Attachment 9.3

ACIL Allen Report

January 2020

Dampier Bunbury Pipeline

ACIL ALLEN CONSULTING

REPORT TO
AUSTRALIAN GAS INFRASTRUCTURE GROUP
20 DECEMBER 2019

DAMPIER TO BUNBURY NATURAL GAS PIPELINE

ECONOMIC DEPRECIATION STUDY (PUBLIC VERSION)

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1 INTRODUCTION

ACIL Allen have been engaged by Australian Gas Infrastructure Group (AGIG) to undertake an economic depreciation study for the Dampier to Bunbury natural gas pipeline (DBP).

The DBP is a long-life regulated pipeline. Some of the DBP assets will not be fully depreciated until around 2085. The rate at which capital is returned to the asset owner, through depreciation allowances, is determined under the existing regulatory approach by the assumed economic life of the asset. However, this assumes that the pipeline can continue to charge consumers the necessary regulated prices (incorporating full depreciation allowances) over the full life of the asset.

The energy sector is in transition in part through the development of technology and through policy aimed at reducing greenhouse gas emissions. Falling costs for renewable technologies, including embedded and distributed applications is threatening the traditional role for large-scale fossil fuelled generation assets in power systems. The drive for renewable energy and emission reduction targets in response to global agreements to reduce greenhouse gas emissions, is shortening the time frame for the transition.

These drivers are expected to erode demand for gas consumption over time as renewable and alternative fuel/feedstock technologies (e.g., hydrogen) become more competitive and government policy further limits the use of fossil fuels. Therefore, it can no longer be simply assumed that the DBP will have enough demand for its services such that it can continue to recover capital consistent with the currently assumed economic life of the asset (driving current depreciation rates), without the risk of facing write-offs in the future because competition from alternatives will not allow the DBP to recover the necessary charges.

ACIL Allen was asked to assess when the alternative renewable and alternative fuel/feedstock technologies would cross over the various scenario projected price curves for gas delivered by the DBP (gas commodity and regulated transmission tariff) and hence erode the capacity of the DBP to levy full regulated charges including return of capital. This report sets out our:

- approach
- assumptions
- analysis of the alternatives culminating in price curves for the alternatives
- a description of the model that was developed to analyse the effect on depreciation
- our findings.

The rest of the report is structured as follows:

— Chapter 2 sets out our broad approach and briefly discusses the scenarios used in the modelling.
— Chapter 3 considers gas usage in each sector modelled and provides gas price projections that were used in the model.
— The hydrogen scenarios that were developed are set out in chapter 4.
— The renewable energy scenarios that were developed are set out in chapter 5.
— The model is described in chapter 6.

2 APPROACH AND SCENARIOS

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. The current economic life of the DBP were established in 2000 based on "standard industry practice" at that time. They have not been revisited since that time. The model operates to 2085 reflecting the maximum amount of time to depreciate all existing assets assuming the current economic lives.

Sectors/Pipelines

The DBP services a range of different consumers across different sectors of the economy. In order to simplify the analysis, consumers were grouped into six sectors plus a residual:

1. alumina
2. gas for power generation
3. other domestic gas
4. chemicals
5. iron ore
6. nickel
7. other minerals

The alumina and gas for power generation sectors consume nearly two-thirds of the gas shipped on the DBP. Chemicals and minerals processing consume around one-fifth of the gas shipped on the DBP. The remaining 15 per cent reflects other domestic gas usage.

Each of the sectors was assessed in terms of the potential for sectoral activity to change gas consumption through external factors such as global competitiveness eroding local production/consumption or income effects in the case of domestic consumers. Apart from gas for power generation and the effects of greenhouse gas policy, there is little evidence that global competitiveness or income effects would cause any real changes for demand for gas delivered by the DBP, under the scenario assumptions considered.

Therefore, existing gas consumption profiles were projected forward over the modelled life of the DBP except for gas for power generation. Gas for power generation was explicitly modelled using ACIL Allen's proprietary model of the WEM using three greenhouse gas scenarios. Each scenario has a different gas consumption path but all paths lead to zero consumption of gas in the power generation sector; by 2060 in the most ambitious greenhouse gas abatement scenario and 2073 for the least ambitious greenhouse gas scenario.

Projected gas consumption is then subject to substitution by either hydrogen or where relevant renewable energy. The rate of substitution is assumed to occur instantaneously once hydrogen or renewable energy become cheaper than delivered natural gas (i.e., the model assumes that hydrogen and/or renewable electricity investors anticipate the cross-over and invest so that they are available in time to capitalise on the opportunities when the prices cross-over)

The model includes the ability to test exogenous step changes in gas usage as a proxy for closure of facilities (e.g., end of economic life and uneconomic to extend for a facility or sector).

Macro drivers

The model incorporates technology and policy scenarios reflecting uncertainty about future outcomes. In assessing scenario drivers, the following matters were considered:

- Environmental policy – more explicitly, government policy aimed at reducing greenhouse gas emissions
- Technological change – including improved efficiency leading to lower use of inputs and fuel switching to use lower or zero greenhouse gas intensity fuels
- Industry obsolescence including:
  - End of economic life of process (e.g., resource extraction, refining)
  - Entrants (globally) displacing existing assets to higher cost producers (e.g., alumina refining).

It was established that policies driving technological change, including greenhouse gas reductions, are the most significant drivers likely to create incentives for investment in new technologies and hasten obsolescence of existing technologies. Therefore, it was concluded that the scenarios should be arranged around technology and greenhouse gas reduction policies.

Scenarios

Three scenarios were agreed around variations in greenhouse gas reduction policy. These scenarios drive gas assumption inputs to the model with the variation between the three scenarios being driven by differences in gas for power generation. In calculating the cross-over with the alternative energy sources, each scenario was then subjected to hydrogen and renewable electricity price paths to determine if/when substitution might occur.

Base case

The Base case assumes that Australia meets its existing commitment to the Paris Agreement to achieve a minimum of 26 per cent emissions reduction by 2030 compared with 2005 levels. The WA government has a net zero emissions target by 2050. The Base case assumes that net zero emissions is achieved by 2070.

This will require emissions to be constrained against the business as usual scenario. The act of constraining emissions imposes a cost on the economy. The marginal cost of a constraint is known as the constraints shadow price; in the case of the carbon constraint on the economy, it reflects the marginal cost of emissions abatement.

The Base case scenario assumes a shadow price for carbon abatement consistent with achieving the 2030 national emissions constraint. It does not assume an explicit carbon price is imposed in the Base case. However, the cost of imposing the constraint (the shadow price) is incorporated into the modelling. After 2030, the shadow price is escalated following a Hotelling[1] rule. The assumed rate used is 3 per cent real on average which is consistent with the rate used in various studies over the last ten years.

As noted above, the electricity sector transition in the Base case is determined through explicit modelling of the SWIS incorporating the 26% carbon constraint implemented as an emissions intensity scheme.

Alumina was subjected to a review of the local Western Australian refineries position on the global cost curve and was held constant over the modelling horizon. Minerals and chemicals were treated in

[1] The concept of establishing an escalation rate for carbon prices based on a Hotelling rule was discussed in some detail in the Treasury economy wide modelling leading to the proposed Carbon Pollution reduction Scheme in 2011. The Hotelling rule is derived from the concept of the efficient exploitation of a non-renewable and non-augmentable resource, the percentage change in net-price per unit of time should equal the discount rate in order to maximise the present value of the resource capital over the extraction period. Greenhouse gas mitigation is considered a finite resource and is expected to mimic finite resource markets. The concept was developed by Harold Hotelling following analysis of non-renewable resource management.

the same manner. Other domestic gas consumption was also held constant over time reflecting slight declines in use per small consumer and limited growth in reticulation to new small customers.

Explicit price curves based on current estimated costs and assumed learning rates were developed for both hydrogen (including production, transport and storage) and renewable electricity (assuming 100% renewables with storage). These curves were then calculated in equivalent gas price terms as follows:

— The hydrogen gas equivalent curve was based on hydrogen costs and hydrogen heating value converted to $/GJ and assumed to be available in the SWIS; i.e., bypass the DBP
— The renewable electricity gas equivalent curve was based on the average resource cost to meet the SWIS demand with 100% renewable electricity converted to $/GJ at assumed heat rates.

The underlying gas consumption projections were then subjected to the hydrogen and where relevant renewable electricity substitution tests (based on gas equivalent pricing) in determining when the cross-over in technologies might occur under different hydrogen and renewable learning curves and price paths. This was implemented by assuming that renewable hydrogen or renewable electricity would displace gas on the DBP once the cost of either or both curves fell below the underlying projected price for gas delivered by the DBP.

Rapid Transition (high)

The Rapid Transition case reflects changes to Australian policy to meet a higher target of 45 per cent emissions reduction by 2030 compared with 2005 levels. In the longer term, Australian emissions are projected to reach a net zero target by 2060. Under this scenario the electricity sector is also assumed to be subject to a 50 per cent renewables target by 2030. These policies collectively drive a faster transition away from gas than in the Base case. The scenario assumes a higher shadow price for carbon reflective of the higher 2030 constraint. As for the Base case, the shadow price is based on the national target. After 2030, the shadow price is escalated in the same way as the base case.

Other sectoral transitions use the same principles as set out in the Base case above with all other gas usage held constant over the modelling horizon. The underlying gas consumption projections were then subjected to the same substitution tests as in the Base case.

Slower action (Low)

The Slower action case assumes that Australia undertakes less effort to reduce greenhouse gas emissions compared with the Base case and reneges on its obligations under the Paris Agreement. It implies no further action to 2030 as the additional abatement required to meet the 15 per cent target would be satisfied by the Kyoto carry-over emissions reduction (amount by which Australia is expected to exceed its Kyoto obligations). Consequently, this scenario also assumes no additional renewable target for the electricity sector.

The scenario assumes no shadow price to 2030. From 2030, a shadow price for carbon is assumed, reflective of the lower emissions target (shadow price is lower than the Base case). This shadow price is escalated at the same rate as in the Base case.

Sectoral transitions use the same principles as set out in the Base and Rapid Transition cases above.

Inputs

It was agreed with AGIG that the model would incorporate publicly available information where possible. International Energy Agency published data has been used to project gas prices based on LNG net back prices. Hydrogen cost structures have been based on the most recent CSIRO report.

3 GAS USAGE AND PRICE PROJECTIONS

The DBP supplies gas to six major sectors with a small residual volume supplied to a group that we collectively refer to as others. The DBP tariff is in two parts: a capacity charge and a throughput (usage) charge. AGIG provided ACIL Allen with details on its customer base including customer contracted and expected throughput. ACIL Allen developed a schedule of contracted gas and gas usage based on the estimated values in 2021 which are shown in Table 3.1. AGIG provided the classification of each shipper into the sectors.

TABLE 3.1 ASSUMED CONTRACTED GAS AND GAS USAGE IN 2021

Sector	Contracted gas (PJ/a)	Gas usage (PJ/a)
Alumina	[redacted]	
Gas for power generation		
Other domestic gas		
Chemicals		
Nickel		
Minerals – iron ore		
Other		
Total		

SOURCE: AGIG AND ACIL ALLEN

An important aspect of the analysis was how the levels of gas (contracted and used) might change over time, especially in the light of competitive pricing pressures for trade exposed sectors and environmental policies aimed at reducing greenhouse gas emissions both nationally and internationally.

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. There are no gas demand shocks assumed in the model.[2]

Gas for power generation is considered through explicit modelling of the SWIS. Gas in the other domestic sector is considered to continue for reticulated gas users, regardless of likely changes in price over time.

[2] The model includes a facility to add exogenous demand shocks.

As noted in Chapter 2, these underlying gas consumption projections were then subject to substitution tests with hydrogen and where relevant, renewable electricity in determining when costs were projected to cross-over.

We have set out our consideration for each sector in the following sections.

3.1 Alumina

The alumina sector (producing alumina from bauxite) consumes the largest volume of gas in Western Australia; consuming around [redacted] per cent of domestic gas consumed each year ~ [redacted] PJ. There are four alumina refineries in Western Australia:

— Three refineries owned by Alcoa at Kwinana, Pinjarra and Wagerup and producing more than 9 million tonnes of alumina each year.

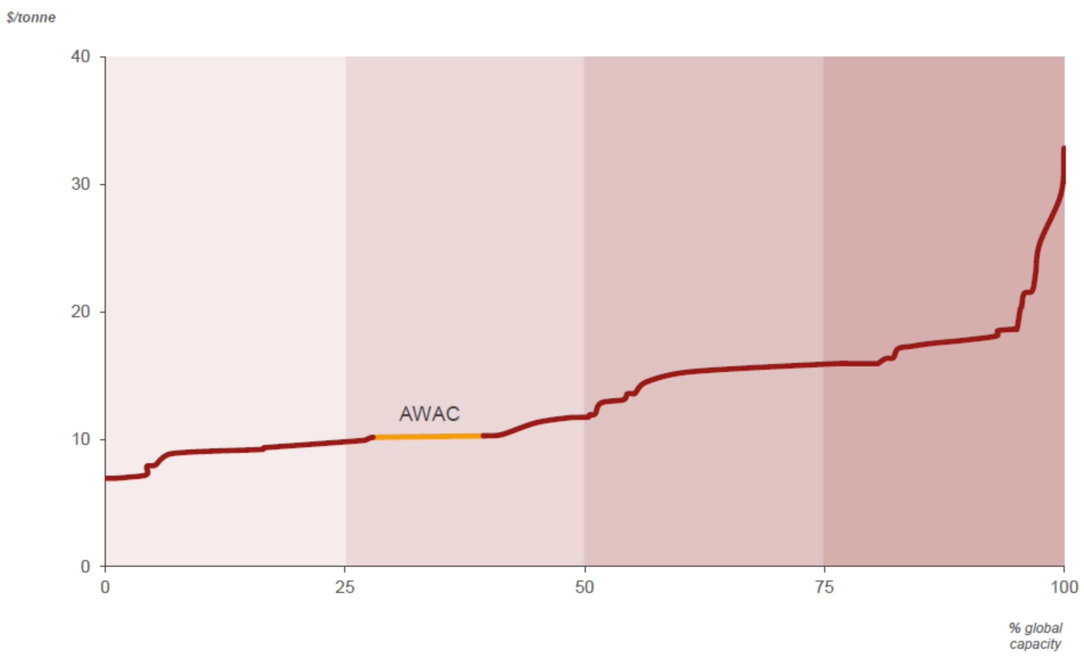
— The Worsley refinery owned predominantly by South 32 producing around 4.6 million tonnes of alumina per annum.

Combined these refineries represent around 10 per cent of the worlds production of alumina.

Bauxite is delivered to the refineries from various mines in the Darling Ranges south east of Perth. While it is a relatively low-grade ore (27-30 per cent aluminium oxide), it is close to the surface with typically ½ metre of overburden. It also has low reactive silica, making the bauxite relatively easy to refine.

Figure 3.1 shows the Alcoa position on the global bauxite cost curve in 2017 (AWAC is a joint venture between Alcoa and Alumina limited). The Alcoa bauxite operations are in the low second quartile in terms of cost.

FIGURE 3.1 GLOBAL BAUXITE MINING CASH COST CURVE BY COMPANY Q4 2017



SOURCE: ALUMINA LIMITED 2017 FULL-YEAR RESULTS – SOURCED FROM HARBOUR ALUMINIUM

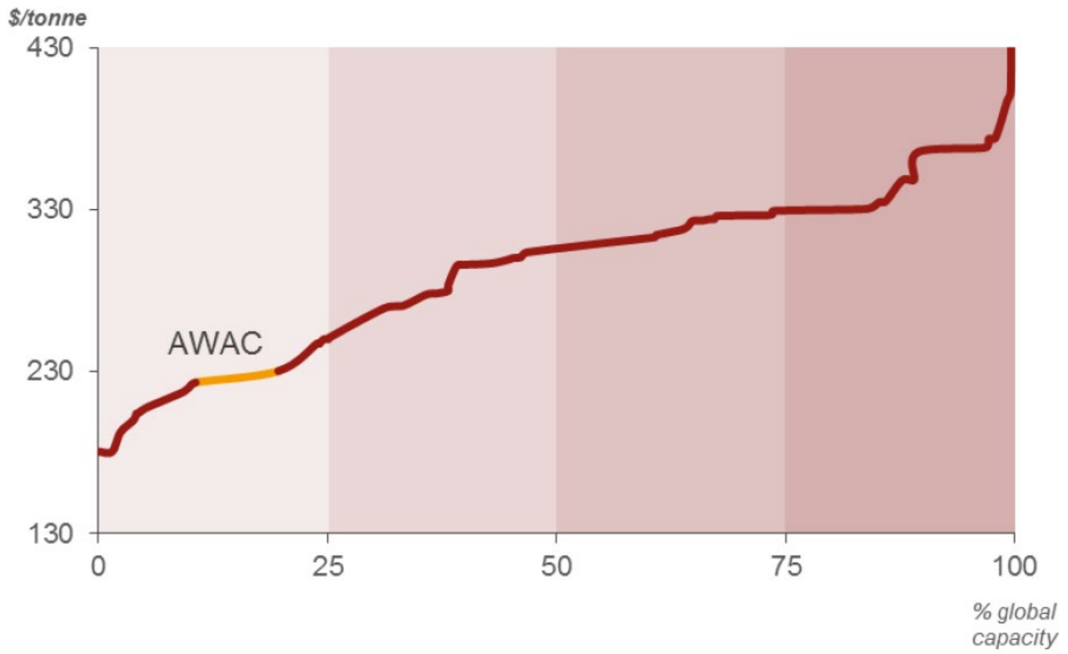
Figure 3.2 shows the Alcoa position on the global alumina refining cost curve in 2017. The Alcoa refining operations are in the first quartile in terms of cost at around $220/tonne of alumina. South32's 2016 annual report states that the cost of producing alumina at Worsley was around $210/tonne of alumina.[3]

[3] South32 (2016), Annual report, p. 59.

Based on the above, it is reasonable to assume that the Western Australian alumina sector is low cost and is in the first quartile of the global cost curve for alumina production. Even should significant growth in alumina refining capacity occur, the proximity of the Western Australian refineries to the large low-cost local bauxite resource, implies that they will retain a competitive position in global alumina production.

ACIL Allen has projected the alumina sector will continue to contract for and use the same quantities of gas into the future. Alumina production consumes around [redacted]GJ per tonne of alumina produced. Even as gas prices rise, including environmental charges, it is unlikely that the Western Australian alumina refinery would lose global competitiveness to the point that they would be displaced or reduce production. Therefore, ACIL Allen assumes that, rather than gas demand declining as gas prices rise and emission standards tighten, alumina production switches from using gas to using hydrogen as its energy source, when the latter becomes cost competitive.

FIGURE 3.2 GLOBAL METALLURGICAL ALUMINA REFINING CASH COST CURVE BY COMPANY Q4 2017



SOURCE: ALUMINA LIMITED 2017 FULL-YEAR RESULTS – SOURCED FROM HARBOUR ALUMINIUM

3.2 Gas for Power generation

Most gas for power generation on the DBP is consumed in the SWIS. ACIL Allen maintains a detailed market model simulator for the SWIS based on the WEM rules; the model is called *PowerMark WA.*

Gas for power generation is subject to several competing technological and policy factors. These include:

— falling renewable technology costs
— increasing embedded rooftop generation and batteries
— changing consumer preferences
— improved appliance efficiency
— Commonwealth and State based policies aimed at limiting greenhouse gas emissions.

Gas for power generation varies significantly based on these factors. Therefore, ACIL Allen developed three gas for power generation scenarios using our *PowerMark WA* simulator. The market simulator incorporates demand profiles including the uptake of embedded rooftop solar PV and batteries and electric vehicles. Batteries are preferred over pumped hydro or other forms of storage in Western Australia because of their modularity, flexibility and limited economies of scale – they can be deployed incrementally in time on an as needs basis without significant cost impact compared to a small number of large-scale deployments. In the time frame that batteries are likely to be required, expected reductions in costs also make them highly competitive with other forms of storage, including pumped hydro.[4] However, pumped hydro projects could be an alternative where the location and geography of a site makes it cost competitive.

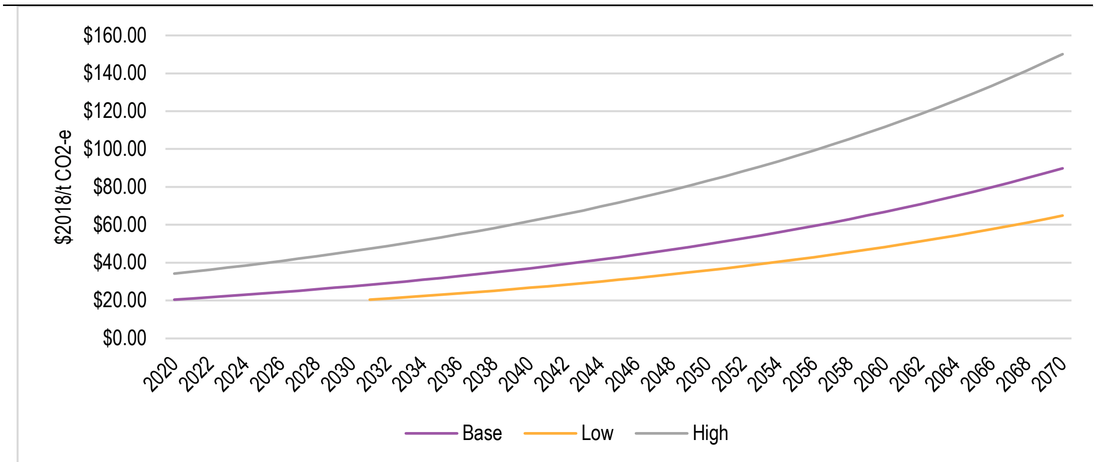
The three cases were designed around variations in emissions policy as follows:

— A Base case assuming Australia continues to pursue a policy of 26 per cent emissions reduction compared with 2005 levels by 2030 with emissions targets in 2050 around 80 per cent below 2005 levels and zero emissions by 2070
— A High case targeting 45 per cent emissions reduction compared with 2005 levels by 2030 and zero emission by 2060
— A Low case based on no further action prior to 2030 after which emissions are targeted leading to zero emissions by 2080.

