Modelling energy costs and prices – A technical note supporting Ināia tonu nei

Contents

1 Introduction

Many of the decarbonisation actions modelled in the Commission's demonstration path to achieving the net-zero 2050 target involve fuel switching. For example, switching from petrol or diesel-powered vehicles to electric vehicles, or switching from using gas or coal-fired heating to electric or biomass heating.

The Commission's modelling has sought to project the likely effect on fuel-supply *costs* from such fuel switching, and the consequent effect on consumer fuel *prices*.

The distinction between cost and price is necessary because of factors such as:

- The marginal pricing approach in the wholesale electricity and gas markets – i.e. where prices over time are driven by the long-run cost of the marginal source of generation or gas production, rather than the average cost of all supply sources.
- The extent to which network or retail costs are driven by demand versus other cost drivers (e.g. number of customers, customer density). This means that some supply costs should not be recovered by demand-based $/kWh prices but by $/day fixed prices, or similar.
- The extent to which electricity and gas network costs may be sunk and therefore not a future economic cost, but may still be recovered from consumer prices.

Understanding how costs may change is important to understand the extent to which different fuel choice futures will cost Aotearoa as-a-whole. Being able to consider all costs from all fuels concurrently, and the inter-linkages between sectors, is particularly important to enable this whole-of-Aotearoa economic cost perspective.

Understanding how prices may change is important to understand possible distributional effects on consumers, and for evaluating the economics of particular fuel switching options and possible consumer behavioural responses to such prices.

This note describes the modelling undertaken for the various fuels.

2 Electricity cost and price modelling

2.1 Modelling of electricity sector costs

The costs of providing electricity services to Aotearoa are comprised of three main components:

1) Generation ('wholesale') – the costs of building, operating, and in some cases fuelling our power stations.
2) Networks ('lines') – comprising the national transmission and local distribution businesses.
3) Retail & metering – comprising the costs of providing metering, billing, call-centres, etc.

The Commission's modelling has sought to project how each of these costs are likely to change in the future for underlying scenarios of factors such as population growth, fuel switching, and fuel and carbon prices.

2.1.1 Generation cost modelling

The ENZ model projects the growth in demand for electricity based on factors such as population growth, fuel switching and the like.

For each year, it then determines the extent to which new generation may need to be developed to meet any demand growth which it then schedules to be built, choosing the cheapest from a cost-supply stack of renewable generation options: geothermal, onshore wind, utility solar, and hydro.

Each renewable type has a highly simplified cost-supply curve which specifies: the total quantity of generation that could be built (with options such as geothermal and hydro having a much more limited quantity of additional sites that can be developed), and the price of the cheapest to the most expensive within this curve. The values for these cost-supply curves have been broadly based on information published by the Ministry of Business, Innovation and Employment (MBIE)[1] supplemented with various other data and analysis.

For a given year, the model chooses the cheapest options as first to be built. These are then no-longer available to be developed. Any build requirements in subsequent years must choose the next-cheapest options.

There are three further factors which affect the relative effective cost of the renewables plant options.

- Firstly, each technology is assumed to have a general cost-reduction over time as technology improves. This rate of cost reduction is different for different technologies. For example, the rate of reduction for solar is materially greater than the rate of reduction for geothermal. This reflects the different pace of global developments for the two technologies.
- Secondly, the variable nature of some technologies (particularly wind and solar) means that as their share of generation increases, they will increasingly face a discount for the generation-weighted average price (GWAP) they earn relative to the market time-weighted average price (TWAP).[2] We refer to this GWAP/TWAP discount as a peaking factor. This increasing discount affects the relative benefit of choosing the different technologies to meet demand. For example, if the cheapest wind option has a levelised cost of $60/MWh but a peaking factor of 0.9, its effective cost is 60÷0.9 = $67/MWh. This would make it a less economic option than a non-variable technology such as geothermal, even if the levelised cost of the geothermal was $65/MWh.
- Lastly, geothermal generation faces a cost due to the carbon emissions associated with its operation. In scenarios with a high carbon price this will negatively affect the economics of geothermal compared with other renewable options.

In addition to building new renewables to meet demand growth, the model also allows for renewables to be built to displace existing fossil-fuelled generation, being the remaining two combined-cycle gas turbines (CCGTs), the open-cycle gas turbines (OCGTs), and the Huntly Rankine coal-fired units.

Such displacement occurs if the long-run marginal cost of the new renewable generation required is less than the cost of continuing to operate an existing fossil station – noting that the existing fossil station doesn't need to recover its capital costs (which are sunk), but will need to recover its fuel and carbon costs, and its fixed and variable non-fuel operating costs.

There are two factors which make this evaluation complex:

- Firstly, a significant part of the duty of the remaining fossil stations is to provide low-capacity factor duties. That is, they operate infrequently to meet times of relatively high demand (e.g. winter mornings and evenings), and/or times of low variable renewable generation (e.g. due to a

[1] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-publications-and-technical-papers/nz-generation-data-updates/

[2] To understand this dynamic, electricity prices are higher at times of relatively scarce generation, and lower at times of relative surplus generation. As variable generation technologies increase their share of generation, their variability will increasingly drive this surplus / scarcity dynamic. Thus, if a lot of wind generation has been developed, at times when it is windy prices will tend to be relatively lower than at times when the country is facing relatively calm weather. This is fundamentally the same dynamic New Zealand faces due to the variability in hydro generation. i.e. prices are much higher in a dry-year compared to a wet-year.

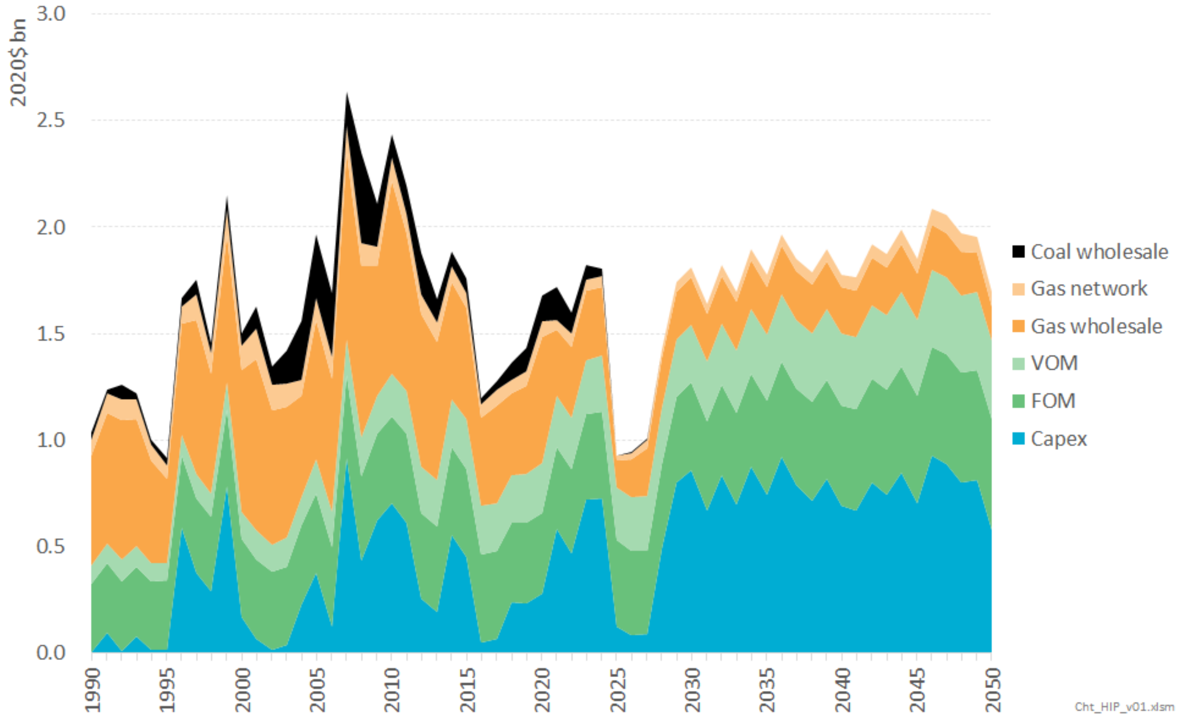
dry-year). This aspect is modelled using a simplified duration curve approach for the amount of generation required at different capacity factors, and factoring the capital and fixed operating costs of the different plant options to meet this duty. For example, the effective capital cost for building a wind farm whose output is only required 25% of the time is four-times greater than the effective capital cost of building a wind farm whose output is required 100% of the time. Fossil options are more economic for such low capacity-factor duties because these fixed costs are much less – particularly for existing plant.

- Secondly, the costs of providing low-capacity factor fuel is also much higher than providing baseload fuel. This is particularly the case for gas, but also (to a lesser extent) for coal. The model addresses this by having an effective price curve for the two fuels which increases as the capacity factor of required operation decreases.

For a given year, the above modelling determines which new renewable projects (if any) are required to be built. The effective price (i.e. taking account of variable renewable peaking factors) of the most-expensive plant built in a year is then deemed to set the time-weighted average market price for that future year. This wholesale price then feeds into the evaluations in other parts of the model of the economics of switching from one fuel type to another. The resultant change in demand then feeds into the model's evaluation of what renewables need to be built for the next year – and so on for all the years in the projection.

