frontier economics

Review of DBNGP economic life assumptions

A report for the Economic Regulation Authority | 23 February 2021

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1 Introduction

On 2 January 2020, DBNGP (WA) Transmission Pty Ltd (DBP) submitted proposed revisions to the access arrangement for the Dampier to Bunbury Natural Gas Pipeline (DBNGP). DBP's proposal covers the five-year period from 1 January 2021 to 31 December 2025 (known as the fifth access arrangement period of AA5). The Economic Regulation Authority (ERA) is to consider DBP's proposal.

As part of its proposal for AA5, DBP proposed to cap the economic life of the DBNGP to 2059.

1.1 Our engagement

We have been engaged by the ERA to provide advice on DBP's proposal to cap the economic life of the DBNGP.

Specifically, we have been engaged to:

- Identify the major underlying assumptions used to determine the end of the life of the DBNGP.
- Identify any significant assumptions missing from DBP's analysis of the future role of the DBNGP.
- For each of the identified assumptions, provide:
    - an assessment of the certainty of the assumption
    - a determination of what a reasonable range may be
    - an assessment of the reasonableness of the assumptions used.
- For each of the identified assumptions, an assessment of what may be reasonable low, expected and high scenarios.

In providing our advice to the ERA we have reviewed:

- DBP's assessment of the economic life of the DBNGP, provided as part of DBP's proposal (**DBP Economic Life Attachment**).[1]
- ACIL Allen Consulting's report on economic depreciation of the DBNGP (**ACIL Economic Depreciation report**).[2]
- A number of spreadsheets that comprise the modelling tools used by DBNGP to assess the economic life of the DBNGP (**ACIL WOOPS Model**).
- DBP's response to the draft decision[3], which included its adoption of the ERA's economic life interpretation in the draft decision and additional information in response to EMCa's comments on the assumptions.

[1] DBP, *Assessment of the Economic Life of the DBNGP*, Attachment 9.2, January 2020.

[2] ACIL Allen Consulting, *Dampier to Bunbury Natural Gas Pipeline; Economic Depreciation Study*, 20 December 2019.

[3] DBP, *Response to Draft Decision on Capital Base*, Attachment 9.7, January 2020

We have also reviewed the following submissions:

- In response to the Issues Paper, submissions from Perth Energy, CITIC Pacific, gasTrading Australia, New Gen Power, Synergy and Wesfarmers Chemicals, Energy and Fertilisers.
- In response to the Draft Decision, submissions from Alinta Energy, Beach Energy, CITIC Pacific Mining, gasTrading Australia, Mitsui E&P, NewGen Power, Wesfarmers Energy (Gas Sales).

A number of these submissions made general comments on the appropriateness of adjusting of economic life assumptions in the 2021-2025 access arrangement period (AA5), especially given uncertainties regarding future of energy market outcomes. These comments are beyond the scope of our report.

However, gasTrading did make specific comment on input assumptions used in the ACIL WOOPS Model. We discuss these specific comments in the relevant sections of our report.

1.2 This report

This report is structured as follows:

- Section 2 provides an overview of the ACIL WOOPS Model.
- Section 3 sets out our review of the ACIL WOOPS Model.
- Section 4 provides our review of projections of throughput and volumes used in the ACIL WOOPS Model.
- Section 5 provides our review of gas price projections used in the ACIL WOOPS Model.
- Section 6 provides our review of carbon price projections used in the ACIL WOOPS Model.
- Section 7 provides our review of hydrogen price projections used in the ACIL WOOPS Model.
- Section 8 provides our review of electricity price projections used in the ACIL WOOPS Model.
- Section 9 provides our review of the scenarios modelled in the ACIL WOOPS Model.

2 Overview of the ACIL WOOPS Model

This section provides our understanding of the ACIL WOOPS Model.

2.1 The ACIL WOOPS Model implements a conceptual model to evaluate implications of different economic lives for the DBNGP

The ACIL WOOPS Model is an Excel-based model that applies a conceptual model from Crew and Kleindorfer to evaluate the economic life of the DBNGP. The Crew and Kleindorfer model considers the impact of different economic lives of a regulated asset that is partially or fully stranded at some point in the future.

The ACIL WOOPS Model implements a slightly modified version of the Crew and Kleindorfer model (as set out in Equation 1 of the DBP Economic Life Attachment) to account for a number of complexities associated with the DBNGP and its context, including changing commodity prices, ongoing capex and opex, different markets for the use of gas, and greenhouse emissions policy.

In essence, the model considers outcomes for the DBNGP in two distinct time periods:

- **Regulated period:** A time period during the economic life[4] of the pipeline, during which projected allowed revenues can be calculated. During this period, the price of gas and a regulated transport charge may be:
  - Cheaper than alternatives, such as renewables and storage for gas-powered generation (GPG), and hydrogen for industrial process. While this is the case, the model assumes that the DBNGP is able to earn the applicable regulated tariff.
  - More expensive than alternatives. While this is the case, the model assumes that the DBNGP discounts the regulated tariff to compete with alternatives until it can no longer earn revenue from transporting gas.
- **'Competitive' period:** A time period after the economic life of the pipeline, in which there are no allowed revenues. During this period, the price of delivered gas may be:
  - Cheaper than alternatives. While this is the case, the model assumes that the DBNGP earns the difference in energy-equivalent, 'delivered' prices. This difference may cause a large increase in revenues in the assessment of short economic lives. In the earlier years of the model, hydrogen and renewables are significantly more expensive than natural gas. If the economic life modelled is short, the model assumes that the DBNGP can capture this

[4] The ERA considered a different definition of 'economic life' to the definition used by the DBP, as discussed in Section 2.2.1. In this section, we use 'economic life' as it is used in the ACIL WOOPS Model which accords with the DBP's proposed definition.

difference in price, leading to large revenues as soon as the regulated price period ends. DBP notes that these revenues should be interpreted with caution.[5]

- More expensive than alternatives: While this is the case, the model also assumes that the DBNGP earns the difference in energy-equivalent, 'delivered' prices. However, the model will only earn the difference to a floor of zero – when the DBNGP can no longer earn revenue from transporting gas, it will stop transport activities rather than earn negative revenues.

These periods are summarised in **Figure 1**.

Figure 1: The model considers outcomes over two time periods depending on the competitiveness of gas

During the …	Gas + DBNGP transport is … Cheaper than alternatives	Gas + DBNGP transport is … More expensive than alternatives
Regulated period (within economic life)	DBNGP earns regulated tariff	DBNGP discounts regulated tariff to a floor of zero
Competitive period (after economic life)	DBNGP earns difference in comparable prices	DBNGP earns difference in comparable prices to a floor of zero

When delivered gas is more expensive than alternatives, the DBNGP is assumed to be unable to continue earning its regulated tariff. If the economic life of the pipeline is significantly beyond this point, the DBNGP may not be able to recover its efficient costs because it will earn a reduced tariff or stop transporting gas entirely as customers switch to cheaper alternatives. If the economic life of the pipeline is before this point, the DBNGP may be able to over-recover its efficient costs because it will earn competitive revenue after fully recovering its efficient costs through a regulated revenue.

5 From DBP Economic Life Attachment 9.2: *"This needs to be borne in mind when looking at the NPV results for very short asset lives; their large size is due to an assumption in the model that we would be able to price at the level of renewables when they are still high in price, and they are thus more a signal that the life is too short, rather than a signal of how much we would actually earn if lives were that short as we would still be under regulation in reality and there is no way the ERA would allow us to price at the level of substitutes if these were well above our costs. The converse is not true of negative NPV results from asset lives being made too long as these reflect prices that the regulator would actually let us charge in a building block model."*

ACIL Allen Consulting states that the purpose of the model as the following (ACIL Economic Depreciation report, p3):

> *The purpose of the ACIL Allen model is to establish the point for each scenario modelled where regulation of the DBP would no longer fully recover deployed capital because competitive based pricing from that point would be less than regulated pricing required to fully recover capital deployed.*

2.1.1 We used the 'working' version of the model provided

We were provided with two versions of the model – a 'vanilla' version which just includes core model functionality and a 'working' version which automates a number of steps required to make modifications to the economic life of the DBNGP and provides some additional summary calculations. In this review of the model, we have used the 'working' version.

2.2 The model considers regulated revenues, the price of gas and alternatives, and forecast transport volumes

The ACIL WOOPS Model requires inputs relating to five key areas, including:

- A capital base, forecast capex and opex, and depreciation for a given economic life of the DBNGP. These inputs are used to calculate an **allowed regulated revenue**.
- A **forecast price of natural gas**, including underlying commodity prices and an assumed carbon price that may change over time.
- A **forecast price of renewables and storage** for electricity generation as an alternative to gas consumption by GPG. This price is based on electricity market modelling by ACIL Allen Consulting. This price is compared to gas prices using an assumed heat rate to derive a price at which GPG is competitive.
- A **forecast price of 'delivered' hydrogen** as an alternative to natural gas as a fuel or feedstock for industrial processes. This price is based on an initial price for hydrogen production, transport and storage which is adjusted over time to account for cost reductions (learning).
- A **forecast of contracted capacity and throughput** over the DBNGP to 2085. There are two components to these forecasts:
    - Volumes associated with industrial processes (about two thirds of chargeable quantities) are assessed and assumed to continue unchanged to 2085.
    - Volumes associated with GPG (about one third of chargeable quantities) reduce according to market modelling and extrapolations undertaken by ACIL Allen Consulting.

The ACIL WOOPS Model uses these inputs to assess the NPV of DBNGP costs and revenues based on an economic life (or end year) provided by the user.

Costs for the DBNGP are determined by the capital base and forecast capex/opex outlays for the given end year. In the 'working' version of the model, these costs are automatically determined in the 'Extended RAB for depreciation' spreadsheet for a given economic life of the DBNGP. We have not interrogated this model and we take these inputs as given.

Revenues for the DBNGP are calculated for the two periods discussed in Section 2.1. The DBNGP earns either a regulated or 'competitive' tariff for volumes transported, depending on whether the period in consideration is during the price regulated period or not, and whether gas is cheaper or more expensive than alternatives.

2.2.1 Two metrics for an appropriate 'economic life' were considered

We understand that DBP originally proposed determining an economic life for the DBNGP by evaluating at which end year the NPV of forecast costs and revenues earned by the pipeline approached zero. Using an end year before this year would lead to revenue earned above efficient costs for the pipeline (surplus). Using an end year after this year would lead to revenue earned below the efficient costs for the pipeline (deficit).

The ERA considered that the 'economic life' has meaning under the NGR 89 and is determined by the last year the pipeline is expected to be used. In the ACIL WOOPS Model, this is the last year the pipeline is able earn revenue, regulated or competitive. This interpretation leads to longer economic lives than the DBP's interpretation, and is likely to lead to a deficit under the DBP's approach. In Section 1.3.3 (p8) of Attachment 9.7, DBP notes:

> *This leads to a small under-recovery of our efficiently incurred capital base (around $125 million) which we believe is an acceptable risk given the time remaining to improve the model and the uncertainty which exists about the future. We note that this acceptance is contingent upon broad agreement with the future scenario we set out in attachment 9.2 of the Final Plan as being most credible (that is, the one that led us to 2059). Significant differences on that point would represent an unacceptable risk of under-recovery to us.*

2.2.2 The model makes a number of important methodological decisions

Using the key inputs outlined in Section 2.2, the model evaluates an NPV of costs and revenues for a given end year (i.e. economic life). A more detailed description of the how the model combines these key inputs is as follows:

- Calculate chargeable quantities for different end uses of the pipeline. Chargeable quantities for each customer are calculated based on the length of pipeline used, and a weighted combination of contracted capacity and throughput.
  - The weightings applied to contracted capacity and throughput are based on an assumed tariff allocation. For example, if 90% of the tariff allocation is to a fixed charge, the contracted capacity is given a 90% weight.
  - These chargeable quantities are aggregated into two categories:

    - consumption that could be displaced by renewables and storage, including gas currently consumed by GPG
    - consumption that could be displaced by hydrogen, including gas currently consumed by industrial processes and all other uses.

- Calculate the gas-equivalent costs of hydrogen (relevant to industrial customers) and renewables/storage (relevant to GPG)
  - The hydrogen equivalent price is a function of a starting price (production, transport and storage) and a learning rate.
  - The renewable and storage equivalent price is a function of a starting price, learning rate and a heat rate.
    - The starting price and learning rate are determined by ACIL Allen Consulting's wholesale market modelling. The learning rate included in the ACIL WOOPS Model is a combination of underlying technology learning rates as well as the mix of technologies that form the modelled least cost mix of options (wind, solar and batteries) in the wholesale market modelling.
    - The heat rate is used to compare the levelised cost of renewables and storage to the short-run marginal cost of GPG. The heat rate is used to convert the levelised cost of renewables and storage into a gas price at which GPG could effectively compete.
- Calculate the regulated transport price based on the selected end year and calculated chargeable quantities. In the 'working' version of the model, this step is automated predominantly by the associated 'Extended RAB for Depreciation' spreadsheet.
- Calculate a gas price each year which includes a carbon price relevant to the scenario.
- Subtract the gas price (inclusive of carbon) in each year from the hydrogen/renewables equivalent prices. Combine these prices into a single 'alternative' price by weighting the gas-exclusive prices by the calculated chargeable quantity forecasts.
  - This price is intended to represent the maximum price the DBNGP could charge for gas transport, assuming customers are willing to pay.
  - This price is given a floor of zero.
- Evaluate the revenues of the DBNGP based on the relevant period and competitiveness of gas as outlined in Section 2.1.
  - When the weighted, gas and carbon exclusive price is above the regulated price in the price-regulated period, gas is a cheaper alternative and so gas flows continue unchanged and DBNGP makes the regulated tariff on this volume.
  - When the weighted, gas and carbon exclusive price is below the regulated price in the price-regulated period, gas is a more expensive alternative and transport prices are discounted so that the DBNGP still transports gas. The DBNGP earns the weighted, gas and carbon exclusive price.
  - When the price-regulated period ends, the DBNGP earns the weighted, gas and carbon exclusive price. As noted, DBP note that high revenues during this period should be interpreted with caution[6].

[6] DBP, *Assessment of the Economic Life of the DBNGP*, Attachment 9.2, p32

- Calculate the NPV of revenue and NPV of costs, and the difference between these values (i.e. check whether there is a deficit or surplus).

This process calculates NPV outcomes for a given end year. Determining an appropriate economic life from the model depends on the definition of economic life.

For AGIG's original definition of economic life (comparing NPV of costs and revenues), calculating an appropriate economic life is an iterative process. The model is run multiple times with different end years until the end year with the smallest positive NPV of net benefits is found.

For the ERA's definition of economic life (last year the pipeline is used), the end year can be determined from the initial result, by checking when the maximum achievable price that can be charged for transport falls to zero.

2.3 The model does not consider detailed switching decisions, detailed transport costs, electrification, and hydrogen blending

2.3.1 The model does not consider detailed switching decisions

The ACIL WOOPS Model considers the switching decisions of gas users to renewables and storage or hydrogen at a high level by comparing the price of alternative fuels. In reality, the switching decision faced by these gas users will be complex. For example, the decision to switch from natural gas to hydrogen for industrial processes will likely require changes in equipment to handle the different properties of hydrogen and natural gas. The age of existing equipment is likely to influence the decision to switch, as switching to hydrogen may bring forward capital investment otherwise not required for several decades. In this case, rather than simply comparing the price of alternative fuels, businesses will also consider the implications for capital expenditure of a decision to switch.

We note also that switching decisions may not be driven purely by the objective of achieving lowest cost. For instance, businesses may switch even if is more costly in order to achieve their own emissions reductions targets or may switch in order to sell their output as green products at a higher price than they would otherwise achieve.

Despite these complexities to real-world switching decisions. we consider it reasonable to assess the switching decisions of natural gas users at a high level in this type of model. The circumstances surrounding switching are specific to individual gas users and not practical to model. There are likely to be circumstances for individual businesses that can both delay and bring forward switching decisions. Therefore, it is difficult to assess the impact of this simplification on the modelled economic life of the DBNGP.

2.3.2 The model does not consider detailed transport costs

The ACIL WOOPS Model derives comparable prices for natural gas, renewables and storage, and hydrogen to determine switching decisions. Part of converting these prices into comparable forms is including the cost of transport for electricity generated by renewables and storage and for the production of hydrogen, as the prices are used to determine how much could be charged for natural gas transport over the DBNGP. In our view there are some issues with this:

- The initial hydrogen price includes two components, a price for production and a price for transport and storage. According to the source of these assumptions, transport in this instance includes the cost of trucking hydrogen from where it is produced to where it is consumed. Essentially, because the model deals with production and transmission costs, but not distribution costs, when determining switching the model implicitly assumes that the cost of distributing hydrogen and natural gas (i.e. building/operating reticulated natural gas/hydrogen networks) is the same.
- It is not clear whether the initial cost of renewables and storage includes transport from the point of generation to the nearest bulk supply point. As the model compares the cost of renewables and storage to existing gas generation, this transmission cost should be included.

2.3.3 The model does not consider electrification of industrial loads

The ACIL WOOPS Model assumes that gas-powered generation will be replaced with renewables and storage, and that industrial loads will replace natural gas used as a feedstock or energy source will be replaced with hydrogen.