ACIL Allen notes that the Western Australian Government has a target of zero net emissions by 2050. This represents a faster transition to zero net emissions than even the High case used in the analysis.

Emissions reduction policy was implemented in the simulator through an emissions intensity scheme applied to the WEM, reflecting national greenhouse gas emissions targets. The permit prices were derived in each case to meet the target policy. The permit price curves for the three scenarios are shown in Figure 3.3.

FIGURE 3.3 EIS PERMIT PRICES FOR EACH SCENARIO



SOURCE: ACIL ALLEN

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.

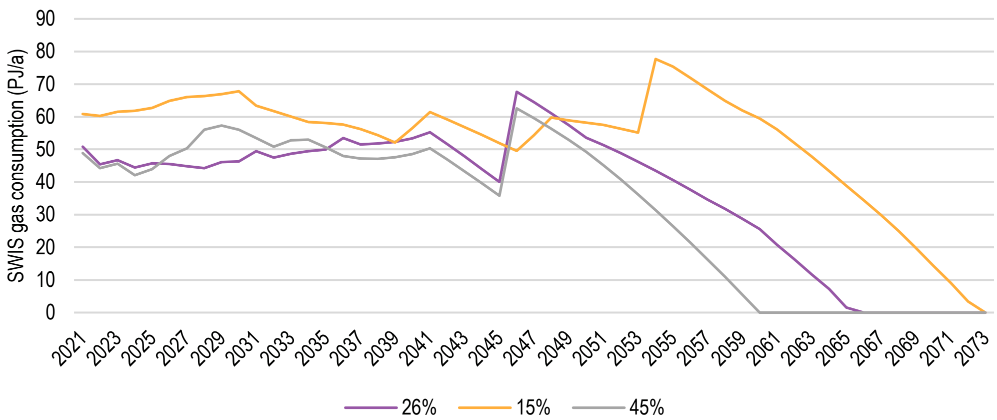
The resulting annual gas for power generation curves in the SWIS for each scenario is shown in Figure 3.4. In broad terms the higher the EIS permit price, the faster that gas for power generation declines. However, the curves are not smooth as growth in demand and the closure of coal-fired power stations 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

[4] For example, the Base case has a projection of around 200 MW of large scale (4-hour) batteries installed by 2040; this is approximately twice this by 2040 in the High case.

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.

These gas for power generation scenarios are included in the analysis for the economic depreciation study.

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



SOURCE: ACIL ALLEN

3.3 Other domestic gas

Other domestic gas is largely made up of commercial and residential consumption of gas for hot water, cooking and space heating. Demand for energy in this sector is driven by fundamental needs that are unlikely to change. However, delivering these needs through appliances that consume gas could be displaced by appliances that use electricity or alternative combustion fuels such as hydrogen. We expect gas consumption by household to decline gradually over time as alternative appliances are deployed.

Gas tariffs in this sector are dominated by distribution network costs which are regulated. However, they are also sunk costs. Faced with competition from electricity or alternative combustion fuels, the regulated gas distributor may choose to reduce network prices to retain customer volume.[5] Therefore, until electricity or alternative combustion fuels can displace natural gas on an economic basis in this sector, we would expect gas volumes to be maintained. Switchover to hydrogen in the other domestic gas sector is implicit through the analysis of economic depreciation in the light of alternative fuels competition (specifically hydrogen), modelled by ACIL Allen.

As the cost of reticulating gas to new customers is high (except for in established areas) we expect limited growth of commercial and residential customers over time. Therefore, ACIL Allen has projected the Other domestic gas sector will continue to contract for and use the same quantities of gas into the future.

3.4 Chemicals

Most of the gas supplied on the DBP as chemical feedstock goes to the Wesfarmers facility at Kwinana, south of Perth. 75 per cent of gas supplied to the chemicals sector is projected to be delivered to the Wesfarmers facility in 2020.

[5] As distribution charges make up such a large portion of domestic gas costs, there is considerable scope to lower charges to maintain gas volumes. This is not the case for the DBP, where transport costs make up a relatively small portion of delivered costs and there is little scope to lower tariffs to compete in the face of technology change.

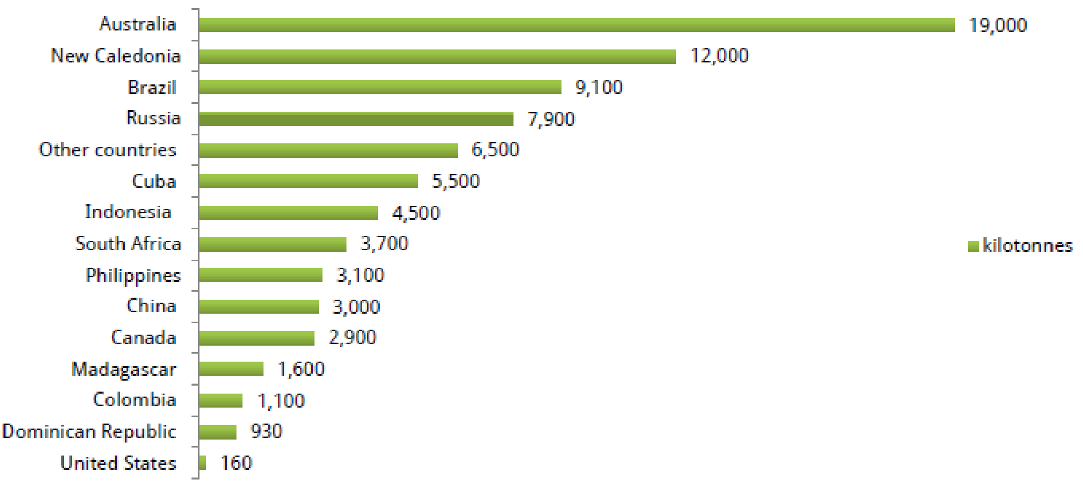
The Wesfarmers Kwinana facility produces ammonia, ammonium nitrate and industrial chemicals for the resource and industrial applications. Some of the ammonium nitrate is exported. ACIL Allen understands that Wesfarmers achieved EBITDA of [redacted] on revenues from this sector in financial year 2018.

ACIL Allen does not have access to detailed global cost curves for this sector. However, as much of the Wesfarmers' product is sold locally and as Wesfarmers appears to have strong margins, ACIL Allen has projected the Chemicals sector (dominated by the Wesfarmers Kwinana facility) will continue to contract for and use the same quantities of gas into the future. Therefore, ACIL Allen assumes, rather than gas demand declining as gas prices rise and emission standards tighten, that chemicals production switches from gas to hydrogen as its source when the latter becomes cost competitive.

3.5 Nickel

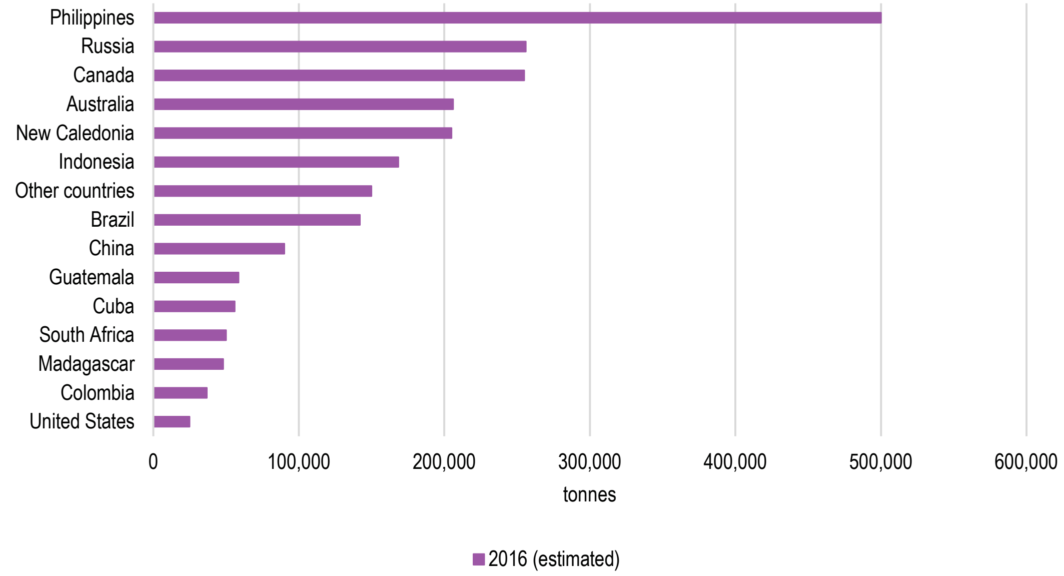
Australia holds the world largest reserves of nickel as is shown in Figure 3.5. More than 90 per cent of Australian reserves are in Western Australia. World nickel production for 2016 is shown in Figure 3.6. The largest producer was the Philippines with Australia being the fourth largest.

FIGURE 3.5 WORLD NICKEL RESERVES



SOURCE: GOLDEN DRAGON CAPITAL (JUL 16), P.6.

FIGURE 3.6 WORLD NICKEL PRODUCTION - 2016



SOURCE: US DEPARTMENT OF INTERIOR (2017) MINERAL COMMODITY SUMMARIES – 2017, US GEOLOGICAL SURVEY, VIRGINIA, P.115.

Demand for nickel is expected to grow with the application of its use in battery storage systems along with its current application in stainless steel and other corrosion resistant alloys (e.g., copper nickel alloys used in desalination plants). CRU projects annual compound growth of 2-3 per cent in corrosion resistant applications and up to 10 per cent compound growth in battery applications to 2035.[6]

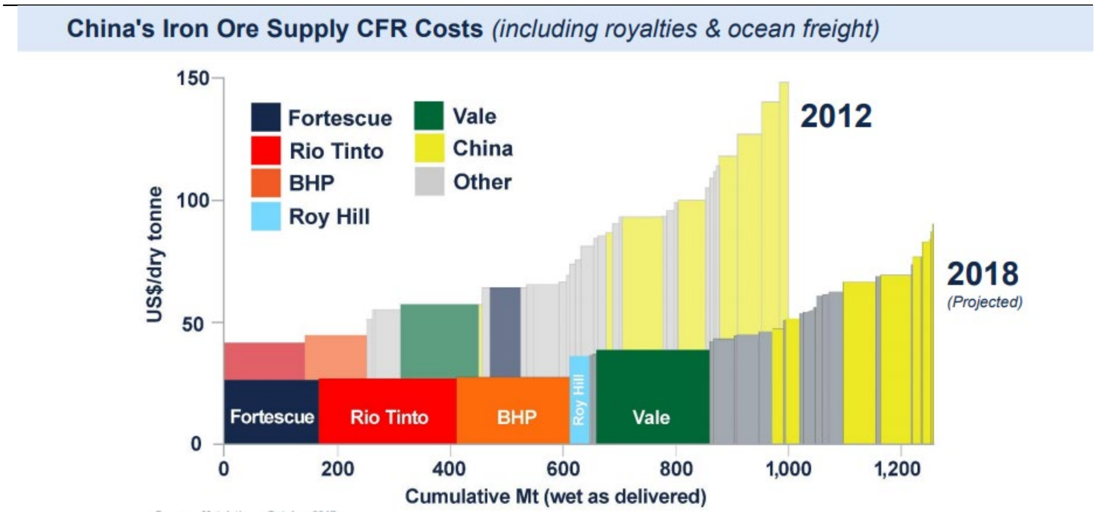
[redacted]

3.6 Minerals Iron Ore

The Western Australian iron ore industry is highly competitive globally. China is the major consumer of Australian iron ore with around 650 million tonnes shipped in 2018. The Australian producers are shown as the lowest cost producers delivering iron ore to China as is shown in Figure 3.7.

[6] CRU cited in Sherritt (March 2017) , Investor Presentation, Sherritt International Corporation

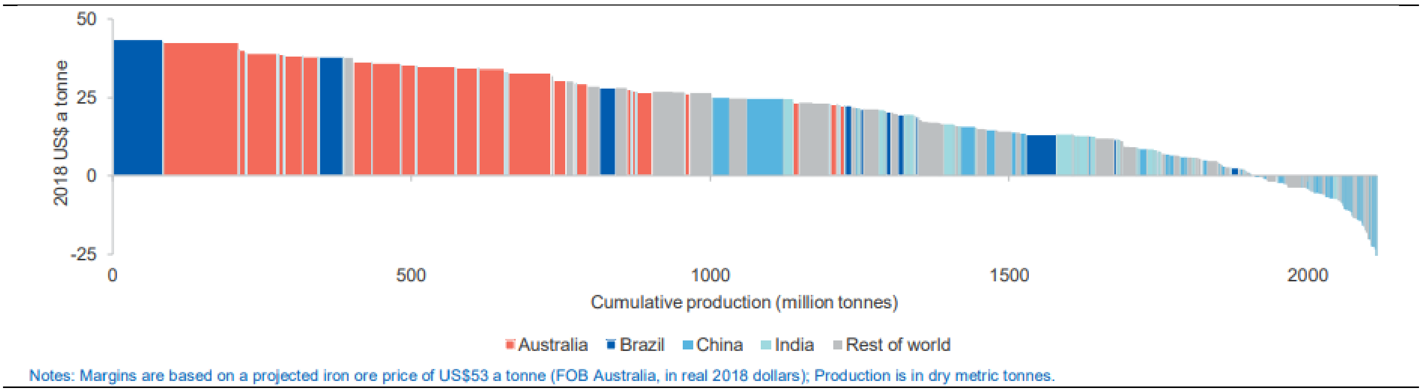
FIGURE 3.7 SUPPLY OF IRON ORE TO CHINA



SOURCE: FORTESCUE (2018)

Global iron ore production exceeds 2 billion tonnes. Australia is the largest producer of iron ore (more than twice that of Brazil, the next largest producer. Figure 3.8 shows a projection by AME Group of margins for global supply in 2023 based on an iron ore price of $53USD per tonne. The Australian producers, dominated by production from haematite, are almost all in the first and second quartiles.

FIGURE 3.8 PROJECTED IRON ORE MARGINS IN 2023 (BASED ON $53USD/TONNE FOB)



SOURCE: AME GROUP (2018)

The Sino Iron project operated by Citic Pacific is located around 100 km south west of Karratha and is based on a large magnetite resource which requires large amounts of power generation to process the resource. The mine includes a combined cycle plant of 480 MW to supply electricity to extract ore from the magnetite mined. It is expected to operate for at least 40 years based on the existing resource and the ability to acquire additional leases. Citic Pacific has invested in excess of $12 billion USD in the project.

While the cash costs for the Sino-Iron project are not publicly available, they are expected to be higher than more prevalent haematite-based mines owned by Fortescue, Rio Tinto, BHP and Roy Hill. However, the resulting iron ore concentrate has a higher iron content and less impurities than the haematite-based ores. This makes the resulting product attractive to steel producers.

The pre-existing investment by Citic Pacific is sunk. ACIL Allen has assumed that project's product will continue to be attractive to steel producers and that gas consumption (primarily for power generation) will continue at current levels – primarily consumed in electricity generation to support the extraction process. Therefore, ACIL Allen's has concluded that the production of iron ore from magnetite at the Sino-Iron Project will remain competitive and continue.

Therefore, ACIL Allen assumes, rather than gas demand declining as gas prices rise and emission standards tighten, that iron ore production switches from gas to hydrogen as its energy source when the latter becomes cost competitive.

ACIL Allen notes that the main use of natural gas by both haematite and magnetite producers is for energy in producing iron ore and that this form of energy could be displaced both by hydrogen and by renewable energy. However, producing electricity to meet steady loads continuously would require a very large volume of batteries to smooth out the variability of renewable output, including days where output is very low (cloudy and still days). This would have a very high cost compared to projected longer-term hydrogen costs and so was ruled out. Where renewable costs were considered to be lower, they would bring forward to point at which gas and alternative costs cross-over, and consequently, the point in time at which DBP would no longer be able to fully recover deployed capital.

3.7 Other

Other contracted gas includes gas used in other mineral production including gold and vanadium. It is assumed that the cost of gas is not significant factor and that the demand for gas continues throughout the modelled period. Therefore, ACIL Allen assumes, rather than gas demand declining as gas prices rise and emission standards tighten, that other mineral production switches from gas to hydrogen when the latter becomes cost competitive.

3.8 Gas price projections

ACIL Allen developed three gas price scenarios for the modelling exercise. The scenarios were based on the International Energy Agency's price projections for Japan (JCC) (included in the 2018 World Energy Outlook) as a representative price for LNG prices. The IEA forecasts are shown for the years projected in Table 3.2.

TABLE 3.2 IEA JCC GAS PRICE PROJECTIONS $REAL 2018 USD/MMBTU

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

Table 3.3 shows the JCC prices in Australian dollars (real 2018).

TABLE 3.3 IEA JCC GAS PRICE PROJECTIONS $REAL 2018 AUD/GJ

IEA Scenario	2017	2025	2030	2035	2040
New Policies	10.2	12.4	12.6	12.6	12.8
Current Policies	10.2	12.5			13.3
Sustainable Development	10.2	11.4			11.1

SOURCE: ACIL ALLEN

Long run Australian gas prices were assumed to trade at LNG net back prices. Prices were netted back to Australia assuming an AUD/USD exchange rate of 0.75, gasification costs of $3USD/GJ and transportation costs from Australia to Japan of $0.67/GJ. Table 3.4 shows the calculated LNG netback prices.

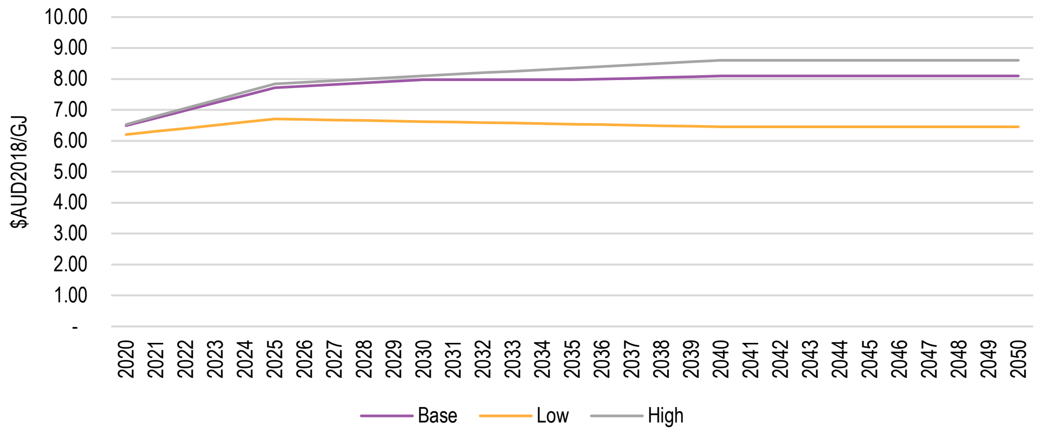
TABLE 3.4 IEA JCC INFERRED AUSTRALIAN LNG NETBACK PRICE PROJECTIONS $REAL 2018 AUD/GJ

IEA Scenario	2017	2025	2030	2035	2040
New Policies	5.6	7.7	8.0	8.0	8.1
Current Policies	5.6	7.8			8.6
Sustainable Development	5.6	6.7			6.5

SOURCE: ACIL ALLEN

The resulting projected gas prices are shown in Figure 3.9. Prices beyond 2050 are assumed to be constant in real terms.

FIGURE 3.9 PROJECTED GAS PRICES BY SCENARIO



SOURCE: IEA WEO AND ACIL ALLEN

4 HYDROGEN TECHNOLOGIES

This chapter assesses the potential range in costs for hydrogen as a replacement for natural gas both as a fuel for process heat and electricity generation and as a feedstock for industrial chemical processes (e.g., fertiliser). The assessment is then used to develop learning curves and price curves for hydrogen in gas equivalent terms. These price curves are used in the modelling (See Chapter 6 below) to determine when the cross-over between natural gas and hydrogen occurs.

This chapter draws heavily on materials published in the National Hydrogen Road Map (NHRM) (Bruce, et al., 2018) developed under the auspices of the CSIRO in 2018. The reader is directed to that study for the likely range of technologies that might be used in hydrogen production and the projected price paths for those technologies.

Hydrogen costs include the cost of production, transport and storage. The model assumes that hydrogen instantaneously displaces gas once the hydrogen gas equivalent and projected natural gas prices cross-over.

4.1 Hydrogen technologies

There are basically two pathways to hydrogen production:

— **Electrochemical technologies** which use electrical current to split water into hydrogen and oxygen.

— **Thermochemical technologies** which use fossil fuels (natural gas, coal) feedstock to produce hydrogen.

Electrochemical technologies are favoured because it produces zero emissions when coupled with renewable technology power sources (thermochemical technologies produce CO_2 as a by-product). Therefore, we have assumed the continued development of electrochemical technologies, more specifically Polymer Electrolyte Membrane (PEM) for the purposes of the analysis. Although currently more expensive than other forms of electrolysis and other production techniques, PEM electrolysis is becoming more competitive as costs of membrane production fall and process efficiency improves.

Other advantages over the alternative Alkaline electrolysis (AE) include faster response times (making it more suitable for coupling with Variable Renewable Energy [VRE] sources) and a smaller physical footprint which is advantageous in situation where there are limitations on space (e.g. hydrogen refuelling stations). Of course, if AE costs were lower than PEM, then the crossover point would occur sooner than modelled under the PEM cost assumptions. Therefore, excluding AE can be considered a conservative assumption in the context of modelling economic depreciation.

