

Powering Auckland's Future

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Executive summary

Affordable, secure and sustainable energy is a critical enabler of Auckland's economic prosperity, household wellbeing, and future growth. Tāmaki Makaurau Auckland generates around 38 per cent of New Zealand's economic output and is home to 1.8 million people. Expected growth will increase demand for transport, buildings, industrial production, and infrastructure at the same time as Auckland transitions away from petrol, diesel and domestic natural gas.

Auckland currently uses around 126 petajoules of energy each year. Transport accounts for approximately 62 petajoules and remains overwhelmingly dependent on liquid fossil fuels. Electricity is the principal energy source for homes and commercial buildings, while gas remains important for industrial process heat and some building heating and hot water. Auckland's energy transition is therefore not a single transition. Transport must move away from petroleum, industry must replace or reduce fossil-fuelled process heat, buildings must become more efficient and increasingly electric, and the electricity system must accommodate new demand without creating unnecessary peaks or infrastructure costs.

Electrification is reducing exposure to declining gas supply and imported petroleum, but it also means that more of Auckland's transport, industry, buildings and economic activity will depend on a reliable electricity system. This increases the consequences of network constraints, delayed investment and major supply disruptions.

The risk is not that Auckland lacks sufficient energy resources overall, but that infrastructure, investment and demand may not be sufficiently coordinated as the system changes. Rapid electrification without corresponding network capacity and flexibility could delay new connections and increase costs, while a poorly managed gas transition could leave some businesses and households exposed before viable alternatives are available. These risks make energy resilience an economic development and infrastructure-planning issue, rather than simply an energy-sector issue.

To understand how these risks may evolve, this study models a Reference pathway and a set of alternative futures for Auckland to 2050. The scenarios test how different combinations of urban form, transport demand, electrification, energy efficiency, distributed energy, industrial growth and fuel switching affect energy demand, infrastructure requirements, costs and emissions. The modelling is not intended to predict a single future, but to identify the choices that most strongly influence Auckland's exposure to energy-system risks.

Even under a business-as-usual 'Reference' future, Auckland's energy system will change substantially

Under the Reference pathway, population and economic growth continue, existing policies remain broadly in place and households and businesses progressively adopt electric vehicles, electric appliances, and alternative industrial technologies. Total delivered energy demand falls over the longer term because electric vehicles and heat pumps provide the same services using substantially less energy than fossil-fuelled technologies. However, the composition and timing of demand become increasingly important.

Electricity demand grows steadily and electricity becomes Auckland's dominant energy source. Peak electricity demand increases by around 80 per cent, from approximately 1.8 GW in 2026 to 3.2 GW by 2075. Transport electrification is the largest contributor to this increase. Without managed charging, demand flexibility and timely network investment, local constraints and connection delays could emerge even where sufficient generation is available nationally.

Domestic gas production is declining, and gas demand is projected to fall to very low levels by the mid-2050s. The transition will affect thousands of households and businesses that must replace gas appliances, industrial equipment and connections. As customers leave the gas system, the fixed costs of the network will be recovered from fewer remaining users. A poorly coordinated transition could expose late-switching households and businesses to rapidly rising prices and create uncertainty for industrial investment.

Business-as-usual therefore represents a transition, but not necessarily an orderly or least-cost transition. It leaves significant risks around electricity peaks, gas-network viability, household affordability, industrial connections and the sequencing of infrastructure investment.

The scenarios show that coordination matters more than electrification alone

The report tests four alternative futures against the Reference pathway. The scenarios vary Auckland's urban form, transport demand, building efficiency, electrification, distributed energy, fuel switching and management of electricity loads. Furthermore, the report also includes a revised reference scenario based on the latest growth projections with Plan Change 120 (PC120), that were not available for the first round of modelling.

The *Compact and Efficient* scenario provides the most favourable overall direction. More compact urban growth, lower private vehicle travel, stronger public and active transport, efficient buildings, distributed energy and smart demand management reduce total energy demand and electricity peaks, even while electrification proceeds more quickly. It delivers the lowest overall energy demand, the largest emissions reductions and the lightest overall infrastructure burden, and thus the lowest overall cost to deliver Auckland's energy requirements. It still requires substantial investment, particularly in public transport, active transport, building performance and flexible electricity systems, but this investment provides wider accessibility, affordability, health, and productivity benefits.

The *Expansion* scenario demonstrates the costs of dispersed growth. Longer travel distances, greater car dependence and less efficient buildings increase energy use and the amount of road, charging, electricity and fuel infrastructure required to serve the region. Delayed electrification may reduce some short-term expenditure, but these savings are outweighed over time by higher fuel costs, infrastructure requirements and emissions.

The *Electricity Stress* scenario shows that rapid electrification is not sufficient by itself. Faster switching away from petrol and gas reduces fossil-fuel demand, but weak building efficiency, unmanaged vehicle charging and limited flexibility produce the highest electricity peaks and the greatest pressure on generation and network capacity. Electrification works best when accompanied by efficient buildings, managed charging, storage, demand response and investment timed to anticipated demand.

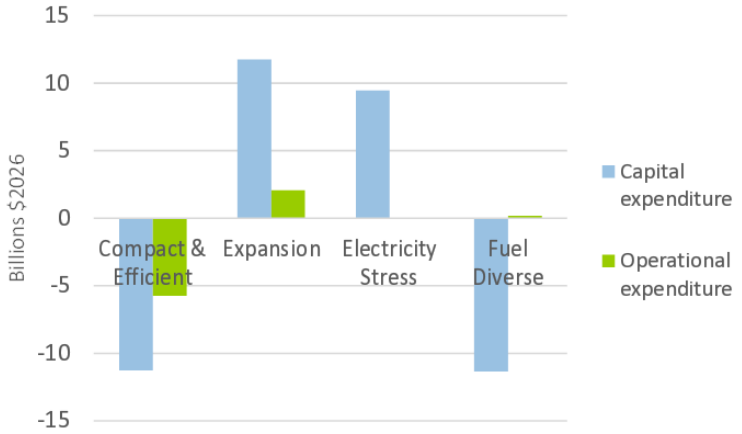
The *Fuel Diverse* scenario combines the same energy-efficiency improvements, more compact urban form, and stronger public and active transport mode shift as the *Compact and Efficient* scenario, but with a lesser shift towards electrification. It therefore provides a counterpoint to *Electricity Stress*, which tests rapid electrification without the accompanying efficiency, flexibility and mode shift. This scenario retains gas, liquid fuels and other energy sources for longer. However, it prolongs Auckland's exposure to gas-supply uncertainty, imported fuel prices, residual emissions and the costs of maintaining parallel fuel systems. It may provide short-term benefits for applications that cannot readily electrify, and the efficiency

improvements reduce the impact of increasing gas prices, but in the long run it does not benefit nearly as much from the lower operating costs associated with electrification as the *Compact and Efficient* scenario.

The *PC120* reference assumes stronger household growth, a shift towards smaller, more compact dwellings, a boost to electric vehicle uptake from fuel prices, and sector-specific changes to economic growth. Other assumptions remain as per the original reference scenario.

Over the period to 2035, the cost differences between scenarios are already material (Figure 1). In present value terms, *Compact and Efficient* reduces both capital and operating expenditure relative to the reference by $17 billion in total, while *Expansion* increases both by $14 billion in total. *Electricity Stress* also requires substantially higher capital investment because stronger demand and peak growth drive additional electricity infrastructure, even though operating expenditure remains close to the reference. *Fuel Diverse* lowers near-term capital expenditure by $11 billion, largely through lower vehicle costs and reduced electricity infrastructure requirements, but operating costs are slightly higher and increase further beyond 2035. These estimates do **not** include costs to build or operate the LNG import terminal assumed under this scenario.

Figure 1: Present value change in expenditure relative to the reference, 2026–2035



The updated *PC120* reference has higher overall energy-related costs than the original reference, while also supporting higher economic growth. The relative differences between the original scenarios remain relevant, however. These differences illustrate how electrification, transport and demand management also affect costs.

The central finding is that the key choice is not simply between faster and slower electrification. It is between a coordinated transition, in which efficiency, flexibility, transport and infrastructure develop together, and an uncoordinated transition in which demand and investment occur sub-optimally.

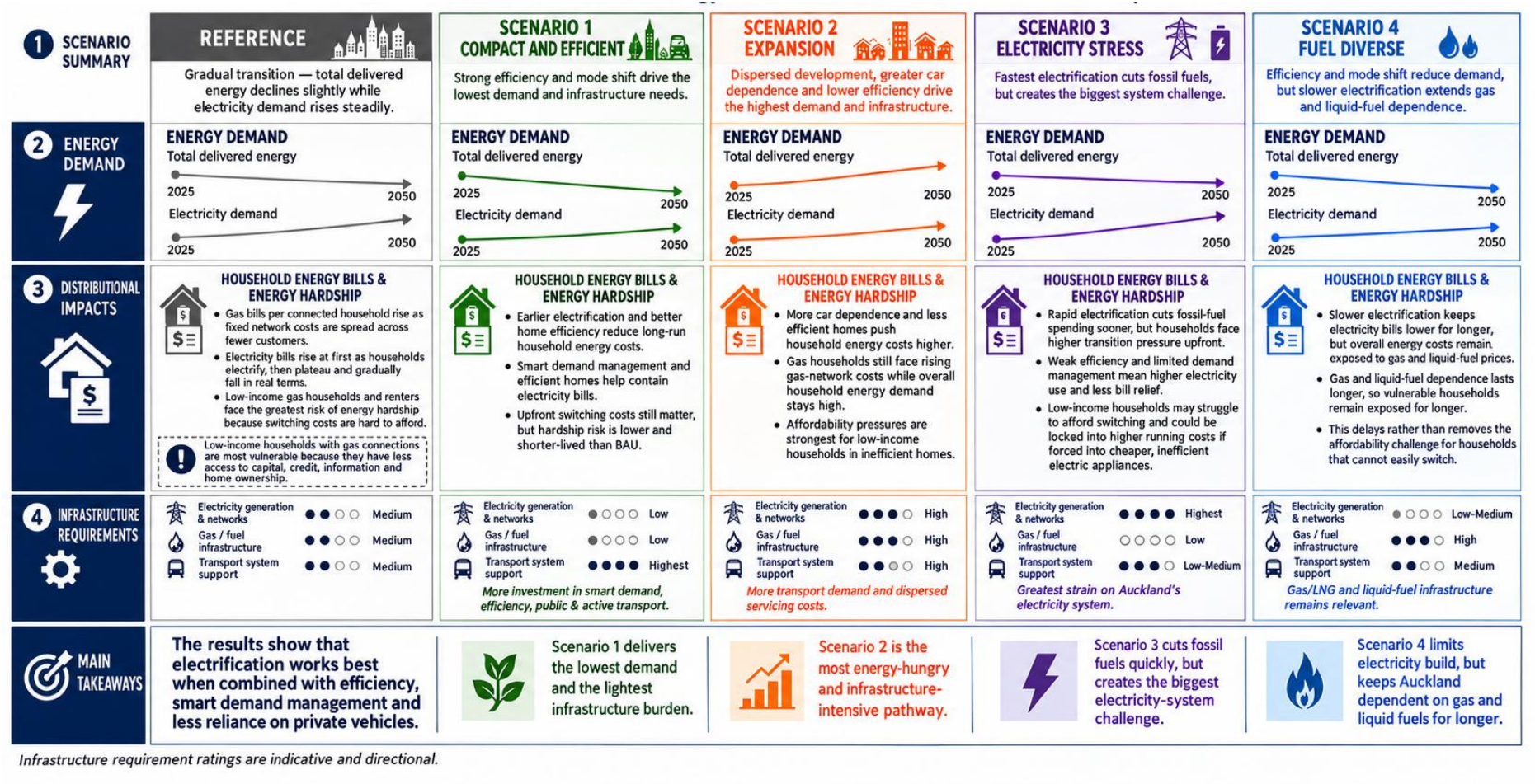
The transition will create both savings and distributional risks

For most Auckland industries, energy represents a relatively modest share of total input costs. However, the effects will be material for some energy-intensive businesses and for firms facing major equipment or electricity-connection investments. Primary metals, indoor cropping, glass and non-metallic minerals, chemicals, wood,

pulp and paper, and other high-temperature industries face the greatest exposure. Early energy-efficiency work, engagement with network providers, flexible connection arrangements, and coordinated planning for industrial clusters can reduce these risks.

Electrification is expected to reduce household transport, heating and hot-water costs over the long term. Electric vehicles have lower fuel and maintenance costs, while efficient electric heating is generally cheaper to operate than gas. However, these benefits require upfront expenditure and will not be shared evenly. Lower-income households, renters and small businesses may have less access to capital, credit, information, and suitable buildings. Low-income households that remain connected to gas could be particularly vulnerable as network costs are spread across fewer customers. Targeted assistance with efficient appliances, electrical upgrades, building retrofits and access to affordable transport options will be necessary to prevent the transition from increasing energy hardship.

Figure 2: Summary of scenario outcomes to 2050



Infrastructure requirement ratings are indicative and directional.

Auckland's most important energy decisions are often made outside the energy sector

Land-use and transport choices determine travel distances, building types, infrastructure utilisation and the location and timing of future electricity demand. Auckland Council's strongest influence therefore lies in integrating energy into the Future Development Strategy, district planning, infrastructure sequencing, transport planning, procurement and management of Council assets.

Auckland's resilience will not come from regional energy self-sufficiency. The region will continue to depend heavily on electricity generated elsewhere in New Zealand. Resilience will instead require strong transmission and distribution connections, diverse national generation, flexible demand, distributed solar and batteries, and appropriate backup for critical services.

Energy efficiency should be treated as an infrastructure investment. Improving buildings, industrial processes and transport accessibility can avoid or defer expenditure on generation, networks, charging infrastructure and fuel supply. Flexibility has similar value. Managed vehicle charging, thermal storage, batteries, flexible industrial demand and time-varying pricing can reduce peak demand and make better use of existing infrastructure.