This does not represent all possible outcomes. Gas-powered generation may replace burning natural gas with burning hydrogen, and industrial loads may choose to electrify instead of switch from natural gas to hydrogen where possible. Different industrial loads will have different abilities to electrify. For example, industrial natural gas consumers that use gas as a feedstock will not be able to simply use electricity in place of natural gas. However, industrial natural gas consumers that use gas for industrial heating applications may be able to invest in new equipment that uses electricity in place of natural gas.

In scenarios where the cost of renewables and storage falls below the equivalent price of natural gas, and the cost of hydrogen does not fall below the cost of natural gas for some time, electrification may be an attractive option for some industrial customers. However, the scope for and costs of electrification for many industrial customers is uncertain, and will also be subject to involved switching decisions as discussed in Section 2.3.1.

2.3.4 The model does not consider hydrogen blending

We understand there are a number of distribution and transmission pipeline owners investigating options around blending hydrogen and natural gas in their pipelines. The economics of blending depends on the relative cost of natural gas and hydrogen, which is also what determines the economics of switching from natural gas to hydrogen. For that reason, we would not expect blending natural gas and hydrogen to be a long-term outcome: if blending is economic because hydrogen is cheaper than natural gas then, in the long-term, we would expect complete switching from natural gas to hydrogen because hydrogen is cheaper than natural gas.

We also note that blending hydrogen and natural gas on the DBNGP may bring forward a reduction in volumes of natural gas consumed, but it is unlikely to materially change volumes flowing on the pipeline and hence tariffs[7], and is unlikely to change the eventual date at which natural gas is no longer used and hence the DBNGP is no longer useful.

For these reasons, we consider the omission of hydrogen blending considerations reasonable.

[7] While the regulatory scheme currently applies to natural gas, regulatory changes could allow higher levels of green hydrogen in the future

3 Review of the ACIL WOOPS Model

This section provides our review of the ACIL WOOPS Model, its key drivers and potential issues with the methodology or the implementation of the methodology.

3.1 Key drivers of results of the WOOPS Model

The most significant key driver of results in the ACIL WOOPS Model is the point at which the full regulated return on the pipeline can no longer be earned. It is around this point at which the economic life is likely to end, because once the pipeline is unable to earn regulated revenue, only small falls in costs of alternatives are required to inhibit the ability of the pipeline to earn any revenue at all. In the model, this point occurs when the weighted combined alternative price falls below the regulated price.

The components of the weighted combined alternative price are the renewables and storage alternative price and the hydrogen alternative price. Because industrial and other users account for the largest share of current gas consumption, the hydrogen price (relevant alternative) carries the most weight (around two thirds) in this combined price. Therefore, from an alternative price perspective, the model is most sensitive to the starting hydrogen price and the changes in the hydrogen price over time (i.e. hydrogen learning).

This is illustrated graphically in **Figure 2**, which presents a chart of the base case. The regulated price is in black, the transport price at which renewables and storage is cheaper than gas is in green, the transport price at which hydrogen is cheaper than gas is in yellow, and the weighted combined transport price at which these weighted alternatives are cheaper is in blue. The base case includes the economic life of the pipeline ending in 2059 (according to the original AGIG definition, or 2063 according to the ERA definition), shortly after the combined alternative price falls below the regulated price in 2056.

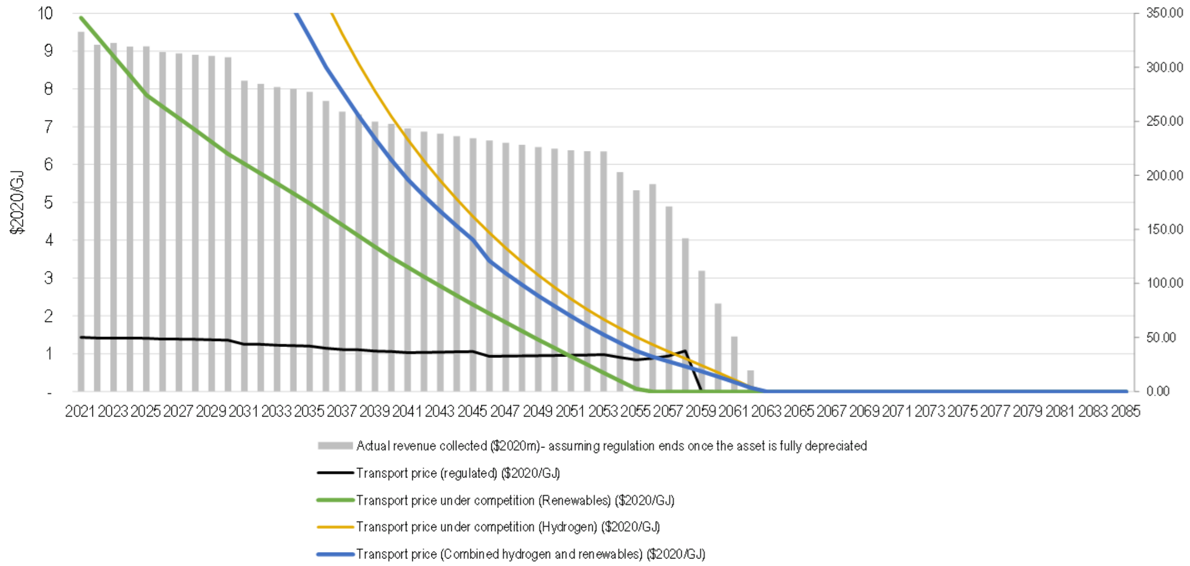
Other key drivers are the price of renewable and storage alternatives to natural gas, the gas price, and the carbon price.

The price of renewables and storage is included in the combined transport price at a weight of about one third. Changing the starting price or learning rate of the renewable and storage alternative will have a lesser impact on the crossover point to changing the hydrogen alternative, given its lower weighted in the combined price.[8]

The model is also sensitive to the gas price and the carbon price because this is what the prices of alternatives are compared to. A lower gas price will make alternatives less attractive and push out the point at which a full regulated return on the pipeline can no longer be earned.

8 However, this is not always the case as discussed in Section 3.2.

Figure 2: Outcomes in the Base Case



Because the key driver of results in the ACIL WOOPS Model is the crossover point, it is assumptions about alternative prices and the price of gas well into the future which drive outcomes. Assumptions around short term movements are only relevant to the extent that they affect subsequent long term outcomes.

3.2 Potential issues with the model

Our review has identified two potential issues with the methodology adopted in the ACIL WOOPS Model. These are:

- the approach to weighting alternative prices
- potential issues around internal consistency within the model.

Our review also identified a number of minor issues. These are discussed in the following sub-sections.

3.2.1 The weighted alternative price doesn't have a basis in reality

As noted in Section 2.2.2, the ACIL WOOPS Model derives a weighted natural gas 'alternative' price to evaluate the ability of the DBNGP to charge a regulated or competitive price for natural gas transport. This weighted alternative price is calculated as the chargeable quantity-weighted price of relevant alternatives. For example, if GPG accounts for 30% of total chargeable quantities, the renewable and storage cost (relevant alternative) will be given a 30% weighting in the combined alternative price. In this example, the price of the hydrogen alternative (relevant alternative for the rest of the load) will be given the 70% weighting.

Using a weighted alternative price assumes that switching from natural gas to hydrogen and renewables happens at the same time for each use case. As illustrated in **Figure 2**, representing the base case, switching points for underlying use cases (green and yellow lines) do not happen at the same point in time. In this instance, switching from GPG to renewables would occur around 2051 and switching for hydrogen would occur in 2059. In the combined case, switching occurs around 2056.

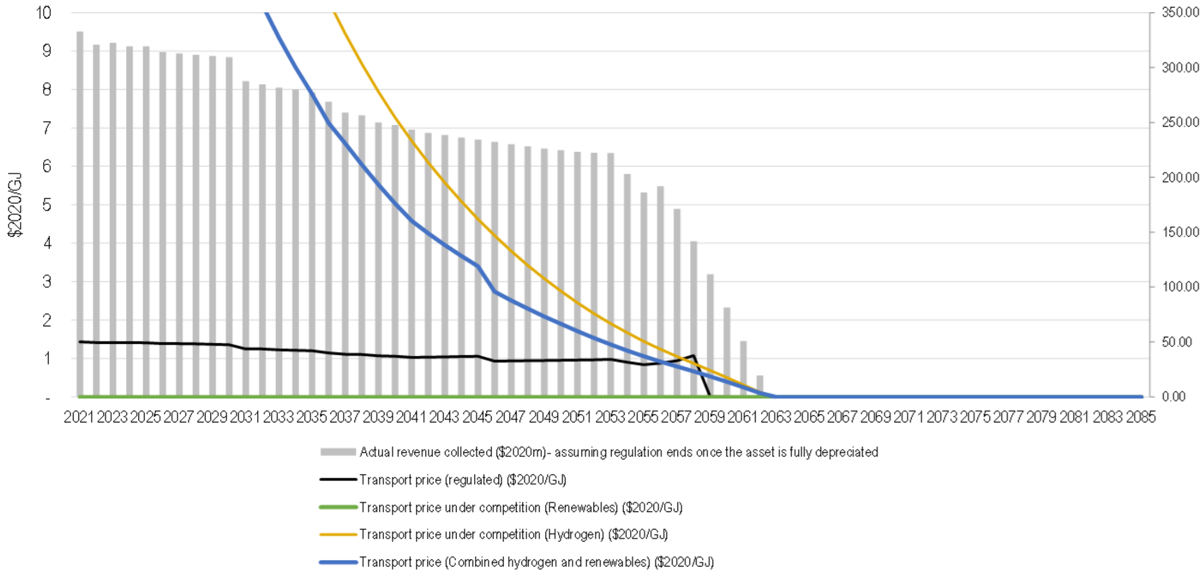
If the alternative price trajectories illustrated in **Figure 2** are correct, we would expect actual outcomes to diverge from modelled outcomes:

- At the point where the renewables line falls below the regulated line, at around 2051, we would expect the DBNGP to begin discounting transport for GPG end users to remain competitive, or lose the volume. At the point at which the renewables line hits its floor of zero, around 2056, we would expect volumes associated with GPG to stop flowing on the DBNGP as GPG can no longer compete with new build renewable alternatives. The loss of volume associated with the loss of GPG load would cause an increase in the transport price, decreasing the competitiveness of natural gas relative to hydrogen.
- At the point where the hydrogen line falls below the regulated line, we would expect the DBNGP to discount transport for industrial end users to remain competitive, or lose the volume. At the point where the hydrogen line hits its floor of zero, around 2063, we would expect natural gas volumes associated with industrial and other users to stop flowing over the DBNGP.

What happens in the model is that full volumes remain on the pipeline to 2063, priced at the lower of the regulated tariff (during the regulated period) and the combined alternative price. Despite renewables and storage being a cheaper alternative to GPG after 2055, gas still flows on the pipeline for GPG because the relevant price is the weighted price, not the GPG alternative (renewable and storage) price. Furthermore, the weighted alternative price comprises individual alternative prices that are floored at zero. The impact of the renewable and storage alternative price decreases in significance on an increasing basis from when it becomes zero because of this floor.

The methodological decision to weight these alternative prices leads to unusual behaviour in the model. For example, decreases in the renewable and storage alternative price or increases in the learning rate (i.e. faster price decreases) do not change the results of the model with base case assumptions. That is, if the price of renewables and storage is set to effectively zero from model start, the result produced by the model – including volumes, NPV of costs and benefits, and economic lifetime of the pipeline – doesn't change. This outcome is illustrated in **Figure 3**.

Figure 3: Outcomes in the Base Case with a very low renewable alternative price



This result arises because by the time at which the combined line crosses over the regulated line, the renewable and storage alternative line is already zero, as seen in **Figure 2**. Reducing the renewable and storage alternative price before this will not affect the crossover point of the combined line, because it is floored at zero, and hence cannot reduce the combined price so that it crosses over earlier.

For this reason, we consider that scenarios where the crossover point of individual alternative lines occur at different times should be interpreted with caution. It is not clear what the significance of the combined price is, other than possibly to adhere to the conceptual model.

3.2.2 The model is not internally consistent in several areas

There are several distinct inputs into the ACIL WOOPS Model that are indirectly related. The combinations of inputs that are included in scenarios or otherwise modelled should be consistent in their direct and indirect relationships. Two areas in the model are of potential concern:

- the GPG gas volumes are derived from electricity market modelling that implies different outcomes for GPG than the electricity market modelling used to determine the renewables and storage costs
- the electricity prices assumed in projecting hydrogen prices are different to the electricity prices used to compare electricity and natural gas prices.

Each of these is discussed further in the remainder of this section.

ACIL Allen Consulting models wholesale market outcomes to 2040 and extrapolates from 2040 to 2085 to derive transport volumes over the DBNGP to 2085. This is noted on pp9-10 of the ACIL Economic Depreciation report:

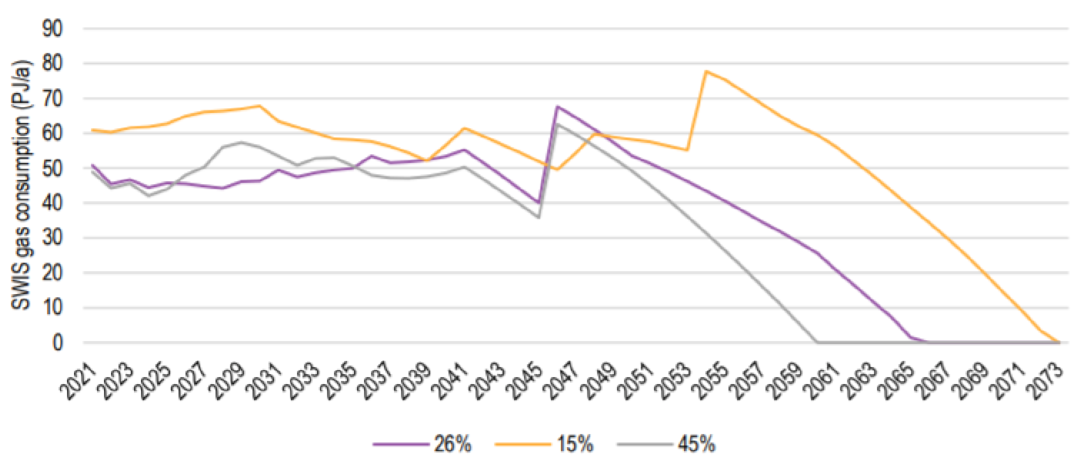
Undertaking detailed modelling over the full modelling horizon was not considered sensible, as uncertainty with respect to input assumptions in later years imputes limited accuracy to the results. Detailed modelling with PowerMark WA was undertaken to 2040 for each case. Beyond 2040, projected gas for power generation was based on extrapolation of the modelling results to meet the longer-term emissions targets while considering the lumpiness of closures of coal and gas fired power stations.

The resulting annual gas for power generation curves in the SWIS for each scenario is shown in Figure 3.4. In broad terms the higher the EIS permit price, the faster that gas for power generation declines. However, the curves are not smooth as growth in demand and the closure of coal-fired power stations at intervals across the period studied lead to short-term increases in gas usage. In the Base case, gas for power generation declines to zero in 2066. In the High case it declines to zero by 2060 and in the Low case by 2073. In the High case, gas consumed in power generation from 2020 until it declines to zero is around 12 per cent less than in the Base case. In the Low case, gas consumed in power generation from 2020 until it declines to zero is around 42 per cent more than in the Base case.

Figure 3.4 referenced in the quote above is reproduced in **Figure 4** below.

Figure 4: Gas used by GPG

FIGURE 3.4 ANNUAL GAS FOR POWER GENERATION FOR EACH SCENARIO - SWIS



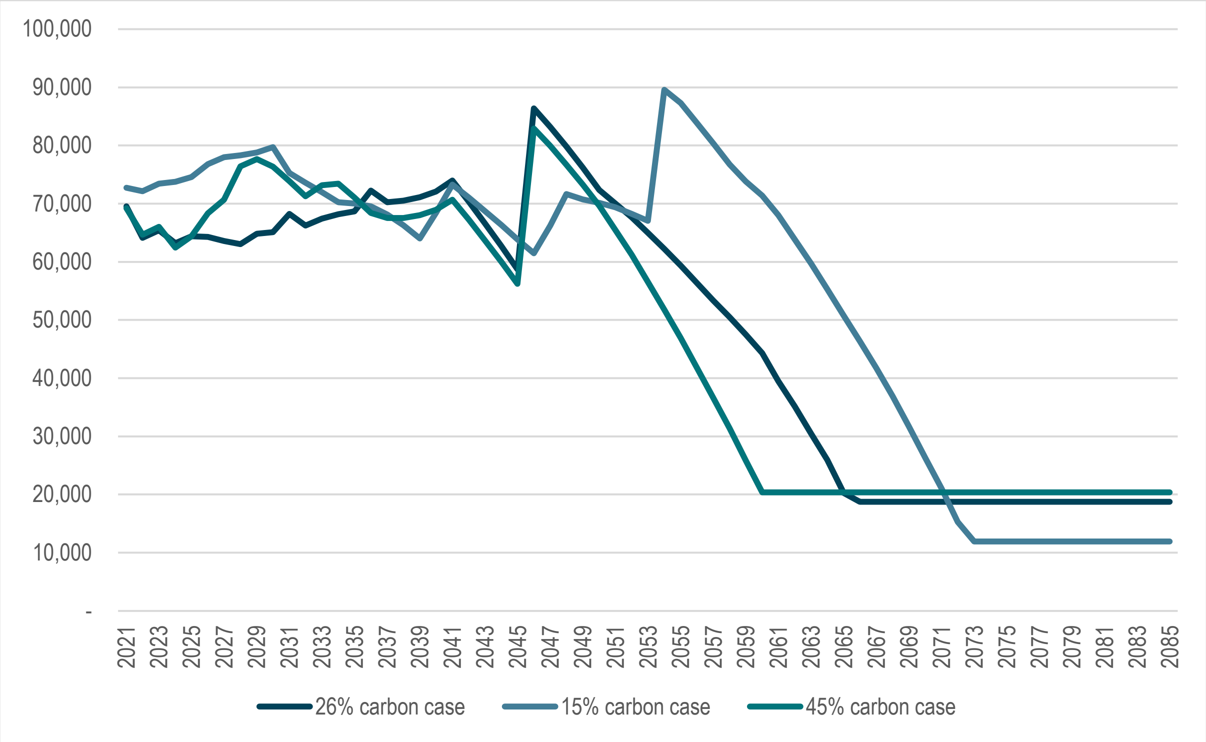
SOURCE: ACIL ALLEN

In a separate exercise, ACIL Allen Consulting models the cost of meeting forecast SWIS demand with a combination of wind, solar PV, and batteries to derive the price at which GPG is no longer competitive with alternative forms of generation.