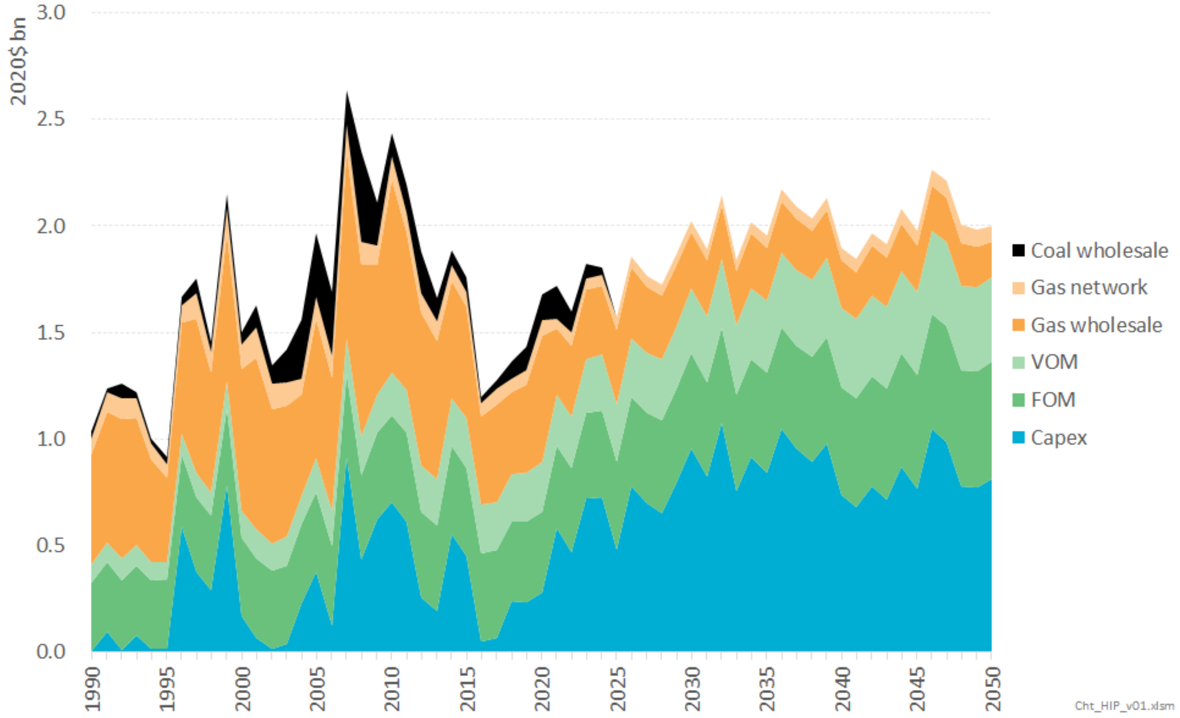
The following graph shows a projection of the different generation cost components under the Commission's demonstration path scenario, with a second graph showing the effect of this same scenario but with the Tiwai smelter continuing to operate post-2024.

Figure 1: Historical and projected generation costs under the Demonstration Path scenario[3]



[3] 'Capex' refers to the capital costs of building a generation plant in a year. In the historical series this includes the costs of building fossil plant, but the projection only has renewables being built in the future. 'FOM' refers to the fixed operating & maintenance costs that are incurred each year a plant is open. 'VOM' refers to the non-fuel variable operating & maintenance costs that are incurred whenever a plant is generating. 'Gas' and 'Coal' refer to the relevant fuel supply costs. FOM, VOM and fuel costs include the costs from existing plant (until such point as they are retired) as well as new plant the model projects as being built.

Figure 2: Historical and projected generation costs under the Tiwai-stays scenario



2.1.2 Electricity network cost modelling

The starting point for the modelling of transmission ('Tx') and distribution ('Dx') costs are published historical and near-term projections of the total allowable revenues for the electricity lines businesses. These revenues are determined based on a regulatory process which seeks to enable the lines businesses to earn just enough revenue to cover their costs plus a reasonable return on their cost of capital if they are run efficiently.

Projecting beyond these short-term 'actual' costs, the Commission modelling has sought to increase network costs based on the scenario projections of those factors which drive network costs, being:

- System peak demand – i.e. ensuring network capacity is large enough to meet those times of peak demand on the system.
- Consumers' 'anytime' peak demand – i.e. building close-to-consumer assets large enough to meet their individual peak demands. The time and level of peak demand for a group of customers beneath a zone-substation may be higher than the level of peak demand from that group of consumers at the time of system-wide peak.
- Generation – for the transmission network in particular, a significant amount of costs are associated with developing transmission assets to connect new renewable power stations.
- Number of customers – being a particularly large driver for distribution businesses to build assets to connect new sub-divisions and the like.

The extent to which of these factors is likely to drive network costs has been based on analysis of published Orion and Transpower data.[4] This analysis was based on:

- a decomposition of the different components of each network's allowable revenues (i.e. to recover the different types of capex and opex), and
- additional data published by the networks (Orion's pricing methodology, plus Transpower's integrated transmission plan) to determine the extent to which each cost recovery component is driven by the different factors set out above.

The results of this analysis indicate that for Orion[5] in the long-term 27% of their costs are driven by peak demand on their network, with a further 12% driven by consumers' anytime maximum demand. Of the remainder, it is assumed that the vast majority is driven by the number of customers (50% of total distribution costs), with a relatively small amount being fixed costs that will not vary materially with changes in the other factors (11% of total distribution costs).

For transmission, the analysis identified that almost 30% of transmission costs are driven by demand growth in the long-run. However, it was not possible to identify the extent to which this was developing/increasing transmission assets into load centres versus developing more distant transmission assets to enable renewable power stations built to meet demand growth. However, in discussions with Transpower, it is understood that a significant proportion of this is driven by the growth in new renewable generation. Therefore it is assumed that 20% of transmission costs are driven by generation growth, with a further 10% from demand growth (being 6% system peak demand and 4% consumers' anytime maximum demand) – i.e. giving 30% in total driven by demand growth (directly or indirectly via generation growth).

Unlike distribution, a relatively small amount of transmission costs are going to be driven by the growth in customer numbers per se, as opposed to the growth in the demand associated with such customer numbers. This is because the load-connecting transmission grid has now been built to achieve coverage for all load centres in Aotearoa. For example, a new subdivision in an existing town or city requires an electricity distribution business to increase its coverage, it generally won't require the transmission network to increase its coverage. It will however require Transpower to ensure that the capacity of the existing transmission network assets are sufficient to meet the increased demand from this subdivision. It has been assumed that 10% of total transmission costs will be driven by customer numbers in the long-term, compared with 50% of total distribution costs.

The remaining 60% of transmission costs are assumed not to grow with demand, but are related to continuing to operate, maintain and renew the existing transmission assets.

These factors are then used to model increases in network costs based on the model derived projections of the underlying driver. For example, population growth is projected to increase the number of customers by 30% by 2050. All other things being equal, this is projected to increase distribution costs by 15% (being 30% x 50%) and transmission costs by 3% (being 30% x 10%), reflecting the increased costs associated with needing to increase the *coverage* of the network.

Any kW and kWh *demand* growth associated with these increased customer numbers will further increase transmission and distribution costs by the associated factors.

[4] Orion data is taken from their pricing methodology, published here: https://www.oriongroup.co.nz/corporate/corporate-publications/pricing-guides-and-information/
Transpower data is taken from various parts of their Integrated Transmission Plan, published here: https://www.transpower.co.nz/keeping-you-connected/industry/rcp3/rcp3-updates-and-disclosures

[5] Orion is considered to be a reasonable reflection of other electricity distribution businesses.

The model projects kWh growth for all the various different sectors and sub-sectors based on modelling of:

- the drivers of the underlying demand for the activity (e.g. population growth increasing the demand for transport services or home heating),
- the extent to which fuel switching from fossil to electricity increases electricity's share of meeting the demand for that activity, and
- the extent to which energy efficiency measures (or mode-shifting to public transport in the case of vehicles) reduce the energy-intensity of the service required to meet that activity demand.

These kWh projections drive that proportion of network costs which are assumed to be driven by kWh directly[6], or indirectly in the case of increased generation to meet this kWh demand. To calculate system peak kW demand a modelling framework was used which ascribes 'system peak load factors' to each demand segment (space heating, water heating, lighting, process heat, EV charging etc.). This enables a kWh value to be converted into a system peak kW value. These system peak load factors were derived using analysis based on various studies of demand shapes such as BRANZ's HEEP analysis.[7] The resultant composite peak demand values for today were then compared with observed actuals to ensure that this building-blocks approach to peak demand estimation is producing sensible numbers.

This projection of peak demand also distinguishes between demand which is transmission-connected and that which is distribution-connected (further distinguishing between LV and HV connected and the associated difference in losses).

It is also known that a significant amount of transmission and distribution lines infrastructure is coming to the end of its economic life over the next couple of decades, giving rise to significant need for investment for asset replacement and renewal. This so-called 'wall of wire' will increase costs over and above that driven by underlying demand growth.

The extent to which this will increase costs has been estimated based on analysis of Transpower's integrated transmission planning schedules for the periods 2015 through to 2035. This analysis suggests an underlying rate of cost increase of 1.75% due to such asset replacement and renewal. This rate of increase is then projected to steadily decline to 0% by 2050 when it is assumed that expenditure will have reached a steady state of renewals each year.

In the absence of similar detailed analysis of distribution costs, this same rate of underlying non-demand or customer-driven cost growth is assumed to apply to the distribution businesses.

