Attachment 6.1

Future of Gas – our approach to accelerated depreciation

Final Plan 2023/24 – 2027/28

July 2022

1. Introduction

This attachment provides an overview of our accelerated depreciation proposal and the work that underpins it. It covers:

- The forces in the energy sector that have driven our approach to depreciation.
- Our role in the energy sector, how we can respond to the challenges the sector faces and what this means for customers and investors.
- How our actions on accelerated depreciation form part of a value proposition for customers along with our hydrogen ready expenditure and prudent network expansion.
- How our modelling framework evolved.
- How the model actually works and the results it has produced; this attachment is also intended to be a manual for our modelling framework so that our approach is transparent and can be replicated.

In simpler terms, this attachment explains what we did (and how), why we did it, and how someone else can replicate our findings and explore our analytical framework.

In developing our proposal we have paid close attention to the AER's expectations in respect of accelerated depreciation proposal as set out in its information paper. These requirements are shown in Figure 1.

Figure 1: AER expectations on accelerated depreciation arguments

AER's expectation:

To demonstrate stranded asset risk, we expect regulated businesses to provide plausible future energy scenarios that covers a spectrum of outlooks from the most pessimistic to the most optimistic for their networks, and to estimate the likelihood (probability) of each scenario. We expect regulated businesses to demonstrate the magnitude of stranded asset risk and possible divestment and investment plans under each scenario. In particular, to demonstrate the materiality of stranded asset risk and the justification for early regulatory intervention, we expect a regulated business to provide compelling evidence to identify:

- the factors that influence the estimates of expected economic lives, such as applicable government policies, evidence of their customers' sentiments in switching away from gas, developments in competing technology etc
- those assets that may be repurposed for transporting hydrogen and those that cannot be
- those assets whose economic lives may need to be adjusted to reflect the potential decline in long-term demand
- the value of stranded assets under the different forecasting scenarios
- the costs that may be avoided or incurred in the different forecasting scenarios
- the level of customer support for the business's proposed action to manage the risk and the quality of that customer engagement
- analysis of the price impact for the business's proposed action.

Source: AER 2021, Regulating Gas pipelines Under Uncertainty: Information paper, November 2021, p45 (available here)

Below we provide an overview of where in our submission evidence supporting each of these elements may be found.

Factors influencing economic lives

The economic lives of our assets form a major part of our proposal. The factors which influence them are explicitly considered in our modelling framework described in detail in Chapters 3 and 4. We consider not only the length of economic lives, but also their structure. The weight of the evidence suggests that straight line depreciation may no longer be the best approach given the nature of the evolving future.

In forming our arguments, we have paid particular attention to the AER's requirements set out in Figure 2 below. In particular, we have paid attention not only to the ongoing use of assets for natural gas post any 2050 net zero target, but also to the use of such assets for the carriage of different gases; for example, hydrogen.

Figure 2: AER expectations on asset lives

AER's expectation:

We would expect regulated businesses to provide compelling evidence to justify the asset lives that they have proposed.

Notwithstanding the 2050 net zero emissions targets adopted by State and Territory governments, this does not necessarily mean the gas networks must be decommissioned or retired completely at that time. There is a possibility that hydrogen or bio-methane can be used as reticulated gas in the future. There is also a possibility that natural gas may continue to be used by specific customers (for example, industrial users who must use natural gas as a chemical feedstock), such that gas networks may continue to operate beyond 2050 at a smaller scale or in specific regions. Therefore, in our view, assuming 2050 as the cap for the expected economic lives of pipeline assets without reasonable evidence or analysis would be inappropriate.

As regulated businesses may face different levels of stranded asset risk, we may consider a departure from our typical approach of assuming uniform standard asset life for a specific class of assets (based on technical life). We may allow the same class of assets to have different assumed asset lives (depending on the economic stranding risk the relevant business faces) among regulated businesses.

Source: AER 2021, Regulating Gas pipelines Under Uncertainty: Information paper, November 2021, p46 (available here)

Although the scenarios which drive our modelling have been developed in light of various net-zero emissions targets, our models are driven by relative prices, of gas, electricity and hydrogen and the appliances which utilise them rather than the policy targets per se. In particular, although some scenarios do involve new connection bans and switching off part or all of our network by a certain date, our approach is not to depreciate to zero by a certain date to avoid the risk of stranding (see Chapters 3 and 4). In respect of asset lives, our proposal deviates from the AER's (to-date) standard technical lives for some long-lived assets, bringing forward some depreciation in the next period. We believe this is more consistent with the economic theory around efficient pricing with fixed cost recovery (see Section 2.3.4).[1]

Although not directly related to economic lives per se, the AER also identifies two further expectations which have an influence on our modelling approach and on our conclusions in respect of how much depreciation needs to be increased. These are summarised in Figure 3 and Figure 4.

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[1] We note that a tilted annuity approach is the logical conclusion of the approach we have followed (see Attachment 6.4). We would be happy to discuss this with the AER, but have not proposed it at this stage because it would require some small changes to the PTRM, which our current approach does not.

Figure 3: AER expectations on building blocks

AER's expectation:

We expect regulated businesses to apply consistent assumptions across all the building blocks of the access arrangement proposal where possible. This includes their demand forecasts, their expected economic lives of their assets, and their economic value and net present value analyses of their expenditure proposals.

Source: AER 2021, Regulating Gas pipelines Under Uncertainty: Information paper, November 2021, p50 (available here)

We have, where possible, been consistent with assumptions. There are some limitations however, because an AA proposal is intended to give the single most efficient outcome for a forecastable forthcoming five year period, whereas our accelerated depreciation proposal is part of a package of actions intended to provide flexibility and reduce risk over a longer period which is uncertain and unforecastable. For example, our accelerated depreciation model tests depreciation proposals in different scenarios (see Section 3.2.2) rather than solving for some "optimal" amount of depreciation. However:

- Where feasible, we create direct linkages, such as linking the opex and capex forecasts in our AA proposal into the depreciation model (see Section 5.3.3).
- The thinking behind our accelerated depreciation, particularly its role in creating flexibility, has also underpinned other aspects of our proposal intended to create flexibility for customers (see Section 2.3.1).

Figure 4: AER expectations on scenarios

AER's expectation:

We expect that, in preparing their access arrangement proposals, regulated businesses would:

- take into account relevant climate change policies and cross-elasticities of demand for natural gas substitutes in their demand forecasts
- forecast a range of different possible demand scenarios, with associated probabilities
- look well beyond the next regulatory period, and would consider demand and supply conditions potentially several regulatory periods into the future
- form a view on whether or not current price levels will be able to maintained in the future, in the face of different demand scenarios. If there is a prospect that prices will not remain stable, we expect this possibility to be explored with customers (as part of the consumer engagement) and to be explained in the access arrangement proposal, including proposed mechanisms for mitigating the consequences.

Source: AER 2021, Regulating Gas pipelines Under Uncertainty: Information paper, November 2021, p53 (available here)

We would argue that our modelling approach goes beyond the AER's requirements outlined in Figure 4. In particular:

- Climate policies, where known, can be directly implemented in our model. Future own and cross price elasticities are unknown, but our accelerated depreciation model creates a depreciation schedule which mimics how depreciation should respond to changing elasticities, in a manner which is consistent with the information we do have about the future (see Section 2.3.4).

- We formed an expert panel to provide independent assistance to develop a series of future scenarios which produce different demand profiles for our network (see Section 3.2.1) over the next eight decades. Note that we have not attached probabilities to these scenarios. This is deliberate; we do not believe that there is sufficient information at this stage (nor will there likely be for at least a decade) to assign probabilities to scenarios. Rather we have developed an approach which does not require probabilities to uncover prudent depreciation strategies (see Section 3.2.2).
- Not only do we consider the feasibility of current prices, but the relative stability of prices (particularly the avoidance of price shocks) is a core part of our approach. Where demand falls rapidly due to building block prices being too high, we risk asset stranding but, before that happens, our consumers face spiralling prices, so relative price stability, where it can be achieved, is in both our and customers' interests. Accordingly, our approach to depreciation is predicated upon finding ways to maintain relative price stability (see Section 3.2). This has been explored extensively with customers as results have been developed (see Section 3.2.3) and we expect to continue to do so.

Assets that may be repurposed for transporting hydrogen and those that cannot be

A key part of our capex planning for this forthcoming AA period has been developing an understanding of which of our assets are and are not hydrogen ready. In simple terms, most of our networks are already capable of carrying hydrogen, and the likely spending to move to 10 percent, and subsequently 100 percent, hydrogen is relatively small. Detail on this is provided in our capex chapter, Chapter 9. This formed an input into our accelerated depreciation modelling.

Value of stranded assets

The value of assets stranded in each scenario, both before and after the accelerated depreciation response, is provided in Sections 4.1 and 4.2, with sensitivity analysis in Section 4.3. Note that not all scenarios have asset stranding, even if we do nothing, and not all scenarios resolve all asset stranding, even when we act. Finally, note that our final solution in respect of the amount of accelerated depreciation we are asking for does not remove all risk.

Costs that may be avoided or incurred

Our model for accelerated depreciation has two types of opex and capex; demand driven and non-demand driven costs. We assume that each new connection incurs $2400 of capex upfront and opex which grows at half the speed of connections and network length on an ongoing basis, and these costs are either incurred or avoided every time the model is run, depending upon the demand forecast in that model run. Non demand-driven costs, such as network augmentation, have been prepared based on internal engineering advice and the assumptions which underpin each scenario developed by our independent expert panel. Each scenario has different non-demand driven opex and capex (which stays the same for each model run in that scenario). Further detail is provided in Section 5.3.1 and see in particular Table 9.

Level of customer support

Our approach to stakeholder consultation has arguably exceeded the requirements of the AER. We discuss some aspects of it, relating particularly to accelerated depreciation, in Section 3.2.3, and more broadly in Chapter 5.

The AER's expectation in respect of customer support are further detailed in Figure 5.

Figure 5: AER expectations on stakeholder consultation

AER's expectation:

Regulated businesses, consumers and regulators may have differing perspectives on how quickly network investments can or should be depreciated. Consumer views are vital in determining what depreciation adjustments would be in the long-term interests of consumers under the circumstances. Consumer views are also important to us in understanding their expectations of future energy needs and the particular challenges that captive customers may face in this energy transition. Such information will enable us to determine what regulatory approaches would be efficient and prudent.

We expect that, in proposing any variation to the existing depreciation schedules, regulated businesses would actively and meaningfully engage with their customers on the range of available options and reflect customers' feedback in their proposals. We consider that good consultation will involve a range of scenarios being put to consumers with respect to demand forecasts, expenditure and any stranding mitigation measures, together with the price impacts of those scenarios.

Source: AER 2021, Regulating Gas pipelines Under Uncertainty: Information paper, November 2021, p47 (available here)

Since our accelerated depreciation approach is novel, we have consulted extensively on it in:

- Customer workshops, with end-user customers
- Our Victorian Gas Network Stakeholder Roundtables and Retailer Reference Groups
- Deep dives with customer representatives and other stakeholders
- One-on-one sessions with any stakeholders who desired them.
- Discussions with the AER and provision of early working versions of the model we use so the AER can familiarise itself with the model before our final plan is submitted.

In respect of accelerated depreciation, our process was very detailed and began well and truly before we had completed our modelling work; as we learned, we passed on this learning to our stakeholders as soon as we could. Our focus in the early consultation with all stakeholders was not necessarily agreement that the particular amount of accelerated depreciation we were seeking was reasonable, or that they agreed with the price impacts.

Rather, we focussed on helping stakeholders develop an understanding of what we are proposing and why. Developing a good understanding of the relevant issues is, we believe, far extremely useful at this early stage, as the debate on accelerated depreciation is one that will likely continue beyond this regulatory review process as the energy transition evolves. Starting the debate on an informed basis is crucial. In this, we believe we have had some success, even amongst stakeholders opposed to any accelerated depreciation or other preparations for an uncertain future. In particular, there was widespread acceptance that out modelling framework was likely sufficiently robust and transparent as to allow the AER, with its technical expertise, to judge the reasonableness of our proposal.

Analysis of the price impact of proposed action

Absent of our accelerated depreciation proposal, network charges would have fallen 22 percent in nominal terms. With it, they are falling 10 percent.

This, however, is far from the only consideration. Our focus in modelling is on long-term price stability, as this is in the long term interests of customers during the energy transition and how we lower our own risk of asset stranding (see Section 2.3).

Price impacts are a core part of our process of modelling and assessing our accelerated depreciation proposals. Our cost structure is largely fixed, so price rises as demand falls. Moreover, there is a feedback loop (in reality, and as an explicit part of our model); as prices rise, demand falls. This feedback loop gets stronger through time as the price of substitutes fall. The final consequence of demand falling is an inability on our part to recover our invested capital. However, before this happens, prices will start to rise as the feedback loop starts to impact our business.

For this reason, minimising price impacts is at the core of what we are trying to do; our accelerated depreciation approach is designed precisely to stop demand reductions caused by (and causing) price increases. Reflective of the fact that our future is competition of a scale and type which is unanticipated in the energy sector, it is in our self-interest, today, to do all we can to avoid price increases, which are in effect the canary in the coal mine of risk of failure to recover our invested capital. Therefore, price stability sits at the core of our accelerated depreciation proposal (see Section 3.2).

Over the short term too, we have been mindful of price impacts, cognizant of the fact that current customers may be unwilling to endure significant price increases to avoid future customers suffering still greater increases. We have limited our accelerated depreciation proposal to minimise price change from the present AA period to the forthcoming one

2. The evolving energy market and our place in it

Our proposal to add accelerated depreciation to the toolkit of options which allow us to sustain our future in the long term interest of customers is a response to how we see the energy market evolving, and in this chapter we describe what we can see about that future. We look first at what we see as the policy challenges, then at the technological and market changes and finally at our opportunities and challenges in this evolving marketplace.

Something that is immediately clear is that the energy sector is on the cusp of a process of considerable change. This is driven in large part by technological progress within the renewable sector, which drives change not solely (or possibly even primarily) because it allows energy to be produced more cheaply, but because it allows energy to be produced in entirely new ways, and by entirely new players. The recent rise of "prosumers" using their rooftop solar to sell into the market as well as buy from it, and the even more recent emergence of lower cost storage options represents only the first stage of a much longer process of market evolution. We believe that the end point of such evolution will be an energy sector profoundly different from the sector today. Networks will still play a role, but it will be different, and likely smaller in terms of energy transported (or at the very least energy time the distance it is moved), and sit within a very different competitive ecosystem where many players co-operate and compete to ensure a balance between the energy produced and consumed by final energy consumers.

The sector is also driven by policy change. Some of this policy change, particularly at a global level, where markets are much larger, has in fact driven the technological change in the renewables sector. However, at the local and national level, policy serves more to accelerate or stymie some of the effects of technological progress and create path dependencies (both deliberately and inadvertently) around the evolution of the energy sector. It also serves to change the costs of the energy sector, again, sometimes by design and sometimes inadvertently. Finally, policy itself is not a static force and policymakers are seldom better informed than others in the sector, which means that policy itself evolves as information about the future is revealed.

If the energy sector were to be described by a single word, that word would be "uncertainty", and uncertainty of a kind of a more fundamental nature than simply a range of possible demand or cost outcomes around a central expected forecast in a regulatory model, involving questions like:

- Will gas networks be in business at all in 2050? If not, will it be policy or technology forces which have caused that outcome, and where will gas consumers' preferences be reflected?
- If we are in business, what will we be transporting? Will it be gas or will it be hydrogen or other renewable gases? If there is to be a transition from one to the other, how will that be planned, and when will it happen.
- If we are transporting renewable gas, what will it be used for, and by whom? Will its use be similar to how natural gas is used, or entirely different? What appliances will it power? Could it power new appliances that perform new roles? Could it play a role in energy storage?
- If we transport renewable gas, who will produce it, where and how? For example a network with distributed hydrogen production has very different characteristics than one with centralised production. Similarly, a network primarily feeding an export industry has different economics to one primarily feeding domestic production; as does the hydrogen itself.
- How much will the market be prepared to pay for renewable gas and, more particularly, for transport, if the option for self-production exists for at least some users as it does to some extent for renewable power today?

- Will our networks, or even the energy sector itself, continue to be regulated as they are today? If not, then how do we plan today for a future where competition exists when the regulatory system does not, at present, anticipate such a fundamental change in its legislative and governance framework? What obligations do regulators have in terms of the energy system they bequeath to a future competitive world, and how might these be met?

We can answer almost none of these questions with any degree of clarity or certainty. This chapter does not contain our predictions for the future, but rather maps out the challenges we face, and the responses we are developing to face those challenges, with a focus on accelerated depreciation. In particular, we focus, in turn, on:

- The evolving policy landscape.
- The evolving technological landscape.
- The responses we can make to the challenges in these landscapes and the consequences of this from the perspectives of customers, investors and the regulatory framework we are required to follow in respect of depreciation in particular.

2.1. The policy landscape

The policy landscape associated with the energy sector is complex at the moment. The AER, in its recent *Regulating Gas Pipelines under Uncertainty* information paper has provided a comprehensive summary of the various different policies covering emissions targets, renewables targets, zero emission vehicles targets, hydrogen support, battery support, residential and other solar support, renewable energy zones, as current in October 2021.[2] To some extent, this is already out of date, as it does not include the recent Labor victory in the Federal election, nor the Victorian Gas Substitution Roadmap, both of which will only become known as the AER makes its Draft and Final Decisions.[3] Moreover, even once these two aspects of policy are understood, this hardly presages the end of energy policy change in Australia; policymakers are no better informed than anyone else in the energy sector and they too are reacting to new information, as it becomes available.

Rather than repeat and update the information provided by the AER on energy policy, we outline our two major concerns in respect of policy. We then turn to some positive developments in policy for our sector. Our concerns are:

- That government will attempt to "pick winners" amongst the different technologies which may prevail in the future. Obviously, a policy which chose a different "winner" and actively discriminated against hydrogen would be the worst for gas networks, but even a policy which picks hydrogen as a "winner" and actively discriminates against competition is not ideal in the long run. Rather than picking winners and closing off options for customers, policy should focus on outcomes, and provide support, where needed, to different ways of meeting those outcomes.
- That governments will inadvertently create path dependencies from their policy choices which could lead to substantial and long term consequences for the energy sector. In an example from outside the energy sector, the colonies which eventually became the states of Victoria and New South Wales chose different railway gauges when developing their railway networks

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[2] *AER 2021, Regulating Gas pipelines Under Uncertainty: Information paper, November 2021, pp65-71 (available here)*

[3] *By way of an example of the speed of change, at the writing of this document, AEMO had just announced that it is suspending the market rules of the NEM (see here), which precipitated the fourth change to this footnote during the drafting of this Attachment.*

in the 1850s, despite being advised not to by the UK government of the day.[4] Melbourne and Sydney were not linked by a single gauge of railway line until the 1960s, and there was no national network using a single gauge until the 1990s. Policy choices can create very long term path dependencies.

We recognize that renewable gas policy is still in its early stages; the National Hydrogen Roadmap, which was amongst the first major policies specifically focused on hydrogen, emerged only in 2018.[5] By contrast, renewable power has been supported in Australia through policies incentivising its uptake such as the SRET and LRET for around 20 years, and through significant financial support from government.[6]

Much recent focus in Victoria has been on the Gas Substitution Roadmap as a key source of uncertainty; some of our stakeholders suggested that they needed to wait for its release before being able to make a decision on our proposal for accelerated depreciation. We too, hope that the final policy is more balanced than early modelling and information, which suggested that the policy might exemplify both of our concerns outlined above.[7] However, more broadly, we also see several positive policy developments, including:[8]

- There are several policy initiatives associated with educational institutions to do basic research, facilitate co-operation between institutions and industry and to keep track of a rapidly evolving environment in hydrogen. Examples include the Future Fuels CRC, the Australian Hydrogen Centre and the Hydrogen Industry Mission at CSIRO.
- Government is investing directly in hydrogen pilot projects via ARENA, NERA and the CEFC at the Federal level and the Victorian Hydrogen Investment Development Plan to assess early stage viability; our Hyp Murray Valley project, for example, received $32.1 million in grant funding from ARENA. The amounts are still small (the Hydrogen Industry Development Plan, is just $7.2 million, for example, compared with $1.3 billion over 10 years for the Solar Homes programme), but so are many of the projects. As smaller scale projects prove themselves, we would expect to see more investment, similar to renewable power, until neither technology requires support.
- International collaboration is being facilitated, with Germany, Japan, Korea and the US, for example. Since technology is fungible, research and development supported in one jurisdiction can produce products which are then sold globally, and Australia can benefit from government support for hydrogen in much larger markets, like the EU. Collaboration projects can help speed up this process of transfer, as well as expose Australian innovation to a wider marketplace.

[4] *See Mills, J, 2010, Australia's Mixed Gauge Railway System: A reassessment of its origins, Journal of the Australian Historical Society 96(1), pp50-61, available here.*
[5] *The policy is available here*
[6] *See deAtholia, T, Flannigan, G & Lai, S, 2020, Renewable Energy Investment in Australia, RBA Bulletin March 2020 (available here) for a summary of the LRET and SRET schemes. Internationally, the support has been greater and over a much longer time period, discussed in detail in this book.*
[7] *Briefly, early information an modelling suggested that the Victorian Government is going to favour electrification (the first concern above), with hydrogen emerging only in the 2040s, without any clear indication of how the gas networks are supposed to remain viable in the meantime as policy actively discriminates against them (concern number 2 above).*
[8] *See the Department of Industry, Science Energy and Resources, 2021, State of Hydrogen 2021, available here, and the CSIRO "HyRresource" page (available here) for recent updates.*

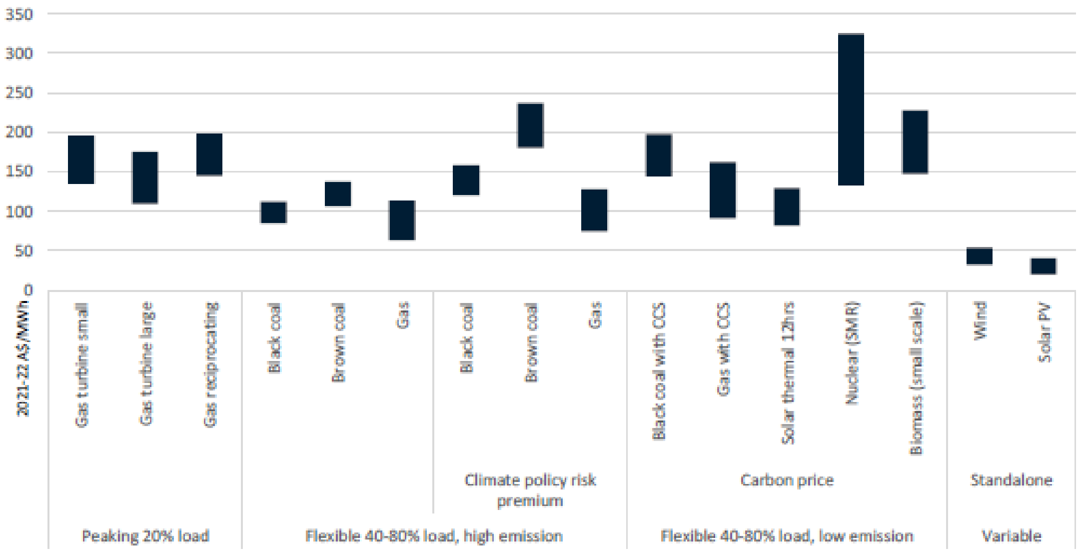
2.2. Technological change and customer choice

Policy, particularly at the Victorian of Federal government level can accelerate or stymie a technology, but it is ultimately technological progress which will drive our sector in the long run. There are two aspects of technological change crucial for our industry; technological change in the way energy is produced (the electrons and molecules), and technological change in the way energy is consumed (the appliances). In both cases, the growth of technological progress and fall in cost of existing technologies and the emergence of new technologies, or new ways of using existing technologies, is key.

2.2.1. Technological change in the way energy is produced

The long-term driving force which affects our sector is technological change, and the opportunities and threats it opens up for our sector. A common way of presenting technology growth and its impact on cost is to look at the levelised cost of electricity, as the CSIRO has been doing for several years now. An example is shown in Figure 6.

Figure 6: LCOE projections CSIRO 2050



Source: Graham, P, Hayward, J and Havas, L, 2021, GenCost 2021-22: Consultation Draft, available here, p50

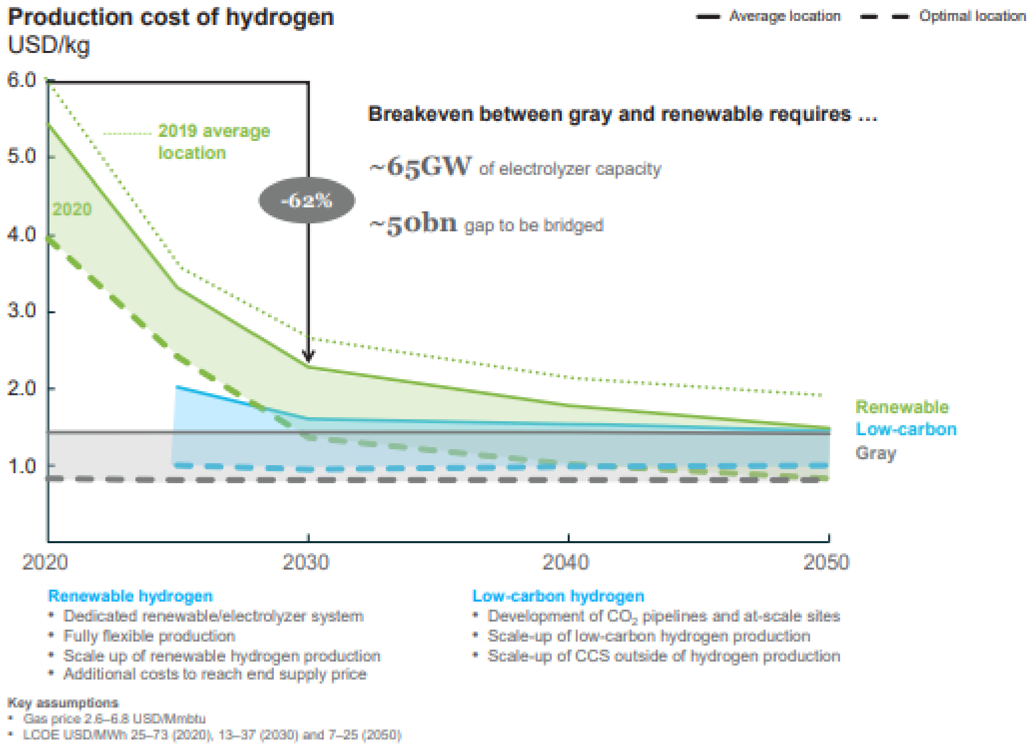
For our networks, it is arguably not the overall falling LCOE of renewable power that matters, since the gas in Figure 6 is gas used to generate electrical power, which is of limited importance for distribution networks. For us, three aspects of cost, driven by technological progress, are important:

- The cost of hydrogen
- The cost structure of renewable power and its impact on electricity networks
- Economies of scale in renewable power and the opportunities it brings

Cost of hydrogen

Hydrogen produced by electrolysis currently costs around between $5 and $7 per kg,[9] with a target of $2 per kg by 2030, at which point in time it will start to become competitive. We have used the cost projections in Figure 7 in our modelling work, which suggest that the $2 per kg goal will be met by around 2030, and will likely halve again by 2050.