Current estimates costs for PEM lie in a range \$6.10 – \$7.40/kgH_2 (\$43 – \$52/GJ) – midrange is assumed for the study at \$6.75/khH_2. NHRM anticipates PEM costs of around \$2.50/kgH_2 (\$18/GJ) by 2025 – we have assumed this for the high case.

The cost of hydrogen from electrolysis can be significantly reduced via the scaling of plant capacities (for example, from 1MW to 100MW), greater utilisation and favourable contracts for low emissions electricity. The cost of electricity is a major factor in the overall cost of hydrogen for the electrochemical methods. Applications in which hydrogen is produced using 'otherwise curtailed' electricity generated during off-peak periods of high renewables output are therefore potentially attractive. However, in the economic depreciation model, hydrogen costs assume full costs for renewable energy (built into the National Hydrogen Roadmap assumptions and cost modelling). They would be lower where low cost curtailed (spilled) energy was used (conservative assumption).

4.1.1 Hydrogen storage

The low energy density of hydrogen in its gaseous state makes storage of H_2 economically challenging. Selection of the most appropriate storage technology represents a trade-off between the quantity of hydrogen, storage footprint (e.g., tank size) and energy usage in storing hydrogen. The basic storage options are:

— Compression
— Liquefaction
— Chemical.

The most common hydrogen storage method is compression via pressurisation in steel or carbon composite cylinders. However, the lower hydrogen density associated with pressurisation has encouraged the use of liquefaction and exploration of other chemical carriers such as ammonia, particularly in the context of hydrogen transport. For the purpose of the study we have focussed on compression at higher pressures between 35 and 350 Bar (assumes all hydrogen will be transported). In practice some hydrogen may be consumed at the point of production. The assumption that all hydrogen is compressed to higher pressures and transported is a conservative assumption (higher cost).

NHRM estimates that compression-based storage costs (Tanks from 35 to 350 bar; salt caverns) currently range from \$0.30 to \$0.53/kg H_2 (\$2.10 to \$3.75/GJ). With likely improvements in compression efficiencies, costs of hydrogen storage are expected to reduce to between \$0.23 and \$0.45/kg H_2 (\$1.60 to \$2.60/GJ) by 2025. We have assumed around \$0.50kg H_2 in 2018 falling to around \$0.25/kg H_2 by 2025.

There is work underway in Australia (both AGIG and Jemena) testing injecting and storing hydrogen in gas distribution networks. This may be a cheaper form of storage, but technical limitations indicate it will only be available as a hybrid of natural gas and hydrogen (not pure hydrogen). If cheaper forms of storage were available, the cross-over point would occur sooner.

4.1.2 Hydrogen transport

Hydrogen must be transported from the place of production or storage for use in application. There are four main options for transporting hydrogen:

— Truck
— Rail
— Pipeline
— Ship

Table 4.1 summarises the associated storage options, transport distances and other considerations for each of these options.

TABLE 4.1 HYDROGEN TRANSPORT METHODS

Vehicle	Storage	Transport Distances	Notes
Truck	Compression, Liquefaction, Ammonia carrier	<1,000 km	Transport of liquefied & compressed H_2 is available commercially. Ammonia carrier less suited given scale requirements and need to convert back to H_2. Higher pressure/liquefaction best suited to longer trucking distances >300 km
Rail	Compression, Liquefaction, Ammonia carrier	>800 – 1,100 km	As per truck, but for greater distance travelled
Pipeline	Compression	1,000 – 4,000 km	More likely to be used for simultaneous distribution to multiple points or for intercity transmission
Ship	Ammonia carrier, Liquefaction	>4,000 km	Unlikely to use compression storage given costs of operation, distance and lower H_2 density. Best suited for export.

SOURCE: NATIONAL HYDROGEN ROADMAP, 2018

The NHRM describes costs on a $/tkm basis with an estimate for 350 Bar compression of $2.98/tkm by truck. Rail and shipping (sea) are cheaper but do not appear relevant for localised production in Western Australia (assumed that hydrogen would be produced locally rather than transported as there is an abundance of renewable energy potential across Western Australia). We have conservatively allowed $1.00/kg for transport in 2018 based on trucking lower levels of compressed hydrogen and falling to $0.52/kg in 2025 for the Base case – reflecting a move to higher rates of compression and the potential for more localised production (less distance).

4.2 Hydrogen utilisation

The main potential uses for hydrogen in Western Australia are discussed below.

4.2.1 Industrial process heat

A significant component of gas usage in Western Australia is used for industrial process heat, especially aluminium production and petrochemicals. Hydrogen blended with natural gas could be used in existing process heat facilities in small proportions (10 – 15 per cent), although each site would need to be assessed specifically to ensure that using blended hydrogen would be safe. The difference in ignition and flame temperature and heat flux between hydrogen and natural gas would require existing facilities to be modified to burn higher proportions of hydrogen. Therefore, a 100 per cent (pure) hydrogen stream would require modest investment in new facilities (burners, storage and handling).

4.2.2 Commercial and residential heating

Residential and commercial existing appliances have the potential to use blended streams with up to 20 per cent of hydrogen. Therefore, there is more potential to use hydrogen in these sectors than in industrial applications. However, to achieve this blending would have to be done at the distribution level, beyond the point at which industrial consumers are supplied. Above this limit of 20 per cent would require changes to valves and burner design to deal with the different characteristics of burning hydrogen compared with methane.

4.2.3 Electricity generation

Hydrogen could be used as an alternative to natural gas in power generation using gas turbines. This would not only compete directly with natural gas but also with various forms of storage (pumped hydro storage, battery energy storage systems) to provide grid firming services. To be utilised in this way, hydrogen costs (per GJ equivalent) would need to fall below gas prices which would be expected to reflect costs of extraction, transportation and costs associated with greenhouse gas emissions.

An integrated hydrogen production and power generation facility also provides grid benefits by absorbing excess non-dispatchable or intermittent generation which is expected to occur as the penetration of renewable generation increases.

The modelling does not incorporate hydrogen for electricity generation as this is assumed to be displaced by renewable electricity with storage.

4.2.4 Industrial feedstock

Use of clean hydrogen as an industrial feedstock involves direct displacement of hydrogen derived from SMR as the incumbent source of production. Use of hydrogen in the petrochemical industry, as a means of treating and refining crude oil has been declining due to Australia's growing dependence on imported refined fuel products. However, with increasing concern over the need to reduce Australia's dependence on liquid fuel imports and to decarbonise the transport sector, there could be a role for hydrogen in treating fuels derived from biomass.

Input of clean hydrogen into ammonia and other chemicals such as methanol could renew demand for these products as the world transitions to a low carbon economy.

ACIL Allen has assumed that no industrial feedstock natural gas is switched to hydrogen in the modelling (conservative assumption).

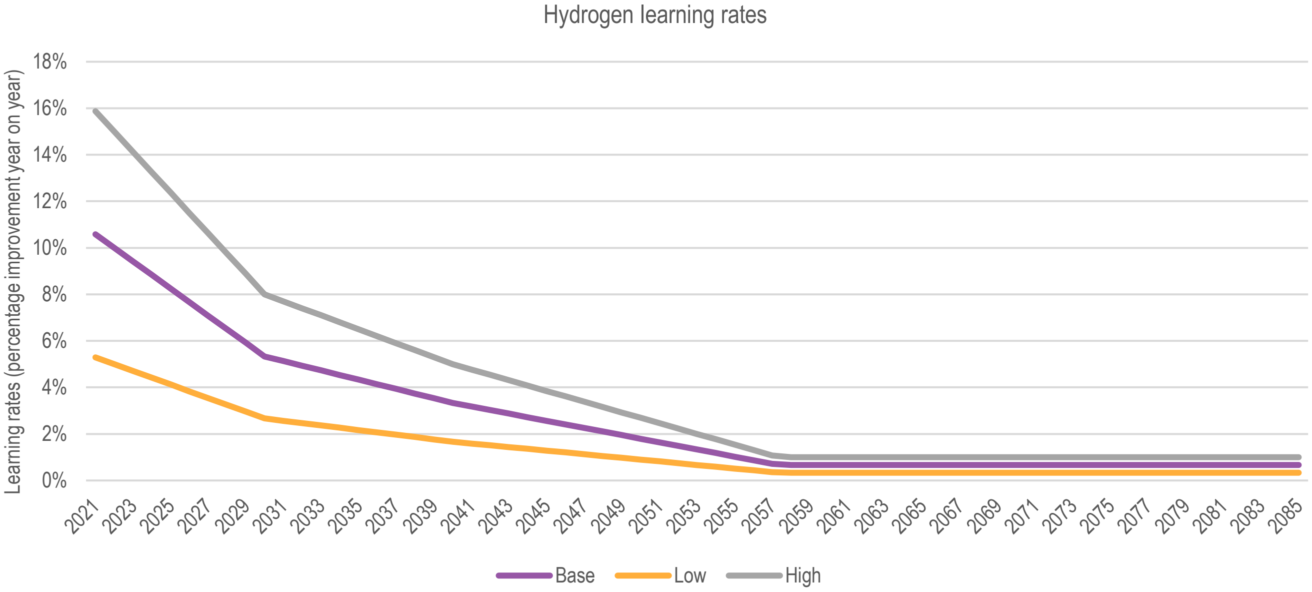
4.3 Hydrogen P(t) curves

Using the above analysis and NHRM estimates for hydrogen production, storage and transport costs between 2018 and 2025, ACIL Allen developed hydrogen price curves for the purposes of calculating the price path of hydrogen substituting for natural gas. The approach taken in developing the price curves was as follows:

— Initial prices for 2018 and 2025 were based on NHRM estimates for the most likely hydrogen technology to be used for large-scale production
— The 2025 NHRM estimates were provided for the NHRM Best Case – which ACIL Allen has assumed for the High case – fast learning
— Fast learning rates for 2018 to 2025 were fitted to the 2018 and 2025 estimates
— Fast learning rates were extrapolated to 2085 (subject to reasonability tests)
— Low and base scenario learning rates were determined as 2/3 of the High rate and 1/3 of the high rate respectively.

The learning rates developed for each scenario are shown in Figure 4.1.

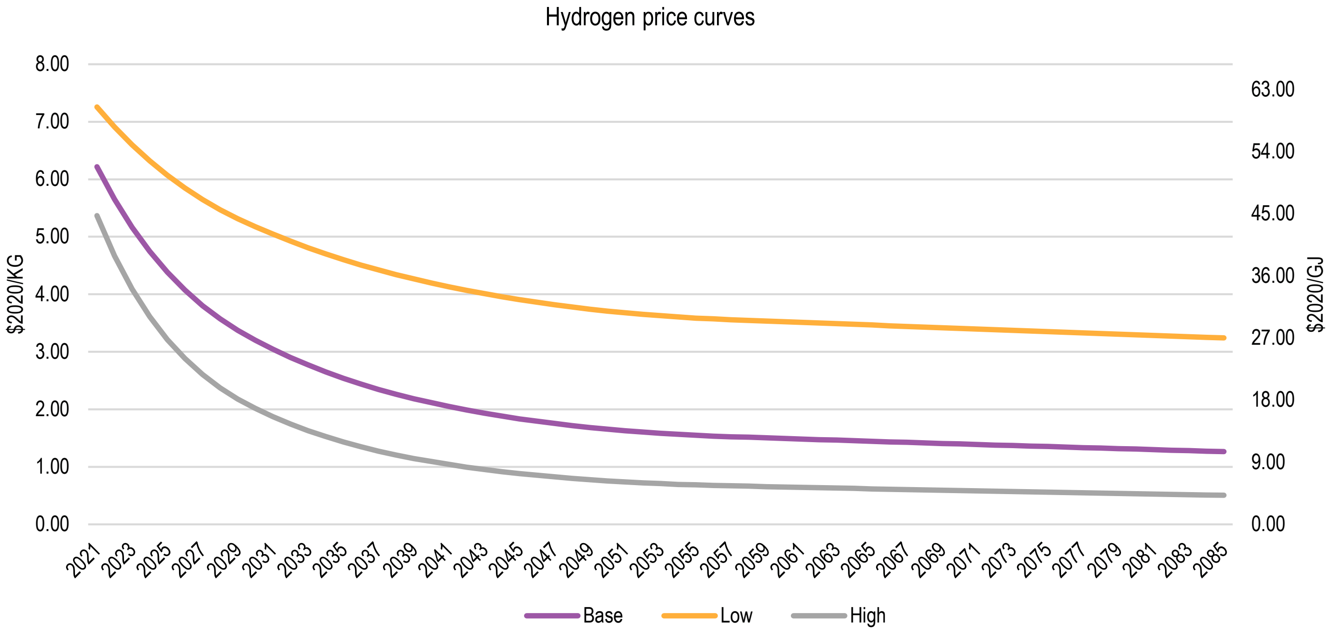
FIGURE 4.1 LEARNING RATES APPLIED TO HYDROGEN PRICE SCENARIOS



SOURCE: ACIL ALLEN BASED ON DATA PRESENTED IN CSIRO 'NATIONAL HYDROGEN ROADMAP', AUGUST 2018

The hydrogen price curves developed for each scenario are shown in Figure 4.2. The high case has the faster decline in prices and the low case the slowest decline in prices. The left-hand side axis shows the price in $2020/kg H_2 and the right-hand side shows the price in terms of gas equivalent calorific value ($2020/GJ) based on an energy content of 120 GJ/kg H_2.

FIGURE 4.2 HYDROGEN PRICE CURVES FOR EACH SCENARIO



SOURCE: ACIL ALLEN BASED ON DATA PRESENTED IN CSIRO 'NATIONAL HYDROGEN ROADMAP', AUGUST 2018

5 ELECTRICITY – RENEWABLE TECHNOLOGIES

This chapter assesses the potential range in costs for renewable technologies as a replacement for natural gas used in electricity generation. In chapter 3, we covered three policy scenarios in which gas was partially displaced in powering electricity generation in the SWIS by renewable technologies. This chapter of the report focusses on price curves for an optimised investment producing 100 per cent renewable electricity generation – overnight costs for displacing electricity in each year of the modelling.

The price curves are based on an optimised least cost mix of renewable and storage technologies to meet annual energy and demand requirements. The shape and scale of annual demand is an important factor in determining the price curves. As most electricity generation served by the DBP is in the South West Interconnected System (SWIS) and covered by the Wholesale Electricity Market (WEM), we have focussed our analysis on price curves for that region.

This chapter draws on renewable technology cost projections developed by ACIL Allen for use in its suite of energy models for the east and west coast of Australia. These cost projections are largely consistent with public data but with adjustments based on ACIL Allen's experience and assessment of recent projects. The key generation technologies used in the assessment are solar PV, wind and battery storage.

Optimised least cost modelling is affected by the cost of technologies and the shape of the demand curve. Embedded rooftop solar PV and battery storage are expected to affect the SWIS demand significantly over time. The modelling approach, inputs and resulting price curves are discussed below.

5.1 Modelling approach

ACIL Allen developed a simplified optimised least cost model to assess costs for developing a 100 per cent renewable/storage power system in the SWIS. Cost estimates were developed for sample years to 2050 and interpolated between sample years and extrapolated to 2085.

Half hourly grid-based demand for each model year was taken from ACIL Allen's proprietary *PowerMark WA* model (see 0 below). This demand is adjusted for embedded solar PV and battery storage and incorporates peak demand and annual energy growth in line with AEMO projections.

The model incorporates wind, solar PV and battery technologies. ACIL Allen model the use of battery storage because they are modular, flexible and have limited economies of scale meaning they can be deployed incrementally on an as needs basis without significant cost penalty. Our assessment for Western Australia is that batteries are the least cost solution (when optionality is considered) compared with pumped hydro and other forms of storage. However, should other forms of storage prove to be cheaper, the price curves would fall and the cross-over would occur sooner. Therefore, limiting storage to batteries is a conservative assumption.

Three wind profiles taken from historical wind generation data for the north, central and south regions of the SWIS and a single solar PV profile were incorporated in a simplified model. Battery capability was assumed to have four hours of storage for each megawatt of capacity installed.

The model allocates wind (diversified across the three zone profiles) and solar generation coupled with battery storage to meet demand in each half-hour on a lease cost basis. Capital costs are allocated on an annualised basis. Variable and fixed operating costs are included in the assessment. The annualised cost of meeting SWIS demand with renewable generation and storage is determined by summing all annualised costs and averaging them across annual demand for energy. Network losses were ignored for the purposes of the modelling.

In 2020, the annual SWIS demand peak to average ratio was modelled at 1.77 with around 2 MW of wind (spread across the three regions), around 1 MW of solar and around 1 MW of batteries projected to be required for each MW of peak demand.

By 2050, the annual SWIS demand peak to average ratio was projected to fall to 1.47 with around 2.7 MW of wind (spread across the three regions), around 0.95 MW of solar and around 0.75 MW of batteries projected to be required for each MW of peak demand.

5.1.1 PowerMark WA

PowerMark WA was initially developed prior to the WEM commencement in 2006 and has been refined over the last 12 years in-line with changes to the market rules. PowerMark WA simulates the operation of the WEM, including projected energy prices, explicit treatment of the capacity market and new entry. As an internally developed model, it draws upon our experience in modelling the NEM, but is specifically tailored to the WEM features and rules.

PowerMark WA takes a range of input assumptions including:

— Wholesale NEM demand traces, including distributed generation contribution
— Correlated wind output profiles
— Generator inputs at unit level on sent-out capacity, thermal efficiencies, auxiliary use, minimum generation levels, emission factors, fuel prices, variable/fixed operating and maintenance costs, planned and forced outage rates, and temperature de-rating
— Maximum STEM, and Maximum Alternative STEM prices series
— Maximum Reserve Capacity Prices, Reserve Capacity Requirements
— Network structure and MLFs
— External policy settings such as carbon prices.

The model simulates the market at a half-hourly resolution producing a range of results including:

— Half hourly energy price series which is comparable to the WEM's Balancing price series
— Individual generator unit performance including dispatch, gross revenues and costs
— Capacity market outcomes – capacity credits allocated and prices by capacity year
— Investment, new entry and retirements.

Each of these detailed results is automatically aggregated up to produce results at monthly, quarterly, financial year and calendar year totals/averages. Results are also provided for peak/off-peak period definitions. Other summary results produced include generator capacity factors, net revenues and EBITDA estimates.

The Reserve Capacity market is an administered pricing mechanism of the WEM in which AEMO sets a forward-looking Maximum Reserve Capacity Price (MRCP), based on assessment of OCGT costs and the required level of capacity for the market. The actual Reserve Capacity price received by participants is modified by the level of capacity oversupply actual delivered by the market. This is proposed to change further in line with a recent proposal from the PUO but is expected to remain administered. PowerMark WA replicates the operation of the Capacity market and provides projections for each of the significant components.

As the RET scheme is national, the model requires inputs not only for NEM regions, but also for other electrical systems such as the Western Australian SWIS and NT systems, for remote locations (for example Mt Isa, Pilbara etc.) as well as distributed generation from small scale solar PV systems. These are considered in setting the LGC forward curve in the modelling.

5.2 SWIS demand

The SWIS annual demand curve is expected to change substantially over time as the penetration of embedded rooftop solar PV and batteries increase. This causes a hollowing out of demand during the middle of the day as rooftop solar PV generates over this period, although some of the generation will be shifted in time by batteries into the early evening.

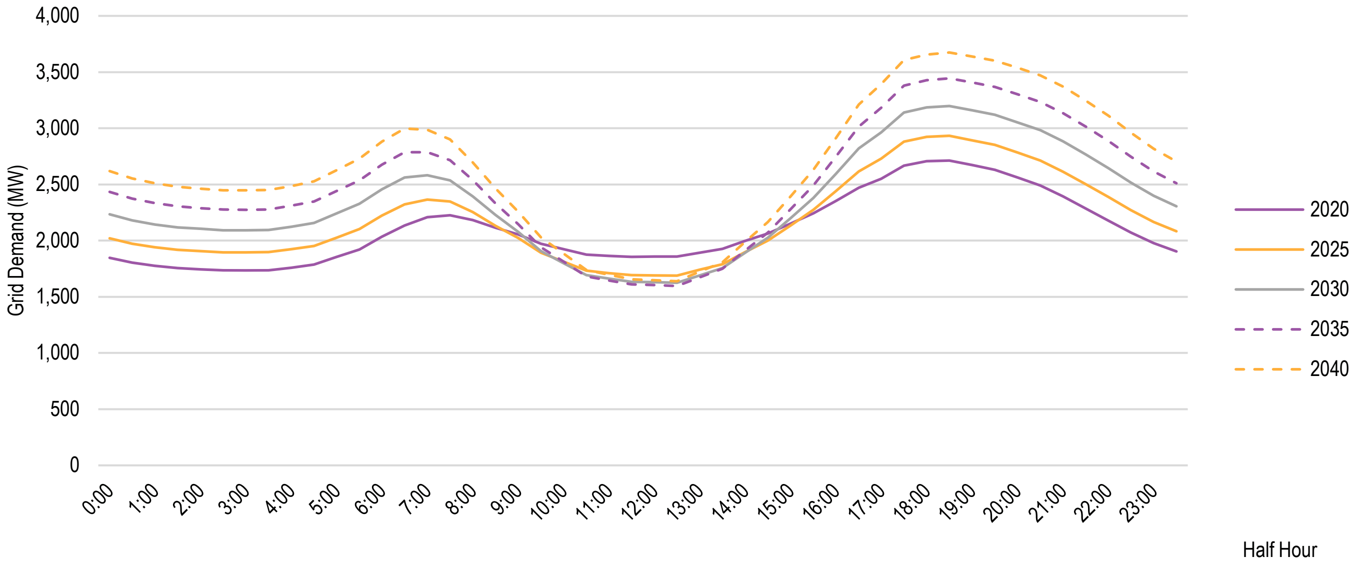
ACIL Allen has developed embedded solar and battery projections based on a consumer payback model (avoided grid costs versus investment costs). The maximum effect is around 750 MW delivering around 1,700 GWh in 2020 rising to around 2,500 MW delivering 5,500 GWh in 2050.