A practical pathway for Auckland

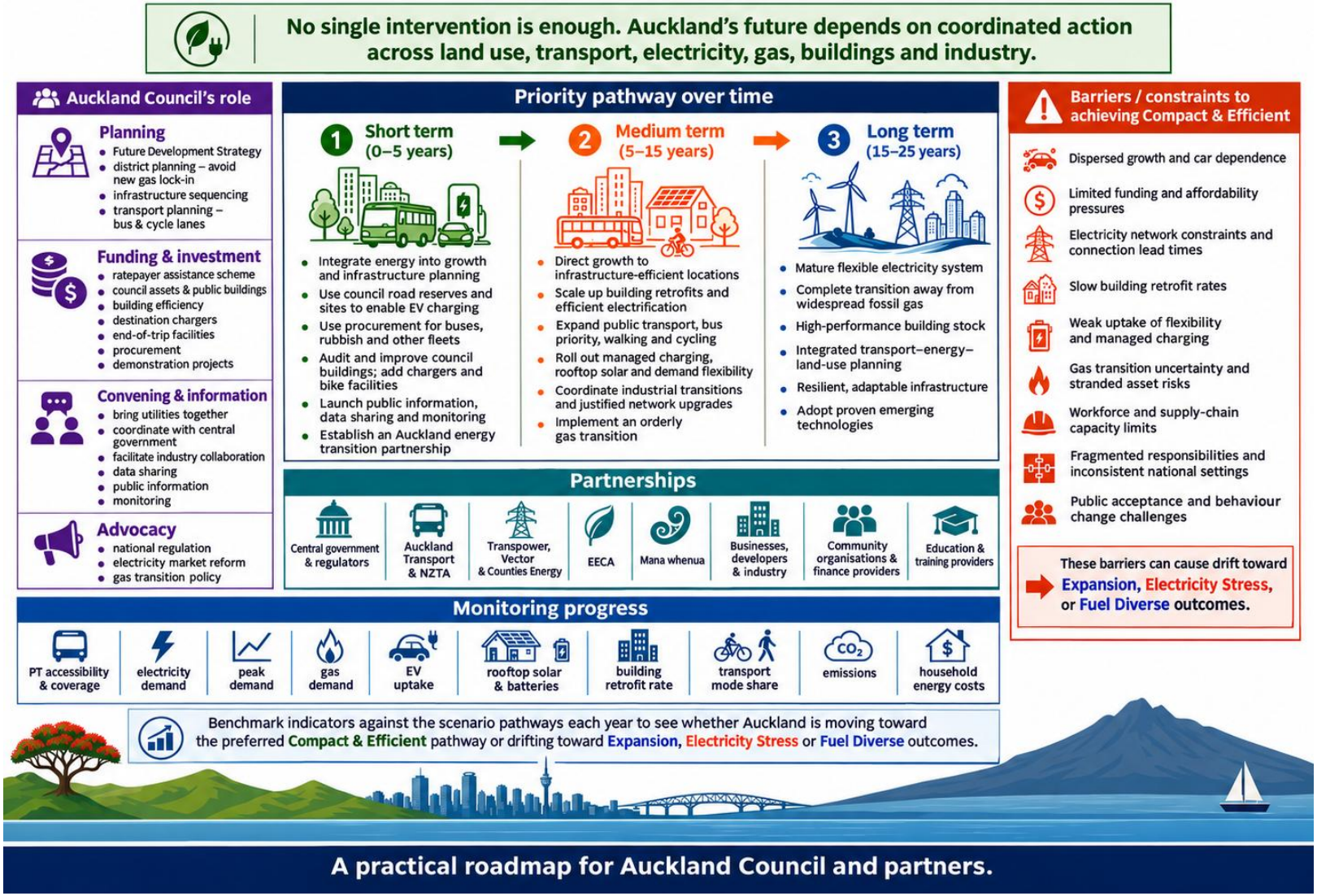
Auckland should pursue the *Compact and Efficient* direction while retaining the ability to respond if actual development begins to resemble the *Expansion*, *Electricity Stress* or *Fuel Diverse* scenarios. The priority actions are to:

- Integrate energy demand, electricity capacity and gas-transition risk into spatial planning, growth decisions, and infrastructure sequencing.
- Prioritise compact, infrastructure-efficient development and expand practical alternatives to private vehicle travel.
- Improve building and industrial energy efficiency before sizing new supply and network infrastructure.
- Coordinate electrification with managed charging, demand flexibility, distributed energy and timely electricity-network investment.
- Establish an orderly gas-transition pathway, investigate planning restrictions on extending gas to new developments, and provide clear information and targeted assistance to affected consumers and businesses.
- Use Council procurement, buildings, fleets and land to demonstrate efficient technologies and support charging, renewable energy and flexible demand.
- Establish a regional energy-transition partnership and monitor electricity demand, peak loads, network readiness, gas connections, transport behaviour, building retrofits, household affordability and emissions.

The recommendation is for implementation to occur in three stages. During the first five years, Auckland should establish governance and monitoring, incorporate energy into planning, reduce immediate demand and prepare coordinated plans for charging, industrial transition and gas replacement. Over the following five to fifteen years, the focus should move to delivery at scale, including building retrofits, public and active transport, managed charging, electricity-network investment, industrial fuel switching and household support. By around 2050, the desired outcome is a compact and accessible city supported by a high-performance building stock, a mature flexible electricity system, substantially reduced fossil-gas use and infrastructure that is resilient to climate, supply and technology risks.

No single organisation can deliver this transition. Historically, many of the agencies involved focused on separate parts of the energy, transport, land-use and infrastructure system. This tends to result in fragmented policy responses and missed opportunities to manage trade-offs across sectors. Auckland will need a more integrated approach and sustained partnerships with central government, regulators, Auckland Transport, NZ Transport Agency Waka Kotahi, Transpower, Vector, Counties Energy, Energy Efficiency and Conservation Authority (EECA), gas infrastructure providers, businesses, mana whenua, and community organisations. The objective of this report is not to predict one future perfectly, but to make low-regrets recommendations that would improve affordability, resilience and emissions outcomes across a range of plausible futures.

Figure 3: Graphic summary of actionable pathways



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1 Introduction

1.1 The case for change

Energy is a fundamental input into Auckland's economy and the wellbeing of its residents. The affordability, reliability, and environmental sustainability "trilemma" of energy influence business competitiveness, household living costs, investment decisions, infrastructure requirements and the region's ability to meet its emissions objectives.

Auckland's continued growth, declining domestic gas supplies, increasing electrification and new electricity-intensive industries will place greater demands on the region's energy infrastructure over coming decades. Businesses that currently depend on gas may need to invest in alternative technologies, while electrification of transport, industry and buildings will increase electricity demand. This increases the importance of ensuring that sufficient, affordable and reliable energy is available when and where it is needed.

Continuing along the current trajectory is therefore not a neutral option. Auckland could remain exposed to declining gas availability and higher fuel costs, while poorly coordinated electrification could increase peak electricity demand and bring forward expensive network investment. The Auckland RETA work already identifies electricity network upgrades and installation costs as important barriers to industrial electrification, while highlighting energy efficiency, load flexibility and storage as complementary ways of reducing these pressures.

Many of the decisions that will determine Auckland's future energy demand are made outside the energy sector. Auckland Council does not control national electricity or fuel markets, but it has significant influence over some underlying drivers through spatial planning, transport, infrastructure investment, regulation, its own assets and procurement, economic development activity, and its ability to convene infrastructure providers, businesses and central government. Purposeful coordination can preserve options and reduce future costs. Delayed or poorly aligned decisions risk locking Auckland into higher energy and infrastructure costs and increased exposure to energy supply and affordability risks.

1.2 What this report examines

The purpose of this study is to help Auckland Council understand how the pressures outlined above may affect Auckland's future energy system, and where Council and its partners can influence those outcomes. The report is an Auckland-specific assessment of current and future energy demand and supply, and it identifies pathways that can support a secure, affordable, resilient and lower-emissions energy system. The study brings together existing evidence, Auckland-specific datasets and integrated energy and economic modelling to examine how the region's energy system may evolve under Reference conditions and under a range of plausible alternative futures.

The study has four main objectives:

1. Establish a coherent baseline of Auckland's current energy use, supply sources and supporting infrastructure.
2. Project Auckland's energy demand, costs and emissions to 2050 under a Reference pathway.
3. Compare alternative future pathways that vary Auckland's urban form, transport patterns, energy efficiency, electrification, fuel switching, distributed energy uptake and industrial development.
4. Identify the implications of these pathways for households, businesses, infrastructure providers and Auckland Council, including areas where early action could reduce future costs and transition risks.

These objectives reflect Auckland Council's need for advice that enables elected members, officers and partner organisations to compare the costs and benefits of different energy-transition pathways and to influence the timing of public and private investment to promote affordability, reliability and sustainability.

The analysis addresses the following key questions:

- How much energy does Auckland currently use, for which activities, and from which sources?
- How are population growth, economic development, urban form, transport patterns, technology uptake, and declining gas availability likely to affect future energy demand?
- What are the likely consequences of continuing broadly along the current pathway?
- How could greater energy efficiency, more compact urban development, transport mode shift, electrification, distributed generation, demand flexibility and alternative fuels alter Auckland's future energy needs, including affordability, reliability, and sustainability?
- What electricity, gas, and transport infrastructure may be required under different futures?
- How do the pathways compare in terms of capital and operating costs, household expenditure, business competitiveness, emissions and resilience?
- Which sectors, locations and communities face the greatest transition risks?
- Where does Auckland Council have meaningful influence, and where will outcomes depend primarily on central government, regulators, network companies, businesses or households?

This assessment complements the forward planning already being undertaken by Transpower, Vector and Counties Energy.

- Transpower, as New Zealand's national transmission grid owner and operator, is developing the Te Kanapu Future Grid Blueprint[1]. Te Kanapu considers how New Zealand's national electricity transmission system should evolve under a range of plausible national futures out to 2050.
- Vector and Counties Energy undertake detailed planning for the distribution networks that serve Auckland's households and businesses.

This report examines what the modelled alternative futures will likely mean for Auckland's energy demand, infrastructure requirements, economy and communities. Rather than developing an alternative national outlook, the analysis builds on national and regional evidence and applies it to Auckland's specific characteristics, growth patterns, and energy challenges.

A central purpose of the study is to connect energy analysis with Auckland Council's wider responsibilities. Energy demand is shaped by decisions about the location and form of development, transport investment, infrastructure sequencing, regulatory planning and Council procurement. Conversely, the availability and cost of energy can affect where businesses invest, whether new development can be serviced efficiently, and whether households and firms can afford to adopt lower-emissions technologies.

The findings are therefore intended to inform Auckland Council's spatial and infrastructure planning, economic development, investment attraction, climate policy, social innovation and partnership activities. They are also intended to help the Council identify where energy considerations should be incorporated more explicitly into long-term planning and investment decisions, and where Council can use its regulatory, investment, advocacy, and

[1] https://www.transpower.co.nz/our-work/te-kanapu

convening roles to support coordinated action by both public and private actors.

The study does not assume that Auckland Council can determine all regional energy outcomes. Rather, it distinguishes between matters the Council can directly influence and those requiring partnership with central government, Auckland Transport, Transpower, Vector, Counties Energy, Firstgas, EECA, businesses, mana whenua, and community organisations.

1.3 Scope

This study considers the Auckland region and examines the evolution of its energy system to 2050, with particular emphasis on conditions in 2035 and 2050. While the analysis focuses on Auckland, it also considers national energy supply, regulatory and market developments where these materially influence regional energy outcomes.

The assessment covers the major components of Auckland's energy system:

- electricity demand, supply, transmission and distribution;
- natural gas demand, supply and distribution;
- transport energy across passenger and freight transport; and
- industrial process heat.

The analysis considers energy use across the residential, commercial, industrial and transport sectors, together with the infrastructure required to support future demand. We examine how alternative patterns of population growth, urban development, economic activity, technology uptake and fuel switching affect energy demand, infrastructure requirements, costs and emissions.

The study does not seek to forecast a single future. Instead, it evaluates a Reference pathway alongside a range of alternative scenarios to explore the implications of different energy transition pathways for Auckland.

An additional Reference scenario incorporates updated Auckland Growth Scenario (AGS23v2) household projections and economic growth projections, including employment forecasts across 19 industry sectors, which became available after the original scenarios were developed. This supports consideration of Plan Change 120, although updated transport modelling is not yet available.

1.4 Approach

The study combines scenario analysis, energy system modelling, economic analysis and stakeholder engagement to assess Auckland's future energy needs and the implications of alternative transition pathways.

A Reference scenario provides the reference case, reflecting current policies, expected population and economic growth, technology uptake and planned infrastructure. Four alternative scenarios examine how different patterns of urban development, transport, electrification, energy efficiency, distributed energy and fuel switching could influence future energy demand, infrastructure requirements, costs and emissions.

The analysis uses the Emissions-Economy New Zealand (ENZ) model, supplemented with Auckland-specific assumptions and evidence from Auckland Council, Transpower, Vector, Counties Energy, EECA, MBIE and other published sources. This enables interactions between energy demand, infrastructure, fuel choice, costs, emissions and economic activity to be assessed in an integrated framework.

The scenarios and key assumptions were informed through stakeholder engagement with representatives from Auckland Council, Auckland Transport, Transpower, Vector, Counties Energy, Firstgas, EECA, NZ Transport Agency Waka Kotahi, major energy users, and other organisations. Stakeholder input was used to test

the plausibility of scenarios and identify the key uncertainties facing Auckland's energy transition.

The research team also engaged with Iwi partners, Ngāti Pāoa Iwi Trust, and Ngāti Whātua o Kaipara who expressed interest in the research.

2 Auckland Today

Tāmaki Makaurau Auckland is the economic centre of Aotearoa New Zealand. Understanding the scale, composition, and energy dependence of its economy is essential context for any scenario work about the region's energy future, and for considerations about the region's future more generally. The choices Auckland makes on energy (how quickly it transitions, at what cost, and under what conditions) will also have consequences that extend well beyond the regional boundary.

2.1 Scale and national significance

Auckland's economy generated $160 billion in GDP in the year to March 2024, representing 38 per cent of New Zealand's total economic output - a share that has grown from 34 per cent at the end of the Global Financial Crisis and continues to increase. The region's GDP is more than double that of Wellington, the next largest contributor. On a per capita basis, Auckland generated $89,000 of GDP per person in 2024, approximately 20 per cent above the rest of the country.

Despite being Auckland's largest economic crisis in recent memory, the post-COVID recessionary environment of 2024–25 is widely expected to be temporary. Provisional data shows a GDP contraction of 1.3 per cent in the year to March 2025 (the first decline since the GFC) but business confidence had reached its highest level since 2014 by early 2025 and the structural growth drivers underpinning the region remain intact.

The region is home to 1.8 million people or 34 per cent of New Zealand's population. That share is projected to rise to 37 per cent by 2048, driven by sustained migration-led growth. Auckland's population is younger, more diverse, and more heavily concentrated in prime working age than the rest of the country: 68 per cent of Aucklanders fall into the 15–64 age band, compared to 65 per cent elsewhere. Auckland is also the world's largest Polynesian city and is home to 24 per cent of all Māori in New Zealand.

Auckland's population is concentrated along the central isthmus and around the major metropolitan centres extending north to Albany, west to Henderson, south to Manukau and Papakura, and east to Botany, reflecting the historic pattern of urban development and transport investment. More recent growth has increasingly occurred in the southern and northwestern parts of the region, while ongoing intensification has increased residential densities in established suburbs and around rapid transit corridors. Despite this shift towards higher-density development, Auckland continues to accommodate substantial greenfield expansion at its urban edge.

Auckland Council's Future Development Strategy (FDS) anticipates that most future growth will occur through a combination of urban intensification and targeted greenfield development. The strategy prioritises intensification within existing urban areas, particularly around the city centre, metropolitan centres and rapid transit stations, while directing greenfield expansion to future urban areas in the north (Silverdale and Dairy Flat), northwest (Whenuapai, Red Hills and Kumeū-Huapai), and south (Drury, Paerata, Pukekohe and surrounding areas). This approach seeks to accommodate continued population growth while making more efficient use of infrastructure, reducing travel distances, and supporting more sustainable transport and energy outcomes.

2.2 Current energy system

Auckland is projected to use around 126 PJ of energy in 2026 (Figure 4). Transport accounts for the largest share, at about 60 PJ excluding international air travel. Transport is overwhelmingly dependent on liquid fossil fuels imported from overseas. Light vehicles alone use 45 PJ. Outside of transport, electricity is the dominant energy source, supplying most residential and commercial demand and a substantial share of industrial activity. Industrial energy demand relies on gas and other fuels for boilers, furnaces and process heat. Biomass and

coal are comparatively minor sources, including burners used for home heating.

Auckland's energy transition is not a single transition, but several occurring simultaneously. While the term energy transition is often associated with replacing fossil fuels with electricity, the figure shows that different sectors face fundamentally different challenges:

- transport is primarily a liquid fuels challenge, with most energy demand currently associated with petrol, diesel and jet fuel. Land transport is likely to transition over time to battery powered electric vehicles.
- industry is primarily a process heat challenge, where gas and other fuels continue to play important roles in boilers, furnaces and industrial processes. Electrified process heat (particularly at lower temperatures) and biomass represent increasingly viable alternatives, especially as New Zealand’s domestic gas production is in decline.
- residential and commercial buildings are increasingly a peak load management challenge, with future change driven by electrification, rooftop solar, and smart devices.
- energy infrastructure is primarily a challenge of managing deep uncertainty, as future investment depends on where and when demand emerges, the pace of electrification, and the need to improve resilience to natural hazards, including those exacerbated by climate change.