Figure 7: Hydrogen cost projections



Source: McKinsey and Hydrogen Council 2021 Hydrogen Insights A perspective on hydrogen investment, market development and cost competitiveness p12 (available here)

The price path for hydrogen will obviously have a huge impact on its viability for our network; if renewable hydrogen is not comparable to other forms of energy for our consumers, they won't demand it. However, it is important to note that what matters is the delivered cost of hydrogen to the network, and this can be influenced not only by how hydrogen is produced, but also what else is produced with it, and what value that has. If hydrogen is produced by electrolysis, a by-product is oxygen and this has value in the marketplace; it is why, for example, our Hyp Murray Valley project was developed with a local water treatment plant as a partner. If it is produced via pyrolysis (which requires less energy to break the chemical bonds), a by-product is carbon, and carbon, in different forms, can be very valuable. For example, a UK company has devised a way to produce graphene from methane.[10] Graphene can fetch up to $1000 per kg, depending on its use and even low value uses (fetching less than $100 per kg) could significantly impact the economics of hydrogen, as three kilogrammes of carbon are produced for every kilogramme of hydrogen. When such a process is applied to bio-methane, it could represent a substantially greener option than simply burning the biomethane and may represent a way in which bio-methane has a long-term future in a gas network that has converted to hydrogen.

[9] *See McKinsey and Hydrogen Council 2021 Hydrogen Insights A perspective on hydrogen investment, market development and cost competitiveness (available here) and note that the analytical work was largely done in 2020.*
[10] *See https://www.levidian.com/home, and a review from the Economist here. There are also many other projects looking at pyrolysis (breaking down methane) to produce both hydrogen and carbon products.*

Cost structure of renewable power and electricity networks

Producing electricity from fossil fuels involves opex and capex as the fuel must be purchased. Producing electricity from renewable sources like wind and solar is almost all capex, because the fuel is free. This has a profound effect on the economics of renewable power compared to the economics of "traditional power" as renewable power is far more dependent upon the cost of capital.

However, because of its economies of scale (see below), it is possible to produce at least some electricity, using renewables, at the household level at near zero marginal cost. This is important for electricity networks because their charging structure is far more weighted to variable charges than is the weight of variable costs in their total cost structure. Consumers who produce some of their own electricity thus avoid more charge than the electricity network avoids costs associated with serving them. This is not a sustainable proposition for electricity networks over the long run if distributed generation increases in scale.

However, since almost all of our consumers (whether they consume natural gas or hydrogen) also have an electricity connection, if they consider electrifying their whole energy load, they are comparing their whole gas bill with the variable component of their electricity bill. To the extent that variable charges fall to meet variable costs, which may be very low indeed if most electricity production is renewable and much is distributed, switching off gas becomes more attractive.

This is clearly an issue for our networks. However, it is also an issue for regulation, as decisions made by the AER in respect of one network can influence other networks in a way which has not been the case in the past. This is a new challenge for the AER as it determines what is in the long-term interests of consumers, as it has not had to consider the impact of one decision on other networks in this way and to this extent in the past.

Economies of scale in renewables

Unlike fossil fuel electricity generation, renewable power generation and storage (particularly solar and batteries) tends to be modular, with bigger facilities tending to be made up of much the same kit as smaller facilities. This means that economies of scale tend to be relatively low.[11] This is already starting to have an effect; the proportion of Australian households with solar panels on their roof is now approximately 30 percent but,[12] by contrast, prior to the advent of rooftop solar, the vanishingly small proportion of households producing their own power did so largely for reasons of security of supply, and not economic benefit.

This has profound consequences for the whole energy sector. Although we are seeing the emergence of "prosumers" at present, the phenomenon is largely atomistic; individual households purchasing their own solar panels, and taking whatever offer their local distribution network offers in respect of selling excess power. We are, however, starting to see some change, with entities such as community batteries and virtual power plants.[13] How these will evolve is unclear, but the nature of the competitive landscape is likely to be fundamentally different.

In particular, as different solutions emerge to take, store, transform and trade excess renewable energy produced at scales from individual households to large-scale Renewable Energy Zones, networks will be used in profoundly different ways than they are today. This will have correspondingly large impacts on their economics. It is not a simple matter of networks having fixed costs and thus, as the proportion of self-supply increases, networks simply increase the

[11] See Feldman, D, Ramasamy, V, Fu, R, Ramdas, A, Desai, J, & Margolis, R 2021. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2020. Golden, CO: National Renewable Energy Laboratory. (available here) for a US perspective.
[12] See https://www.energy.gov.au/households/solar-pv-and-batteries
[13] See, for example, here or this provider of flat rate plans using consumer batteries and solar panels or this not-for-profit offering community battery and other community-based energy services.

network access charge to recover costs. This works when the proportion of self-supply is small, but rapidly becomes uneconomic (and indeed induces more self-supply) as the proportion of self-supply increases. Moreover, it is likely to be highly inefficient; if all a community battery does is store excess power produced in a street, why should it pay for transmission lines that it does not use? Moreover, if such a community battery is effectively the contact point between a small local network and the grid, why should the rest of the grid pay for the local network? This is one relatively simple example of a highly complex and novel set of risks and risk management issues which will need to be addressed by networks of the future.

To add to the complexity, although most of the debate about "prosumers" at present is around electricity and rooftop solar, elsewhere around the world, there are other kinds of "prosumer" using the gas network. In Japan, combined heat and power units which take natural gas, strip out everything except the hydrogen, use the hydrogen in a fuel cell and use the waste heat to heat water have been available for roughly a decade.[14] Hydrogen versions of the same, which are actually simpler because the incoming gas does not need to be processed, have recently been released.[15] Meanwhile, in Australia, a company is developing what is effectively a "hydrogen battery" whereby customers manufacture hydrogen via electrolysis at home and store it as a metal hydride.[16] These solution are currently cost prohibitive for all but the early adoptive fringe, but the fact that it is technically feasible to run an electric house using all green power, with the gas network essentially forming the battery, means that "gas prosumers" could well play a role in future market developments.[17]

Against all of these possibilities of innovation is set the basic issue that most consumers (even prosumers) are most interested in cheap, reliable energy supplies, and have limited interest in becoming active energy traders. How the market niches between the possibilities of the technologies and the desires of consumers get filled will be a key part of the evolution of the industry. We foresee a great deal of competition, trialing of new ideas, and many successes and failures in the marketplace before this evolution is complete. The future will be quite unlike the past.

2.2.2. Technological change in the way energy is used

The second key technological challenge is the challenge in the way energy is used. At present, gas is used by our residential customers for space heating, water heating or cooking.[18] Each of these three uses has some degree of competition, even if the substitute is not perfect:

- Induction cooktops are a substitute for gas cooktops. Although somewhat maligned in the past, they are becoming a much closer substitute now even though "cooking with gas" has a strong cultural cachet and some types of cooking (particularly restaurants) are much more reliant on gas for its cost and its ability to deliver heat.

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[14] *See https://www.j-lpgas.gr.jp/en/appliances/*

[15] *https://news.panasonic.com/global/press/data/2021/10/en211001-4/en211001-4.html. Note that "Kibou" in the name means "hope", which is indicative of the nascent stage of the technology.*

[16] *See https://lavo.com.au/. Their units store hydrogen to produce electricity but it is technically feasible to design the unit to use the hydrogen directly, and to take hydrogen from the gas network.*

[17] *Electricity started to replace gas for lighting well before it became less expensive, and gas remained a part of the lighting market for decades after it was more expensive than electricity. See Fouquet, R and Pearson PJG, 2006, Seven Centuries of Energy Services: The Price and Use of Light in the United Kingdom (1300-2000), The Energy Journal 27(1) 139-77 (available here).*

[18] *Commercial users have a wider variety of uses, though most are some derivative of this which just uses more gas or for a narrower purpose; for example, cooking in a restaurant or bakery, or using gas in a workshop to, say, cure protective surfaces on metal. Some larger industrial users also make use of gas for its chemical properties. The more specialised the commercial or industrial use, the less competition from electrification.*

- Heat pumps are substitute for gas space heaters. Although they are less efficient at very cold temperatures, expensive and lack the feeling of warmth of gas that some consumers favour,[19] the fact that most can cool and heat mean they are competing more and more with gas.
- Heat pumps for instantaneous gas hot water. These are relatively weak competitors at present, partly on cost and partly because they have a limited supply of hot water; essentially the size of the tank.

Competing with these products requires gas appliances to continue to become more efficient and, more particularly, for hydrogen appliances to enter the market at a suitable price, and for the hydrogen they burn to be sufficiently low cost to users of hydrogen (see Section 2.2.1) to make them viable. This suggests some major challenges. However, there is no particular reason to expect that the only use for the hydrogen flowing through our networks is one of the same uses that already exists for natural gas. For example:

- Hydrogen does not need to be burned to provide energy. It is technically feasible for hydrogen to be turned back into electricity using a fuel cell (or a combined heat and power unit, which makes efficient use of the waste heat from the fuel cell), as discussed above. Depending upon how the costs of the relevant technology evolve, this may provide a new niche for gas.
- Hydrogen can be used as a fuel for transport, competing with diesel, kerosene and petrol. This is also a market subject to competition from electrification. However, electricity has lost this race once before,[20] and, whilst scaling up electric vehicle use may require substantial upgrades to the electricity network, use of hydrogen as a fuel would mean a reduction in the use of the transportation network as fuel could be transported via our distribution network to service stations and other loci of demand, rather than requiring the use of specialist trucks
- Appliances that produce hydrogen may also be valuable to consumers, if they can sell hydrogen to networks in just the same way as renewable power is sold today. This might be an appliance producing graphene rather than electricity from biogas, or it might be an appliance turning excess solar power in summertime into something which can be stored long term, rather than solar cells being switched off to avoid electricity network issues.

The above is only an educated guess, made at a time when the future is highly uncertain and the costs, two decades hence, of appliances which have only just emerged (or are still to emerge) is essentially unknown. The point is not that the appliances above will, or even might, be the market for hydrogen transportation services. The point is rather that thinking that the future market for hydrogen is much the same as the current market for natural gas is very likely to lead to missed opportunities.

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[19] *In one of our consumer workshops, a disability advocate objected to our use of the term "fuel of choice" for gas because, for many of her stakeholders, the nature of the heat from a gas heating appliance was a necessary part of their treatment not easily replicated by electricity.*

[20] *See Taalbi J & Nielsen H, 2021, The role of energy infrastructure in shaping early adoption of electric and gasoline cars, Nature Energy volume 6, pages970–976, (available here). Early electric vehicles were neither technically inferior to or more expensive to operate than early internal combustion engines, but they were hampered by the lack of a viable electricity network.*

Box 1: Hydrogen and its price in the market

As noted in the main text, there is no particular reason to expect that hydrogen use will replicate natural gas use. Additionally, as a manufactured product, rather than a mind product, there is no reason to expect that it will be produced in the same locations or on the same scale; it may in fact prove much more economical to manufacture it nearer demand.

There is also, however, no need to expect it to be priced to consumers in the same way as gas, or electricity at present. In particular, both gas and electricity transport prices (a large part of the final bill in both cases) are cost based; both are priced in a highly formulaic manner based upon the AER's building block model. The fact that it is both electricity and gas transport that is priced in this way is significant; we compete with electricity but we are competing with a transport mode which is priced the same way our prices are formed.

The future will not be like this. Electricity and hydrogen need not be transported at all for some customers, but could be manufactured on site. Even for those who buy some transported product, self-production costs will influence the price that the transport leg can charge. This is true regardless of whether consumers can self-produce hydrogen and electricity or only one of the two; we will need to "price" match to the competition, rather than "cost match" to the regulator. This is a fundamental change to our marketplace.

2.3. Our place and our opportunities in this changing marketplace

The various challenges and uncertainties discussed in the preceding section are quite different from the fairly stable world envisaged by a building block regulatory model of regulation. However, it is not entirely unfamiliar. In fact, it looks very like almost any competitive marketplace undergoing change and subject to market forces.

Our response to the challenges noted above are discussed below and, whilst they may appear somewhat novel for a regulated firm, they are familiar to a competitive firm. The fact that we are pursuing such measures is itself indicative of the changing forces driving our own planning; even if a competitive market is decades away, the long life of our assets means we need to start planning now, or our window to do so might close more rapidly than we can predict. Thus we have started to bring the strategies of a competitive firm into our toolkit.

In this section, we explain one of these key strategies in a general sense, and then show its application to this AA proposal, with a particular focus on accelerated depreciation; the main topic of this attachment. We seek to show how accelerated depreciation fits into a wider adaptive strategy.

We explore the adaptive strategies, and accelerated depreciation as part of them in particular from three perspectives:

- That of the consumer
- That of the investor
- That of the regulatory framework we need to follow when designing our depreciation profile.

In respect of the first two we place particular emphasis on the counter-factual; what would happen if we simply did nothing and moved forward as though the next 20 years would be the same for our business as the last 20. In this discussion, it is important to realise that, the risks associated with the future have emerged, but they are not yet captured in any part of the regulatory process. In particular, as the AER points out, they are not included in the WACC, where most risk is priced.[21] Doing nothing does not represent a "saving" for consumers, it represents merely a delay in reckoning which, we believe will increase costs in the long run,

[21] *AER 2021, Regulating Gas pipelines Under Uncertainty: Information paper, November 2021, p28 (available here)*

because it will make planning for the future that much more challenging. This is not in the long interests of consumers.

2.3.1. Options to face a competitive future

The strategies deployed by a competitive firm facing uncertainty are quite different from those adopted by a firm (competitive or otherwise) facing a stable external environment. In a world of stability, a firm needs only to optimize against whatever the, highly certain, future is will be

In the real world, there is no certain future against which to optimise. Moreover, investment takes time from conception of a plant to switching it on, and for at least some of that time, it will not be clear if the investment will be profitable or not. A competitive firm needs to invest, despite the uncertainty, because failure to do so would mean that another firm, more willing to take risks, will take market share. For example, a mining company which only starts thinking about obtaining a mining lease when the price of ore is favourable, will find there are no leases left.

A competitive firm does not, however, simply invest in a project in its entirety in one large lump sum as soon as the potential need for the project becomes apparent. Rather, it seeks to create real options through its investment, by investing in stages. A financial option is a contract which gives the holder the right, but not the obligation, to buy or sell an asset at a certain price. A real option is an action which gives the investor an ability, but not an obligation, to take further actions to realise profits.[22]

To continue the mining example, securing a lease over a tract of prospective land generates a real option; to invest in a mine if prices look favourable. By contrast, simply investing in the whole mine up-front regardless of market conditions does not create a real option because, once the investment is sunk, the mining company is better off running the mine, so long as it covers its operating costs and some of the sunk investment, than it is leaving the mine idle and earning nothing. Full up-front investment is less valuable to the firm over the long run because it is less flexible; the real option creates flexibility and is thus something with value. By the same token, when prices fall, mothballing a mine so it can be brought on-line more quickly if prices recover is more costly in the short run, but lower cost in the long run compared to an alternative of closing down the mine completely, and then attempting to re-start it when prices recover.

Options are generated by spending small amounts of money that provide a firm with the capacity to do more investment (or curtail investment) in the future, rather than undertaking large, irreversible spending now. Their key property is the flexibility they provide

Options are usually generated by following a pattern whereby the lowest cost, longest lead time investments are undertaken first, and firms gradually move up the ladder of cost and down the ladder of time until the final investment decision produces a plant or a mine or a factory that can start producing items for sale. Just like a financial option, a real option can be cancelled if it becomes clear that further investment is unviable, and only the capital expended to date is lost.

In the gas sector, for example, policymakers (firms are not the only ones to create options) have started the process of legislative change to allow hydrogen to be carried in gas pipelines, and to amend appliance standards to allow hydrogen to be used. This is despite hydrogen being a long way, at present, from viability. Policymakers have done this (and industry has strongly supported it) because, if they waited until hydrogen was definitively viable, the lead times for all the legislative and governance framework would leave consumers unable to access the benefits of hydrogen for several years, resulting in welfare losses. If hydrogen turns out not to be viable,

[22] For a formal, and seminal treatment of the theory of real options, see Dixit, AK and Pindyck RS, 1994, Investment Uncertainty, Princeton University Press.

then policymakers will have incurred unnecessary costs, but, so long as these are smaller than the welfare losses which would occur if customers demanding hydrogen had to wait while the legal framework caught up, the choice of policymakers is the correct one.

Real options need not only be generated with one future in mind. If several futures are feasible and it is uncertain which one will eventuate then, provided the expected losses for the futures that do not eventuate are smaller than the delay costs associated with waiting until the future is certain, it is perfectly rational for a firm to take out options that would pay off under different, and even mutually exclusive states of the world. In fact, failure to do so mean that a firm was basing its entire future one possible state of the world, and a prayer that this will be the state which eventuates. Prudent businesses, looking to the interests of their customers, do not do this..

Real options generate profits for firms, but their ultimate beneficiary is the consumer of the goods and services provided by the firm in question. Every interaction between a firm and customers is mutually beneficial; since consumers differ in the value they get from goods and services and the price of the good or service reflects the value placed by the marginal consumer (that is, the consumer who values it least, amongst those who value it enough to pay the cost of production), almost all consumers receive a surplus when they consumer a good or service. Analogous to the case of profits and delay costs alluded to above, if a firm creates real options fitted to several different and mutually exclusive future states of the world, provided the cumulative additional consumer surplus generated by having access to the good or service earlier than if no options had been taken (or indeed at all if failure to create an option means no good or service is produced in that state of the world) is greater than the additional costs created (and subsequently recovered from consumers) because some real options needed to be abandoned, the consumers are better off.

All of these general statements about real options have specific application to our situation. We face several different, and mutually exclusive futures. In extremis, we face one where hydrogen succeeds, all of our current and future costs can be efficiently recovered and our customers can continue to obtain services (similar or no) from our pipelines via hydrogen and they can obtain value from this. However, if we make no investments now, then hydrogen is delayed, and so are the benefits. A second future might involve our eventual demise. However, if this demise is not planned, then those consumers who remain will suffer losses as we slowly fade out of business through less than optimal (within whatever constraints exist at a point in time) maintenance expenditure to keep the network operational to service their needs. This does not, of course, allow any amount of spending we like to meet the different futures, and deciding how much to allow for options is part of the task for us, which the AER needs to consider. However, it equally does not mean simply planning for only one future, and hoping that that is the future which eventuates. Failure to create real options for our consumers is not in their long run interests.

Not all of the options we are seeking to create are contained in the AA proposal. For example, nobody understands how a hydrogen network of the future will operate, this is something which has never been done before. There is therefore a great deal of work being done internally to create the human and organizational capital necessary. This is not recovered from current consumers, who pay only the opex associated with delivering current services.

In this AA proposal, we focus on three options, to provide flexibility for our consumers. These are:

- Accelerated depreciation – which creates flexibility by reducing the amount of RAB to be recovered in future when price pressures are greater. This creates options associated with future states of the world and reduces risk in the long term interests of our customers.

- Some network hydrogen expenditure – plugging the small number of gaps in our network needed to operate with even a little hydrogen, so we can start the process of transformation. This creates options in future states of the world where hydrogen is viable.
- Prudent network expansion – to spread risk over larger numbers of customers. This reduces risks and costs to existing customers in future states of the world where demand may reduce dramatically or, in a worst case scenario, we cease to exist. This will assist with price stability during the transition (whatever form it takes) and at the same time increasing the customer base , and therefore the probability of bringing about a state of the world where hydrogen is successful.

Although our main focus in this attachment is accelerated depreciation, we explain how each of these elements fit together to create flexibility for customers.

Accelerated depreciation

Our accelerated depreciation profile does not seek to recover all of our invested capital by, say 2050. The maximum amount of accelerated depreciation the model will permit without causing a price spiral (in the Electric Dream scenario) is $642 million, and this would still leave around 8 percent of the RAB unrecovered. By contrast, we are asking for only $145 million. Seeking to recover our whole RAB in a "worst-case" scenario would not create an option or flexibility; this would be the start of a plan for our demise by 2050.

Our accelerated depreciation proposal creates flexibility by essentially creating some "breathing space" against a possible future where our demise occurs. Since depreciation only recovers the asset once, over the life of our business, consumers pay not one dollar more for the assets we deploy; all we are doing is changing the timing of the return of assets. Moreover, since depreciation reduces the RAB, more depreciation now means the RAB is smaller in the future than it would otherwise be. This means that the building block price will be lower, which means in turn that the competitive threat from other sources of energy is less on the one hand and the price hydrogen needs to reach in order to meet that threat is a little higher than it otherwise would be.

Although the future is unclear, there is some directionality about it which is relatively clear. For example, it appears fairly unlikely that the Victorian Government will suddenly loosen its climate commitments. If we wait another five years before acting, the most likely outcome is that we will need to make the same adjustment over a shorter period of time, which means larger price increase than is required at present.This at a time when substitute prices are likely to be lower, and competitive threats greater. This will result in price volatility and potentially closes off options, none of which is in the long term interests of consumers.

Against this, if it turns out in five years that we need not have acted, depreciation can be dialled back, asset lives can be lengthened again, and consumer prices can be lowered.

Hydrogen expenditure

Detail on our hydrogen related spending is contained in Chapter 9. We propose to spend $10 million on hydrogen readiness over the next five years. The term "hydrogen readiness" is a little misleading as this spending would not make us able to become a 100 percent hydrogen network immediately it is completed. Rather, it gives us the option to continue down that path. If hydrogen is not viable, we are not obligated to spend a single dollar more on hydrogen readiness. Moreover, the spending we are doing is not wasted; the new pieces of kit can handle either hydrogen or natural gas, and so all that has really happened is some pieces of kit have been replaced a little earlier than they otherwise would need to be.

The next steps in spending after this AA are not, moreover, large, because we will plan spending to minimise additional costs, just as the AER would ordinarily require us to do. For example, in order to carry 100 percent hydrogen, different meters would be required as the calorific value of hydrogen is different. However, we do not plan on installing new natural gas only meters for the next 15 years, and then suddenly switching out all of our meters at the same time. Instead, as each generation of meters is due for replacement, we will replace them with hydrogen ready meters, at a small (and declining, as more hydrogen ready meters are manufactured) additional cost to new gas only meters. The same philosophy would apply as we actually transition to hydrogen; we would not have a "handover day" when all of the network is purged of natural gas, and then the whole network is filled with hydrogen. This would be very costly. Instead we would switch separable parts of the network through time to lower costs.

We would expect policymakers, moreover, to take a similar approach to appliances. Rather than making no requirements for hydrogen ready appliances for 15 years and then requiring every household to switch over a short period of time, we would expect standards to be developed today (or at least 15 years before we move to 100 percent hydrogen, if appliances last roughly that long on average), such that each time a new appliance is needed, it is replaced with a hydrogen ready appliance, and at roughly the same cost[23]

Prudent network expansion

Some stakeholders have suggested that, if it is apparent that the network might one day no longer be used, we should cease all expansion of the network as soon as this possibility becomes apparent, suggesting, in turn, that failure to do so would just make the asset stranding problem larger.

There are several problems with this line of argument. In the first instance, we are legally obliged to connect new customers who ask for a connection and it is efficient for us to do so (customer are not obliged to be connected to gas) and we could not refuse a new connection. Moreover, customers want new connections and are neither irrational nor misled in so doing. If a customer firmly believed the network would no longer exist in 20 years, she would still be rational in connecting with brand new appliances, as these have a life of only 15 years.

The more important issue, however, is the fallacy that more customers now means more risk later. This is simply not true. Our prices are essentially average costs; price is our overall costs divided by demand. If a new customer costs less to the network than the current average cost, then the new average cost, and hence our prices, are lower. If our prices are lower, then there is a lower risk of a demand reaction to price which precipitates a death spiral, and less of a risk of asset stranding and price spikes for remaining customers

This basic piece of mathematics holds even if asset stranding is certain, provided we do not keep adding new customers up until the point of stranding. This is shown in Table 1, which provides the results of a simple simulation exercise, examining the impacts of adding either small (10, compared to an existing customer base of 1000 customers) or large (500) new customers who impose lower costs ($90, compared to $100 per customer) on the network than existing customers do. A "shock" is imposed at a point in time (between 15 and 50 years hence) whereby the whole asset is stranded. Since this shock is known, in the model, all existing and new assets are depreciated to zero by this point in time. The model then compares the cost per customer (depreciation on the whole RAB – new plus existing customer connections – plus a return on the same RAB, divided over the total number of existing and new customers at that point in time) of a case where all else in that model run is held equal, and new customers are either allowed, or disallowed. In this simple model, these costs are essentially the price that would be charged to customers for their gas consumption each year. In the case where new customers are allowed,

[23] *See Frazer-Nash Consultancy, 2018, Appraisal of Domestic Hydrogen Appliances, Report prepared for the UK Department of Business, Energy & Industrial Strategy, p41 (available here)*

they are added up until a point in time 10 years before the shock happens. As can be seen, across almost all cases, prices are lower (subtracting the cost of the case where new customers are allowed from the case where they are not, all else being held equal, gives a positive number in the final row of Table 1) because the impact of a larger customer base is larger than the impact of the costs of those new customers. The results of the simple modelling exercise suggest that adding new customers can in fact lead to lower prices, even with asset stranding risk, and a conclusion that the presence of asset stranding risk *necessitates* a new connection ban to stop the risk from increasing is simply incorrect. In fact, adding new lower cost customers lowers price and, since price drives demand, lowers asset stranding risk.

Table 1: Price impacts of adding lower cost consumers with asset stranding

	Run 1	Run 2	Run 3	Run 4	Run 5	Run 6	Run 7	Run 8
Cost per existing customer	$100	$100	$100	$100	$100	$100	$100	$100
Costs per new customer	$90	$90	$90	$90	$90	$90	$90	$ 90
Number of existing customers	1000	1000	1000	1000	1000	1000	1000	1000
Number of new customers per annum	10	10	10	10	500	500	500	500
Remaining life of existing assets at year zero	30	30	30	30	30	30	30	30
RAB at year zero	$100K	$100K	$100K	$100K	$100K	$100K	$100K	$100K
Life of new assets	50	50	50	50	50	50	50	50
Time of shock	50	30	20	15	50	30	20	15
WACC	5%	5%	5%	5%	5.0%	5.0%	5.0%	5.0%
NPV of difference in costs per customer	$0.33	-$0.58	$1.32	$3.01	$11.34	$1.73	$12.92	$30.44

We note that, under Victorian law, if a new customer costs more than the current average, we are able to charge a connection fee.[24] This requirement does not, however, consider stranded asset risk. One way to address this could be to allow a connection charge where the cost is more than, say, 90 percent of the average. This would allow us to ensure that the cost imposed on the network of new consumers, which is what drives the risks consumers are being asked to bear through time, does not rise, but in fact falls.[25] Provided new customers are well informed as to what the charge entails, they would suffer no loss from the charge existing; in fact it would be valid as a way to prevent them imposing additional risk on existing customers. We note that other networks overseas impose connection charges for similar reasons, but charge the whole connection cost up-front, rather than just the increment required to reduce asset stranding risk.[26] Such a change sits outside the AA process as it is a Victorian Government requirement, not a requirement of the AER. As such, we will consider these sorts of options outside the AA process, but note that this solution would be far better than not continuing to connect new customers, and is why, in this proposal, we do not agree that demand growth in the short run need increase asset stranding risk in all instances; in fact it is not difficult to ensure that it does not.

A final point is also important; if the hydrogen transition succeeds, prudent network growth now means that more future consumers will be able to enjoy the benefits hydrogen could bring, because they will have a connection already. This is particularly important on the urban fringe; if it is relatively cheap to reticulate gas to a new subdivision before houses are built and relatively expensive to go back and dig up established streets 20 years later when said customers decide they want hydrogen. However, it is more than that; a growing network is one where hydrogen has a greater chance of success, as the potential market is bigger.