The demand used in the simplified modelling is the grid demand (i.e., underlying demand less embedded PV generation.) The shape of grid-based demand changes significantly over time with the take-up of rooftop solar PV and batteries.

Figure 5.1 shows annualised time of day demand profiles between 2020 and 2040 at five-year intervals. Demand in the overnight and evening peak periods shows consistent growth over the 20-year period. However, the period between 8 AM and 4 PM is increasingly hollowed out by the installation of rooftop solar PV. The result of this is what has popular become known as the duck-curve effect.

Over time, the duck-curve effect causes more excess energy to be spilled from solar PV during the middle of the day.[7] This increases incentives for battery storage to capture the excess energy (at very low prices) and return it to the grid during peak periods (when prices are high).

FIGURE 5.1 ANNUALISED TIME OF DAY DEMAND PROFILES



SOURCE: ACIL ALLEN

In the simplified modelling, there are a small number of hours per year that can't be met by the combination of batteries, wind and solar generation. It is assumed that the shortfall is met through demand management rather than very large costs being imposed on consumers by continuing to build storage and renewable installations.

[7] This is the effect driving surplus renewable energy that may be available at low or zero prices for hydrogen electrolysis.

5.3 Technology costs

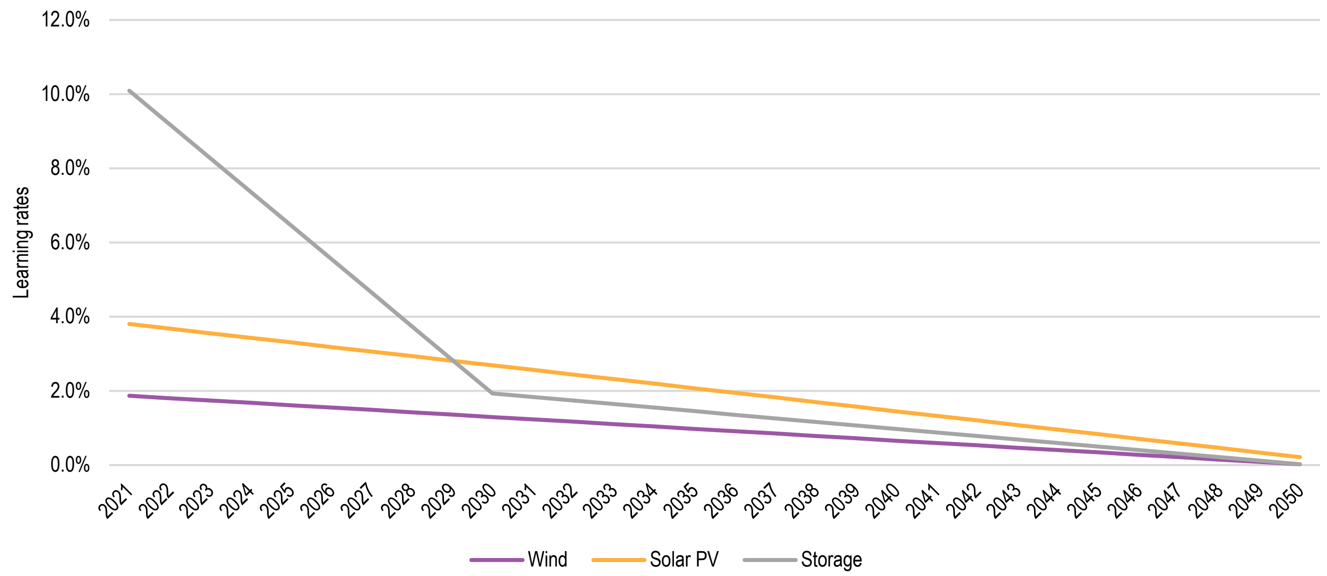
As noted above, technology capital and operating costs used in the analysis have been developed by ACIL Allen as inputs to its energy modelling suite. ACIL Allen uses these inputs widely in market analysis and due diligence exercises involving both debt and equity investors. They have been tested across a wide variety of modelling exercises.

The learning rates have been developed using historical observations of wind and solar capital cost reductions and have been adapted for battery storage.

Capital cost projections are based on starting values linked to costs associated with recent projects and then adjusted over time by technology learning rates. ACIL Figure 5.2 shows the learning rates for the technologies used in the model.

Wind generation technology is relatively mature with learning rates falling from just under 2% in 2020 to close to zero in 2050. Large-scale solar PV is also relatively mature but is expected to continue to show significant cost improvements over the next 20 years. We project a fast decline in battery storage costs to the mid to late twenties as manufacturers and developers continue to find significant improvements in manufacture and installation. After 2030, we project rates to gradually fall in line with the rate of learning that has been observed in other energy technologies.

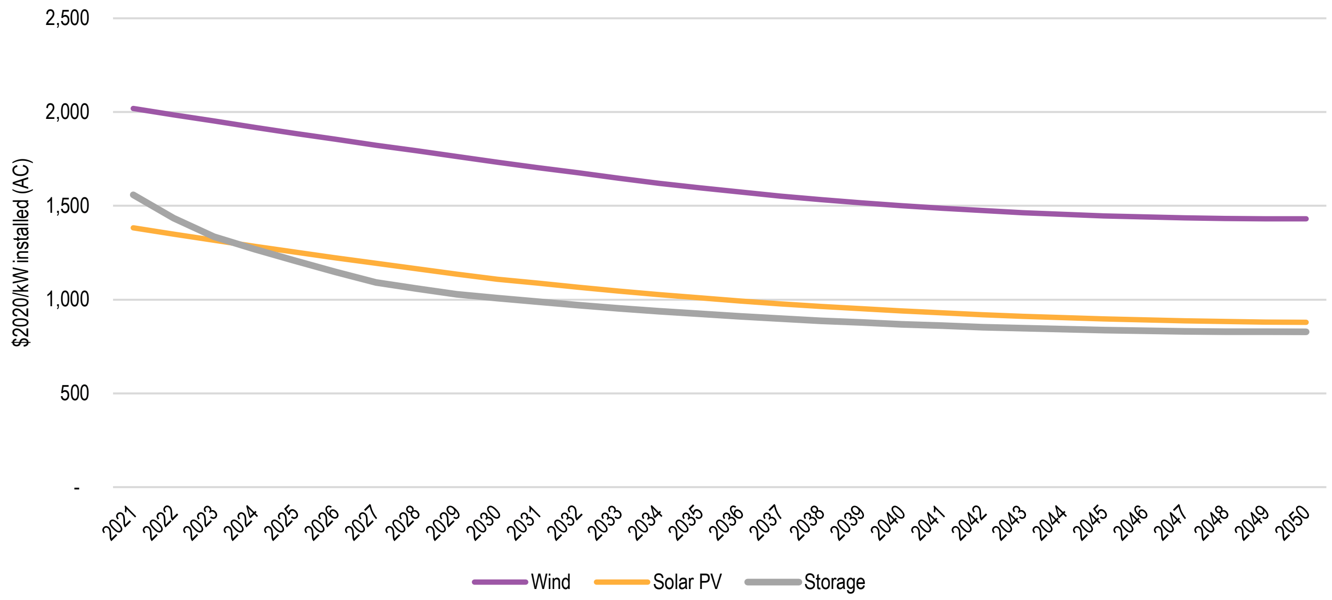
FIGURE 5.2 TECHNOLOGY LEARNING RATES



ACIL ALLENSOURCE:

The starting values and learning rates result in Capex cost curves for each of the technologies as shown below. Wind is projected to deliver around 30 per cent capital cost savings ($2020) by 2050. Similarly, solar is projected to deliver around 40 per cent and battery storage around 53 per cent cost savings by 2050.

FIGURE 5.3 CAPEX COST CURVES FOR RENEWABLE AND STORAGE TECHNOLOGIES ($2020)



SOURCE: ACIL ALLEN

Fixed and variable operating costs were also used in the optimised least cost model in order to determine total costs of meeting demand with renewable and storage technologies. The costs are assumed to be constant in real terms and are shown in Table 5.1. It should be noted that these costs are conservatively high compared with AEMO's input assumptions for the Integrated System Plan, except for wind for which AEMO assumes lower fixed costs but higher variable costs. This is set out in the workbook "2018 Integrated System Plan Modelling Assumptions.xlsx"[8], if the generally lower AEMO numbers were used, the 100 per cent renewable price curves would be lower and would compete with gas sooner.

TABLE 5.1 TECHNOLOGY FIXED AND VARIABLE OPERATING COSTS

Technology	Assumed Annual Fixed cost ($2020/MW)	Assumed Variable cost ($2020/MWh)	AEMO ISP Annual Fixed cost ($2020/MW)	AEMO ISP Variable cost ($2020/MWh)
Wind	67,844	0	49,590	17
Solar PV	49,322	0	31,981	0
Storage	11,630	2	0	0

SOURCE: ACIL ALLEN

5.4 Price curves

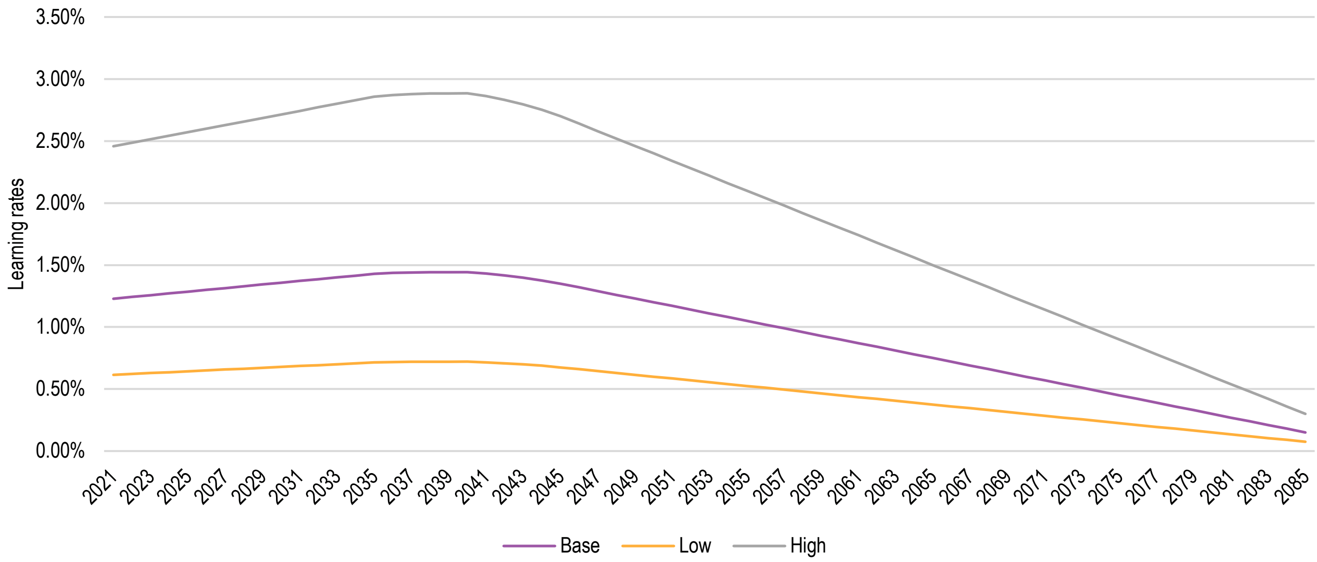
The above capital and operating costs (applied to the three wind and solar generating profiles) along with the SWIS demand profile were used to develop a base case price curve for generating electricity in each of the years modelled. This resulted in a 100 per cent renewable energy learning curve as shown in Figure 5.4. The curve reflects the annualised cost of the optimal mix of plant installed in each year – i.e., it assumes that in each year, the whole system would be optimised (previous decisions have no affect). This curve reflects the efficient frontier assuming only renewables and storage can be

[8] AEMO Prices have been escalated to 2020 prices. Data is available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-database

deployed. High and low case learning rates were developed by doubling (in the high case) and halving (in the low case) the base case learning rates.

The learning rates rise until around 2040 and then decline. This is a function of the changing shape of the demand curve and different technology learning rates leading to a changing mix of renewables and batteries (per unit of electricity) over time. The modelling indicates that the proportion of wind per unit of demand increases slightly over the intervals modelled to 2050 whereas solar declines to 2040 and then increases to 2050 and batteries fall to 2050. Batteries have the highest learning rate (to 2030) followed by solar and then wind. The compounding effect of the falling proportions of solar and wind and their higher learning rates leads to a rise in learning rates to around 2035. After 2035, the proportion of wind in the renewable mix dominates and learning rates trend downwards.

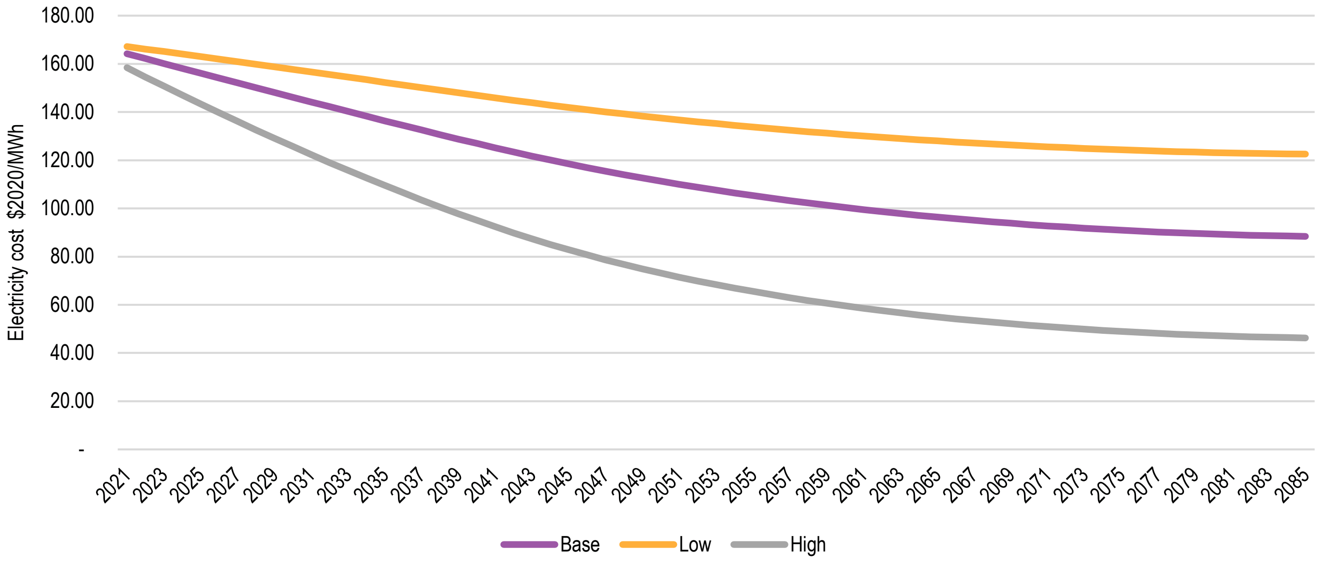
FIGURE 5.4 SWIS ELECTRICITY PROJECTED LEARNING RATES – 100 PER CENT RENEWABLE ENERGY



SOURCE:

Applying the learning rates to the calculated starting values (around $160/MWh for the base case) gives the price curves for each of the cases, shown in Figure 5.5.

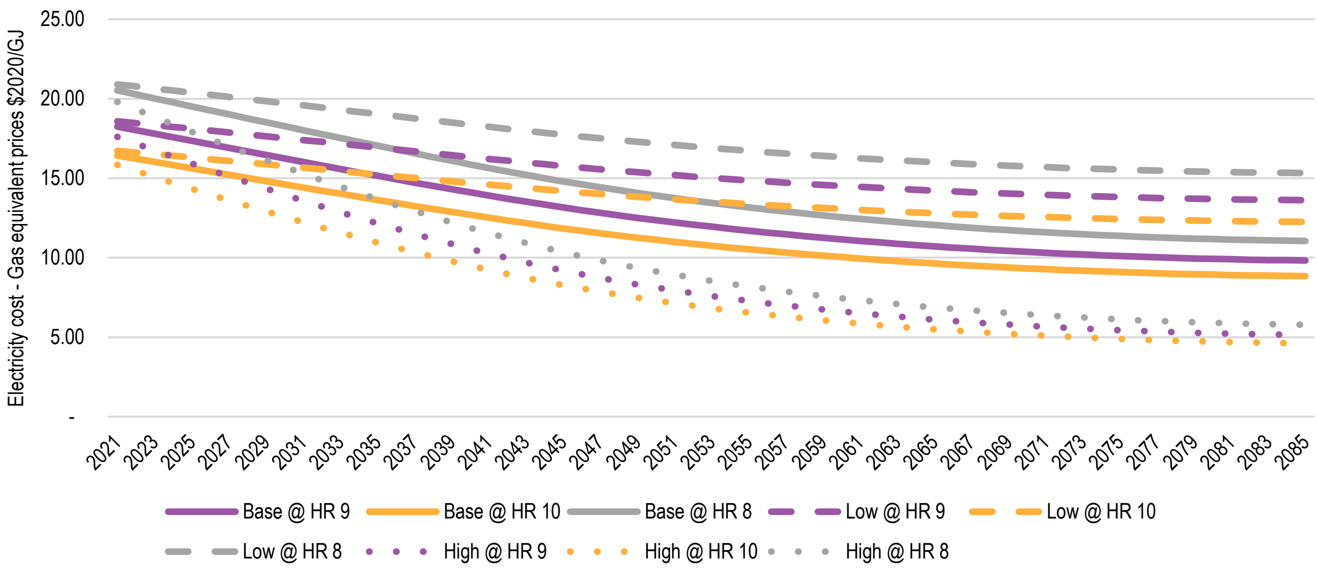
FIGURE 5.5 100 PER CENT RENEWABLE ELECTRICITY PRICE CURVES



SOURCE:

Figure 5.6 shows the electricity learning curves converted to gas equivalent prices at heat rates of 8, 9 and 10 GJ/MWh (covers the typical range of annual average heat rate for the SWIS).

FIGURE 5.6 100 PER CENT RENEWABLE ELECTRICITY PRICE CURVES – GAS EQUIVALENT PRICES



SOURCE: ACIL ALLEN

6 MODEL DESCRIPTION

6.1 Overview

The purpose of this chapter is to provide instructions for persons to understand and operate the model. It is expected that this will include representatives of AGIG and the ERA. It includes the main assumptions and methodology underlying the economic depreciation model.

The model consists of a set of integrated worksheets which estimate and compare the delivered price of gas against two substitutes, hydrogen and renewable electricity. Based on a set of input assumptions that drive the relative delivered gas price versus hydrogen and renewables, the model estimates the point in time over the life horizon of the asset when competitive pressures drive the achievable transport price and revenue below the regulated revenue and regulated transport price.

The model works on the assumption that DBP continues to haul gas for all its relevant customers up to the point where the actual transport price that can be charged to DBP's customers (the lower of the transport price under competition and regulation) falls to zero. At this point DBP's customers are expected to shift to alternative sources and the volume of gas hauled by the DBP would be expected to fall to zero.

Before this point is reached, there is the point where the delivered price of the alternative technologies falls below the delivered price of gas. This is the point after which the DBP can no longer earn its allowable revenue under regulation but is instead forced to earn a lower revenue corresponding to the predicted revenue under competition.

The point at which the regulated transport price and regulated revenue can no longer be achieved is referred to in this study as the "crossover" point. Where a regulator is aware that a crossover point is possible, the regulator can bring forward economic depreciation to speed up the rate at which capital is returned to the regulated investor. However, raising regulated prices of an asset potentially brings forward the crossover point. This risk increases the longer a regulator waits to act as price rises would have to be higher to fully recover capital. Where left too late, competitive pressures negate the ability of the regulator to fully compensate the regulated investor.

The window during which the regulator can successfully act is defined as the Window of Opportunity (WOO) – see (Crew & Kleindorfer, 1992). The point beyond which the regulator can successfully act is known as the Window of Opportunity' passed (WOOPS). The Crew and Kleindorfer work extends earlier work by Schmalensee (1989).

Schmalensee showed that where the firm faces no competition, is not subject to technological change and is allowed to earn a rate of return equal to its cost of capital in any given period, that the method of calculating depreciation is not important as long as the total depreciation over the life of the asset sums to the original cost of the investment. This notion is called the Invariance Proposition and implies that the NPV of the return on capital and depreciation (return of capital) is zero for any depreciation schedule (provided the book value of the asset in a given period t is equal to the original cost of the asset minus the sum of deprecation up to period t-1).

Crew and Kleindorfer demonstrated that the depreciation method is no longer irrelevant when the firm is faced with competition and technological change. Under these conditions, the price of substitute technologies can fall low enough to prevent actual earnings from equalling allowed or regulated earnings; therefore, the Invariance proposition no longer holds.

The main factors driving the relative competitiveness of gas against hydrogen and renewables are the trajectory of gas commodity prices, projections of emissions reduction policy, projections of technology learning rates that drive the price declines of the substitute technologies, and the relevant assumptions that drive regulated revenue such as depreciation, Opex and the return on the asset as well as projections of gas volumes sold.

For each of the drivers, three separate scenarios are constructed, a base or central case as well as an associated high and low case.