We consider that the inputs that are included in each of these modelling exercises should be the same. However, the results produced by each set of modelling imply significantly different times at which gas consumption for GPG ceases, suggesting this may not be the case. The renewable alternative modelling suggests that the cost of building and operating a combination of solar PV, wind and storage is cheaper than the cost of burning gas in existing gas-fired power stations by 2056 in the base case with a 26% carbon price (as illustrated in **Figure 2**). However, in the wholesale market modelling to derive gas consumption for GPG, GPG in the base case with a 26% carbon price continues to consume gas to around 2066, around a decade later. If new-build renewables and storage are cheaper than the short-run marginal cost of running existing gas, there should be no reason to continue running GPG out past 2056.

Furthermore, when the reductions in gas volumes in **Figure 4** are incorporated into the ACIL WOOPS Model, annual differences in the modelled outcomes are subtracted from existing contracted capacities and throughputs. As the starting consumption of the ACIL Allen Consulting wholesale market modelling is lower than the existing contracted capacities and throughputs, chargeable quantities never fall to zero in the ACIL WOOPS Model.

Figure 5: Chargeable quantities for GPG



Source: Calculated chargeable quantities from ACIL WOOPS Model, Gas Volumes tab

A second internal consistency issue relates to the price of hydrogen and the price of renewables and storage that are input into the model. This issue is discussed in detail in Section 7.2.1.

3.2.3 Other issues

There are two other issues we have identified with the ACIL WOOPS Model that relate to the way that the cost of electricity from renewables and storage is compared to the cost of gas for GPG. In principle, this comparison is intended to determine the price of gas for GPG at which the electricity generated from GPG will be more expensive that electricity from renewables and storage. However, there are two issues with the way that this comparison is undertaken in the ACIL WOOPS Model:

- When converting the price of electricity from renewables and storage into a gas-equivalent price, the price of electricity should be adjusted for both the heat rate of a gas-fired generation and the variable operating maintenance cost of a gas-fired generator. The ACIL WOOPS Model adjusts only for the heat rate.
- When converting the price of electricity from renewables and storage into a gas-equivalent price our view is that it would be appropriate to account for the fixed capital and operating costs of GPG (just as fixed capital and operating costs are accounted for in determining the cost of electricity from renewables and storage. There is an argument for excluding the fixed capital and operating costs of GPG from the comparison: for all existing, fixed capital and operating costs are sunk and therefore irrelevant to economic decisions. However, given that the comparison of relative costs is a long-term comparison, and the most relevant period is the 2050s and 2060s, our view is that existing GPG will have reached the end of its life. In this case, the relevant question is whether new build GPG can compete with new build renewables and storage.

4 Key assumption 1: contracted capacity and throughput

This section sets out our assessment of the projections of contracted capacity and throughput that are used in assessing the economic life of the DBNGP.

- First, we describe how projections of contracted capacity and throughput are developed by ACIL Allen Consulting (Section 4.1)
- Second, we describe the relevance of the contracted capacity and throughput values in the model (Section 4.2)
- Finally, we assess the projections of contracted capacity and throughput (Section 4.3).

4.1 How projections of contracted capacity and throughput are developed

ACIL Allen Consulting project contracted capacity and throughput for natural gas customers who use the DBNGP. These customers are categorised into one of seven groups based on what the gas is used for. ACIL Allen Consulting was provided current and expected contracted capacities and throughput. It then assessed whether any changes to contracted capacities or throughput would be expected given a change in the price of gas by considering each sector in the context of the market(s) in which it sells output. In short, it found that only gas-powered generation is likely to change contracted capacity or throughput in the presence of changes to gas prices considered in the study.

In all of the industrial sectors, apart from the gas for power generation sector, the Western Australian producers are either so low on the cost curve, or gas is such a small portion of total costs, that the range of increases in gas prices considered in the study are unlikely to lead to a reduction in gas demand; i.e., these producers are assumed to be viable while paying higher gas prices.

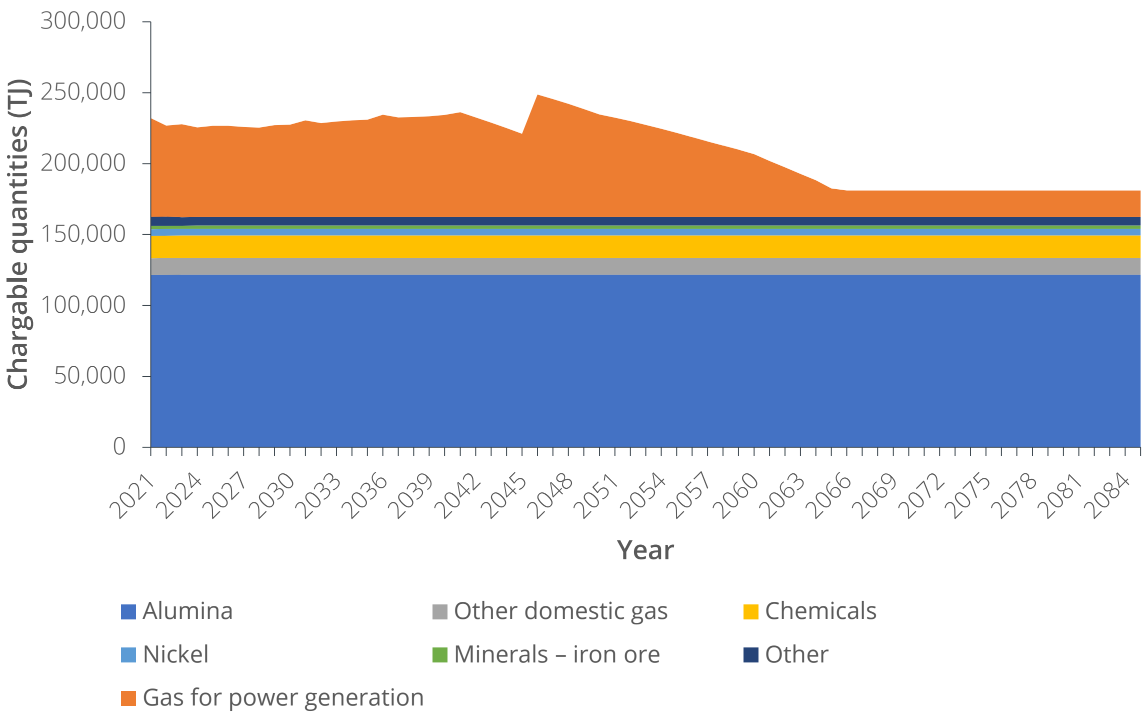
For this reason, ACIL Allen Consulting modelled changes to contracted capacity and throughput for gas-powered generation in its wholesale electricity market model *PowerMark.*

4.2 The relevance of contracted capacity and throughput in the ACIL WOOPS Model

In the ACIL WOOPS Model, contracted capacity and throughput volumes are combined into 'chargeable quantities' based on the proportions of the capacity (90.05%) and throughput (9.95%)

tariff components. The result of weighting these projections for the Base Case is presented in **Figure 6**.

Figure 6: Projection of chargeable quantities, Base Case



Source: Calculated chargeable quantities from ACIL WOOPS Model, Gas Volumes tab

As noted, the only category of consumption to vary significantly is the 'Gas for power generation' category. This is the only category of consumption that changes per scenario, as a result of different carbon prices applied.

This projection of chargeable quantities is used in the ACIL WOOPS Model to represent flows over the DBNGP until the combined hydrogen and renewables and storage alternative price falls below the cost of delivered gas, at which point it is assumed to cease. That is, this entire load as presented (for the Base Case) is either 'on', when delivered gas is competitive with hydrogen or renewables and storage, or 'off', when delivered gas is more expensive.

This projection determines the regulated tariff the DBNGP is able to charge, which contributes to the delivered cost of gas to which alternative prices are compared. The tariff is calculated as the allowed revenue for a given year divided by the chargeable quantities as projected above. Consequently, if projections of chargeable quantities fall over time, the tariff required for the DBNGP to recover its allowed revenue must increase, all else equal.

4.3 Assessment of projections of contracted capacity and throughput

We consider ACIL Allen Consulting's approach to projecting potential contracted capacity and throughput reasonable. That is:

- We consider it reasonable to project forward historical contracted capacity and throughput for customers in which reasonable changes to gas or carbon prices are assessed to be unlikely to alter consumption of natural gas. Alternatives, such as bottom-up modelling by sector or by customer, would be time consuming and complex.
- We consider it reasonable to model gas consumption for customers in which reasonable changes to gas or carbon prices are assessed to be likely to alter consumption of natural gas, as is the case for gas-powered generation.

However, in our view, there is an issue in the way that projections of contracted capacity and throughput are used within the model. In particular, the binary nature of the contracted load – that it is either 'on', when delivered gas is competitive with hydrogen or renewables and storage, or 'off', when delivered gas is more expensive – leads to outcomes in which natural gas customers still demand gas even when it is severely uneconomic for them. This is related to the issue regarding the 'combined' price outlined in 3.2.1.

In reality, switching away from natural gas is likely to occur customer by customer as individual circumstances dictate. As customers reduce their natural gas consumption, volumes on the DBNGP will fall, and tariffs constructed to recover a given regulated return will need to increase. In essence, there is a feedback loop where one customer's switching decision affects all others through the regulated tariff. This feedback loop is not captured in the treatment of the projected contracted capacity and throughput as the switch from gas to alternatives (both hydrogen and renewables and storage) happens simultaneously.

Based on ACIL Allen Consulting's assessment of each sector, this is unlikely to present a major problem: it finds that natural gas consumers in all sectors other than gas for power generation are not sensitive to changes in prices as considered in the modelling exercise. A loss of gas flows on the DBNGP relating to a total displacement of gas-powered generation in the SWIS will only increase tariffs in the order of $0.50/GJ, which is unlikely to promote switching in other sectors.

As noted in Section 2.3.3, the projections of contracted capacity and throughput do not consider the option for industrial customers to electrify as an alternative to switching natural gas for hydrogen. On the basis of ACIL Allen Consulting's assessment of each sector, electrification of some customers is unlikely to increase delivered gas prices materially enough to promote switching in other sectors.

5 Key assumption 2 – Gas price projections

This section sets out our assessment of the gas price projections that are used in assessing the economic life of the DBNGP.

- First, we describe how gas price projections are developed by ACIL Allen Consulting (Section 5.1).
- Second, we assess the reasonableness of the input assumptions used by ACIL Allen Consulting in developing the gas price projections used in the WOOPS model (Section 5.2).
- Third, we consider how the resulting gas price projections compare with historical and current gas prices in Western Australia (Section 5.3).
- Finally, we summarise our conclusions on gas price projections (Section 5.4).

5.1 How gas price projections are developed

5.1.1 Gas price projections are based on LNG net-back prices

ACIL Allen Consulting develop gas price projections by calculating an LNG net-back price for Western Australia.

Basing domestic gas price projections on a calculation of LNG net-back prices is a common approach to developing domestic gas price projections in Australia's export-exposed gas markets. However, it is not the only approach to developing domestic gas price projections.

The logic that domestic gas prices will be equal to the LNG net-back price is based on the assumption or assessment that the marginal source of gas supply to the domestic market will have an opportunity cost that is equal to the LNG net-back price. This would be the case if the next best option to supplying gas to the domestic market for this supplier would be to export the gas as LNG (which clearly depends on the supplier being able to access the infrastructure required to export LNG).

As we discuss in Section 5.3, historical and current prices suggest that domestic prices in Western Australia have been lower than LNG netback prices.

This is a point noted by gasTrading in its submission. gasTrading suggest the use of netback prices in particular is inappropriate given the Domestic Gas Reservation Policy which "partially decouples domestic gas from LNG netback pricing". For these reasons, gasTrading recommend that the ACIL model should test gas prices over "much broader range".

5.1.2 Calculating LNG net-back prices

ACIL Allen Consulting use a relatively standard approach to calculating LNG net-back prices, the steps of which are summarised in **Table 1**.

Table 1: Steps used by ACIL Allen Consulting to calculate the LNG net-back price

Step	Source	LNG net-back price in 2017
1. **Start** with the LNG price in Japan	IEA projections	$8.10, USD/mmbtu
2. **Convert** to Australian dollars using exchange rate	ACIL assumption	0.75 AUD/USD
3. **Convert** to $/GJ using energy content	-	1.055 GJ/mmbtu
4. **Deduct** liquefaction costs *	ACIL assumption	$4.00, AUD/GJ
5. **Deduct** transportation costs	ACIL assumption	$0.67, AUD/GJ
Results in LNG net-back price at LNG facility in Western Australia		**$5.60, AUD/GJ**

Source: ACIL Economic Depreciation report, page 14-15.

** ACIL Allen Consulting report gasification costs, but given they are calculating an LNG net-back price we assume they mean liquefaction costs to produce LNG in Western Australia rather than gasification costs to convert the LNG to gas in Japan.*

As demonstrated in **Table 1** the key inputs into this calculation are:

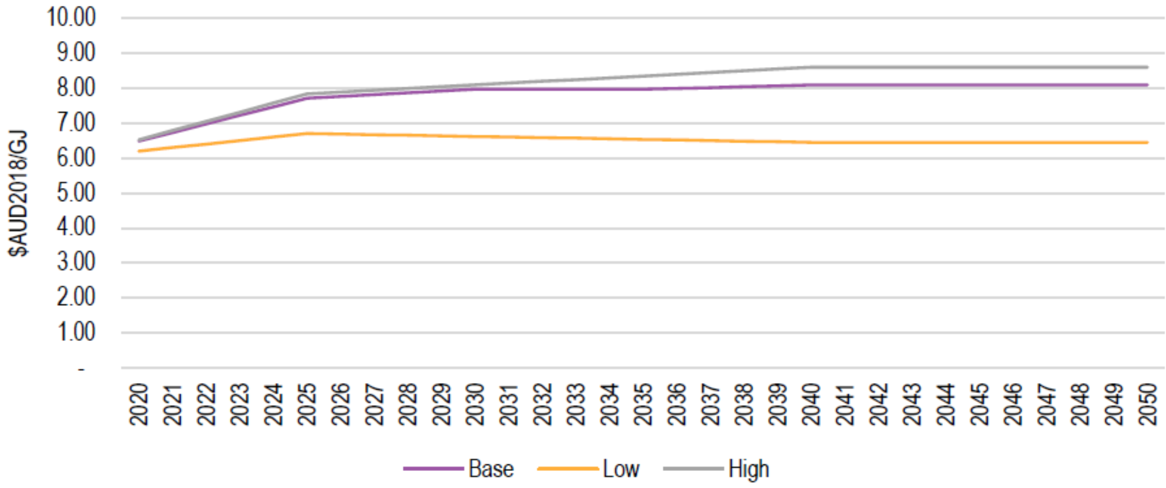
- the assumed LNG price in Japan
- the exchange rate
- shipping and liquefaction costs.

We discuss each of these inputs in the sections that follow.

Results of ACIL Allen Consulting's approach

The result of ACIL Allen Consulting's approach to projecting gas prices is shown in **Figure 7**.

Figure 7: ACIL Allen Consulting projections of gas prices



Source: ACIL Economic Depreciation report, Figure 3.9.

5.2 Assessing the inputs into gas price projections

5.2.1 Japan gas prices

ACIL Allen Consulting uses forecasts of the gas price in Japan as the starting point for its calculation of the LNG net-back price.

The forecasts of Japanese gas prices that ACIL Allen Consulting use are from the World Energy Outlook 2018 from the International Energy Agency (IEA), which are shown in **Figure 8**. The IEA makes clear that these Japanese gas prices are LNG import prices in Japan.