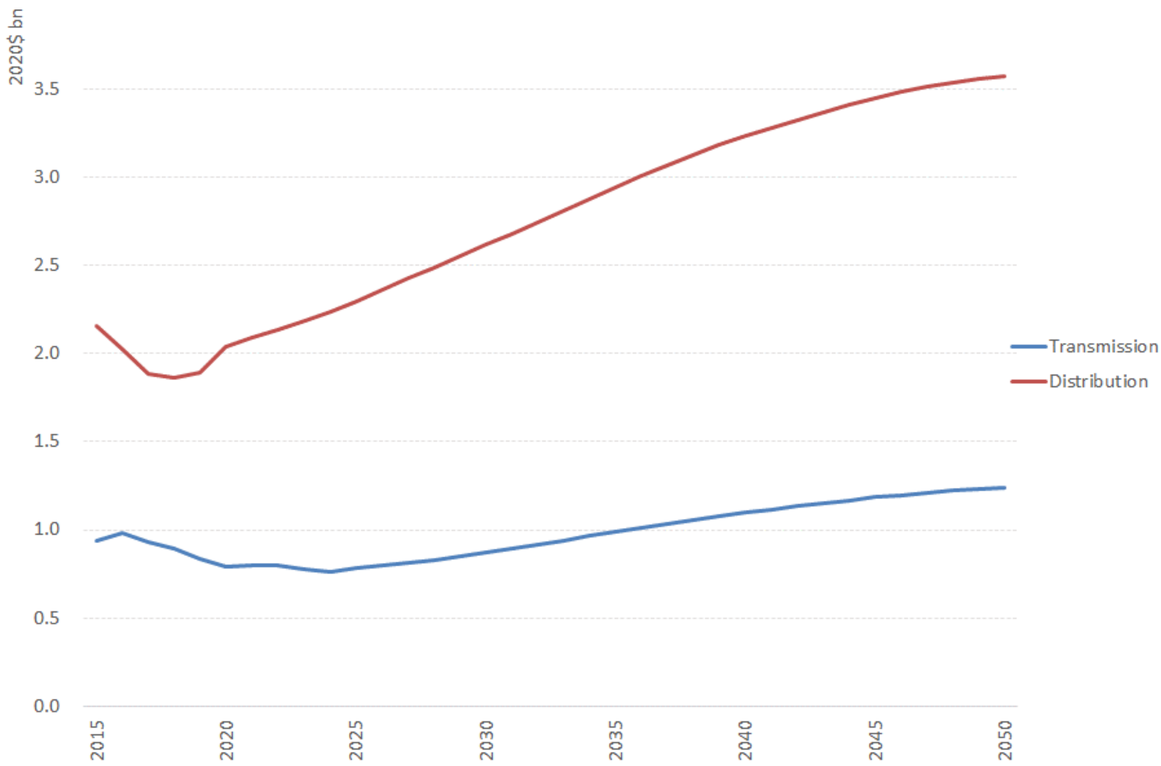
The following figure shows the projection of transmission and distribution business costs for the demonstration path.[8]

[6] The growth in consumers' anytime maximum demands is assumed to occur at the same rate as the growth in kWh demand. This is considered to be a reasonable proxy.

[7] https://www.branz.co.nz/environment-zero-carbon-research/heep2/heep/

[8] Note: Although transmission costs appear to be growing much less than distribution costs, because they are starting from a much lower base they are actually growing at broadly the same rate.

Figure 3 – Projected electricity network costs for the demonstration path



2.1.3 Retail & metering costs

The costs of providing metering and billing services are estimated on a per-customer basis, based on analysis undertaken for the 2019 Electricity Price Review and cross-checked by an analysis which 'decomposed' reported retail tariffs in Powerswitch combined with reported electricity lines tariffs.

These costs are assumed to rise directly in line with customer numbers.

2.2 Modelling of electricity prices

2.2.1 Total electricity costs

The following charts show the projected total electricity system charges to consumers for

- the demonstration path scenario (which has the aluminium smelter exiting in 2025)
- the demonstration path if the Tiwai aluminium smelter stays; and
- the Current Policy Reference case (which has the aluminium smelter exiting in 2025)

For comparison, the graphs also show the historical total electricity system costs from 2000 as reported by MBIE.[9]

[9] The historical costs have been reported by MBIE for different consumer groups in nominal terms. These have been inflated to 2020$ using CPI (for residential) and PPI (for non-residential) inflators.

Figure 4: Total electricity system costs to consumers under the demonstration path

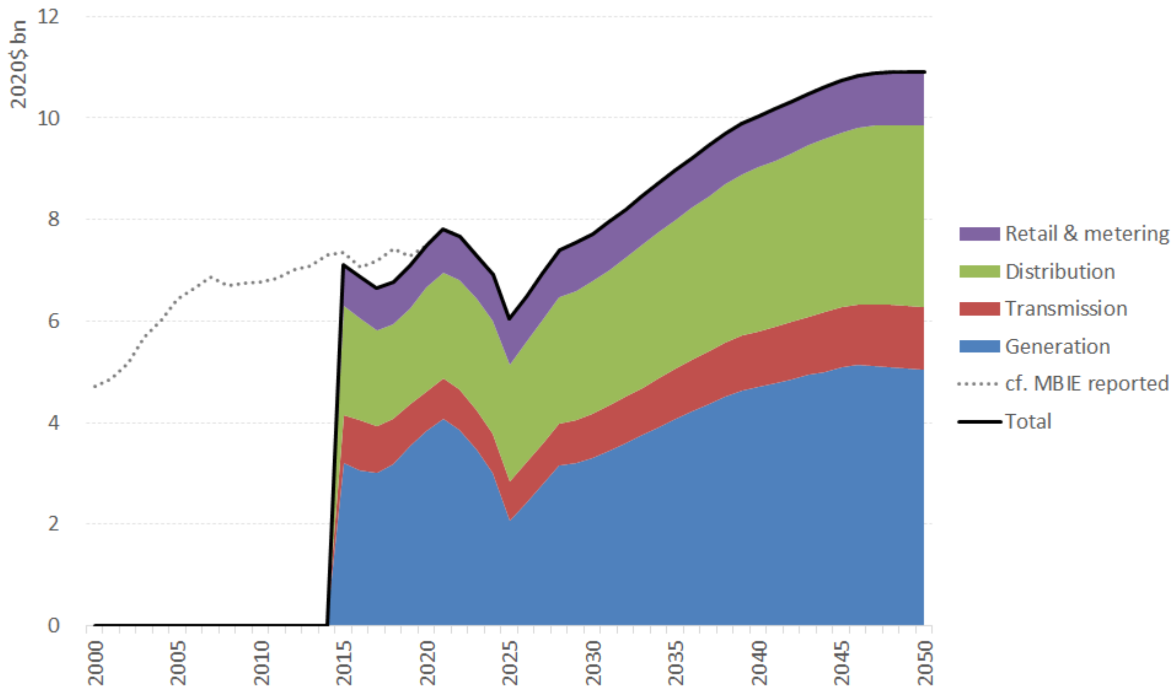


Figure 5: Total electricity system costs to consumers under the Tiwai-stays scenario

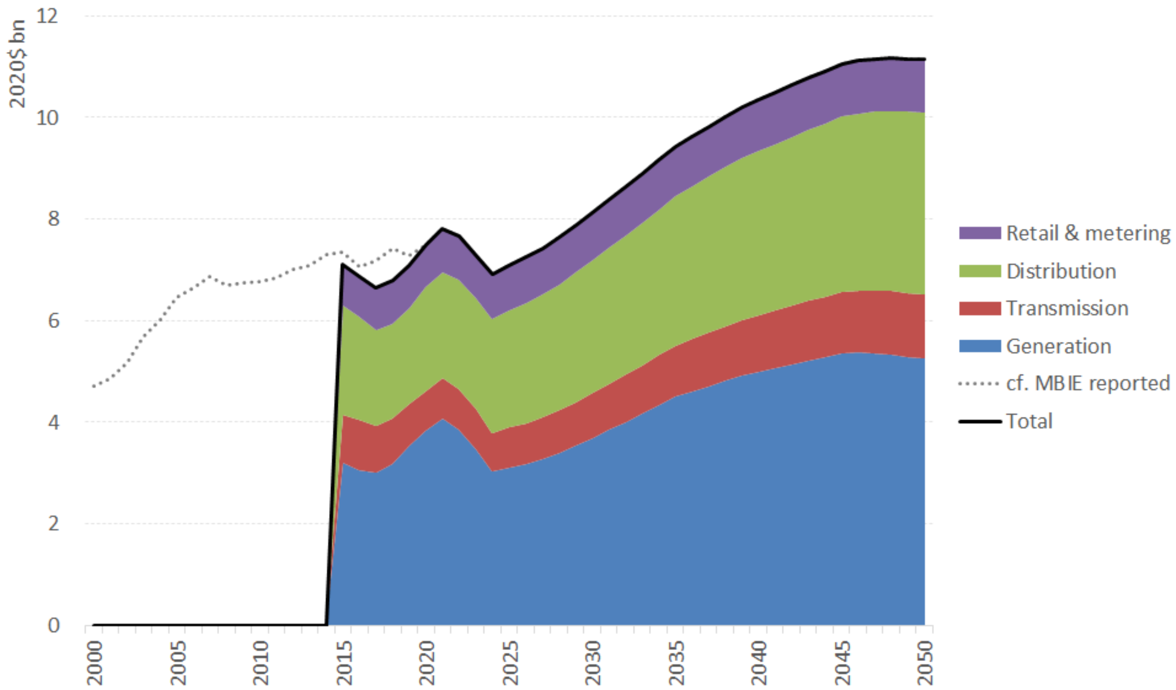
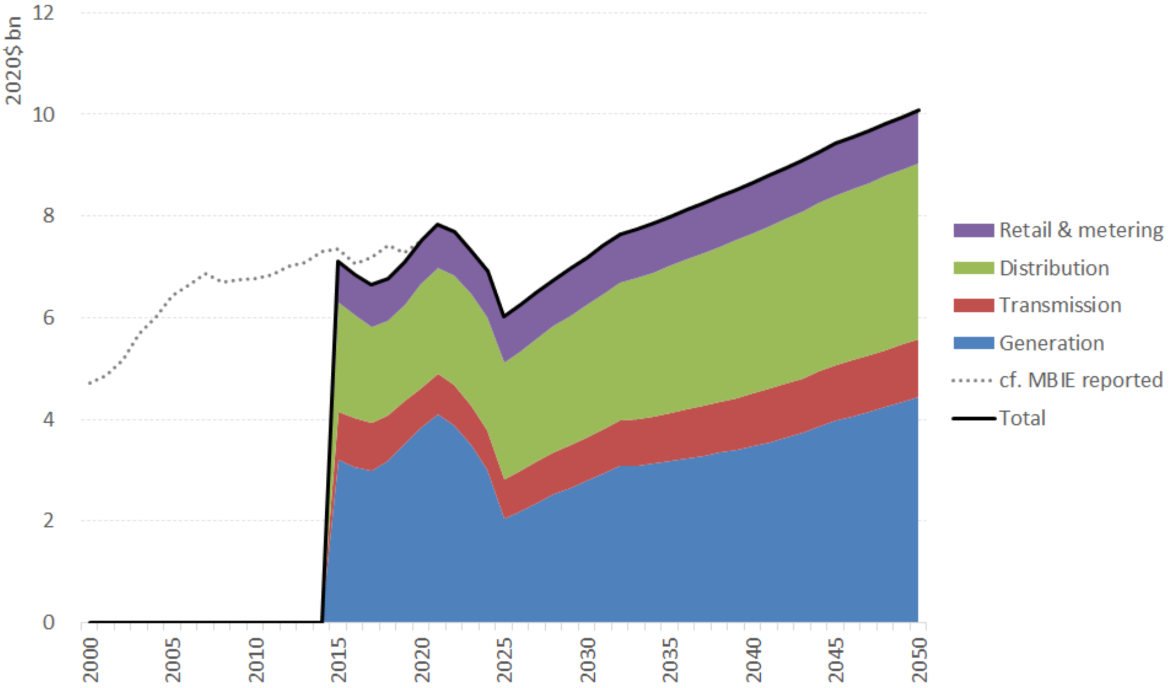