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[24] There is a specific calculation we must undertake, involving the NPV of revenues over a certain number of years and a comparison with the connection and operating cost, but the basic approach is the same. The governing rules are available here.

[25] The modelling which underpins Table 1 is not sufficient on its own to formalise the new requirement. It fails to consider, for example, differences in consumption for new versus existing customers, but a more sophisticated model would be easy to develop.

[26] See https://www.vector.co.nz/business/gas/new-connection/simple

2.3.2. The consumer perspective on what we are trying to achieve

A key question from stakeholders during our consultation, particularly in respect of accelerated depreciation was "what's in it for consumers?" and "why should consumers pay for this?"; a topic we now address.

We have been required to look to the long run interests of consumers in the regulatory framework for some time. However, in a stable world, the interests of consumers in the short term look much the same as the interests of consumers in the long term, save for planning assets such that they will still be able to provide services into the long term. In this new and changing world, however, future consumers diverge in their interests from current consumers.

All consumers differ in respect of their agency; a consumer who rents their home has less agency than one who owns their home, for example as, although they can choose to rent a home with or without gas, they cannot change appliances once they have rented a home, which means they have less agency. Future consumers, however, have no agency at all; even if they are the same people as those we serve now, their future selves can have no influence on the choices they make now, even if they differ in what they value.[27]

The counterfactual to our accelerated depreciation proposal (and other options) is not simply business as usual with the gas and electricity systems continuing to operate as previously with exactly the same consumption and investment requirements. Rather, the future will be affected positively or negatively by the challenges noted in Section 2. Existing customers and investors, those with agency, can react to these risks now. Depending upon how they do so, their actions may serve to limit the actions of future consumers, who have no such agency.

For example, if some accelerated depreciation was not allowed in the next AA period, some current consumers, surveying the risks in the industry and seeing that the AER will likely need to act in future and believing that this will create higher price rises, may act to switch out of gas now, rather than take the chance with one more round of gas appliances. With fewer customers, prices rise. If enough change their minds, through time, future consumers, regardless of their desires in respect of hydrogen, may be denied that option.[28] Regulatory decisions should avoid these outcomes.

These actions do not just effect gas consumers. It might be thought that those who leave the gas sector leave its problems behind them. However, this is not necessarily true. There is some debate as to whether the electricity system can handle the increase in demand from customers switching away from gas, with different views on the size of the load compared to current summer peak electricity demand. Both sides of the debate, however, tend to focus on a planned transition, not on consumers leaving gas in an unplanned fashion with limited scope for the electricity sector to plan to manage the change in demand.[29] Additionally, the modelling tends to focus on the NEM as a whole, whereas many of the problems will arise at a much more localised level; down residential streets where the branch lines and local substations are not designed for a sudden increase in load. Those who leave the gas sector may find that they do not leave risk behind, but in fact create it, and face its consequences.

These are the outcomes we are seeking to avoid. Accelerated depreciation does increase price compared to what they would otherwise be today. However, the national gas objective directs our attention to the long run interests of consumers, not just over the next AA period. The whole approach is designed to ensure customers have choice and that where a transition does happen,

[27] *How many people, at 50, would advise their 20 year old self to make different life choices, if they could but do so?*
[28] *See also AER 2021, Regulating Gas pipelines Under Uncertainty: Information paper, November 2021, p425 (available here)*
[29] *We are not the only country experiencing these risks. In the UK, unforeseen demand from battery storage systems and data centres has meant that some new housing developments will not have electricity available until 2027 to 2030 (see here).*

the transition is well planned This avoids significant price hikes for those with the least agency on gas networks, and helps to avoid problems which have not been foreseen in the electricity networks.

2.3.3. The investor perspective on what we are trying to achieve

Like current consumers, investors have agency. In particular, although the AER sets prices, it is investors who decide whether to deploy any new funds, and the returns required by investors which pay back funds already invested. As noted above, the way investors exercise this agency changes quite substantially if the signal from regulators and policymakers is that the business is not sustainable, compared to a signal that it is.

In a simple economic model, investors ignore sunk costs when making new investment decisions; even if the RAB is written down to zero, if new investment can make money using the network, the investment will happen. Moreover, so long as operating the assets covers variable costs and some fixed costs, a firm will keep the asset operational rather than shut it down and earn nothing. There may be some truth in this in reality; decisions on hydrogen investment will consider the viability of that investment environment first and foremost, although a record of deliberately allowing long term assets to fail is unlikely to improve that investment environment very much.

However, even if investors would invest after losses on past investments have crystalised, we are not at that point yet. Rather, we are at the point where current investments might be lost, at least in part, which means that investors, with agency, have a very strong incentive to look for ways to avoid this from happening. Only when these options have been exhausted will investors write down assets, crystalise the loss and carry on as economic textbooks tell them they ought to. There are several actions investors could take, none of which are particularly favourable for consumers. These include:

- Focus their efforts, in Australia at least, on recovering invested capital from the transport of natural gas as much as they can, saving hydrogen investment for other, more prospective markets until the situation in Australia is resolved. This is likely to involve "sweating" the assets; running them in an unsustainable fashion to get their money back as quickly as possible.
- If some capital is unrecoverable, issues will arise as to whether networks were adequately given an opportunity to recover efficiently incurred investment or whether wider market forces caused this result; considerations that arose in the Market Street Railway case in the US. [30]
- Finding out whether governments are really willing to let gas assets fail. Privatisation is supposed to remove risk from the books of government. However, if governments do not have a credible threat to let assets fail, firms facing pressure will seek government support, or government re-purchase to minimise their own risks. This is precisely what happened in respect of railways in Tasmania and New Zealand.[31]

There may be other options that we have not considered. Whether any such options would succeed is a matter of conjecture. However, whilst investors are focused on activities such as these, they are not focused on sustainably serving the long run interests of consumers. Worse, by focusing on activities such as these in the short to medium term, investors may create a path

[30] *See Graffy, E and Khim, S, 2014, Does Disruptive Competition Mean a Death Spiral For Electric Utilities?, Energy Law Journal, 35(1) 1-44, (available here)*

[31] *See Laird, Philip G., "Government rail asset sales, and return to the public sector, in New Zealand and Tasmania" (2013). Faculty of Engineering and Information Sciences - Papers: Part A. 1421 (available here)*

dependency which makes it harder for the industry to get back onto a sustainable pathway once policymakers do respond to the relevant risks.

2.3.4. The legal perspective on what we are trying to achieve

A final point to make is in respect of the regulatory requirements for our accelerated depreciation proposal. Under the National Gas Rules, not only are we permitted to change depreciation schedules but we are required to keep abreast of forces which might cause these to change, and to change them as necessary. Specifically, we are required under NGR 89(1) to:

The depreciation schedule should be designed:

a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and

b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and

c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and

d) so that (subject to the rules about capital redundancy), an asset is depreciated only once (ie that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the AER permits, for inflation)); and

e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

The key requirements are (a) and (b); (c) is a requirement to design depreciation schedules which can change, which is relatively easily met, and indeed a key part of our overall strategy into the future as information changes, whilst (d) can be seen to be met by inspecting our model and is met by the PTRM itself and (e) is a restriction on the AER not to allow so little depreciation as to endanger cashflows (not an issue we are dealing with in the short term). The key, therefore, is to establish a depreciation schedule which ensures that, over the economic life of the relevant assets, efficient prices are created in the market.

The RAB is a fixed cost, and the efficient means of allocating a fixed cost to cause the smallest deviation in demand is well-established in economics; base the allocation on elasticity of demand, with those with a lower elasticity of demand paying more of the fixed cost and those with a higher elasticity of demand paying less.[32] The intuition being that those who are less price sensitive suffer less if prices rise than those who are more sensitive and might, if prices were based on all paying an equal part of fixed costs, choose not to consume the product at all, and suffer a welfare loss.

If a network is a monopoly, and this is not expected to change through time, it is reasonable to assume that the elasticity of demand through time is constant; there may be differences between consumers at a point in time, but one cohort to the next could reasonably be expected to have the same elasticity. Under such conditions, the AER's existing approach of straight line real

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[32] *See Baumol, W and Bradford, D, 1970, "Optimal Departures from Marginal Cost Pricing" American Economic Review, 60(3), 265-83. (available here).*

depreciation is reasonable, because it allocates the same portion of fixed costs to each cohort of consumers through time.

However, if the prices of substitutes are falling through time, (see Attachment 6.4) then consumers will become more price sensitive in respect of gas as other options become more viable. Under this situation, tilting depreciation such that more of the fixed costs are recovered now and less later is the efficient response, because less price sensitive customers pay more and more price sensitive customers pay less, which, for some of them, will mean the difference from being able to consume gas or not.[33] The net result is that more demand is served by the same assets; a net improvement in efficiency.

We cannot know exactly what the future elasticity of demand will be; if we did, we would not need our complex modelling. However, the way our model works replicates the effects of allocating fixed costs based on elasticity in that (and arguably, goes further by examining the impact of various additional forces, which a standard elasticity analysis would assume are held constant), by changing the depreciation schedule, we prevent future demand from declining, keeping prices low and more stable and keeping our network sustainable.

This, in fact, can be measured; one can look at the total amount of gas (including hydrogen) being sold over the life of the assets under different depreciation schedules (see Sections 3.2.2 and 4.1). Since gas provides utility to our customers, more gas means a greater consumer surplus. Thus, the AER has a somewhat direct way in which to ensure that the NGR is being met; look to the amount of gas being sold through time under different depreciation schedules, favouring those which can be shown to maximise sales, which minimises prices for consumers (given that our costs are largely fixed) and thereby leads to maximum efficiency. This is shown in Section 4.1 with more detail provided in Attachment 6.4.

Box 2: Other regulators and accelerated depreciation

This proposal is not the first to foreshadow accelerated depreciation; it is not even the first of our proposals to do so. The AER summarises several jurisdictions which have done so in its recent Regulating Gas Pipelines under Uncertainty paper (REF). From these, we highlight two:

- The ERA in WA allowed accelerated depreciation for our DBP asset. Our approach to tilting depreciation, rather than shortening asset lives, came out of our experience in this process. That experience is summarized here, pp9-18.
- More recently, the New Zealand Commerce Commission has allowed gas distribution businesses shorter asset lives based on potential timing of asset redundancy due to policy constraints, rather than the consumer choice model we utilise here. Although the basis is different to our approach, it suggests a more formal way of treating scenarios where the ending of a network's life is given a high probability than simply motivating a change in policy with qualitative discussion of impacts. The paper is available here.

[33] *In many cases, the current and future consumers will actually be the same people, but with different opportunity sets at different points in time. Thus, in many cases, it is a matter of the same people paying a little more for their gas at a time when they are relatively price insensitive and a little less when they are more price sensitive, but no more (in fact, somewhat less, if such pricing preserves demand) over their lifetime of consumption.*

3. Model overview and analytical process

In this section, we provide a brief overview of how the model operates and the process we have taken in developing the model. This includes not only the various steps of the process, but also how and what we have learned along the way. This history helps put the results of the model, summarised in the following chapter, into context.

3.1. The theoretical basis of what we are doing

As noted in Section 2.3.4, as the elasticity of demand changes, there is a need to change the depreciation schedule to maintain efficient pricing. However, since the future elasticity is unknown, we need to develop a framework which can take what we do know about the future and use it to create efficient prices in the same manner as we would do if we did know demand elasticity.

The basic framework, in terms of theory, which we use, is due to Crew and Kleindorfer,[34] who extend the work of Schmalensee,[35] who showed that, if the cost of capital was correct, then any pattern of depreciation is suitable (his "invariance proposition") to the case where technological progress affects the price of a substitute for the monopoly good/service. This changes, quite substantially, the "invariance" proposition of Schmalensee and in fact narrows the range of appropriate depreciation options which might be employed to take account of the risk of future competition. Adopting an assumption of such technological progress makes a significant difference, as Daryl Biggar at the ACCC points out:[36]

> *A further piece of the jigsaw on depreciation/amortisation was suggested by Crew and Kleindorfer. This paper focused on the possibility of an external constraint on the ability of the firm to recover its costs in the future*
>
> *Greenwald noted that the regulatory asset base could not increase above the present value of the future revenue stream for an unregulated monopolist. In the Crew and Kleindorfer paper, the present value of the future revenue stream for the unregulated monopolist is declining exponentially over time, perhaps due to forces of competition or technological change. This places a declining upper limit on the path of the regulatory asset base over time. The result, unsurprisingly, is that front-loading of capital recovery is essential if the regulated firm is to remain viable.*
>
> *In essence, when the regulated firm will be constrained by other forces in how much it can recover in the future, the regulator must take this into account in the present, and allow the firm a higher rate of depreciation. This is the origin of the tilted annuity concept used by some regulatory authorities in telecommunications regulation. Crew and Kleindorfer point out that traditionally there has always been a sense among regulators and utilities that problems could be put right "at the next rate case". However, they*

[34] *Crew, M and Kleindorfer, P, 1992, Economic Depreciation and the Regulated Firm under Competition and Technological Change, Journal of Regulatory Economics, 4(1), 1992, 51-61 (available here)*

[35] *See Schmalensee, R, 1989, "An Expository Note on Depreciation and Profitability under Rate-of-Return Regulation", Journal of Regulatory Economics, 1(3), 1989, 293-98 (available here). A later paper (Burness , HS and Patrick RH, 1992, "Optimal Depreciation Payments to Capital and Natural Monopoly Regulation", Journal of Regulatory Economics, 4, 35-50- available here) points out that the consequences of an allowed rate of return that is too high is a desire by regulated firms to delay depreciation (so they can earn extra profits on their RAB for longer) whilst the consequences of an allowed rate of return that is too low is a desire to depreciate more quickly, so that capital in the RAB can be deployed elsewhere to earn better returns for the risk level involved*

[36] *See Biggar, D, 2011, The Fifty Most Important Papers in the Economics of Regulation, ACCC/AER Working Paper No. 3, May 2011, p21 (available here)*

> *emphasise that this is clearly not always true. If some other constraint – such as changes in demand or technology – prevents the regulated firm from earning a normal return in the future, the regulator must take that into account in its depreciation policy today.*

In other words, if there is a threat of future competition, and the regulator intends on giving the regulated firm a reasonable opportunity to recover their efficiently incurred capital spend, the range of suitable depreciation pathways may be limited. It may also no longer be straight-line (see Section 2.3.4).

The Future of Gas Modelling framework is based on the Crew and Kleindorfer (1992) concept of the window of opportunity for capital recovery. The basic premise is that there is a limited time for regulators to take remedial action to ensure capital recovery when a regulated firm faces competition and technological change. If timely action is not taken there is no alternative, but for the company to fail to recover some of its assets. The precursor to these losses is a period of rapidly increasing prices as consumers leave the network, and the network seeks to recover its fixed costs from a steadily smaller pool of demand.

The Future of Gas modelling framework applies the window of opportunity for capital recovery concept under explicit assumptions. These assumptions are that technological change in electrical energy and appliances, and climate policy, result in electrical appliances becoming a viable substitute for natural gas and gas appliances at some point in the future.

Since we are looking at the context of a distribution network, with a very large number of individually small customers, we have a highly heterogeneous customer grouping. Moreover, we have a set of customers who tend to make decisions on whether to stay with gas or switch at distinct times associated with the amortisation of their existing appliances when they reach the end of their useful life, rather than making a decision based on price at any point in time. This is somewhat different to the simple, and much smoother case presented in the Crew and Kleindorfer paper, and indeed, we extend the work of Crew and Kleindorfer by considering a range of issues which do not form part of their simple model. However, the basic intuition remains the same, that is:

- Our customers have alternatives for the services gas currently provides in their homes which is declining in price and likely to be lower than gas (including when natural gas switches to hydrogen) at some stage in the future.
- Our market power is likely to vanish and we have a limited time period over which we might be able to recover our invested capital.
- We are seeking to re-order our capital recovery so that recovery is feasible.

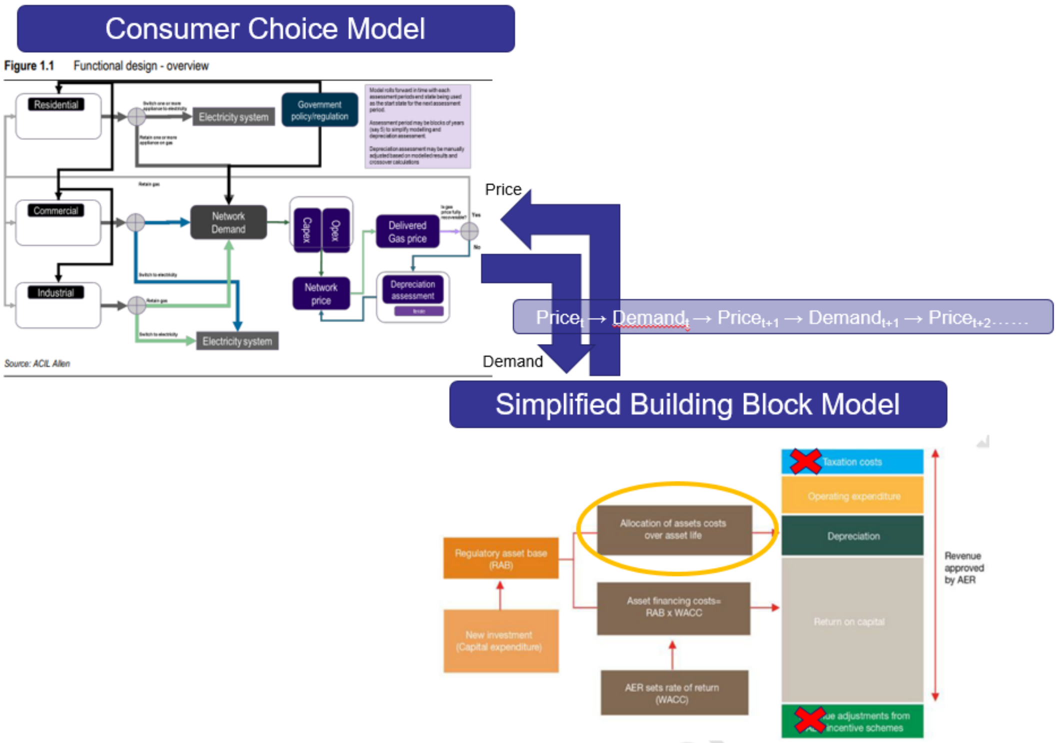
3.2. The basics of the modelling approach

Our modelling approach involve three broad components:

- A scenario-setting component, which was undertaken with the assistance of an independent expert panel who set the scenarios.
- A consumer choice component, which models how consumers respond to relative prices.
- A simplified building block model which converts our costs into a set of prices.

We describe the formation of the scenarios in Section 3.2.1 below, and in more detail in Attachment 6.2, being the report from KPMG, who facilitated the process, on the expert panel process. The consumer choice component is described in more detail in Attachment 6.3, being the expert report from ACIL Allen, who developed this model for us. The details on the building block model (which we developed ourselves and which differs for AGN and Multinet due to their different asset profile) are provided in Section 5 below which explains the operation of the model. The interaction between the building block mode and the consumer choice model is shown in Figure 8.

Figure 8: Interaction between building block and consumer choice model



The building block model is a simplified version of the PTRM extended out to 2100, excluding components like inflation and tax and setting a new price every year. The main "lever" in the model is a parameter which controls the degree to which depreciation is curved away from a straight line approach by shifting depreciation forward.[37]

The consumer choice model posits a number of different consumer types (their suburb proxies their socio-economic status and we have different appliance profiles within each type). The main choice each consumer type makes occurs when an existing appliance comes to the end of its life and the consumer chooses to either buy another appliance of the same fuel, or switch.[38] They do this by considering the NPV of the total cost of the new appliance over its life. However, rather than just switching as soon as the appliance bundle using one fuel is cheaper than the other, relative price affects the probability (or in the way the model is implemented, the proportion of the relevant cohort of consumers) of a switch. Thus, some consumers switch away from gas even when the electricity equivalent is more expensive and some stay with gas even when it is more expensive. This gives rise to an "S-curve" of switching as shown in Figure 9.[39]

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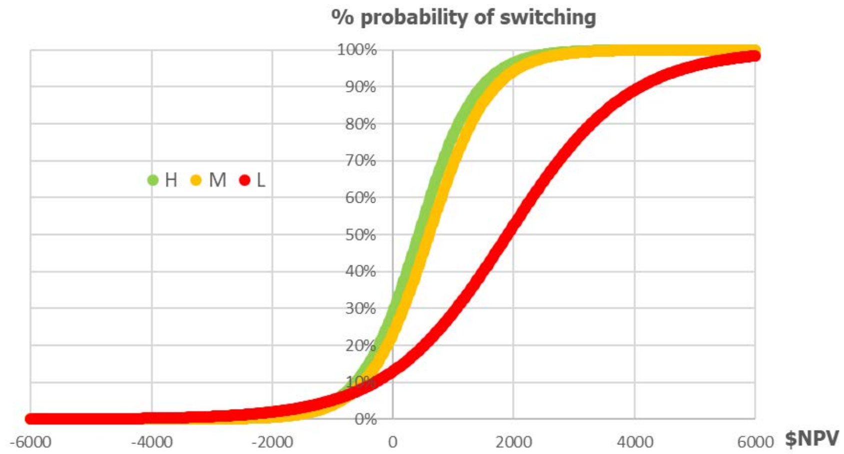
[37] This parameter is applied to depreciation of existing assets. The model also has the functionality to reduce asset lives, but we use the tilt factor as this better allows us to price match to electricity through time.

[38] Consumers are held to have a cooker, a cooker plus water heater or a cooker plus water heater plus space heater (our internal consumption data gives a rough approximation of how many of each type are in each suburb). They switch all appliances in their bundle at once and the model does not have, for example, a household dropping just a hot water system. However, within the lifespan of the appliance bundles, consumers respond to gas prices, and reduce or increase their consumption, which means we implicitly assume that customers have appliances all the same age and reduce gas use across all appliances while they are in use, rather than dropping one in isolation. We make this simplification because our main focus is on overall gas demand.

[39] "Tuning" the s-curves to obtain the shapes shown was a considerable challenge as we have no extant data with which to do so. Discussions with the AER on this were most fruitful in finding a solution.

Figure 9: Consumer switching S-curve



Once the scenarios are set, the interaction between the consumer choice and building block models proceeds as follows:

- The building block model takes a forecast of costs and a forecast of demand in a given year, divides the former by the latter and produces a price for that year, which is passed to the consumer choice model.
- Consumers react to this price by switching or not, and the resultant demand is multiplied by the price to give a revenue. The demand realised in the consumer choice model is then passed back to the building block model to play a role in forecasting costs and demand.

From this interaction we get a time series of costs from the building block model and time series of revenues from the consumer choices model. These can be compared and, if costs outweigh revenues, we change the depreciation profile in the building block model. This works because current and near-term consumers face a set of relative prices which favour gas more and are thus less likely to switch than consumers in the future if prices increase. Thus, bringing forward depreciation loses less demand now than it gains in the future; in essence the model is directly implementing the apportionment of fixed costs based on demand elasticity that we note in Section 2.3.4 will lead to efficient market outcomes in the energy market.

As the model solves year-by-year, it is non-linear in nature. This makes finding solutions non-trivial (see below), but it also acts as a brake on how much depreciation can be brought forward. If the acceleration of depreciation is too great, very quickly, demand falls and the network enters a death spiral. This helps guard against too much depreciation being brought forward.

The model is run in different scenarios. We have four scenarios from the expert panel and these are described below.

3.2.1. The scenario journey

In an environment of considerable uncertainty about the future, such as that faced by the energy sector, any prediction is likely to be wrong. Rather than make predictions, we create plausible scenarios across a wide range of potential states of the world, and test the performance of the different accelerated depreciation plans across these scenarios.

There are many ways in which we could have designed the scenarios. We could, for example, have designed them internally, based on our own views of how the future might unfold. However, this is not particularly independent, and it may make it harder for the AER to verify and trust our modelling process. Alternatively, we could have relied upon existing scenarios developed by other organisations, like the ISP and GSOO produced by AEMO. However, these face the problem of transparency for us, as it is not always clear exactly how each element of a scenario has been developed, and we might run the risk of not being "true" to the particular forecast.[40]

The route we took, therefore, was to form an independent panel of experts, and ask them to come up with four scenarios for us. This process was run by KPMG, and is detailed in Attachment 6.2. The members of this panel are shown in Table 2.

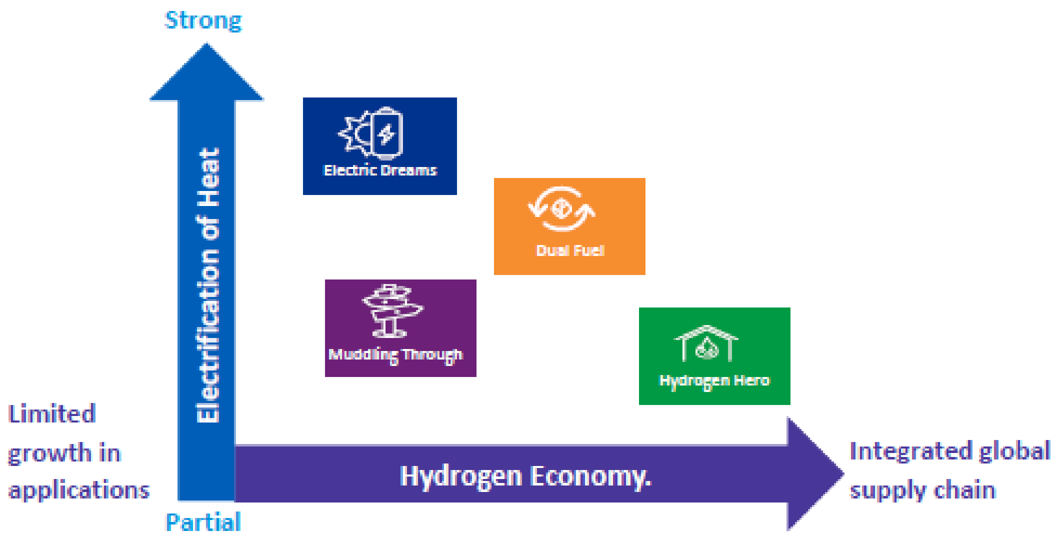
Table 2: Expert panel members

Name	Position
Anna Freeman	Director, Energy Generation – Clean Energy Council
Alison Reeve	Deputy Program Director, Energy Fellow – Grattan Institute
Lynne Gallagher	Chief Executive Officer – Energy Consumers Australia
Matt Clemow	Group Manager, Gas Operations – AEMO
Mark Grenning	Director – Energy Users Association Australia
Dr Patrick Hartley	Leader of Hydrogen Industry Mission - CSIRO
Ross Jamieson	President – Gas Appliance Manufacturers Association of Australia
Ben Wilson*	Chief Executive Officer - AGIG
Jon D'Sylva	EGM Strategy and Transformation - Ausnet

** Ben was replaced by Craig deLaine towards the end of the process when Craig took over as CEO of AGIG.*

The panel met over four workshops to develop the scenarios which we used. This process was facilitated by KPMG and focused on key drivers of the future as the "sub-structure" of the scenarios chosen. These drivers were narrowed down to two, being the electrification of heat and the extent of the hydrogen economy, and the expert panel then put the four scenarios on different points determined by these relevant axes. This is shown in Figure 10

Figure 10: Expert panel scenarios



[40] *We note that AEMO does provide a lot of documentation on its process of developing scenarios, but there are still gaps. For example, AEMO publishes electricity demand and supply volumes, but not prices. Other sources of prices exist, but might not be developed under the same assumptions AEMO has used.*

A summary of the four scenarios is provided in Table 3.