Figure 8: Japanese gas prices from IEA World Energy Outlook 2018

				New Policies				Current Policies		Sustainable Development	
Real terms ($2017)	2000	2010	2017	2025	2030	2035	2040	2025	2040	2025	2040
IEA crude oil ($/barrel)	39	88	52	88	96	105	112	101	137	74	64
Natural gas ($/MBtu)											
United States	6.0	4.9	3.0	3.3	3.8	4.3	4.9	3.4	5.3	3.3	3.6
European Union	3.9	8.4	5.8	7.8	8.2	8.6	9.0	7.9	9.4	7.5	7.7
China	3.6	7.5	6.5	9.2	9.4	9.5	9.8	9.3	10.2	8.3	8.5
Japan	6.6	12.3	8.1	9.8	10.0	10.0	10.1	9.9	10.5	9.0	8.8
Steam coal ($/tonne)											
United States	38	64	60	63	63	64	64	64	69	58	56
European Union	47	103	85	80	83	84	85	84	98	69	66
Japan	45	120	95	85	88	89	90	89	105	74	70
Coastal China	35	130	102	91	93	94	94	95	106	81	79

Source: IEA, World Energy Outlook 2018. page 602.

The IEA provides Japanese natural gas prices for three different scenarios: the New Policies scenario, the Current Policies scenario and the Sustainable Development scenario. ACIL Allen Consulting use the Japanese natural gas prices from these three scenarios in the three scenarios in their WOOPS model.

The IEA provides Japanese natural gas prices for a number of future years (2025, 2030, 2035 and 2040 for the New Policies scenario, and 2025 and 2040 for the other two scenarios). ACIL Allen Consulting create annual prices by linear interpolation between the IEA data points up to 2040, and an assumption of unchanged real prices beyond 2040.

Our view is that the Japanese gas price forecasts from the IEA's World Energy Outlook are one of a number of appropriate sources for LNG price forecasts in Japan. However, our view is that there are nevertheless some issues with the use of these gas price forecasts, which we outline in the following sections.

ACIL Allen Consulting reports incorrect prices, but appears to use the correct prices

The ACIL Economic Depreciation report sets out the Japanese gas prices that it uses (from the IEA's World Energy Outlook 2018) in Table 3.2, reproduced in **Figure 9**. The prices in Table 3.2 correspond with the prices from the IEA's World Energy Outlook 2018 for 2017, but thereafter diverge.

Figure 9: Japanese gas prices from the ACIL Economic Depreciation report

IEA Scenario	2017	2025	2030	2035	2040
New Policies	8.1	9.2	9.4	9.5	9.8
Current Policies	8.1	9.3			10.2
Sustainable Development	8.1	8.2			8.5
SOURCE: ACIL ALLEN					

Source: ACIL Economic Depreciation report, Table 3.2.

It appears that the China gas price from the IEA's World Energy Outlook 2018 have been transposed into Table 3.2 of the ACIL Economic Depreciation Study (Attachment 9.3) report in error (although these also do not match in every case).

However, as far as we can tell, ACIL Allen Consulting's calculation of the net-back price correctly use the Japanese gas price from the IEA's World Energy Outlook 2018.

ACIL Allen Consulting appears to treat prices in $2017 as prices in $2018

The Japanese gas prices reported in Table 3.2 of the ACIL Economic Depreciation report are stated to be in $2018. However, the equivalent prices from the IEA's World Energy Outlook 2018 are stated to be in $2017.

As far as we can tell, ACIL Allen Consulting's calculation of the netback price does incorrectly treat Japanese gas prices from the IEA's World Energy Outlook 2018 as though they are expressed in $2018. If this is the case, then the resulting net-back gas prices would be understated by a small amount. By our calculation the increase in the long-term net-back price would be around $0.25/GJ in Australian dollars (relative to ACIL Allen Consulting's long-term central case estimate of $8.10/GJ in Australian dollars).

Under the WOOPS model, a higher gas price would bring forward the crossover point between gas prices and the prices of competing energy sources.

There are more recent estimates of Japanese gas prices from the IEA than those that ACIL Allen Consulting has used

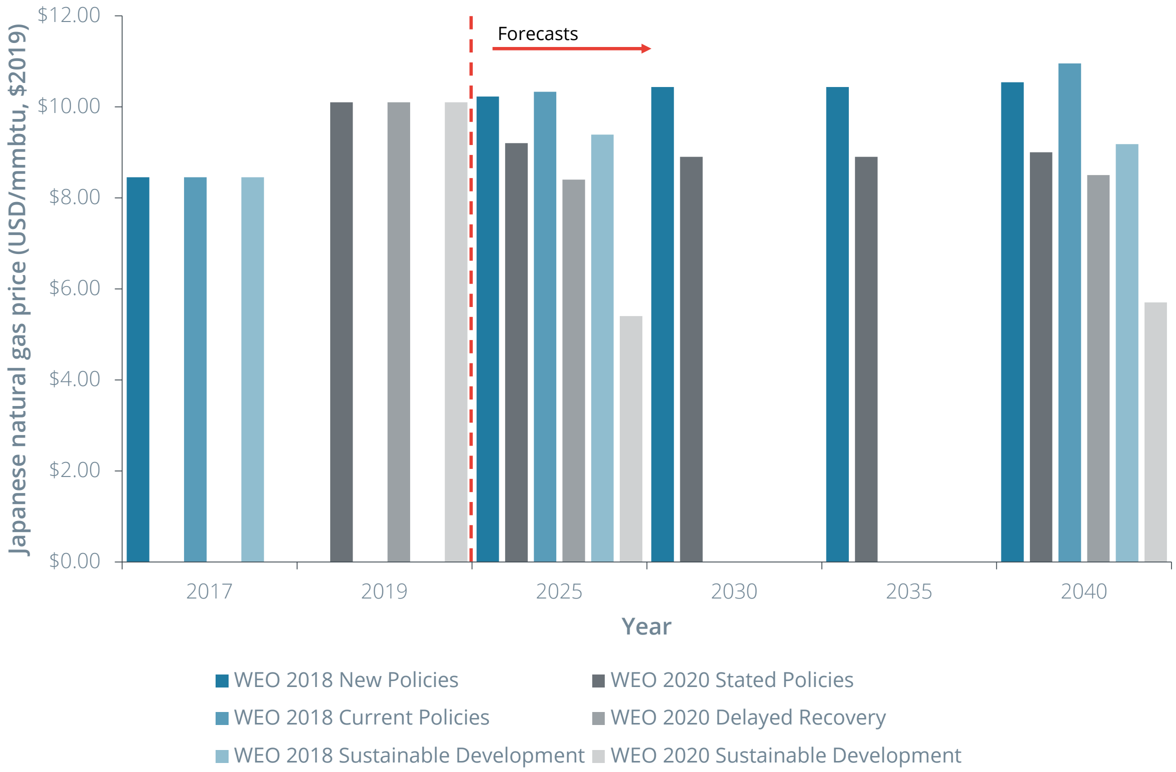
ACIL Allen Consulting rely on the 2018 edition of the IEA's World Energy Outlook, presumably because that was the current edition at the point ACIL Allen Consulting undertook their modelling. Since then, the IEA has also released the 2019 and 2020 editions of its World Energy Outlook, each of which publishes equivalent forecasts of Japanese gas prices.

The World Energy Outlook 2020 has forecasts of Japanese gas prices that are both materially lower and have a wider range than the equivalent forecasts from the World Energy Outlook 2018, as seen in **Figure 10**.

The effect of using the most recent forecasts of Japanese gas prices from the IEA to calculate net-back gas prices in Western Australia would be material. By our calculation, the difference in the long-term net-back price forecasts between the central forecasts from the World Energy Outlook 2018 and the World Energy Outlook 2020 would be around $2.40/GJ in Australia dollars (relative to ACIL Allen Consulting's long-term central case estimate of $8.10/GJ in Australian dollars).

Under the WOOPS model, a lower gas price would push back the crossover point between gas prices and the prices of competing energy sources.

Figure 10: Comparison of Japan gas price forecasts from IEA's WEO2018 and WEO2020



Source: Frontier Economics analysis of WEO 2018 and WEO 2020.

The range of gas price forecasts from the IEA's World Energy Outlook 2018 is quite narrow

The range of long-term forecasts of Japanese gas prices across the 3 scenarios presented in the IEA's World Energy Outlook 2018 is, in our view, quite narrow. In 2040, the forecast Japanese gas price varies between $8.80/mmbtu and $10.50/mmbtu, in 2017 US dollars. In our view, this range of Japanese gas prices does not reflect the range of uncertainty about long-term Japanese gas prices.

One way of thinking about the potential range of future Japanese gas prices is to consider the range of historical Japanese gas prices. The World Bank publishes historical data on annual LNG prices in Japan. This annual price data, from 1977 to 2020, is shown in **Figure 11** (the red line). When thinking about the potential range of long-term prices, our view is that considering the range across individual years is generally not appropriate since we rarely see either the highest or lowest annual prices consistently achieved. Instead, we have calculated the lowest average price over 20 successive years and the highest average price over 20 successive years on the basis that these successive average prices reflect relatively long-term outcomes. This range is from $5.80/mmbtu (the average price from 1986 to 2005) to $11.63/mmbtu (the average price from 2001 to 2020), in 2020 US dollars. This range is also shown in **Figure 11** (the blue lines), and compared with the range from the IEA's World Energy Outlook 2018 used by ACIL Allen Consulting.

Figure 11: Historical Japan LNG prices

Source: Frontier Economics analysis of WEO 2018 and World Bank data.

Some alternative forecasts provide a broader range of future LNG prices. For instance, the United States Energy Information Administration (EIA) has a range of delivered gas prices in Asia in which the high case is more than double the low case. However, AEMO's forecasts of natural gas prices in eastern Australia have a range in which the difference between the high case and the low case is only a little wider than the range in ACIL Allen Consulting's forecasts.

The narrow range of gas price projections used by ACIL Allen Consulting is a point made by gasTrading in its submission. gasTrading highlight an apparent inconsistency between the treatment of natural gas and hydrogen price. Namely, they suggest while natural gas pricing assumptions used are relatively conservative, "very aggressive reductions" in the hydrogen gas prices are proposed, and this results in hydrogen prices falling below gas prices. Therefore, they suggest that a "similar range of future energy prices" should apply to natural gas and note that with a renewable energy price in 2085 of $50/MWh in the 'High' model case, gas may still be competitive in the future at $5/GJ and an assumed heat rate of 10GJ/MWh.

5.2.2 Exchange rates

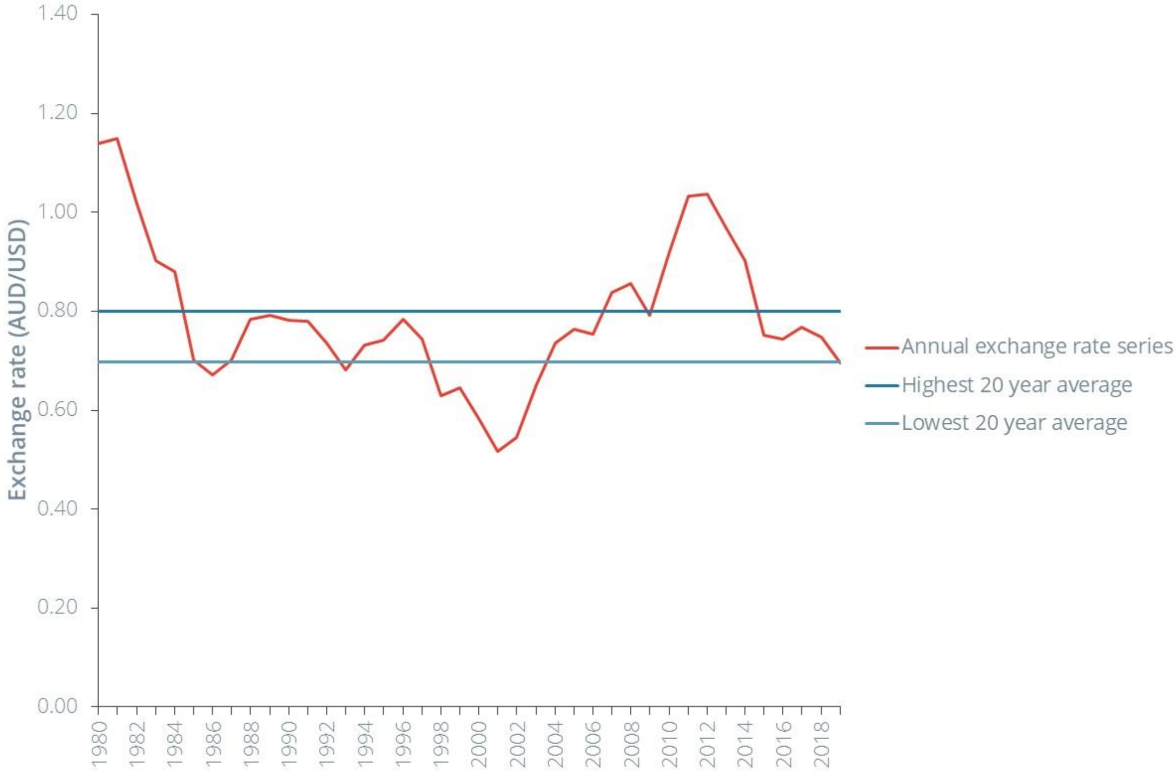
ACIL Allen Consulting assumes that the exchange rate over the forecast period will be constant at 0.75 AUD/USD, under all scenarios. ACIL Allen Consulting does not provide a source for this exchange rate assumption.

The exchange rate projection of 0.75 AUD/USD is quite similar to the most recent exchange rate projection from the International Monetary Fund (IMF) World Economic Outlook of 0.74 AUD/USD.

ACIL Allen Consulting does not use different exchange rates for their different scenarios for the net-back gas price. In our view, however, there is good reason to include different exchange rate assumptions in projecting net-back gas prices under different scenarios. As seen in **Figure 12**, the historical exchange rate has been variable. Even when looking at 20 year average exchange rates (applying a similar logic to when looking at historical Japanese gas prices) the range for the exchange rate is from 0.70 (the average exchange rate from 1986 to 2005) to 0.80 (the average price from 1980 to 1999). A relatively high average of 0.78 also occurred from 2000 to 2019. This range is also shown in **Figure 12** (the blue lines).

The effect of a higher AUD/USD exchange rate is to reduce the netback price in Australia. A higher exchange rate reduces the price in Australian dollars that Australian producers can obtain for selling LNG. A lower exchange rate increases the price in Australian dollars that Australian producers can obtain for selling LNG.

Figure 12: Historical exchange rates



Source: Frontier Economics analysis of IMF data.

5.2.3 Avoided shipping and liquefaction costs

ACIL Allen Consulting deducts an assumed amount of $4.00/GJ for liquefaction costs and an assumed amount of $0.67/GJ for transportation costs from Australia to Japan, under all scenarios. ACIL Allen Consulting does not provide sources for these amounts.

As part of its 2017-2025 Gas Inquiry, the ACCC calculates LNG netback price series for the east coast which includes a transportation component from Argus Media Ltd.[9] The $0.67/GJ for transport costs used by ACIL Allen is comparable to the average of reported forward shipping prices from the ACCC to January 28 2021 at $0.71/GJ.

The appropriate amount to deduct for liquefaction costs depends on whether:

- The marginal supplier of gas to the domestic market is assumed to export LNG from an existing LNG facility, for which the capital costs are already sunk and, therefore, should not be included in estimating opportunity cost. This is often referred to as a short-run net-back price.
- The marginal supplier of gas to the domestic market is assumed to export LNG from a new LNG facility, for which capital costs are not sunk and, therefore, should be included in estimating opportunity cost. This is often referred to as the long-run net-back price.

ACIL Allen Consulting does not clarify whether its estimate of net-back price is a short-run net-back price or a long-run net-back price. However, given ACIL Allen Consulting's estimate of

9 Available https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2025/lng-netback-price-series

liquefaction costs is $4.00/GJ, it seems clear that it is an estimate of a long-run netback price. For the purposes of comparison. the liquefaction costs that the ACCC uses in determining a short-run net-back price have recently averaged $0.50/GJ.

Information on the fixed costs of the liquefaction component of LNG facilities is not readily available. The fixed costs will depend on a number of factors, including whether the facilities are greenfield or brownfield. Given this uncertainty about the fixed costs of the liquefaction component of LNG facilities, our view is that it would be prudent to test a range of assumptions about these costs.

A high shipping cost will reduce the netback price in Australia, because transport costs are subtracted (netted back) from the price received at the destination. High liquefaction costs will reduce the netback price in Australia for the same reason.

5.3 Historical domestic gas prices in Western Australia

The final sense-check we can do for ACIL Allen Consulting's gas price assumptions is to compare the final net-back gas price in Western Australia from ACIL Allen Consulting with historical data on domestic gas prices.

The Western Australian Department of Mines, Industry Regulation and Safety (DMIRS) publishes annual data on domestic gas prices in Western Australia. The data published by DMIRS reflects the volume-weighted price of gas sales from producers into the domestic market and is heavily weighted by gas prices set under bilateral contracts.

The domestic gas prices published by DMIRS are compared with the net-back gas price in Western Australia from ACIL Allen Consulting in **Figure 13**.