These differences demonstrate why a single forecast is insufficient for planning Auckland's future energy system. The pace and scale of transport electrification, industrial fuel switching, population growth, urban development and technology adoption will reshape different parts of the energy system in different ways. Consequently, this report considers a range of plausible future scenarios to explore how these interacting transitions could affect Auckland's future energy demand and infrastructure requirements.

2.3 How Auckland differs from the rest of New Zealand

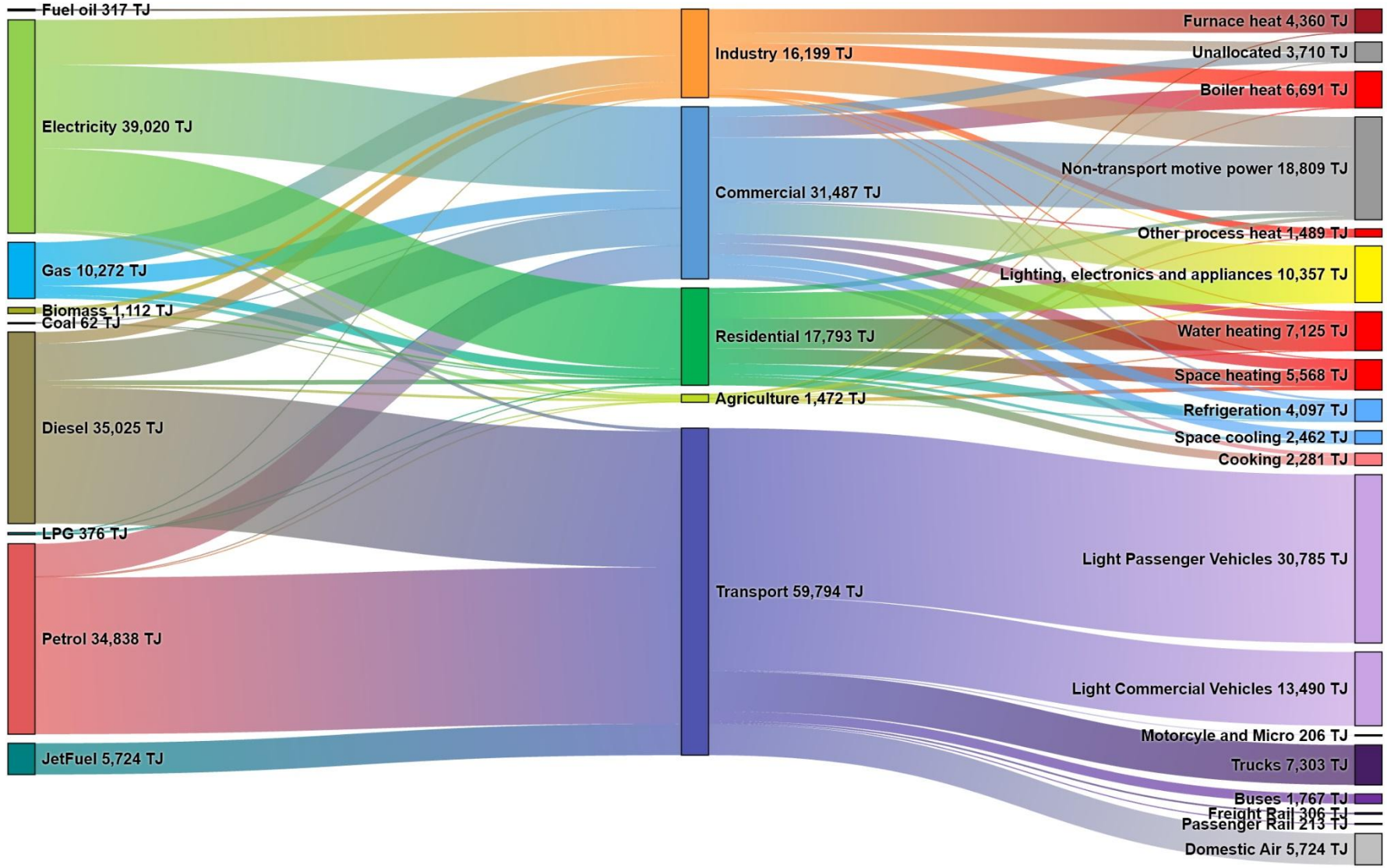
Auckland is predominantly an energy-consuming rather than energy-producing region. It relies on electricity generated elsewhere in New Zealand, natural gas transported into the region, and imported liquid fuels. Its energy resilience therefore depends critically on strong transmission and distribution connections, sufficient infrastructure capacity, and effective use of efficiency, flexible demand and distributed energy resources.

The Auckland region has relatively low emissions intensity, accounting for only 13% of greenhouse gas emissions in 2023 (Auckland Council, 2025). This low emissions share reflects limited agricultural activity and electricity generation within the region, and a greater concentration in service industries than the rest of the country.

The region contains around 195 process-heat sites, nearly twice as many as the next-largest region, but demand is spread across many small and medium-sized users. Auckland’s transition therefore involves many individual business investment and network-connection decisions across the region.

Auckland’s metropolitan scale and growth make the relationship between urban form, transport and energy particularly important. Continued outward growth increases travel distances, car dependence and the infrastructure required to move people and freight. Auckland plays a disproportionately important role in New Zealand’s freight and logistics system, meaning that the energy implications of its transport choices extend well beyond the region.

Figure 4: Sankey diagram of 2025 energy use in terajoules by source, sector, and end use



3 Recent developments affecting Auckland's energy outlook

What has changed in Auckland's planning environment that makes this study necessary?

Several important developments have occurred in recent years that have changed the context for energy planning in Auckland. These include changes in national policy, developments in electricity and gas infrastructure, evolving economic conditions, and growing recognition of the links between energy, transport and urban development. This section summarises these recent developments before considering the factors that will influence Auckland's future energy demand.

3.1 Changing national climate and energy policy

Since 2023, New Zealand's climate and energy policy has undergone a significant change in direction. While the Climate Change Response Act and New Zealand's emissions budgets remain in place, recent policy has shifted towards greater reliance on market mechanisms, particularly the New Zealand Emissions Trading Scheme (ETS), as the primary tool for reducing emissions. This represents a departure from earlier approaches that relied more heavily on sector-specific regulations and incentives to deliver emissions reductions.

Several policy changes illustrate this new direction. The Clean Car Discount was discontinued in 2023, and the Clean Car Standard has subsequently been amended, reducing the rate at which vehicle emissions standards tighten and allowing greater flexibility for vehicle importers. Similarly, national direction under the Resource Management Act that prohibited the installation of new coal-fired process heat boilers has been withdrawn. Industrial decarbonisation is now expected to be driven primarily through carbon pricing under the ETS rather than direct regulation or co-funding.

The Government has also cancelled work on a National Energy Strategy that was intended to provide a long-term framework for New Zealand's energy transition. Instead, policy has focused on addressing more immediate priorities, including improving energy security, accelerating consenting for renewable electricity generation and transmission infrastructure, and responding to concerns over declining domestic gas supply. These initiatives address pressing challenges, but without a national energy strategy there is less formal coordination of longer-term decisions across the energy system, with future development shaped through a combination of market responses, sector planning, and individual policy decisions.

For Auckland, this creates greater uncertainty around the timing of transport electrification, industrial fuel switching and energy demand, reinforcing the value of considering multiple plausible future scenarios rather than relying on a single policy trajectory.

3.2 Auckland's economic outlook has softened, but long-term growth remains strong

Auckland's economy has weakened since 2023 as high interest rates, inflation, and subdued domestic demand contributed to a recession during 2024 and 2025. The slowdown has been reflected in reduced construction activity, rising unemployment, and weaker business investment. However, inflation has eased, interest rates have begun to decline, and business confidence is showing signs of recovery (Auckland Council, 2025).

Despite these short-term challenges, Auckland's long-term growth outlook remains positive. As New Zealand's largest city and economic centre, Auckland is expected to continue experiencing strong population growth, increased employment and ongoing urban development. While recent economic conditions may delay investment and moderate energy demand in the near term, they are unlikely to alter the underlying drivers of long-term energy demand.

3.3 Urban development choices are increasingly important

Urban development is increasingly recognised as a key influence on Auckland's future energy demand and emissions. The location and density of new housing and employment affect transport demand, infrastructure costs, and the feasibility of public transport, walking and cycling as compared to private vehicle travel.

Auckland's Future Development Strategy identifies a more compact urban form as an important means of accommodating population growth while making more efficient use of existing infrastructure. Similarly, the Transport Emissions Reduction Pathway (Auckland Council, 2022) and Auckland's Vehicle Kilometres Travelled Reduction Plan (Auckland Council, 2024) recognise that urban form will play a critical role in reducing transport energy use and emissions. As Auckland continues to grow, decisions about where and how development occurs will have long-lasting implications for energy demand, network investment and the cost of delivering energy infrastructure.

Recent analysis by the New Zealand Green Building Council has also strengthened the evidence around the role of building efficiency and electrification in reducing fossil gas demand and moderating future energy requirements. These implications are discussed further in Section 4.2.

3.4 Plan Change 120 and updated growth expectations

Auckland's future urban development is being reshaped by Plan Change 120 (PC120), which was notified in November 2025[2]. The plan change proposes significant changes to the Auckland Unitary Plan to accommodate future housing growth while strengthening protections against natural hazards. PC120 seeks to encourage more housing in well-connected locations, especially around the city centre, metropolitan centres, rapid transit stations and selected frequent bus routes. The plan change is intended to provide greater housing choice while also making more efficient use of existing infrastructure and reducing development in areas exposed to significant natural hazards.

In April 2026, the Government reduced Auckland's minimum housing capacity requirement from approximately two million to 1.4 million dwellings[3]. This allows Auckland Council greater flexibility over where development capacity is enabled. Auckland Council then proposed amendments to PC120 in July 2026, retaining opportunities for intensification around key centres and transport corridors and reducing the extent of intensification elsewhere[4].

These changes will also affect Auckland’s future energy needs. Where new housing is built, and the type of housing developed, will influence electricity consumption, transport energy use and the investment needed in electricity networks. More compact development can reduce energy demand, as smaller homes and shared walls generally require less heating, while better access to jobs, services and public transport can reduce the need to drive. However, concentrating housing in existing urban areas can also put additional pressure on local electricity networks, potentially requiring upgrades to meet growing demand.

Updated economic growth projections have also become available, providing forecasts of employment across 19 industry sectors. These are important for estimating future energy demand because energy intensity varies between industries and regional trajectories are different to the national outlook.

[2] https://akhaveyoursay.aucklandcouncil.govt.nz/aucklands-future-housing-plan
[3] https://environment.govt.nz/acts-and-regulations/legislation/resource-management-auckland-housing-amendment-act/
[4] https://ourauckland.aucklandcouncil.govt.nz/news/2026/08/aucklanders-get-another-say-on-plan-change-120

The original energy modelling scenarios for this study were developed before the revised Auckland Growth Scenario (AGS23v2) and updated economic growth projections became available. To incorporate the more recent information and provide results relevant to Auckland's evolving planning context, an updated current policy scenario has been modelled using the revised household and economic growth projections.

This additional scenario provides an updated assessment of Auckland's future energy requirements under the revised growth outlook. It does not represent a detailed assessment of the incremental effects of PC120, because updated transport modelling is not yet available. However, it provides a more current baseline that reflects Auckland Council's latest expectations for the region's growth trajectory.

3.5 The gas system has fundamentally changed

New Zealand's gas system has changed materially in recent years. Production from existing fields has declined more rapidly than previously anticipated, while estimates of remaining reserves and future production have been revised down. Gas availability has consequently tightened, prices have risen, and some business users have had trouble securing longer-term supply contracts.

At the same time, the strategic outlook for gas distribution has shifted. Rather than planning for continued network growth, Auckland's gas distribution company, Vector, is now considering how a declining gas pipeline network in Auckland could be managed. Its 2023 report (Vector Limited, 2023) identifies growing risks of asset stranding, under-recovery of network costs and regulatory arrangements that were designed for an expanding rather than contracting customer base. Vector estimates potential under-recovery of $973 million through to 2050 under an unmanaged wind-down and highlights the substantial costs consumers could face if they were required to replace gas appliances prematurely.

These developments mean that Auckland's gas system can no longer be treated as a stable continuation of past arrangements. Declining upstream supply and uncertainty over the long-term viability of the distribution network have become established features of the current energy context. The implications for future gas prices, fuel switching and electricity demand are considered later in this report.

3.6 Electricity is the critical enabling infrastructure

Electricity has taken on a more central role in Auckland's economy and infrastructure planning in recent years, as well as New Zealand more generally. It is no longer used primarily to meet established household and business demand; it is increasingly the infrastructure through which transport, industrial production, and other energy uses are being modernised. The 2023 government co-funded project to install an electric arc furnace at New Zealand Steel's Glenbrook site is a prominent example of this shift, replacing coal-based production with a major new electricity-dependent industrial process.

This changing role is now evident in electricity network planning. Vector's 2026 Electricity Asset Management Plan for its electricity distribution network identifies data centres, large commercial connections, infrastructure projects, and conversions from gas to electricity as material drivers of additional network investment. Relative to its previous plan, Vector increased forecast expenditure for large customer connections and system growth and now proposes nearly $5.4 billion of capital investment over the ten years to 2036. Counties Energy is similarly investing in new substations, capacity upgrades and network resilience in response to growth in southern Auckland.

The publication of EECA's Auckland Regional Energy Transition Accelerator (RETA) report in 2025 also reflects the increased importance of electricity infrastructure. The report assesses network capacity alongside the requirements of 191 process-heat sites and

treats access to transmission and distribution capacity as a central consideration in industrial energy decisions.

For this study, these developments mean that electricity infrastructure (or lack thereof) should be treated as an enabler (or constraint) for the energy transition. Different scenarios should therefore test not only different levels of electrification, but also different patterns of demand growth, network utilisation and load flexibility.

At the same time, meeting future electricity demand will involve more than increasing generation and network capacity. Demand flexibility, distributed energy resources, and energy efficiency can reduce peak electricity demand, defer investment in generation and network infrastructure, and improve the utilisation and resilience of the electricity system. Recent work has highlighted the substantial potential for demand-side flexibility to contribute to these outcomes (EECA, 2026).

3.7 Energy security has become a higher priority

Recent events have increased the emphasis placed on energy security alongside affordability and emissions reduction.

The oil price shock from the US-Israel-Iran war demonstrated that Auckland (and New Zealand) remains highly exposed to international liquid fuel markets. Even though the disruption occurred overseas, higher global oil prices were rapidly transmitted into domestic transport costs, freight costs and business operating costs. The event reinforced the importance of energy security and highlighted the value of reducing dependence on imported petroleum through greater energy diversity and resilience.

At the same time, declining domestic gas supply and periods of electricity system stress have reinforced the need for a resilient electricity system. Auckland was previously supported by significant local gas-fired generation, including the Southdown and Ōtāhuhu power stations. Both stations were subsequently retired as ageing assets faced significant refurbishment costs and changing site economics. Over the same period, major transmission and voltage-support investments, including new transmission capacity and Static Synchronous Compensators (STATCOMs), increased the amount of electricity that could be supplied reliably into Auckland from elsewhere in New Zealand. This transition reduced emissions and electricity costs but also increased Auckland's reliance on the resilience of the national transmission grid owned and operated by Transpower.

This increased focus on resilience is reflected in the 2025 New Zealand Infrastructure Resilience Index (NZIER & Downer New Zealand, 2025), which ranked Auckland as New Zealand's least resilient region overall. The assessment attributed this largely to the region's dependence on nationally significant electricity infrastructure and the authors' perceptions of the cascading consequences of infrastructure disruption.