Table 3: Scenario summary

Scenario name	Scenario description
Electric Dreams	Characterised by deep electrification underpinned by strong market driven growth of renewables, investment in system flexibility and efficiency and policy support for net zero by 2050. Accelerated electrification of a wide range of applications leads to a rapid rise in electricity demand, which outstrips renewable supply and briefly prolongs the reliance on fossil fuel generation. This is largely replaced with renewables and grid-firming infrastructure at an orderly and increasing pace over the next decade. Gas distribution networks become increasing stranded as customers electrify through to the late 2030s.
Dual Fuel	Characterised by the fusion of extensive domestic electrification and the development of a material expert industry for hydrogen in the medium term. Domestic hydrogen is utilised for certain industrial applications and in select residential locations. Net zero is achieved by 2050 due to focused market and policy action and the orderly retirement of fossil fuel use. Gas networks are largely stranded by 2050, however, a subset service 100% hydrogen customers.
Muddling Through	This reflects an uncontrolled, uncoordinated future characterised by stop-start progress towards net zero and limited changes to energy market dynamics. In this scenario, net zero by 2050 is at risk, driven by disorderly and uncoordinated government policy action. This leads to a combination of electrification with some gas distribution networks converted to low carbon fuels in the late 2030s as they attempt to remain viable.
Hydrogen Hero	Australia reaches net zero by 2050 through the orderly growth of aa significant hydrogen industry for export and domestic use through widespread renewable generation. Hydrogen and electricity networks become linked in the 2030ss to provide stable, economically competitive, decarbonized energy. Gas distribution networks are fully utilized to deliver hydrogen to home, commercial and industrial applications.

More detail on the narratives for each scenario is provided in Attachment 6.2. The direct input from this scenario development to the modelling process was a series of setting for different drivers. An example of these is provided in Figure 11.

Figure 11: Expert panel scenario driver settings

Category	Scenario Driver	Electric Dreams	Dual Fuel	Muddling Through	Hydrogen Hero
Economic	Wholesale domestic electricity price	Low	Low-Medium	Medium	Low
	Wholesale domestic natural gas price	High	High	Medium	High
	Wholesale domestic hydrogen price	Medium	Low-Medium	High	Low
	Delivered electricity price	Medium/High	Medium	High	Medium
End Use Technology (Demand)	Electricity network demand	High	High	Medium	High
	Natural gas demand	Low	Low	High	Low
	Hydrogen export demand	Low	High	Low	High
	Hydrogen industrial demand	Low	Medium	Low	High
	Hydrogen residential & commercial demand	Low	Low-Medium	Low	High
Policy and Regulation	Extent of decarbonisation policy (incl. carbon price level)	High	High	Low	High
	Pace of decarbonisation to 2030 (fast vs. slow)	Medium	Medium	Medium	Medium
Production Technology (Supply)	Extent of grid scale battery storage	High	High	Low-Medium	Medium
	Extent of renewable electricity supply	Medium	Medium-High	Low-Medium	High
	Extent of other dispatchable energy supply (e.g., VPP, Pumped Storage)	High	High	Medium	Medium
	East coast domestic natural gas production (relative to demand)	Low	Low	High	Low
	Volume of transmission connected hydrogen production	Low	Medium-High	Low-Medium	Medium-High
	Volume of distribution connected hydrogen production	Low	Low-Medium	Low-Medium	High
Role of the networks	Blending H2 uptake (up to 10%, 2030, on the pathway to 2050)	Low	Medium	Low	High

None of the drivers are specified in any quantitative manner; the expert panel did not provide us with forecasts of electricity prices, for example. Instead, we took the “high-medium-low” indicators from the Expert Panel and looked for independent forecasts which could span this range, placing the relevant prices from that forecast in the relevant scenarios. For example, the AEMO GSOO has gas price forecasts for its scenarios (many of which are rather similar to ours), so we took the low price paths from these AEMO scenarios and put them into the scenarios where the expert panel said that gas prices ought to be low.

Box 3: Scenarios and the calibration of S-curves

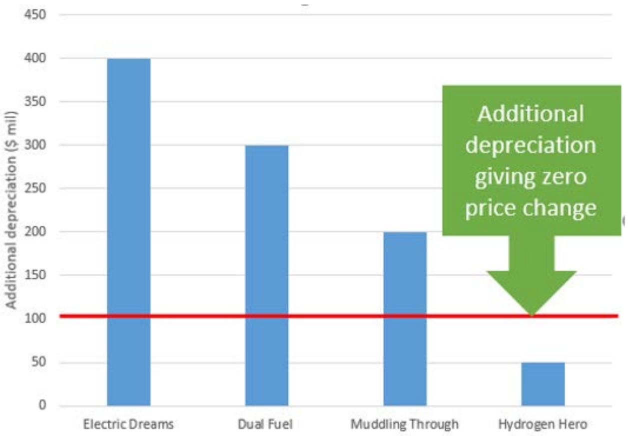
As noted above, sitting the centre of the consumer choice model is an S-curve, which determines the proportion of customers who will choose to switch for each difference in relative prices. However, a problem we have with the S-curve is that we are trying to model behaviour for which we have very little data; there might be plenty of data on, say, choices between using cars and buses for commuting at different fuel prices, because this is something which has a long time series of consumer behaviour, but there is next to no data on how consumers might respond to relative power prices in a world where some of the key ingredients (like household batteries, for example) barely exist yet.

This is an area where the expert panel scenarios were particularly useful because at least two of them (Electric Dreams and Dual Fuel) have definitive end points. If we know, for example, that the network will close in 2050 because the expert panel told us that is part of the scenario, then we can “tune” the S-curve for that scenario such that consumer choice alone will drive this outcome. That is, consumers will react to relative price changes such that by 2050, none are consuming gas. Other scenarios, which are not as extreme in outcomes, can then be give slightly less aggressive S-curves. This proved to be a very useful way of dealing with what might otherwise have been a challenging problem for the model.

3.2.2. The modelling journey

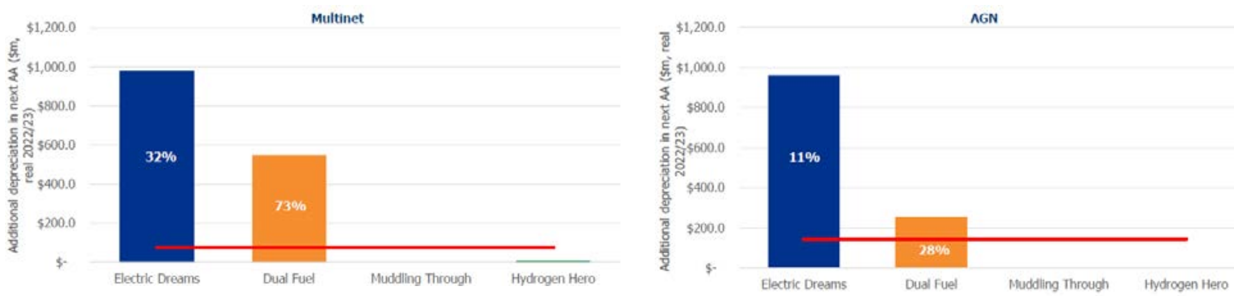
The modelling process we followed was very much one where we learned as we went along. At the outset of the process, we had in mind a conceptual framework like that shown in Figure 12.

Figure 12: Early conceptual view of model results



We assumed that a solution for accelerated depreciation that removed the risk of asset stranding would be found for each scenario and that they would occur across a range, meaning we would need another choice variable to determine the actual amount of depreciation. Since we had planned to avoid price changes from the current to the next AA, so long as a depreciation amount that achieved this was within the range, we proposed to use this. When we ran the model ahead of the Draft Plan, we found results like those in Figure 13. As described in the Draft Plan (see p63), the bars represent the amount of additional depreciation the model said we needed to reduce asset stranding and the percentages in the bars represent the amount of reduced asset stranding that amount of additional depreciation (in the next AA) would. Thus, for Multinet, in the Dual Fuel scenario, almost $600 million of additional depreciation would reduce our asset stranding risk by around 73 percent. The red lines are the amounts of depreciation we eventually chose, based largely on the basis that these produced no price rise from the current to the next AA.

Figure 13: Draft plan future of gas modelling results



This was a much wider range than we had anticipated, and some scenarios, given the settings for the various inputs, appeared to have already passed the point when some asset stranding could not be avoided.

The approach we used to obtain these figures was essentially a "naïve" approach. That is, we started with no accelerated depreciation for each scenario, compared the NPV costs and the NPV of revenues (see discussion of the model above) and then tried to "goal seek" depreciation to reduce the difference between the two NPVs.[41] We did this over a large range of "sub-scenarios" within each scenario, which mostly reflected different electricity prices (an input we did not

[41] *The way the model works is that the depreciation pathway is a tilting function; as you increase the value in a cell in the model, more depreciation (of the longest-lived asset classes, and only on existing assets; this is how the model is constructed, but it also allows one to change the lives of new assets) is brought forward. Thus one can, in principle, use the "goal seek" function in Excel to change the value in one cell, and see what it does to the difference between the NPV of costs and the NPV of revenues in another cell.*

believe we had very robust forecasts for before the draft plan). As a way of delivering an answer sufficiently robust to underpin our submission to the AER, this approach was not adequate. However, the exercise did teach us some key lessons, which we have subsequently incorporated into our work. These include:

- Spurious optimisation – sometimes the model would suggest that a move from a loss (so NPV of costs greater than NPV of benefits) of say $10 million to a loss of, $1 million would be effected by adding $100 million in depreciation. Although the model is not incorrect, it is immediately obvious that no regulator would allow an increase in depreciation of that magnitude to deal with so small a marginal benefit. What results like this illustrate is the non-linear nature of the model.
- Local optima – sometimes, the starting point of the goal-seek mattered, and one would obtain a different optimum depending upon whether one started with zero additional depreciation compared to say $50 million extra. This suggested that naïve goal-seeking was not the answer.
- Excessive loading onto the next AA – since the major impact in the model comes when consumers choose (or not) to switch, and since only roughly 1/15th of consumers come up for switching in every year (with an appliance life of 15 years), the model tries to find solutions whereby non-switching consumers pay very high prices until they switch. We solve this by imposing a maximum regulatory price (see Section 5.3.2) which creates less aggressive accelerated depreciation solutions.
- Lack of asset recovery – depending on variable electricity charges, in some cases, no scenario allowed us full asset recovery – in terms of Crew and Kleindorfer's paper, we had passed the WOOPS point. Electric Dreams in particular had many case like this across different electricity price paths. This suggests that the best we could hope for is partial asset recovery; not an ideal outcome.
- Lack of tools – the focus of the early modelling was on one lever; the depreciation tilt. This is applied only to existing long-lived assets in the RAB already. The model contains the ability also change the lives of new assets and in early runs of the model, we found many situations where this has a significant effect on asset stranding. In fact, in many cases, a combination of changing asset lives for new assets and tilting depreciation on the existing asset worked best.

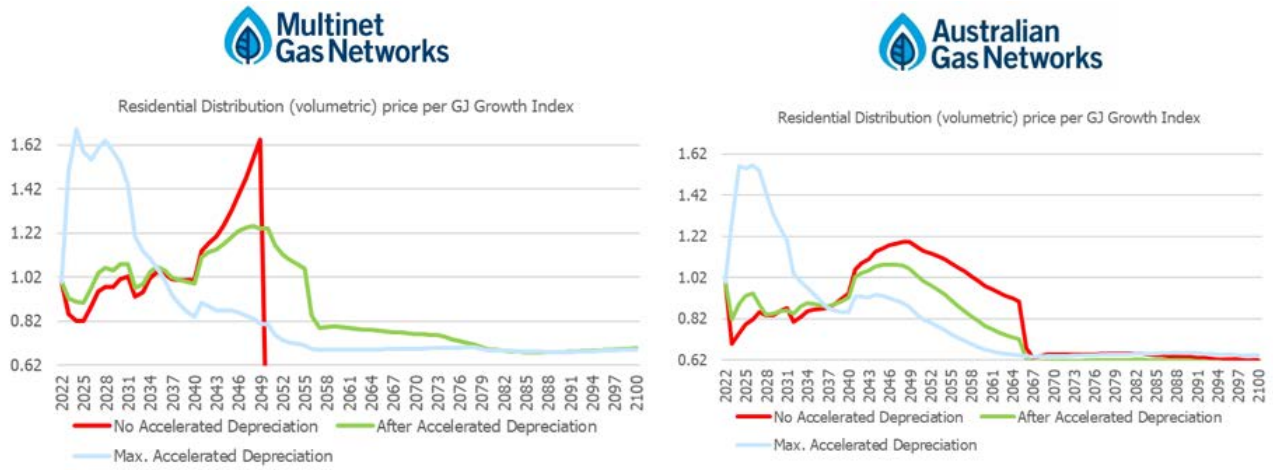
This led us to a change in focus from the "naïve" approach of the draft plan to a focus on consumer price pathways. In particular, keeping relatively stable price paths that attempt to "price match" with electricity is the best solution for us. The reason is fairly simple; demand is a function of price, so if a particular price is too high, we get a drop in demand, which leads to further price increases until we cannot charge enough to recover all of our invested capital and we get some degree of economic asset stranding. In an environment like ours, where demand can change much more quickly than costs, avoiding the first demand shock allows us to avoid further price shocks and eventually asset stranding. In fact, since price spirals precede economic asset stranding, consumer prices are effectively the canary in our coal mine.

As we went further down this approach, we realised that, since stability in pricing is largely a function of demand, we could assess depreciation plans by considering the amount of additional demand each one engendered. The more additional demand is generated, the higher is the utilization of the asset by customers through time and the higher is the total consumer surplus This, in fact, can be used as a test of the efficiency of a given depreciation approach as per the requirements of NGR 89(1)(a) (see Attachment 6.4).

The various learnings we have experienced through using the model have led us to a different approach for the Final Plan, whereby we use the model not to *find* solutions, but to *test* proposed solutions and see whether they give reasonable outcomes for both consumers and investors. Although we were not aware of the field when we started our work, it turns out that there is a large body of literature on making decisions under conditions of "deep uncertainty" (when, as Donald Rumsfeld famously put it, the unknowns are unknown) and this approach of testing solutions plays a prominent role in this literature.[42]

Once we had settled on this approach, our focus shifted to working out if there was some way in which we could narrow the zone for testing solutions, and this led us to the framework shown in Figure 14. This shows the Dual Fuel scenario, and comes from a set of slides given to stakeholders in our VGNSR briefing on 31 March. Note that our final results follow a similar form, but differ because the model has changed from these indicative slides, and the green line represents the Final Plan depreciation solution in the new model.

Figure 14: Framework for testing solutions



The lines are not prices per se, but rather indices, with 1 being the current price. The red line in each case represents the price path, out to 2100 if we did nothing in respect of depreciation. For Multinet, one can see that the network "strands" (in the sense that an inability to recover costs in regulatory prices triggers a default event, see Section 5.2) in 2050. The green lines are the price trajectories which would occur if we put in the depreciation amounts proposed in our Draft Plan. The blue lines are the maximum depreciation the model will allow us over the next AA period. Thus, we would see a large price increase (to a bit over 162 percent in Multinet and a bit less than 162 percent for AGN) for a short period of time and then, because this would reduce our RAB significantly, a fall in future years.

Our modelling approach subsequent to the draft plan has focused on the area between the green and grey lines in Figure 14 to ascertain whether we can engender a more stable price path (noting that some of the inputs have changed since the Draft Plan). This is done visually, and then we look at the extra demand which has been generated in the different scenarios. Since each scenario is distinct, we do not look at the maximum total additional demand across four scenarios, or any similarly simplistic metric, but rather look to plans which give a significant increase in demand, and relatively stable price paths.

[42] *See Marchau VAWJ, Walker WE, Bloemen PTJM & Popper, SW, 2019, Decision Making under Deep Uncertainty: From Theory to Practice, Springer Link, (available here) Note that more sophisticated approaches than the one we have used are possible, particularly in respect of using scenario drivers and solution algorithms. This is an area of future research for us, but in this AA, we need to show we can walk, before we try running; and we need to make sure other stakeholders are walking with us. Mr Rumsfled's philosophical point is better known to economists as "Knightian Uncertainty".*

3.2.3. The stakeholder and customer journey

Stakeholder consultation on the topic of accelerated depreciation has been extensive, and is something which will continue not only through to the AER's Final Decision, but through the next decade or so as the uncertainties in the energy sector resolve themselves, and we start to understand what the future truly holds. Given the uncertain policy environment and the new approach we are taking, it is unsurprising that stakeholders found it difficult to form a view on whether they supported our accelerated depreciation proposal. We focused on seeking to ensure our stakeholders had an understanding of what we are proposing, and agreement that, if accelerated depreciation were to be sought, then our modelling approach was the right way for the AER to approach the matter.

There were two limbs to our stakeholder consultation process. The first of these was consultation with the AER itself. This we started early in the process, because we knew that most of the ideas we were putting forward, and the modelling framework itself was brand new. We understood that early engagement, so that the AER understood what we were trying to do from the outset was key; this is not the kind of topic which lends itself to an expert report containing all the "right answers".

To this end, we have provided early versions of the model to the AER, even before we had it working properly and before all of the inputs have been finalised. This helps the AER understand the evolution of the model, particularly how changes in inputs can change results.

Specific engagement with the AER included:

- Discussions on principle during June 2021, before we had commenced building the model at all. This started with conversations about what we had done in WA (including a detailed walk through of the history of that process) and what and why we proposed to make changes for the Victorian distribution context.
- Observers on expert panel during July to September 2021. Although the AER were not members of the panel itself, representatives from the AER sat in on the panel sessions as observers and thus could see exactly how the scenarios were formed
- Presented AER gas futures paper to our stakeholder forum in November 2021. The AER's discussion paper *Regulating Gas Pipelines Under Uncertainty*, was released around the same time as one of our stakeholder workshops which was dealing with our future of gas proposal. The AER took this opportunity to brief our stakeholders (as well as stakeholders more widely, whom we also invited to our forum at the behest of the AER) on its emerging thoughts in the area.
- Discussion on draft plan modelling in December 2021. This was shortly before the release of our Draft Plan and was essentially the first time that we had been able to make all of the elements of our model work together and start producing results. As well as the information in Figure 13, we gave the AER all of the other model runs, and went through in detail how we had obtained our results, including some of the problems and shortcomings we could see emerging in the model
- Technical modelling updates; since Feb 2022. These are essentially "training sessions" whereby we have sat down with the AER and worked with them to show them how the model works. There have been several of these sessions, and the information flow has been two-way, with the AER making material contributions to aspects of the model, such as the tuning of the S-curves noted above. The model itself was provided to the AER shortly before Easter 2022. This version of the model does not contain our final set of model inputs, but is

otherwise a fully working model. As we update and finalise our inputs, we will provide these to the AER, and other interested stakeholders.

- Sessions on our learnings from the Draft Plan in March 2022. After the publication of our Draft Plan, we had sufficient time to return to the model and start to understand how it worked better. We have briefed the AER on our developing learnings (many of the figures in Section 3.2.2 come from slides presented to the AER) in these sessions, and indeed been assisted by the AER as well.
- Board updates in May 2022. Here we provided a brief update directly to the AER Board on the overall modelling process and the role AER staff played in it. Since the update was brief, and results are yet to be finalised, it could only cover the model's broad details. However, it gave the Board a good starting point for understanding what we are seeking to achieve.

In addition to the above, we also had numerous conversations with AER staff through the process. This greatly assisted us in developing our thinking around our modelling and assumptions. The early, detailed engagement with the AER staff has, we believe, allowed a much more timely and robust consideration of a novel issue than would have been possible using the standard "propose-respond" model where we wait for our Final Plan before really engaging with the AER. We would like to thank AER staff for being generous with their time and expertise.

The second part of our consultation was with stakeholder representatives from our VGNSR and RRG (representing consumers and retailers respectively), the AER's CCP (who were, unfortunately, only formed part way through our consultation process and had little opportunity to engage in the early stages of our process) and customers.

In respect of the goal of understanding on the part of customers, we believe that we were largely successful. Whilst some stakeholders simply opposed any consideration of any accelerated depreciation at all, and some felt that, particularly in like of the Gas Substitution Roadmap still not being released, they could not make a firm decision, we found in general that:

- Final customers did understand what we were trying to achieve. In fact, they were more accepting of our proposal than other stakeholders with a greater degree of regulatory expertise. This may be because final customers are familiar with competition, and thus are not surprised when we come up with an approach that effectively does the same thing as, say their local Bunnings in respect of pricing.
- As we went through the process, more stakeholders came to a better understanding of what we were trying to achieve. This did not mean that stakeholders necessarily agreed, however, understanding is a key first step to a healthy debate on this topic during this review process and in coming years.[43]
- Most stakeholders accepted the robustnesss and transparency of the modelling framework. More particularly, most felt that the framework was sufficiently robust that the AER would be able to ensure that our claims for accelerated depreciation were reasonable, or at least supported by the evidence we say it is. This, again, is a key part of the debate.

There were two main concerns from stakeholders who disagreed entirely with accelerated depreciation. Some saw both hydrogen spending and allowing new connections today as inconsistent with accelerated depreciation. Other stakeholders have expressed a view that, if we

[43] See AER, 2022, *Regulating Gas Pipelines under Uncertainty*, p(vii)

are asking customers to pay for accelerated depreciation,[44] then investors should pay for hydrogen options.

Both of these views misunderstand somewhat what we are trying to do in respect of hydrogen spending and accelerated depreciation as ways of reducing risk and creating options across different potential future states of the world. One stakeholder suggested that we were trying to have an "each way bet". This is exactly what we are trying to do, but we are doing so on behalf of customers rather than at their expense, because "each way bets" keep options open for customers.[45] Spending some money on hydrogen keeps the option of hydrogen open, undertaking some accelerated depreciation gives some protection if hydrogen is not viable, and prudently adding new customers lowers prices for all, and thus forestalls, to some degree, demand reduction (see Section 2.3.1).

In respect of who pays for which option, the issue is that the party paying for an option under the current condition of uncertainty will expect to be able to reap the rewards if that option is successful. If the rewards which are available are not enough to cover the risks being faced now, then the party will not pay. This is a problem in regulation, because it operates once the success of an option is known (there is no sense in regulating hydrogen as a monopoly before it is even viable) and regulatory prices thus do not capture the risk that did exist before the success of an option is known.[46] Investors could pay for all of the costs associated with the hydrogen option, but the quid-pro-quo would necessarily be a different set of rewards than regulation would usually provide. By contrast, if customers share the risks now, they legitimately share the benefits later.

[44] *Noting that it is current consumers who pay instead of future consumers paying what for them would be a higher, or at least more consequential, price.*

[45] *See AER, 2022, Regulating Gas Pipelines under Uncertainty, p(x), where the AER points to its own desire not to foreclose on options for consumers.*

[46] *See Gans, J and King, S, 2003, Access Holidays for Network Infrastructure Investment, Agenda, 10(2) 163-78, (available here). This insight led to the creation of the Greenfields Pipeline Exemption in transmission, and some very similar approach would be required here.*

4. Model results

In this chapter, we provide the core of our work, the results of the model. As discussed in the previous section, our approach has not been to finely tune the model and use it to show clearly the exact amount of accelerated depreciation which is needed in a given scenario. Maybe in a decade or so, when the future is much clearer, we will have sufficient information for such precision. For the moment, such precision is spurious, given the nature of the information we have to work with. Rather, we use the model as a way of testing potential depreciation proposals. Specifically, what we have sought to do is take a depreciation pathway and test it against the scenarios to see if:

- Our risk profile is, over all scenarios, reduced to a degree which is close enough to the risk level we have faced in the past to be acceptable to us and not to require any changes to the rewards we seek for risk.
- The price path for consumers is as stable as we can make it, given the constraints of the modelling framework and the extent of price rises which may be required initially.
- We can get a substantial increase in demand for gas (and thus allocative efficiency) over the life of the assets by accelerating depreciation.

We summarise the results first, and then explore how sensitive our findings are to changes in parameters. In respect of the latter, we note that we have submitted a full working version of our models to the AER along with this Final Plan. Any stakeholder can extend the sensitivity analysis in any direction they desire; in keeping with the use of an independent expert panel to develop scenarios, we have constrained our sensitivity analysis to remain in the broad scope of each of the scenarios provided to us.

4.1. Key Metrics

Table 4 shows a summary of key output metrics from the Future of Gas modelling under proposed and maximum depreciation for AGN. Maximum depreciation is the highest amount of depreciation that can be input without breaching the price cap for regulatory prices of 1.7 times the current price (see Section 5.3.2). Depreciation which produces prices higher than this would prematurely drive the demise of the business through said high prices. In the model, this is assumed to happen as soon as the price cap is breached, meaning any asset unrecovered at that date is lost (see discussion under Figure 15 in Section 5.2).

Results in the proposed and maximum depreciation panels are changes relative to the ‘No Accelerated Depreciation’ base case. The key output metrics are extension of business life, reduction in unrecovered asset and change in total volumes of gas transported.

The extension in business life is the additional years the business can keep running the asset financially uncompromised (that is, beyond the year the price cap is breached). Reduction in unrecovered asset is the reduction in asset left unrecovered at the new out of business date (if applicable) once accelerated depreciation is applied. The change in total volumes is the change in the sum total of residential GJs of gas sold over the modelled horizon of operation.

The volumes discussed here are residential GJs. This is for ease of multiplying prices by quantities in the Incenta analysis referenced further below. Including commercial volumes complicates the analysis and does not materially change the outcomes.

While regulation is primarily concerned with maximizing volumes to improve economic efficiency through providing more of a valued good to society, the three metrics are interlinked. Generally, the longer the business remains in operation the more gas it can sell to consumers at the requisite service standard to recover more asset. Time in business is the main driver of volumes.

Table 4: Summary of Modelling Results

Scenario	Electric Dreams	Dual Fuel	Muddling Through	Hydrogen Hero
No Accelerated Depreciation ($m)	**0**	**0**	**0**	**0**
Compromise Date	2045	2050	2086	Perpetual Going Concern
Unrecovered Asset ($m)	728	727	104	0
Proposed Depreciation ($m)	**145**	**145**	**145**	**145**
Extension of Business Life (years)	0	29	14	Perpetual Going Concern
Reduction in Unrecovered Asset ($m)	194	631	43	0
Change in Total Volumes	-3.0%	51.4%	19.8%	6.6%
Maximum Depreciation ($m)	**642**	**617**	**632**	**812**
Extension of Business Life (years)	2	45	Perpetual Going Concern	Perpetual Going Concern
Reduction in Unrecovered Asset ($m)	577	645	104	0
Change in Total Volumes	-24.3%	107.2%	24.3%	12.6%

Accelerating depreciation does not extend business life under Electric Dreams. AGN recovers more asset with accelerated depreciation, however, volumes of gas sold decrease instead of increase, which signifies a loss of consumer welfare and efficiency. The exercise of accelerating depreciation under this scenario is purely one of asset recovery, rather than one of increasing consumer welfare as well.

However, care needs to be taken in interpreting this to mean that doing nothing is in the long run interests of consumers. At the time of modelling, AGN customers could access electricity tariff deals that were on average around 10 per cent lower than electricity charges available to customers in the Multinet network. The S-curves used between Victorian gas networks are identical to each other and so, all else being equal, differences in electricity tariffs will differentiate results. When the electricity tariff used for Multinet customers is applied to AGN, accelerated depreciation results in an extension of business life and more volumes sold. The model results are sensitive to electricity prices going forwards.