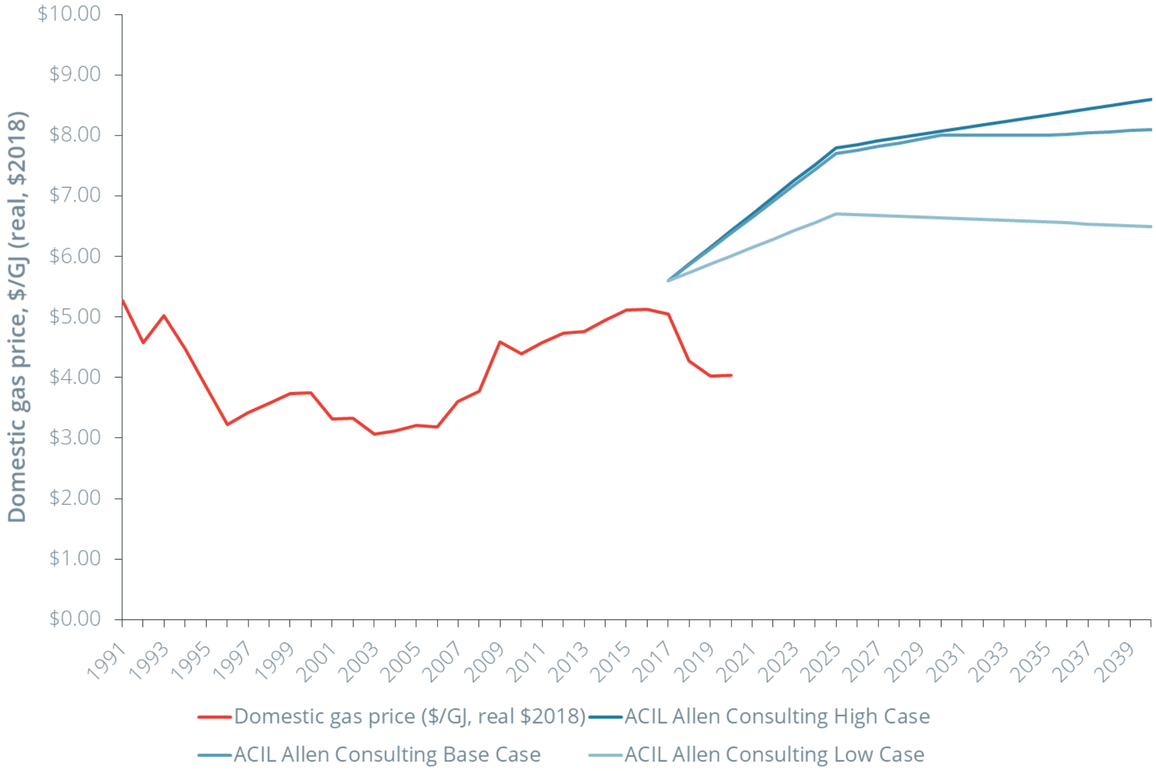
A number of things are clear from **Figure 13**:

- Since 2017 the trend in the historical gas price and the trend in the ACIL Allen Consulting's gas price forecasts have diverged – the DMIRS data shows a decline in domestic gas prices while ACIL Allen Consulting's forecasts are for an increase in gas prices.
- The gas prices forecast by ACIL Allen Consulting in each of their three scenarios are each materially higher than the highest annual historical gas price reported by DMIRS. The highest prolonged (20 year) period of historical prices was for the period 2001 to 2020, which had an average price of $4.11/GJ in 2018 Australian dollars. In contrast, the long-term gas price forecast from ACIL Allen Consulting is between $6.50/GJ and $8.60/GJ in 2018 Australian dollars.

Recent gas spot prices in the gasTrading platform in Western Australia have been even lower than the historical gas prices reported by DMIRS.

This was a point made by gasTrading in its submission, noting that they regard the level of gas prices used by ACIL Allen Consulting as inappropriate given the prices used reflect neither "historical or current gas prices in Western Australia" and lie "at least 20% above today's…long term contract prices".

Figure 13: Historical domestic gas prices and ACIL Allen Consulting's forecasts



Source: Frontier Economics analysis of data from DMIRS, ACIL Allen Consulting.

5.4 Conclusion on gas price projections

Based on our review we make the following recommendations regarding gas price assumptions:

- The projections of Japanese LNG prices used as an input should be updated to the latest projections from the IEA.
- These projections should be tested against historical outcomes for Japanese LNG outcomes to determine whether the three scenarios reasonably reflect the observed long-term trend and variability in Japanese LNG prices. Of course there may be good reasons that future patterns of Japanese LNG prices will differ from historical patterns of Japanese LNG prices; if so, these reasons should be explored.
- The projections of exchange rates and avoided liquefaction and transportation costs should be varied by scenario, rather than kept constant across the three scenarios.
- The resulting net-back gas price in Western Australia should be tested against historical domestic gas prices in Western Australia to determine whether the three scenarios reasonably capture the observed long-term trend and variability in domestic gas prices. As with LNG prices, there may be good reasons that future patterns of domestic gas prices will differ from historical patterns of domestic gas prices; if so, these reasons should be explored.

We have given effect to these recommendations to develop gas price forecasts for three scenarios that we consider reasonably represent the potential range for long-term gas prices in Western Australia.

The steps we have taken in developing the gas price forecasts for three scenarios are as follows:

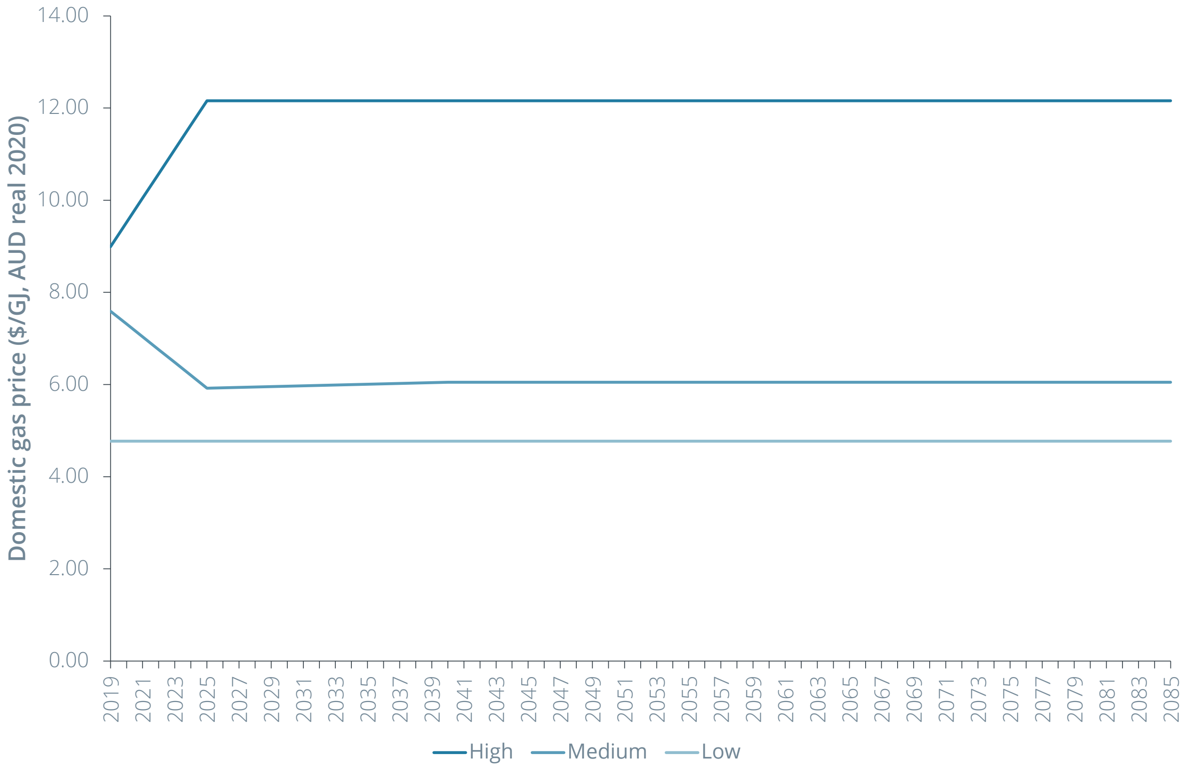
- Our starting point is the gas price forecasts from the IEA's World Energy Outlook 2020. The IEA's World Energy Outlook 2020 provides long-term forecasts of Japanese LNG prices under three scenarios. However, we note that the high scenario has long-term Japanese LNG prices that are materially below the highest 20-year average of historical Japanese LNG prices. Therefore, in our high scenario, we replace the high price forecast from the IEA's World Energy Outlook 2020 with the highest 20-year average of historical Japanese LNG prices.
- We convert Japanese LNG prices from USD to AUD using different exchange rates for each scenario. In our high scenario we use a low exchange rate of 0.70 (representing the lowest 20-year average of historical exchange rates, using data since 1980). In our medium scenario we use a medium exchange rate of 0.75 (consistent with that used by ACIL Allen Consulting). In our low scenario we use a high exchange rate of 0.80 (representing the highest 20-year average of historical exchange rates, using data since 1980). We use a low exchange rate in our high gas price scenario and a high exchange rate in our low gas price scenario because this leads to a wider spread between the high gas price scenario and the low gas price scenario. It is not clear to us that there will be a future long-term relationship between Japanese LNG prices and Australian dollar exchange rates that would imply we should use together a high Japanese LNG price forecast and a high Australia dollar exchange rate.
- We calculate net-back costs by deducting different amounts for avoided liquefaction and shipping costs for each scenario. In our medium scenario we use ACIL Allen Consulting's estimate of $4.67. In our high case we assume that this amount is 25% lower (resulting in a higher net-back price) and in our low case we assume that this amount is 25% higher (resulting in a lower net-back price).
- We then test the reasonableness of the resulting gas price forecasts. We note the following:
  - The resulting net-back price in the low scenario is very low in the long-term (close to $1/GJ). At this level the net-back price is below expected long-term gas production costs and, therefore, would not represent the opportunity cost of supplying gas to the domestic market. Rather, the opportunity cost would likely be long-term gas production costs. As a proxy for this we use the 10 year average historical domestic gas price in Western Australia (from DMIRS data). This 10 year average historical domestic gas price becomes the domestic gas price forecast in our low case.
  - The resulting net-back price in the high scenario is quite close to the net-back price forecast by AEMO in its high scenario for eastern Australia.

These key inputs are summarised in **Table 2** and the resulting forecasts are shown in **Figure 14**.

Table 2: Key inputs into gas price forecasts

Data point	Frontier Economics high scenario	Frontier Economics medium scenario	Frontier Economics low scenario
Japanese gas price forecast	Highest 20-year average of historical Japanese LNG prices	IEA World Energy Outlook 2020, medium case	IEA World Energy Outlook 2020, medium case
Exchange rate	Lowest 20-year average of historical exchange rates	ACIL Allen Consulting forecast	Highest 20-year average of historical exchange rates
Avoided liquefaction and shipping costs	ACIL Allen Consulting forecast, less 25%	ACIL Allen Consulting forecast	ACIL Allen Consulting forecast, plus 25%
Resulting domestic gas price forecast	**Net-back price calculated based on above**	**Net-back price calculated based on above**	**Estimate of long-term domestic production cost, which is higher than net-back price calculated based on above**

Figure 14: Frontier Economics gas price forecasts



Source: Frontier Economics

6 Key assumption 3 – carbon prices

This section sets out our assessment of the carbon price projections that are used in assessing the economic life of the DBNGP.

- First, we describe how the carbon price projections are developed by ACIL Allen Consulting (Section 6.1).
- Second, we assess the reasonableness of the input assumptions used by ACIL Allen Consulting in developing the carbon price projections used in the WOOPS model (Section 6.2).
- Finally, we summarise our conclusions on carbon price projections (Section 6.3).

6.1 How carbon price projections are developed

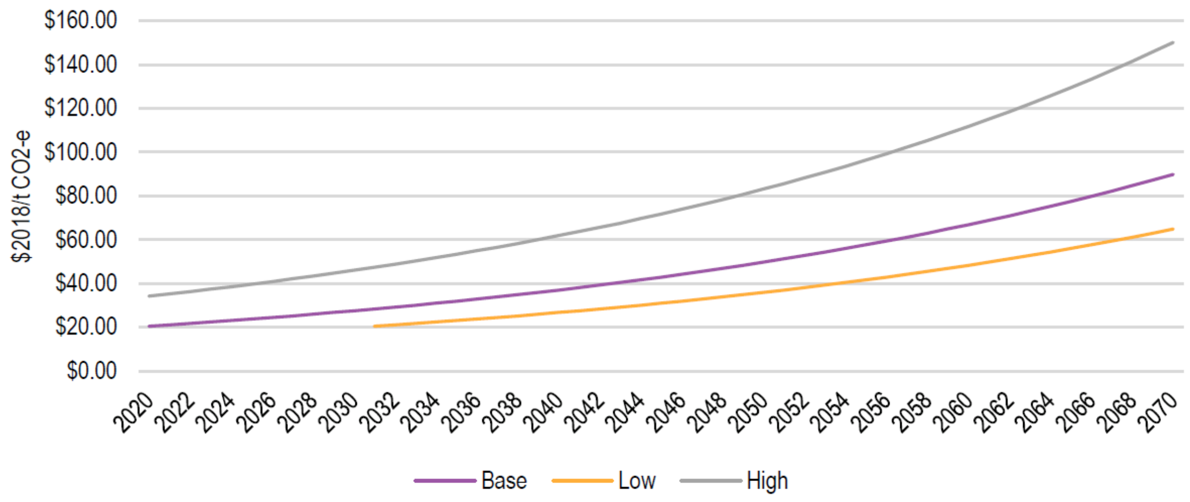
ACIL Allen Consulting develop carbon price assumptions by implementing an emissions reduction policy in its electricity market model for Western Australia and determining a carbon price to meet the target policy. Three scenarios were developed to reflect three different emissions policies:

- A base case assuming 26 per cent emissions reduction by 2030, 80 per cent emissions reduction by 2050 and net zero emissions by 2070
- A high case assuming 45 per cent emissions reduction by 2030 and net zero emissions by 2060
- A low case assuming no further action by 2030 and net zero emissions by 2080

Results of ACIL Allen Consulting's approach

The result of ACIL Allen Consulting's approach to projecting carbon prices is shown in **Figure 15**.

Figure 15: ACIL Allen Consulting projections of carbon prices



Source: ACIL Economic Depreciation report, Figure 3.3.

The carbon prices are used to determine a carbon-inclusive gas price, making use of the projected carbon price and an estimate of the emissions intensity of gas that is consistent with the emissions intensity of gas from the National Greenhouse Account Factors.

6.2 Assessing the inputs into gas price projections

ACIL Allen Consulting provided essentially no information on the basis on which carbon prices have been projected.

This leaves us to assess the carbon price projections only by comparing the projections to other sources of data.

In this regard we note that ACIL Allen Consulting's projections of carbon price being at around the price at which Australia Carbon Credit Units have been priced in recent years. We also note that the range of carbon price forecasts from ACIL Allen Consulting is broadly consistent with the carbon price forecasts from the IEA's World Energy Outlook.

Given the substantial uncertainty about the future price of carbon we consider that the broad range of carbon price assumptions between ACIL Allen Consulting's three scenarios is justified.

6.3 Conclusions on carbon price projections

As discussed, the extent to which we have been able to review the methodology and assumptions used by ACIL Allen Consulting to develop carbon price projections has been extremely limited.

Nevertheless, based on the review we have been able to undertake, and recognising the uncertainty associated with future carbon prices, we consider that the carbon price projections are reasonable and the scenarios provide a reasonable range for the carbon price.

However, there are two methodological points that we make:

1. ACIL Allen Consulting have not modelled a scenario that includes net zero emissions by 2050. Net zero emissions is increasingly adopted globally by governments and businesses, either as a target or an aspiration. The adoption of net zero emissions by 2050 has become more common since ACIL Allen Consulting's report. Given this, we consider that a carbon price based on net zero emissions by 2050 would be a reasonable scenario to investigate.
2. The ACIL WOOPS model undertakes a comparison of gas prices with prices of alternative fuels and, given this, carbon must be accounted for by including an implied price on carbon. However, this approach means that the model is subject to estimation error in determining the carbon price that would occur under each policy scenario. For instance, it may be the case the implied carbon price required to achieve ACIL Allen Consulting's modelled policy scenario is higher or lower than estimated by ACIL Allen Consulting. One way of testing this result would be to compare the emissions implied by ACIL Allen Consulting's modelling of the electricity sector and gas sector in each scenario with the assumed emissions reduction target. While this comparison would not be precise (since it would involve comparing an economy-wide emissions reduction target with emissions reductions achieved in two sectors of the economy) it may provide some evidence on the appropriateness of the assumed carbon prices.

7 Key assumption 4 – Hydrogen prices

This section sets out our assessment of the hydrogen price projections that are used in assessing the economic life of the DBNGP.

- First, we describe how hydrogen price projections are developed by ACIL Allen Consulting (Section 7.1).
- Second, we assess the reasonableness of the input assumptions used by ACIL Allen Consulting in developing the hydrogen price projections used in the WOOPS model (Section 7.2).
- Finally, we summarise our conclusions on hydrogen price projections (Section 7.3).

7.1 How hydrogen price projections are developed

Hydrogen prices are calculated by ACIL Allen Consulting by summing estimates of hydrogen production costs, hydrogen transport costs and hydrogen storage costs.

ACIL Allen Consulting relies on estimates of hydrogen production, hydrogen transport and hydrogen storage costs from the CSIRO's 2018 National Hydrogen Roadmap to develop their projections of hydrogen prices.

