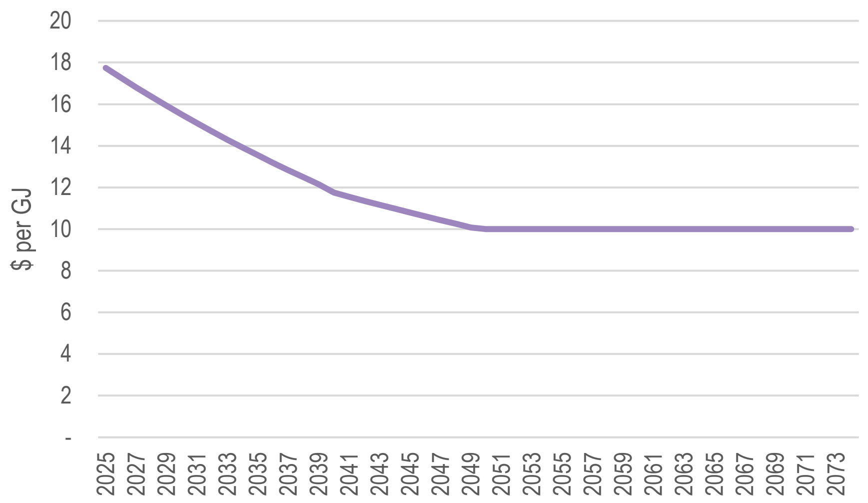


Source: ACIL Allen

4.2.5 Hydrogen Prices

The cost of green hydrogen is assumed to start high at $17 per GJ in 2025 and gradually decrease to $10 per GJ by 2050 as per AEMO projections (see Figure 4.9). It is assumed that gas prices under this scenario remain at $10 per GJ for the remainder of the projections. Wholesale and reticulated gas is taken to switch to 100 per cent green hydrogen by 2033.

Figure 4.9 Projected hydrogen prices



Source: AEMO

5 Modelling results

This section presents the results of the methodology described in the previous section.

Specifically, under the four scenarios we present:

— Gas volumes and customer numbers
— Closing Regulatory Asset Base (RAB)
— Depreciation (including brought-forward depreciation)
— The impact on average tariffs

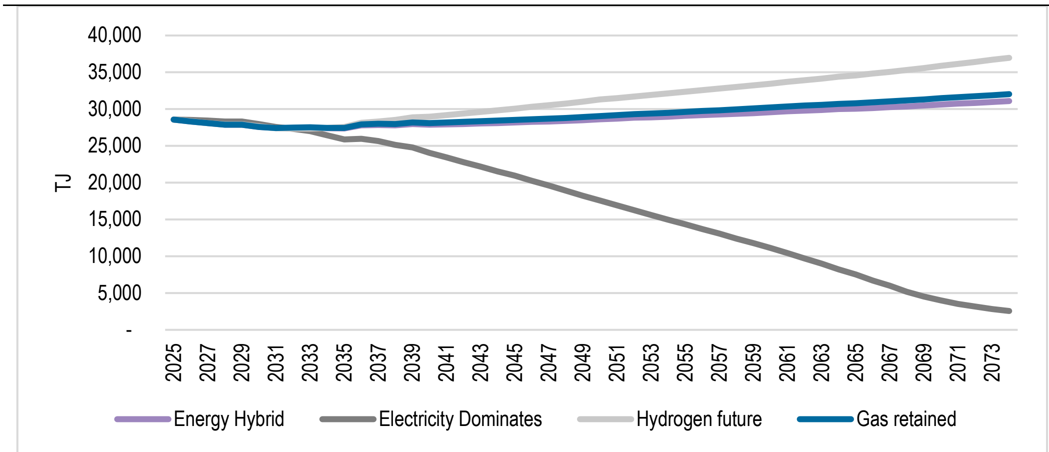
5.1 Volume and Customer Numbers

The gas volume paths under the four scenarios over the forecast period are shown in Figure 5.1.

Apart from the Electricity Dominates scenario, the other scenarios show some gas volume growth over the forecast period. The Hydrogen Future scenario is projected to deliver the fastest growth rate, reflecting substantial reductions in the retail price of gas. Under this scenario, gas volumes are projected to reach 36,960 TJ by 2074, equivalent to an annualised growth rate of 0.53 per cent per annum from 2025. The Energy Hybrid and Natural Gas Retained scenarios follow more moderate growth paths, each reaching 31,089 TJ and 32,029 TJ, respectively.

The Electricity Dominates scenario shows a collapse in the volume of gas consumed and reflects the almost complete phasing out of gas from the energy mix. Under this scenario, gas consumption declines by 4.8 per cent per annum to reach a low of 2,561 TJ by 2074.

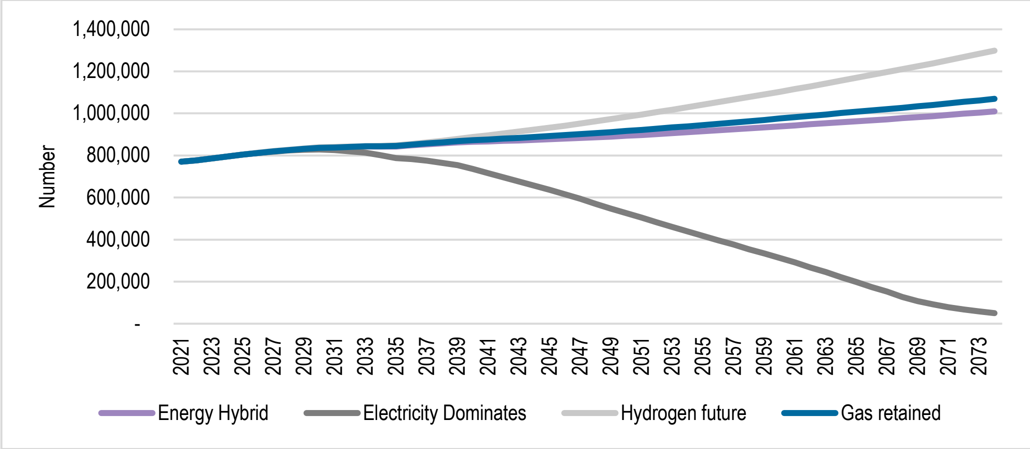
Figure 5.1 Projected gas demand, Terajoules



Source: ACIL Allen

A similar pattern to Figure 5.1 can be seen in the projected customer numbers for all four scenarios (see Figure 5.2). Under the Hydrogen Future scenario, total customers are projected to reach 1.30 million in 2074, a growth rate of 0.98 per cent annually. Natural Gas Retained and Energy Hybrid show moderate growth in customer numbers, with Natural Gas Retained reaching 1.07 million and Energy Hybrid reaching 1.01 million customers. Electricity Dominates represents an extreme case where customers collapse to just 50,200 at the end of the forecast period.

Figure 5.2 Projected customer numbers



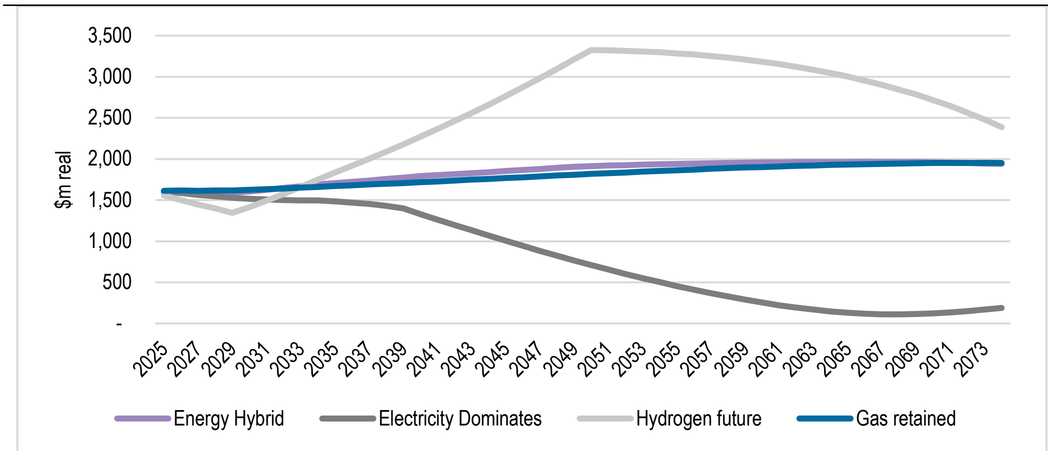
Source: ACIL Allen

5.2 Closing Regulatory Asset Base (RAB)

The trajectory of Closing RAB under the four scenarios is shown in Figure 5.3. The Energy Hybrid and Natural Gas Retained follow a similar path, reaching $2,015 million by 2074. The Hydrogen Future RAB path surges to a peak of $3,438 million in 2050 before beginning to decline. This rise in the RAB reflects the significant capital expenditure required to reconfigure the network to carry hydrogen gas.