The model allows the user to impose his or her view of any of the drivers and analyse the impact on the crossover point. Of interest is the ability to change the asset's depreciation schedule, bringing forward future returns, to assess what impact this has on the crossover point relative to the assets last year of operation. This enables the model user to analyse the impact of changes in depreciation on the firm's ability to earn its cost of capital over the useful life of the asset. Changes to the depreciation schedule are entered in row 4 of the 'Capital base and reg revenue' worksheet. The reader is directed to section 6.2.8 where a detailed description of the 'Capital base and reg revenue' worksheet is provided.

The crossover point is calculated both from the point of view of the customer, when the delivered price of the gas commodity falls below the delivered price of the substitute as well as from the point of view of the DBP, when the achievable transport price falls below the regulated price required to achieve the firms cost of capital.

The modelling tool has been developed in Microsoft Excel and is presented as a set of worksheets which follow a logical structure from left to right.

The model is constructed and documented according to best practice design principles, including:

- Logical structure
- Clear separation of inputs, calculations and outputs
- Logical flow of calculations
- Designed to facilitate sensitivity testing of inputs
- Consistent design standards, colour coding, etc
  - cells which contain hard-coded inputs are coloured light purple
- Clear and comprehensive documentation

The model allows for separate low, base and high scenarios for each of the inputs.

The main summary output sheet produced by the model is the 'Results-scenario' worksheet. This is the most important output sheet produced by the model and summarises the output for each possible combination of scenarios of gas prices, carbon reduction scenarios, and hydrogen and renewables learning rates. This worksheet summarises the main variables that serve as inputs into the calculation of the crossover point as well as showing the predicted delivered price paths of gas versus its substitutes over time, and the predicted transport price under regulation versus the transport price under competition. The worksheet also shows the crossover point when the combined delivered price of the substitutes falls below the delivered price of gas. At this point, the DBP's customers are assumed to switch to the substitute technology. For a detailed description the reader is directed to section 6.4.4 of this document.

6.2 Model inputs

The first eight worksheet tabs of the model (not including the 'Results-scenarios' worksheet which is a summary of results and coloured dark purple) are coloured light purple. These are the worksheets which provide the data inputs to the rest of the model where calculations are made and outputs are generated. Each of the input worksheets contains cells which are shaded purple. These cells are input cells and can be changed by the model user.

The input worksheets are:

— Key input sheet
— Loads
— Discrete load movements
— Gas price projections
— Carbon price curves
— Technology learning rates
— Gas for power generation
— Capital base and reg revenue

6.2.1 Key input sheet

The key input sheet contains the main constants and conversion factors that are applied within the calculation worksheets of the model.

The main constants set in this worksheet are:

— Carbon content of gas (tonnes of CO_2-e per GJ) (cell B2)
  – used to convert the carbon price curve into a premium that is added to the gas price projection
— The heat rate (cell B3)
  – used to convert the renewables price curve from $/MWh to a $/GJ gas equivalent charge
— Hydrogen energy density (GJ/kg) (cell B9)
  – Used to convert the price of hydrogen from $/kg to gas equivalent $/GJ
— Starting value for the hydrogen commodity cost ($/kg) (cell B12 to B14)
— Staring value for hydrogen transport and storage ($/kg) (cell B16 to B18)
— Starting value for the price of renewables ($/MWh) (cell B20 to B22)

The starting values of hydrogen and renewables then evolve in line with the technology learning rates that are applied in subsequent worksheets in the model.

The capacity reservation (cell B24) and commodity charge (cell B25) constants are denoted as percentages and are used to weight the DBP's contracted capacity and throughput volumes to obtain a single volume measure, which is then used to calculate a single gas transportation tariff.

Finally, the input sheet contains an estimate of the real after tax WACC which is used to calculate the return on the asset in the components of revenue calculations made in the 'Capital base and reg revenue' worksheet.

6.2.2 Loads

The loads input sheet shows the historical and projected loads of the DBP's customers. These customers are categorised into seven customer groups:

— Alumina
— Gas for power generation
— Other domestic gas
— Chemicals
— Nickel
— Minerals- Iron ore
— Other

Other information contained in this worksheet includes whether the customer is a full haul or part haul customer and the haulage distance over which customer uses the DBP.

The first block of cells down to row 56 contains the actual contracted volume by customer measured in TJ/day. This set of numbers are the converted into a weighted contracted volume based on the haulage distance. This is done in rows 60 to 113. This is then converted into an annual volume in rows 116 to 169.

The same set of calculations is then applied to the throughput for each of the DBP's customers. Rows 203 to 256 contains the actual throughput by customer measured in TJ/day. Rows 260 to 313 then weight the throughput volumes by haulage distance while rows 316 to 369 convert the throughput from a TJ/day measure to an annual throughput measure.

The distance weighted contracted and throughput annual volumes form a key input into the calculation of the regulated transport price, which is defined as the allowable regulated revenue divided by the gas volume. It is also an input into the calculation the projected revenue shown in row 112-114 of the 'Results-scenarios' worksheet. To calculate the predicted revenue under competition, the price of the substitute technology is multiplied by the weighted average of the contracted and throughput volume.

6.2.3 Discrete load movements worksheet

The discrete loads worksheet enables the model user to impose exogenous changes to the annual contracted and throughput volumes (measured in TJ) by customer class. These then flow through to all the other parts of the model where gas volumes are used to make calculations.

Exogenous reductions in annual throughput and contracted volume have the effect of increasing the regulated transport price (keeping regulated revenue the same) and changing the relative competitiveness of gas versus the substitute by increasing the delivered price of gas. This also reduces the predicted revenue under competition (due to lower volumes) and depending on the timing and size of the change, may result in the crossover point being brought forward.

For example, the model user may want to incorporate the impact of a plant closure at some point in the future, thus reducing gas volumes. For example, if we were expecting a reduction in both contracted and throughput volumes in alumina of 10,000 TJ from 2021 onwards, we would enter minus 10,000 in the year 2021 and all the years that follow (see Figure 6.1). This would apply until the load was re-instated whereby the entry would become zero again.

FIGURE 6.1 DISCRETE LOAD MOVEMENTS WORKSHEET

1								
2	**26% carbon case**							
3	**Annual gas volume (TJ) by sector- Contracted**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
4	Alumina	-	-	-	-	-	-	-
5	Gas for power generation	[redacted]						
6	Other domestic gas	-	-	-	-	-	-	-
7	Chemicals	-	-	-	-	-	-	-
8	Nickel	-	-	-	-	-	-	-
9	Minerals – iron ore	-	-	-	-	-	-	-
10	Other	-	-	-	-	-	-	-
11	**Annual gas volume (TJ) by sector- Throughput**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
12	Alumina	-	-	-	-	-	-	-
13	Gas for power generation	[redacted]						
14	Other domestic gas	-	-	-	-	-	-	-
15	Chemicals	-	-	-	-	-	-	-
16	Nickel	-	-	-	-	-	-	-
17	Minerals – iron ore	-	-	-	-	-	-	-
18	Other	-	-	-	-	-	-	-

SOURCE: ACIL ALLEN

It is important to note that the discrete load movements worksheet contains blocks of input cells for each of the three carbon reduction scenarios that are modelled, the 26% case (base case) as well as the 15% case (low case) and 45% case (high case). This enables the model user to apply different assumptions of exogenous load movements depending on the carbon reduction scenario, for example a larger decline under the 45% carbon reduction scenario compared to the low and base case scenarios.

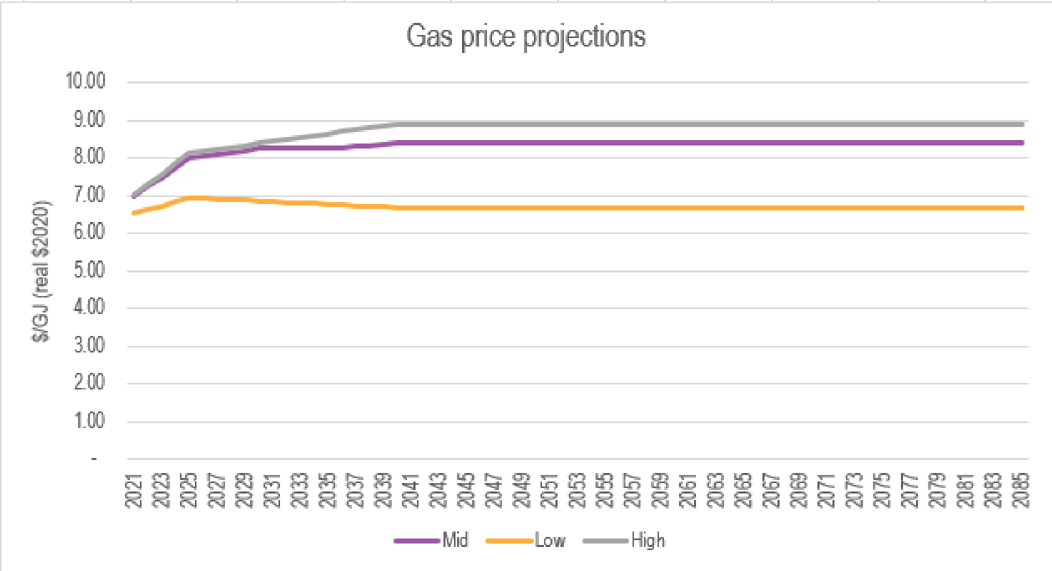
If the user applies the same volume change across all three scenarios, they are required to enter the same change in each of the three blocks.

6.2.4 Gas price projections

The worksheet “Gas price projections’ contains the projected mid, low and high gas price scenarios ($2020/GJ) from 2021 to 2085 (see Figure 6.2). It is within this worksheet that changes to the assumed gas commodity price can be applied and their effect subsequently analysed. The worksheet allows the user to enter three separate scenarios for the projected gas commodity price.

FIGURE 6.2 GAS PRICE PROJECTIONS WORKSHEET

	A	B	C	D	E	F	G	H	I	J	K	L
1	**Scenario**		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
2	Mid	$2020/GJ	6.97	7.23	7.48	7.74	7.99	8.04	8.10	8.15	8.20	8.25
3	Low	$2020/GJ	6.53	6.63	6.73	6.84	6.94	6.93	6.91	6.89	6.87	6.86
4	High	$2020/GJ	7.03	7.30	7.58	7.85	8.12	8.17	8.23	8.28	8.33	8.38



SOURCE: ACIL ALLEN

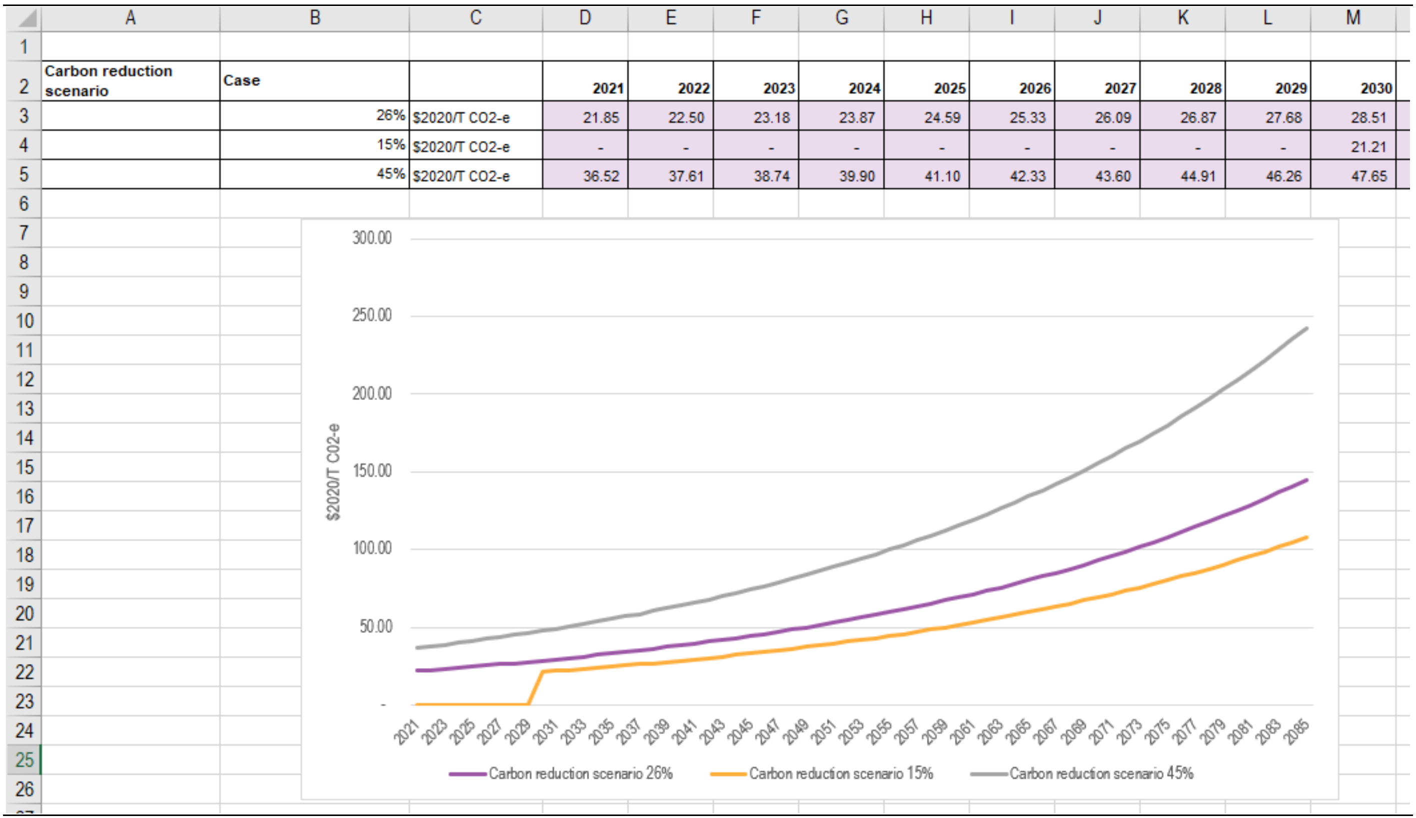
6.2.5 Carbon shadow price curves

The separate carbon shadow price scenarios under the three carbon reduction scenarios (15%, 26% and 45%) are input into the ‘Carbon price curves’ worksheet.

These carbon shadow prices are used to calculate the gas commodity price including the cost of the carbon content of the gas. Figure 6.3 provides a snapshot of the ‘Carbon price curves’ worksheet.

The user can alter these carbon shadow prices to reflect different emission reduction policies and targets. This changes the uplift in costs for gas and affects the crossover with hydrogen and renewables. However, it does not change the underlying SWIS gas for power generation scenarios which were based on specific emissions reduction scenarios and which were developed through electricity market simulations with the *PowerMark WA* simulator.

FIGURE 6.3 CARBON PRICE CURVES WORKSHEET



Carbon reduction scenario	Case		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	26%	$2020/T CO2-e	21.85	22.50	23.18	23.87	24.59	25.33	26.09	26.87	27.68	28.51
	15%	$2020/T CO2-e	-	-	-	-	-	-	-	-	-	21.21
	45%	$2020/T CO2-e	36.52	37.61	38.74	39.90	41.10	42.33	43.60	44.91	46.26	47.65

SOURCE: ACIL ALLEN

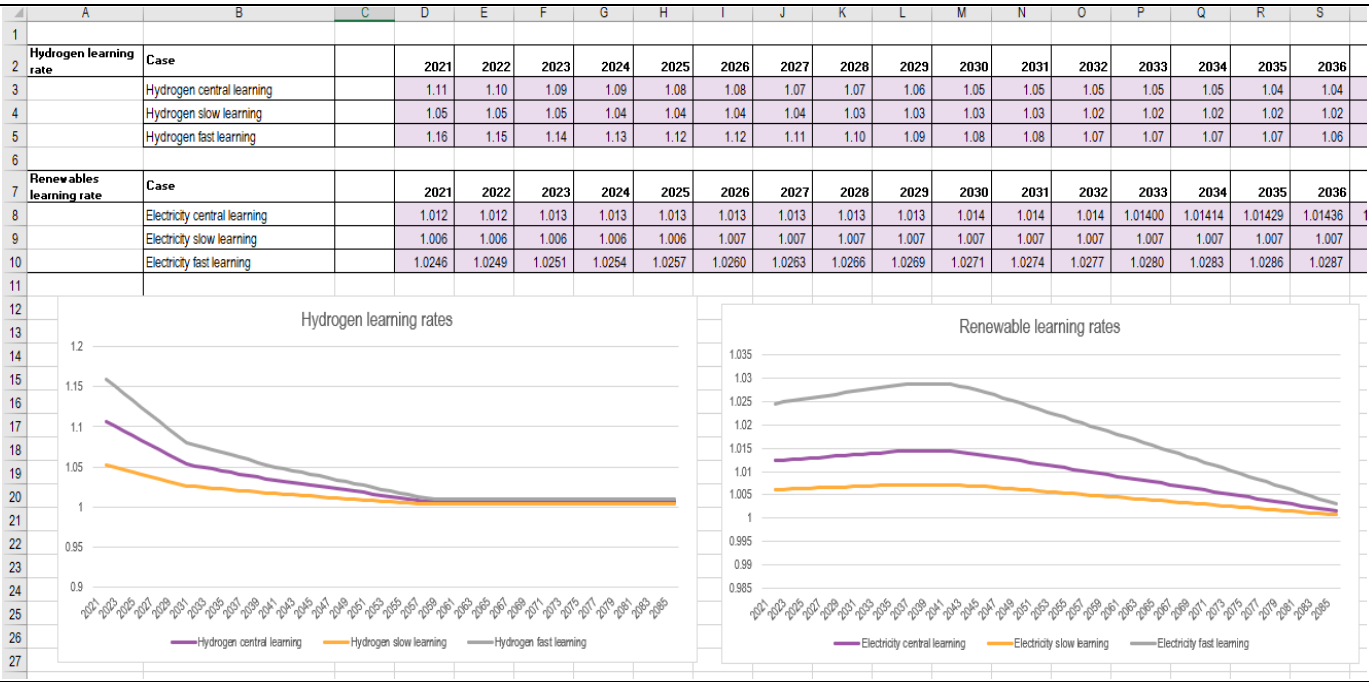
6.2.6 Technology learning rates

The assumed learning rates applied to the price of hydrogen and renewables over the model's time horizon are presented in the 'Technology learning rates' worksheet. The learning rates capture the rate at which the price of the substitute technologies decline over time. They are defined as 1 plus the percentage price reduction, so that a learning rate of 1.15 in a given year implies a 15% decline in the price of the substitute technology. As the learning rate approaches 1, the rate of change in the price of the substitute technology approaches zero. This occurs as the technology matures (see Figure 6.4).

Three separate learning curves are required for each of the substitute technologies, a central learning case, a slow learning case and a high learning case.

It can be seen from Figure 6.4 that the renewables learning curve has a hump in it, increasing to about 2040, before commencing a steady decline. The rationale for this pattern is provided in section 5.4 of this report.

FIGURE 6.4 TECHNOLOGY LEARNING CURVES WORKSHEET



Hydrogen learning rate	Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	Hydrogen central learning	1.11	1.10	1.09	1.09	1.08	1.08	1.07	1.07	1.06	1.05	1.05	1.05	1.05	1.05	1.04	1.04
	Hydrogen slow learning	1.05	1.05	1.05	1.04	1.04	1.04	1.04	1.03	1.03	1.03	1.03	1.02	1.02	1.02	1.02	1.02
	Hydrogen fast learning	1.16	1.15	1.14	1.13	1.12	1.12	1.11	1.10	1.09	1.08	1.08	1.07	1.07	1.07	1.07	1.06

Renewables learning rate	Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
	Electricity central learning	1.012	1.012	1.013	1.013	1.013	1.013	1.013	1.013	1.013	1.014	1.014	1.014	1.01400	1.01414	1.01429	1.01436
	Electricity slow learning	1.006	1.006	1.006	1.006	1.006	1.007	1.007	1.007	1.007	1.007	1.007	1.007	1.007	1.007	1.007	1.007
	Electricity fast learning	1.0246	1.0249	1.0251	1.0254	1.0257	1.0260	1.0263	1.0266	1.0269	1.0271	1.0274	1.0277	1.0280	1.0283	1.0286	1.0287

SOURCE: ACIL ALLEN

6.2.7 Gas for power generation

While all other customer category volumes are exogenously determined, the one exception is the gas for power generation category.

The gas for power generation volumes are modelled independently using ACIL Allen's proprietary electricity market model PowerMark. Three separate trajectories for gas for power generation volumes were produced by PowerMark, one for each of the separate carbon reduction scenarios.

The absolute value of the changes produced by PowerMark are then added or subtracted to the original gas for power generation load provided in the 'Loads' worksheet. These changes are applied to both the contracted volume and throughput, resulting in revised gas for power generation volumes that differ according to carbon scenario.

As discussed earlier in section 3, the other sectors supplied by AGIG, apart from gas for power generation, operate at points sufficiently low on their cost curves or gas makes up only a small share of total costs that changes in the gas price arising from different carbon abatement scenarios are unlikely to affect the operations of these customers. They are therefore assumed to consume the same volume of gas over time, under all three carbon abatement scenarios.

Figure 6.5 presents a snapshot of the 'Gas for power generation' worksheet. Rows 3 to 5 are the inputs that are obtained from PowerMark. Rows 9 to 11 then show the absolute changes in the PowerMark volumes. These are then added (or subtracted from) to the original Gas for Power generation loads (after converting them to TJs from PJs) coming from the 'Loads' worksheet. The adjusted volumes are shown in rows 14 to 21 of the worksheet.

The adjustments are made from 2021 onwards only which corresponds to the commencement of the next regulatory period.