We have a significantly different view to the authors of that report as to Auckland's energy resilience. In particular, Auckland's electricity system benefits from substantial redundancy within the national transmission network, and transmission assets are generally at least as reliable as local generation. However, a major supply failure would still cause significant disruption given Auckland's scale and economic importance. This reinforces the importance of maintaining resilience as electricity becomes increasingly central to transport, industry and essential services.

3.8 Energy outcomes need to be more integrated into broader Auckland planning decisions

The developments described above reinforce the need to consider Auckland's energy system as an interconnected whole. Changes in policy, fuel availability, urban development and infrastructure planning are increasingly linked, with decisions in one part of the system influencing outcomes elsewhere. This means that future

energy demand cannot be understood by considering individual fuels or sectors in isolation.

They also increase uncertainty around the pace and direction of change. Population and economic growth remain important drivers of energy demand, but future outcomes will also depend on technology uptake, consumer behaviour, government policy, fuel availability and infrastructure constraints.

Rather than attempting to predict a single future, this study adopts a scenario-based approach to explore how different combinations of these drivers could influence Auckland's future energy demand and infrastructure requirements.

4 Drivers of Future Energy Demand

What mechanisms determine future energy demand, and which of those are varied in the scenarios?

Future energy demand will be shaped by a combination of long-term structural trends, decisions made by governments, businesses and households, and constraints imposed by the energy system. These drivers provide the basis for the scenario framework developed in the following chapter.

4.1 Underlying drivers

The underlying drivers of future energy demand are the long-term demographic, economic, and spatial trends that determine the scale and location of energy use. These factors change relatively slowly and are largely independent of energy policy, but they establish the baseline level of demand that future energy systems will need to meet.

4.1.1 Population growth and demographic change

Population growth is expected to remain the primary driver of long-term energy demand in Auckland. More people increase demand for housing, transport, businesses and public services, while demographic trends such as household formation and ageing influence the type and location of energy use. Auckland is expected to continue accounting for a growing share of New Zealand's population over coming decades.

4.1.2 Economic growth and structural change

Economic growth increases demand for energy across the residential, commercial, industrial and transport sectors. However, the relationship is influenced by the structure of the economy, with service industries generally requiring significantly less energy per dollar of economic output than manufacturing and other energy-intensive activities. Future demand will therefore depend on both the pace of economic growth and the composition of Auckland's economy.

4.1.3 Urban development

The way Auckland grows will influence both the amount and location of future energy demand. Higher-density development generally supports shorter travel distances (including active modes of travel like walking and cycling, and public transport) and more efficient infrastructure, while dispersed greenfield growth typically requires greater transport and network investment, as well as potentially greater levels of travel by private vehicles. However, increasing density in existing suburbs can impose significant electricity distribution upgrade costs if the associated electricity demand is not managed in a way that avoids significant peak demand growth.

Decisions about urban form will therefore have an important influence on future energy demand and infrastructure requirements.

4.2 Choices that shape future energy demand

While population and economic growth establish the baseline level of energy demand, future energy consumption will also be shaped by decisions made by governments, businesses and households. These choices will influence not only how much energy is consumed, but also the mix of fuels, the timing of demand, and the infrastructure required to support it.

This study examines alternative combinations of these choices to provide insights into their relative merits, trade-offs and implications for Auckland's future energy demand and infrastructure requirements.

4.2.1 Technology and consumer choices

The technologies adopted by households and businesses will have a major influence on future energy demand. Decisions to replace fossil fuel technologies with electric alternatives will increase electricity

demand while reducing demand for liquid fuels and natural gas. For example:

- Electric vehicle uptake.
- Electrification of industrial processes.
- Heat pumps replacing gas or solid fuel heating.
- Rooftop solar, batteries, and home energy management systems.
- Investment in more energy-efficient buildings, appliances and equipment.

The pace of technology adoption will depend on costs, consumer preferences, business investment and government incentives.

Recent work by the New Zealand Green Building Council (NZGBC) highlights that building technology choices can have wider implications for New Zealand's energy system. Efficient electrification of space and water heating could materially reduce natural gas and LPG use while also lowering net electricity consumption, particularly where heat pumps replace less efficient heating technologies. This could preserve scarce gas for harder-to-transition industrial uses and reduce winter electricity demand peaks (NZGBC, 2025).

Distributed technologies such as rooftop solar and hot-water heat pumps also reduce on imported fuels, lower peak electricity demand and reduce pressure on firm generation requirements (NZGBC, 2026).

4.2.2 Government and system choices

NZGBC (2024) emphasises that these outcomes depend on the policy environment, including building standards, fossil gas phase-out measures, and energy-performance disclosure, rather than on energy prices and consumer choice alone. The system determines the opportunities available to households and businesses and can significantly affect the scale, timing and location of future energy demand. Examples include:

- Urban planning and the location of future development.
- Investment in public transport and other transport infrastructure.
- Electricity generation, transmission, and distribution investment.
- Management of the transition away from natural gas.
- Energy efficiency standards and certification.
- Electricity market design and incentives for demand flexibility.
- Climate, energy and infrastructure policies.

These decisions shape the broader energy system within which consumer choices are made. Different combinations of technology adoption and system-level decisions could lead to markedly different energy futures for Auckland, providing the basis for the scenario analysis presented in this report.

4.3 Enabling factors and constraints

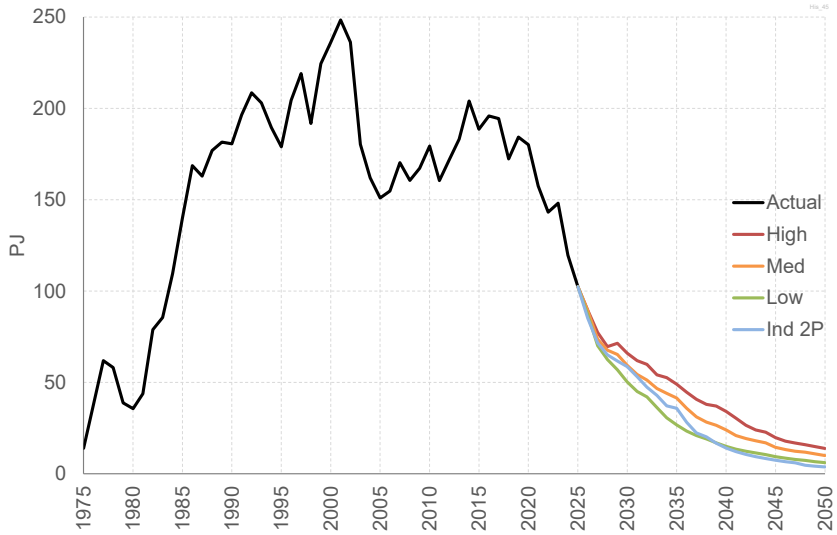
While underlying trends and technology choices influence future energy demand, not all future pathways are equally feasible. The availability of fuels, the capacity of energy infrastructure, and the resilience of the energy system will influence which transition pathways can be achieved, and at what cost. These factors therefore act as enabling conditions and constraints on Auckland's future energy system.

4.3.1 Fuel availability

The availability of energy fuels will influence the options available to households and businesses. In particular, declining domestic natural gas production has increased uncertainty around the future role of gas in Auckland's energy system. After many years of gas providing affordable, reliable energy to power many of New Zealand's homes

and businesses, the past eight years have been a torrid one. All of New Zealand's three offshore fields (Pohokura, Maui, and Kupe) suffered significant declines in production from existing wells, and failures (Figure 5).

Figure 5: Actual and projected gas production[5]



As gas demand declines, the economics of the gas distribution network will also change. Because network operating costs are largely fixed or relate to existing capital investment, declining throughput is expected to increase network charges for remaining consumers, potentially accelerating further disconnections. In simple terms a 10% decline in demand results in approximately a 10% increase in pipeline prices for remaining consumers.

Parts of the gas network could become uneconomic before gas resources are fully exhausted, reinforcing the need for an orderly transition that allows consumers and businesses to switch fuels over time rather than through abrupt network closure. These developments increase uncertainty around future gas demand, industrial fuel switching, and the long-term role of gas infrastructure in Auckland.

Liquid fuels are expected to remain important for aviation, freight, and other sectors where alternatives are currently limited. However, continued reliance on imported petroleum products also exposes Auckland to international supply disruptions and price volatility.

There is likely an energy equity dimension to this transition, as the households that are most likely to be the last to switch away from petrol driven cars or gas heating for their homes are the poorer households who can't afford the up-front capital to invest in the electric alternatives or face additional barriers from being in rented accommodation.

4.3.2 Energy infrastructure

Future energy demand will depend not only on how much energy is required, but also on the capacity of the infrastructure needed to supply it. Investment in electricity generation, transmission and distribution will be required to support increasing electrification, while

[5] The High / Med / Low projections are based on Concept modelling of the success of future drilling campaigns for existing fields. The 'Ind 2P' projection is the latest published projection from the gas producers as to the amount of gas production, to a 50% level of probability (ie, it is equally probable that gas production could be higher or lower) from wells that have already been drilled or where the gas producers have committed to future drilling campaigns. The Ind 2P projection does not include any assessment from the producers as to the amount of additional gas that could be developed from gas accumulations in existing fields that have been classed as 'Contingent Resources'. These are gas accumulations that the producers have assessed as being part of the field, but for which they haven't yet made any commitment to drill to develop them.

the timing and location of network upgrades will influence where new demand can be accommodated. Important considerations include:

- Availability of electricity generation.
- Capacity of Transpower's national transmission grid.
- Distribution network (Vector and Counties Energy) constraints within Auckland.
- Connection requirements for major industrial and commercial loads.
- The potential for demand flexibility, distributed generation and storage to improve utilisation of existing infrastructure.

As electricity becomes an increasingly important energy carrier, infrastructure planning is a critical enabler of Auckland's future energy system.

4.3.3 Energy resilience

Recent events concerning declining domestic gas production and conflict in the Middle East have highlighted the importance of energy security alongside affordability and emissions reduction. Future energy systems will need to be resilient to fuel supply disruptions, extreme weather events and changing patterns of electricity demand.

Key considerations include:

- Exposure to international fuel supply disruptions and price shocks.
- Resilience of electricity and fuel infrastructure to natural hazards exacerbated by climate change, such as extreme winds and flooding.
- Demand flexibility and distributed energy resources (e.g., rooftop solar and batteries) that improve system resilience.
- The ability of the energy system to respond to periods of peak demand or supply shortages.

Strengthening resilience can reduce the risks associated with an increasingly electrified energy system while improving Auckland's ability to adapt to future uncertainties.

5 Scenario Framework

Like Transpower's Te Kanapu Future Grid Blueprint, which is developing a long-term view of the national transmission grid to 2050 and beyond under a range of plausible economic and energy futures, this study uses scenario analysis to explore uncertainty rather than predict a single future. Te Kanapu varies national economic and electricity futures to identify transmission investments that are robust across different futures. The scenarios developed here instead focus on uncertainties that Auckland can influence or which materially affect Auckland outcomes, including urban form, transport demand, distributed energy, electrification, fuel switching and energy efficiency.

5.1 Scenario design principles

The scenarios were developed according to the following principles:

- Explore plausible futures, not predictions. The scenarios represent credible alternative futures for Auckland's energy system rather than forecasts or preferred outcomes.
- Use a common reference case. A reference scenario provides the baseline against which all alternative scenarios are assessed. It does not assume that energy use remains unchanged, but instead projects the continuation of current trends, expected technology uptake, and existing policy settings.
- Focus on the key drivers of change. Scenarios vary only those factors expected to materially influence energy demand and infrastructure requirements, including urban form, transport demand, electrification, energy efficiency, distributed energy resources, demand flexibility and fuel switching.
- Maintain internal consistency. Assumptions within each scenario are designed to be coherent and mutually reinforcing, representing realistic combinations of future conditions.
- Hold common assumptions constant. Population growth and other background assumptions are generally kept consistent across scenarios so differences in outcomes can be attributed to the scenario variables rather than changes in Auckland's overall scale.
- Describe future states rather than policy settings. The scenarios characterise possible future energy systems rather than modelling individual policy or regulatory interventions.
- Separate scenarios from sensitivities. Core scenarios capture distinct future pathways, while uncertainty in other assumptions is examined through sensitivity analysis.

5.2 Scenario development process

The scenario framework was developed through an iterative process combining evidence review, stakeholder engagement and quantitative modelling. Existing Auckland and national studies were first reviewed to identify the principal drivers of future energy demand, infrastructure requirements and emissions. These findings informed an initial set of scenario dimensions and narratives.

Meetings were held with a range of stakeholders before a workshop to gather sector-specific information, understand existing plans and projections, identify key uncertainties, and obtain relevant data and evidence. These discussions informed the initial scenario framework and workshop materials.

A stakeholder workshop was then held to test and refine the proposed framework. Participants represented local and central government, electricity and gas network operators, transport agencies, major energy users and infrastructure organisations, ensuring that the scenarios reflected a broad range of perspectives across Auckland's energy system.

The workshop focused on four key tasks:

1. Reviewing the proposed scenario framework and identifying any important gaps
2. Identifying which assumptions should vary between scenarios and which should remain common.
3. Testing whether the scenarios represented a useful and plausible range of futures for Auckland.
4. Identifying additional evidence and datasets to support the quantitative assumptions.

Workshop feedback led to several important refinements, including simplifying the scenario structure, holding population growth constant across scenarios, focusing on the interactions between urban form, transport and energy, and distinguishing between core scenario assumptions and sensitivity testing.

Following the workshop, the scenarios were translated into quantitative assumptions using available evidence and projections from relevant agencies. This resulted in five internally consistent scenarios that reflect stakeholder priorities while providing a robust basis for comparative modelling.

5.3 Scenario descriptions

5.3.1 Scenario 0 – Reference scenario

The Reference scenario represents Auckland's central expected trajectory based on current population projections, policy settings, technology trends and infrastructure plans. Electrification continues across transport, buildings and industry, broadly in line with current expectations. Energy efficiency improves gradually, distributed energy resources continue to expand, and the transition away from fossil fuels proceeds steadily but unevenly across sectors.

Under this pathway, Auckland experiences growing electricity demand from population growth, transport electrification, and fuel switching, while gas demand gradually declines. Transport emissions fall largely through technology change rather than major shifts in travel behaviour or urban form. The scenario provides a reference case against which alternative futures can be assessed and highlights the infrastructure, affordability and resilience challenges Auckland is likely to face if current trends continue.

5.3.2 Scenario 1 – “Compact and Efficient”

In this scenario, policy settings support the containment and consolidation of urban growth, with more development occurring within existing urban areas and in mixed-use centres served by high-frequency public transport. Higher-quality urban design, improved building efficiency, and better transport choices bring homes, jobs and services closer together and make public transport, walking, and cycling more attractive. As a result, reliance on private vehicles and overall transport energy demand are lower than under the reference scenario.

The energy transition is also more proactive. New buildings are more energy efficient, existing buildings are upgraded more rapidly, and greater use is made of smart technologies that shift demand away from peak periods. Electrification proceeds quickly across transport and buildings, supported by higher uptake of rooftop solar, batteries and distributed energy technologies. The combination of efficiency, flexibility and coordinated urban growth moderates overall energy demand growth while reducing emissions and infrastructure costs.

5.3.3 Scenario 2 – “Expansion”

This scenario describes an Auckland where recent trends towards higher-density development and greater public transport use reverse, and the city expands outward through lower-density development. Homes, employment and services become more dispersed, increasing travel distances and reinforcing dependence on private vehicles. Public and active transport play a smaller role, resulting in

higher transport energy demand and greater pressure on transport infrastructure.

The energy system also evolves more slowly than the reference scenario. New buildings are less efficient, existing buildings are retrofitted at a lower rate, and uptake of distributed energy technologies and demand-side flexibility remains limited. Gas use declines more slowly and energy demand grows more rapidly across households, businesses and industry. The result is a larger and more infrastructure-intensive energy system, requiring greater investment in networks and generation while delivering weaker emissions outcomes.