The Electricity Dominates scenario shows a moderate decline to 2040 before commencing a rapid decline after that, with the asset base reaching a low of $111.2 million in 2068.

Figure 5.3 Closing RAB, real $million



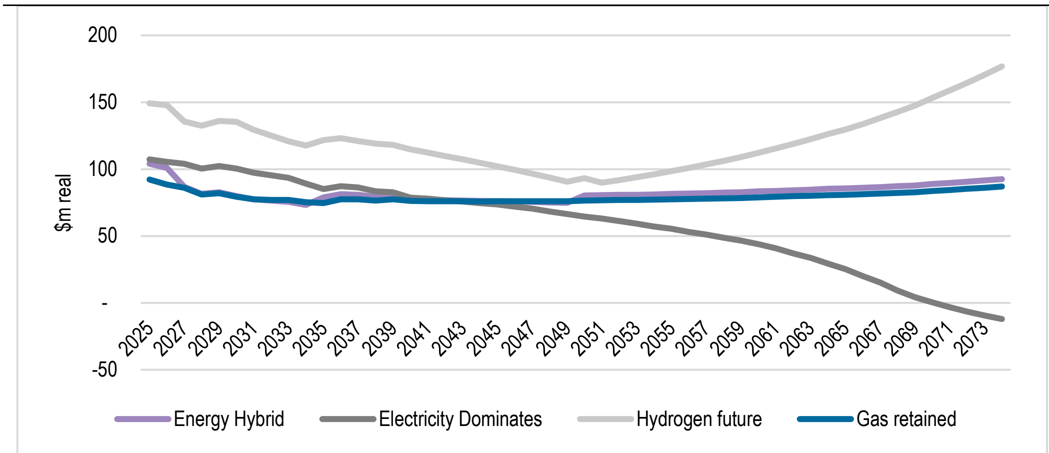
Source: ACIL Allen

5.3 Depreciation

5.3.1 Total depreciation

Total depreciation under the four scenarios is shown in Figure 5.4. The highest depreciation is charged under the Hydrogen Future scenario, a function of the substantial capital expenditures required to reconfigure the network to carry hydrogen gas. Total depreciation under the Electricity Dominates scenario declines rapidly and reaches zero in 2071. Total depreciation under the remaining two scenarios is more stable, reflecting the more stable outlook for customer growth and demand for gas.

Figure 5.4 Total deprecation (including brought-forward), real $million

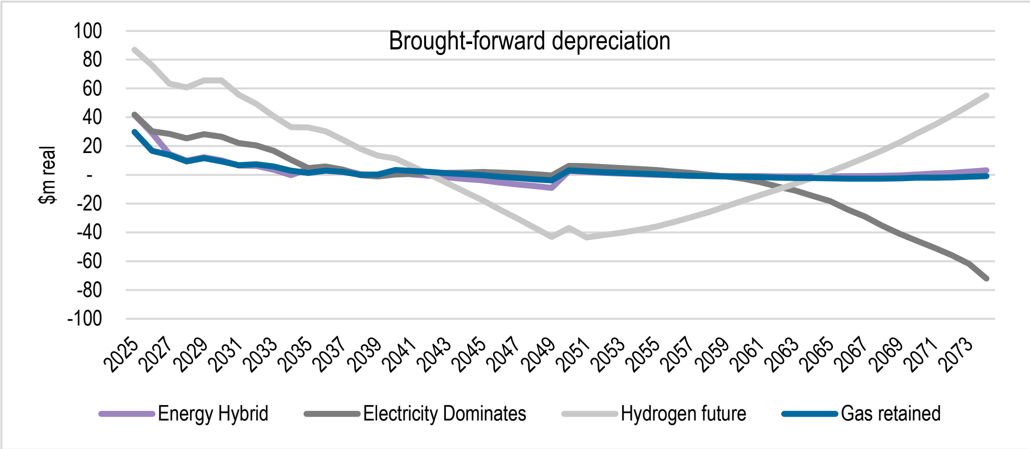


Source: ACIL Allen

5.3.2 Brought-forward depreciation

Figure 5.5 isolates brought-forward depreciation from total depreciation. The most significant spike in brought-forward depreciation occurs under the Hydrogen Future scenario, which spikes to $86.9 million in 2025. This is followed by the Electricity Dominates scenario, which spikes by $41.9 million, while Energy Hybrid increases by $41.7 million in 2025. The lowest increase in brought-forward depreciation occurs under the Natural Gas Retained scenario, which increases by $29.8 million in 2025. Brought-forward depreciation declines from the initial 2025 value in all scenarios.

Figure 5.5 Brought-forward depreciation, real $million

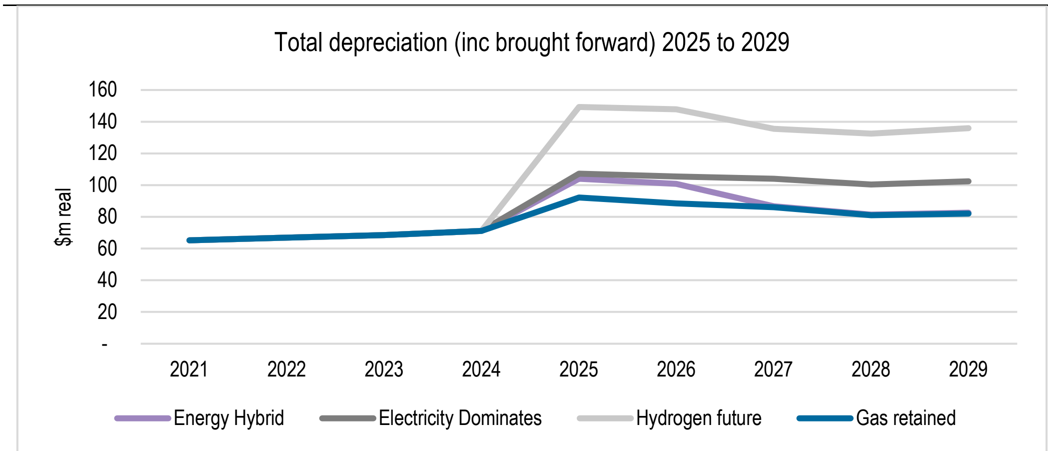


Source: ACIL Allen

5.3.3 2025 step up in depreciation

Accelerating depreciation from 2025 results in a significant increase from 2025, compared with the period 2021 to 2024, as shown in Figure 5.6. This step-up in depreciation contributes to the rise in tariffs in 2025, compared with the earlier years.

Figure 5.6 Total deprecation (including brought-forward), real $million – 2021 to 2029



Source:

5.4 Average tariffs

This section compares the constant annual average tariff with the original PTRM annual average tariff for all tariff types under all four scenarios. The two tariffs are defined as follows:

— Constant annual average tariff refers to the uniform annual average tariff used to determine the requirement for bringing forward depreciation.

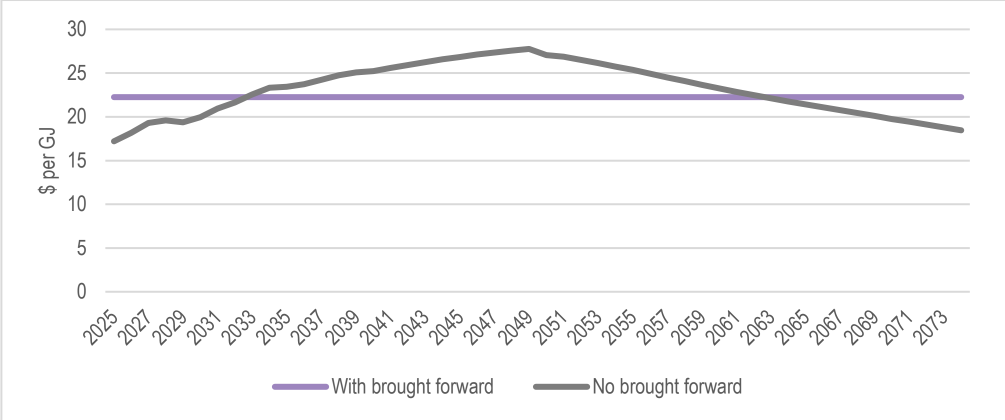
— Annual average tariff refers to the original PTRM tariff before any acceleration of depreciation.