FIGURE 6.5 GAS FOR POWER GENERATION WORKSHEET

	A	B	C	D	E	F	G	H	I	J	K
1											
2	From Power mark	Cal Year	PJ	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
3	**Gas for Power Generation (PJ)**	26%	PJ	50.80	45.41	46.69	44.47	45.68	45.56	44.83	44.29
4		15%	PJ	60.85	60.23	61.54	61.84	62.68	64.88	66.07	66.39
5		45%	PJ	48.86	44.30	45.62	42.10	44.00	47.98	50.31	56.05
6											
7											
8	**Volume changes**			**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
9		26% Scenario		- 3.82	- 5.39	1.28	- 2.22	1.21	- 0.12	- 0.74	- 0.53
10		15% Scenario		- 0.61	- 0.63	1.31	0.30	0.84	2.20	1.19	0.32
11		45% Scenario		- 4.13	- 4.56	1.32	- 3.53	1.90	3.98	2.33	5.74
12											
13	**Gas for Power Generation (TJ)**	**Contracted (TJ)**		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
14		26% Scenario		70,056	64,666	65,949	63,728	64,935	64,818	64,082	63,550
15		15% Scenario		73,268	72,642	73,957	74,261	75,097	77,294	78,487	78,804
16		45% Scenario		69,750	65,194	66,518	62,988	64,893	68,869	71,202	76,938
17											
18		**Throughput (TJ)**		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
19		26% Scenario		64,854	59,464	60,748	58,526	59,733	59,616	58,880	58,349
20		15% Scenario		68,066	67,441	68,755	69,059	69,896	72,092	73,286	73,603
21		45% Scenario		64,549	59,992	61,316	57,786	59,691	63,667	66,001	71,736
22											

SOURCE: ACIL ALLEN

6.2.8 Capital base and reg revenue

The capital base and reg worksheet is where the allowable regulated revenue is calculated based on each of its components:

— Depreciation
— Return on asset
— Opex
— Tax and imputation credits

Figure 6.6 shows a snapshot of this worksheet. The main items that are required to be entered externally are shaded in light purple. These are the assets initial opening value, Capex, depreciation, Opex and tax and imputation credits.

The main input variable of interest is the depreciation schedule, which allows the model user or analyst to consider the impact of different depreciation schedules on the regulated transport price and ultimately on the amount of the asset's total value that is captured before the cossover point is reached. At this point the predicted revenue under competition falls below the predicted revenue under regulation, resulting in the actual revenue able to be collected falling below the level required under regulation.

FIGURE 6.6 CAPITAL BASE AND REG REVENUE

	A	B	C	D	E	F	G	H	I	J
1										
2		**Asset account $m 2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
3		Opening Value	3,350.67	3,262.85	3,182.83	3,085.78	2,994.37	2,899.00	2,807.98	2,715.12
4		Capex	38.1	36.5	23.2	31.2	30.4	31.9	31.9	31.9
5		Depreciation	-125.917	-116.477	-120.279	-122.558	-125.735	-122.882	-124.728	-126.79
6		Closing Value	3,262.85	3,182.83	3,085.78	2,994.37	2,899.00	2,807.98	2,715.12	2,620.19
7										
8		Cumulative depreciation	125.92	242.39	362.67	485.23	610.97	733.85	858.57	985.37
9	**Revenue**									
10		**Components of revenue ($m 2020 real)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
11		Depreciation	125.92	116.48	120.28	122.56	125.73	122.88	124.73	126.79
12		Return on asset	103.18	100.48	98.01	95.02	92.21	89.27	86.47	83.61
13		Opex	91.37	91.94	92.64	90.48	90.71	91.43	91.43	91.43
14		Tax and imputation credits	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15		**Regulated revenue ($M)**	320.47	308.90	310.94	308.06	308.66	303.58	302.63	301.83
16										

SOURCE: ACIL ALLEN

The first block of rows between row 2 and 5 contain the key inputs, asset opening value, Capex and depreciation. These are denoted in $2020 dollars.

Row 4 contains the depreciation schedule that is input by the model user. These cells are shaded in purple to denote that they are inputs. Other inputs to be entered by the model user are Capex in row 3, as well as Opex and Tax and imputation credits in rows 13 and 14 respectively.

It is important to ensure that the sum of depreciation over the life of the asset is equal to the assets starting value plus the sum of Capex over the sum of the asset. This means that any alternative depreciation schedule that is entered must fully depreciate the asset over the life of the asset. Moreover, if the asset is fully depreciated and no longer operating, it is necessary to set the Opex and tax and imputation credits to zero in the years following the end of operations.[9]

Rows 10 to 15 then build up the regulated revenue based on each of its components. The return on the asset is calculated by multiplying the asset's opening value by the real pre-tax WACC which is found in the 'Key input sheet'.

The regulated revenue is a key input into the calculation of the regulated transport tariff.

6.3 Intermediate calculation worksheets

The main intermediate calculation worksheets are:

— Gas volumes

— Gas- Transport costs

— Gas commodity (in carbon)

— Hydrogen and Renewable P(t)

— P(t) crossover-Hydrogen

— P(t) crossover – Renewables

6.3.1 Gas volumes

The gas volumes form the denominator in the regulated tariff calculation. The gas volumes worksheet presents the contracted and throughput volumes by customer category for each of the three carbon reduction scenarios.

[9] While technically the asset could be operated for Opex only, there would be no incentive for the investors to do so.

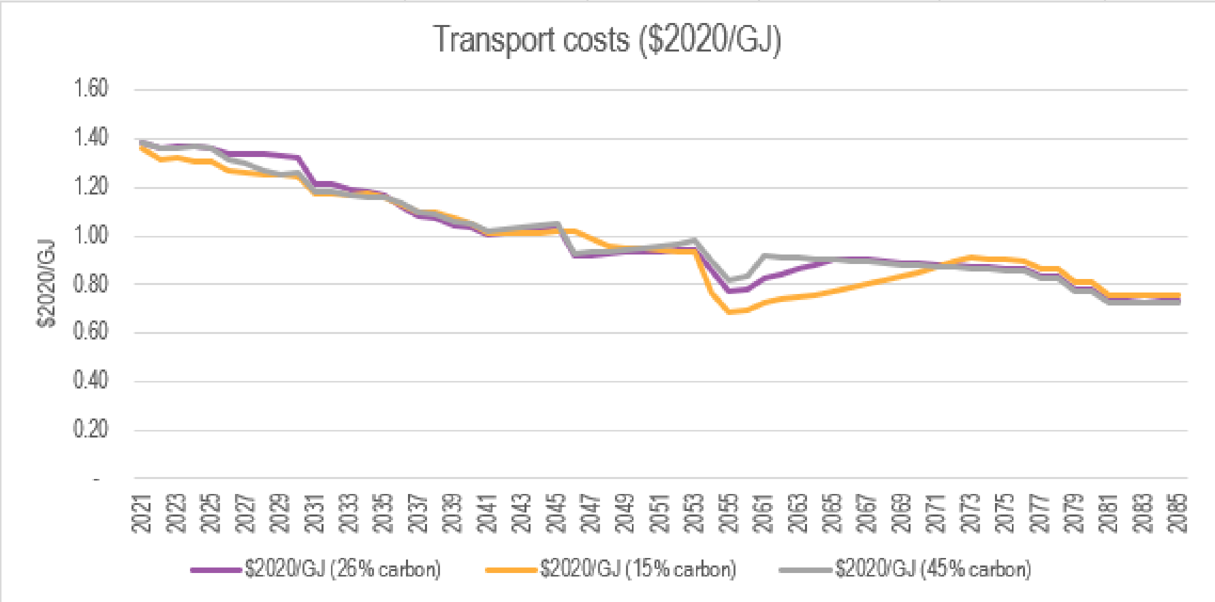
Apart from the gas for power generation customer category, the volumes are equal to the volumes in the Loads worksheet, plus any exogenous discrete load movements that are applied. In the case of gas for power generation, the gas volumes are obtained from the 'gas for power generation' worksheet where the volumes are adjusted to account for the impact of the different carbon reduction scenarios.

6.3.2 Gas- Transport costs

The 'Gas-Transport costs' worksheet (see Figure 6.7) combines the gas volumes and regulated revenue to calculate the projected regulated transport tariff over the life of the asset. Separate regulated tariff trajectories are calculated for each carbon reduction scenario. The regulated tariff is calculated by dividing the regulated revenue by the weighted average of the contracted capacity and total throughput.

FIGURE 6.7 GAS-TRANSPORT COSTS WORKSHEET

	A	B	C	D	E	F
1	**26% carbon case**					
2	**Regulated transport cost ($/GJ)**	**2021**	**2022**	**2023**	**2024**	**2025**
3	Contracted capacity (GJ)	234,531,940	229,037,387	229,926,700	227,744,218	228,979,455
4	Total throughput (GJ)	209,990,875	206,612,507	207,592,624	205,197,137	206,195,906
5	**$2020/GJ (26% carbon)**	1.38	1.36	1.37	1.37	1.36
6						
7	**15% carbon case**					
8	**Regulated transport cost ($/GJ)**	**2021**	**2022**	**2023**	**2024**	**2025**
9	Contracted capacity (GJ)	237,743,787	237,013,665	237,934,304	238,276,995	239,141,722
10	Total throughput (GJ)	213,202,722	214,588,785	215,600,229	215,729,914	216,358,173
11	**$2020/GJ (15% carbon)**	1.36	1.32	1.32	1.31	1.30
12						
13	**45% carbon case**					
14	**Regulated transport cost ($/GJ)**	**2021**	**2022**	**2023**	**2024**	**2025**
15	Contracted capacity (GJ)	234,226,108	229,565,441	230,494,838	227,004,088	228,937,080
16	Total throughput (GJ)	209,685,043	207,140,562	208,160,763	204,457,007	206,153,531
17	**$2020/GJ (45% carbon)**	1.38	1.36	1.36	1.37	1.36
18						
19						



SOURCE: ACIL ALLEN

6.3.3 Gas- commodity (inc carbon)

The projected commodity cost of gas is calculated in the 'Gas commodity (in carbon)' worksheet. This is equal to the projected gas price plus the cost of carbon. The cost of carbon is calculated by multiplying the carbon price in the Carbon price curves worksheet by the carbon content of gas (from the 'Key input sheet').

There are nine separate trajectories for the gas commodity cost (including carbon), one for each possible combination of the low, medium and high gas price scenarios and the three carbon reduction scenarios.

The sum of the gas transport cost and commodity cost equals the total delivered cost of gas. This can be compared with the total delivered cost of the two substitutes, hydrogen and renewables to ascertain the relative competitiveness of gas against the available alternatives over time.

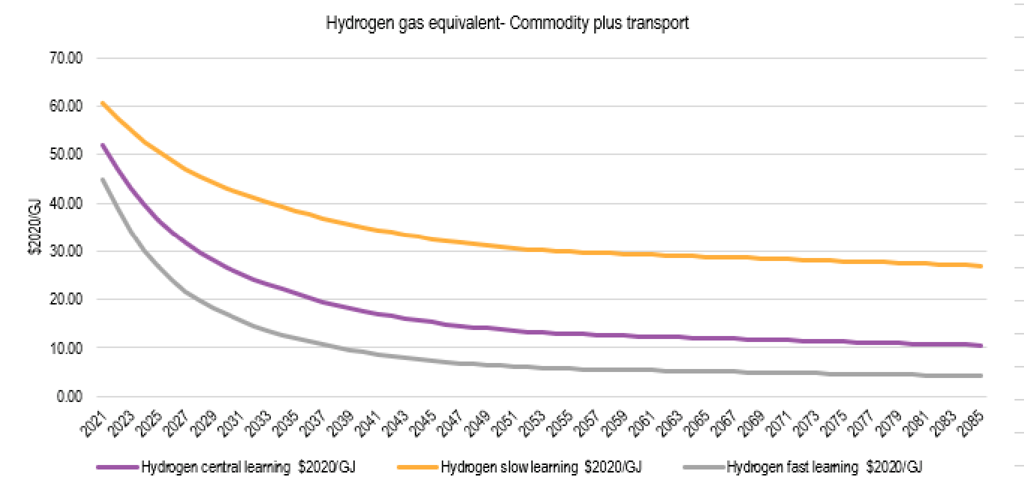
6.3.4 Hydrogen and renewables P(t)

The 'Hydrogen and renewables P(t)' worksheet calculates the trajectory of the delivered cost of each of the substitute technologies.

Figure 6.8 shows the segment of the worksheet where the hydrogen price trajectory is calculated.

FIGURE 6.8 HYDROGEN AND RENEWABLES P(T)- SNAP SHOT 1

	A	B	C	D	E	F	G	H	I	J
1				2021	2022	2023	2024	2025	2026	2027
2	Hydrogen commodity cost	Hydrogen central learning	$2020/kg	5.09	4.62	4.23	3.88	3.59	3.33	3.11
3		Hydrogen slow learning	$2020/kg	5.94	5.65	5.40	5.17	4.97	4.78	4.62
4		Hydrogen fast learning	$2020/kg	4.39	3.82	3.35	2.95	2.63	2.36	2.13
5										
6	Hydrogen transport and storage	Hydrogen central learning	$2020/kg	1.13	1.03	0.94	0.86	0.80	0.74	0.69
7		Hydrogen slow learning	$2020/kg	1.32	1.26	1.20	1.15	1.10	1.06	1.03
8		Hydrogen fast learning	$2020/kg	0.98	0.85	0.74	0.66	0.58	0.52	0.47
9										
10	Hydrogen Total	Hydrogen central learning	$2020/kg	6.22	5.65	5.17	4.75	4.38	4.07	3.80
11		Hydrogen slow learning	$2020/kg	7.26	6.91	6.60	6.32	6.07	5.85	5.65
12		Hydrogen fast learning	$2020/kg	5.37	4.67	4.09	3.61	3.21	2.88	2.61
13										
14	Hydrogen gas equivalent	Hydrogen central learning	$2020/GJ	51.81	47.10	43.05	39.55	36.54	33.94	31.69
15		Hydrogen slow learning	$2020/GJ	60.47	57.59	55.00	52.68	50.59	48.72	47.06
16		Hydrogen fast learning	$2020/GJ	44.73	38.90	34.08	30.09	26.78	24.02	21.71



SOURCE: ACIL ALLEN

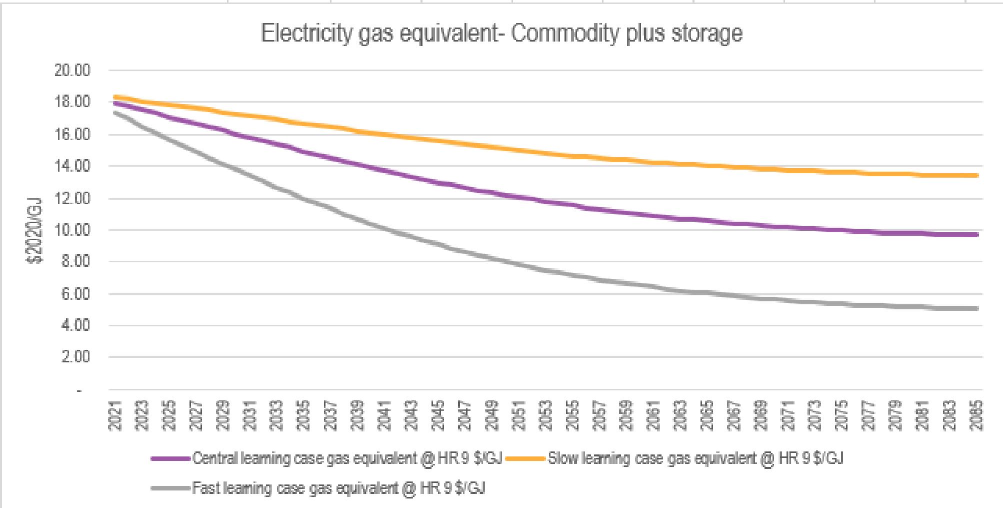
Rows 2 to 8 show the price trajectory of the commodity and transport and storage costs for each of the three learning rate scenarios, slow, central and fast. The price in a given year is calculated by dividing the previous year's price by the technology learning rate in that same year, apart from the first year which is set as a starting value.

Rows 10 to 12 show the total delivered cost of hydrogen (including the commodity and transport and storage) over time for the three learning rate scenarios. Rows 14 to 16 then convert the prices in rows 10 to 12 to gas equivalent $/GJ from $/kg. This is done by dividing the $/kg price by the hydrogen energy density factor (GJ/kg) which is one of inputs in the 'Key input sheet'.

Figure 6.9 shows the segment of the worksheet where the renewables price trajectory is calculated.

FIGURE 6.9 HYDROGEN AND RENEWABLES P(T)- SNAP SHOT 2

	A	B	C	D	E	F	G	H	I	J	K
34				**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
35	Electricity P(t) Real 2020	Electricity central learning	$/MWh	161.80	159.81	157.82	155.84	153.87	151.89	149.92	147.95
36		Electricity slow learning		164.74	163.72	162.70	161.67	160.64	159.60	158.56	157.52
37		Electricity fast learning		156.11	152.32	148.59	144.90	141.27	137.69	134.16	130.69
38	Heat rate										
39	9	Central learning case gas equivalent @ HR 9	$/GJ	17.98	17.76	17.54	17.32	17.10	16.88	16.66	16.44
40	10	Central learning case gas equivalent @ HR 10	$/GJ	16.18	15.98	15.78	15.58	15.39	15.19	14.99	14.80
41	8	Central learning case gas equivalent @ HR 8	$/GJ	20.22	19.98	19.73	19.48	19.23	18.99	18.74	18.49
42	9	Slow learning case gas equivalent @ HR 9	$/GJ	18.30	18.19	18.08	17.96	17.85	17.73	17.62	17.50
43	10	Slow learning case gas equivalent @ HR 10	$/GJ	16.47	16.37	16.27	16.17	16.06	15.96	15.86	15.75
44	8	Slow learning case gas equivalent @ HR 8	$/GJ	20.59	20.47	20.34	20.21	20.08	19.95	19.82	19.69
45	9	Fast learning case gas equivalent @ HR 9	$/GJ	17.35	16.92	16.51	16.10	15.70	15.30	14.91	14.52
46	10	Fast learning case gas equivalent @ HR 10	$/GJ	15.61	15.23	14.86	14.49	14.13	13.77	13.42	13.07
47	8	Fast learning case gas equivalent @ HR 8	$/GJ	19.51	19.04	18.57	18.11	17.66	17.21	16.77	16.34



SOURCE: ACIL ALLEN

Rows 35 to 37 show the price trajectory for renewables for the three learning rate scenarios, measured in real terms in $2020/MWh. Rows 39 to 47 then convert these prices to the gas equivalent price measured in $2020/GJ by dividing by a specific heat rate (measured in GJ/MWh). In the model we allow three possible heat rates, 8,9 or 10 for the conversion. The model user can set the heat rate in the 'Key input sheet'.

6.3.5 P(t) crossover- Hydrogen

The P(t) crossover- Hydrogen sheet then compares the delivered price of gas against the delivered price of hydrogen for each combination of gas price, carbon reduction and technology learning rate scenario.

FIGURE 6.10 P(T) CROSSOVER- HYDROGEN

	A	B	C	D	E	F	G	H	I
1	**Gas (commodity including Carbon plus transport)**	$2020/GJ	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
2	Mid gas 26% carbon	$2020/GJ	$ 9.48	$ 9.75	$ 10.04	$ 10.33	$ 10.62	$ 10.69	$ 10.78
3	Mid gas 15% carbon	$2020/GJ	$ 8.34	$ 8.54	$ 8.80	$ 9.04	$ 9.29	$ 9.31	$ 9.35
4	Mid gas 45% carbon	$2020/GJ	$ 10.24	$ 10.52	$ 10.84	$ 11.16	$ 11.47	$ 11.54	$ 11.64
5	Low gas 26% carbon	$2020/GJ	$ 9.03	$ 9.15	$ 9.29	$ 9.43	$ 9.57	$ 9.57	$ 9.59
6	Low gas 15% carbon	$2020/GJ	$ 7.89	$ 7.95	$ 8.05	$ 8.14	$ 8.25	$ 8.20	$ 8.17
7	Low gas 45% carbon	$2020/GJ	$ 9.79	$ 9.93	$ 10.09	$ 10.26	$ 10.42	$ 10.42	$ 10.45
8	High gas 26% carbon	$2020/GJ	$ 9.54	$ 9.82	$ 10.14	$ 10.44	$ 10.75	$ 10.82	$ 10.91
9	High gas 15% carbon	$2020/GJ	$ 8.39	$ 8.62	$ 8.89	$ 9.15	$ 9.42	$ 9.44	$ 9.49
10	High gas 45% carbon	$2020/GJ	$ 10.29	$ 10.60	$ 10.93	$ 11.27	$ 11.60	$ 11.67	$ 11.77
11									
12	**Hydrogen gas equivalent**	$2020/GJ	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
13	Hydrogen central learning	$2020/GJ	$ 51.81	$ 47.10	$ 43.05	$ 39.55	$ 36.54	$ 33.94	$ 31.69
14	Hydrogen slow learning	$2020/GJ	$ 60.47	$ 57.59	$ 55.00	$ 52.68	$ 50.59	$ 48.72	$ 47.06
15	Hydrogen fast learning	$2020/GJ	$ 44.73	$ 38.90	$ 34.08	$ 30.09	$ 26.78	$ 24.02	$ 21.71
16									
17	**Price differentials**								
18	**Gas v hydrogen crossover- Mid gas price- Central learning**	Crossover year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
19	26% carbon	**2058**	$ 42.33	$ 37.35	$ 33.01	$ 29.22	$ 25.92	$ 23.25	$ 20.91
20	15% carbon	**2063**	$ 43.48	$ 38.56	$ 34.25	$ 30.51	$ 27.25	$ 24.62	$ 22.34
21	45% carbon	**2050**	$ 41.57	$ 36.58	$ 32.21	$ 28.39	$ 25.07	$ 22.40	$ 20.05
22	**Gas v hydrogen crossover- Mid gas price- Slow learning**		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
23	26% carbon	**2085**	$ 50.99	$ 47.84	$ 44.96	$ 42.34	$ 39.97	$ 38.04	$ 36.28
24	15% carbon	**2085**	$ 52.14	$ 49.05	$ 46.20	$ 43.64	$ 41.30	$ 39.41	$ 37.70
25	45% carbon	**2085**	$ 50.24	$ 47.07	$ 44.16	$ 41.51	$ 39.12	$ 37.18	$ 35.42
26	**Gas v hydrogen crossover- Mid gas price- Fast learning**		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
27	26% carbon	**2036**	$ 35.25	$ 29.15	$ 24.04	$ 19.76	$ 16.16	$ 13.33	$ 10.93
28	15% carbon	**2036**	$ 36.39	$ 30.35	$ 25.28	$ 21.05	$ 17.49	$ 14.71	$ 12.36
29	45% carbon	**2034**	$ 34.49	$ 28.37	$ 23.24	$ 18.93	$ 15.31	$ 12.48	$ 10.07

SOURCE: ACIL ALLEN

Rows 2 to 15 show the trajectories for each possible scenario for both the delivered gas and hydrogen prices. Rows 18 onwards then present the price differentials between gas and the substitute technology. This is presented for each possible combination of scenarios. The cells coloured in light orange in column B show the last year for which the delivered gas price is below the delivered price of hydrogen.