Figure 6: Total electricity system costs to consumers under the Current Policy Reference case



Under the demonstration path, consumer electricity costs are projected to fall initially due to the increase in renewable generation and improvement in gas supply lowering wholesale prices, and the exit of the Tiwai smelter lowering wholesale prices even further. However, they are then projected to steadily increase to approximately $11 billion per year by 2050 in real terms – an increase of $3.5 billion or 47% above today's value.

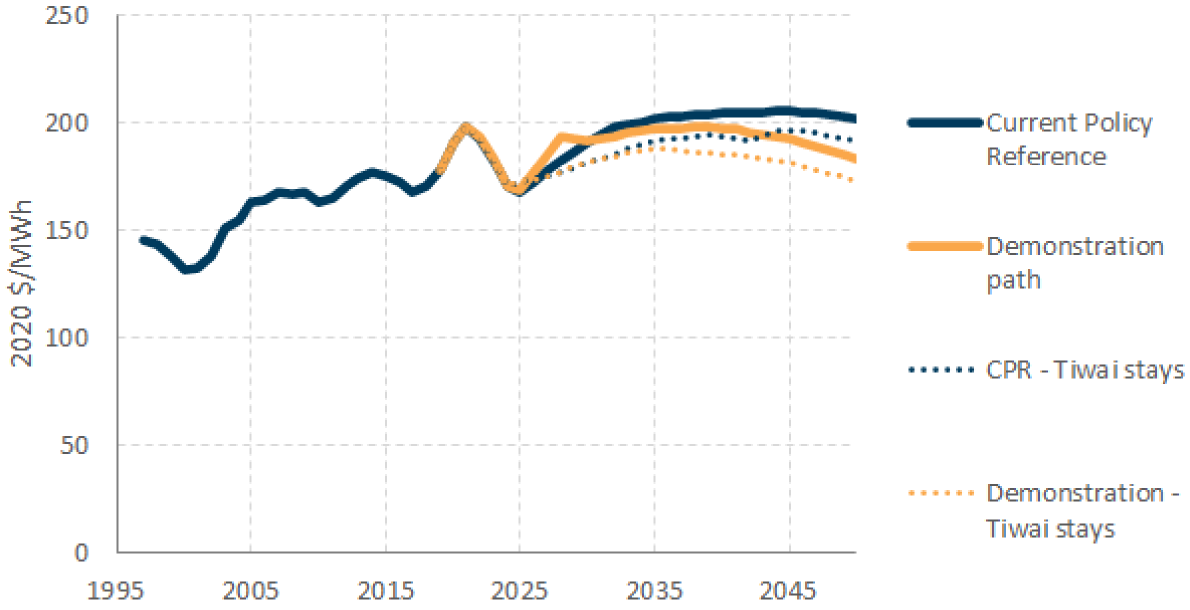
If the aluminium smelter were to stay, the post-2025 fall in consumer costs will not be as great, but the eventual total 2050 costs will only be slightly higher than if it had exited. This is principally due to a slightly higher renewable project cost setting the wholesale market price – with the higher price being due to a combination of having to move slightly up the cost-supply curve of available projects, and also having a higher proportion of variable renewables with an increased peaking factor penalty.

Under the Current Policy Reference case, costs move in a similar pattern to the demonstration path, but only rise to $10 billion per year by 2050 in real terms. This indicates that the electrification associated with the demonstration path is responsible for just under 30% of the projected cost increases by 2050, with the remaining 70% due to demand increases from general population and economic growth and the asset replacement and renewal costs from networks.

Given that total costs recovered from consumers are projected to grow by 47% by 2050, you might expect that the $/kWh price of electricity to grow by a similar amount. However, because total kWh is also growing along with total costs, the increase in the cost per kWh will be a lot less. Indeed, as Figure 7 below shows, because electricity demand growth is projected to be marginally greater than cost growth, total variablised consumer prices[10] are projected to fall slightly in the long term, with average $/kWh prices in the (higher-electrification) Demonstration Path scenario being lower than in the Current Policy Reference scenario.

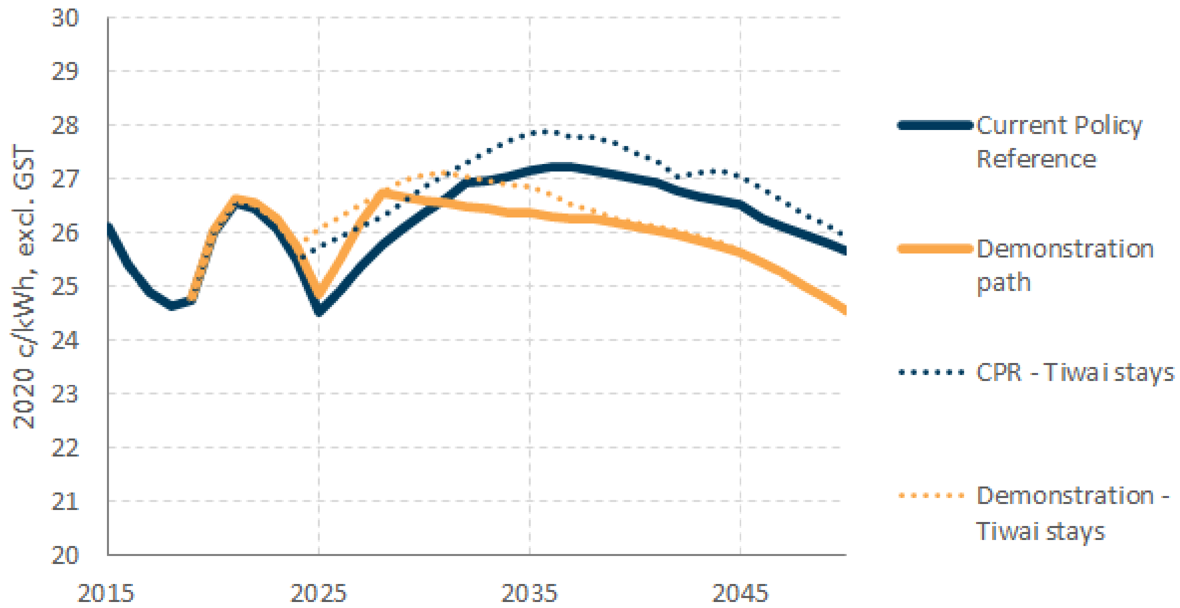
[10] Total variablised prices are calculated as the sum of all costs recovered from all consumers (residential, commercial, and industrial) divided by total kWh across all consumers. Actual prices for each consumer group will be very different, both in terms of $/kWh level and structure (e.g. the mix of fixed charges and variable charges).

Figure 7: Fully-variablised electricity prices across all consumers



This pattern also holds for the change in the fully-variablised price averaged across all residential consumers, as shown in Figure 8.

Figure 8: Average fully-variablised electricity prices for residential consumers



Note on electricity pricing reforms

The above analysis assumes that consumer prices move to more cost-reflective structures, this includes:

- prices which signal the different costs of electricity at peak and off-peak times, and
- recovery of the non-demand-driven costs of network and retail via fixed charges rather than $/kWh charges.

This is consistent with the Electricity Authority's direction of electricity price reforms, and the Electricity Price Review's recommendations which the government has said it intends to implement. The effect of these reforms will be to lower the effective cost of electricity options relative to their fossil alternatives.