Each of the tariff classes is discussed in the following sections.

5.4.1 Residential (Tariff B3)

Under the Hydrogen Future scenario, the residential constant average annual tariff rises to $22.25 per GJ after 2025 (see Figure 5.7). Without brought-forward depreciation, the annual average tariff will increase to $27.76 per GJ in 2049 before commencing a linear descent.

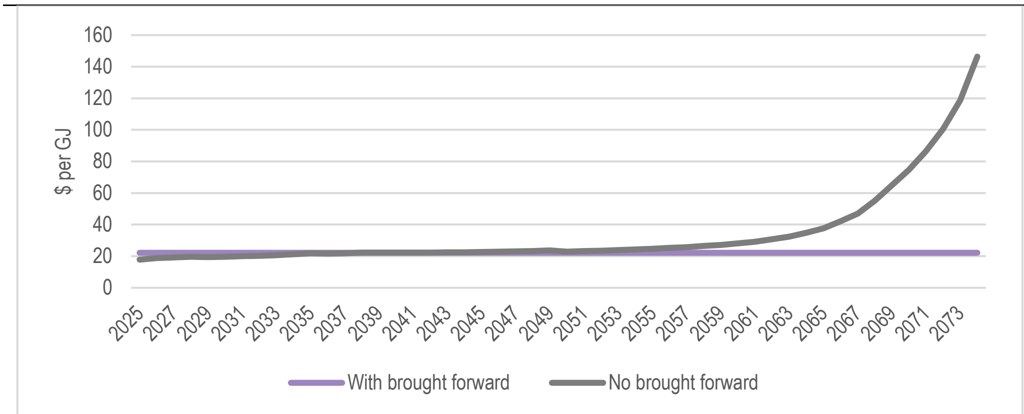
Figure 5.7 Residential Tariff B3, brought-forward versus no brought-forward, Hydrogen Future



Source: ACIL Allen

Under the Electricity Dominates scenario, the constant annual average tariff is calculated to be $22.16 per GJ (see Figure 5.8). Without brought-forward depreciation, the annual average tariff will exceed $22.18 by 2038, reaching $146 per GJ in 2074.

Figure 5.8 Residential Tariff B3, brought-forward versus no brought-forward, Electricity Dominates



Source: ACIL Allen

Figure 5.9 and Figure 5.10 show the same results under the Energy Hybrid and Natural Gas Retained scenarios. Both scenarios show a moderately higher peak for the annual residential average tariff without brought-forward depreciation, with the most significant differential occurring in 2049.

Figure 5.9 Residential Tariff B3, brought-forward versus no brought-forward, Energy Hybrid

Source: ACIL Allen

Figure 5.10 Residential Tariff B3, brought-forward versus no brought-forward, Natural Gas Retained

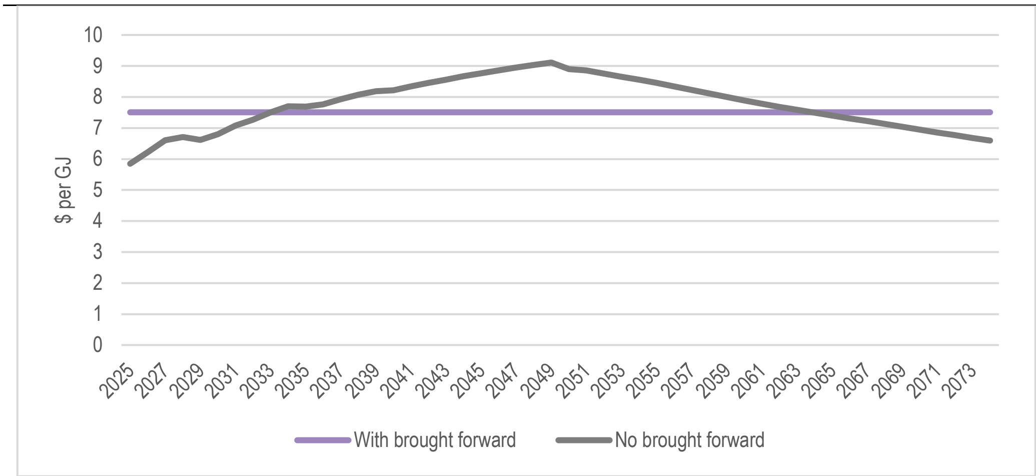
Source: ACIL Allen

5.4.2 Commercial (Tariff B1)

The following four figures present the constant average tariff against the average annual tariff for commercial tariff B1.

Under the Hydrogen Future scenario, the constant average annual tariff for the B1 tariff class was found to be $7.51 per GJ. Without brought-forward depreciation, the annual average tariff for B1 rises to a peak of $9.11 per GJ in 2049 and then declines gradually.

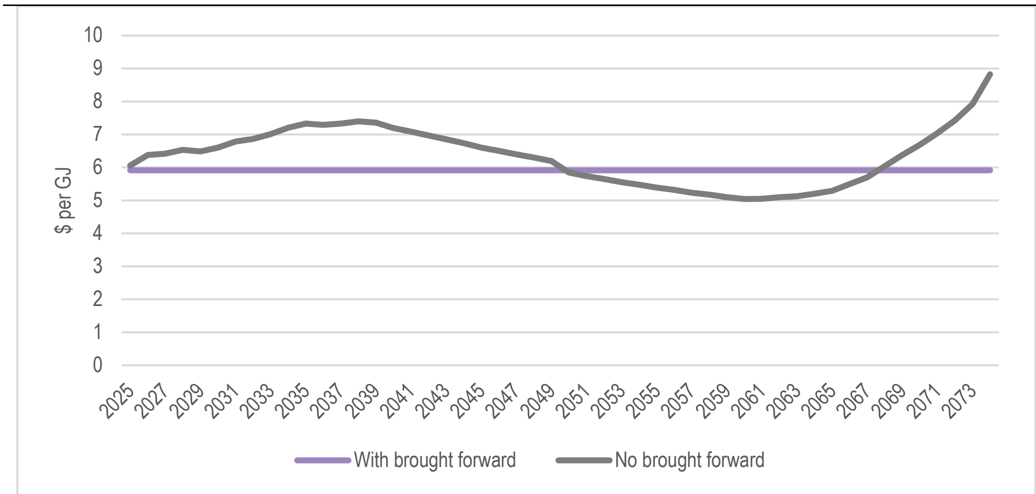
Figure 5.11 Commercial Tariff B1, brought-forward versus no brought-forward, Hydrogen Future



Source: ACIL Allen

Under the Electricity Dominates scenario, the constant average annual tariff for the B1 tariff class was $5.91 per GJ. Without brought-forward depreciation, the annual average tariff for B1 rises to $7.40 per GJ in 2039 before declining to 2060 and then rising again to a peak of $8.83 per GJ in 2074.

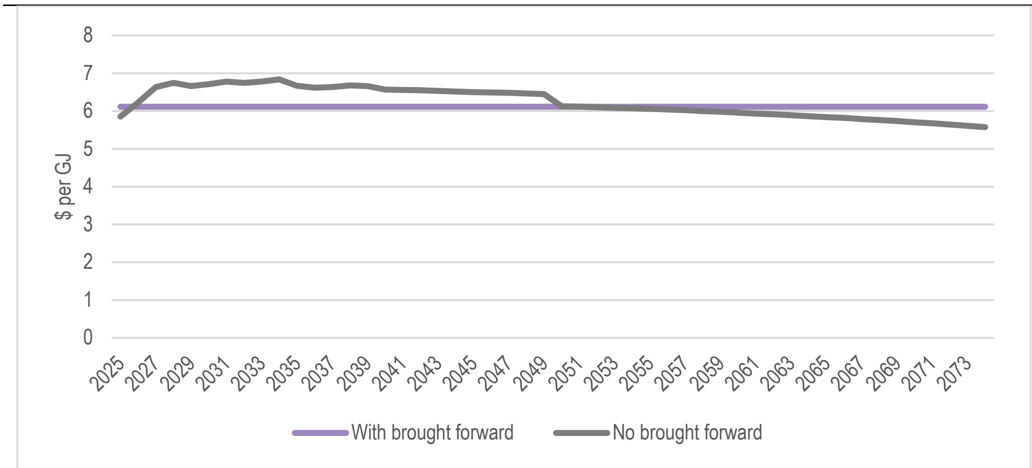
Figure 5.12 Commercial Tariff B1, brought-forward versus no brought-forward, Electricity Dominates



Source: ACIL Allen

Under the Energy Hybrid scenario, the constant average annual tariff for the B1 tariff class was $6.11 per GJ. Without brought-forward depreciation, the annual average tariff for B1 rises to $6.84 per GJ in 2034 before declining to $5.57/GJ in 2074.