5.3.4 Scenario 3 – "Electricity Stress"

This scenario explores a future in which Auckland's dependence on electricity grows rapidly, but supporting investments in efficiency, flexibility and distributed energy do not keep pace. Electrification accelerates across transport, buildings and industry, while the transition away from gas occurs more quickly than expected. At the same time, uptake of rooftop solar, batteries, smart demand management and energy efficiency measures remain relatively weak.

The result is strong growth in electricity demand, particularly during peak periods, placing significant pressure on transmission and distribution networks. Electricity-intensive industries and new large loads further increase demand. The scenario does not assume that electricity infrastructure simply fails to keep pace. Rather, it is a stress test of the additional generation, transmission and distribution capacity that would be required to accommodate this pattern of demand, and the potential implications for network investment, connection constraints and electricity costs. It therefore illustrates the consequences of rapid electrification occurring without a corresponding increase in efficiency, flexibility, and distributed resources.

5.3.5 Scenario 4 – "Fuel Diverse"

This scenario explores a future in which Auckland pursues energy efficiency, urban intensification, and transport improvements, but places less emphasis on electrification as the dominant decarbonisation pathway. Compact urban form, improved building performance and stronger public and active transport reduce overall energy demand and improve liveability outcomes.

However, households and businesses are less likely to switch away from gas, and electric vehicle uptake is slower. Distributed generation, including rooftop solar, is higher than under the reference scenario, reflecting the scenario's emphasis on a more diverse mix of energy sources. For industrial process heat, biomass is adopted more widely where practical, reducing reliance on electricity as the primary replacement fuel. This pathway reduces some pressure on electricity networks and generation investment but increases dependence on alternative fuels and leaves greater exposure to gas supply, fuel price and residual emissions risks. It provides a useful counterpoint to electrification-led futures and helps test the implications of pursuing emissions reductions through a broader mix of technologies and fuels.

5.4 Scenario assumptions

Each alternative scenario represents a distinct but plausible future for Auckland, constructed by varying a common set of assumptions relating to urban form, transport, energy demand, technology uptake and fuel choices. The scenarios are not forecasts but exploratory pathways designed to test the implications of different strategic directions and external conditions. Table 1 summarises the high-level assumptions that distinguish each scenario from the reference case.

Table 1: High-level summary of scenario assumptions relative to the reference scenario

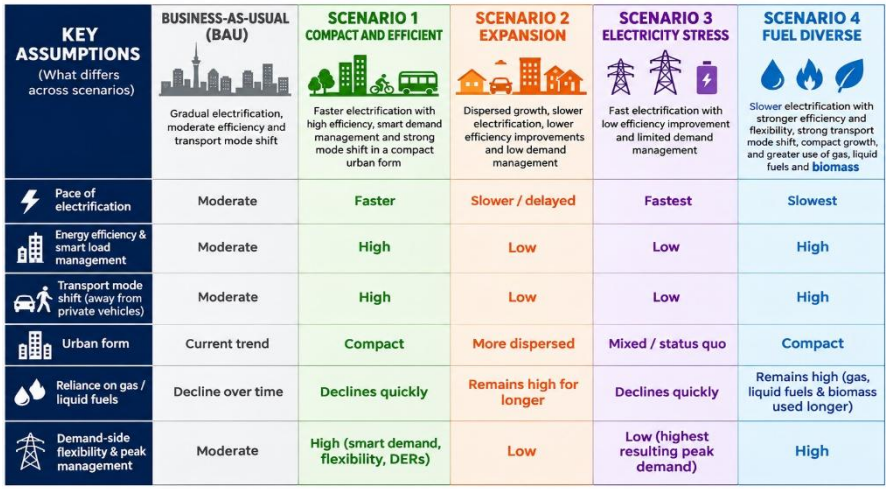
Scenario component	1. Compact and Efficient	2. Expansion	3. Electricity Stress	4. Fuel Diverse
Population growth	Mid	Mid	Mid	Mid
Urban form	More dense	Less dense	Mid	Mid
Transport demand	Lower	Higher	Higher	Lower
Transport mode shift	More PT+AT	Less PT+AT	Less PT+AT	More PT+AT
EV uptake	Higher	Lower	Higher	Lower
New building efficiency	Higher	Lower	Lower	Higher
Building retrofit rate	Higher	Lower	Lower	Higher
Smarter load management	Higher	Lower	Lower	Higher
Gas switching propensity	Higher	Lower	Higher	Lower
New gas connections	None	Mid	None	Higher
Imported LNG	None	None	None	From 2028
Rooftop solar & batteries	Higher	Lower	Lower	Higher
Utility-scale renewables	Higher	Lower	Mid	Mid
Electricity-intensive industries	Lower	Higher	Higher	Lower
Industrial heat biomass proportion	Mid	Mid	Lower	Higher

The following table shows the assumed share of travelled kilometres by mode for each scenario. Scenarios 1 and 4 have increases in active modes and all forms of public transport, resulting in a significantly lower residual share of private road transport by the end of the 2030s. Scenarios 2 and 3, in contrast, have a slight decrease or no change to active and public transport modes.

Table 2: Residential transport mode shift assumptions

Scenario	Mode	2023	2028	2033	2038	2043
0	Pedestrian	1.7%	1.7%	1.7%	1.7%	1.7%
0	Cycling	0.4%	0.4%	0.4%	0.4%	0.4%
0	Trains	1.4%	3.4%	3.4%	3.4%	3.4%
0	Bus	3.4%	4.0%	4.2%	4.4%	4.7%
0	Ferry	0.5%	0.5%	0.5%	0.5%	0.5%
1 & 4	Pedestrian	1.7%	2.5%	3.0%	3.0%	3.0%
1 & 4	Cycling	0.4%	0.4%	2.5%	4.6%	6.7%
1 & 4	Trains	1.4%	5.7%	7.3%	9.1%	11.0%
1 & 4	Bus	3.4%	4.0%	8.0%	12.0%	12.0%
1 & 4	Ferry	0.5%	0.5%	2.0%	2.0%	2.0%
2 & 3	Pedestrian	1.7%	1.0%	1.0%	1.0%	1.0%
2 & 3	Cycling	0.4%	0.4%	0.3%	0.3%	0.4%
2 & 3	Trains	1.4%	3.0%	2.5%	2.5%	2.5%
2 & 3	Bus	3.4%	3.4%	3.4%	3.4%	3.4%
2 & 3	Ferry	0.5%	0.5%	0.5%	0.5%	0.5%

Figure 6 - Key differences in assumptions across scenarios



KEY ASSUMPTIONS (What differs across scenarios)	BUSINESS-AS-USUAL (BAU)	SCENARIO 1 COMPACT AND EFFICIENT	SCENARIO 2 EXPANSION	SCENARIO 3 ELECTRICITY STRESS	SCENARIO 4 FUEL DIVERSE
	Gradual electrification, moderate efficiency and transport mode shift	Faster electrification with high efficiency, smart demand management and strong mode shift in a compact urban form	Dispersed growth, slower electrification, lower efficiency improvements and low demand management	Fast electrification with low efficiency improvement and limited demand management	Slower electrification with stronger efficiency and flexibility, strong transport mode shift, compact growth, and greater use of gas, liquid fuels and biomass
Pace of electrification	Moderate	Faster	Slower / delayed	Fastest	Slowest
Energy efficiency & smart load management	Moderate	High	Low	Low	High
Transport mode shift (away from private vehicles)	Moderate	High	Low	Low	High
Urban form	Current trend	Compact	More dispersed	Mixed / status quo	Compact
Reliance on gas / liquid fuels	Decline over time	Declines quickly	Remains high for longer	Declines quickly	Remains high (gas, liquid fuels & biomass used longer)
Demand-side flexibility & peak management	Moderate	High (smart demand, flexibility, DERs)	Low	Low (highest resulting peak demand)	High

5.5 Common assumptions

The scenarios share a consistent set of national energy market assumptions so that differences in results reflect the Auckland-specific scenario settings rather than unrelated changes in the wider energy system:

- **Carbon price**: based on existing policies and MCERT's central assumptions for future NZ ETS settings.
- **Appliance costs**: based on EECA analysis of current and projected costs, efficiency and performance for household, commercial and industrial energy-using equipment.
- **Vehicle costs**: based on Concept's analysis of projected purchase and operating costs for internal-combustion, hybrid, electric, and other vehicle technologies.
- **Battery costs**: based on Concept's analysis of projected battery costs and performance, including stationary and vehicle batteries.
- **International fuel prices**: based on central projections for international oil, coal and LNG prices, with petrol, diesel and LPG prices linked to the international oil-price outlook. Short-run projections follow J.P. Morgan. The post-2030 price oil is 72 US$/bbl, with a low-high range of $56-$85.
- **Electricity generation assets**: existing generation assets, expected retirements and the costs and availability of potential new renewable, thermal and storage technologies are held consistent across scenarios. New investment is modelled in response to electricity demand, fuel prices and carbon costs.
- **Gas demand:** All scenarios barring "Fuel Diverse" do not assume LNG imports, resulting in a steady decline of gas from residential, commercial, and industrial users at a level that results in most of New Zealand's estimated reserves and developable contingent resources being used up. For the reference scenario this results in complete reduction of residential and commercial demand by 2050, with industrial demand five years later. The "Compact" and "Electricity Stress" scenarios have these exits four and eight years earlier, respectively, consistent with the scenario framing. The "Fuel Diverse" scenario sees gas use exit fifteen years later than the reference scenario due to the presence of LNG imports.
- **Gas wholesale prices:** For the scenarios that don't have LNG, gas prices are assumed to steadily rise over a ten-year period from current levels to a level that's broadly consistent with the cost of LPG. This is due to the rationing dynamic around scarce NZ reserves described in more detail in section 7.4. The Fuel Diverse scenario has gas prices rising over a shorter period to

the level of subsidised LNG – ie, without recovering the cost of the terminal[6], and which are lower than the cost of LPG.

The gas assumptions are informed by Concept's more detailed modelling of gas supply, demand, network economics and customer exit for its latest gas market forecast.

Wholesale electricity prices, electricity network prices, and gas pipeline prices are all calculated endogenously in the model, with variations between the scenarios principally being due to the variations in the timing of gas demand reductions.

5.6 Sensitivities

Sensitivity analysis is used to test how robust the scenario results are to uncertainty in major external drivers. The selected parameters are factors that could materially affect Auckland's future energy demand, costs and infrastructure requirements, but are not directly determined by Auckland Council or by the core scenario narratives.

The sensitivity parameters include:

- **Population:** The central case uses Statistics New Zealand's 2023 central subnational population projection, with the corresponding low and high projections used for the sensitivity cases. Population affects the number of households, transport activity, commercial activity and demand for energy infrastructure.
- **GDP:** The central projection is based on Treasury's 2025 Long-term Fiscal Model. The low and high cases reduce or increase long-run labour productivity growth by 0.3 percentage points. This captures uncertainty in future economic activity while remaining consistent with the range used in Treasury's long-term fiscal sensitivities.
- **Oil prices:** The central case assumes a 2026 oil price of US$85 per barrel, declining to US$72 by 2030. The low and high cases test paths from US$72 to US$56 and from US$120 to US$85, respectively. Oil prices influence travel demand and fuel switching.
- **Long-run LNG prices** vary from $18/GJ to $24.50/GJ, with a central assumption of $20.40/GJ. These affect the gas prices in the "Fuel Diverse" scenario.
- **Wholesale gas prices** in the Low and High sensitivities are lower and higher due to the cost of LPG being lower or higher – noting that as discussed in Section 0, wholesale gas prices rise as reserves decline, and are eventually capped at the cost of LPG.
- **Gas demand:** The Low sensitivity extends demand to 2065-2070 due to an assumed higher level of developable gas reserves in New Zealand.

The following Table 3 lists the model parameter differences for the sensitivity scenarios.

Table 3: Sensitivity parameter assumptions for central, low and high scenarios

Parameter	Central	Low	High
Population	Statistics NZ central population projections 2023	Statistics NZ low scenario	Statistics NZ high scenario
GDP	As per Treasury Long-term Fiscal Model 2025	Long-run productivity growth 0.3% lower	Long-run productivity growth 0.3% higher

[6] Recovering the cost of the terminal is added to electricity wholesale prices, in line with the government's current policy intention to recover terminal costs from the electricity generation and retail sector.

Oil	USD 85/bbl, decreasing to $72 by 2030	USD 72/bbl, decreasing to $56 by 2030	USD 120/bbl, decreasing to $85 by 2030
LNG	Long-run $18.10/GJ	Long-run $20.40/GJ	Long-run $24.50/GJ
Gas pipeline	Res, com and ind exit 2050-2055	Res, com and ind exit 2065-2070	No exit

5.7 PC120 Reference: Updated growth and economy projections

The additional PC120 scenario was added to assess how the updated growth projections and assumptions affect Auckland's future energy demand under the reference situation. Low and high projections were not available for household or employment growth, limiting the scope for testing alternative growth trajectories.

The impacts of PC120 are more closely aligned with the assumptions of the "Compact and Efficient" scenario than those of the "Expansion" scenario, particularly in terms of urban density. However, PC120 does not include direct mechanisms to encourage electrification or demand management, meaning that outcomes resembling the "Electricity Stress" or "Fuel Diverse" scenarios remain possible. The PC120 scenario is intended to isolate the effects of the updated assumptions, rather than suggest that the alternative futures explored in this report are no longer plausible.

5.7.1 Revised assumptions

Projected household growth increases from being 33% higher by 2050 to 36% higher (Table 4). There is a significantly higher proportion of multi-unit dwellings than in the past decade. Multi-unit dwellings are expected to be smaller than in recent years.

Table 4: Revised assumptions following PC120 modelling

Assumption	Original reference	Updated reference
Household growth	33% more dwellings by 2050	36% more dwellings by 2050
Economic growth	HBA business assessment 2023	2026 revised employment growth projections
Dwelling density	Multi-unit share of new dwellings remains at the average of the past 5 years.	Multi-unit dwelling share doubles by 2030, as in the Compact & Efficient scenario
Dwelling sizes	Floor area of new dwellings remains at the average of existing post-2020 stock.	Multi-unit dwellings 20% smaller than existing post-2020 stock.
Transport fleet	2025 projections.	Incorporates 2026 trends in EV uptake.
Transport mode	Slow and steady decrease in private vehicle share	No change

The revised employment projections suggest that Auckland's economy will develop quite differently from what was expected in 2023. Employment growth is now expected to be much stronger in service sectors such as health care, hospitality, professional services and utilities. Employment in manufacturing and primary sectors is projected to decline, consistent with the trend seen in Auckland region GDP from 2022-2024.

EV uptake assumptions were also updated to reflect recent fleet statistics, while assumptions about transport mode shares remain unchanged, with a gradual decline in the share of travel by private vehicles.

6 Scenario outcomes

6.1 Reference Outlook

6.1.1 Overview

The reference scenario represents Auckland's most likely future under current policy settings and central planning assumptions. It provides the reference case against which alternative scenarios are compared and is intended to reflect the continuation of existing demographic, economic, technological and behavioural trends rather than an aspirational or policy-led future.

Population growth follows the central subnational population projections published by Stats NZ, while economic growth is based on the central government GDP outlook. Auckland therefore continues to expand as New Zealand's largest metropolitan economy, with growth in households, employment and economic activity driving a steady increase in energy service demand across the residential, commercial, industrial and transport sectors. Growth remains concentrated around the existing urban structure envisaged in the Future Development Strategy, with a mixture of intensification within existing urban areas and continued expansion into planned greenfield locations.

The reference scenario assumes that existing energy and climate policies remain in place, with no major new interventions beyond those already announced or reasonably expected. The gradual electrification of transport, buildings and industry continues as technologies mature and become increasingly cost competitive. Electric vehicle uptake continues broadly in line with current market expectations, while households and businesses progressively replace fossil-fuelled equipment at the end of economic life. Improvements in appliance, vehicle and building efficiency continue through normal technology turnover, although these are not accelerated by additional policy measures.