The inability to prolong AGN's business life and increase volumes sold under the lower electricity usage tariffs suggests the window of opportunity for capital recovery, as outlined by Crew and Kleindorfer (1992), has passed in an Electric Dreams type scenario. However, if we chose to do nothing now within the Electric Dreams scenario, and defer regulatory capital recovery until the next AA period, the price increases associated with this would lead to greater consumer detriment.

As things stand, acting now allows for relatively small losses in demand (3 per cent loss in volumes), which are well within the boundaries of uncertainty associated with the model demonstrated by the positive volumes in all other scenarios.

Other scenarios are much more positive for AGN, with an unequivocal gain for both investors and consumers.

Dual Fuel benefits from longer life and higher volumes sold with accelerated depreciation, but it does not extend the business life into perpetuity. The maximum depreciation extends the business life into perpetuity under the Muddling Through scenario but the life falls short of perpetuity when applying proposed depreciation. In both of these cases, however, the extension of business life gives us sufficient breathing room, in real life (as distinct from the model and the limitations of its assumptions) to be able to plan for the future.

Higher accelerated depreciation results in significantly more gas/hydrogen sold in all scenarios except Electric Dreams. Volumes sold also increases with the amount of accelerated depreciation as can be seen by the change in total volumes from 'No Accelerated Depreciation' to 'Proposed Accelerated Depreciation' to the higher still 'Maximum Depreciation'. An increase in gas sold produced just by changing the depreciation profile represents a more efficient use of the infrastructure. It occurs because depreciation is being shifted from a time when consumers are more price sensitive to a time when they are less price sensitive, so the loss to current consumers is much smaller than the gain to future consumers (and consumers who consume both now and in the future get a gain in their own utility). This is in-keeping with the way economic theory suggests a depreciation schedule should operate in order to promote efficiency (see Section 2.3.4 and Attachment 6.4).

The welfare gain associated with the increase in demand can be quantified (see Attachment 6.4), and the relevant gains are summarized in Table 5. Incenta's method of assessment is set out in Attachment 6.4, but in broad terms involves estimating the standard change in economic welfare from a change in the mark-up over marginal cost under the simplified assumption of a linear demand curve.

One complexity with this estimation, however, is that the greatest contribution of advancing depreciation under some scenarios (notably "dual fuel" for both networks) is to extend the life of the network, and hence the duration for which the service is available to customers.

Incenta has estimated this gain in allocative efficiency by assuming the increase in use generated by advancing depreciation creates a fixed per unit increase in allocative efficiency, for which we assume a fixed per unit gain of $2 per GJ, which is equivalent to assuming a gap between the price and marginal cost of distribution services of $2 per GJ, which we believe to be conservative. This is shown in the right-most column, with the second column from the right showing the gain if the extension of supply is ignored.[47]

Table 5: Welfare gains from increases in demand from proposed depreciation change

Scenario	Change in quantities (%)	Efficiency gain - ignoring benefit of extending supply ($m)	Efficiency gain - $2/GJ benefit from extending supply ($m)
Electric Dreams	-3.0%	-107	-107
Dual Fuel	51.4%	-131	718
Muddling Through	19.8%	1,164	1,561
Hydrogen Hero	6.6%	1,117	1,117

The resulting estimates of the change in allocative efficiency are set out in Table 5.[48] The results shown are the simple sum of the annual changes in allocative efficiency over the life of supply. This table shows that our proposed advancement of depreciation is estimated to increase allocative efficiency:

[47] *The importance of the extension of supply for allocative is most apparent in the "dual fuel" scenario. Table 5 shows that advancing depreciation under this scenario for AGN results in a very large increase in the total volume of gas delivered (a 51.4 per cent increase), but an allocative efficiency loss if the benefit of the extension in supply is ignored. However, under this scenario, advancing depreciation is projected to reduce the volumes sold during the period when gas supply would exist irrespective of advancing depreciation, but to allow supply to be extended under cost-based prices for a further 29 years compared to the case if the depreciation method and settings remained unchanged.*

[48] *The changes in allocative efficiency presented here reflect the sum of the annual allocative efficiency effects over the life of the relevant network under the indicated scenario.*

- in all cases except "electric dreams" and "dual fuel" if the allocative efficiency benefit from extending supply is ignored; and
- in all cases except "electric dreams" if a conservative estimate of the benefit of the extension of supply is considered.

Moreover, Incenta has also tested plausible sensitivities to the key inputs, and find that the results remain qualitatively unchanged

4.2. Price Stability

We also assess the accelerated depreciation proposal by assessing its effect on price stability over time. Volatile delivered gas prices create uncertainty around the utility derived from a consumer appliance over its useful life. High gas consumption costs can strand these consumer assets. Low prices in the immediate term are only beneficial provided they are not a result of deferring costs leading to price volatility in the form of future price rises. Of particular concern is rapid price increases associated with demand falling, which are borne by those consumers who are less able to switch away from gas.

We show the long run price path underlying the analysis in Table 4 under:

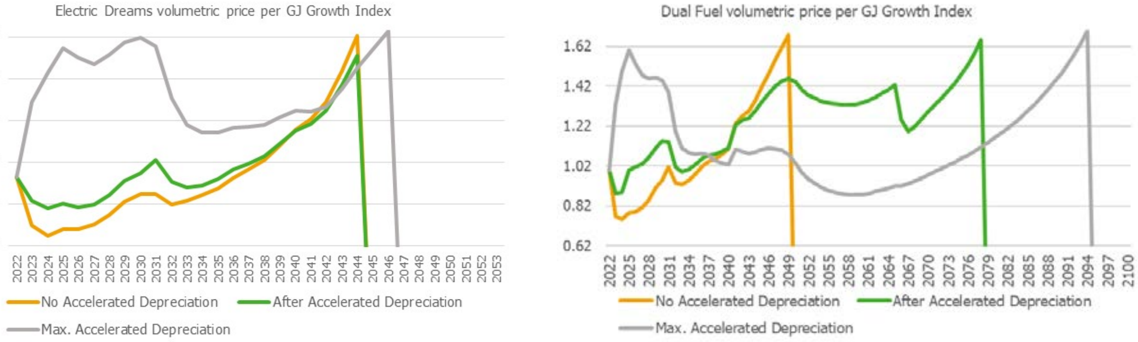
- no accelerated depreciation (orange);
- the proposed accelerated depreciation (green); and
- the maximum accelerated depreciation (grey).

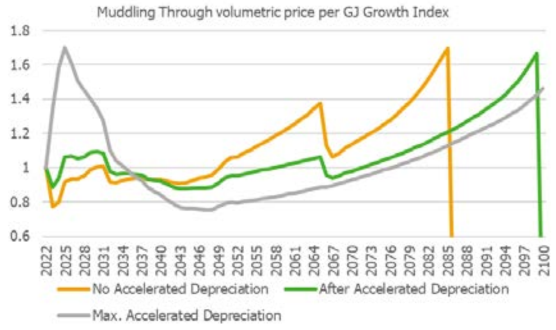
The vertical segment of the lines meeting the horizontal axis correspond to the compromise date and extension of business life in Section 4.1.

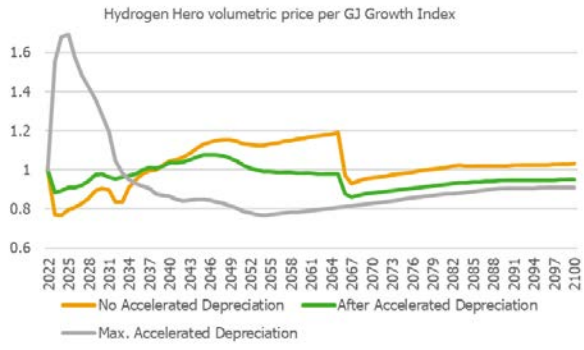
In lieu of any other constraints, price stabilisation in all graphs requires finding a price path between the orange and grey lines that is as close to one on the vertical axis as possible. For natural monopolies with high proportions of fixed costs, we practically achieve this by maximizing volumes of gas sold over the long run to divide these fixed costs into higher demand. Note that, since we are doing this by adjusting depreciation, and since the model is non-linear, getting very flat price paths is practically impossible; the key focus is on minimising price spikes, which are most damaging to consumers.

Figure 15 presents the results of this analysis.

Figure 15: Price Stability Analysis







Maximum Accelerated Depreciation (grey)

In Electric Dreams and Dual Fuel, maximum depreciation results in the highest prices in the long term. This is because the AGN network has a high proportion of lower income customers. Lower income customers are less inclined to switch early on due to limited access to upfront funds for new appliances and so large-scale customer loss occurs later when electrical appliance costs have fallen. Thus AGN's customers would suffer the greatest harm from electrification or similar policies given current price relativities between AGN and Multinet customers.

Maximum depreciation in Electric Dreams fails to stabilize customer losses into perpetuity. The only benefit shown in the model in these extreme circumstances, as outlined above, is recovery of more invested capital; in fact, almost all of the invested capital would be recovered in both scenarios, based on model results. However, the extension of life in the Dual Fuel scenario does, in more practical terms, allow us much greater scope for planning a response to the pressures inherent in the scenarios.

In Dual Fuel the business still ceases by 2095 and in Muddling Through the price is less stable in the later years than Hydrogen Hero. This is because of the more competitive electricity tariff accessible to AGN discussed in Section 4.1.

In Electric Dreams and Dual Fuel the grey price path under maximum depreciation slopes upward toward the end because of scenario specifics such as energy price-growth differentials (gas vs electricity), low consumer preference for gas/hydrogen, electric appliance subsidies and inability to economically access hydrogen produced in industrial areas.

In Muddling Through and Dual Fuel the grey price path under maximum depreciation slopes upward toward the end because electrical appliance costs fall faster than gas appliance costs and the capex accumulates in the RAB as assets are replaced.

A prudent network would be reluctant to maximize depreciation in the way shown in Figure 15 even if the regulator allowed it because the network does not have perfect information on the price sensitivity of future customers. That is, we know what the price sensitivity of our current customers is around the current price, but we have no data on how they might respond to a price which is, say, twice the current level. We refer to this as the 'imperfect information' constraint, and it motivates caution on our part in terms of price increases we would propose, above and beyond caution at what the AER's response might be.

If the network accelerates depreciation too fast, it risks losing customers beyond theoretical models of natural monopoly because those models assume no substitutes, whereas gas is a fuel of choice. The network also risks losing customers beyond that predicted by models that account for substitution (such as the Future of Gas model) because of the imperfect information problem.

The most information the network has is past prices, observed demand and potentially some understanding of connection loss drivers, for example distinguishing price driven customer losses from other phenomena. In light of this, there is logic in staying close to past prices, provided price driven demand loss has not been evident.

Proposed Accelerated Depreciation (green)

The lower electricity tariffs prevalent in the AGN network make it more challenging to stabilise prices under all scenarios. This is evident in the increasing trend in the green line for all scenarios except Hydrogen Hero. Despite this, the price stability outcomes under proposed accelerated depreciation are better for all scenarios than applying no accelerated depreciation.

4.3. Sensitivity Analysis

As outlined in Incenta Economics' analysis total volumes of gas sold over the long run is the key metric used to quantify consumer welfare and efficiency. Here we test how total volumes change in response to changes in the:

- amount of accelerated depreciation in the future of gas proposal to see how sensitive welfare/efficiency outcomes are to changes in our proposal;
- key drivers set with reference to the Expert Panel scenario narratives; and
- expenditure proposed in the final plan given that this is likely to change as the regulatory reset process moves through its phases.

All changes are with reference to the outcomes under the proposed accelerated depreciation amount for each network.

4.3.1. Accelerated Depreciation Impact on Total Volumes

Table 6 presents the results of changing the amount of accelerated depreciation.

Table 6: Future of Gas Depreciation Proposal Sensitivity

Proposal $144m								
Accelerated Depreciation Proposal (-/+ 20m)	**Electric Dreams**		**Dual Fuel**		**Muddling Through**		**Hydrogen Hero**	
Impact on Gas Volumes	0.4%	1.7%	-5.0%	5.0%	-1.6%	1.5%	-0.8%	0.7%

Decreasing the proposal from $144 to $124 million results in a minor drop in volumes of gas sold across all scenarios, except Electric Dreams, which experiences a minor increase. As discussed in Section 4.1 and Section 4.2, this anomalous result stems from AGN customers generally having access to lower electricity usage tariffs than Multinet customers. Using Multinet tariffs in the AGN model produces total volumes positively correlated to accelerated depreciation in Electric Dreams like the other scenarios.

Dual Fuel is slightly more sensitive than the other scenarios due to some network segment's inability to access hydrogen produced in industrial areas. Section 4.3.2 elaborates on this issue.

For all scenarios except Electric Dreams, the results appear symmetric. Increasing depreciation to $164 million increases gas volumes sold by approximately the same decrease in volumes sold when decreasing depreciation to $124 million. The positive figures associated with increasing depreciation to $164 million across all scenarios suggests some gains from increasing the depreciation proposal substantially.

4.3.2. Scenario Key Driver Analysis

The Expert Panel scenario narratives differentiate future states of the world across six key parameters:

- Consumer preferences;
- gas, hydrogen and electrical energy prices;
- incentives such as subsidies for electrification;
- moratoria on gas connections; and
- access to industrial hydrogen.

We examine the impact each of these parameters has on the scenarios output total gas volumes under the proposed accelerated depreciation for each network by modifying them as shown in Table 7.

For consumer preferences and energy prices, we find the least and most extreme set of inputs in the Future of Gas model and substitute them between scenarios. The S-curves reflect consumer preferences with Hydrogen Hero being the least sensitive and Electric Dreams being the most sensitive (See Figure 9 and discussion in Box 2). Gas prices are lowest by 2050 for Hydrogen Hero and highest by 2050 for Electric Dreams. Electricity prices are also lowest by 2050 for Hydrogen Hero and highest by 2050 for Muddling Through.

Electric Dreams has two unique drivers; incentives in the form of high subsidisation to encourage electrification and moratoria on gas connections. Dual Fuel has one unique driver; economical access to hydrogen produced in industrial areas. We remove these drivers from their respective scenario to examine the impact.

The S-curve and energy prices report "NA" where they already apply and so produce zero per cent change. For example, Electric Dreams already uses the most sensitive S-Curve and so will not produce any change. Hydrogen Hero already uses the lowest gas electricity prices and so will not produce change. The last three drivers are binary (on/off) rather than low/high and so only apply once, removing them from the scenario to which they belong. Table 7 presents the results.

Table 7: Key Drivers of Scenario Outcomes

Key Drivers of Scenario Outcomes @ $144m								
Impact on Gas Volumes	**Electric Dreams**		**Dual Fuel**		**Muddling Through**		**Hydrogen Hero**	
S-Curve (least/most sensitive switching)	26.1%	NA	102.6%	-34.6%	32.9%	-16.0%	NA	-72.8%
Gas Price (low/high by 2050)	-11.4%	NA	93.2%	-32.2%	103.0%	-12.7%	NA	-58.0%
Electricity Price (low/high by 2050)	-41.5%	-2.9%	-50.5%	107.3%	-61.8%	NA	NA	60.0%
Incentives	52.3%	NA	NA	NA	NA	NA	NA	NA
Moratoria	5.1%	NA	NA	NA	NA	NA	NA	NA
Access to Industrial Hydrogen	NA	NA	39.2%	NA	NA	NA	NA	NA

Electric Dreams

Electric Dreams is the least sensitive scenario because it already reflects an extreme combination of circumstances as per the scenario narrative. This includes highest gas prices, substantial incentives such as subsidies for electrification, moratoria on gas connections, higher electric appliance efficiency/lower maintenance costs compared to gas and greater gas consumption per connection sensitivity to price.

Under these extreme conditions, it is difficult for any one driver alone to change total volume outcomes.

We calibrated the original Electric Dreams S-curve so that the asset is compromised some time prior to 2050 as per the Expert Panel scenario narrative reflecting preference of climate conscious customers. Applying stronger preferences for gas, reflected in the least sensitive S-curve, increases volumes by 26.1 per cent.

Reducing the gas price path reduces volumes by 11.4 per cent. Lower gas prices reducing volumes is an anomalous effect attributed to the lower tariffs accessible to AGN customers as discussed in Section 4.1 and 4.2.

Electric Dreams already uses a high price path due to strong demand for electricity under this scenario and the lack of large-scale renewable build out mentioned above. Reducing electricity prices to a more competitive path (that underpins hydrogen) decreases gas volumes by 41.5 per cent, further increasing the downside of the scenario.

Increases in electricity prices have a minor impact (-2.9 per cent) because the highest electricity price path follows the existing Electric Dreams path closely. The 2.9 per cent result is negative because the highest price path (by 2050) used to produce the result is actually lower in earlier years.

Since the *use of a low price path in Electric Dreams does not match the narrative* and applying a higher price path has a minor effect, we can conclude in the long-run electricity prices are not the key driver of the pessimistic scenario outcomes within the context of the scenario narrative. However, we do know for AGN the access to lower tariffs in the short-run have a major impact on Electric Dream's outcomes by comparing it to Multinet.

Removing incentives (electrification subsidies) has a major impact increasing demand by 52.3 per cent. To the extent that consumers find the consumption of gas welfare-enhancing, this suggests the subsidies may be having a significant, unquantified effect on consumer welfare. Lifting the moratoria has a milder impact in this scenario increasing demand by 5.1 per cent.[49] This does not mean moratoria are harmless to the business or to consumer welfare, they just have a *relatively* low impact value compared to the other drivers.

In summary, the main drivers of Electric Dreams outcomes for AGN are *short-run* electricity prices and incentives in the form of electrification subsidies.

Dual Fuel

Dual Fuel is the most sensitive scenario because of limited access to hydrogen producing industrial areas discussed in section 4.3.1. Compared to Multinet, AGN has a larger proportion of customers with economical access to hydrogen produced in industrial areas, which improves the viability of the AGN business under Dual Fuel. The lower electricity tariffs generally accessible to AGN customers partially offset this benefit.

The comparison to Multinet is made because both networks use the same S-curve for Dual Fuel and so differences in network geography will drive divergent results all else equal. We calibrated the original Dual Fuel S-curve so that the asset is financially compromised around 2050 *for both AGN and Multinet* as per the Expert Panel scenario narrative.

Stronger preferences for gas reflected in the least sensitive Hydrogen Hero S-curve increase volumes by 102.6 per cent, whereas weaker preferences for gas only decrease volumes by 34.6 per cent. We expect this because there is a significant difference between the Dual Fuel and

[49] *Note that we have not tested the imposition of moratoria in scenarios where gas and hydrogen are much more attractive to consumers.*

Hydrogen Hero S-curves, while there is much less difference between the Dual Fuel and Electric Dreams (most sensitive) S-curve.

The gas/hydrogen prices used in Dual Fuel are a major driver of results, evident by the 93.2 per cent increase in volumes when replacing the scenario's existing price path with the lowest one. Lower gas and hydrogen prices greatly assist in re-growing customer connections in the remaining areas near industry left on the network.

The highest gas/hydrogen price path has a smaller absolute impact of 32.2 per cent even though it represents a far more substantial change over the existing Dual Fuel price path than the lowest price path. This suggests consumer demand is more responsive to gas and hydrogen price decreases than increases under Dual Fuel assumptions.

Electricity prices are the largest driver of Dual Fuel outcomes, with high electricity prices increasing volumes by 107.3 per cent. Lower electricity prices have less of an impact only decreasing volumes by 50.5 per cent, likely reflecting the low electricity price path's proximity to the existing Dual Fuel path.

In summary, low gas/hydrogen prices are the key driver of Dual Fuel outcomes for AGN. The network and consumers do better losing large segments to electrification under lower gas prices than keeping those segments of the network under high gas prices. Volumes only increase 39.2 per cent when removing the constraint on access to industrial hydrogen compared to 93.2 per cent when gas price is lowest, despite segment loss.

Muddling Through

Muddling Through is less sensitive to scenario inputs than Dual Fuel, but more sensitive than Electric Dreams. Similar to Electric Dreams, a range of other parameters such as high consumer discount rates and lower sensitivity of gas consumption per connection to gas prices reduce the sensitivity of Muddling Through outcomes to inputs show here.

Muddling Through uses the same S-curve as Dual Fuel, because this is the medium sensitivity S-curve and nothing in the Expert Panel scenario narrative suggested the use of more extreme customer preferences.

The S-curve has a moderate impact on outcomes with the least sensitive curve increasing gas volumes by 33 per cent while the most sensitive curve loses 16 per cent of volumes. The least sensitive curve has the greatest impact because it is much more different to all the other curves demonstrating a strong preference for gas and lack of desire to electrify.

Reducing gas prices has a major impact increasing volumes by 103 per cent. This is because Muddling Through uses the second highest price path on account of lacking large scale renewable electricity build out to underpin low cost hydrogen production. The lowest gas price path is that underpinning successful hydrogen production which is a major decrease and hence increases volumes sold substantially.

Increasing gas prices represents a small step because Muddling Through already uses a high price path due to the lack of large-scale renewable electricity build-out mentioned and so volumes only decrease by 12.7 per cent.

Reducing electricity prices to the hydrogen supportive price has a high impact reducing volumes of gas sold by 61.8 per cent. Again, this is due to the large difference between Muddling Through electricity price path, which lacks large-scale renewable electricity build out, and the Hydrogen Hero electricity price path underpinned by such build out.

In summary, a lack of large-scale renewable electricity build out, underpinning very low electricity prices and low gas prices are the key drivers of Muddling Through scenario outcomes.

Hydrogen Hero

Like Muddling Through, Hydrogen Hero is a less sensitive to scenario inputs than Dual Fuel, but more sensitive than Electric Dreams.

Hydrogen Hero has the least sensitive S-curve where customers would be reluctant to electrify unless substantial cost savings were evident. We intentionally calibrated it this way so that the gas network would succeed as per the Expert Panel scenario narrative. Substituting in the most sensitive S-curve therefore results in volume loss of 72.8 per cent.

Hydrogen prices under Hydrogen Hero are very low due to large-scale renewable electricity build out result in the availability of very low cost electricity to produce low cost hydrogen. Substituting in higher gas/hydrogen prices results in a substantial loss of volumes (58 per cent) indicating low hydrogen prices are a key driver of Hydrogen Hero outcomes.

Under Hydrogen Hero electricity prices are also extremely low for the reasons already mentioned. Using the highest electricity prices results in a 60 per cent increase in volumes sold.

In summary, the key driver of Hydrogen Hero outcomes is the low gas/hydrogen prices underpinned by large-scale renewable electricity build out.

A key theme is across all of the scenarios is that gas/hydrogen prices tend to be a key driver of outcomes. This is likely because it affects both consumption per connection through gas price elasticity and the number of connections through the S-Curve.

4.3.3. Final Plan Capex and Opex Impact on Total Volumes

At the time of producing the Future of Gas results capex and opex in the PTRMs was not finalised. To address this some sensitivity is run to assess the impact of potential changes in capex and opex submitted in the Final Plan. The impact on volume is assessed after changing capex or opex by minus or plus $10 million per year.

Table 8 presents the results of this analysis.

Table 8: Final Plan Capex and Opex Sensitivity

Impact of Change in Totex Proposal on Volume @ $144m								
Impact on Gas Volumes	**Electric Dreams**		**Dual Fuel**		**Muddling Through**		**Hydrogen Hero**	
Opex (-/+ 10m per year)	7.7%	-5.7%	41.0%	-41.3%	10.6%	-16.8%	8.3%	-9.5%
Capex (-/+ 10m per year)	2.8%	-0.6%	6.2%	-6.1%	1.8%	-2.3%	1.2%	-1.3%

Changes in opex for Electric Dreams and Hydrogen Hero have an absolute impact of less than 10 per cent. As outlined in section 4.3.2 Dual Fuel is particularly sensitive due to losing large segments of customers and so requires competitive gas prices to regrow the network in the remaining areas it operates.

Muddling Through has a much more sensitive S-curve than Hydrogen Hero, but also has better general potentially to realise long-term success than Electric Dreams. This makes it more sensitive to opex than those two scenarios.

Note that it is opex in the final year of the regulatory period that has an impact on the volumes. This is because it is the base for all opex forecasts out to 2100.

Capex changes have a lower and minor impact across all scenarios due to increasing costs only by associated depreciation which is much less than a dollar for dollar effect.

5. Model Manual

As noted in the introduction, the intent of this attachment is not simply to explain what we did, but also to explain how to use the tool which we have developed in order to obtain our results. This chapter forms that explanation, with further detail in appendices. A reader, using this chapter and the two more detailed appendices, should be able to use our models, replicate our results and use their own inputs to explore their own results.

Note that Section 3.2 provides more background to the development of the model.

5.1. Model Background

The model we use to determine the effect of the four future scenarios developed by the Expert Panel (See Section 3.2.1) on the network consists of two components; a building block model and consumer choice model. Together these form the Future of Gas Model. The Future of Gas model is set up to emulate the assumptions, and where stated, the outcomes of the four scenarios.

The objective of our modelling is two-fold (see Section 3.2.2), based on the theoretical framework of Crew and Kleindorfer (1992) on how to determine how much acceleration to employ. From the perspective of investors, we are trying to keep the business sustainable through time, and from the perspective of consumers, we are trying to keep prices stable and effect an improvement in allocative efficiency. The two are closely linked; if we do not accelerate depreciation, prices increase rapidly first, and consumers suffer a loss of welfare as they are progressively priced out of gas, and the end result of this process is some degree of economic asset stranding on the part of investors. Importantly, the interests of consumers and investors are clearly linked; we satisfy the objectives of one by satisfying the objectives of the other; something which the modelling framework makes explicit.

5.1.1. Model components

The future of gas model has two components, a Building Block and a Consumer Choice model. The Consumer Choice and Building Block model link together as a time series (the Future of Gas Model). This is shown diagrammatically in Figure 8 and described in detail in the accompanying text in Section 3.2.

Building block model

We have developed a gas distribution cost and pricing model (the Building Block Model) which emulates the AER Post-Tax Revenue Model over 80 years except on a pre-tax real annual (instead of 5 year) basis for modelling simplicity. The model also assesses the viability of the network under each of the scenarios and employs the ability to front-load capital recovery through a variety of options such as tilting depreciation on the opening RAB, shortening the weighted average remaining life on the opening RAB and shortening asset lives.

Consumer choice model

ACIL Allen Consulting have developed an 80 year model of demand for gas connections and volumes (the Consumer Choice Model) the dynamics of which are primarily driven by upfront appliance cost and running cost differences between electricity and gas. Running costs are a product of appliance energy consumption and retail energy (volumetric) tariffs. Gas volumetric tariffs are partly determined by regulated gas distribution charges which come from the Building Block Model.

5.2. Quick Start Guide to Using the Model

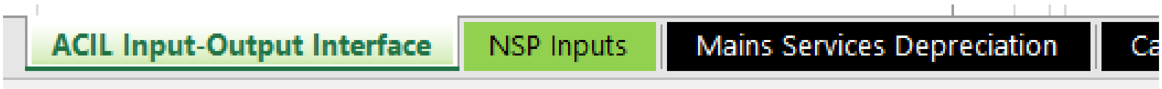
Below is a quick start guide to using the Future of Gas model as a 'black box' with the focus on changing model settings to examine the effect on outputs. After following the quick start guide the user will have an overall picture of what the intention of the modelling is and can then move on to examining the inputs and how they flow through the model.

As mentioned in Section 3.2, the model seeks to examine four scenarios were developed by an expert panel with the assistance of KPMG. The scenarios are described in Section 3.2.1 and the model is designed to run in each scenario in isolation.

To begin using the model, it is important to note that the Building Block and Consumer Choice Model workbooks *both need to be open* and linked. For more detail on how to link the models see Appendix A.