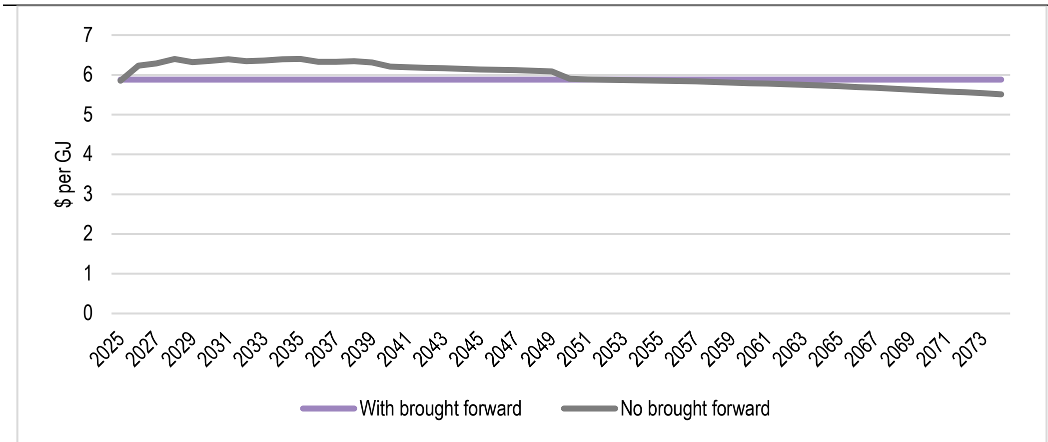
Figure 5.13 Commercial Tariff B1, brought-forward versus no brought-forward, Energy Hybrid



Source: ACIL Allen

Under the Natural Gas Retained scenario, the constant average annual tariff for the B1 tariff class was found to be $5.88 per GJ. Without brought-forward depreciation, the annual average tariff for B1 rises to $6.40 per GJ in 2028 before gradually declining to $5.51 per GJ in 2074.

Figure 5.14 Commercial Tariff B1, brought-forward versus no brought-forward, Natural Gas Retained



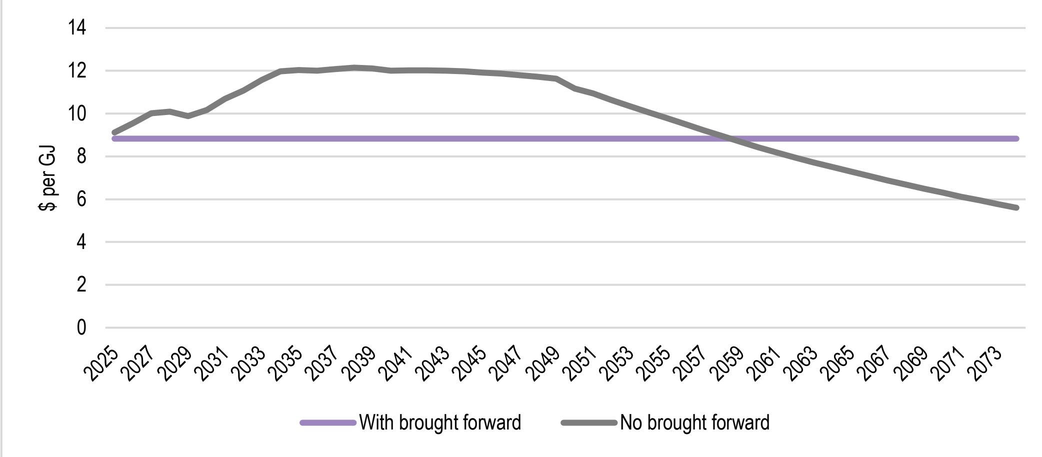
Source: ACIL Allen

5.4.3 Commercial (Tariff B2)

The following four figures present the constant average tariff against the average annual tariff for commercial tariff B2.

Under the Hydrogen Future scenario, the constant average annual tariff for the B2 tariff class was found to be $8.83 per GJ. The annual average tariff for B2 rises to $12.11 per GJ in 2039 without any brought-forward depreciation and then declines through to 2074.

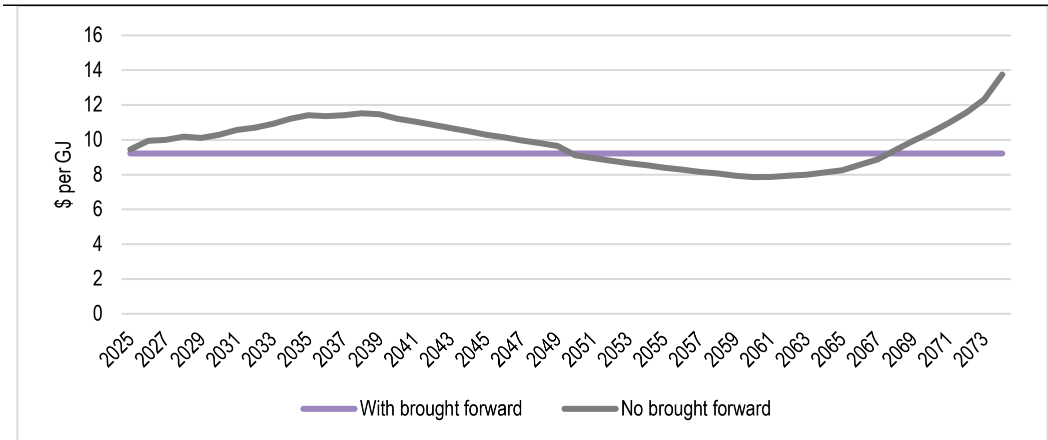
Figure 5.15 Commercial Tariff B2, brought-forward versus no brought-forward, Hydrogen Future



Source: ACIL Allen

Under the Electricity Dominates scenario, the constant average annual tariff for the B2 tariff class was $9.21 per GJ. The annual average tariff for B2 rises to $11.53 per GJ in 2038 without any brought-forward depreciation, declines to 2060 and then rises again to 2074.

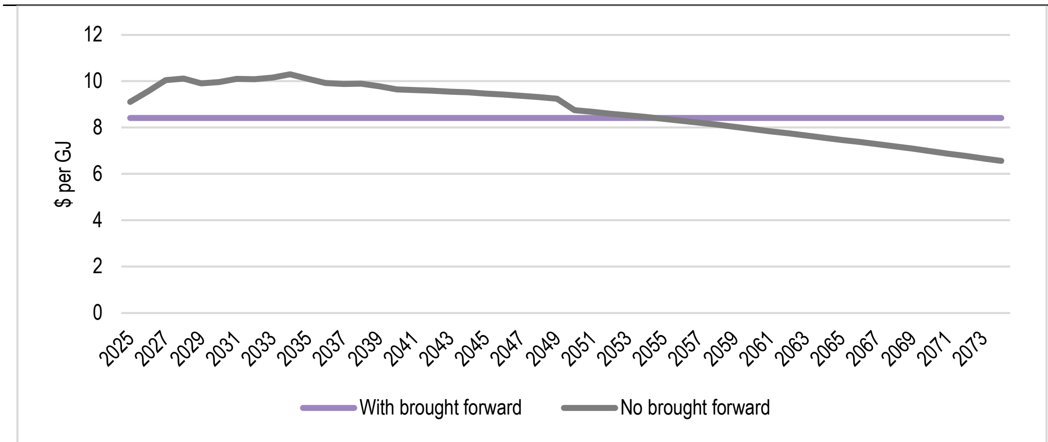
Figure 5.16 Commercial Tariff B2, brought-forward versus no brought-forward, Electricity Dominates



Source: ACIL Allen

Under the Energy Hybrid scenario, the constant average annual tariff for the B2 tariff class was $8.42 per GJ. The annual average tariff for B2 rises to $10.30 per GJ in 2034 without any brought-forward depreciation and then declines through to 2074.