This year corresponds to the crossover point from the point of view of the DBP's customers. After this year, competition results in AGIG being unable to charge the regulated transport price and collect the amount revenue that regulation allows. Once the differential between the delivered gas price and delivered hydrogen price grows large enough, the DBP will be forced to cease operating entirely (unless it is willing to charge a negative transport price to retain its customers).

6.3.6 P(t) crossover- Renewables

The P(t) crossover- Renewables compares the delivered gas price against the delivered price of renewables. The worksheet is laid out similarly to the P(t)-Hydrogen worksheet, with rows 2 to 21 showing the delivered price of gas and the substitute under the different scenarios. Row 24 onwards then presents the price differential between the two energy sources, with column B showing the crossover year, the last year before the delivered cost of gas falls below the delivered cost of the substitute. This corresponds to the crossover point from the customers' perspective.

FIGURE 6.11 P(T) CROSSOVER- RENEWABLES

	A	B	C	D	E	F	G	H
1	**Gas (commodity including Carbon plus transport)**	$2020/GJ	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
2	Mid gas 26% carbon	$2020/GJ	9.48	9.75	10.04	10.33	10.62	10.69
3	Mid gas 15% carbon	$2020/GJ	8.34	8.54	8.80	9.04	9.29	9.31
4	Mid gas 45% carbon	$2020/GJ	10.24	10.52	10.84	11.16	11.47	11.54
5	Low gas 26% carbon	$2020/GJ	9.03	9.15	9.29	9.43	9.57	9.57
6	Low gas 15% carbon	$2020/GJ	7.89	7.95	8.05	8.14	8.25	8.20
7	Low gas 45% carbon	$2020/GJ	9.79	9.93	10.09	10.26	10.42	10.42
8	High gas 26% carbon	$2020/GJ	9.54	9.82	10.14	10.44	10.75	10.82
9	High gas 15% carbon	$2020/GJ	8.39	8.62	8.89	9.15	9.42	9.44
10	High gas 45% carbon	$2020/GJ	10.29	10.60	10.93	11.27	11.60	11.67
11								
12	**Electricity gas equivalent**	HR	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
13	Electricity central learning@HR9	$2020/GJ	17.98	17.76	17.54	17.32	17.10	16.88
14	Electricity central learning@HR10	$2020/GJ	16.18	15.98	15.78	15.58	15.39	15.19
15	Electricity central learning@HR8	$2020/GJ	20.22	19.98	19.73	19.48	19.23	18.99
16	Electricity slow learning@HR9	$2020/GJ	18.30	18.19	18.08	17.96	17.85	17.73
17	Electricity slow learning@HR10	$2020/GJ	16.47	16.37	16.27	16.17	16.06	15.96
18	Electricity slow learning@HR8	$2020/GJ	20.59	20.47	20.34	20.21	20.08	19.95
19	Electricity fast learning@HR9	$2020/GJ	17.35	16.92	16.51	16.10	15.70	15.30
20	Electricity fast learning@HR10	$2020/GJ	15.61	15.23	14.86	14.49	14.13	13.77
21	Electricity fast learning@HR8	$2020/GJ	19.51	19.04	18.57	18.11	17.66	17.21
22								
23	**Price differentials**	HR	9					
24	**Gas v Renewables crossover- Mid gas price-Central learning**	Crossover year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
25	26% carbon	**2050**	8.50	8.01	7.49	6.98	6.48	6.19
26	15% carbon	**2055**	9.64	9.21	8.73	8.27	7.80	7.56
27	45% carbon	**2044**	7.74	7.23	6.70	6.15	5.63	5.34
28	**Gas v Renewables crossover- Mid gas price-Slow Learning**		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
29	26% carbon	**2068**	8.82	8.44	8.04	7.63	7.23	7.05
30	15% carbon	**2076**	9.97	9.65	9.28	8.92	8.56	8.42
31	45% carbon	**2056**	8.07	7.67	7.24	6.80	6.38	6.19
32	**Gas v Renewables crossover- Mid gas price- Fast Learning**		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
33	26% carbon	**2037**	7.87	7.18	6.47	5.77	5.08	4.61
34	15% carbon	**2038**	9.01	8.38	7.71	7.06	6.40	5.99
35	45% carbon	**2034**	7.11	6.40	5.67	4.94	4.23	3.76

SOURCE: ACIL ALLEN

6.4 Model outputs

The main output worksheet are:

— WOOPS- Hydrogen
— WOOPS- Electricity
— WOOPS-Combined
— Results-scenarios

6.4.1 WOOPS Hydrogen

The 'WOOPS-Hydrogen' worksheet calculates the same crossover point as the P(t) crossover worksheet but this time from the point of view of the DBP rather than its customers.

Figure 6.12 shows the first block of data in the worksheet. This contains the regulated transport price under the three carbon reduction scenarios as well as the transport price that could be charged under competition for the various gas price, carbon reduction and learning rate scenarios. The transport price under competition is the transport price which equalises the delivered price of gas and the substitute commodity.

Once the difference between the commodity prices becomes large enough, the transport price under competition falls to a lower bound of zero. At this point there are no more customers prepared to use the gas network (unless a negative transport price is charged) and the asset ceases operating.

FIGURE 6.12 WOOPS-HYDROGEN SNAP SHOT 1

	A	B	C	D	E	F	G	H	I	J
1				Transport price ($/GJ)-Regulated		2021	2022	2023	2024	2025
2				$/GJ (26% carbon)		1.38	1.36	1.37	1.37	1.36
3				$/GJ (15% carbon)		1.36	1.32	1.32	1.31	1.30
4				$/GJ (45% carbon)		1.38	1.36	1.36	1.37	1.36
5										
6				Transport price -under competition						
7		Gas price	Carbon scenario	Learning rate		2021	2022	2023	2024	2025
8	Mid0.26Hyd	Mid	26%	Hydrogen central learning		43.71	38.71	34.37	30.59	27.28
9	Mid0.15Hyd	Mid	15%	Hydrogen central learning		44.84	39.87	35.57	31.82	28.55
10	Mid0.45Hyd	Mid	45%	Hydrogen central learning		42.96	37.94	33.57	29.76	26.43
11	Low0.26Hy	Low	26%	Hydrogen central learning		44.16	39.31	35.12	31.49	28.33
12	Low0.15Hy	Low	15%	Hydrogen central learning		45.29	40.47	36.31	32.71	29.60
13	Low0.45Hy	Low	45%	Hydrogen central learning		43.41	38.53	34.32	30.66	27.48
14	High0.26Hy	High	26%	Hydrogen central learning		43.66	38.64	34.28	30.48	27.15
15	High0.15Hy	High	15%	Hydrogen central learning		44.78	39.80	35.47	31.71	28.42
16	High0.45Hy	High	45%	Hydrogen central learning		42.90	37.86	33.48	29.65	26.30
17	Mid0.26Hyd	Mid	26%	Hydrogen slow learning		52.37	49.21	46.33	43.71	41.33
18	Mid0.15Hyd	Mid	15%	Hydrogen slow learning		53.50	50.36	47.52	44.94	42.60
19	Mid0.45Hyd	Mid	45%	Hydrogen slow learning		51.62	48.43	45.53	42.89	40.48
20	Low0.26Hy	Low	26%	Hydrogen slow learning		52.82	49.80	47.07	44.61	42.38
21	Low0.15Hy	Low	15%	Hydrogen slow learning		53.95	50.96	48.27	45.84	43.65
22	Low0.45Hy	Low	45%	Hydrogen slow learning		52.07	49.03	46.27	43.78	41.53
23	High0.26Hy	High	26%	Hydrogen slow learning		52.32	49.13	46.23	43.60	41.20
24	High0.15Hy	High	15%	Hydrogen slow learning		53.44	50.29	47.43	44.83	42.47
25	High0.45Hy	High	45%	Hydrogen slow learning		51.56	48.35	45.43	42.77	40.35
26	Mid0.26Hyd	Mid	26%	Hydrogen fast learning		36.63	30.51	25.41	21.13	17.52
27	Mid0.15Hyd	Mid	15%	Hydrogen fast learning		37.76	31.67	26.60	22.36	18.79
28	Mid0.45Hyd	Mid	45%	Hydrogen fast learning		35.87	29.73	24.60	20.30	16.67
29	Low0.26Hy	Low	26%	Hydrogen fast learning		37.08	31.11	26.15	22.03	18.57
30	Low0.15Hy	Low	15%	Hydrogen fast learning		38.20	32.27	27.35	23.25	19.84
31	Low0.45Hy	Low	45%	Hydrogen fast learning		36.32	30.33	25.35	21.20	17.72
32	High0.26Hy	High	26%	Hydrogen fast learning		36.57	30.43	25.31	21.02	17.39
33	High0.15Hy	High	15%	Hydrogen fast learning		37.70	31.59	26.51	22.25	18.66
34	High0.45Hy	High	45%	Hydrogen fast learning		35.82	29.66	24.51	20.19	16.54

SOURCE: ACIL ALLEN

Figure 6.13 shows the segment of the worksheet which presents the forecast achievable transport price. This is equal to the minimum of the regulated price and the price that would prevail under competition in any given year. When the price under competition falls below the regulated price, this corresponds to the crossover point (from the DBP's point of view). After this point it's no-longer possible for the regulated firm to earn the revenue allowable under regulation.

Column E from row 38 onwards shows the last year before which the achievable transport price falls to zero and the asset ceases operation.

FIGURE 6.13 WOOPS-HYDROGEN SNAP SHOT 2

	A	B	C	D	E	F	G	H	I
36				**Forecast achievable transport price**					
37		**Gas price**	**Carbon scenario**	**Learning rate**	**Last year of operation**	**2021**	**2022**	**2023**	**2024**
38		Mid gas	26% carbon	Hydrogen central learning	**2062**	1.38	1.36	1.37	1.37
39		Mid gas	15% carbon	Hydrogen central learning	**2068**	1.36	1.32	1.32	1.31
40		Mid gas	45% carbon	Hydrogen central learning	**2052**	1.38	1.36	1.36	1.37
41		Low gas	26% carbon	Hydrogen central learning	**2070**	1.38	1.36	1.37	1.37
42		Low gas	15% carbon	Hydrogen central learning	**2077**	1.36	1.32	1.32	1.31
43		Low gas	45% carbon	Hydrogen central learning	**2059**	1.38	1.36	1.36	1.37
44		High gas	26% carbon	Hydrogen central learning	**2059**	1.38	1.36	1.37	1.37
45		High gas	15% carbon	Hydrogen central learning	**2065**	1.36	1.32	1.32	1.31
46		High gas	45% carbon	Hydrogen central learning	**2051**	1.38	1.36	1.36	1.37
47		Mid gas	26% carbon	Hydrogen slow learning	**2085**	1.38	1.36	1.37	1.37
48		Mid gas	15% carbon	Hydrogen slow learning	**2085**	1.36	1.32	1.32	1.31
49		Mid gas	45% carbon	Hydrogen slow learning	**2085**	1.38	1.36	1.36	1.37
50		Low gas	26% carbon	Hydrogen slow learning	**2085**	1.38	1.36	1.37	1.37
51		Low gas	15% carbon	Hydrogen slow learning	**2085**	1.36	1.32	1.32	1.31
52		Low gas	45% carbon	Hydrogen slow learning	**2085**	1.38	1.36	1.36	1.37
53		High gas	26% carbon	Hydrogen slow learning	**2085**	1.38	1.36	1.37	1.37
54		High gas	15% carbon	Hydrogen slow learning	**2085**	1.36	1.32	1.32	1.31
55		High gas	45% carbon	Hydrogen slow learning	**2085**	1.38	1.36	1.36	1.37
56		Mid gas	26% carbon	Hydrogen fast learning	**2037**	1.38	1.36	1.37	1.37
57		Mid gas	15% carbon	Hydrogen fast learning	**2038**	1.36	1.32	1.32	1.31
58		Mid gas	45% carbon	Hydrogen fast learning	**2036**	1.38	1.36	1.36	1.37
59		Low gas	26% carbon	Hydrogen fast learning	**2040**	1.38	1.36	1.37	1.37
60		Low gas	15% carbon	Hydrogen fast learning	**2042**	1.36	1.32	1.32	1.31
61		Low gas	45% carbon	Hydrogen fast learning	**2038**	1.38	1.36	1.36	1.37
62		High gas	26% carbon	Hydrogen fast learning	**2037**	1.38	1.36	1.37	1.37
63		High gas	15% carbon	Hydrogen fast learning	**2037**	1.36	1.32	1.32	1.31
64		High gas	45% carbon	Hydrogen fast learning	**2035**	1.38	1.36	1.36	1.37

SOURCE: ACIL ALLEN

The block of cells from row 68 onwards presented in Figure 6.14 show both the final year of operation of the gas pipeline (column E) and the final year that the regulated transport price can be charged (column F). Column F corresponds to the crossover point because it is the last year that the allowable revenue under regulation can be achieved.

For example, in the mid gas price scenario, 26% carbon reduction scenario and hydrogen central learning case, shown in row 69, the final year where the regulated transport price is achievable is 2058. However, it takes another five years to 2062, before the asset is completely stranded and the achievable transport price falls to zero.

FIGURE 6.14 WOOPS-HYDROGEN SNAP SHOT 3

	A	B	C	D	E	F
68				Transport price -charged	Last year of operation (asset stranded)	Last year regulated price is charged
69		Mid gas	Mid gas 26% carbon	Hydrogen central learning	2062	2058
70		Mid gas	Mid gas 15% carbon	Hydrogen central learning	2068	2063
71		Mid gas	Mid gas 45% carbon	Hydrogen central learning	2052	2050
72		Low gas	Low gas 26% carbon	Hydrogen central learning	2070	2066
73		Low gas	Low gas 15% carbon	Hydrogen central learning	2077	2072
74		Low gas	Low gas 45% carbon	Hydrogen central learning	2059	2055
75		High gas	High gas 26% carbon	Hydrogen central learning	2059	2055
76		High gas	High gas 15% carbon	Hydrogen central learning	2065	2061
77		High gas	High gas 45% carbon	Hydrogen central learning	2051	2048
78		Mid gas	Mid gas 26% carbon	Hydrogen slow learning	2085	2085
79		Mid gas	Mid gas 15% carbon	Hydrogen slow learning	2085	2085
80		Mid gas	Mid gas 45% carbon	Hydrogen slow learning	2085	2085
81		Low gas	Low gas 26% carbon	Hydrogen slow learning	2085	2085
82		Low gas	Low gas 15% carbon	Hydrogen slow learning	2085	2085
83		Low gas	Low gas 45% carbon	Hydrogen slow learning	2085	2085
84		High gas	High gas 26% carbon	Hydrogen slow learning	2085	2085
85		High gas	High gas 15% carbon	Hydrogen slow learning	2085	2085
86		High gas	High gas 45% carbon	Hydrogen slow learning	2085	2085
87		Mid gas	Mid gas 26% carbon	Hydrogen fast learning	2037	2036
88		Mid gas	Mid gas 15% carbon	Hydrogen fast learning	2038	2036
89		Mid gas	Mid gas 45% carbon	Hydrogen fast learning	2036	2034
90		Low gas	Low gas 26% carbon	Hydrogen fast learning	2040	2038
91		Low gas	Low gas 15% carbon	Hydrogen fast learning	2042	2039
92		Low gas	Low gas 45% carbon	Hydrogen fast learning	2038	2036
93		High gas	High gas 26% carbon	Hydrogen fast learning	2037	2035
94		High gas	High gas 15% carbon	Hydrogen fast learning	2037	2036
95		High gas	High gas 45% carbon	Hydrogen fast learning	2035	2034

SOURCE: ACIL ALLEN

6.4.2 WOOPS Electricity

The 'WOOPS-Electricity' worksheet calculates the crossover point from the point of view of the DBP.

Just like the 'WOOP-Hydrogen' worksheet, the first block of cells between row 1 and 34 (see Figure 6.15) show the regulated transport price and the transport price that would prevail under competition for all the possible scenarios.

FIGURE 6.15 WOOPS-ELECTRICITY SNAP SHOT 1

	A	B	C	D	E	F	G	H	I
1				**Transport price ($/GJ)-Regulated**		**2021**	**2022**	**2023**	**2024**
2				$/GJ (26% carbon)		1.38	1.36	1.37	1.37
3				$/GJ (15% carbon)		1.36	1.32	1.32	1.31
4				$/GJ (45% carbon)		1.38	1.36	1.36	1.37
5									
6				**Transport price -under competition**					
7		**Gas Price**	**Carbon scenario**	**Learning rate**		**2021**	**2022**	**2023**	**2024**
8	Mid0.26Ele	Mid	26%	Electricity central learning		9.88	9.37	8.86	8.35
9	Mid0.15Ele	Mid	15%	Electricity central learning		11.00	10.53	10.05	9.58
10	Mid0.45Ele	Mid	45%	Electricity central learning		9.12	8.59	8.06	7.52
11	Low0.26Ele	Low	26%	Electricity central learning		10.33	9.97	9.61	9.25
12	Low0.15Ele	Low	15%	Electricity central learning		11.45	11.13	10.80	10.48
13	Low0.45Ele	Low	45%	Electricity central learning		9.57	9.19	8.81	8.42
14	High0.26El	High	26%	Electricity central learning		9.82	9.29	8.77	8.24
15	High0.15El	High	15%	Electricity central learning		10.95	10.45	9.96	9.47
16	High0.45El	High	45%	Electricity central learning		9.07	8.52	7.97	7.41
17	Mid0.26Ele	Mid	26%	Electricity slow learning		10.21	9.80	9.40	9.00
18	Mid0.15Ele	Mid	15%	Electricity slow learning		11.33	10.96	10.60	10.23
19	Mid0.45Ele	Mid	45%	Electricity slow learning		9.45	9.03	8.60	8.17
20	Low0.26Ele	Low	26%	Electricity slow learning		10.65	10.40	10.15	9.89
21	Low0.15Ele	Low	15%	Electricity slow learning		11.78	11.56	11.34	11.12
22	Low0.45Ele	Low	45%	Electricity slow learning		9.90	9.62	9.35	9.07
23	High0.26El	High	26%	Electricity slow learning		10.15	9.73	9.31	8.89
24	High0.15El	High	15%	Electricity slow learning		11.27	10.89	10.50	10.12
25	High0.45El	High	45%	Electricity slow learning		9.39	8.95	8.51	8.06
26	Mid0.26Ele	Mid	26%	Electricity fast learning		9.25	8.54	7.83	7.13
27	Mid0.15Ele	Mid	15%	Electricity fast learning		10.37	9.70	9.03	8.36
28	Mid0.45Ele	Mid	45%	Electricity fast learning		8.49	7.76	7.03	6.31
29	Low0.26Ele	Low	26%	Electricity fast learning		9.69	9.14	8.58	8.03
30	Low0.15Ele	Low	15%	Electricity fast learning		10.82	10.29	9.77	9.26
31	Low0.45Ele	Low	45%	Electricity fast learning		8.94	8.36	7.78	7.21
32	High0.26El	High	26%	Electricity fast learning		9.19	8.46	7.74	7.02
33	High0.15El	High	15%	Electricity fast learning		10.32	9.62	8.93	8.25
34	High0.45El	High	45%	Electricity fast learning		8.43	7.68	6.94	6.20

SOURCE: ACIL ALLEN

The block of cells from row 37 to row 64 (see Figure 6.16) show the forecast achievable transport price which corresponds to the minimum of the regulated price and price under competition. Cells from E38 to E64 show the final year of operation before the achievable transport price falls to zero.