Electricity demand increases steadily throughout the projection period as population growth, commercial activity, data centres, transport electrification and industrial fuel switching outweigh ongoing improvements in energy efficiency. At the same time, Auckland continues to experience declining use of reticulated natural gas as ageing gas appliances are replaced and concerns around long-term gas availability and affordability encourage gradual fuel substitution. However, this transition remains largely market driven rather than policy mandated.

Structural changes in Auckland's energy demand broadly follow national trends. Transport remains the largest final energy user, although petroleum demand gradually declines as the vehicle fleet electrifies. Buildings become increasingly electrified, with growing uptake of efficient electric heating and hot water systems. Industrial energy demand evolves more slowly, reflecting the long lives of process heat equipment, capital replacement cycles and site-specific economic considerations. Process heat users continue to improve energy efficiency and selectively adopt electric technologies or biomass where commercially attractive, but widespread transformation occurs progressively rather than rapidly. Auckland's large and diverse industrial base means this gradual transition remains an important source of future electricity demand.

Distributed energy resources continue to expand under the reference scenario, including rooftop solar, battery storage, and demand response technologies, but their uptake reflects current market trajectories rather than accelerated adoption. These technologies provide local benefits and modest reductions in peak demand growth but do not fundamentally alter Auckland's dependence on the wider electricity system.

The scenario also assumes continued investment in electricity transmission and distribution networks to accommodate increasing demand and changing load patterns. Network planning responds to

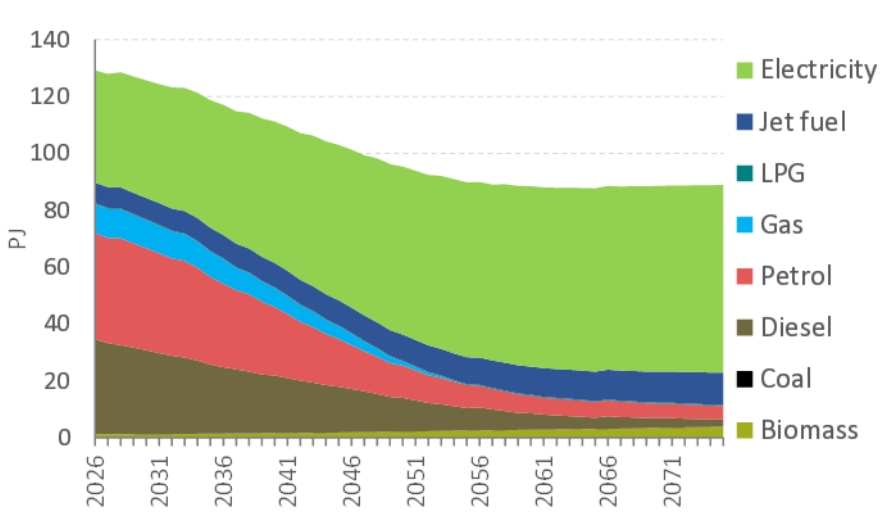
population growth, urban development, electric vehicle charging, process heat electrification, and emerging large electricity users such as data centres. While network constraints arise in some locations, they are addressed through planned reinforcement, operational improvements and increasing use of demand-side flexibility rather than representing binding limits on economic growth.

6.1.2 Overall Demand by Energy Source

Under the reference scenario, total final energy demand declines from around 126 PJ in 2026 to approximately 82 PJ by the early 2070s, despite continued population and economic growth. This reduction is primarily driven by the replacement of internal combustion vehicles and fossil-fuelled heating with much more efficient electric technologies, meaning less final energy is required to deliver the same energy services.

The fuel mix changes substantially over the projection period. Electricity demand increases from around 36 PJ to more than 60 PJ, becoming more than half of energy used by 2046, while petrol demand falls from around 38 PJ to 5 PJ as the light vehicle fleet electrifies. Gas and LPG are largely phased out by the early 2060s. Diesel also falls 92% by 2075, with the remainder being unallocated industry, which does not have an explicit decarbonisation pathway in the model, and a small amount remaining in freight transport.

Figure 7: Reference energy demand by source (PJ)

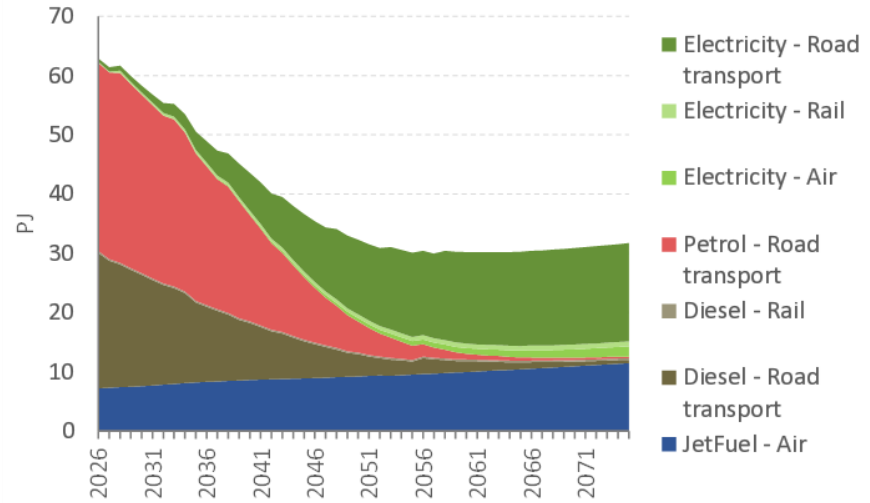


6.1.3 Transport Energy Demand

Under the reference scenario, transport energy demand declines from around 60 PJ in 2026 to approximately 31 PJ by the early 2070s, despite continued growth in travel demand. The reduction reflects the much higher final efficiency of electric vehicles compared with internal combustion engines. Electricity for road transport increases from less than 1 PJ to around 18 PJ. Petrol demand falls from 31 PJ to zero and diesel road transport declines from 23 PJ to less than 1 PJ.

Aviation remains largely dependent on liquid fuels throughout the projection period, with jet fuel demand increasing modestly from around 7 PJ to 11 PJ in line with passenger growth. Sustainable aviation fuel (SAF) makes up only a small share of aviation fuel use, reaching around 14% by 2050. Rail transport becomes almost fully electrified, while electricity use for aviation remains a relatively small contributor, reflecting limited uptake of electric aircraft within the projection period.

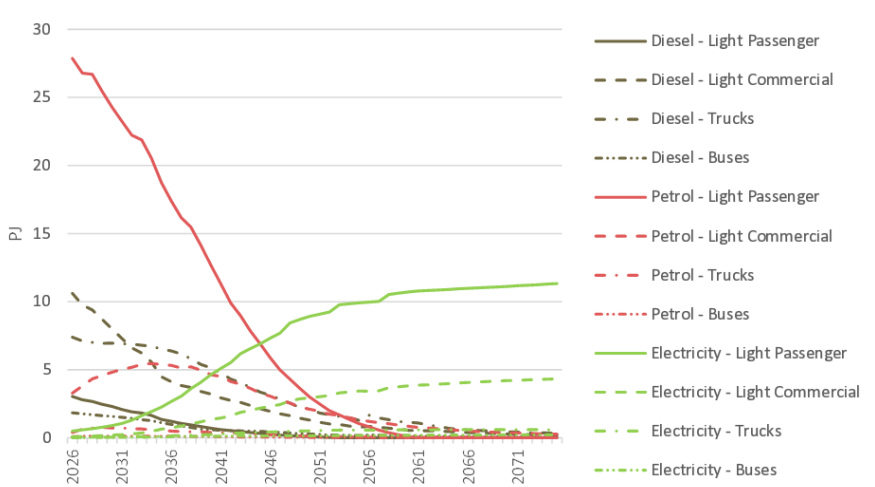
Figure 8: Transport energy demand by fuel (PJ)



The transition is led by the light passenger fleet (Figure 9), which begins as by far the largest consumer of road transport energy and undergoes the fastest shift from petrol to electricity. As this transition progresses, electricity becomes the dominant energy source for passenger vehicles, illustrating the significant efficiency gains associated with vehicle electrification.

Commercial vehicles, trucks and buses follow a more gradual pathway. Diesel remains the dominant fuel for these vehicle classes for much longer, reflecting slower fleet turnover and the greater challenges associated with electrifying heavier vehicles. Nevertheless, all vehicle types show a steady decline in liquid fuel use and increasing electricity consumption over time, with the timing and pace of the transition varying according to vehicle characteristics and technology readiness.

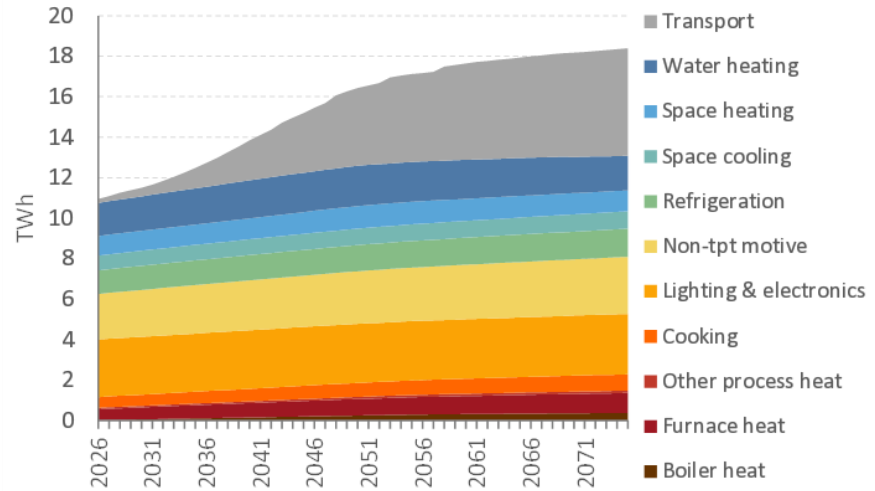
Figure 9: Road transport energy demand by vehicle type (PJ)



6.1.4 Non-transport energy demand by end use

Outside transport, electricity demand grows more steadily, reflecting population growth, economic activity, and the gradual electrification of buildings and industry. Lighting, appliances and electronics, non-transport motive power, water heating, refrigeration, and space heating and cooling all show moderate increases over time as gas use is supplanted by electricity. Electricity use for process heat also rises as fossil fuel equipment is progressively replaced with electric alternatives.

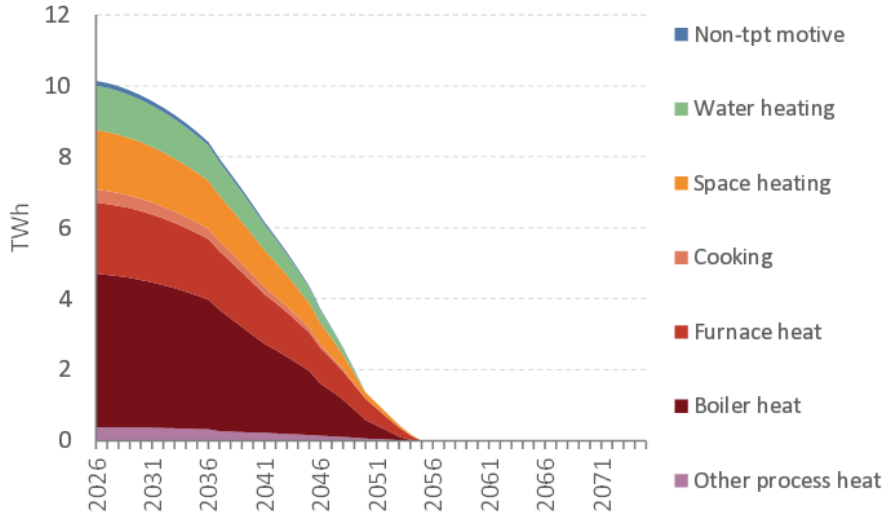
Figure 10: Electricity demand by end-use (TWh)



Gas demand declines across all end uses under the reference scenario, reaching effectively zero by the mid-2050s (Figure 11). This downward trajectory is driven primarily by the progressive depletion of New Zealand's domestic natural gas reserves, which increases gas prices and encourages a gradual shift towards electrification and other alternative fuels – including, for some hard-to-electrify high-temperature furnace heat uses, switching to other fossil fuels: LPG or diesel. Industrial boiler heat accounts for the largest share of gas consumption initially and remains the dominant end use throughout most of the transition, followed by furnace heat, space heating and water heating.

The trajectories reflect the differing rates at which equipment can be replaced. Process heat applications decline more gradually because of the long lifetimes and capital costs of industrial equipment plus the more challenging economics of switching to alternatives, while gas use for building end uses, such as space and water heating, falls away more quickly as electric technologies become the default replacement option and the economics of switching to electricity are strongly favourable. The reference scenario does not include liquefied natural gas (LNG) imports to replace declining domestic gas production, as imported LNG is assessed to remain uneconomic relative to alternative fuels and electrification. The “fuel diverse” scenario explores an alternative future where LNG imports are enabled.

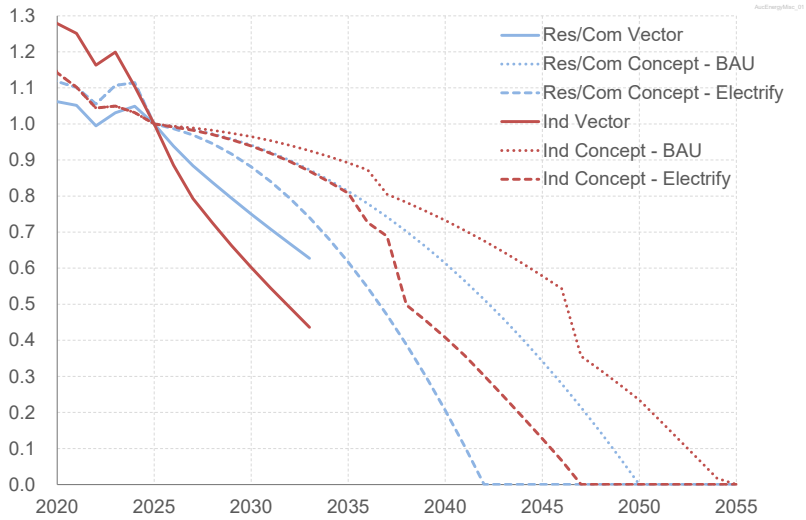
Figure 11: Gas demand by end use (PJ)



Compared with Auckland gas distributor Vector’s forecasts, the reference and other scenarios generally project a slower decline in gas demand. For the residential and commercial sector, Vector's gas demand falls 40% by 2035, whereas our projections fall more slowly. The difference is even more pronounced in the industrial sector.

These differences primarily reflect different assumptions about the pace of switching away from gas to alternatives rather than the overall direction of travel. Both sets of forecasts show substantial long-term reductions in gas demand. Our scenarios assume a more gradual rate of switching away.