The basic idea of the modelling use is to select a scenario in the "ACIL Input-Output Interface" tab in the Building Block model, observe the price stability and asset stranding value with no accelerated depreciation, then enter various amounts of accelerated depreciation to see the effect on stability and stranding.[50]

First select the "ACIL Input-Output Interface" tab in the Building Block model:



Next choose the Scenario you wish to examine, for example Scenario '2' is selected below:

Depreciation	
Standard Asset Life	50
Focus Date (end of WARL on opening RAB)	2055
Focus date applies to next AA capex?	No
Resulting RAB @ focus date	660,691,477
BAU RAB @ focus date	664,336,664
Additional Depreciation in next GAAR	-
Scenario	2
Tilt	0.0000001

Scenarios

(1) Electric Dreams

(2) Dual Fuel

(3) Muddling Through

(4) Hydrogen Hero

(5) Base line (holds everything constant at year 1 values or 'middle' values where there is no historical data)

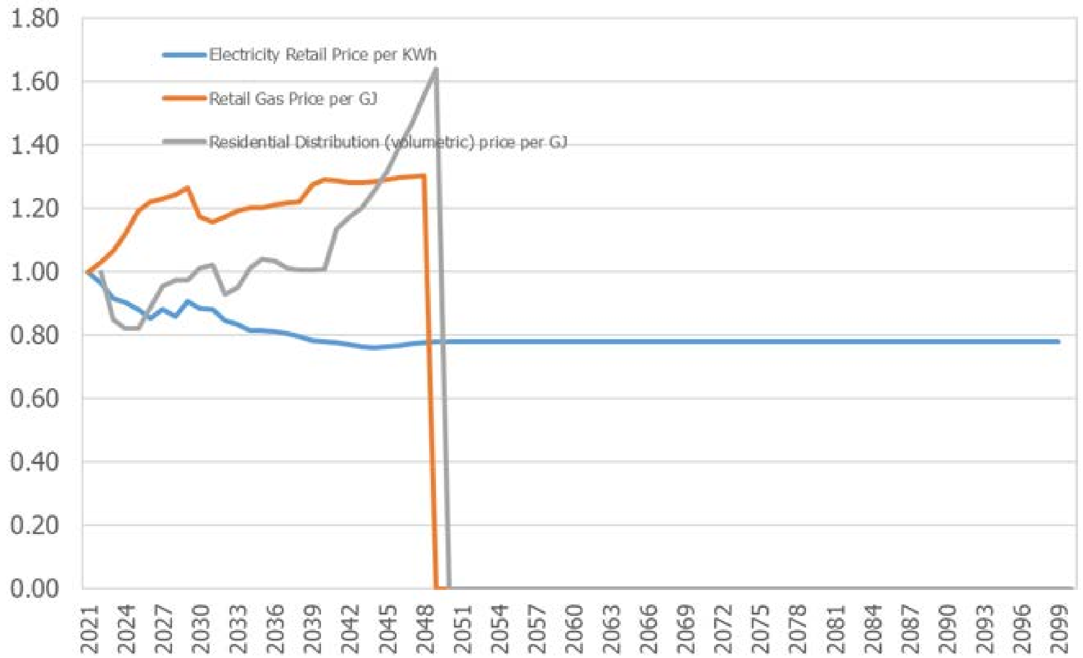
Next, ensure the Accelerated Depreciation or *Tilt* in the image above is set to '0.0000001' which effectively means zero accelerated depreciation.

[50] *See Appendix A2 for further detail on setting up model inputs.*

Assess the effect of the Scenario *without* accelerated depreciation

The first step of the modelling process is to examine the situation without any acceleration of depreciation. The user should examine the effect of price stability on the Retail Distribution (volumetric) price per GJ (Grey line) in the graph 'Residential Retail Electricity vs Gas Price Index' in the "ACIL Input-Output Interface" tab. The 'death spiral' effect of demand declining faster than building block costs, typically looks like the 'bull horn' in the grey line below. This is the departure from stability we are seeking to avoid; prices will never be exactly flat, because the relevant calculus is between the full cost of different alternatives of which fuel costs are only one part, and the fuel costs for an electric appliance are not flat. Stability is thus a relative term compared to the "death spiral" prices seen below.

Figure 16: Residential retail electricity price vs gas price index – no accelerated depreciation



The model is set up with a maximum price of 1.7X the existing price (which can be changed). This is principally to avoid solutions which load more depreciation than would be feasible under regulation because, in the model, a maximum of $1/15^{th}$ of the customer body has the opportunity to switch in a given year. When the price rises to 1.7X the current price, the regulator prevents any future price rises. This is likely to create a situation whereby the network is financially compromised, as it would result in revenues (given demand) which would be unable to support costs.

In reality, the network would likely restructure its operations, taking losses if necessary in order to stay operational. However, the point of the modelling exercise is to avoid coming to this impasse,[51] and thus the model adopts the more extreme perspective that the network ceases to operate as soon as the price ceiling is reached, losing whatever asset value is left. In many circumstances, the stated losses may not be much of an exaggeration of reality because demand is typically falling precipitously when prices pass the 1.7X barrier, leaving very limited operational viability unless a very large portion of the remaining RAB is written down.

Next examine the "Compromised Asset Date" and "NPV of asset at compromise date" in the 'Evaluation panel' in the "ACIL Input-Output Interface" tab.

[51] *Additionally, modelling exactly how a network would get itself out of, or avoid, technical default in this situation is well beyond the scope of a simple modelling exercise such as this.*

Evaluation	PV
Compromised Asset Date	**2045**
NPV of long run cash flows	-$28,514,863
NPV of Asset at Compromise Date	-$534,307,223
NPV of long run cash flows + asset at compromise date	**-$562,822,086**

This estimates how long until the business is disrupted, typically due to reaching the price limit mentioned above, and financial value of compromised assets; the assets that cannot be fully recovered because the price ceiling is reached before the asset is fully depreciated.

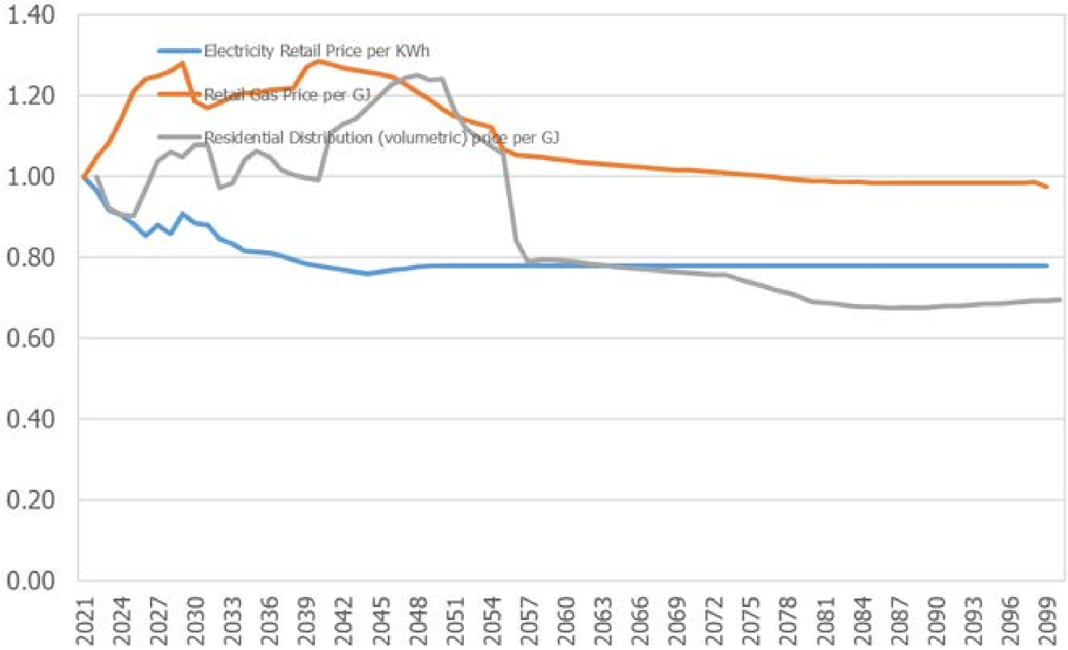
Assess the effect of the Scenario *with* accelerated depreciation

Alter the amount of accelerated depreciation by changing the 'tilt' pictured below.[52] The example below uses a tilt of 0.021 to create additional depreciation in the next GAAR of $76,240,970.

Depreciation	
Standard Asset Life	50
Focus Date (end of WARL on opening RAB)	2055
Focus date applies to next AA capex?	No
Resulting RAB @ focus date	631,591,916
BAU RAB @ focus date	707,671,961
Additional Depreciation in next GAAR	76,240,970
Scenario	2
Tilt	0.0210000

Next, examine the effect on price stability in the Retail Distribution (volumetric) price per GJ (Grey line) in the graph 'Residential Retail Electricity vs Gas Price Index' in the "ACIL Input-Output Interface" tab. The primary goal is to stabilise the grey line as much as possible, which will assist in avoiding the network breaching price caps and risking the assets becoming compromised.

Figure 17: Residential retail electricity price vs gas price index – with accelerated depreciation



[52] *See Attachment 6.4 for a discussion on how our tilt factor compares to a more generalised tilted annuity. We have not used a tilted annuity at this stage because doing so would require changes to the PTRM, which we consider a step too far at this stage, particularly when we get a very close approximation to the results of a tilted annuity without changing the PTRM.*

The graph above shows that this is the case under the 'Dual Fuel' Scenario with prices fluctuating around 1, up to a maximum of around 1.25 times current prices in 2050, before declining as the long life assets currently in the RAB drop off.

Next, examine the effect of accelerated depreciation on the asset falling into default because the regulatory price constraint has been breached.

Evaluation	PV
Compromised Asset Date	**0**
NPV of long run cash flows	$1,093,275
NPV of Asset at Compromise Date	$0
NPV of long run cash flows + asset at compromise date	**$1,093,275**

In the 'Dual Fuel' example here additional depreciation in the next GAAR of $76,240,970, allows the business to remain a going concern and removes entirely the risk that the network will breach its regulatory price cap and thus the risk of any RAB being financially compromised by hitting aa regulatory price cap which will not recover costs.

The same process can be carried out with any of the scenarios numbered 1 through to 4. Experimenting with various amounts of 'tilt' or additional accelerated depreciation under each scenario will demonstrate the effect on price stabilisation and business default in each of the scenarios.

The input structure for each of the scenarios follows. These inputs can be modified and the analysis above re-run to gauge the effect of restructuring scenarios.

5.3. Model Inputs

There is a large array of other inputs not mentioned in the process above for simplicity of exposition. For example, electricity retail tariffs, gas network opening RAB and weighted average remaining life, capex/opex schedules, appliance efficiency and real growth in upfront appliance costs, customer discount rates, long run historical connection and disconnection rates. However, there is scope within the modelling framework to change all these elements as required; most can be changed within a single worksheet in the Consumer Choice model.

For ease of understanding what drives differences between scenarios inputs have been split into scenario driven inputs, scenario independent inputs and inputs which come from the PTRM or RFM. We discuss inputs under these headings below, showing where the data come from and how the data are entered into the model.

5.3.1. Scenario Driven

The following inputs change depending on which scenario is chosen:

- Gas prices
- Electricity prices
- S-curve parameters
- Current Victorian government incentives and subsidies for electrification
- Income-based net present value discount rates
- Appliance efficiency assumptions
- Appliance maintenance cost

- Shutdown of parts of the network
- New connection moratoria
- Gas price elasticity
- Opex and capex
- Appliance cost changes.

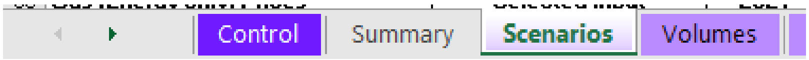
Gas Prices

Data Source

Wholesale gas prices under each scenario are based on prices underlying the AEMO 2022 Gas Statement of Opportunities.[53]

Data Entry

The gas prices for each of the scenarios are found in the 'Scenarios' tab of the Consumer Choice Model shown in bold below:



The green and blue cells shown for the first few years below as an example are where prices should be inputted. The 'Selected Input' column (shown as 4) can also be used as a manual override to test whether changing the gas prices to those of a different scenario will change the outcomes of a given scenario. For example, applying gas prices from Scenario 4 when, when Scenario 2 is selected to see its effect on the outcomes of Scenario 2.

Gas (Energy only) Prices	Selected Input	2021	2022	2023	2024
	4	10.162	11.630	11.963	12.053
1		9.943	11.213	11.390	11.380
2		10.215	11.684	12.015	12.118
3		10.294	11.976	13.097	13.545
4		10.196	11.646	11.963	12.053

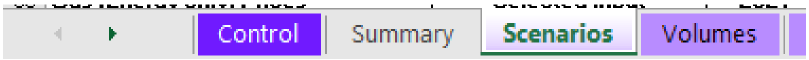
Electricity Prices

Data Source

Electricity prices were sourced from ACIL Allen forecasts tailored to each scenario out to 2050 and held constant thereafter. These are wholesale prices from their PowerMark model, which ACIL Allen run every quarter, and which summarise the then most recent forecast of the lowest-cost way to generate electricity in the NEM out to 2050. This is described in the ACIL Allen report at Appendix 6.3 (pp13-14)

Data Entry

The electricity prices in $ per KWh for each of the scenarios are found in the 'Scenarios' tab of the Consumer Choice Model shown in bold below:



The format is the same as for gas prices in that the green cells with blue text show where the data are inputted, and there is a "shortcut" option of selecting the prices from a different scenario to see the impact of different prices on a given scenario.

[53] *Lewis Grey Advisory, 2021, Lewis Gray Advisory 2021 Gas Price Projections for the 2021 GSOO, (available here)*

Electricity Prices	Selected Input	2021	2022	2023	2024
Residential - Variable Component	4	0.240	0.266	0.255	0.242
Commericial - Variable Component	4	0.149	0.157	0.148	0.139
			1.000	0.958	0.909
Electric Dreams	OLD	24.198	Updated	24.000	0.198
Residential (cents/kWh real 2021)					
Fixed component	1	3.091	3.461	3.421	3.320
Variable Component	1	24.198	27.090	26.777	25.989
Commercial (cents/kWh real 2021)					
Fixed component	1	1.906	2.024	1.989	1.916
Variable Component	1	14.915	15.842	15.570	14.997
Dual Fuel					
Residential (cents/kWh real 2021)					
Fixed component	2	3.091	3.405	3.308	3.150
Variable Component	2	24.198	26.652	25.891	24.658
Commercial (cents/kWh real 2021)					
Fixed component	2	1.906	1.985	1.910	1.797
Variable Component	2	14.915	15.537	14.953	14.069
Muddling Through					
Residential (cents/kWh real 2021)					
Fixed component	3	3.091	3.452	3.400	3.284
Variable Component	3	24.198	27.019	26.612	25.703
Commercial (cents/kWh real 2021)					
Fixed component	3	1.906	2.019	1.976	1.893
Variable Component	3	14.915	15.801	15.471	14.818
Hydrogen Hero					
Residential (cents/kWh real 2021)					
Fixed component	4	3.091	3.392	3.284	3.118
Variable Component	4	24.198	26.553	25.705	24.406
Commercial (cents/kWh real 2021)					
Fixed component	4	1.906	1.975	1.892	1.773
Variable Component	4	14.915	15.463	14.813	13.879
Baseline			1.000	1.000	1.000
Residential (cents/kWh real 2021)					
Fixed component	5				
Variable Component	5	24.198	26.828	26.828	26.828
Commercial (cents/kWh real 2021)					
Fixed component	5				
Variable Component	5	14.915	15.661	15.661	15.661

The cells highlighted in yellow are network specific adjustments reflecting actual tariffs observed on that network. These adjustments modify the whole time series of variable charges under all scenarios so there is no abrupt price change between actuals and forecast.

Note the fixed component or 'daily supply charge' is irrelevant to the outcomes of the model under current settings. This is under the assumption that consumers will always remain connected to electricity, regardless of retail gas and gas appliances prices and so there is no scope for saving on the electricity fixed charge. Our networks compete with the variable electricity charge, and not the full charge.

S-Curve Parameters

Data Source

Our internal analysis. The s-curve is virtually a cumulative distribution function where the y-axis is the annual number of existing customers that disconnect and the x-axis is the net present value of electrification versus renewing existing gas appliances. In the case of new connections and reconnections, the y-axis is the annual number of new/returning customers that connect and the x-axis is the net present value of electrification versus installing gas appliances.

To create an empirical cumulative distribution function (based on observed data) one needs to document a wide variation of negative NPVs (favouring gas) and positive NPVs (favouring electricity) along the corresponding disconnection/connection outcome. These data do not exist.

Historically NPVs are overwhelmingly negative (favouring gas) providing insufficient variation along the x-axis. Even if the variation did exist, the disconnection (or connection) outcomes must link to the NPV and not some other event such as a renovation or rebuild. Due to the absence of data, we directly shape our s-curves based on heuristics instead of fitting them to observed data. We shape the s-curve as follows.

The s-curve is an equation (logistic distribution function), that turns NPVs into cumulative probabilities. Cumulative probabilities are the sum of existing connections that will disconnect in a given year at a given NPV as a proportion of existing connections that were due to make a decision on gas appliance renewal in that year.

In the case of new connections cumulative probabilities are the sum of prospective new connections that connect in a given year at a given NPV as a proportion of all prospective new connections in that year.

Mathematics necessitates NPV conversion into numerical values that will not generate errors in the s-curve equation, returning values between zero and one. Conversion is through an equation we refer to as the relative utility function in the context of the future of gas model. This equation is a constant plus a coefficient on a given NPV.

By choosing the constant and coefficient, we can manipulate the output of the s-curve function so that when we plot the s-curve cumulative probability output against a range of input NPVs we see a chosen shape of s-curve.

S-curve parameters are tuned to each scenario to give outcomes consistent with the expert panel narrative of that scenario also taking unofficial AER guidance into account on the shape to avoid absurd outcomes. The key objective when calibrating each S-curve is to produce asset-recovery risk outcomes consistent with the Expert Panel narrative as these narratives are providing the key information we use to understand how consumer tastes vary from scenario to scenario.

In the Expert Panel narrative, the Electric Dreams scenario postulates that ‘Gas distribution networks become increasingly stranded as consumers electrify through the late 2030s’ and characterises residential customers as ‘climate conscious’. The Duel Fuel scenario narrative highlights that the networks are ‘largely stranded by 2050’. The Muddling Through scenario narrative refers to ‘high uncertainty of stranded asset risk’ and Hydrogen Hero the ‘continued utilisation of assets’.

Dual Fuel appears to offer the most explicit view of timing with reference to 2050 as a particular year, so the starting point was to calibrate the Dual Fuel S-curve with the asset-recovery risk occurring in 2050.

We interpreted Electric Dreams as having higher asset-recovery risk and the statement on climate conscious consumers as indicating higher predisposal to electrify. Thus, we calibrated its S-curve to be the most sensitive of the scenarios where the risk of recovering the asset was highest a few years before Electric Dreams.

Hydrogen Hero implies the strongest preference for gas (natural gas or hydrogen) across all scenarios with the continued utilisation of assets. To produce outcomes with continued utilisation of assets in the modelling the S-curve was de-sensitised to be the least sensitive across the scenarios.

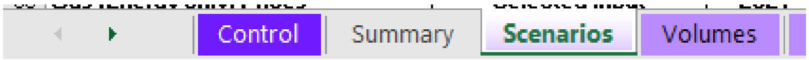
Muddling Through was less clear on asset recovery, but there was no information to suggest the S-curve would be as sensitive as Electric Dreams or as insensitive as Hydrogen Hero. Accordingly, we used the same S-curve as Dual Fuel.

The aim of the modelling is to show how asset recovery policies may help in producing better consumer outcomes under different states of the world as dictated by the scenarios. Therefore, we check and recalibrate S-curves to produce the same outcomes when any model inputs are changed.

Model users should take care not to misinterpret the modelling as an exercise in producing scenarios where no asset-recovery risk exists. There are limitless combinations of both sensible and nonsense numerical inputs that can produce these outcomes. These will not be helpful in demonstrating consumer benefits of various asset recovery policies under adverse states of the world. Rather, model users should be guided, as we were, by the Expert Panel scenarios (or indeed their own coherent scenario narratives if these exist) and will need to check to make sure the S-curves do not need to be altered to reflect the scenario narrative when inputs are changed.

Data Entry

The S-Curve parameters for each of the scenarios are found in the 'Scenarios' tab of the Consumer Choice Model shown in bold below:



The green and blue cells shown are where S-Curve parameters should be inputted.

Connection/Disconnection Sensitity	Residential		Commercial	
1	1.40	-0.01150	1.40	-0.00205
2	2.20	-0.00500	2.20	-0.00089
3	2.20	-0.00500	2.20	-0.00089
4	2.00	-0.00280	2.20	-0.00052
Selected Input	2.00	-0.00280	2.20	-0.00052

Current incentives and subsidies for electrification

Policy (see Section 2.1) is subject to constant change, and our modelling cannot reflect all possible policy prescriptions. Importantly, it does not yet reflect policy outcomes from the Gas Substitution Roadmap, which is yet to be released. However, there are existing Victorian government policies which cause changes in relative appliance prices. We discuss how we have included these in the model below. We note that similar approaches might be used to incorporate new policy initiatives within the model framework.

Data Source

The Electric Dreams scenario narrative outlines subsidies for electrical appliances as a driver of outcomes. The scenario goes beyond policies already in place today, setting the scene for an electrified future. We have implemented subsidies as a 5 per cent drop in appliance costs cumulatively over the coming regulatory period in light of Victorian Ministerial announcements exemplified by these quotes attributable to Minister for Energy, Environment, Climate Change and Solar Homes Lily D'Ambrosio:[54]

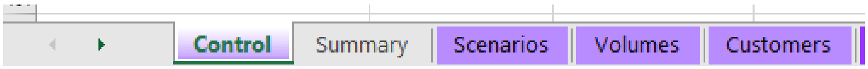
> *"With winter on its way, these rebates will help community housing tenants to be more comfortable, while also saving money on their bills."*
>
> *"This is a part of our plan to halve our emissions by 2030. Our $1.6 billion energy efficiency package is the equivalent of taking 6.8 million cars off the road in the next decade."*

We undertook sense checks based on the upper limit of $1.6 billion based on the above statement. The maximum number of households seeking appliance subsidy in the model is 1/15th of connections or approximately 46,667 households per year. The average appliance cost is then multiplied by the accumulating 5 per cent subsidy each year to get a subsidy dollar amount per connection. The amount is then multiplied by 46,667 in each of the 5 years during the regulatory period. The totals came out at figures well below $1.6 billion.

Due to political uncertainty, the subsidy is not included in the model beyond the first 5 years.

Data Entry

The 5 per cent subsidy for Electric Dreams is entered in the 'Control' tab of the Consumer Choice model shown below:



The specific cell pictured below in green.

Appliance costs			-5.00%
Cooking	**real % change (p.a.)**	**2022**	**2023**
Electric cooktop (induction)	-0.50%	0.00%	-5.00%
Gas stove	0.00%		
Hot water			
Heat pump hot water	-0.50%	0.00%	-5.00%

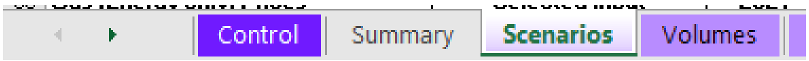
Income based NPV discount rates

Data Source

Absolute levels are based on current financial markets conditions. Relativities between discount rates are based on our internal review of relevant academic literature.[55] The assumption that networks with higher income demographics will electrify sooner because the discount rates of these consumers are lower, meaning that any cost savings in the future are more relevant to their decision to switch.

Data Entry

The discount rates for each of the scenarios are found in the 'Scenarios' tab of the Consumer Choice Model shown in bold below:



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[54] *See https://www.premier.vic.gov.au/helping-vulnerable-victorians-stay-warm-and-cool-less*

[55] *See Richard G. Newell, RG & Siikamaki, JV, 2015, Individual Time Preferences and Energy Efficiency, NBER Working Paper 20969, (available [here](#)).*

The green and blue cells shown are where the discount rates should be inputted if different discount rates are required.

Discount Factor	1	2	3	4	5	Selected Input
High income	7%	7%	8%	7%	5%	5%
Medium income	10%	10%	11%	10%	10%	10%
Low income	17%	17%	18%	18%	15%	15%
Commercial	5%	5%	6%	5%	3%	3%

These discount rates apply to local government areas that are classified as either high, middle or low income. This classification process is outlined in Section 5.3.2.

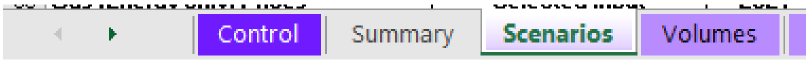
Appliance Efficiency

Data Source

Assumptions are from work that underpinned the AEMO scenarios,[56] and we assume the maximum value for whichever is the favoured technology, and zero for the less favoured, with mid-range for both if no favouring. These represent the rate per annum that appliance efficiency improves (positive means lower energy consumption in the NPV calculation described in ACIL Consumer Choice Model manual).

Data Entry

The appliance efficiency rates for each of the scenarios are found in the 'Scenarios' tab of the Consumer Choice Model shown in bold below:



The green and blue cells shown are where the appliance efficiency rates should be input.

Appliance efficiency	1	2	3	4	5	Selected Input
Cooking						
Electric cooktop (induction)	0.64%	0.60%	0.57%	0.00%	0.00%	0.64%
Gas stove	0.00%	0.00%	0.57%	0.64%	0.00%	0.00%
Hot water						
Heat pump hot water	0.64%	0.64%	0.00%	0.00%	0.00%	0.64%
Gas instant hot water	0.00%	0.00%	0.00%	0.82%	0.00%	0.00%
Room heating						
RCAC split system	0.00%	0.00%	0.00%	0.20%	0.00%	0.00%
Gas wall furnace	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ducted heating						
Ducted RCAC	0.29%	0.29%	0.20%	0.00%	0.00%	0.29%
Ducted gas heating	0.00%	0.00%	0.20%	0.20%	0.00%	0.00%

Maintenance Cost Growth

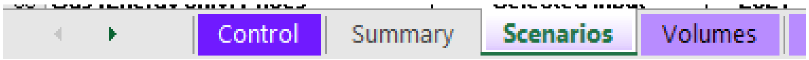
Data Source

It is assumed these change linearly with efficiency; that is, if efficiency increases by one percent, maintenance costs fall by one percent. Thus, maintenance cost changes are the same in absolute value terms (though opposite in sign) to efficiency changes. A negative percentage means a decline in maintenance costs.

[56] *See Butler, D, Amandine DR, Graham, P, Kelly, R, Reedman, L, Stewart, I and Yankos, T, 2020, Decarbonisation Futures: Solutions, actions and benchmarks for a net zero emissions Australia - Technical Report, (available here)*

Data Entry

The maintenance costs for each of the scenarios are found in the 'Scenarios' tab of the Consumer Choice Model shown in bold below:



The green and blue cells shown are where the maintenance cost rates of change should be inputted if a different set of inputs are required.