Hydrogen production costs

For hydrogen production costs, ACIL Allen Consulting relies on the CSIRO's estimates of the levelized cost of hydrogen (LCOH). LCOH is an estimate of the cost per unit of energy of producing hydrogen (typically measured in $/kg or $/GJ). LCOH essential sums the expected capital costs, operating costs and fuel costs associated with operating a plant over its life to produce hydrogen, and divides this total cost by the total amount of hydrogen expected to be produced by the plant over its life.

The CSIRO's National Hydrogen Roadmap provides estimates of the LCOH for two cases:

- A current base case LCOH (taken to be a 2018 LCOH).
- A best case LCOH for 2025.

ACIL Allen Consulting uses these two LCOH estimates to generate a price curve in which the learning rate between 2018 and 2025 was extrapolated to 2085. This was taken to be the fast learning case. The extrapolation is seen in the shape of the projected hydrogen prices in **Figure 16**.

Base learning cases and slow learning cases were determined as 2/3 and 1/3 of the learning rate of the fast learning case.

Hydrogen transport costs

For hydrogen transport costs, ACIL Allen Consulting relies on the CSIRO's estimates of the cost of truck transportation of hydrogen. ACIL Allen Consulting assumes that transportation in 2018 will be at low pressure and over long distances (resulting in higher transport costs) while transportation in 2025 will be at high pressure and over short distances (resulting in lower transport costs).

ACIL Allen Consulting uses these two transport costs estimates to generate price curves using the same approach used for hydrogen production costs.

Implicit in this approach is the view that hydrogen production will, on average, be located some distance from the source of consumption (or the source of injection into a distribution network). Co-locating hydrogen production with the site of consumption may reduce hydrogen transportation costs at the expense of higher electricity transportation costs or less efficient sites for renewable electricity generation. ACIL Allen Consulting's model does not seek to address the complexities of locational decisions for renewable generation, electricity storage, hydrogen production and hydrogen storage, which we think is a reasonable simplification for these purposes.

Hydrogen storage costs

For hydrogen storage costs, ACIL Allen Consulting relies on the CSIRO's estimates of the cost of storage in compression tanks.

As with hydrogen production costs, the CSIRO's National Hydrogen Roadmap provides estimates of the storage costs for two cases:

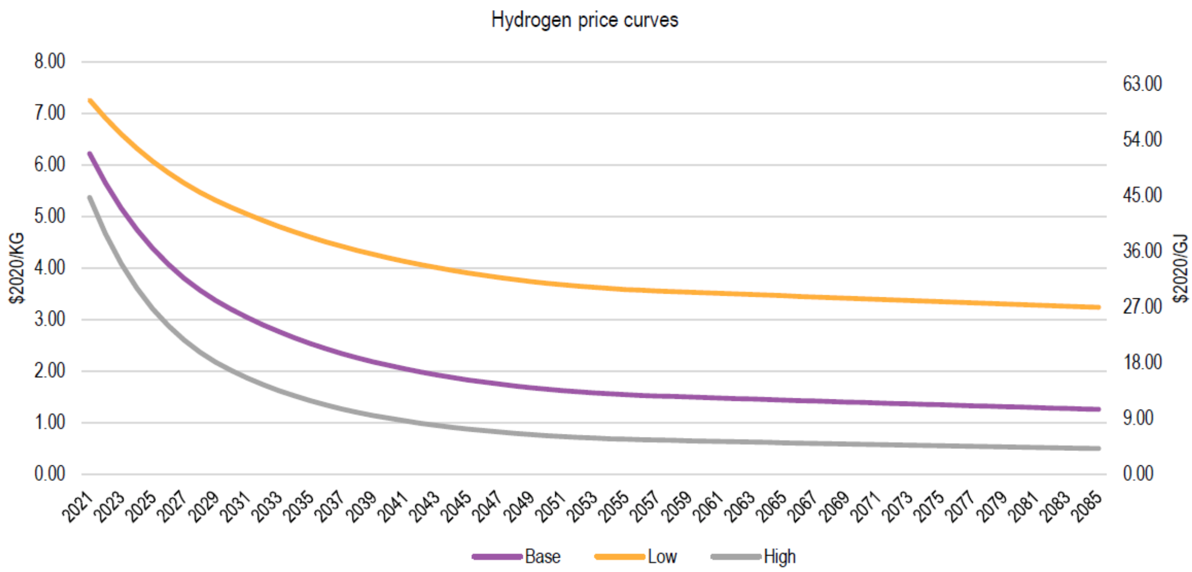
- A current base case (taken to be a 2018).
- A best case for 2025.

ACIL Allen Consulting uses these two storage costs estimates to generate price curves using the same approach used for hydrogen production costs and hydrogen transport costs.

Results of ACIL Allen Consulting's approach

The result of ACIL Allen Consulting's approach to projecting hydrogen prices is shown in **Figure 16**. Note that **Figure 16** omits data from 2018 to 2020. By our estimate, the starting price in 2018 is around $8.25/kg.

Figure 16: ACIL Allen Consulting projections of hydrogen prices



Source: ACIL Economic Depreciation report, Figure 4.2.

7.2 Assessing the inputs into hydrogen price projections

Given that ACIL Allen Consulting largely relies on cost estimates from the CSIRO's National Hydrogen Roadmap, the main focus of our assessment of the ACIL Allen Consulting's hydrogen price projections is whether ACIL Allen Consulting have made appropriate use of the CSIRO's cost estimates.

Based on our review of the CSIRO's National Hydrogen Roadmap, we have two main concerns with ACIL Allen Consulting's projections. These relate to:

- the electricity price assumed by the CSIRO
- ACIL Allen Consulting's approach to projecting the CSIRO's cost estimates.

We also note that there are alternative, and more recent, estimates of hydrogen costs available from the IEA.

7.2.1 Electricity price assumed by CSIRO

The cost of electricity is a key input into the LCOH from electrolysers. In estimating the LCOH from electrolysers, the CSIRO has made an assumption about the cost of electricity (as well as the other costs of the electrolyser). These assumptions are outlined in **Figure 17**.

Figure 17: Assumptions used by CSIRO to estimate LCOH

KEY COST DRIVER	UNIT	BASE CASE	KEY ACTIONS	BEST CASE
Av electricity price	c/kWh	6	Optimise electrolyser position and secure favourable PPAs	4
Capacity factor	%	85	Optimised operation	95
Scale/Capacity	MW/day	1	Secure offtakes, aggregate demand, risk sharing	100
Scale/Capacity	Kg H_2 / day	444	As above	53,333
Asset life	Years	40	No change	40
Capex (less risk)	$/kW	3496	Scaling benefits, smaller footprint of stack, lower cost BoP	968
Capex (less risk)	$/kg H_2/year	7,865	As above	1,814
Opex	$/kW/y	75	Improve lifetime of components through R&D	19
Opex	$/kg H_2/year	169	As above	36
Stack replacement interval	hours	120,000	Improved catalyst layers and membranes	150,000
Efficiency	kWh/kgH_2	54	Reduction in current densities, improved system components, more efficient BOP, more efficient catalysts, etc.	45
Risk	%	10	First of kind demonstration at scale	5
Real discount rate	%	7	No change expected	7
Cost of capital	%	7	Utilise green bonds and CEFC support	5
LCOH	**$/kg**	**6.08-7.43**		**2.29-2.79**

Source: CSIRO, National Hydrogen Roadmap 2018, Table 45.

It is clear from **Figure 17** that, in estimating the LCOH, the CSIRO assumes a delivered electricity price of 6 c/kWh ($60/MWh) in 2018, falling to 4 c/kWh ($40/MWh) in 2025.[10] These electricity prices reflect the average electricity price paid in order to operate an electrolyser at an 85-95% capacity factor.

ACIL Allen Consulting calculates a renewable electricity price for Western Australia that is far in excess of the CSIRO's electricity price assumptions. The prices calculated by ACIL Allen Consulting represent the levelised cost of renewable electricity and storage to supply the load shape of the SWIS to 2085. We consider that this is likely comparable to the electricity price that would result from operating an electrolyser with a flat load at around an 85-95% capacity factor. That is, we consider that the electricity cost assumed in determining the cost of hydrogen from electrolysis in Western Australia, and the levelised costs calculated by ACIL Allen Consulting for Western Australia, should be comparable.

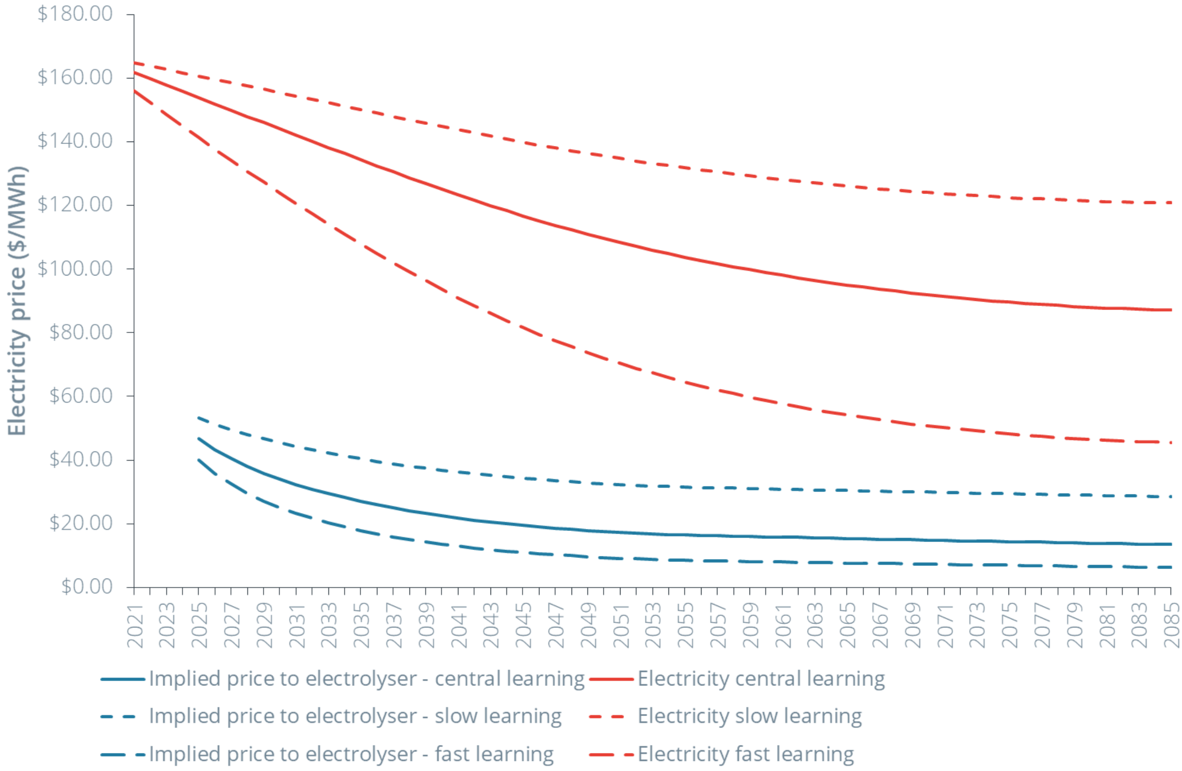
Figure 18 compares the renewable electricity price forecast by ACIL Allen Consulting for its three scenarios (blue lines) with the assumed delivered electricity price to the electrolyser assumed by CSIRO after accounting for ACIL Allen Consulting's approach for developing price curves from the CSIRO's assumptions (red lines). Note that these prices are not directly comparable: the CSIRO

10 These estimates of the electricity price are based on electricity being provided from the grid to enable operation of the electrolyser at a high capacity factor (85%). The CSIRO note that that they assume that cheaper electricity could be obtained at times from the grid, when there is excess renewable output, but because relying on this would restrict the capacity factor of the electrolyser (to an assumed 10%) the LCOH would be significantly higher.

derived prices are delivered prices, so to make these prices comparable the network costs applicable to electrolysers should be added to ACIL Allen Consulting's electricity price forecasts.

Nevertheless, **Figure 18** makes clear that there is an internal inconsistency in the assumptions that go into ACIL Allen Consulting's WOOPS model: the electricity price assumption that is implicit in ACIL Allen Consulting's hydrogen price projections is far below its own estimate of the cost of renewable electricity[11] in Western Australia.

Figure 18: Electricity price comparisons (blue is ACIL Allen Consulting, red is CSIRO)



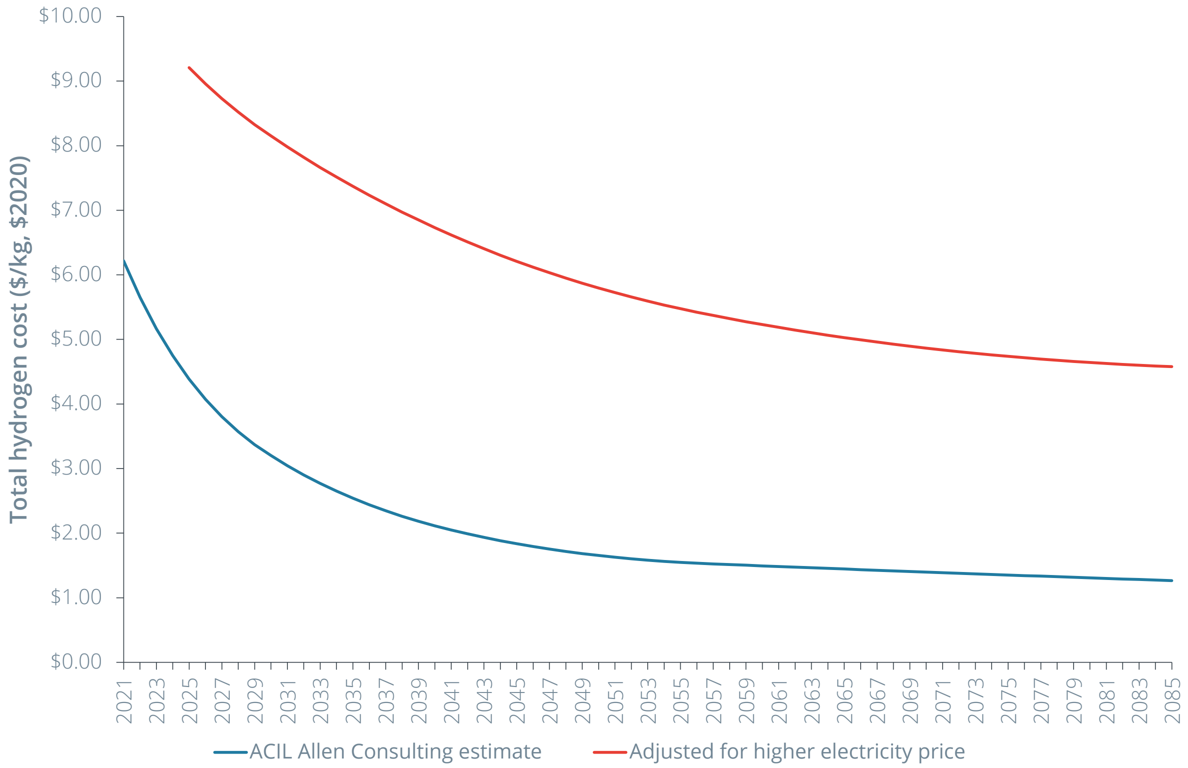
Source: Frontier Economics analysis of CSIRO, National Hydrogen Roadmap 2018 and ACIL WOOPS Model.

Note: the implied price of electricity to the electrolyser assumes that the post-2025 reductions to LCOH are a reflection of equivalent reductions in all inputs to the LCOH. This is not quite right given the different drivers of cost reductions between 2018 and 2025, but gives an indication of implied electricity cost reductions.

If ACIL Allen Consulting was to use its own estimate of renewable electricity costs in Western Australia in projecting hydrogen costs, the impact on the projected hydrogen cost would be substantial, as seen in **Figure 19**. The blue line shows ACIL Allen Consulting's Base Case estimate of hydrogen costs in $/kg. The red line shows what that cost would be had ACIL Allen Consulting used its renewable electricity price in the calculation of its hydrogen price. That is, because ACIL Allen Consulting's electricity prices are substantially higher than the electricity price assumed by CSIRO, the resulting hydrogen price is substantially higher.

11 We consider that the cost of renewable electricity is an appropriate benchmark since the CSIRO's estimates of LCOH do not include any carbon cost.

Figure 19: Hydrogen cost projections with different electricity prices – central case



Source: Frontier Economics analysis of ACIL WOOPS Model.

7.2.2 Projecting the CSIRO's cost estimates

As discussed in Section 7.1, ACIL Allen Consulting uses two LCOH estimates from CSIRO to generate a price curve in which the learning rate between 2018 and 2025 is extrapolated to 2085. The approach implicitly assumes that cost reductions of the type projected by CSIRO from 2018 to 2025 can continue to be achieved.

The four factors that account for the largest reduction in CSIRO's estimates of LCOH from 2018 to 2025 are:

- the reduction in capital cost from $3,496/kW to $968/kW
- the reduction in the electricity price from 6c/kWh to 4 c/kWh
- the increase in efficiency from 54 kWh/kgH_2 to 45 kWh/kgH_2
- the reduction in the cost of capital from 7% to 5%.

In our view, it is not reasonable to assume that CSIRO's estimates of these changes can be extrapolated beyond 2025, for the reasons discussed below.