Figure 12: Comparison with Vector gas projection[7]

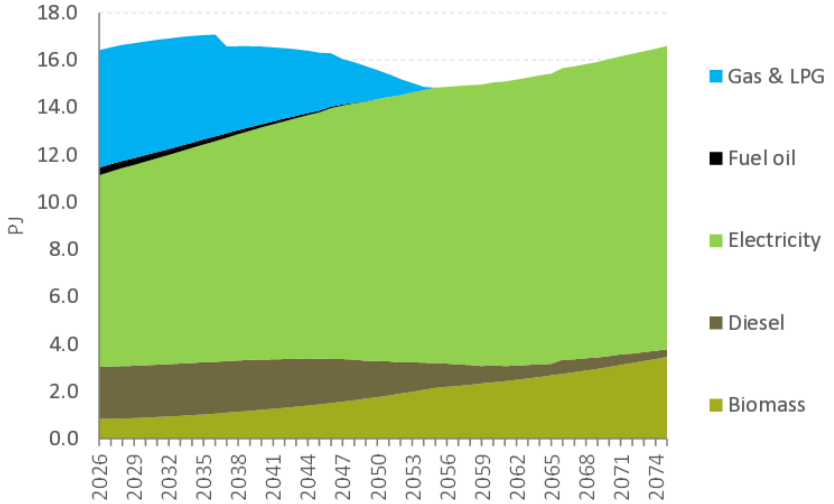


6.1.5 Industrial Energy Demand

Industrial energy demand becomes progressively more electrified under the reference scenario (Figure 13) as declining domestic gas reserves lead to the phase-out of gas by the mid-2050s. Electricity increasingly replaces gas for industrial energy services, while biomass use also grows steadily as a low-emissions fuel for process heat. Fuel oil remains a negligible energy source throughout the projection period.

Diesel consumption decreases significantly with the decarbonisation of industrial heat. The small remainder represents an unallocated energy use within the EECA energy end use dataset, assumed to be mobile motive demand. No explicit decarbonisation pathway is applied to this demand, consistent with EECA TIMES-NZ scenarios.

Figure 13: Industrial energy demand by fuel (PJ)

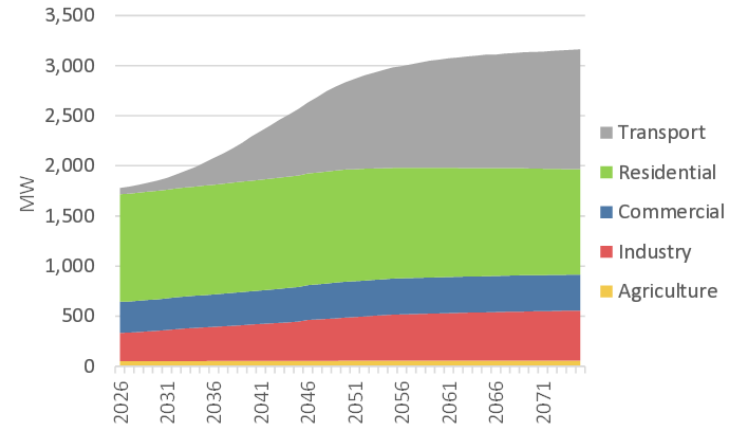


6.1.6 Electricity Network Implications

Peak electricity demand increases substantially under the reference scenario, rising from around 1.8 GW in 2026 to approximately 3.2 GW by 2075, an increase of around 80%. Most of this growth is driven by transport electrification, while residential, commercial and industrial peak demand increase more gradually with population growth and the progressive electrification of buildings and industry.

[7] Vector projection taken from data supplied to the Commerce Commission in mid-2025, and published by the Commission here: https://www.comcom.govt.nz/assets/Documents/2026-gas-default-price-quality-path/Concept-Consulting-Gas-demand-projections-to-feed-into-the-default-price-quality-path-DPP-regulation-of-gas-distribution-businesses-22-August-2025-v2.pdf

Figure 14: Reference peak electricity demand by sector (MW)

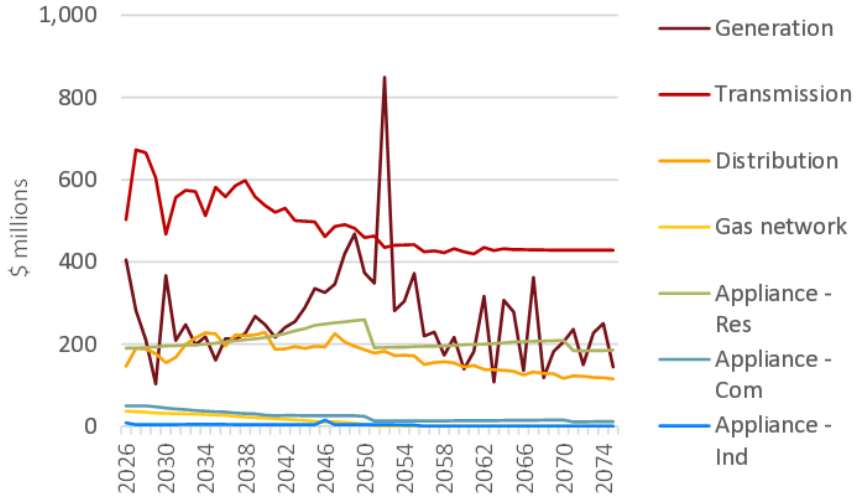


A significant uncertainty is the extent to which 'smart' systems can be developed to enable EV charging to occur outside of peak periods and for vehicle-to-grid (V2G) to occur to inject power from vehicles *back into* the grid at peak times. The reference scenario assumes the shape of the charging demand profile remains as it is currently. To the extent that such smart approaches can be achieved at scale in Auckland, the growth in peak electricity demand – and associated electricity network investment requirements – could be substantially less. This is something that is explored in scenario 1.

6.1.7 Capital and Operating Costs

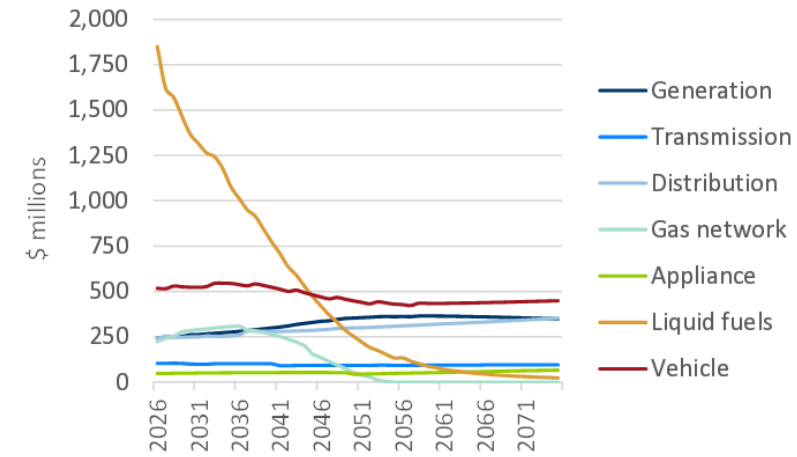
Non-transport capital investment is dominated by electricity network expenditure throughout the projection period, with ongoing investment in transmission and distribution required to accommodate growing electricity demand (Figure 15). Electricity generation investment (pro-rated by regional demand) is more variable, reflecting the timing of new generation projects, while expenditure on the gas network declines steadily as the system contracts with falling gas demand. Appliance replacement costs increase gradually across the residential, commercial and industrial sectors as buildings transition from fossil fuel technologies to electric alternatives, before stabilising once the transition is largely complete. This results in a visible step-change around the year 2050.

Figure 15: Reference non-transport capital expenditure



Operating expenditure shifts substantially under the reference scenario (Figure 15) as electricity progressively replaces fossil fuels. Expenditure on liquid fuels declines rapidly throughout the projection period as transport electrifies, while spending on electricity generation increases gradually in line with higher electricity demand. Vehicle operating costs, including maintenance, repairs, tyres, registration, insurance and other non-fuel running costs, decline over time as more efficient electric vehicles enter the fleet.

Figure 16: Reference operational expenditure



6.1.8 Energy prices

Electricity demand rises substantially under the reference, but this does not translate into proportionally higher electricity prices. The average retail electricity price is projected to increase modestly in the near term, from around 33 c/kWh to 35 c/kWh by 2030 (in real terms, excluding GST). This reflects higher network costs and higher gas-powered generation costs. Beyond 2030, electricity prices are expected to plateau as additional renewable generation and storage enters the system and network costs stabilise.

Gas follows a different trajectory. As demand declines, the fixed costs of the gas network are recovered from a shrinking customer base, pushing up network charges per consumer. Wholesale gas prices are also projected to rise faster than wholesale electricity prices, at around 2 to 5% per year in real terms, but network costs per customer rise faster still. As a result, the overall cost of gas per GJ is projected to more than double before 2050. The drivers of these gas price increases are discussed further in Section 7.4.

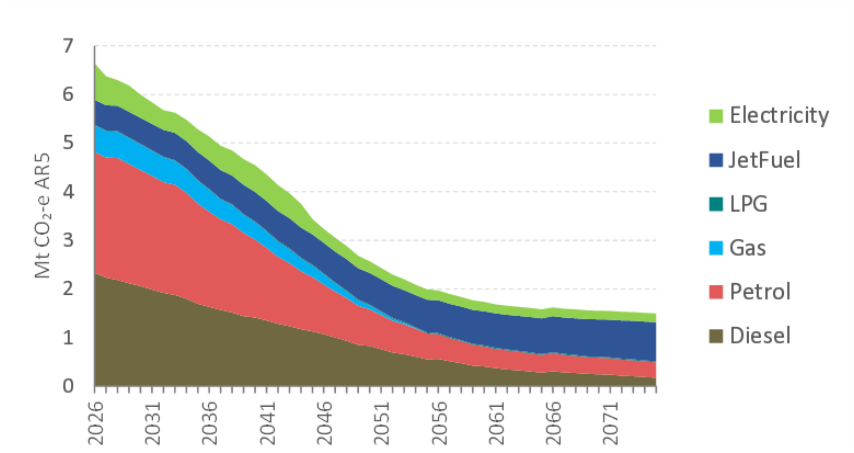
These rapidly diverging price trajectories mean that the cost impacts on households and businesses will vary substantially depending on the technologies they adopt and the fuels they continue to use. The impacts on different industries and household groups are discussed further in sections 8 and 9 respectively.

6.1.9 Emissions

Figure 17 shows that energy-related emissions decline steadily under the reference scenario, falling from around 6.6 mt CO_2-e in 2026 to 1.5 mt CO_2-e by the early 2070s. The modelled emissions profile is broadly consistent with national projections, with Auckland accounting for approximately 24% of New Zealand's energy-related emissions in 2026.

The largest reductions occur in petrol and diesel emissions as transport progressively electrifies, while gas emissions also decline as buildings and industry transition away from fossil fuels. However, this electrification, combined with an increase in coal-powered generation, initially increases the emissions associated with electricity generation from 2032 to 2041. Emissions then fall rapidly as the electricity system continues to decarbonise through the expansion of renewable generation and grid-scale batteries. Jet fuel emissions remain relatively stable throughout the modelling period, becoming a larger share of residual emissions as emissions from other energy sources decline.

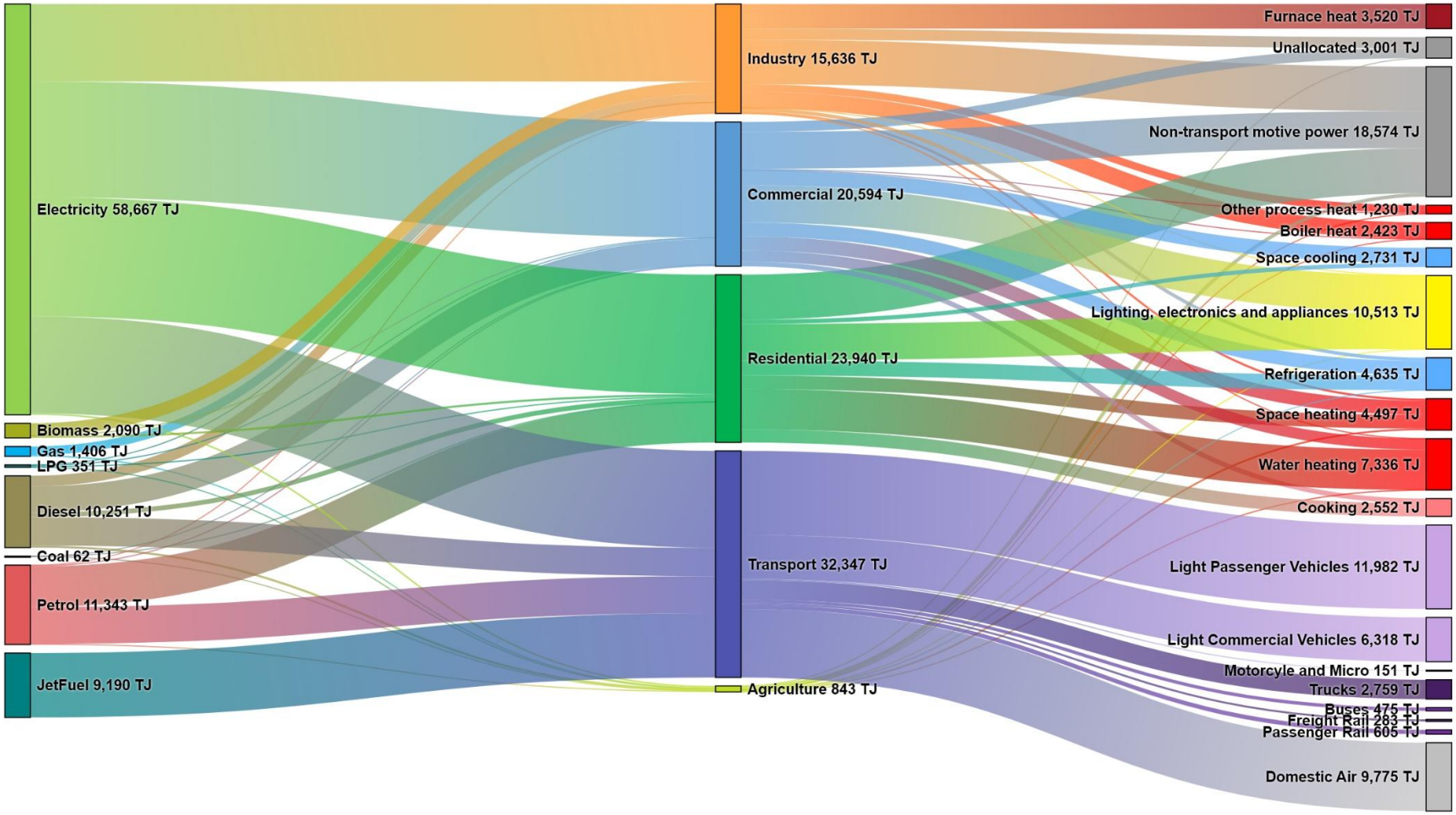
Figure 17: Reference greenhouse gas emissions (kt CO_2-e)



6.1.10 Key Insights

The reference scenario represents a steady energy transition driven by technology improvements, the depletion of domestic natural gas reserves, and existing policy settings, rather than additional decarbonisation measures. Transport electrification and the decline of natural gas lead to a substantial shift from fossil fuels to electricity, reducing total final energy demand despite continued economic and population growth. At the same time, electricity demand and peak loads increase, requiring continued investment in electricity generation and networks while the gas network is progressively retired.

Figure 18: Reference Sankey showing 2050 energy use in terajoules by source, sector, and end use



6.1.11 Reference Sensitivities

The low and high sensitivity scenarios test how Auckland's future energy system could change under different economic conditions. The “Low” scenario assumes lower population growth, slower economic growth, and lower fossil fuel prices, reducing both energy demand growth and the incentive to electrify.

The “High” scenario assumes stronger population and economic growth together with higher fossil fuel prices, leading to higher electricity demand and faster electrification. These scenarios provide a reasonable range around the reference case and help illustrate how sensitive future energy demand and infrastructure requirements are to changes in the wider economic environment.

Overview

Compared with the Central reference scenario, the Low scenario represents an alternative “state of the world” characterised by slower population and economic growth and lower fossil fuel prices, rather than changes assumed to arise solely from conditions within Auckland. Petrol demand is lower because of reduced transport activity associated with slower growth. Gas demand is higher throughout the 2040s-2060s as lower prices reduce the incentive to electrify, but by 2075 it converges with the central scenario.

Figure 19: Difference in total energy demand between the low and central reference scenarios.