To the extent that such reforms aren't implemented, the degree of electrification of transport and heating would not be as great. As a result, the cost and price outcomes would move towards the Current Policy Reference case and away from the demonstration path.

Another recommendation from the Electricity Price Review was to alter the allocation of shared network costs, as it was identified that they appeared to be skewed too-heavily towards residential consumers. Such a revised cost-allocation would lower prices for residential consumers and increase prices for business consumers. However, as there has been no firm policy direction on this recommendation, the price analysis for the Commission's modelling assumes a continuation of current network cost allocation approaches, with the exception that a greater amount of transmission costs will be recovered from generators – consistent with the current transmission pricing methodology (TPM) proposal from the Electricity Authority.

3 Fossil gas cost and price modelling

3.1 Modelling of fossil gas costs

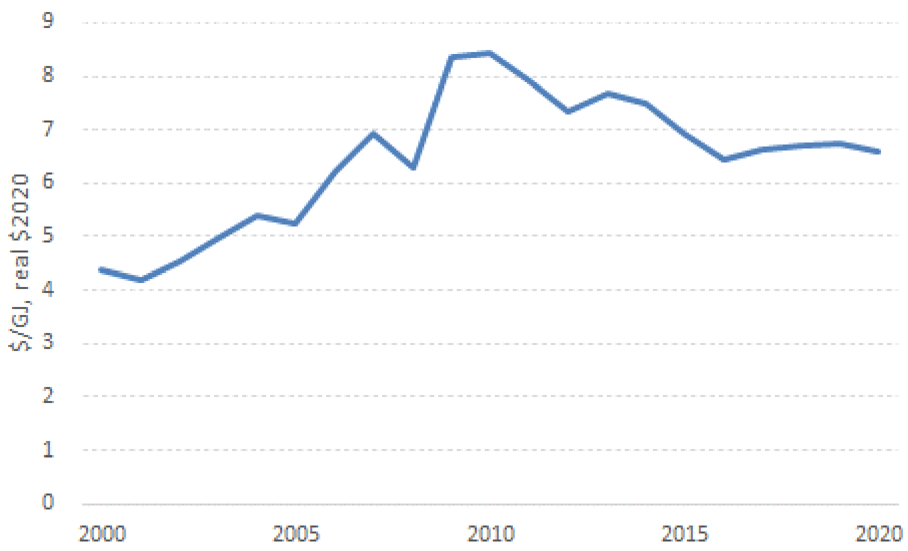
There are four main cost components for providing fossil gas to consumers:

1) Wholesale – the costs of exploring for, extracting, and processing fossil gas.
2) Carbon – the price of carbon under the Emissions Trading Scheme (ETS) multiplied by the carbon intensity of gas.
3) Networks ('Pipelines'), comprising the high-pressure transmission network spanning the north island, and the local lower-pressure distribution businesses.
4) Retail and metering – comprising the costs of providing metering, billing, call-centres, etc.

3.1.1 Wholesale costs of fossil gas

Figure 9 shows the historical pattern of wholesale gas prices as reported by MBIE.

Figure 9: Historical wholesale gas prices



Source: MBIE stats

The projection in the ENZ modelling sought to roughly replicate how the factors that have driven historical gas prices might drive future gas prices – namely the progressive development of gas reserves and resources to meet demand to achieve a balanced supply / demand situation. On average, wholesale gas prices in such a balanced situation would be expected to be broadly similar to the average of historical prices (i.e. approximately $6 to $6.5/GJ) – while noting that the relatively lumpy nature of gas field developments means that the historical pattern shown in Figure 9 features periods of relative scarcity and surplus.

However, one of the key features of the future which has not been a driver of the past, is that no new offshore exploration licences will be issued. As such, the stock of future gas which can be developed is limited to existing offshore fields, and existing and possible future onshore-Taranaki fields.

The model seeks to capture this dynamic by explicitly modelling the reported reserves and resources[11] from existing fields and a potential new onshore-Taranaki field, and how such reserves and resources are progressively 'used up' by projected demand.

As reserves and resources are used up, for any given year, the model calculates when in the future all reserves and resources would be used up if demand were to continue at current levels. This then calculates a 'shadow' LNG price – being the exogenously-assumed future price of LNG imports ($12/GJ) discounted by the number of years before such LNG imports would be required based on current levels of demand.

The wholesale gas price in the given year is then set equal to the greater of the previous year's price and this shadow LNG price. Over time this results in wholesale prices slowly rising as reserves and resources are used up and the time when Aotearoa would require LNG imports gets closer.

Importantly, as gas prices rise, this makes it economic in the model for some existing gas consumers to switch to alternatives. Examples include industrial process heat consumers switching to biomass or electro-boilers, or gas-fired power generation being displaced by renewables. Any increase in carbon prices will further contribute to the effect of making it more economic to switch to alternatives.

As consumers start to switch away, the time when LNG imports would be required also gets pushed out. This modelled rationing effect means the wholesale price only slowly moves up the demand curve and, in the demonstration path, never reaches LNG import price. In contrast, under the Current Policy Reference case, which has low carbon prices, gas demand is a lot higher meaning that wholesale prices steadily rise as reserves and resources are used up until reaching LNG import pricing by 2055.

In other words, due to this fuel-switching-driven rationing dynamic, the modelling results in an inverse relationship between future carbon prices and future wholesale gas prices. The Gas Industry Company's 2019 Gas Supply / Demand study[12] reached a similar conclusion as to this likely linkage between wholesale gas outcomes and carbon prices.

One significant simplification in this analysis is that the timing of petrochemical production ceasing, and the threshold gas price for such production to cease, have both been exogenously specified as scenario assumptions. The rationale for this simplified approach is that there are major

[11] Reserves are the gas accumulations which are deemed economic to produce based on near-term expected conditions, whereas resources are the gas accumulations which aren't yet economic to produce but could be in the future – in particular as reserves are extracted giving rise for a need to develop the resources to convert into reserves.

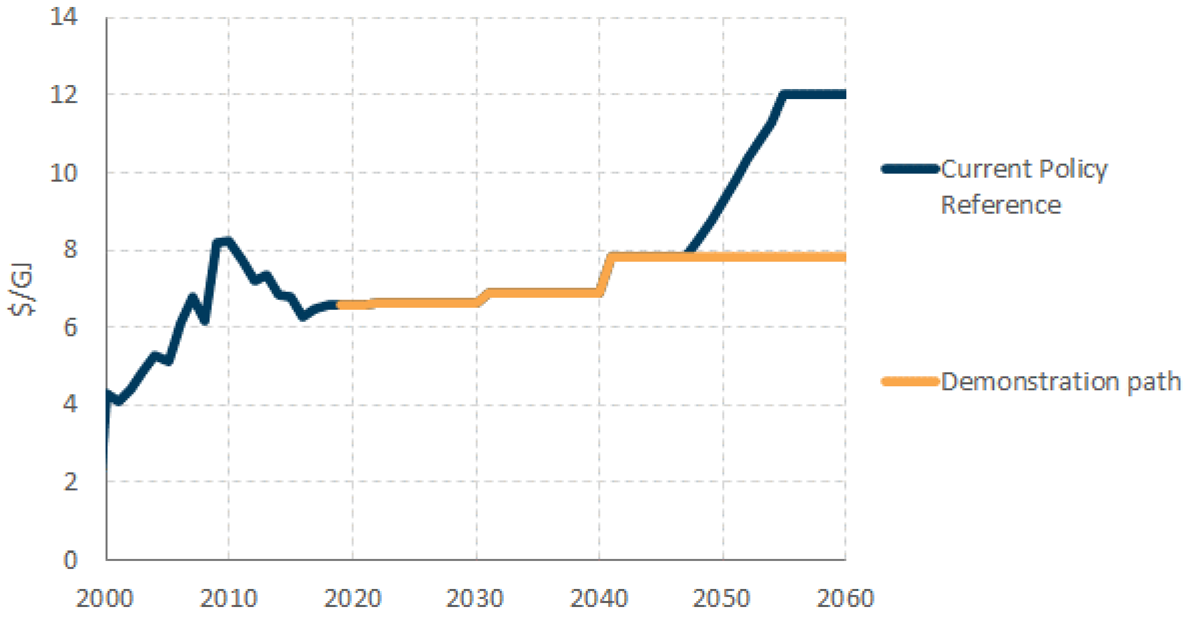
[12] https://www.gasindustry.co.nz/work-programmes/gas-supply-and-demand/long-term-gas-supply-and-demand-scenarios-2019-update/

uncertainties over the future international methanol and urea markets – not least because of how international carbon policies will develop. Therefore, trying to model domestic plants' exit decisions would be subject to a large margin of error. Accordingly, scenario assumptions have been chosen which are considered reasonable based on current understanding of the petrochemical market dynamics. However, there is a material degree of uncertainty over the timing of exit and level of threshold prices.

The effect of these exogenously specified exits of these very large sources of demand is that the modelled wholesale price curve moves in steps over the first couple of decades, corresponding to the exogenously specified exit years and threshold prices.

The resulting projection of wholesale gas prices are shown in the following figure:

Figure 10: Wholesale gas prices (real $2020)



The model attempts to model long-term, not short-term dynamics

Current spot wholesale gas prices are considerably higher than those shown in Figure 10. This is principally due to the current situation of relative scarcity driven by:

- the unexpected loss of 50% of the Pohokura gas field's output (New Zealand's largest gas producing field), and
- the unexpected continuation of the Tiwai aluminium smelter (equivalent to almost 13% of national electricity demand) and the consequent under-building of renewable generation that would otherwise have occurred over the past three to five years had there been no uncertainty about its continued operation.