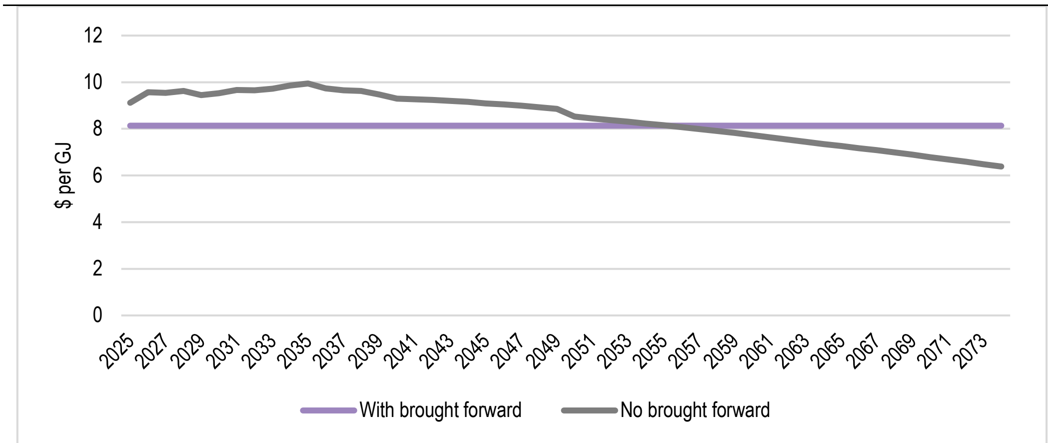
Figure 5.17 Commercial Tariff B2, brought-forward versus no brought-forward, Energy Hybrid



Source: ACIL Allen

Under the Natural Gas Retained scenario, the constant average annual tariff for the B2 tariff class was calculated to be $8.14 per GJ. The annual average tariff for B2 rises to $9.95 per GJ in 2035 without any brought-forward depreciation and then declines through to 2074.

Figure 5.18 Commercial Tariff B2, brought-forward versus no brought-forward, Natural Gas Retained



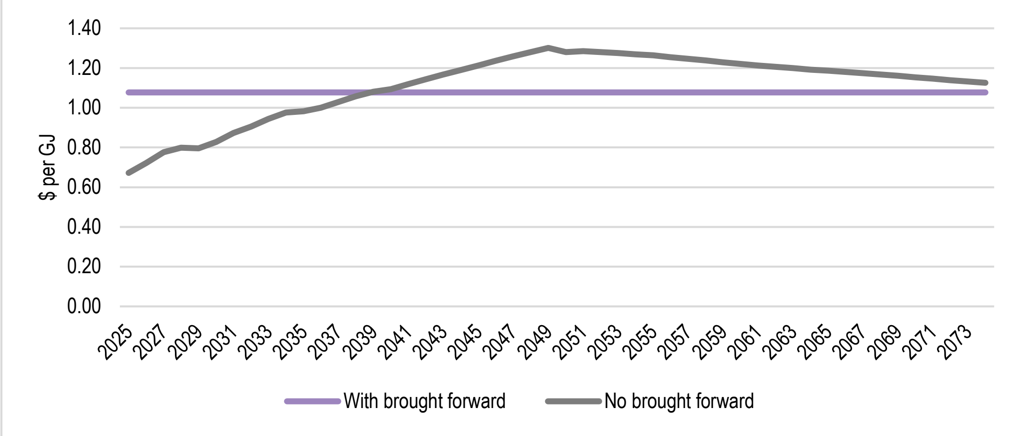
Source: ACIL Allen

5.4.4 Industrial (Tariff A1)

A similar set of results for the four scenarios is shown in the following four figures for tariff class A1.

Under the Hydrogen Future scenario, the constant average annual tariff for the A1 tariff class was calculated to be \$1.08 per GJ. This is compared to the annual average tariff for A1, which rises to \$1.30 per GJ in 2049 without any brought-forward depreciation before declining through 2074.

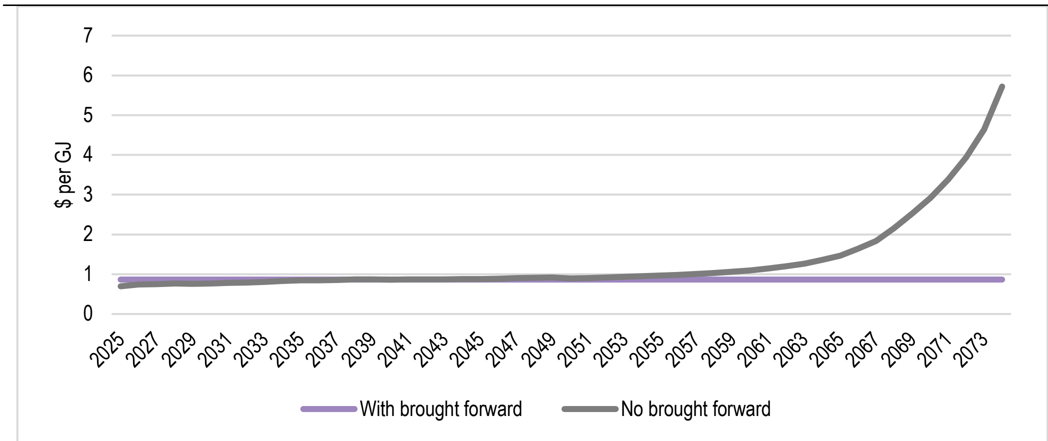
Figure 5.19 Industrial Tariff A1, brought-forward versus no brought-forward, Hydrogen Future



Source: ACIL Allen

Under the Electricity Dominates scenario, the constant average annual tariff for the A1 tariff class was calculated to be \$0.87 per GJ. This is compared to the annual average tariff for A1, which rises to \$5.72 per GJ in 2074 without any brought-forward depreciation.

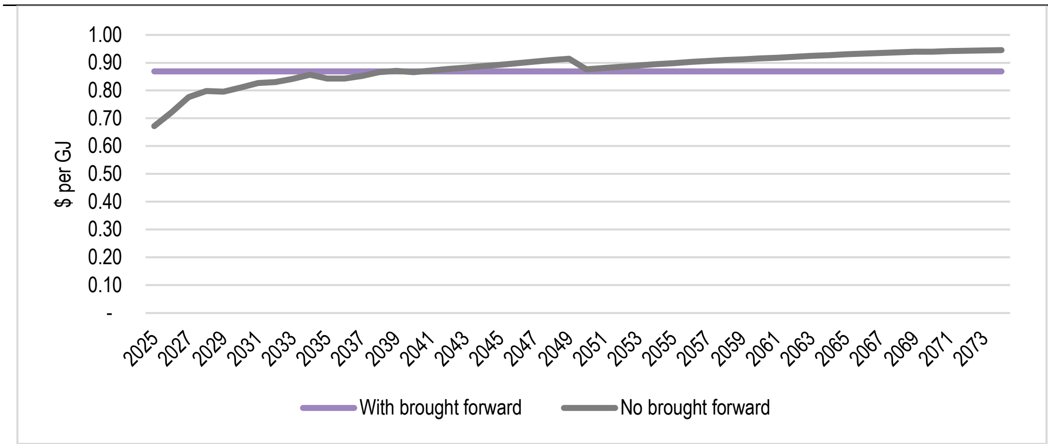
Figure 5.20 Industrial Tariff A1, brought-forward versus no brought-forward, Electricity Dominates



Source: ACIL Allen

Under the Energy Hybrid scenario, the constant average annual tariff for the A1 tariff class was calculated to be \$0.87 per GJ. This is compared to the annual average tariff for A1, which rises to \$0.95 per GJ in 2074 without any brought-forward depreciation.

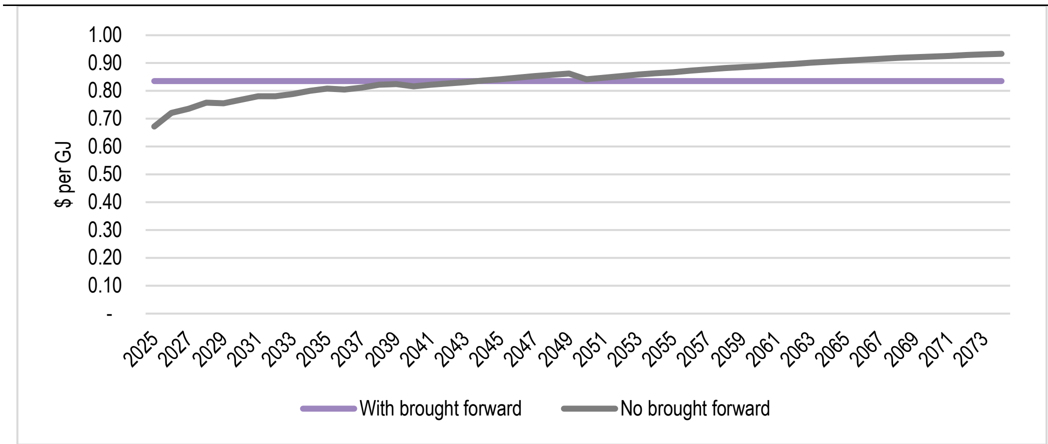
Figure 5.21 Industrial Tariff A1, brought-forward versus no brought-forward, Energy Hybrid



Source: ACIL Allen

Under the Natural Gas Retained scenario, the constant average annual tariff for the A1 tariff class was calculated to be $0.84 per GJ. This is compared to the annual average tariff for A1, which rises to $0.93 per GJ in 2074 without any brought-forward depreciation.