Capital cost reductions

A material driver of the capital cost reduction estimated by CSIRO between 2018 base case and the 2025 best case is the benefits of increased scale (the system size is assumed to increase from 1 MW/day in 2018 to 100 MW/day in 2025). It is not clear that such large reductions in cost because of increased scale could be achieved through ongoing increases in scale.

The assumed reduction in cost of capital from 7% in 2018 to 5% in the 2025 best case are attributed to the use of green bonds and CEFC support. Presumably this is a one-off reduction (that may, in fact, not even persist) and not necessarily something that will lead to ongoing reductions in the cost of capital below 5%.

Electricity price reductions

As discussed in Section 7.2.1, even electricity prices of 4 c/kWh in 2025 are well below ACIL Allen Consulting's own estimates of long-term renewable electricity costs. Further reductions below this simply increase the disparity between implied electricity prices to the electrolyser and ACIL Allen Consulting's estimates of long-term renewable electricity costs.

Efficiency improvements

The CSIRO National Hydrogen Roadmap makes clear that further efficiency improvements beyond the 2025 best case assumed efficiency of 45 kWh/kgH_2 are unlikely:

> *Current electrolyser efficiencies are between 54-58kWh/kg depending on the technology. Note that the thermodynamic efficiency limit for electrolysis is 40 kWh/kgH2 (the higher heating value of hydrogen). It is generally considered that efficiencies better than 45 kWh/kg are unlikely to be achieved.*

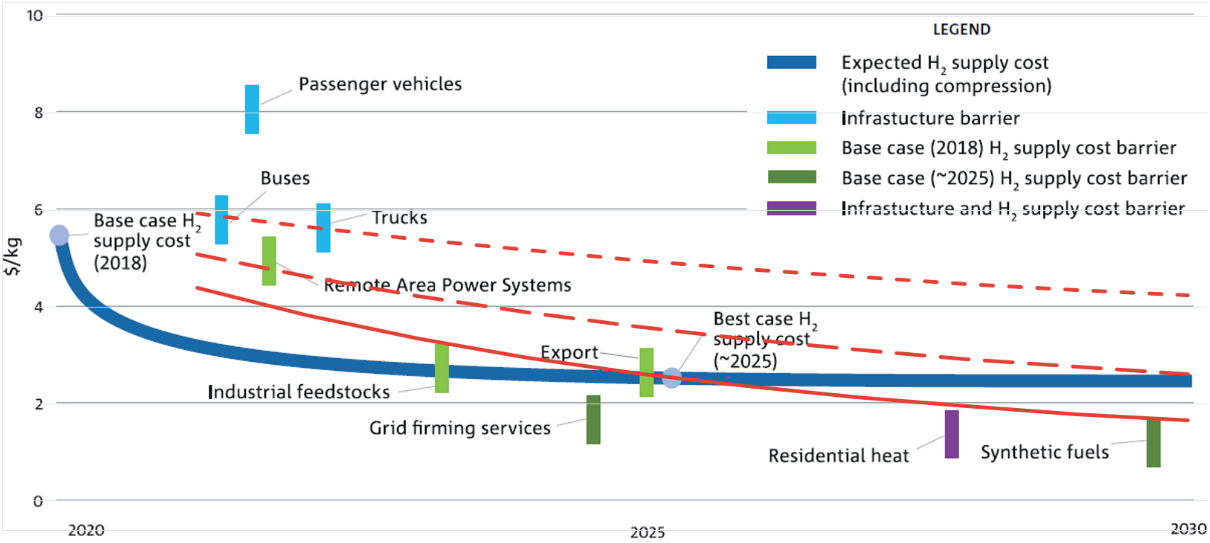
CSIRO's extrapolation of LCOH

The CSIRO National Hydrogen Roadmap includes an extrapolation of the LCOH beyond 2025. **Figure 20** reproduces that extrapolation of the LCOH from the CSIRO (the blue line) and overlays the LCOH projections from ACIL Allen Consulting (the red lines).

It is clear from **Figure 20** that the CSIRO is projecting that LCOH will remain relatively constant from the level achieved in the 2025 best case, for the remainder of the 2020s. In contrast, ACIL Allen Consulting's extrapolation has ongoing reductions in LCOH for the remainder of the 2020s (and, indeed, beyond). The result is that by 2030 ACIL Allen Consulting's LCOH in the fast learning case is well below the CSIRO's 2025 best case LCOH and even ACIL Allen Consulting's LCOH in the central learning case is equal to the CSIRO's 2025 best case LCOH.

As far as the results of the WOOPS modelling is concerned it is the ongoing reductions in LCOH that are most important, because it is the relativity between hydrogen prices, electricity prices and gas prices in the long-term (2050 and beyond) that determines the result of the modelling. Therefore, the assumption of continual cost reductions for hydrogen based on the CSIRO estimates for 2018 base case and the 2025 best case is a key driver of outcomes.

Figure 20: Comparison of LCOH curves



Source: CSIRO National Hydrogen Roadmap 2018, Figure 19 and Frontier Economics analysis of ACIL WOOPS Model.

7.2.3 Alternative estimates of hydrogen costs

Since the release of the CSIRO National Hydrogen Roadmap in 2018, the IEA has released a major study – the Future of Hydrogen – in 2019. The IEA report provides an alternate source of projections for some of the key drivers of LCOH. In most cases, these projections suggest that the LCOH will be higher than projected by the CSIRO National Hydrogen Roadmap. For instance:

- The IEA project that the capital cost of Polymer electrolyte membrane (PEM)electrolysers will be $1,433/kW in 2030 (within a range of $867/kW to $2,000/kW) and $733/kW in the long-term (within a range of $267/kW to $1,200/kW). In comparison, the CSIRO project that the capital cost of PEM electrolysers will be $968/kW by 2025.
- The IEA project that the stack lifetime of PEM electrolysers will be 75,000 hours in 2030 (within a range of 60,000 to 90,000 hours) and 125,000 hours in the long term (within a range of 100,000 to 150,000). In comparison, the CSIRO project that the stack lifetime of PEM electrolysers will be 150,000 hours in 2025.
- The IEA project that the efficiency of PEM electrolysers will be 51 kWh/kgH_2 in 2030 (within a range of 49 kWh/kgH_2 to 53 kWh/kgH_2) and 47 kWh/kgH_2 in the long-term (within a range of 45 kWh/kgH_2 to 50 kWh/kgH_2). In comparison, the CSIRO project that the efficiency of PEM electrolysers will be 45 kWh/kgH_2 in 2025.

These differences result in material differences in LCOH. For instance, by our calculations, changing CSIRO's 2025 best case assumptions only by adopting the IEA's *2030* mid-point estimates for capital cost, stack lifetime and efficiency would increase the 2025 best case LCOH from $2.42/GJ to $3.09/GJ.

7.3 Conclusion on hydrogen price projections

Based on our review we make the following recommendations regarding hydrogen price assumptions:

- The electricity price assumptions used in determining the cost of hydrogen production and storage should be internally consistent with the electricity price assumptions used elsewhere in the ACIL WOOPS Model.
- If hydrogen cost projections continue to be based on the CSIRO's estimates of LCOH on 2018 and the 2025 best case, then the extrapolation of these cost estimates should have closer regard to the plausibility of continued ongoing reductions in these costs and to the CSIRO's on views on likely ongoing cost reductions.

As an alternative, hydrogen cost projections could be based on the more recent cost estimates published by the IEA, with the range of estimates published by the IEA providing one means of developing a range of estimates for the three scenarios.

As we have discussed, a key driver of the cost of hydrogen from electrolysers is the cost of electricity used in the electrolyser. When producing hydrogen from renewable electricity there is a trade-off between:

- making more efficient use of the electrolyser by running it at a high capacity factor (which lowers the amount that must be recovered from each unit of production in order to recover fixed capital costs)
- accessing cheaper electricity by running the electrolyser at a lower capacity factor, only at times of high renewable generation (which lowers average electricity prices).

To properly investigate this trade-off requires electricity market modelling to properly investigate the interactions between patterns of demand for electricity by electrolysers and the resulting electricity price. We have not been engaged to undertake electricity market modelling of this kind. Nevertheless, we have sought to address the recommendations set out above to develop hydrogen price forecasts for three scenarios that we consider reasonably represent the potential range for long-term gas prices in Western Australia.

The steps we have taken in developing the hydrogen price forecasts for three scenarios are as follows:

- Our starting point is estimates of capital costs, operating costs and efficiencies for PEM electrolysers from the IEA's Future of Hydrogen report.[12] The IEA's Future of Hydrogen report provides a range for capital costs and efficiencies for today, 2030 and the long-term (which we treat as applying to 2050 and beyond). We use the high point of the IEA's range for our high case, the low point of the IEA's range for our low case and the average of the IEA's rage for our medium case.
- We convert capital costs and operating costs from USD to AUD using different exchange rates for each scenario, using the same approach that we use when calculating net-back gas prices (described in Section 5.4).

[12] The IEA provides estimates of capital costs, operating costs and efficiencies for alkaline electrolysers, proton exchange membrane (PEM) electrolysers and solid oxide electrolysis cells (SOECs). We have used the capital cost, operating cost and efficiency assumptions for PEM electrolysers. The IEA estimates that PEM electrolysers will remain higher cost than alkaline electrolysers, but offer other advantages including a smaller plant footprint, greater operating flexibility and the production of highly compressed hydrogen for decentralised production and storage. While the IEA estimates that PEM electrolysers are higher cost than alkaline electrolysers, we note that in the long-term the difference between the cost of these alternative technologies is forecast to decline, and the IEA's low case forecast for long-term capital costs is the same for alkaline electrolysers and PEM electrolysers.

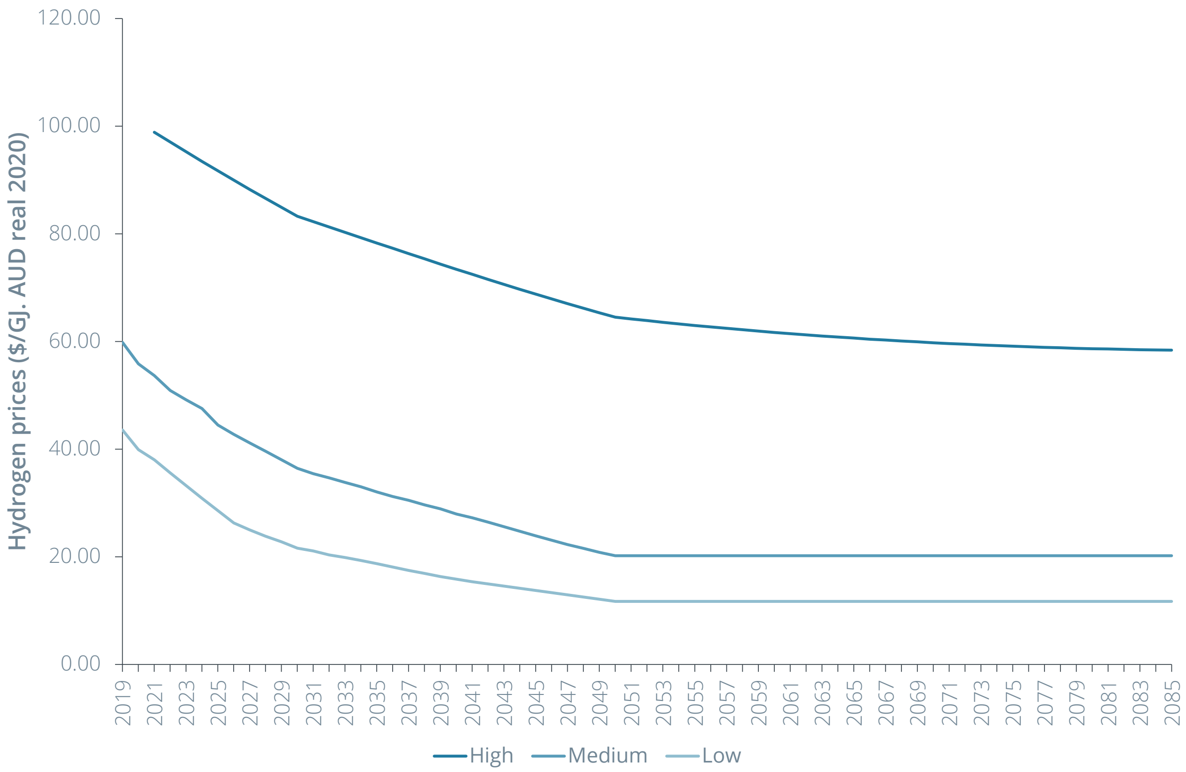
- For capital cost and economic life estimates we use estimates from the IEA's Future of Hydrogen report for our high case and estimates from the base case and best case from the CSIRO estimates (which are lower than the IEA's estimates) for our medium case and low case respectively.
- The inputs that we use for electricity prices and electrolyser capacity factor we derive together (due to the interactions discussed above). We do this in the following way:
  - For the high case we use ACIL Allen Consulting's high electricity price forecast and an assumed capacity factor of 85% for the electrolyser. Implicitly we are assuming that an electrolyser operating at an 85% capacity factor would face an electricity price that is equal to the average annual electricity price for the SWIS that ACIL Allen Consulting has calculated. In reality, the electricity price may be lower, if the electrolyser does not operate at times of highest electricity prices.
  - For the medium case and the high case we use an estimate of the levelized cost of solar PV generation as a forecast of the electricity price for the electrolyser. We calculated the levelized cost of solar PV generation based on estimates of capital costs, operating costs and capacity factors of solar PV from AEMO's Integrated System Plan (ISP). We use AEMO's medium case and low case cost inputs for our medium case and low case respectively. In each case we match the capacity factor of the electrolyser to the capacity factor of solar PV generation (reflecting the assumption that the electrolyser is supplied solely by solar PV). We use the levelized cost of solar PV rather than other renewable generation options on the basis that under AEMO's forecasts it has the lowest levelized cost.
- We then test the reasonableness of the resulting hydrogen price forecasts against other estimates.

These key inputs are summarised in **Table 3** and the resulting forecasts are shown in **Figure 21**.

Table 3: Key inputs into hydrogen price forecasts

Data point	Frontier Economics high scenario	Frontier Economics medium scenario	Frontier Economics low scenario
Electrolyser capital cost, operating cost and efficiency	IEA Future of Hydrogen, high end of range	IEA Future of Hydrogen, average of range	IEA Future of Hydrogen, low end of range
Cost of capital and economic life	IEA Future of Hydrogen	CSIRO, National Hydrogen Roadmap, base case	CSIRO, National Hydrogen Roadmap, best case
Electricity price	ACIL Allen Consulting high electricity price forecast	Levelized cost of solar PV based AEMO ISP medium case cost assumptions	Levelized cost of solar PV based AEMO ISP low case cost assumptions
Electrolyser capacity factor	85%	Equal to solar PV capacity factor	Equal to solar PV capacity factor
Levelized cost of hydrogen	Calculated based on the above	Calculated based on the above	Calculated based on the above

Figure 21: Frontier Economics hydrogen price forecasts



Source: Frontier Economics

We have assessed these prices in the context of three recent alternative hydrogen production cost projections: [13]

- **Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe (2020)**[14] from the International Council on Clean Transportation. This report produces an estimate for three cases:
  - Grid connected, where the electrolyser is grid connected and therefore can produce hydrogen gas at a 100% capacity factor. For this case, median price in the US decreases from $11.75/kg in 2020 to $7.69/kg in 2050. Over the same period, minimum price decreases from $8.08/kg to $5.53/kg. In the EU, the median price decreases from $17.48/kg in 2020 to $10.25/kg in 2050; during that same timeframe the minimum price decreases from $6.44/kg to $4.28/kg
  - Direct connect, where the electrolyser is connected directly to a renewable electricity generator. For this case, median price decreases from $14.15 /kg in 2020 to $7.96/kg in 2050; during that same timeframe the minimum price decreases from $6.08/kg to $3.25/kg. In the EU, the median price decreases from $25.64/kg in 2020 to $13.36/kg in 2050; during that same timeframe the minimum price decreases from $5.41/kg to $2.97/kg.
  - Curtailed Electricity, where the electrolyser is only operated on the grid on electricity that would otherwise be curtailed. For this case, median price decreases from $14.69/kg in 2020 to $7.89/kg in 2050; during that same timeframe the minimum price decreases from $8.13/kg to $6.33/kg. In the EU, the median price decreases from $14.47/kg in 2020 to $8.11/kg in 2050; during that same timeframe the minimum price decreases from $7.96/kg to $6.23/kg.

  These costs are generally higher than our estimates. The most comparable scenarios are the Direct Connect and Curtailed electricity scenarios, which represent the production of green hydrogen.

- **Green hydrogen production costs in Australia (2020)** [15] from the Crawford School of Public Policy's Centre for Climate & Energy Policy (Crawford).

  The report develops projections of hydrogen production costs in Australia with key drivers of its estimates being assumptions regarding electrolyser capital costs ($500-$1000/kWe), capacity factors (30%, 45% and 90%) and electrical efficiency. Ultimately, the report arrives at a cost to produce hydrogen for 2030 of:
  - Between $3.12/kg and $3.82/kg at the mean estimated electricity cost for solar PV

13 Where costs were reported in USD, an exchange rate of $ USD = $AUD 0 .75 was used to convert reported estimates. Costs are reported in real AUD$2020.