The model is not designed to model such short-term outcomes – not least because of the inherent uncertainty over the likelihood of gas supply failures, and the uncertainty over how negotiations for the future of the aluminium smelter will play out. As such, the model simulates long-term outcomes where the supply and demand are broadly in balance and assumes that decisions for consumer fuel-switching away from gas will be based on these long-term wholesale gas prices.

Will future wholesale gas price dynamics be the same as historically?

As noted above, the methodology seeks to simulate outcomes where a steady stream of investment is undertaken to develop future resources to meet future demand and achieve a supply/demand balance that is broadly similar to the historical average.

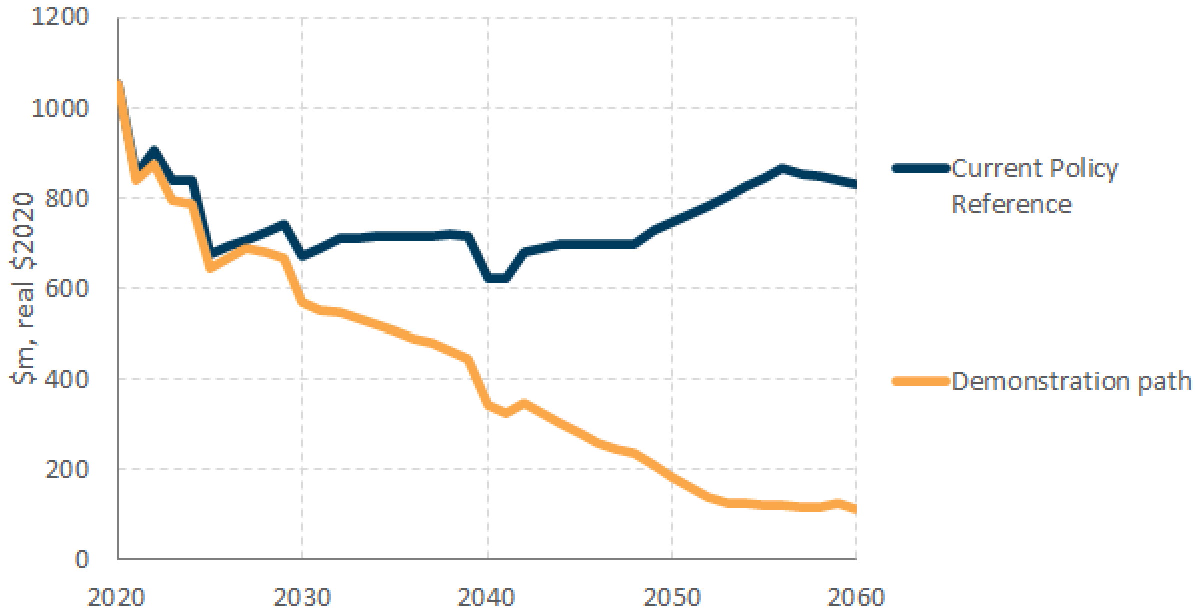
However, some stakeholders have suggested that this pattern of measured investment may not occur going forward due to the changing policy dynamic relating to decarbonisation. Interestingly, two very different views are emerging as to the outcomes for wholesale prices, despite both views being based on the same underlying policy position:

- One view is that, because of uncertainty over future policies for decarbonisation upstream investors may be wary of investing the billions of dollars that will be required over the next few decades to maintain gas production to meet remaining demand while the transition away from fossil gas occurs. In such a future, gas prices may rise more quickly towards LNG import parity levels.
- The alternate view is that, faced with this uncertainty over future policies, gas producers may seek to accelerate the monetisation of their gas resources by lowering the price which they would be willing to receive for investment in the development of resources. i.e. they may evaluate that it is worth getting 'something today', rather than take the risk that an acceleration of decarbonisation policies (either domestic or international) results in them getting 'nothing tomorrow'. In this scenario, they would effectively be facing reduced returns on the sunk investments in exploration and development of processing capabilities.

It is hard to know whether or which of these dynamics will prevail going forward. However, currently there appears to be no shortage of investment going into development of additional resources, in large part stimulated by the current situation of scarcity and the associated high prices.

To sanity check whether the projected wholesale prices will be adequate to provide sufficient revenues, Figure 11 shows the projected wholesale gas revenues for the two scenarios.

Figure 11: Projected total wholesale gas revenue

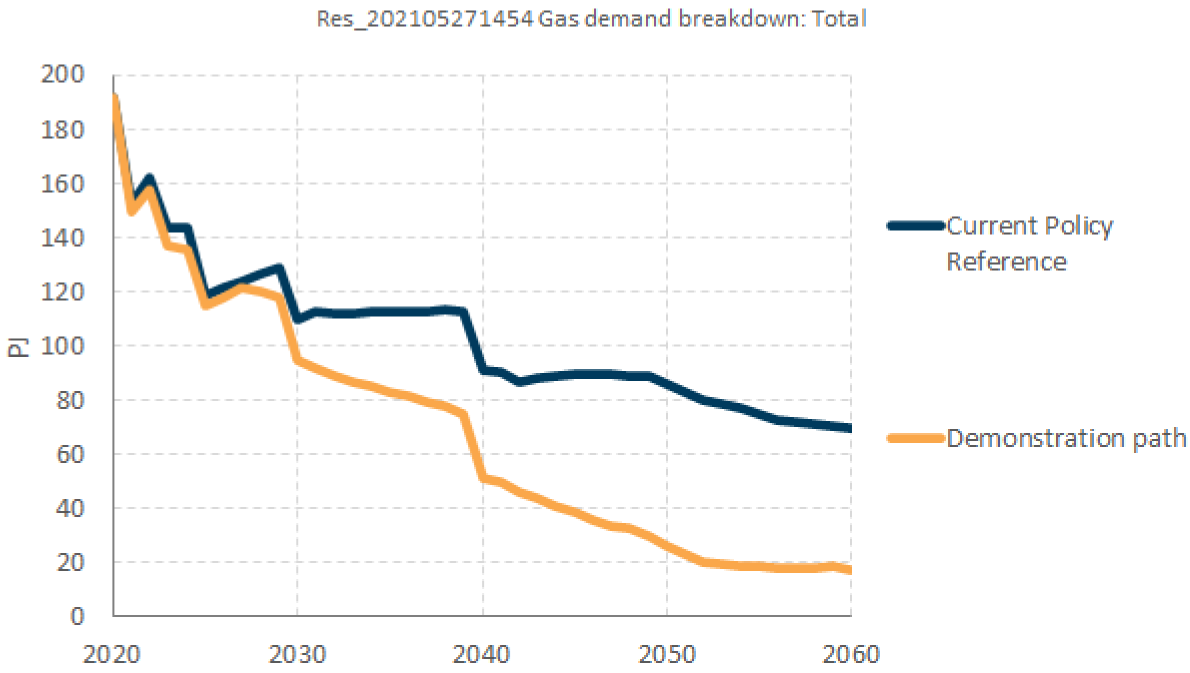


As can be seen, for the decade out to 2030, total wholesale gas revenues are projected to be $7.6 billion for the Current Policy Reference case, and $7.2 billion for the demonstration path. This can be compared with third party estimates of the amount of investment required to maintain gas production at current levels:

- The Gas Industry Company estimates the industry needs to invest $0.3 to 0.5 billion every 3 to 5 years to maintain production at current levels.
- Energy research company, Enerlytica, estimate even more investment is required: $2 billion during the 2020s to maintain current production levels.

Both such values are substantially below the projected wholesale revenues, and therefore the projections are considered consistent with the level of investment required – particularly given that, as shown by Figure 12 below, the projections don't require gas production to be maintained at current levels given the displacement of gas-fired power generation with renewables and some reduction in petrochemical demand with the closure of the Waitara Valley methanol train.

Figure 12: Projected total gas demand



3.1.2 Carbon costs

The price of carbon in the ETS will flow through to the price of gas based on the emissions intensity of fossil gas which is about 0.05 tCO_2/GJ.

Thus, at today's carbon price of approximately $40/$tCO_2$, the cost of carbon will increase consumer gas prices by $2.1/GJ.

Under the demonstration path, carbon prices are modelled as having to rise to $250/$tCO_2$ by 2050 to incentivise sufficient decarbonisation investments to meet the net-zero target. At $250/$tCO_2$, the carbon component in the cost of gas would be $13.3/GJ.

However, because of the rationing effect described in section 3.1.1 previously, there is likely to be an inverse relationship between wholesale gas prices and carbon prices i.e. wholesale gas prices will likely be lower in a future with high carbon prices and vice versa.

Some emissions-intensive trade-exposed (EITE) industrial sectors receive 'free' NZ Units for the ETS under the industrial allocation process. For the most emissions-intensive sectors the level of free allocation was 90% but is now 89% in 2021 and declining by 1% a year under current policy. This free allocation of 89% of units reduces the effective carbon cost faced by the sector to 11% of the cost faced by other parts of the economy that don't face free allocation. For methanol, this effective cost is reduced even further as the requirement to surrender NZ Units under the ETS currently only applies to the 1/3 of emissions associated with the gas consumed for providing energy for the methanol's manufacture. The gas that is used as a feedstock and is embodied in the methanol does not face a cost of carbon because it is exported overseas.

The combined dynamics of rationing and free allocation mean there could potentially be some emissions 're-bound', particularly in relation to methanol production i.e. a high carbon price future resulting in faster fuel-switching from non-EITE consumers and lower wholesale gas prices, which in turn extends the likely life of methanol production plants. Again, this was also one of the dynamics highlighted in the Gas Industry Company's 2019 Gas Supply / Demand study.