Figure 5.22 Industrial Tariff A1, brought-forward versus no brought-forward, Natural Gas Retained



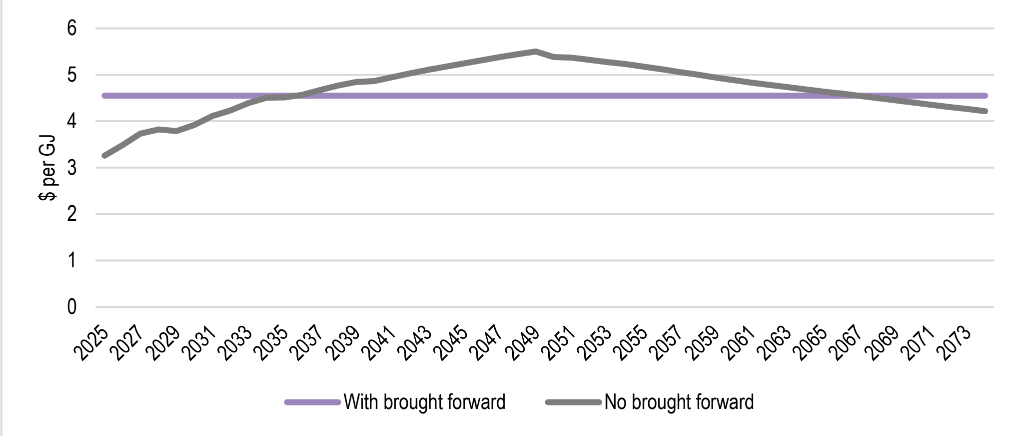
Source: ACIL Allen

5.4.5 Industrial (Tariff A2)

The following four figures show the results for the A2 tariff class.

Under the Hydrogen Future scenario, the constant average annual tariff for the A2 tariff class was calculated to be $4.55 per GJ. This is compared to the annual average tariff for A2, which rises to $5.50 per GJ in 2049 without any brought-forward depreciation before declining through to 2074.

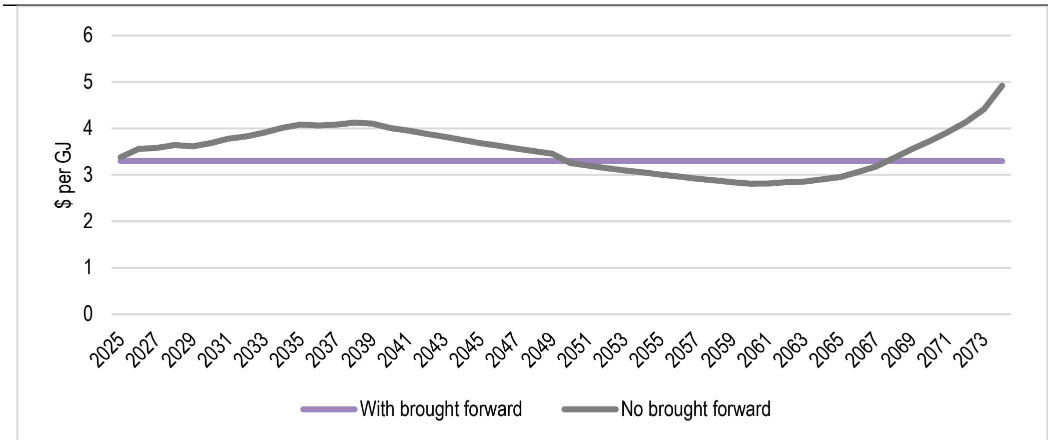
Figure 5.23 Industrial Tariff A2, brought-forward versus no brought-forward, Hydrogen Future



Source: ACIL Allen

Under the Electricity Dominates scenario, the constant average annual tariff for the A2 tariff class was calculated to be $3.30 per GJ. This is compared to the annual average tariff for A2, which rises to $4.12 in 2038, declines and then rises again to $4.92 per GJ in 2074 without any brought-forward depreciation.

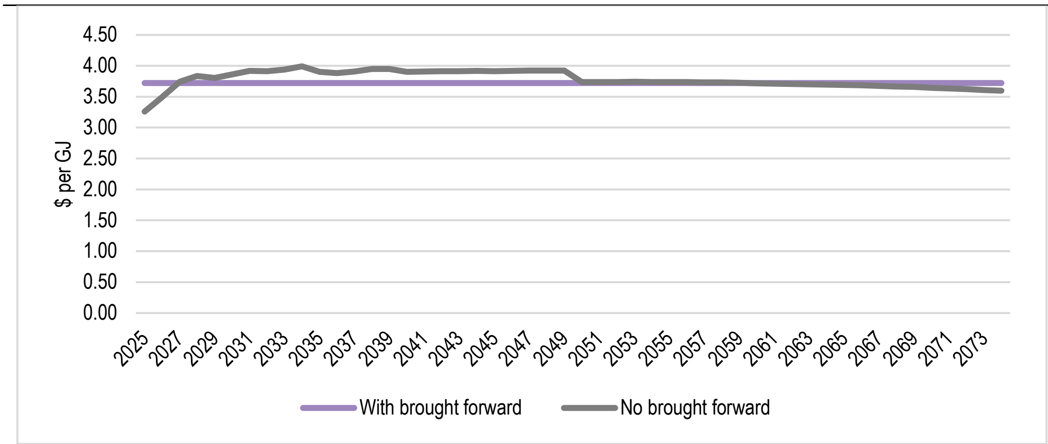
Figure 5.24 Industrial Tariff A2, brought-forward versus no brought-forward, Electricity Dominates



Source: ACIL Allen

Under the Energy Hybrid scenario, the constant average annual tariff for the A2 tariff class was calculated to be $3.72 per GJ. This is compared to the annual average tariff for A2, which rises to $3.99 per GJ in 2034 without any brought-forward depreciation and then gradually declines to 2074.

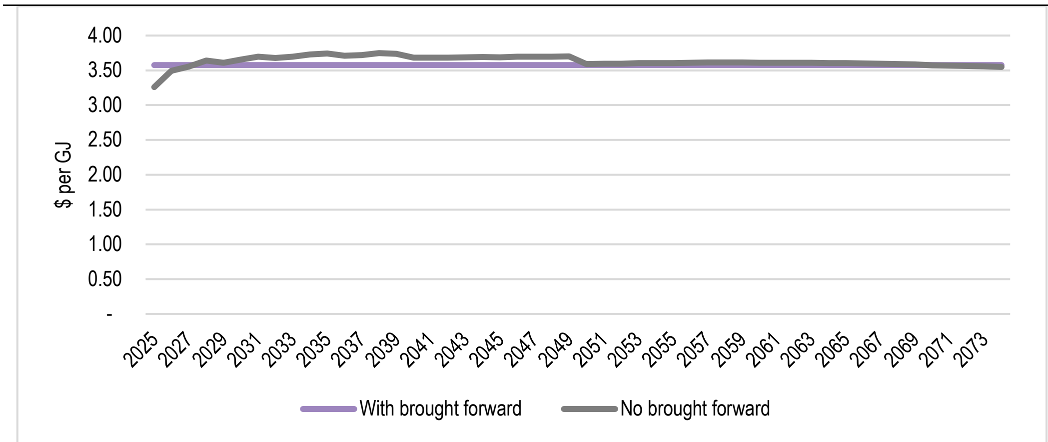
Figure 5.25 Industrial Tariff A2, brought-forward versus no brought-forward, Energy Hybrid



Source: ACIL Allen

Under the Natural Gas Retained scenario, the constant average annual tariff for the A2 tariff class with brought-forward depreciation was calculated to be $3.58 per GJ. This is compared to the annual average tariff for A2, which rises to $3.75 per GJ in 2038 without any brought-forward depreciation, then declines in steps through to 2074.

Figure 5.26 Industrial Tariff A2, brought-forward versus no brought-forward, Natural Gas Retained



Source: ACIL Allen

Conclusions and recommendations 6

6.1 Scenarios

6.1.1 Scenario summary

Four scenarios were developed in concert with ATCO and a group of ATCO's stakeholders:

— **Hydrogen Future** – Rapid learning rates relating to green hydrogen and renewable gas production enable these gases to displace natural gas domestically and internationally. The resulting green hydrogen industry mirrors the current natural gas and LNG industries with a broader high-volume export focus enabling the economic servicing of a smaller domestic market.