14 Report available at https://theicct.org/sites/default/files/publications/final_icct2020_assessment_of%20_hydrogen_production_costs%20v2.pdf (accessed 15 February 2021)

15 Report available at https://ccep.crawford.anu.edu.au/sites/default/files/publication/ccep_crawford_anu_edu_au/2020-09/ccep20-07_longden-jotzo-prasad-andrews_h2_costs.pdf (accessed 15 February 2021)

  - Between $1.89/kg and $3.71/kg at the lower range of projections for electricity cost for solar PV

  These costs are in the low range of our scenarios. The key driver of the difference between our estimates and the range of Crawford estimates appear to reflect the capital costs they assume for electrolysers, based on estimates by the IEA[16] and Nel Group.[17] They assume a cost of either $500/kWe or $1000/kWe across their cases, which starts below our low scenario and extends to between our low and medium scenario for capital costs for 2030.

- **Hydrogen Economy Outlook**[18] from BloombergNEF

  The report develops projection of hydrogen production costs based on an 'integrated design of the electrolyser and generator', a large-scale alkaline electrolyser, transport costs based on 50km of transmission movement. Its cost estimate for Australia is based on a solar PV connected electrolyser and storage using a salt cavern.

  Ultimately, the report arrives at a cost to produce hydrogen of $1.97/kg in 2030, decreasing to $1.12/kg by 2050. This estimate for 2030 is close to our low scenario for 2050, while the 2050 estimates sits significantly lower than our low estimate for 2050. The report also suggests that if the cost of electrolysers fall sufficiently with scale, then renewable hydrogen could be produced for $0.93 to $2.13/kg in most parts of the world before 2050.

  The key driver of the difference between our estimates and the range of BloombergNEF estimates appears to be the significantly lower capital costs for electrolysers used by BloomberNEF. They assume a cost of $180/kWe in 2030 which decreases to $131/kWe in 2050, which is around 1/5 and 1/2 of the capital costs we have used in our low scenario for 2030 and 2050 respectively.

16 The Future of Hydrogen (2019), IEA, pp.46-47.

17 Nel Group provide their estimates here, p.7: https://www.fch.europa.eu/sites/default/files/S2.3-J.A.L%C3%B6kke,Nel.pdf (accessed 15 February 2021)

18 Report available at https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf (accessed 16 February 2021)

8 Key assumption 5 – Electricity prices

This section sets out our assessment of the electricity price projections that are used in assessing the economic life of the DBNGP.

- First, we describe how the electricity price projections are developed by ACIL Allen Consulting (Section 8.1).
- Second, we assess the reasonableness of the input assumptions used by ACIL Allen Consulting in developing the electricity price projections used in the WOOPS model (Section 8.2).
- Finally, we summarise our conclusions on electricity price projections (Section 8.3).

8.1 How electricity price projections are developed

Electricity prices are projected by ACIL Allen Consulting by using its electricity market model – *PowerMark WA*. The model was used to determine the least cost mix of renewable and storage technologies (wind, solar PV and batteries) to meet forecast SWIS system demand for electricity each year. The model is run so that the optimal mix of plant is installed in each year (that is, modelled decisions about investment in previous years have no affect).

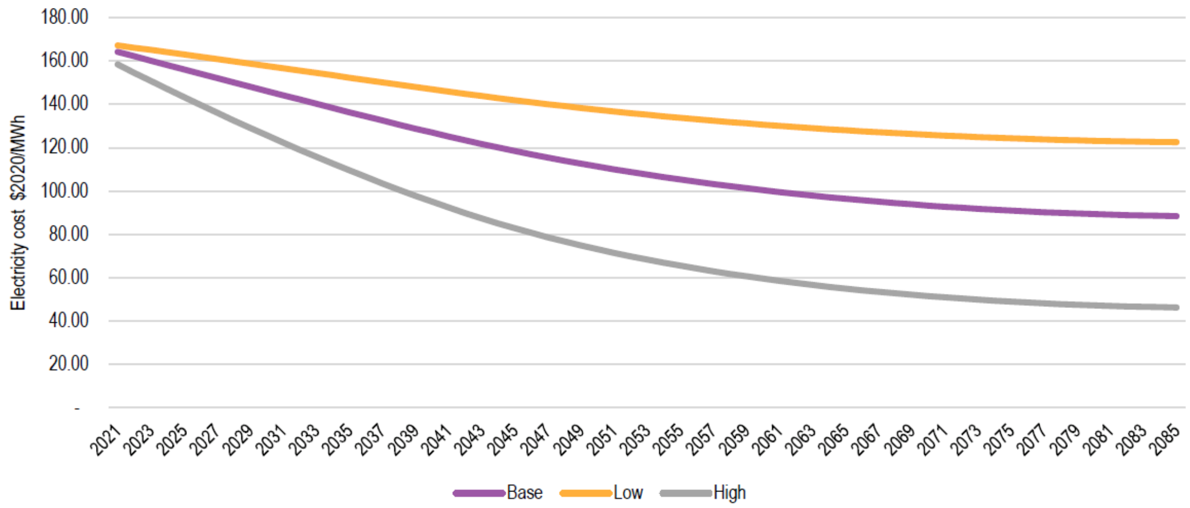
Once the model generates forecast electricity prices, these are converted into a gas equivalent price using an assumed heat rate for a gas-powered generator. The logic behind this step is to determine the gas price at which the operating cost of a gas-fired generator would match ACIL Allen Consulting's estimate of the renewable electricity price in Western Australia. As we discuss in Section 3.2.3, while obtaining gas equivalent prices in this way is reasonable, our view is that there are flaws in the implementation of this logic.

The key inputs into ACIL Allen Consulting's modelling are forecasts of system demand and estimates of the costs of renewable and storage technologies. Each of these inputs are discussed in the following section.

Results of ACIL Allen Consulting's approach

The result of ACIL Allen Consulting's approach to projecting electricity prices is shown in **Figure 22**.

Figure 22: ACIL Allen Consulting projections of electricity prices



Source: ACIL Economic Depreciation report, Figure 5.5.

8.2 Assessing the inputs into electricity price projections

8.2.1 System demand

ACIL Allen Consulting does not provide any detailed information about the source of data for system demand that it uses.

It seems likely that the starting point for ACIL Allen Consulting's projection of system demand would be forecasts of demand from AEMO. ACIL Allen Consulting describes a process by which it then adjusts forecast demand to account for its own projections of uptake of distributed solar and battery.

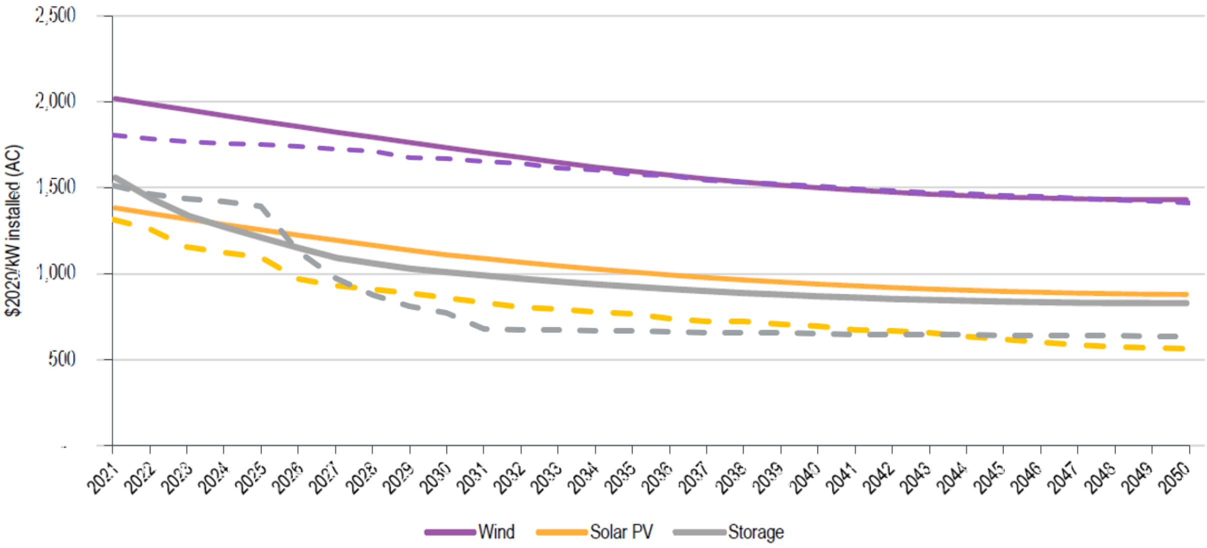
Without further information on the sources of data and modelling undertaken by ACIL Allen Consulting we are unable to provide a view on the reasonableness of the forecast of system demand.

While AEMO forecasts of demand have decreased since this modelling was undertaken, we note that this is unlikely to materially affect the modelling results. Because the reported cost is a levelised cost, and the optimal mix of plant is installed in each year, only the shape of demand will impact the results.

8.2.2 Technology costs

The principal driver of the cost of renewable generation and storage is the capital cost of those technologies. ACIL Allen Consulting relies on capital costs developed by itself as part of its energy modelling work. **Figure 23** compares ACIL Allen Consulting's capital cost estimates (solid lines) with the more recent estimates from AEMO's 2020 Integrated System Plan (dashed lines). While the long-term estimate of capital cost for wind are quite similar, AEMO's estimates for solar PV and battery costs are materially lower in the long-term. All other things being equal, adopting AEMO's capital cost estimates would result in a lower projected electricity price.

Figure 23: Comparison of capital cost assumptions



Source: ACIL Economic Depreciation report, Figure 5.3, AEMO 2020 ISP

Another key driver of the cost of renewable generation and storage is the assumed cost of capital. ACIL Allen Consulting does not provide any information on its assumed cost of capital.

8.2.3 Heat rate

ACIL Allen Consulting converts electricity prices to gas-equivalent prices using heat rates of 8, 9 and 10 GJ/MWh, noting that this covers the typical range of annual average heat rates for the SWIS). ACIL Allen Consulting ultimately bases the results of its modelling on an assumed heat rate of 9 GJ/MWh.

In our view, given that the WOOPS model is focused on long-term outcomes (2050 and beyond) the appropriate heat rate to use would be an estimate of the heat rate of a typical gas-fired generator that would be operating at this time. We note that AEMO's 2020 ISP estimates that the heat rate of a new build CCGT is currently 7.58 GJ/MWh. With ongoing technological improvements, this would be expected to be somewhat lower by 2050.

The effect of using a lower heat rate would be to increase the gas equivalent price calculated by ACIL Allen Consulting.

8.3 Conclusion on electricity price projections

Based on our review we make the following recommendations regarding electricity price assumptions:

- Given the pace of development in solar PV and battery markets, there may be benefit to using more recent estimates of the cost of these technologies. AEMO's 2020 ISP, for instance, estimates that the cost of these technologies is materially lower than estimated by ACIL Allen Consulting.
- When converting electricity prices to gas-equivalent prices, a heat rate estimate for the gas plant that is likely to be operating throughout the modelling period should be used.

- As noted in Section 3.2.2, there should be consistency between the electricity price projections and the volumes of gas flowing over the DBNGP for gas-powered generation. That is, when the renewable and storage price projections fall below the cost of the short-run marginal cost of gas, there should be no reason to operate gas-powered generation.

It is difficult to comment on a reasonable range for electricity projections without undertaking modelling similar in nature to what ACIL Allen Consulting has done. We note that several recent studies have calculated a cost of 100% renewable and storage systems in the SWIS. However, these studies use a large number of assumptions and are heavily assumption driven. Therefore, it is difficult to assess the differences between different estimates. The studies we have considered include:

- A 2017 study of 90-100% renewable electricity in the SWIS which found a levelised cost to be around $110/MWh in 2030. [19]
- A 2019 presentation by developers of energy market modelling software (SIREN and Powerbalance) suggests a levelised cost of $133-$158, although the basis of these costs are unclear (appear to be $2014) and the year at which these costs are relevant is unclear.[20]

[19] 90-100% renewable electricity for the South West Interconnected System of Western Australia, Energy, Available http://re100.eng.anu.edu.au/resources/assets/1703LuRESWIS.pdf

[20] Transition to 100% Renewable Electricity on the SWIS – can it be done and at what cost? , p19, https://businesslaw.curtin.edu.au/wp-content/uploads/sites/5/2019/06/cc-SIREN-30-May-2019.pdf

9 Scenarios

9.1 ACIL Allen Consulting modelled three scenarios

ACIL Allen Consulting modelled three scenarios in the ACIL WOOPS Model: a Base Case, a Rapid Transition (High) Case, and a Slower Action (Low) Case. The scenarios consist of various configurations of the key inputs discussed in the preceding sections. **Table 4** provides an overview of the scenarios adopted in the ACIL WOOPS Model.

Table 4: Scenarios modelled in the ACIL WOOPS Model

Parameter	Base	Rapid transition (High)	Slower action (Low)
Gas price	Central	High	Low
Carbon price	26% by 2030, net zero by 2070	45% by 2030, net zero by 2060	15% by 2030
Hydrogen start cost	$6.22/kg	$5.37/kg	$7.26/kg
Hydrogen learning rate	Central	Fast	Slow
Electricity start cost	$161.80/MWh	$156.11/MWh	$164.74/MWh
Electricity learning rate	Central	Fast	Slow
Gas consumption	Gas powered generation modelled to be consistent with relevant carbon price; industrial loads the same across scenarios.		

9.2 We consider the composition of scenarios reasonable, but the inputs problematic

We consider the composition of these scenarios to be reasonable. ACIL Allen Consulting has developed three scenarios by varying the key input parameters of the ACIL WOOPS Model in ways that reflect the intent of the scenarios. For example, in the Rapid Transition Case, gas prices are increased relative to the Base Case and costs of alternatives to gas, including hydrogen and renewables and storage costs, are decreased relative to the Base Case. The directions of the changes of key parameters in each scenario are plausible, and the directions of the changes are not internally inconsistent.

However, in this report we have highlighted a number of concerns with the inputs that are used in these scenarios. In Section 3.2.2, we noted that the electricity costs and gas consumption volumes were not internally consistent. In Sections 5.4 and 7.2.3, we have proposed alternate gas and hydrogen price scenarios which are, in our view, more reflective of the possible range of price outcomes based on the information available today. In Sections 4 and 8, we noted that it is difficult to adjust electricity prices and gas consumption volumes without undertaking modelling similar to the type undertaken by ACIL Allen Consulting.

In the following section, we model four alternative scenarios that focus on the key sensitivities to the ACIL WOOPS Model, the gas price and the hydrogen price.

9.3 We have considered alternative scenarios with different gas and hydrogen prices

We have developed four alternative scenarios to reflect our view of the wider range of gas and hydrogen prices projected to 2085. These scenarios are outlined in **Table 5**.

Table 5: Alternative scenarios modelled in the ACIL WOOPS Model

Parameter	Medium gas/Medium hydrogen	High gas/Medium hydrogen	High gas/low hydrogen	Medium gas/Low hydrogen
Gas price	Frontier Medium	Frontier High	Frontier High	Frontier Medium
Carbon price	26% by 2030, net zero by 2070	26% by 2030, net zero by 2070	26% by 2030, net zero by 2070	26% by 2030, net zero by 2070
Hydrogen cost	Frontier Medium	Frontier Medium	Frontier Low	Frontier Low
Electricity start cost	$161.80/MWh	$161.80/MWh	$161.80/MWh	$161.80/MWh
Electricity learning rate	Central	Central	Central	Central
Gas consumption	Gas powered generation modelled to be consistent with relevant carbon price; industrial loads the same across scenarios.			

Given that we have not updated the electricity price, these scenarios include the internal inconsistency noted in Section 3.2.2 relating to the electricity price and the hydrogen cost. We have modelled these scenarios in an unmodified version of the ACIL WOOPS Model, and so issues with the use of a 'combined' electricity and hydrogen price are present in the interpretation of the results, as discussed in Section 3.2.1.

However, these scenarios address the key sensitivities in the model, because both the gas price and the hydrogen price have the largest impact on the economic life of the DBNGP in the ACIL WOOPS Model. This is the case for both definitions of 'economic life', the DBP and ERA definitions, as discussed in Section 2.2.1.

Table 6: Scenario results

Result	Medium gas/Medium hydrogen	High gas/Medium hydrogen	High gas/low hydrogen	Medium gas/Low hydrogen
DBP end year	2085	2085	2041	2077
ERA end year	2085	2085	2043	2080

Results for the alternative scenarios are presented in **Table 6** for each definition of economic life. The wider range of inputs for gas and hydrogen does not provide a wider range of end-year outcomes than the DBP's original scenarios, ranging from pre-2035 in the High Scenario to 2085 in the Low Scenario. This is because the latest end year is capped at 2085; were it not for this cap, the alternative scenarios would likely provide a greater range of outcomes than the original scenarios, despite only varying the gas and hydrogen prices.

Although we cannot compare like for like between original and alternative scenarios, the alternative scenarios presented do generally lead to later end years for the DBNGP's economic life regardless of definition of economic life. This is because the model is particularly sensitive to the assumed gas and hydrogen prices, and the alternative gas and hydrogen prices are generally more favourable to the continued use of the DBNGP than the prices used in the original modelling. In particular, the Frontier Medium gas price is significantly lower than ACIL Allen Consulting's assumed Central gas price, and the Frontier Medium hydrogen price is significantly higher than ACIL Allen Consulting's assumed Central hydrogen price.

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