3.1.3 Fossil gas pipeline costs

New Zealand's gas is transported over the high-pressure transmission ('Tx') network operated by First Gas, and then (in most cases[13]) reticulated to final consumers via lower-pressure distribution ('Dx') networks operated by First Gas, Powerco, Vector and GasNet.

In 2020, consumers were charged $132m for gas transported over the transmission network, and a further $130m for gas transported over the distribution network: $262m in total – all costs excluding GST.

It is estimated that residential consumers paid approximately $98m of such fees ($85m distribution, and $13m transmission), commercial consumers $59m ($34m distribution and $25m transmission), with the remaining fees recovered from large industrial, petrochemical, and power station consumers.

Such pipeline fees are to recover the amortised costs of past capital expenditure, future capital expenditure, and the ongoing operating costs.

Table 1 presents the results of a high-level comparison of reported network expenditures with current fees.

Table 1: Breakdown of pipeline fees

	Annual expenditure as % of current fees			|	Growth-related capex	
	Opex	Capex	Residual	|	% of capex	% of fees
Tx	34%	32%	34%	|	8%	3%
Dx	30%	46%	24%	|	64%	30%
Total	32%	39%	29%	|	36%	16%

GasNetworkComplianceReporting_v08.xlsm

This indicates that ongoing operational and capital costs across all networks are equivalent to approximately 71% of network fees, with the 'residual' 29% being used to recover the amortised costs of past capital expenditure. The costs of ongoing capital expenditure will be added to the regulatory asset base and recovered in the fees through an amortised capital charge.

It also indicates that, for distribution businesses in particular, a significant proportion of ongoing capital expenditure is for growth-related activities (costs reported in the Commerce Commission disclosures as 'consumer connections' or 'system growth').

[13] Some very large consumers of gas (e.g. power-stations, petrochemical plants, and large industrial sites) take gas directly from the transmission system.

Taking all factors into account, a transition away from fossil gas distributed over the gas network consistent with the demonstration path[14] would only require continued network expenditure equivalent to approximately 57% of current fees. This figure could potentially be less if there were also some operational cost savings associated with not undertaking growth-related capital expenditure.

However, while the economic costs of maintaining the pipelines in the demonstration path may be relatively low, aggregate consumer fees will likely still need to be higher to recover the amortised costs of past, regulator-approved capital expenditure. That said, aggregate consumer fees should also gradually decline in this scenario as avoided system growth-related capital expenditure will not need to be recovered via future amortised capital recovery fees.

The modelling seeks to capture the above dynamics in a simplified fashion by the use of an approach which alters the required transmission and distribution revenue in factored-proportion to changes in demand, with the factor being higher for distribution than transmission. At the time the modelling was done for setting the budgets, this gas network cost analysis was at a fairly early stage of development. Subsequent work has helped refine this analysis of cost and price impacts, but the effect on fuel switching and emissions is second-order.

3.1.4 Fossil gas retail & metering costs

The costs of providing metering and billing services are estimated on a per-customer basis. They are assumed to be the same as for electricity retailing. This assumption was cross-checked by an analysis which 'decomposed' reported retail tariffs in Powerswitch combined with reported gas network tariffs.

For the model, these costs are assumed to be directly proportional with customer numbers. However, it is potentially the case that as gas customer numbers fall to relatively low levels, the effective per-customer cost-to-serve could rise. This possible dynamic has not been modelled for this analysis.

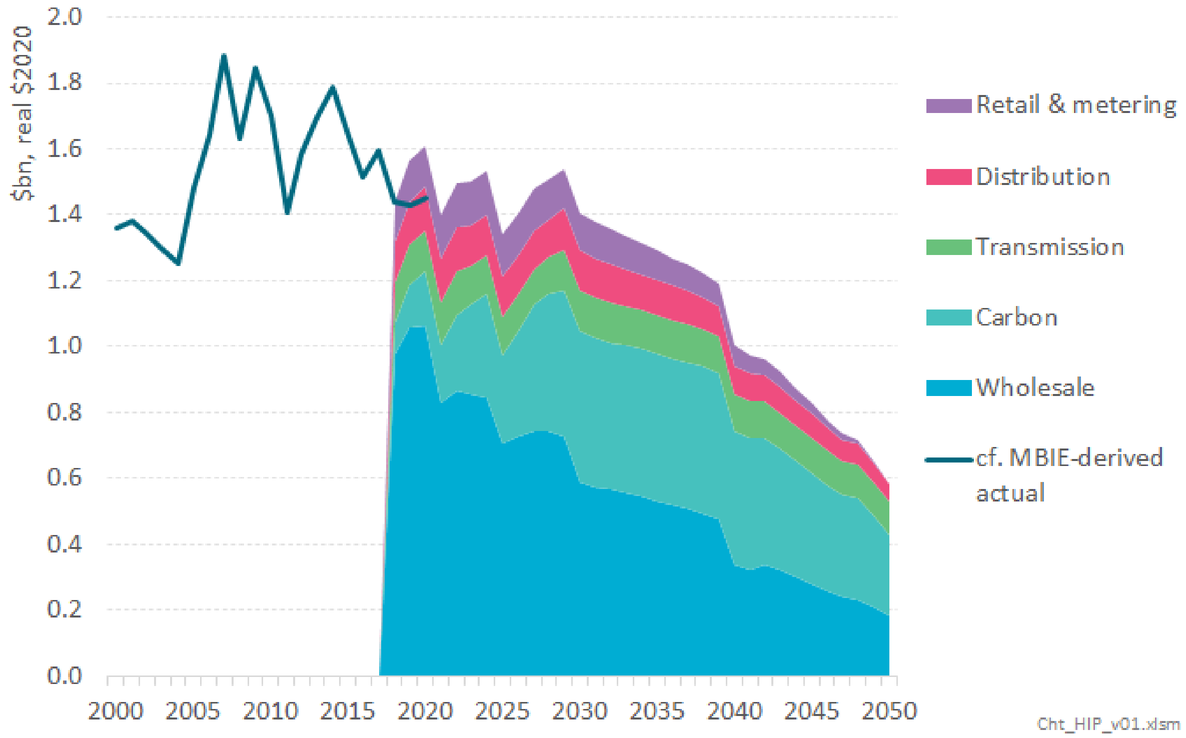
3.1.5 Overall projection of fossil gas costs

Figure 13 show the total projected gas sector costs to consumers under the Demonstration Path, along with an estimate of historical total sector costs derived from MBIE reporting.[15] The jagged step changes in the projection relate to major step changes in demand, such as the projected exit of methanol trains or the post-Tiwai-exit drop in demand for gas-fired power generation.

[14] In the demonstration path there is no more growth in gas demand and a steady transition away from reticulated gas.

[15] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/

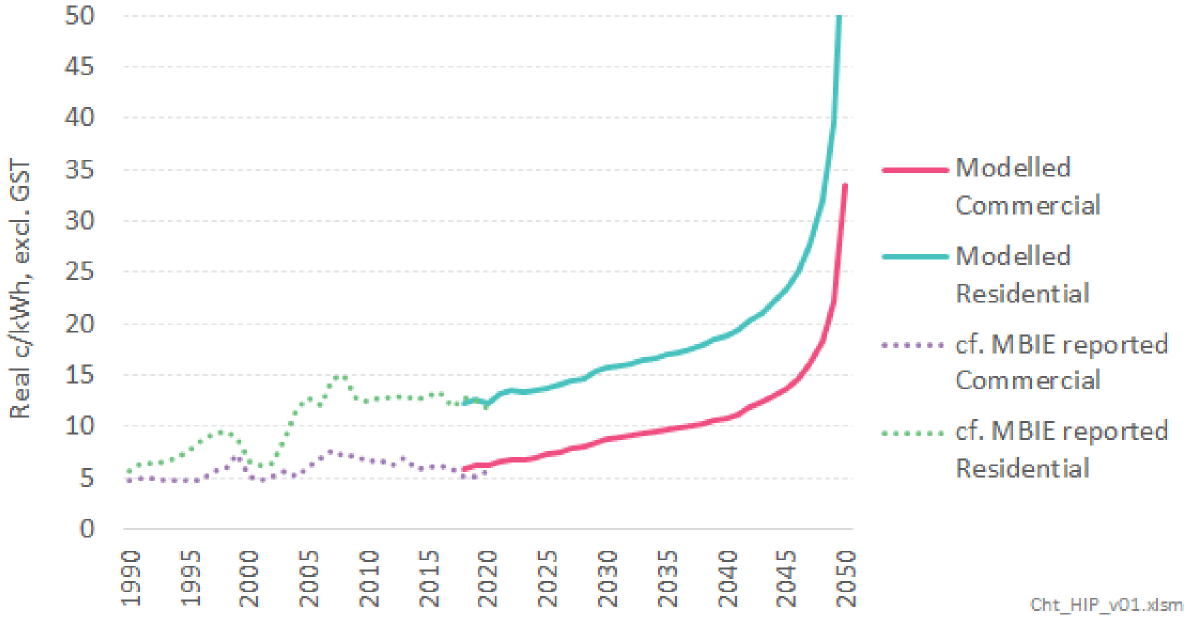
Figure 13: Projection of total gas sector costs to consumers under the Demonstration Path



3.2 Modelling of fossil gas prices

Figure 14 shows a plot of projected fully-variablised[16] average consumer gas prices for residential and commercial consumers, along with the MBIE reported actual average values for historical years.