FIGURE 6.16 WOOPS-ELECTRICITY SNAP SHOT 2

	A	B	C	D	E	F	G	H	I
36				Forecast achievable transport price					
37		Gas Price	Carbon scenario	Learning rate	Last year of operation	2021	2022	2023	2024
38		Mid gas	26% carbon	Electricity central learning	2055	1.38	1.36	1.37	1.37
39		Mid gas	15% carbon	Electricity central learning	2059	1.36	1.32	1.32	1.31
40		Mid gas	45% carbon	Electricity central learning	2047	1.38	1.36	1.36	1.37
41		Low gas	26% carbon	Electricity central learning	2063	1.38	1.36	1.37	1.37
42		Low gas	15% carbon	Electricity central learning	2069	1.36	1.32	1.32	1.31
43		Low gas	45% carbon	Electricity central learning	2053	1.38	1.36	1.36	1.37
44		High gas	26% carbon	Electricity central learning	2052	1.38	1.36	1.37	1.37
45		High gas	15% carbon	Electricity central learning	2056	1.36	1.32	1.32	1.31
46		High gas	45% carbon	Electricity central learning	2045	1.38	1.36	1.36	1.37
47		Mid gas	26% carbon	Electricity slow learning	2073	1.38	1.36	1.37	1.37
48		Mid gas	15% carbon	Electricity slow learning	2081	1.36	1.32	1.32	1.31
49		Mid gas	45% carbon	Electricity slow learning	2059	1.38	1.36	1.36	1.37
50		Low gas	26% carbon	Electricity slow learning	2081	1.38	1.36	1.37	1.37
51		Low gas	15% carbon	Electricity slow learning	2085	1.36	1.32	1.32	1.31
52		Low gas	45% carbon	Electricity slow learning	2066	1.38	1.36	1.36	1.37
53		High gas	26% carbon	Electricity slow learning	2070	1.38	1.36	1.37	1.37
54		High gas	15% carbon	Electricity slow learning	2078	1.36	1.32	1.32	1.31
55		High gas	45% carbon	Electricity slow learning	2057	1.38	1.36	1.36	1.37
56		Mid gas	26% carbon	Electricity fast learning	2040	1.38	1.36	1.37	1.37
57		Mid gas	15% carbon	Electricity fast learning	2041	1.36	1.32	1.32	1.31
58		Mid gas	45% carbon	Electricity fast learning	2037	1.38	1.36	1.36	1.37
59		Low gas	26% carbon	Electricity fast learning	2045	1.38	1.36	1.37	1.37
60		Low gas	15% carbon	Electricity fast learning	2047	1.36	1.32	1.32	1.31
61		Low gas	45% carbon	Electricity fast learning	2041	1.38	1.36	1.36	1.37
62		High gas	26% carbon	Electricity fast learning	2038	1.38	1.36	1.37	1.37
63		High gas	15% carbon	Electricity fast learning	2040	1.36	1.32	1.32	1.31
64		High gas	45% carbon	Electricity fast learning	2036	1.38	1.36	1.36	1.37

SOURCE: : ACIL ALLEN

Figure 6.17 shows the rows 68 to 95 in the worksheet which calculate both the last year before the crossover point is reached and the achievable transport price falls below the regulated price as well as the final year of operation before the achievable transport price falls to zero.

FIGURE 6.17 WOOPS-ELECTRICITY SNAP SHOT 3

	A	B	C	D	E	F
68				Transport price -charged	Last year of operation (asset stranded)	Last year regulated price is charged
69		Mid gas	26% carbon	Electricity central learning	2055	2050
70		Mid gas	15% carbon	Electricity central learning	2059	2055
71		Mid gas	45% carbon	Electricity central learning	2047	2044
72		Low gas	26% carbon	Electricity central learning	2063	2059
73		Low gas	15% carbon	Electricity central learning	2069	2065
74		Low gas	45% carbon	Electricity central learning	2053	2050
75		High gas	26% carbon	Electricity central learning	2052	2048
76		High gas	15% carbon	Electricity central learning	2056	2051
77		High gas	45% carbon	Electricity central learning	2045	2042
78		Mid gas	26% carbon	Electricity slow learning	2073	2068
79		Mid gas	15% carbon	Electricity slow learning	2081	2076
80		Mid gas	45% carbon	Electricity slow learning	2059	2056
81		Low gas	26% carbon	Electricity slow learning	2081	2077
82		Low gas	15% carbon	Electricity slow learning	2085	2085
83		Low gas	45% carbon	Electricity slow learning	2066	2063
84		High gas	26% carbon	Electricity slow learning	2070	2065
85		High gas	15% carbon	Electricity slow learning	2078	2072
86		High gas	45% carbon	Electricity slow learning	2057	2053
87		Mid gas	26% carbon	Electricity fast learning	2040	2037
88		Mid gas	15% carbon	Electricity fast learning	2041	2038
89		Mid gas	45% carbon	Electricity fast learning	2037	2034
90		Low gas	26% carbon	Electricity fast learning	2045	2042
91		Low gas	15% carbon	Electricity fast learning	2047	2043
92		Low gas	45% carbon	Electricity fast learning	2041	2038
93		High gas	26% carbon	Electricity fast learning	2038	2036
94		High gas	15% carbon	Electricity fast learning	2040	2037
95		High gas	45% carbon	Electricity fast learning	2036	2033

SOURCE: ACIL ALLEN

6.4.3 WOOPS combined

While the ‘WOOPS-Hydrogen’ and ‘WOOPS-Electricity’ worksheets consider the relative competitive position of gas against hydrogen and renewables separately, the ‘WOOPS-Combined’ worksheet considers the competitive position of gas against both hydrogen and renewables.

This is done by creating a single weighted average transport price under competition. To do this, we segment the DBP’s customers into those that are more likely to shift to hydrogen as a substitute and those more likely to shift to renewables. The relative volumes of each of the two customer classes are then used as weights to calculate a single transport price under competition. The customer category that is assumed to switch to renewables as the substitute technology is the gas for power generation customer class. The other DBP customer categories are assumed to switch to hydrogen as a substitute.

The worksheet has the same layout and structure as the WOOPS-Hydrogen and WOOPS-Electricity worksheets, however, the number of possible scenario combinations has expanded from 27 to 81, reflecting the fact that two sets of learning rates, one for hydrogen and one for renewables, are now relevant, whereas previously these were considered separately.

From the point of view of the DBP, the 'WOOPS-Combined' worksheet shows when the crossover point for the entire firm is reached rather than for each subset of customers depending on which substitute technology they switch to.

The combined crossover point lies between the individual crossover points for hydrogen and renewables. After the first customer segment hits its crossover point, the model assumes that the second set of customers whose transport price under competition is still above the regulated transport price, is charged more to compensate AGIG for the loss of revenue from the first customer class that has shifted to the substitute technology. This is only possible until the combined crossover point is reached, after which it is no longer possible to charge the remaining customers a price between the regulated price and the price under competition sufficient to compensate for revenue lost. At this point the firm cannot achieve the revenue allowable under regulation and the crossover point has been reached.

6.4.4 Results-scenarios

The 'WOOPS Hydrogen', 'WOOPS-Electricity' and 'WOOPS combined' worksheets present results for every possible combination of scenarios. As a result, the worksheets contain large volumes of information that can be difficult to navigate.

For this reason, the 'Results-scenarios' work sheet was created to provide a summary for any given scenario.

The top right hand of the worksheet corner contains a set of four input cells each with its own drop-down list. This part of the worksheet is shown in Figure 6.18.

FIGURE 6.18 SCENARIO SETTINGS – RESULTS-SCENARIOS WORKSHEET

	A	B	C	D
1				
2	**Scenario settings**			
3	Gas Price	Mid		
4	Carbon reduction scenario	26%		
5	Hydrogen learning rate	Hydrogen central learning		
6	Renewables learning rate	Electricity central learning		
7				

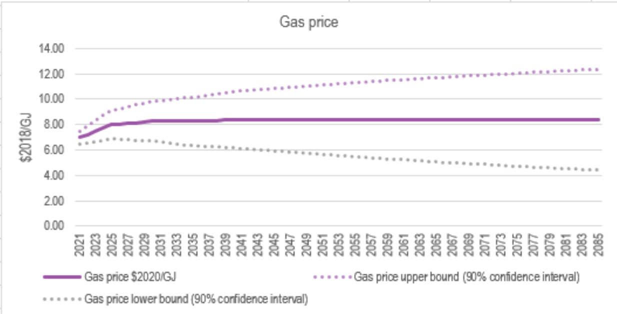
SOURCE: ACIL ALLEN

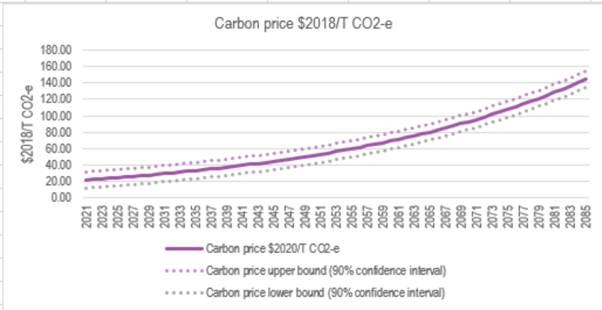
Once the scenario settings have been applied, the worksheet uses a set of VLOOKUP functions to retrieve the relevant data from the other output sheets in the model.

The first block of summary information (see Figure 6.19) shows the gas commodity price, the carbon price and the gas price including carbon for the relevant scenario.

FIGURE 6.19 RESULTS-SCENARIOS WORKSHEET SNAPSHOT 1

	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1				3	4	5	6	7	8	9	10	11	12	13
2				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
3		Gas price	$2020/GJ	6.97	7.23	7.48	7.74	7.99	8.04	8.10	8.15	8.20	8.25	8.25
4		Carbon price	$2020/T CO2-e	21.85	22.50	23.18	23.87	24.59	25.33	26.09	26.87	27.68	28.51	29.36
5		Gas price (inc carbon)	$2020/GJ	8.10	8.39	8.68	8.97	9.26	9.35	9.44	9.53	9.63	9.72	9.76
6														
7		Technology learning rates		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
8		Hydrogen		1.106	1.100	1.094	1.088	1.083	1.077	1.071	1.065	1.059	1.053	1.051
9		Renewables		1.012	1.012	1.013	1.013	1.013	1.013	1.013	1.013	1.013	1.014	1.014



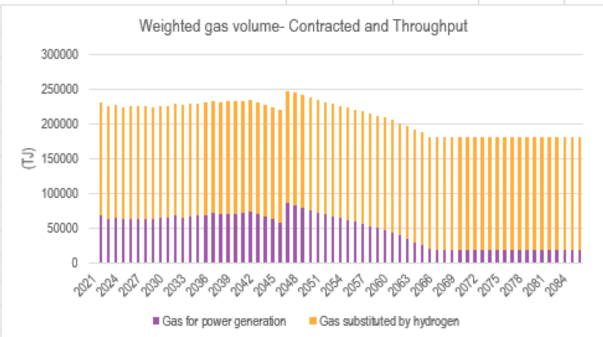


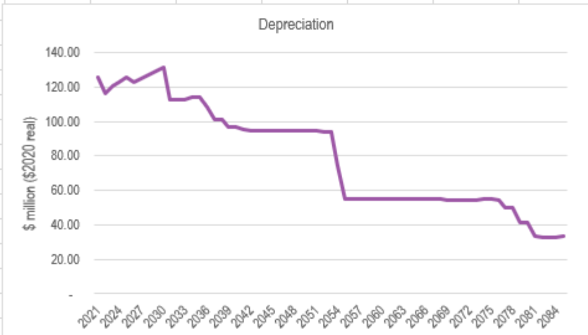
SOURCE: ACIL ALLEN

The second block of information from rows 27 to 55 (see Figure 6.20) shows the contracted, throughput and weighted average volumes categorised by customers whose gas consumption will be substituted by hydrogen and those substituted by renewables. Row 55 shows the assumed depreciation schedule applied in the allowable regulatory revenue calculations.

FIGURE 6.20 RESULTS-SCENARIOS WORKSHEET SNAPSHOT 2

	C	D	E	F	G	H	I	J	K	L	M	N	O	P
26		Contracted	Gas volumes (TJ)		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
27			Gas substituted by renewables	Gas for power ge	70,056	64,666	65,949	63,728	64,935	64,818	64,082	63,550	65,334	65,608
28			Gas substituted by hydrogen		164,476	164,371	163,977	164,016	164,045	164,045	164,045	164,045	164,045	164,045
29			Total (TJ)		234,532	229,037	229,927	227,744	228,979	228,863	228,127	227,595	229,378	229,652
30														
31		Throughput	Gas substituted by renewables	Gas for power ge	64,854	59,464	60,748	58,526	59,733	59,616	58,880	58,349	60,132	60,406
32			Gas substituted by hydrogen		145,137	147,148	146,845	146,671	146,463	146,463	146,463	146,463	146,463	146,463
33			Total (TJ)		209,991	206,613	207,593	205,197	206,196	206,079	205,343	204,811	206,595	206,869
34														
35		Weighted	Gas substituted by renewables	Gas for power ge	69,539	64,148	65,432	63,210	64,417	64,301	63,565	63,033	64,816	65,090
36			Gas substituted by hydrogen		162,552	162,658	162,273	162,291	162,296	162,296	162,296	162,296	162,296	162,296
37			Total (TJ)		232,091	226,807	227,705	225,501	226,713	226,596	225,860	225,329	227,112	227,386





SOURCE: ACIL ALLEN

Rows 58 to 62 (see Figure 6.21) show the crossover point from the customer's perspective, which compares the delivered price of gas against the delivered price of hydrogen, renewables and the combination of the two. Once the delivered price of the substitutes falls below the delivered price of gas, customers shift to the substitute and the crossover point has been reached.

FIGURE 6.21 RESULTS-SCENARIOS WORKSHEET SNAPSHOT 3

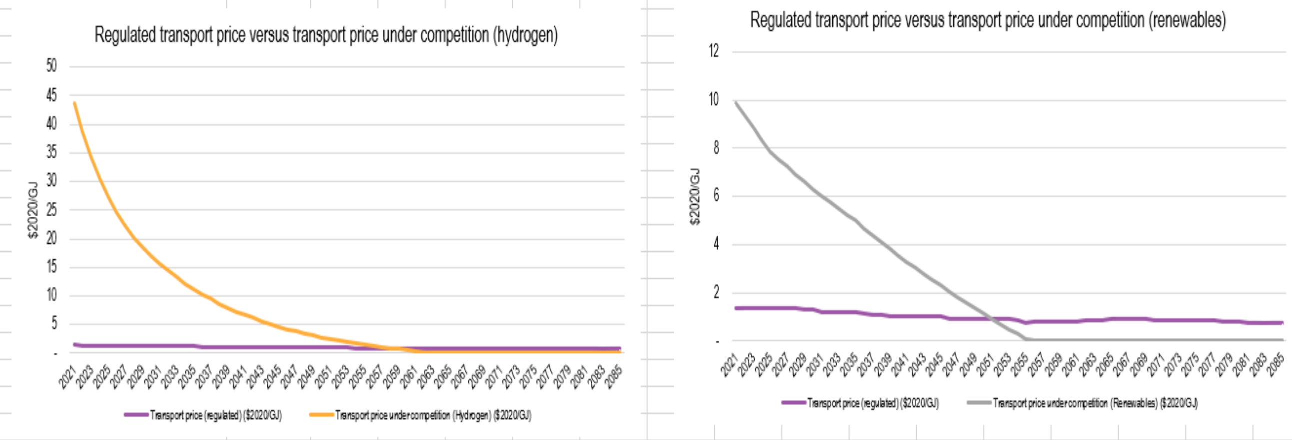
	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
58	Crossover point from customer perpective	CROSSOVER												
59	Gas price (inc carbon and transport) ($2020/GJ)		9.48	9.75	10.04	10.33	10.62	10.69	10.78	10.87	10.95	11.04	10.97	11.02
60	Delivered price of hydrogen (inc transport and storage) ($2020/GJ)	2058	51.81	47.10	43.05	39.55	36.54	33.94	31.69	29.76	28.10	26.67	25.37	24.18
61	Delivered price of renewables ($2020/GJ)	2050	17.98	17.76	17.54	17.32	17.10	16.88	16.66	16.44	16.22	16.00	15.79	15.57
62	Combined delivered price of hydrogen and renewables ($2020/GJ)	2056	41.67	38.80	35.72	33.32	31.01	29.10	27.46	26.03	24.71	23.62	22.54	21.68

SOURCE: ACIL ALLEN

In the block of rows from row 81 to 86, the crossover point from the DBP's perspective is presented. Once the transport price that can be charged under competition falls below the regulated transport price, AGIG is longer able to collect the revenue allowable by regulation and the crossover point has been reached. Furthermore, once the transport price under competition falls to zero, the DBP ceases to haul gas for its customers.

FIGURE 6.22 RESULTS-SCENARIOS WORKSHEET SNAPSHOT 4

	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
81	Crossover point from AGIG perspective	CROSSOVER	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
82	Transport price (regulated) ($2020/GJ)		1.38	1.36	1.37	1.37	1.36	1.34	1.34	1.34	1.33	1.32	1.21	1.21	1.19	1.18
83																
84	Transport price under competition (Hydrogen) ($2020/GJ)	2058	43.71	38.71	34.37	30.59	27.28	24.59	22.25	20.23	18.47	16.95	15.61	14.37	13.23	12.18
85	Transport price under competition (Renewables) ($2020/GJ)	2050	9.88	9.37	8.86	8.35	7.84	7.53	7.22	6.91	6.60	6.28	6.02	5.76	5.50	5.24
86	Transport price (Combined hydrogen and renewables) ($2020/GJ)	2057	33.58	30.41	27.04	24.35	21.76	19.75	18.02	16.50	15.08	13.90	12.77	11.87	10.96	10.13



SOURCE: ACIL ALLEN

Finally, rows 106 to 108 (see Figure 6.23) show the regulated transport price path, the competition transport price path (combining both hydrogen and renewables) and the actual price path, which is the lesser of the regulated and competition price paths.

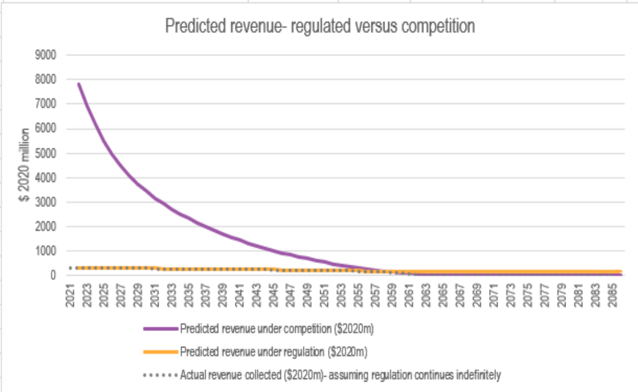
Rows 112 to 114 then compare the predicted revenue under competition with the revenue predicted under regulation. The actual revenue collected is the lesser of the two.

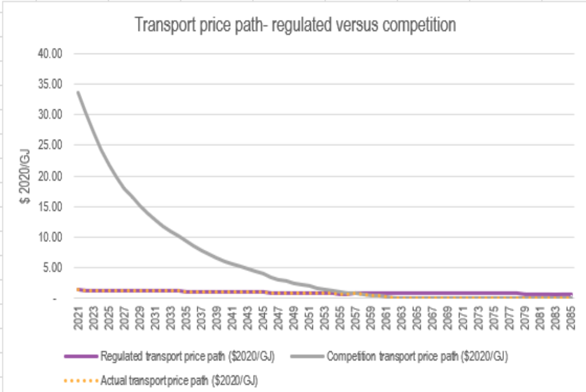
The predicted revenue under competition is calculated as the price times volume. As the (weighted) price of the substitute technology declines the predicted revenue under competition also falls. The predicted revenue under regulation is derived using the standard building blocks approach, which is the sum of the return on the asset, depreciation, Opex and tax and imputation credits.

FIGURE 6.23 RESULTS-SCENARIOS WORKSHEET SNAPSHOT 5

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Regulated transport price path ($2020/GJ)	1.38	1.36	1.37	1.37	1.36	1.34	1.34	1.34	1.33	1.32	1.21	1.21	1.19
Competition transport price path ($2020/GJ)	33.58	30.41	27.04	24.35	21.76	19.75	18.02	16.50	15.08	13.90	12.77	11.87	10.96
Actual transport price path ($2020/GJ)	1.38	1.36	1.37	1.37	1.36	1.34	1.34	1.34	1.33	1.32	1.21	1.21	1.19

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Predicted revenue under competition ($2020m)	7,792.48	6,898.27	6,157.38	5,491.98	4,932.82	4,475.06	4,070.60	3,718.19	3,425.29	3,160.45	2,943.80	2,713.54	2,517.86
Predicted revenue under regulation ($2020m)	320.47	308.90	310.94	308.06	308.66	303.58	302.63	301.83	301.24	300.43	278.92	276.47	273.83
Actual revenue collected ($2020m)- assuming regulation continues indefinitely	320.47	308.90	310.94	308.06	308.66	303.58	302.63	301.83	301.24	300.43	278.92	276.47	273.83
Actual revenue collected ($2020m)- assuming regulation ends once the asset is fully depreciated	320.47	308.90	310.94	308.06	308.66	303.58	302.63	301.83	301.24	300.43	278.92	276.47	273.83





SOURCE: ACIL ALLEN

A

GLOSSARY OF TERMS

ACIL Allen	ACIL Allen Consulting
AUD	Australian dollar
bbl	Barrel – a unit of volume for crude oil
CCGT	Combined cycle gas turbine
CO_2-e	Carbon dioxide equivalent – a measure of greenhouse gas emissions
CPI	Consumer Price Index
CSG	Coal seam gas
EIS	Emissions Intensity Scheme
EV	Electric vehicles
GHG	Greenhouse gas
GJ	Gigajoule – one thousand million joules
GPG	Gas for power generation
GT	Gas turbine
GWh	GigaWatt hours – one thousand MegaWatt hours
kWh	kilowatt hours – one thousand Watt hours
LGC	Large Scale Generation Certificate – issued under the Large-scale Renewable Energy Target scheme
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
LRMC	Long run marginal cost
Mt	million tonnes
MW	Mega Watt – one million Watts

MWh	Mega Watt hour – one million Watt hours
NEM	National Electricity Market
NPV	Net present value
OCGT	Open cycle gas turbine
PJ	Petajoule – one million gigajoules
PV	Photovoltaic
SRMC	Short run marginal cost
SWIS	South west interconnected system
USD	United States dollar

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