— **Electricity Dominates** – Renewable electricity generation and storage experience a rapid reduction in cost through fast technological learning. As such, the relative cost of electricity against natural gas and renewable gases falls to such an extent that a broad-based electrification of industry and households occurs.

— **Energy Hybrid** – Technical learning rates for renewable gases and electrification develop similarly, resulting in some customers electing to electrify and some remaining on the gas network. From an economic and environmental point of view, electricity and zero emissions gases become viable alternatives for natural gas. This results in a mixed response from residential/commercial and industrial consumers, with an even split electing to follow electrification or to stick with a gas-based energy supply chain.

— **Natural Gas Retained** – global and local factors result in natural gas being retained in the ATCO network. Zero-emissions gases such as green hydrogen or renewable methane experience slow technological learning rates, which results in them generally remaining uneconomic at scale. As such, natural gas continues to be embraced as a 'transition fuel' used in large volumes globally to quickly and reliably reduce carbon emissions through coal-to-gas switching and to support/firm renewable generation. The carbon emissions intensity of natural gas and natural gas products such as LNG also reduce significantly through rapid technological learning relating to CCS/CCUS and improved access to adequate and affordable carbon offset options.

6.1.2 Scenario effects

The Energy Hybrid and Gas Retained scenarios project minimal disruption to gas markets in Western Australia. The Hydrogen Future and Electricity Dominates scenarios project considerable disruption, with the first requiring a significant investment in gas distribution infrastructure associated with the transition to hydrogen and the second resulting in a rapid decline in usage of gas as customers disconnect from the distribution system (switching to electricity) from around 2030.

The Energy Hybrid and Gas Retained scenarios show a slight decline in gas demand (compared with 2025) through to 2032 and then return to slight growth after that. Customer numbers growth does not decline in either scenario. The reduction in gas demand is the ongoing reduction by each customer (energy efficiency). Demand growth after 2032 is driven by new customers offsetting energy efficiency improvements per customer.

The Hydrogen Future scenario also shows a slight decline in demand to 2035, after which demand is projected to rise quickly as customer numbers grow. This demand growth is driven by the falling price of gas (hydrogen), resulting in gas consumption becoming very competitive with the alternative of switching to electricity.

The Electricity Dominates scenario shows a slight decline in overall demand by 2030. From 2030, customer numbers are projected to decline by around 1 per cent per annum initially, rising to about 6 per cent by 2060 and nearly 14 per cent by 2074. The average annual rate of decline in customer numbers is around 6 per cent per annum from 2030 to 2074.

6.1.3 Scenario weighting

Each scenario is a distinct future driven by specific technology and policy developments. They represent plausible futures but do not represent the complete set. Also, each scenario does not have an equal probability of occurring. Therefore, as the relative probability of each scenario is unknown, and the scenarios are not a complete set of the future, deriving conclusions by some form of a weighted average of results or settling on the central case is not feasible. Therefore, we have not used either of these approaches in our conclusions or in developing our recommendations.

6.1.4 Comparative effects on depreciation

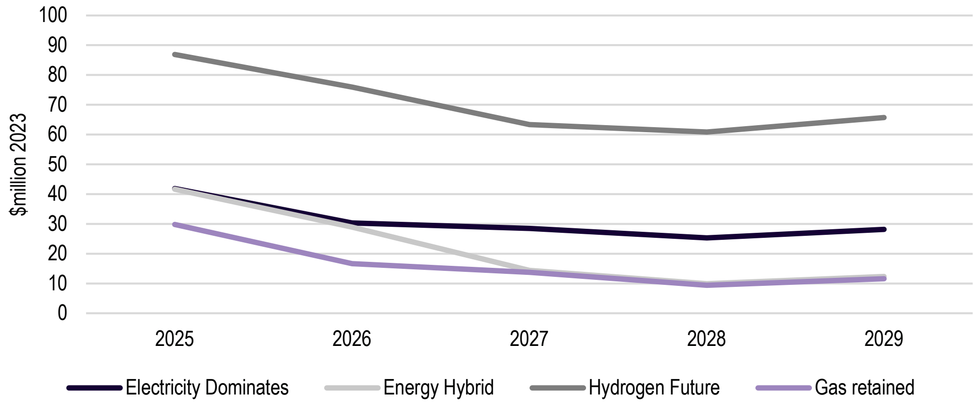
The depreciation schedules differ across the four scenarios, as shown in Figure 5.4 and Figure 5.5. The calculated brought-forward depreciation drives this difference to ensure tariff prices remain constant over the whole period. The standard regulatory cycle is five years in length which allows flexibility in decisions relating to tariff pricing. Decisions made in the upcoming regulatory cycle (2025-2029) concerning accelerating depreciation in the regulatory cycle can be adjusted in future regulatory cycles based on better information that becomes available in the intervening period.

Figure 6.1 compares the brought-forward depreciation schedules by scenario for 2025-29.

The Hydrogen Future scenario sits well above the other three scenarios, as substantial capital expenditures (compared with the other scenarios) are required to reconfigure the network to carry hydrogen gas. Therefore, there is significantly more capital to depreciate than in the other cases.

Electricity Dominates and Energy Hybrid start at similar levels in 2025 and 2026. The Gas Retained brought-forward depreciation is lower than all others in the first two years. From 2027 to 2029, the Energy Hybrid scenario shifts to track the Gas Retained scenario. The Energy Hybrid brought-forward depreciation decreases in 2027 because operating expenditure (as provided by ATCO) rises compared with the other scenarios. When operating expenditure increases, brought-forward depreciation must fall to maintain the constant average annual tariff assumption.

Figure 6.1 Brought-forward depreciation by scenario – 2025-29



Source: ACIL Allen

6.2 Recommended actions

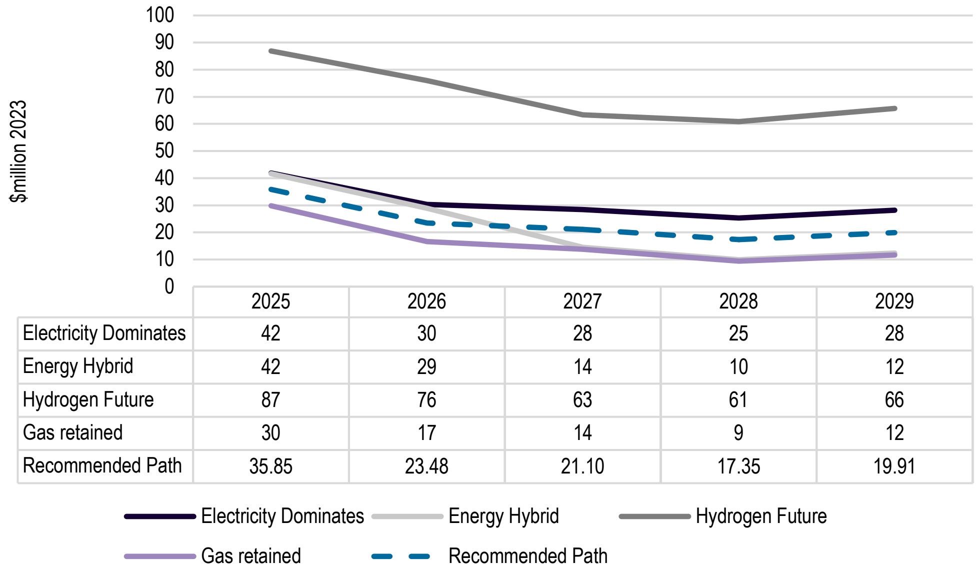
As shown in Figure 6.1 above, the potential range of brought-forward depreciation by scenario from 2025 to 2029 is between $50 and $60 million annually. As each scenario is plausible, any brought-forward depreciation path could be considered reasonable. However, the least "no regrets" approach would be to choose a brought-forward depreciation path that follows or is close to the most significant number of scenarios possible.

The Hydrogen Future brought-forward depreciation is an outlier[2], whereas the other three cluster relatively closely over the five years. The Electricity Dominates, and the Gas Retained scenarios, bound the cluster. The Energy Hybrid brought-forward depreciation path sits within the bounds of the other two. Therefore, we recommend choosing a brought-forward depreciation path for 2025 to 2029 that is halfway between the Electricity Dominates and Gas Retained paths. We consider this to be the least "no regrets" option.

The recommended brought-forward depreciation path is shown in Figure 6.2 below.