Figure 14: Fully variablised gas prices for demonstration path

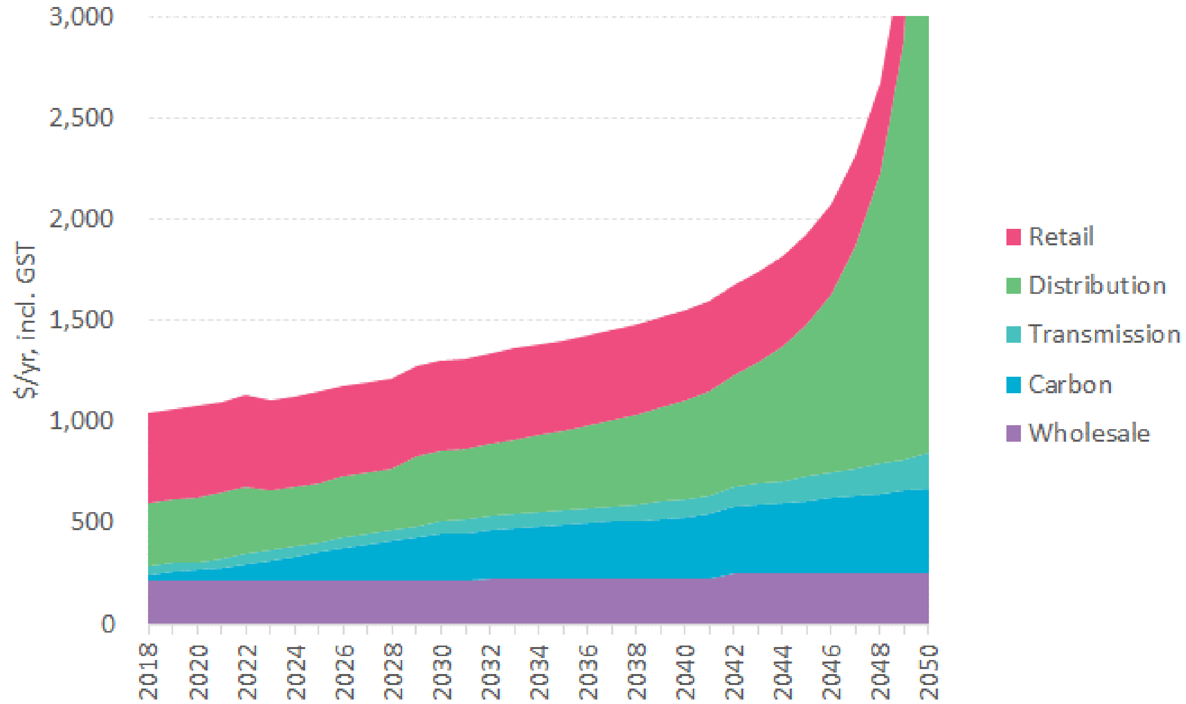


[16] Fully-variablised means that any $/day fixed charges to consumers are divided by kWh consumption to give a $/kWh value.

As can be seen, there is a steady increase over the next couple of decades, before a rapidly accelerating increase in the last decade to 2050.

To help understand what is driving this projected change, Figure 15 below gives a breakdown of the average household gas bill out to 2050 under the demonstration path.

Figure 15: Average household gas bill for the demonstration path



Initially, the largest driver of the increase in household gas bills is the steadily increasing carbon price. However, from the middle of the next decade, increasing pipeline costs (particularly distribution) start to become the largest driver of gas bill increases, with an exponential increase towards the 2040s.

This increase in the pipeline component of consumer bills is not because the overall costs of the pipelines are increasing. Indeed, as detailed in section 3.1.3 and illustrated in Figure 13, total pipeline costs to be recovered from consumers are likely to decrease due to the avoidance of those costs which would otherwise have been incurred to meet new connections and system growth.

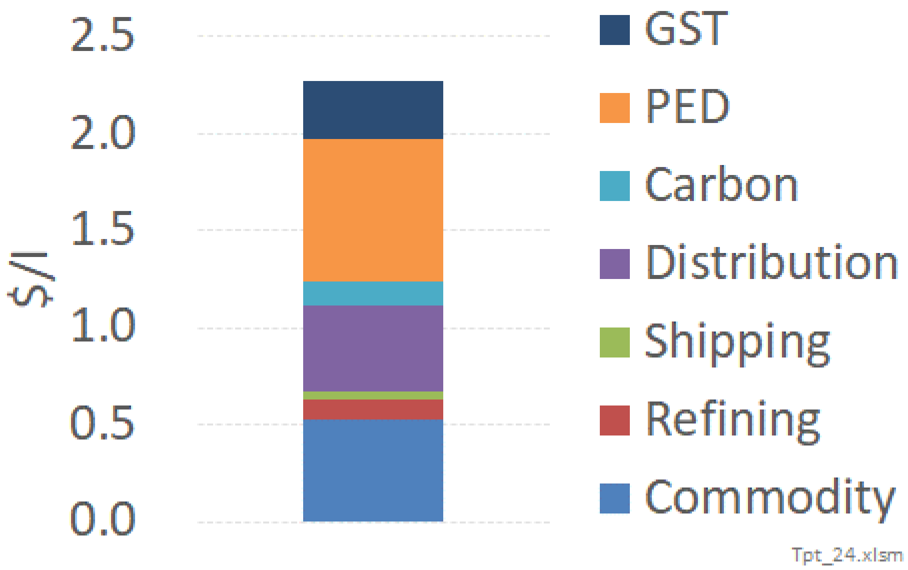
Rather, the increase is due to these pipeline costs not falling as fast as the total number and GJ volume of customers. As customers progressively switch away from reticulated fossil gas over the next thirty years, the remaining customers are faced with an ever-greater share of the pipeline cost recovery. It is possible that this dynamic may trigger an acceleration of fuel-switching greater than that modelled here, as an ever-declining group of customers face an ever-increasing price – the so-called 'death spiral' phenomenon. The extent to which this may happen or whether other factors may affect pricing outcomes such as reduced pipeline shareholder capital recovery and/or altered economic regulation of the pipelines, has not been explored for this modelling.

4 Petroleum fuels cost and price modelling

4.1 Petrol & diesel

Figure 16 shows a rough breakdown of the cost components driving current average prices at the petrol pump.

Figure 16: Breakdown of current petrol price



The ENZ model accounts for all of these in its projections as follows:

- Commodity price is simply the US$ per barrel world price of oil, factored by the NZ$/US$ exchange rate and the litres/barrel constant. Both the world oil price and NZ$ exchange rate are exogenous assumptions. For our Current Policy Reference case and the demonstration path they are set to be US$60 per barrel and 0.65 US$/NZ$, respectively.
- The refining cost is a constant factor expressed in US$ per barrel. This factor has been derived from past analyses published by MBIE which decompose the cost of petrol.
- Shipping cost is expressed as a percentage of the commodity and refining cost. This percentage has been derived from past analyses published by MBIE and the New Zealand Automobile Association (the AA).
- The carbon cost is simply the $/t$CO_2$ carbon price for the scenario, multiplied by the emissions factor for a litre of petrol.
- Distribution covers the costs of the service station infrastructure, including transporting the petrol from the refinery or import terminal to the service station. This is expressed as a constant dollar per litre value and has been derived from past analyses published by MBIE and the AA.
- Petrol Excise Duty ('PED') is expressed as a constant dollar per litre value, based on the current level charged by government to cover roading costs.
- GST is simply a 15% charge on top of all the other charges.

The price of diesel is derived in fundamentally the same way except that:

- PED is not charged on diesel sales, with the cost of roading instead being recovered via Road User Charges ('RUCs'). The level of PED and RUC is set by the Government so that a similar amount of roading revenue is recovered by petrol and diesel vehicles travelling a similar distance.

- Slightly different emissions factors are used for diesel.

Uncertainty over future petrol and diesel cost outcomes

One of the biggest uncertainties relates to the future world price of oil and the NZ$ exchange rate. Both of these are treated as exogenous assumptions with the ability to test the sensitivity of outcomes by having different scenario values. Importantly, such scenario values for oil price and exchange rate apply consistently to all other parts of the economy within the ENZ model.

As the volume of petrol and diesel sales fall due to the shift to electric vehicles, the charge required to cover petrol and diesel distribution costs will need to rise, as the fixed costs of the fuel distribution infrastructure will need to be recovered over a smaller volume of sales. While some of this dynamic could be managed by service station consolidation (i.e. progressively closing service stations to reduce fixed costs), beyond a certain reduction in petrol and diesel volumes there will need to be material price increases which would likely grow at an exponential rate. This is the same as the 'death spiral' dynamic for recovery of fixed gas network costs. However, due to uncertainty of the scale of such cost increases, no such price increases were included for this stage of the ENZ modelling. As such, projected petrol and diesel prices for the latter part of the projection are likely to be an under-estimate.

4.2 LPG

The cost of LPG is calculated in a very similar way to that of petrol and diesel:

- The wholesale component is based on the same approach as for petrol and diesel in that it is derived from the world price of oil and factored by shipping and the NZ$/US$ exchange rate.
- The cost of carbon is added using the emissions factor for LPG.
- There is a cost component to cover the fuel distribution and retail cost-to-serve. This is expressed in $/GJ and is different for residential, commercial and industrial customers. While some costs are likely to vary with customer numbers, some of the infrastructure costs will not scale with customers. Therefore, as LPG volumes decline in the demonstration path with customers switching away to low-carbon fuels such as electricity, it is likely that this component of the cost of LPG would need to increase – similar to the dynamic for petrol and diesel distribution costs. However, due to uncertainty of the scale of such cost increases, no such price increases were included for this stage of the ENZ modelling.