Maintenance costs	1	2	3	4	5	Selected Input
Cooking						
Electric cooktop (induction)	-0.64%	-0.60%	-0.57%	0.00%	0.00%	-0.64%
Gas stove	0.00%	0.00%	-0.57%	-0.64%	0.00%	0.00%
Hot water						
Heat pump hot water	-0.64%	-0.64%	0.00%	0.00%	0.00%	-0.64%
Gas instant hot water	0.00%	0.00%	0.00%	-0.82%	0.00%	0.00%
Room heating						
RCAC split system	0.00%	0.00%	0.00%	-0.20%	0.00%	0.00%
Gas wall furnace	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ducted heating						
Ducted RCAC	-0.29%	-0.29%	-0.20%	0.00%	0.00%	-0.29%
Ducted gas heating	0.00%	0.00%	-0.20%	-0.20%	0.00%	0.00%

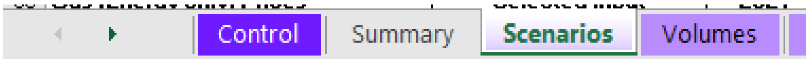
Shutting down parts of the network

Data Source

The model allows for part of the network to be shut down. Values of 1 represent that part of the network remaining open while values less than 1 represent the phasing out of connections in that area and 0 a total shut down of a particular part of the network. At present, only the Dual Fuel scenario calls for part of the network to be shut down at a point in time.

Data Entry

The settings to phase out shut down network segments under each of the scenarios are found in the 'Scenarios' tab of the Consumer Choice Model shown in bold below:



The green and blue cells indicate input settings for residential. Commercial is found directly below these cells in the same place in the Consumer Choice Model. Years 2021 to 2039 are hardcoded as '1' as none of the scenarios dictate change to network segments in those years (only 2021 is shown). When Scenario 2 'Dual Fuel' is selected local government areas with limited access to industrial hydrogen production are phased out from 2040 to 2049.

Residential Network ON/OFF (0 is OFF/Disconnect)		0.9	0.8	0.7	0.6	0.5	0.4	0.3	0.2	0.1	0
LGA	2021	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
Bass Coast (S)	1	1	1	1	1	1	1	1	1	1	1
Bayside (C)	1	0.9	0.8	0.7	0.6	0.5	0.4	0.3	0.2	0.1	0
Boroondara (C)	1	0.9	0.8	0.7	0.6	0.5	0.4	0.3	0.2	0.1	0
Cardinia (S)	1	0.9	0.8	0.7	0.6	0.5	0.4	0.3	0.2	0.1	0
Casey (C)	1	1	1	1	1	1	1	1	1	1	1
Frankston (C)	1	1	1	1	1	1	1	1	1	1	1
Glen Eira (C)	1	0.9	0.8	0.7	0.6	0.5	0.4	0.3	0.2	0.1	0
Greater Dandenong (C)	1	1	1	1	1	1	1	1	1	1	1
Kingston ©	1	1	1	1	1	1	1	1	1	1	1
Knox (C)	1	1	1	1	1	1	1	1	1	1	1
Manningham (C)	1	1	1	1	1	1	1	1	1	1	1
Maroondah (C)	1	1	1	1	1	1	1	1	1	1	1
Melbourne (C)	1	1	1	1	1	1	1	1	1	1	1
Monash (C)	1	1	1	1	1	1	1	1	1	1	1
Nillumbik (S)	1	0.9	0.8	0.7	0.6	0.5	0.4	0.3	0.2	0.1	0
Port Phillip (C)	1	0.9	0.8	0.7	0.6	0.5	0.4	0.3	0.2	0.1	0
South Gippsland (S)	1	1	1	1	1	1	1	1	1	1	1
Stonnington (C)	1	1	1	1	1	1	1	1	1	1	1
Whitehorse (C)	1	1	1	1	1	1	1	1	1	1	1
Yarra Ranges (S)	1	1	1	1	1	1	1	1	1	1	1

The inputs lowest down on the 'Scenarios' tab below mark which areas are considered to likely have access to industrial hydrogen. Those marked with a '0' for connect are phased off at 10 per cent fewer connections a year (green and blue cells at top of image above) than would have been the case otherwise until connections are zero in 2049.

		Disconnect	Connect
Bass Coast (S)	Residential (one or two large industrial)	0	1
Bayside (C)	Residential	1	0
Boroondara (C)	Residential	1	0
Cardinia (S)	Residential	1	0
Casey (C)	Residential Growth. Industrial Area	0	1
Frankston (C)	Residential & Industrial Areas	0	1
Glen Eira (C)	Residential	1	0
Greater Dandenong (C)	Industrial	0	1
Kingston (C)	Residential (near water) & Industrial Areas more inland.	0	1
Knox (C)	Residential & Industrial Areas	0	1
Manningham (C)	Residentia (mainly) but some Industrial Areas	0	1
Maroondah (C)	Residential & Industrial Areas (outer east)	0	1
Melbourne (C)	Industry	0	1
Monash (C)	Industrial with mixed residential	0	1
Nillumbik (S)	Residential	1	0
Port Phillip (C)	Residential – very dense development.	1	0
South Gippsland (S)	Residential (one or two large industrial)	0	1
Stonnington (C)	Inner residential – does include some smaller industry	0	1
Whitehorse (C)	Residential & Industrial Areas	0	1
Yarra Ranges (S)	Regional Area – Residential with some Industry	0	1

Since the settings involve completely phasing out/shutting down LGAs, the same settings (although inverted where 1 means no new connections and zero status quo) are also imposed upon new connections outlined next.

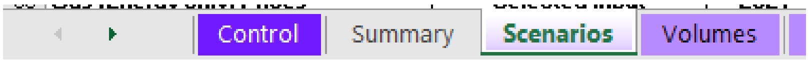
New connection moratoria

Data Source

The model allows for the possibility of a new connection moratorium in any one of the local government areas in the model. Values of zero represent no moratorium, while values between zero and one represent the phasing out of new connections through time (if this is required) and 1 represents no new connections in that local government area. Moratoria are only encountered in the Electric Dreams scenario from 2031, where they occur with no transition.

Data Entry

The settings to phase out shut down network segments under each of the scenarios are found in the 'Scenarios' tab of the Consumer Choice Model shown in bold below:



The green and blue cells indicate input settings for residential. Commercial is found directly below these cells in the same place in the Consumer Choice Model. Years 2021 to 2030 are hardcoded as '0' as none of the scenarios dictate change to network segments in those years (only 2021 is shown).

When Scenario 1 'Electric Dreams' is selected values for Scenario one shown in green and blue below change to 1 which flow through to all local government areas as per the scenario narrative. When Scenario 2 'Dual Fuel' is selected local government areas with limited access to industrial hydrogen production are phased out from 2040 to 2049. This is shown by the phasing starting in 2040 in blue and green cells of 0.1 working up to 1 by 2049 (only up to 2044 is shown).

Scenario 1		1	1	1	1	1	1	1	1	1	1	1	1	1	1
Scenario 2															
Scenario 3															
Scenario 4															
Baseline 5		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Network No new connections										0.1	0.2	0.3	0.4	0.5	
LGA	2021	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Bass Coast (S)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Bayside (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Boroondara (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Cardinia (S)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Casey (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Frankston (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Glen Eira (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Greater Dandenong (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Kingston ©	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Knox (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Manningham (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Maroondah (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Melbourne (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Monash (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Nillumbik (S)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Port Phillip (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
South Gippsland (S)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Stonnington (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Whitehorse (C)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Yarra Ranges (S)	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Gas price elasticity

Data Source

Only own price elasticities for delivered gas are scenario dependent (electricity cross price elasticities are not) and are based on a range from Conway and Prentice (2020) then adjusted upwards from the difference between electricity and gas in Labandeira et al (2017).[57] Scenarios with stronger degrees of electrification have higher elasticities, using the intuition is that

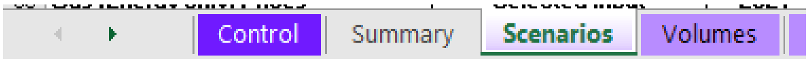
[57] *See Conway, L and Prentice D, 2020, How Much do Households Respond to Electricity Prices? Evidence from Australia and Abroad, Economic Papers, 39(3), pp2901-311, (available here) and Labandeira, X, Labeagac, JM and López-Otero, X, 2017, A meta-analysis on the price elasticity of energy demand, Energy Policy, 102, pp549-68, (available here)*

consumers are more elastic when delivered gas has a shorter term future, and lowest elasticity if gas has a long term future.

Note that own price elasticities (and the much lower cross price elasticities with electricity) are used whilst an appliance is active. Both have a relatively small impact on demand, with the much greater effect coming from the appliance switching choice.

Data Entry

The settings for elasticity under each of the scenarios are found in the 'Scenarios' tab of the Consumer Choice Model shown in bold below:



The green and blue cells indicate input settings for own price (gas price) elasticity under each scenario.

Elasticities	1	2	3	4	5	Selected Input
Residential						
Weather	0.36	0.36	0.36	0.36	0.36	0.36
Gas price	-0.80	-0.70	-0.60	-0.40	-0.10	-0.80
Electricity price	0.01	0.01	0.01	0.01	0.08	0.01
Commercial						
Weather	0.16	0.16	0.16	0.16	0.16	0.16
Gas price	-0.90	-0.80	-0.70	-0.50	-0.35	-0.90
Electricity price	0.01	0.01	0.01	0.01	0.30	0.01

Opex and capex

In this section we provide an overview of the opex and capex inputs (both fixed and variable) for the different scenarios. Table 9 provides an overview of rationale, to meet the requirements of the AER as summarized in Figure 1. We then discuss the sources and inputs for opex and capex across the four scenarios

Table 9: Rationale for capex and opex by scenario

Scenario name	Scenario description
Electric Dreams	Strong market driven growth of renewables, investment in system flexibility, efficiency, and policy support for net zero by 2050 worsen network asset managers outlook for asset stranding risk from the outset. Losses of connections and volumes that become more evident through 2030 as consumers electrify prompting network asset managers to take more drastic cost cutting measures. Capex is avoided in favour of incurring reactive operating expenditure on short-term solutions that would typically be more expensive than longer-term capex solutions if they were to be repeatedly incurred under a business as usual scenario. This begins in a relatively aggressive fashion from 2028 generally keeping total expenditure lower than the other scenarios until around 2058. After 2058, the reactive operating expenditure program drives total expenditure to approach or exceed that under Mudding Through and Hydrogen Hero which are closer to business as usual type capital and operating expenditure programs which are more efficient over the long run. Safety driven programs such as mains replacement continue, however the network avoids a material proportion of the low-pressure program. The network also avoids augmentation as network demand declines further. Over time, transmission pipeline assets become less utilised

Scenario name	Scenario description
	and so the need for inline inspection becomes less important as pressure is reduced to minimise risk. Asset integrity work becomes more reactive as payback periods shorten. The only investment in network incurred is that which has payback periods within end of network life or are driven by mandatory compliance. Meter replacement would continue, but decline after reaching the peak in 2030. IT capex is completely avoided after 2035 as it becomes evident that the major 10 yearly replacement (smoothed across the data) may not be required. If the network could accurately foresee its demise, say by 2050, the business would taper down total expenditure. However, tapering total expenditure in the Future of Gas model, may artificially extend the life of the asset beyond the point where operation ceases due to having a competitive, but unviable cost structure. Under this tapering, the asset cannot continue operating beyond the foreseen date. Other than ICT capex, which is a 10 yearly program and so could feasible cease, we do not taper down total expenditure in the Future of Gas model for the above reason. Instead, we leave capital and operating expenditure structure in place and leave the model to determine when the network ceases to be competitive and thus ceases to be a going concern.
Dual Fuel	Unlike Electric Dreams mains replacement continues to 2033 under the expectation that hydrogen keeps the network viable in the same say as the Hydrogen Hero scenario. Post 2030, the same smaller mains replacement program as Hydrogen Hero, Muddling Through and Dual Fuel continues up to 2040. However, unlike Hydrogen Hero, hydrogen only becomes viable in locations close to industrial areas of hydrogen production. All other locations electrify. Prior to 2040 some additional metering costs ('other capex' outside meter replacement) relative to Hydrogen Hero are incurred due to the complexity of measuring blended versus pure hydrogen. Post 2040 the electrification of some locations described above becomes evident in demand. Mains replacement is avoided with the higher-pressure elements of the network remaining, while avoiding around half of the costs associated with the lower pressure parts of the network. SCADA system spending remains stable with some costs avoided on fringe points. IT capex is completely avoided after 2040-45 as it becomes evident that the major 10 yearly replacement (smoothed across the data) may not be required. After 2050 the same operational expenditure policy as Electric Dreams is adopted where capex is avoided in favour of incurring operating expenditure on short-term solutions that would typically be more expensive than longer-term capex solutions if they were to be repeatedly incurred under a business as usual scenario.
Muddling Through	This scenario sees no significant changes to net demand as low carbon fuels struggle to become viable and electrical alternatives are no more competitive than natural gas at least in the short to medium term. This scenario is more similar to business as usual than the other scenarios with respect to avoiding complete hydrogen conversion costs seen in Dual Fuel and Hydrogen Hero and continuing to incur capex that otherwise would have been avoided as outlined in Electric Dreams.
Hydrogen Hero	Under this scenario consumers exhibit a preference for gas powered energy. The scenario is characterised by low hydrogen prices as a result of an abundant supply of cheap renewable energy being available. Even though electrification may be marginally more cost-effective usage wise, consumer preferences for gas energy result in hydrogen prevailing.

Scenario name	Scenario description
	Higher network capacity is required to accommodate the lower energy density of hydrogen incurring approximately 15% higher augmentation costs (captured in the building block model's variable capex). New meters are also required to accommodate hydrogen costing around an additional $75 per connection over 10 years. Investment in meters and augmentation must start 5-10 years earlier than commissioning to ensure readiness. After the hydrogen ready meter replacement is largely complete, the costs stabilises at a slightly higher level than the replacement capex historically incurred for non-hydrogen ready meters. Relative to Dual Fuel, billing systems costs are avoided due to simpler metering/billing systems using pure hydrogen for example additional investment in gas chromatographs. Operational expenditure policy is similar to that in Muddling Through in that these scenarios are closer to business as usual and so do not require a switch to short-term maintenance solutions over capital expenditure on investments which cost more in the short-term, but are lower cost over the longer-term.

Opex Data Source

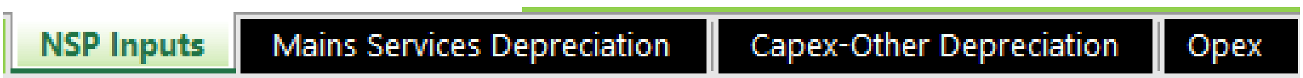
This input outlines forecast fixed and variable opex costs avoided or incurred under the different scenarios. The first five years of total opex reflect that submitted in the PTRM and is not scenario dependent and so is outlined further below in section 0 on scenario independent inputs. Subsequent years' total opex indexes the previous year by an opex growth factor and then add incurred or remove avoided costs under the scenario.

Variable opex components are based on the opex growth factor. The opex growth factor is a weighted average of 50 per cent net connections growth, which itself is an output of the model, and 50 per cent of network length growth which is an assumed (input) proportion of net connections growth based on past observations.

Fixed opex components incurred or avoided under each scenario come from our asset management team. These are input as cumulative additions or reductions, with the year on year difference in these inputs being added or subtracted to the opex time series (additions or subtractions will accumulate in the total opex time series by virtue of each year being dependent on the last which incorporates the adjustment.

Opex Data Entry

The inputs for variable and fixed opex for each of the scenarios are found in the 'NSP Inputs' tab of the Building Block model shown in bold below:



The green and blue cells shown are where the assumption around network length growth as a proportion of connections growth and cumulative opex scenario adjustments should be input (only first four years shown).

Opex									
PTRM Inputs	2023	2024	2025	2026	2027	2028	2029	2030	2031
Opex inc ARS, VCAP and DRC (PTRM Input)	77,855,078	77,333,533	76,725,241	76,960,175	77,336,318				
Network Length Growth proportion of Connections Growth	50%								
Opex Scenario Adjustments Input (cumulative)									
1						205,768	412,564	620,395	1,038,134
2						-	-	-	399,403
3							-	-	199,701
4						-	-	-	199,701
5						-	-	-	-

Capex Data Source

This input outlines forecast fixed and variable capex costs avoided or incurred under the different scenarios. The first five years of total capex reflect that submitted in the PTRM and is not scenario dependent, so is outlined further below in Section 5.3.3 on scenario independent inputs. Subsequent year's total capex is split into two main categories:

- long life assets, which are those that are assigned the maximum life in the PTRM; and
- short-life asset which are all other PTRM asset categories that are not assigned the maximum life.

Long life assets have three subcategories, connections/inlets/services, augmentation, mains growth and replacement.

Connections/inlets/services capex is gross new connections post June 2027 multiplied by an input assumed cost per connection and a factor that converts the capex into a figure net of contributions, including overheads and a half year WACC (as per PTRM format).

Augmentation uses an input base year assumption (June 2028) that is indexed by either a choice of 1% or net connection growth output by the model, depending on which mode you select. Additionally, augmentation capex is also assumed to step up by 15% in the input year hydrogen (closer to 100% blend) is commissioned to account for its lower energy content, the timing of which is scenario dependent.

Mains growth and replacement are fixed capex components incurred or avoided under each scenario, forecast by our asset management team. They are input directly as a view of capital expenditure for the mains growth and replacement program under the given scenario in the given year.

Short life assets, like mains growth and replacement, are fixed capex components incurred or avoided under each scenario, forecast by our asset management team. They are input directly as a view of capital expenditure for the mains growth and replacement program under the given scenario in the given year.

Capex Data Entry

The inputs for variable and fixed opex for each of the scenarios are found in the 'NSP Inputs' tab of the Building Block model shown in bold below:

NSP Inputs	Mains Services Depreciation	Capex-Other Depreciation	Opex

The green and blue cells shown are where the capex per connection, augmentation base year capex, augmentation growth, capitalised network overheads and capital contributions are input. The hydrogen commissioning year for a given scenario and fixed capex components (mains replacement/long life, all other shorter life assets) are inputted further below. Note, only the first 3 years are shown for the fixed capex inputs below.

Capex-Other Depreciation								
PTRM Inputs (Net. Inc OH and half-year WACC)	**2023**	**2024**	**2025**	**2026**	**2027**			
Long-life assets								
Connections/inlets/services	115,249,212	114,242,197	116,144,337	127,851,299	140,511,992	(PTRM Assets tab)		
Augmentation								
Mains growth and replacement								
Total Long Life Assets	115,249,212	114,242,197	116,144,337	127,851,299	140,511,992	(PTRM Assets tab)		
Short-life assets								
Meters, buildings, SCADA, IT, other	32,308,712	41,055,931	28,771,497	26,471,905	24,045,213	(PTRM Assets tab)		
Post 2027/28 Assumptions								
Capex per Connection (Gross ex-OH and ex-half year WACC)	2,400	(Assumption based on reg. team discussion)						
Augmentation Base Year Capex (Gross ex-OH and ex-half year WACC)	1,768,000	(Assumption based on reg. team discussion)						
Augmentation Growth	1%	(Assumption based on reg. team discussion)						
Augmentation (hydrogen)	15%	(Assumption based on reg. team discussion)						
Capitalised Network Overheads	8%	(Assumption based on reg. team discussion)						
Capital Contributions	7%	(Assumption based on reg. team discussion)						
Half Year WACC	1.23%							
Asset Management Plan Scenario	**Hydrogen Commissioning Year**							
1	0							
2	0							
3	0							
4	2037	(Assumption based on Hydrogen plans)						
						2028	**2029**	**2030**
Capex	**Sub-Category**							
1	Mains Replacement/Long Life Assets					1,000,000	1,000,000	1,000,000
	All Other Assets					14,568,377	14,650,978	14,734,818
2	Mains Replacement/Long Life Assets					85,802,021	85,802,021	4,213,804
	All Other Assets					10,862,471	25,245,062	18,030,410
3	Mains Replacement/Long Life Assets					85,802,021	85,802,021	20,000,000
	All Other Assets					10,862,471	12,245,062	11,930,392
4	Mains Replacement/Long Life Assets					85,802,021	85,802,021	4,213,804
	All Other Assets					10,862,471	12,245,062	11,930,392
5	Mains Replacement/Long Life Assets					26,058,227	26,058,227	26,058,227
	All Other Assets					26,019,542	26,019,542	26,019,542

Appliance cost changes

Data Source

All scenarios, except Electric Dreams, use an assumption of 0.5 per cent real fall in electrical appliance costs up until 2050 and converge to zero thereafter. Electric Dreams uses a real appliance cost fall of 5 per cent out to 2027 and then reverts to the same pattern as the other scenarios thereafter.

Gas appliances assume zero real fall in appliance costs. This is based on the assumption that innovation in gas appliances is more mature than electrical appliances. Using the value of zero for gas is more of a simplification to allow the cost relatives between gas and electrical appliances to be expressed solely through electrical appliance cost growth than an explicit view that gas appliance costs will stay constant in real terms.

Desroches et al. (2012) find that appliance costs tend to decline in real terms over several decades.[58] Dale et al. (2008) find that during 1974-1987 appliance costs fell by 2-3 per cent each year reducing to 0.5-1.5 per cent in later periods.[59] Given that an assumption of zero is being used for gas and that appliance costs cannot continue to decrease at the same rate infinitely we used the conservative assumption of 0.5 per cent for electrical appliance costs and zero thereafter.

For the Electric Dreams scenario appliance cost growth was selected in the near term to emulate subsidies driving electrification and stranding between 2030 and 2050 as per the scenario

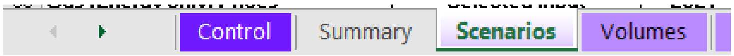
[58] *Desroches, LB, Garbesi, K, Chan, P, Greenblatt, J, Kantner, C, Lekov, A, Meyers, S, Rosenquist, G Van Buskirk, R, Yang, HC, 2013, Incorporating Experience Curves in Appliance Standards Analysis, Energy Policy, 52, pp402-16, (available here)*

[59] *Dale, L, Antinori, C, McNeil, M, McMahon, JE & Fujita KS, 2009, Retrospective Evaluation of Appliance Price Trends, Energy Policy, 37(2), pp597-605, (available here).*

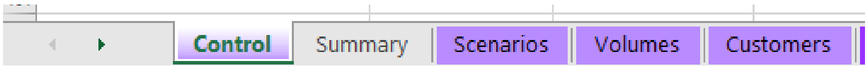
narrative, while ensuring total costs of the subsidy fall within stated budgets and budget time frames.

Data Entry

The settings for appliance cost growth for all scenarios except ‘Electric Dreams’ are found in the ‘Scenarios’ tab of the Consumer Choice Model shown in bold below:



The ‘Electric Dreams’ settings are found in the ‘Control’ tab of the Consumer Choice Model shown in bold below:



The assumption of 0.5 per cent cost decline outlined above is input as a negative into the green cell shown below in the ‘Scenarios’ tab:

Appliance costs	-0.50%	
Cooking	real % change (p.a.)	
Electric cooktop (induction)	-1%	-0.50%
Gas stove	0%	0.00%
Hot water		
Heat pump hot water	-1%	-0.50%
Gas instant hot water	0%	0.00%
Room heating		
RCAC split system	-1%	-0.50%
Gas wall furnace	0%	0.00%
Ducted heating		
Ducted RCAC	-1%	-0.50%
Ducted gas heating	0%	0.00%

The assumption of 5 per cent cost decline for the first few years of the ‘Electric Dreams’ scenario is input as a negative into the green cell shown below in the ‘Control’ tab:

Appliance costs			-5.00%		
Cooking	real % change (p.a.)	2022	2023	2024	2025
Electric cooktop (induction)	-0.50%	0.00%	-5.00%	-5.00%	-5.00%
Gas stove	0.00%				
Hot water					
Heat pump hot water	-0.50%	0.00%	-5.00%	-5.00%	-5.00%
Gas instant hot water	0.00%				
Room heating					
RCAC split system	-0.50%	0.00%	-5.00%	-5.00%	-5.00%
Gas wall furnace	0.00%				
Ducted heating					
Ducted RCAC	-0.50%	0.00%	-5.00%	-5.00%	-5.00%
Ducted gas heating	0.00%				
Gas disconnection charge	0.00%				
Electricity connection upgrade	0.00%				

5.3.2. Scenario Independent

The following inputs do not change as different scenarios are chosen:

- Local Government Area income classification

- Upfront appliance costs
- Asset lives
- Weather and electricity price elasticity
- Appliance replacement decision point
- Distribution share of retail fixed charge
- Appliance maintenance costs
- Non-appliance cost related connections and disconnections
- Reconnections as a share of gross connections
- Maximum price threshold
- Gas retail price stack components
- Starting price for the electricity variable charge

Local Government Area (LGA) Income Classification

Data Source

Our internal analysis and ABS census gross household income data by local government area. The ABS definition of low, medium and high household income is based on equivalised household income quintiles. Equivalised household income controls out the effect of household size to make all households comparable. The ABS classifies the highest equivalised income quintile as high, the middle quintile as middle income and lowest quintile as low. The second and fourth quintile are excluded from the definition.

The future of gas modelling is loosely based on this definition, but instead simplified by dividing the equivalised household income distribution in the ABS census into thirds instead of quintiles.

LGA income data in the future of gas model is averaged out, that is, high and low income households are averaged out toward a more 'medium' income. This makes it impossible to match LGA incomes to Australian household income distribution definitions, because high and low parts of the household income distribution can coexist in the same LGA, that is, low income households are not perfectly separated out into a particular LGA, nor are high income households.

For this reason all LGAs are considered medium income, but either fall on the higher medium or lower medium end of the scale based on the distribution split into thirds.

Median gross weekly household income on the census data was $1701. No LGAs in the data set has incomes matching the mid-point of the highest or even second highest gross income quintile, likely due to being only a small portion of each LGA. For this reason anything over the median ($1701) was considered medium high income.

When it came to classifying low and medium income LGA's previous classifications had a higher proportion of medium income households which applied lower discount rates to future savings in NPV switching analysis and so would switch more quickly. This resulted in a very sensitive model for AGN with asset stranding occurring very easily under scenarios in earlier models. The low income threshold was raised to a point ($1,500) that reasonably stabilised the earlier models and was more consistent with the classification undertaken by ACIL Allen in the more stable MGN model.

Upfront Appliance Costs

Data Source

We base appliance costs on data in a recent report commissioned by the Gas Appliance Manufacturers Association of Australia.[60] The report details low, typical and high estimates. We used typical estimates under the idea these would better represent costs over the long model horizon.

The report uses quotes based data for three housing archetypes, which give the best coverage of housing types in Victoria, and three options for electrification versus a base case using gas heating. The difference between the electrification options is in the home space heating/cooling solution. Option 1 uses split system air-conditioning for the whole house. Option 2 uses split system air-conditioning in only two rooms. Option 3 uses ducted air-conditioning for the whole home.

Our cooking appliance costs, used the average installed costs across all housing archetypes for gas base case and the average installed costs for electrical cooking which were the same for option 1, 2 and 3.

We derived installed water heating costs from the Frontier Report using the same process as for cooking appliances.

Room heating in the future of gas modelling refers to a small heating load of around 15GJ per year using an appliance like a portable gas heater or wall furnace. The smallest housing archetype in the Frontier Report was archetype 2, however even this archetype appears too large to fit the definition room heating in the future of gas model, because the archetype uses ducted gas and the costs space heating and cooling were 2 – 2.5 times higher than our initial estimates.

For this reason, we used our own modelling of appliance and installation costs for small load room heating based on data found on the internet for appliances producing 15-19GJ per annum at average Victorian heating hours, labour rates and estimates of time taken for installation and rectification.

Gas house heating is the average of the larger archetypes, 1 and 3, gas base case fully installed.

The electrification of house heating also uses the same larger archetypes, but is based only option 1. This is because option 3 uses ducted reverse cycle air-conditioning, which we consider an unlikely option for most households due to ducted gas households most likely having existing split-systems for cooling, which saves electrification costs, and the high cost of ducted reverse cycle air-conditioning.