2 Outlier in terms of the numbers presented, not with respect to the likelihood of the scenario occurring.

Figure 6.2 Recommended brought-forward depreciation path – 2025-29

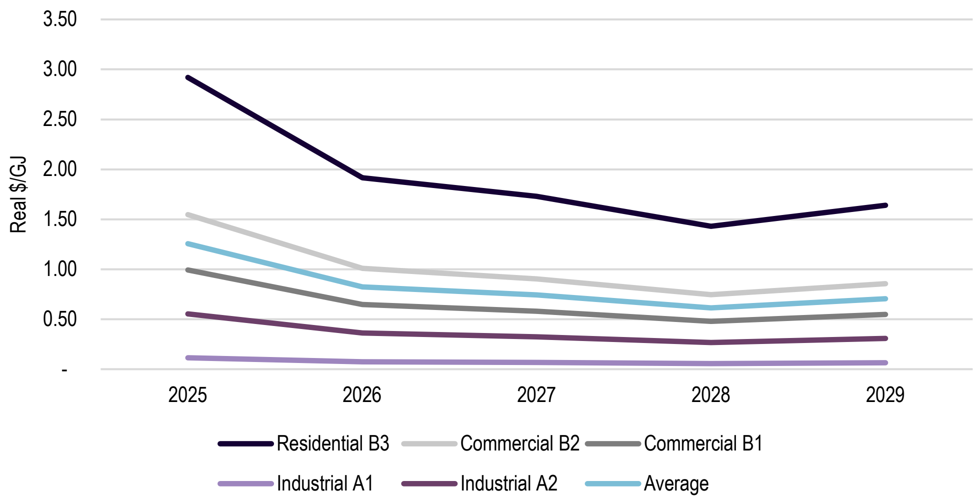


	2025	2026	2027	2028	2029
Electricity Dominates	42	30	28	25	28
Energy Hybrid	42	29	14	10	12
Hydrogen Future	87	76	63	61	66
Gas retained	30	17	14	9	12
Recommended Path	35.85	23.48	21.10	17.35	19.91

Source: ACIL Allen

The tariff increase by customer class is shown in Figure 6.3 below. The tariff increases were calculated using the original allocation of revenues to each tariff class divided by the annual gas demand for that class. The residential B3 tariff increases by an average of $1.93 annually over the five years. The commercial B2 tariff increases by an average of $1.01 over the five years.

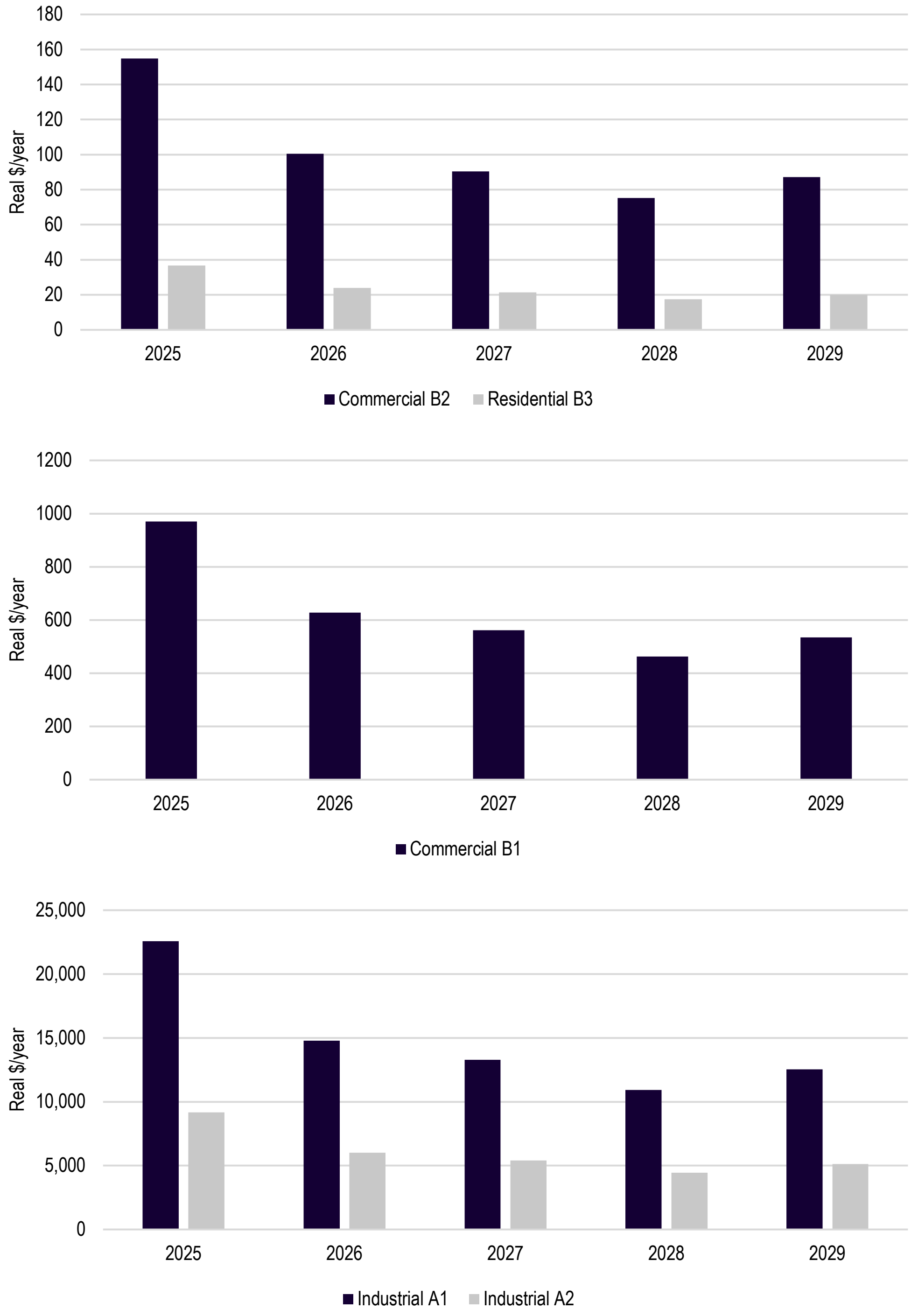
Figure 6.3 Recommended Path average tariff increases by customer class – 2025-29



Source: ACIL Allen

The average annual increase in the customer bill by customer class is shown in Figure 6.4 below. This increase is calculated by multiplying the average tariff increase for each customer class by the average annual consumption for each customer class. The average annual increase in customer bills for residential B3 customers is around $24 per annum over 2025-29. For commercial B2 customers, the average yearly increase in customer bills is around $102 per annum.

Figure 6.4 Average annual increase in customer bill by customer class – 2025-29



Source: ACIL Allen

A Glossary of terms

Abbreviation	Definition
AA6	Access Arrangement for the period commencing 2025
ACIL Allen	ACIL Allen Consulting
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
ATCO	ATCO Gas Australia Pty Ltd
AUD	Australian dollar
Brought-forward depreciation	Acceleration of regulatory depreciation, compared with the standard life-based regulatory depreciation
Carbon price	Price for 1 tonne of CO_2-e
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CO_2-e	Carbon dioxide equivalent – a measure of greenhouse gas emissions
CPI	Consumer Price Index
Electrification	The act of switching from appliances powered by natural gas to electricity-powered appliances
ERA	Economic Regulation Authority
ESOO	Electricity Statement of Opportunities
GJ	Gigajoule – one thousand million joules
GPG	Gas for power generation
GSOO	Gas Statement of Opportunities
GSP	Gross State Product
GWh	Gigawatt hours – one thousand Megawatt hours
H_2	Hydrogen gas – made up of diatomic molecules
kWh	kilowatt-hours – one thousand watt-hours
LGA	Local Government Area
LNG	Liquefied Natural Gas
MOU	Memorandum of Understanding
Mt	million tonnes
MW	Megawatt – one million Watts

Abbreviation	Definition
MWh	megawatt-hour – one million watt-hours
Net zero	Reduction in greenhouse gas emissions to zero where offsets are included as emission reductions
NPV	Net present value
PJ	Petajoule – one million gigajoules
PV	Photovoltaic
RAB	Regulated Asset Base
Safeguard Mechanism	Commonwealth emissions reduction scheme requiring major (non-electricity) greenhouse gas emitters to phase emissions down over time
S curve	The shape of a logistic function
SWIS	South West Interconnected System
USD	United States dollar
WACC	Weighted Average Cost Of Capital
WEM	Wholesale Electricity Market
WOOPS	Window of Opportunity PaSt

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