We then adjust electrification of house heating costs as follows. According to the latest ABS data at least 82 per cent of larger Victorian households have air-conditioning installed. Of that 82 per cent, we assume larger households tend to have ducted gas and so are most likely to have existing split systems installed for cooling.

We make a conservative assumption that these households have half the capacity they need for heating which halves the costs. This is conservative in the sense that, if households tend to have more than half the capacity they need for heating, electrification costs will be lower.

Of the 18 per cent that have no air-conditioning we allocate a proportion of the split-system installation costs to cooling and the rest to heating based on typical heating and cooling hours published on energyrating.gov.au.

[60] *Frontier Economics, 2022, Cost of Switching from gas to Electric Appliances in the Home: Report for the Gas Appliance Manufacturers Association of Australia.*

Electrical connection upgrade costs outlined in the Frontier Report are significant, however the need for upgrades was not clear for all households. We used the average upgrade cost for archetype 1 and 3, option 1 to be consistent with the multi-split system installation cost used for electrification of household heating. The Frontier Report considered that the smaller archetype 2 would not need electric connection upgrade costs.

On this basis, we only apply connection upgrade costs to whole of house gas heating in the future of gas model, because all other household types have either room heating or no gas heating which would not require a connection upgrade.

Electrical contractor websites state that most households in Victoria have a 63 amp connection, which we confirmed with Energy Safety Victoria. We weighted the connection upgrade cost by 50 per cent, on the basis that at least 50 per cent of households need not upgrade and putting the full cost in would overstate the NPVs in the future of gas model in favour of gas.

Energy consumption data is a combination of internal analysis and ACIL pre-populated numbers based on a Grattan Institute report.[61]

ACIL pre-populated all cooking and gas hot water energy consumption. Electric heat pump hot water is based on internal analysis cross checking against internet sources taking lower coefficient of performance in colder weather into account.

Room and house gas heating is based on internal analysis and assumes 48 and 250 square meters of heating space respectively. Other assumptions include 750 annual hours of run time, 0.13 KW of energy per square meter, a 68 per cent household coverage ratio, coefficient of performance of 4 for room split-systems and 3.5 for larger reverse cycle systems and a star rating of 5.5 for gas appliances giving a thermal efficiency of 0.87.

Data Entry

The appliance cost settings are found in the 'Control' tab of the demand model shown in bold below:

The upfront appliance costs are entered in the following cells.

[61] *See Dundas, G and Wood, T, 2020, Flame Out: The future of natural gas, (available here)*

Appliance capital costs	
Cooking	**$ real 2021**
Electric cooktop (induction)	2900
Gas stove	2100
Hot water	
Heat pump hot water	3700
Gas instant hot water	1400
Room heating	
RCAC split system	2199
Gas wall furnace	1747
Ducted heating	
Ducted RCAC	4542
Ducted gas heating	2244
Gas disconnection charge	100
Electricity connection upgrade	1500

Energy consumption is entered in the following cells.

Appliance consumption	
Cooking	**Average consumption**
Electric cooktop (induction) kWh	133.30
Gas stove (GJ)	1.20
	-
Hot water	-
Heat pump hot water (kWh)	2,200.00
Gas instant hot water (GJ)	20.60
	-
Room heating	-
RCAC split system (kWh)	1,170.00
Gas wall furnace (GJ)	19.37
	-
Ducted heating	-
Ducted RCAC (kWh)	4,735.71
Ducted gas heating (GJ)	68.59

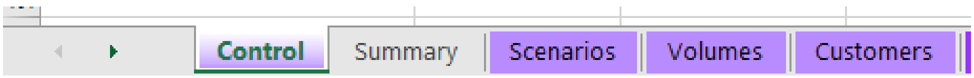
Asset Lives

Data Source

Discussions with our commercial team, based on their market knowledge. We note that 15 years is a conservative assumption, applicable most particularly to space heaters; water heaters and cooktops are replaced more frequently, though the latter is not always because the old appliance is no longer operational. Use of shorter asset lives would increase the sensitivity of the model to price changes, leading to more accelerated depreciation, which is why we have used more conservative lives.

Data Entry

The asset life settings are found in the 'Control' tab of the Consumer Choice Model shown in bold below:



The asset lives are entered in the following cells:

Asset lives	Years
Cooking	15
Hot water	12
Room heating	15
Ducted heating	15
Service charge	15

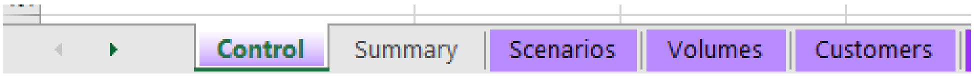
Weather and Electricity Price Elasticity

Data Source

Weather elasticity information was calculated by ACIL Allen (see Attachment 6.3 p10), whilst electricity cross price elasticities are consistent with the demand modelling undertaken by CoRE (See Attachment 13.1) for our demand forecasts.[62]

Data Entry

The weather and electricity elasticities are found in the ‘Control’ tab of the Consumer Choice Model shown in bold below:



The values are entered into the correspondingly named rows.

Elasticities	Residential	Commercial
Weather	0.356	0.155
Gas price	-0.8	-0.9
Elecricity price	0.008	0.008

Appliance Replacement Decision Point

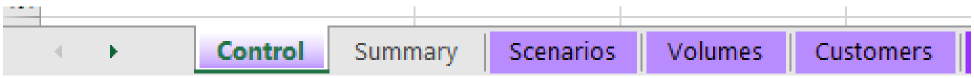
Data Source

The decision point determines what proportion of the network customer base is due to face a decision to replace gas appliances that have reached the end of their life. We use a simplifying assumption that appliance purchases across the state are made uniformly over the long run. That is, the whole state does not go out and buy new appliances simultaneously, but instead a roughly equal proportion of the state make purchases each year.

If these appliances last 15 years on average then approximately 1/15th of customers on the network are due for gas appliance replacement each year.

Data Entry

The decision point is found in the ‘Control’ tab of the Consumer Choice Model shown in bold below:



[62] *CoRE's cross price elasticity in 2027/28 is slightly higher than we have used here. Our figure comes from earlier iterations of the modelling. However, the differences are so small as to make no appreciable difference to results.*

The value is entered in the cell shown below.

Decision point	15

Distribution share of retail fixed charge

Data Source

This is used to recalculate the retail fixed charge across time when the gas distribution fixed charge output from the model changes.

ACIL Allen prepopulated this in the model (see Attachment 6.3 pp15-16).

Data Entry

The distribution share of retail fixed charge is found in the 'Control' tab of the Consumer Choice Model shown in bold below:

Control	Summary	Scenarios	Volumes	Customers

The values are entered into the respectively labelled cells for residential and commercial.

Distribution share of retail fixed charge	%
Residential	30%
Commercial	29%

Maintenance Costs

Data Source

Prepopulated by ACIL Allen (Attachment 6.3 p19).

Data Entry

Maintenance costs are found in the 'Control' tab of the Consumer Choice Model shown in bold below:

Control	Summary	Scenarios	Volumes	Customers

The values are entered into the cells shown below.

	Maintenance costs (p/a)
Cooking	$
Electric cooktop (induction)	0
Gas stove	2
Hot water	
Heat pump hot water	43
Gas instant hot water	32
Room heating	
RCAC split system	29
Gas wall furnace	26
Ducted heating	
Ducted RCAC	29
Ducted gas heating	29

Non-Appliance Cost Related Connections and Disconnects Growth

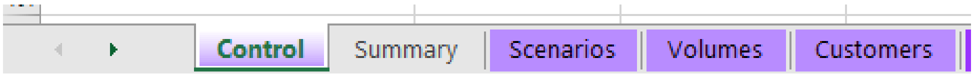
Data Source

These are the long run average rates of connection and disconnection based on the historical record of our networks. In lieu of any appliance cost related drivers of change, the model will revert to these 'natural' rates of growth and attrition.

The connections growth represents a *maximum* rate of new connections that can be reached if the future is business as usual. Modelling outcomes can detract from this rate. The disconnections rate is the *minimum* rate that can be reached if the future is business as usual. Modelling outcomes can increase this rate. Thus, the model serves to produce deviations from our historical rates of connections and disconnections which are caused by the changing economics of appliances.

Data Entry

The non-appliance cost related connections and disconnections growth rates are found in the 'Control' tab of the Consumer Choice Model shown in bold below:



The values for residential and commercial are entered into the cells shown below.

	Residential	Commercial
Non-Appliance Cost Related Growth	2.00%	2.00%
Non-Appliance Cost Related Disconnections	0.50%	0.50%

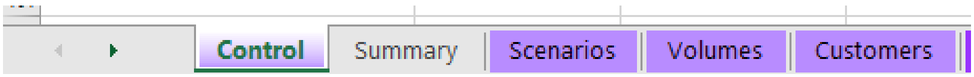
Reconnections as a share of gross connections

Data Source

This parameter is currently redundant as the connection growth (above) is a simpler approach which supplants estimates of growth based on changes in housing stock and reconnections. It is kept in the model should the need arise to revert modelling connections growth this way for example, for comparison. The figure is based on our internal analysis.

Data Entry

Reconnections as a share of gross connections is found in the 'Control' tab of the Consumer Choice Model shown in bold below:



The values are entered into the cells shown below.

Reconnections as share of gross connections	25%

Maximum Price Threshold

Data Source

Our internal analysis in discussion with AER secretariat. This refers to the maximum price on gas distribution costs. Without a maximum threshold the Building Block Model will allow prices that are much too high.

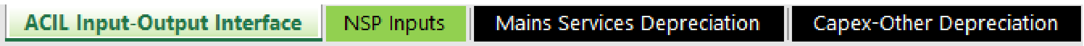
This happens because the maximum number of customers who can switch in any given year is $1/15^{th}$ of the market, with the remaining $14/15^{th}$ responding to higher prices only via the relatively low own and cross price elasticities, which is to say, not very much. From a modelling perspective, this causes the model to find solutions which bring forward too much depreciation, as the consequences on demand are smallest when the market is at its maximal size. In reality, regulation would prevent very high prices by disallowing such large depreciation changes, regardless of the conclusions of a model.[63] The real-world would not be subject to these kinds of modelling constraints, and thus we implement a maximum price ceiling, notionally imposed by the regulator to protect consumers, to assist in finding solutions with less acceleration of depreciation.

AER staff suggested prices 70 per cent higher than today (1.7x) could be a starting point for the threshold. We were cautioned that this is not a formal position of the AER and does not reflect AER views on pricing in any way. We have used it in this context. We note that it lowers acceleration of depreciation feasible over the next AA period compared to higher ceilings.

AER staff also suggested that perhaps relative gas and electricity prices should be used to set the threshold. We took this into consideration and it does make sense, but found under the death spiral situation gas is already financially unfavourable relative to electricity and becoming more unfavourable. Because of this it becomes simpler to only determine a threshold on gas distribution prices, rather than conduct an additional check if delivered gas is unfavourable by comparing it to electricity.

Data Entry

The setting for the maximum price threshold is found in the 'ACIL Input-Output Interface' tab of the Consumer Choice Model shown in bold below:



The value of 1.7 is input into the green cell shown below as a multiple of 2022 prices:

Evaluation	PV
Revenue Requirement	**$5,223,687,938**
Undiscounted shortfall/gain	
Still in Business Constaints	
Price multiple threshold (multiple of 2022 price)	1.70

Gas Retail Price Cost Stack Components

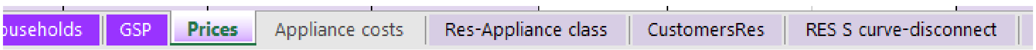
Data Source

ACIL Allen pre-populated. This includes a starting point for the fixed retail charge in $ per day, transmission charge, AEMO and environmental costs plus retail margin. See ACIL Allen report at Attachment 6.3 (p15-16).

Note that we do not build up a cost stack for electricity; our retail electricity charges have been provided by ACIL Allen calibrated to each of the scenarios.

Data Entry

Retail cost stack components are found in the 'Prices' tab of the Consumer Choice Model shown in bold below:



The fixed charges for residential and commercial are entered into the following cells (only the first two years are shown here).

[63] *In essence, the model takes extreme advantage of consumer sunk costs, in the framework of Biggar, D, 2009, Is Protecting Sunk Investment by Consumers a Key Rationale for Natural Monopoly Regulation?, Review of Network Economics 8(2), 128-52 (available here). Regulators, like Dr Biggar, prefer much more reasonable price outcomes.*

Starting point	Retail fixed charge $/day
Residential	Commercial
0.62	0.62
0.62	0.62

The retail cost stack components outlined above for residential are entered into the correspondingly named cells below (only the first two years are shown here).

Residential	Real $2021							
Year	Distribution fixed charge $/day	Distribution $/GJ	Retail fixed charge $/day	Wholesale $/GJ	Transmission $/GJ	AEMO costs $/GJ	Environmental $/GJ	Retail margin $/GJ
2021	0.190	4.38	0.62	10.16	$ 2.32	$ 0.23	$ 0.46	$ 1.02
2022	0.190	$ 4.38	0.62	$ 11.63	$ 2.32	$ 0.23	$ 0.46	$ 1.02

The retail cost stack components outlined above for commercial are entered into the correspondingly named cells below (only the first two years are shown here).

Commercial	Real $2021							
Year	Distribution fixed	Distribution $/GJ	Retail fixed charge	Wholesale $/GJ	Transmission $/GJ	AEMO costs $/GJ	Environmental $/GJ	Retail margin $/GJ
2021	0.3131	1.60	0.75	10.16	$ 2.32	$ 0.23	$ 0.46	$ 0.84
2022	0.3131	$ 1.60	0.75	$ 11.63	$ 2.32	$ 0.23	$ 0.46	$ 0.84

Starting price for the electricity variable charge

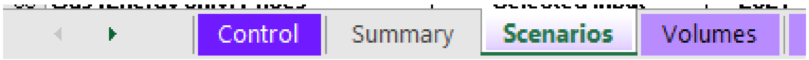
Data Source

Each network has its own starting price based on the Origin Energy GST inclusive discounted offer at January 2021. We use offers on the Citipower network for AGN and United Energy network for Multinet. These represent the relevant geographic areas for each gas network.

The discounted offers are less than the starting 2021 price in the ACIL Allen forecasts tailored to each scenario. A check of offers available in the Multinet network area on confirmed the availability of substantially discounted rates lower than the ACIL 2021 price.[64] To avoid a jump in the time series in its first year and associated shocks in the Future of Gas model we reduced the ACIL forecast series by the difference between the Origin Energy offer and the ACIL price in 2021.

Data Entry

The starting prices are found in the 'Scenarios' tab of the Consumer Choice Model shown in bold below:



The starting price value for the relevant network is entered in green cell right of the cell labelled 'Updated' shown below.

64					
65	Residential – Fixed compor	1		3.461	3.421
66	Residential – Variable Com	1	0.214	0.240	0.240
67	Commercial – Fixed compo	1		2.024	1.989
68	Commericial – Variable Cor	1	0.149	0.157	0.156
69				1.000	0.998
70	Electric Dreams	OLD	24.198	Updated	21.400

5.3.3. PTRM and RFM Inputs

The first five years of costs in the building block model are not scenario dependent and instead use values in the submitted in the Final Plan.[65] In this section we discuss inputs which come from

64 *See wattever.com.au*

65 *Note that the values ion the model are not identical to the Final Plan in every instance. This is because the Final Plan is being developed right up to the point of submission, and running the Future of gas model takes time. We have thus used inputs from the*

the PTRM and RFM, noting that these are, in most cases, the first five years of the relevant input only.[66] They include:

- Mains and services asset class inputs. Note that this is the asset class to which accelerated depreciation is applied as it is the longest-lived asset.
- Depreciation of other, shorter-lived assets.
- Demand and revenue for next AA.
- WACC
- Initial demand forecasts for next AA

The inputs transferred from the respective networks PTRMs are on a 'real' or constant dollar basis as at GAAR open.

Mains and Services Depreciation Inputs

Data Source

Standard life is the longest life listed in the 'PTRM input' tab of the Final Plan PTRM, specifically the 'Standard Life' column under Opening Capital Base and Opening Tax Asset Base for 2023/24.

Opening RAB is the sum of opening asset values on categories assigned the longest standard life found in the same place described for standard life above.

Weighted average life is the opening asset value weighted remaining life on each of the asset categories assigned the longest standard life.

Data Entry

The mains and services depreciation data inputs are entered in the 'NSP Inputs' tab of the Building Block model shown in bold below:

ACIL Input-Output Interface	**NSP Inputs**	Mains Services Depreciation	Capex-Other Depreciation	Opex	Demand and Revenue	Building Blo

Mains and Services Depreciation				
	Standard Life		Opening RAB @ 2023 from PTRM	WARL
	50		1,301,487,770	31.98

The data are entered into the respectively named cells shown above.

Opex (first 5 years)

Data Source

Final Plan PTRM 'PTRM Inputs' tab, Forecast Operating and Maintenance Expenditure Total

Data Entry

The first five years of opex are entered in the 'NSP Inputs' tab of the building block model shown in bold below:

ACIL Input-Output Interface	**NSP Inputs**	Mains Services Depreciation	Capex-Other Depreciation	Opex	Demand and Revenue	Building Blo

Opex					
PTRM Inputs	2023	2024	2025	2026	2027
Opex inc ARS, VCAP and DRC (PTRM Input)	77,855,078	77,333,533	76,725,241	76,960,175	77,336,318

PTRM and RFM from roughly one month out from the submission of the Final Plan, and we conduct sensitivity analysis associated with these values.

[66] *Some, such as WACC, are assumed to be constant through time.*

Capex (first 5 years)

Data Source

Final Plan PTRM 'Assets' tab, Real Net Capital Expenditure (capex). All the longest life assets with the same life are summed together. All other asset with shorter lives are summed together as a second line-item. This simplifies the model as the acceleration of depreciation is applied only to the longest lived asset class (which is also generally the largest), and the remaining assets which are not affected by the model are lumped together and given a weighted average remaining life for depreciation purposes..

Data Entry

The first five years of capex are entered in the 'NSP Inputs' tab of the Building Block model shown in bold below:

ACIL Input-Output Interface	NSP Inputs	Mains Services Depreciation	Capex-Other Depreciation	Opex	Demand and Revenue	Building Blo

Capex-Other Depreciation					
PTRM Inputs (Net. Inc OH and half-year WACC)	**2023**	**2024**	**2025**	**2026**	**2027**
Long-life assets					
Connections/inlets/services	115,249,212	114,242,197	116,144,337	127,851,299	140,511,992
Augmentation					
Mains growth and replacement					
Total Long Life Assets	115,249,212	114,242,197	116,144,337	127,851,299	140,511,992
Short-life assets					
Meters, buildings, SCADA, IT, other	32,308,712	41,055,931	28,771,497	26,471,905	24,045,213

Long lived assets can be summed together and entered into anyone of the three rows shown here or broken out. Either way makes no difference to the modelling. Shorter life assets are summed together and entered into the row labelled 'short-life assets'.

Depreciation on shorter life assets

Data Source

Final Plan PTRM 'Assets' tab Real Straight-line depreciation. Only depreciation on assets falling into the Short-life asset category mentioned above are summed together for all years up to the year where depreciation falls to zero where the asset are fully depreciated.

In addition, the opening balance and weighted average remaining life on the short-life asset category is needed. These are both calculated on data found in the 'PTRM input' tab of the Final Plan PTRM Opening Capital Base and Opening Tax Asset Base for 2023/24 and Roll Forward Model. Note that the weighted average remaining life calculations may need to be reinstated in the Roll Forward Model and linked to the PTRM.

The opening balance is the sum of the opening asset value on all asset categories that are included in the Short-life category. The weighted average life is the opening asset value weighted remaining life on each of the asset categories in the Short-asset life category. It is rounded to the nearest whole number, to avoid calculations for a fraction of year in the building block model.

Data Entry

The depreciation on shorter life assets is entered in the 'NSP Inputs' tab of the Building Block model shown in bold below:

ACIL Input-Output Interface	NSP Inputs	Mains Services Depreciation	Capex-Other Depreciation	Opex	Demand and Revenue	Building Blo

All Other Assets (For MGN Meters, buildings, SCADA, IT, other					
Weighted Average Life (whole numbers only)	6.00	(based on Weighted average in whole numbers only)			
Opening Balance	93,182,627	(PTRM Input)			
	2023	**2024**	**2025**	**2026**	**2027**
PTRM Depreciation on Other Capex up to AA5 (Assets)	24,249,524	18,329,494	20,326,041	21,876,509	24,283,742

The weighted average asset life and opening balance are input into the respectively named cells. The depreciation on short-life assets is entered into the row labelled 'PTRM Depreciation on Other

Capex'. Note that even though only years 2023 to 2027 are shown here all values from the PTRM must be entered up to the year all short-life assets in the PTRM are fully depreciated.

Demand and Revenue

Data Source

Final Plan PTRM 'Forecast Revenues' tab. The PTRM contains prices and quantities for the final year of the previous AA. The price structure across fixed and volumetric charges for residential, commercial and industrial are implicit in this data, as 'revenue share weighted' costs. This structure is used in the building block model to allocate costs and price in way that is consistent with the PTRM across time, although on an annual rather than five yearly basis.

Note that although data are shown in the 'Demand and Revenue' tab of the building block model for years subsequent to the last year of the AA, they are not utilized in the model and are presented only for the purpose of reconciliation to the PTRM.

Data Entry

The price and quantity data is entered in the 'NSP Inputs' tab of the Building Block Model shown in bold below:

ACIL Input-Output Interface	**NSP Inputs**	Mains Services Depreciation	Capex-Other Depreciation	Opex	Demand and Revenue	Building Blo

Pricing data is entered into the green cells (only a subset has been shown here) following the structure of prices in the PTRM 'Forecast Revenue' tab.

Demand and Revenue				
	P_0	X_02	X_03	X_04
X-Factor (real price change)	-0.23%	0%	0%	0%
Prices (P0)	Standing Charge ($ per	Peak Energy ($/(	Shoulder Energy ($	Off Peak Energy ($/
Year	2022-23	2022-23	2022-23	2022-23
Residential (Metro)	69.30	0.00	0.00	0.00
0 - 0.05 GJ	0.00	9.32	0.00	0.00
0.05 - 0.1 GJ	0.00	6.24	0.00	0.00
0.1 - .15 GJ	0.00	2.98	0.00	0.00
.15 - .25 GJ	0.00	1.51	0.00	0.00
> 0.25 GJ	0.00	1.13	0.00	0.00
0	0.00	0.00	0.00	0.00

Quantity data is entered into the green cells (only a subset has been shown here) following the structure of quantities in the PTRM 'Forecast Revenue' tab.

Quantities	Customer Numbers						Volumes - Peak Energy ($/GJ)	
Year	2022-23	2023/24	2024-25	2025-26	2026-27	2027-28	2022-23	2023/24
Residential (Metro)	700312	682393	677360	675156	672849	670751		0
0 - 0.05 GJ	0	0	0	0	0	0	9128056	8794531
0.05 - 0.1 GJ	0	0	0	0	0	0	5810524	5598216
0.1 - .15 GJ	0	0	0	0	0	0	4209913	4056089
.15 - .25 GJ	0	0	0	0	0	0	5981703	5763140
> 0.25 GJ	0	0	0	0	0	0	10501171	10117474

This data is summarized into a weighted average fixed and volumetric charge for residential and commercial and weighted average fixed charge only for industrial.

Since industrial makes up less than one per cent of revenue its associated costs and revenues are excluded from analysis after the first five years in the building block model for modelling simplicity (ie the revenue shares used after the end of the first five years sum to less than 100%).

WACC

Data Source

Final Plan PTRM, 'WACC' tab pre-tax real WACC.

Data Entry

The WACC is entered in the 'NSP Inputs' tab of the Building Block Model shown in bold below:

ACIL Input-Output Interface	**NSP Inputs**	Mains Services Depreciation	Capex-Other Depreciation	Opex	Demand and Revenue	Building Blo

Building Block	
Pre-tax real WACC	2.48%

The real pre-tax WACC is entered into so named cell shown above.

Initial Regulatory Demand Forecast Inputs

Data Source

The building block model produces annual (instead of five year) 'regulatory forecasts' of demand for pricing. The forecasts use an 'error correction' framework. This adds the difference between the previous two-year's demand on to the previous year's demand. The idea is that last year's demand is the naïve forecast of next year's demand. The regulator observes the error between this forecast and actual demand in the previous year and adds this onto the actual demand.[67]

The Building Block model uses demand realisations from the Consumer Choice model to make its forecast, but such forecasts do not exist for the first two years of the model horizon, and thus we need to get our forecast from somewhere else; that is the PTRM from the current AA and the first CoRE forecast in our demand model for the AA (see Attachment 13.1).

Data Entry

The demand data from the CoRE model is entered in the 'NSP Inputs' tab of the Building Block model shown in bold below:

ACIL Input-Output Interface	**NSP Inputs**	Mains Services Depreciation	Capex-Other Depreciation	Opex	Demand and Revenue	Building Blo

ACIL Input-Output Interface	2021-2022 Average	2022-23 Average
Residential Fixed	702,268	
Residential Volumetric	37,093,192	
Commercial Fixed	16,165	
Commercial Volumetric	5,763,700	
Industrial		
Gross New Connections		
Residential	14,695	13,236
Commercial	526	505

Residential and commercial connections are entered into the cells labelled 'fixed', volumes in the cells labelled 'volumetric' and gross new connections in the cells so labelled.

[67] This can be changed in the model, but doing so adds complexity and we believe this approach gives a good approximation to regulatory forecasting over the long run, where the regulator would seek to ameliorate the impacts of over and under forecasting.

A.1 Appendix A

How to link the Future of Gas models if they become unlinked

The models are linked in the following places:

Building Block Model

Worksheet: ACIL Input-Output Interface

Row 10 to 11: Link row 10 column E to Demand Model 'Summary' cell E4 and row 11 column E to Demand Model 'Summary' cell E7 and copy horizontally (no cell lock).

Row 15 to 16: Link row 15 column E to Demand Model 'Summary' cell E5 and row 16 column E to Demand Model 'Summary' cell E8 and copy horizontally (no cell lock).

Row 20 to 21: Link row 20 column E to Demand Model 'Summary' cell E12*1000 and row 21 column E to Demand Model 'Summary' cell E13*1000 and copy horizontally (no cell lock).

Row 45: Link column C so that the formula is divided by cell L71 in the Demand Model 'Forecasts' worksheet and multiplied by 1000 (that is year 2022 total residential volume).

Row 48: Link column C so that the formula is divided by cell L141 in the Demand Model 'Forecasts' worksheet and multiplied by 1000 (that is year 2022 total commercial volume).

Demand Block Model

Worksheet: Summary

Row 50 and 51: Link row 50 column D to Building Block Model 'ACIL Input-Output Interface' row 87 column D divided by 365 (MGN only, AGN not divided by 365 as daily format already) and copy horizontally (no cell lock). Link row 51 column D to Building Block Model 'ACIL Input-Output Interface' row 88 column D and copy horizontally (no cell lock).

Row 53 and 54: Link row 53 column D to Building Block Model 'ACIL Input-Output Interface' row 89 column D divided by 365 (MGN only, AGN not divided by 365 as daily format already) and copy horizontally (no cell lock). Link row 54 column D to Building Block Model 'ACIL Input-Output Interface' row 90 column D and copy horizontally (no cell lock).

Worksheet: Scenarios

Cell B1: Link to Building Block Model 'ACIL Input-Output Interface cell C31