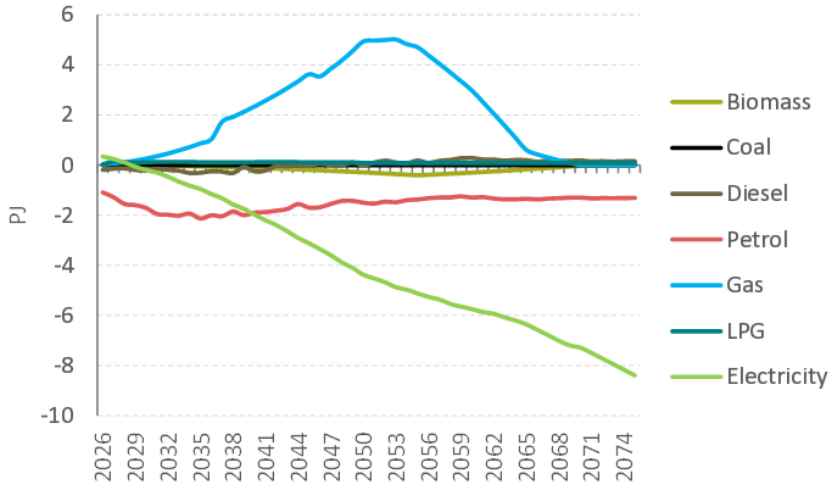
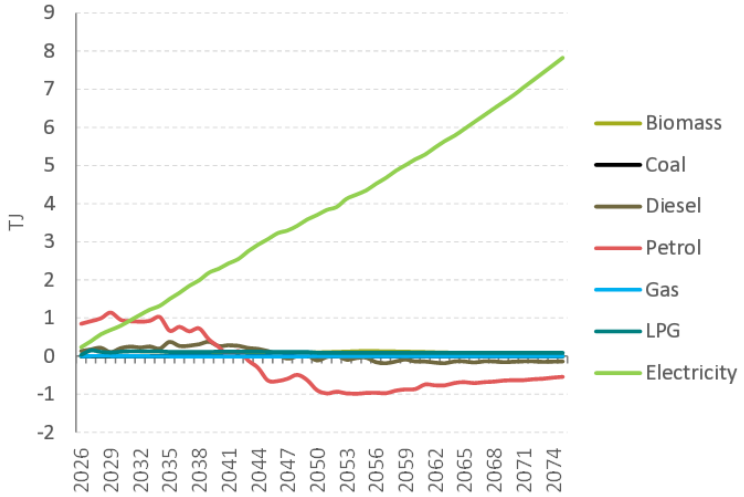


Figure 20: Difference in total energy demand between the high and central reference scenarios.



Key Insights

The sensitivity analysis shows that population and economic growth assumptions have their greatest effect on future electricity demand, with electricity acting as the main “swing fuel” across the sensitivities. This reinforces the importance of the cost and availability of electricity supply and infrastructure to Auckland’s energy transition. The difference between the Low and High scenarios widens over time, although even under the Low sensitivity electricity demand remains broadly stable rather than declining.

These results may also understate the potential effect of changes in Auckland’s industrial composition. The industrial growth sensitivity is based on relatively modest differences in aggregate GDP projections rather than industry-specific growth assumptions. Faster growth in electricity-intensive industries could therefore produce substantially stronger electricity demand growth than indicated by the aggregate GDP sensitivity, while slower growth would tend to keep electricity demand closer to current levels rather than cause it to decline..

6.2 Alternative Futures

The following sections compare the reference projection with the four alternative scenarios developed through the stakeholder workshop. To avoid repeating the reference results, the figures present the differences in energy demands relative to the reference projection. This highlights the incremental effect of each scenario and provides a clearer comparison of how alternative assumptions about urban development, technology uptake and fuel choice affect Auckland's energy futures.

6.2.1 Total Energy Demand

Relative to the reference, the “Compact and Efficient” scenario reduces demand across most energy sources (Figure 21), with the largest and most sustained reduction occurring in electricity demand. This reflects the combined effects of more compact urban growth, higher building and appliance efficiency, and increased uptake of rooftop solar reducing grid electricity demand. Petrol demand also falls sharply due to reduced private vehicle travel, while diesel, gas, LPG and biomass demand show more modest reductions. Smart load management helps reduce peak electricity demand rather than total electricity consumption.

The urban “Expansion” scenario increases demand for petrol, diesel and gas, reflecting greater private vehicle travel, lower energy efficiency, and slower uptake of public and active transport (Figure 22). Electricity demand is lower due to reduced electrification, while biomass demand also declines as fossil fuels remain in use for longer. As electrification eventually increases in later decades, the differences in petrol and gas demand narrow, although biomass demand remains below the reference throughout the projection period.

The “Electricity Stress” scenario substantially increases electricity demand, reflecting faster electrification of transport and buildings despite lower energy efficiency and limited demand-side flexibility. Electricity demand peaks around the mid-2040s before moderating as efficiency improvements and market-driven electrification converge with the reference, while gas and petrol demand fall sharply as they are displaced by electrification. Biomass demand remains below the reference, reflecting greater reliance on electrification for process heat.

The “Fuel Diverse” scenario has much lower electricity demand as stronger energy efficiency is combined with a slower transition to electrification. Gas demand remains significantly higher than the reference through to the mid-2050s as it continues to be used for non-power applications. The uptake of biomass for industrial process heat is correspondingly lower, although when sites do switch away from gas they are more likely to choose biomass than under the reference scenario. Petrol demand is initially below the reference due to greater transport mode shifting, but from the mid-2040s becomes

higher as slower fleet electrification offsets these gains. By 2075, petrol, diesel and gas demand converge with the reference.

Figure 21: Total energy demand - Compact and Efficient vs. reference

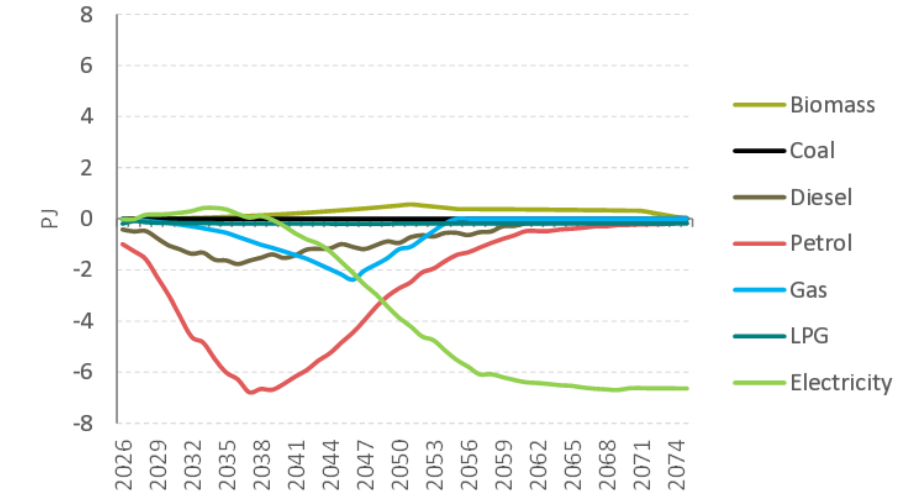


Figure 22: Total energy demand - Expansion vs. reference

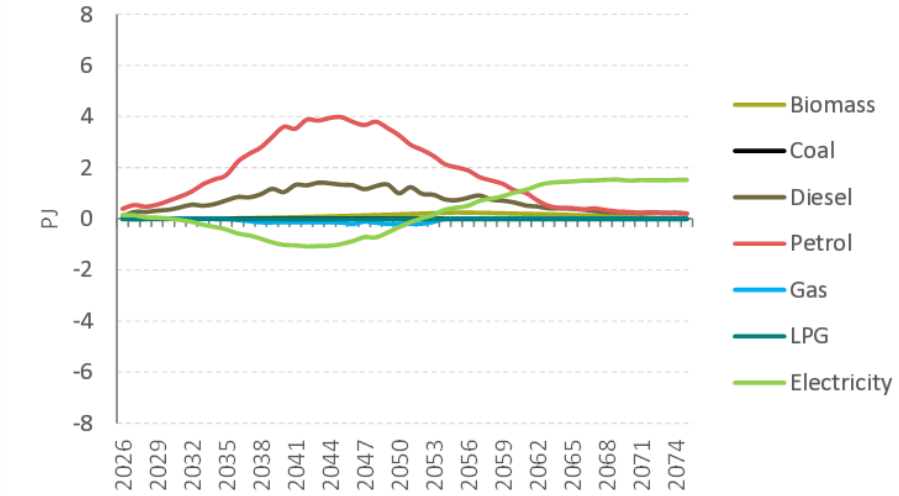


Figure 23: Total energy demand - Electricity Stress vs. reference

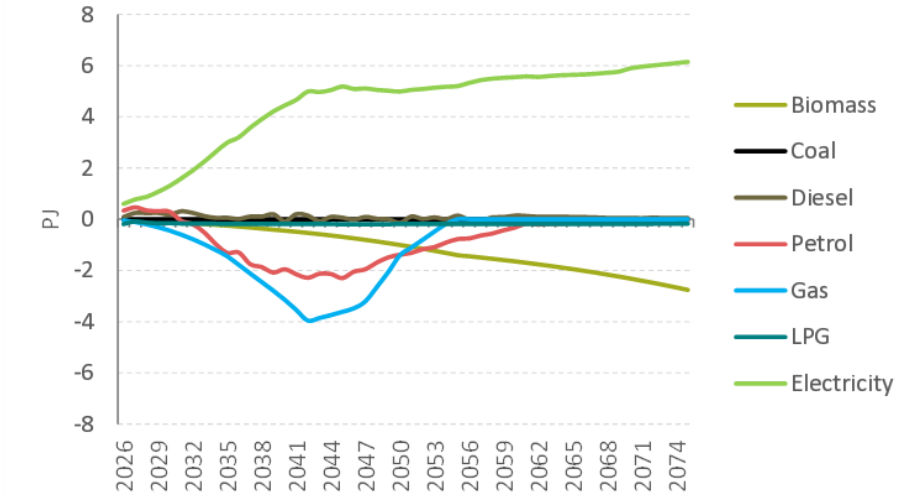
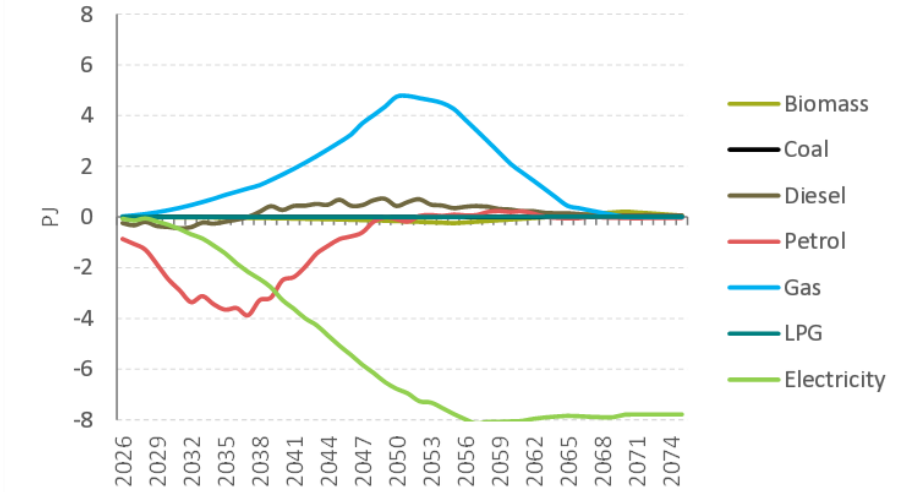


Figure 24: Total energy demand - Fuel Diverse vs. reference



6.2.2 Electricity Demand

Relative to the reference scenario, the “Compact and Efficient” scenario substantially reduces transport electricity demand as fewer vehicle kilometres travelled outweigh the effects of faster electrification. Residential and agricultural electricity demand is modestly higher throughout the projection period, while commercial demand changes little. Industrial electricity demand fluctuates over time as greater energy efficiency is partially offset by increased electrification of industrial processes.

The urban “Expansion” scenario initially reduces transport electricity demand because of slower electric vehicle uptake, but from around 2060 transport electricity demand exceeds the reference as higher travel demand outweighs the earlier delay in electrification. Commercial electricity demand is consistently higher, reflecting lower efficiency for commercial demand. Industrial electricity demand is initially higher because stronger industrial activity increases energy use, but later falls below the reference scenario as slower electrification increasingly offsets this effect. Residential and electricity demand remain close to the reference as lower energy efficiency is balanced by less electrification.

The “Electricity Stress“ scenario substantially increases industrial electricity demand because industrial biomass conversions are not undertaken, consistent with EECA's RETA electricity pathway, resulting in greater electrification of industrial process heat. Residential and commercial electricity demand are also consistently higher than the reference (e.g., due to less emphasis being placed on energy efficiency and expeditious switching away from gas), while transport electricity demand is higher due to faster EV uptake.

The “Fuel Diverse“ scenario has substantially lower transport electricity demand as both slower electric vehicle uptake and greater transport mode shifting reduce electricity use. Residential and commercial electricity demand are also consistently lower because greater reliance on gas delays electrification, while industrial electricity demand is temporarily lower as industrial process heat continues to use gas for longer before gradually converging with the reference.

Figure 25: Electricity demand - Compact and Efficient vs. reference

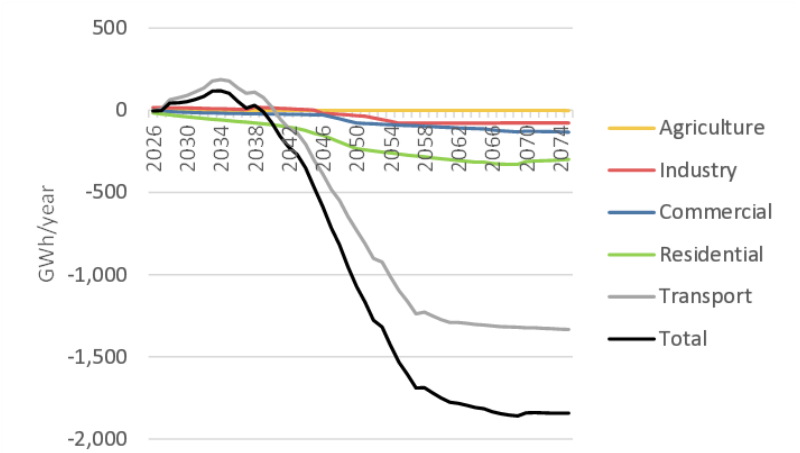


Figure 26: Electricity demand - Expansion vs. reference

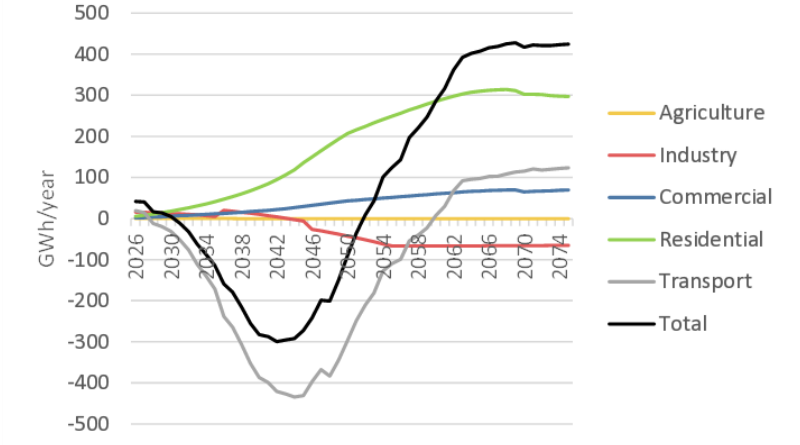


Figure 27: Electricity demand - Electricity Stress vs. reference

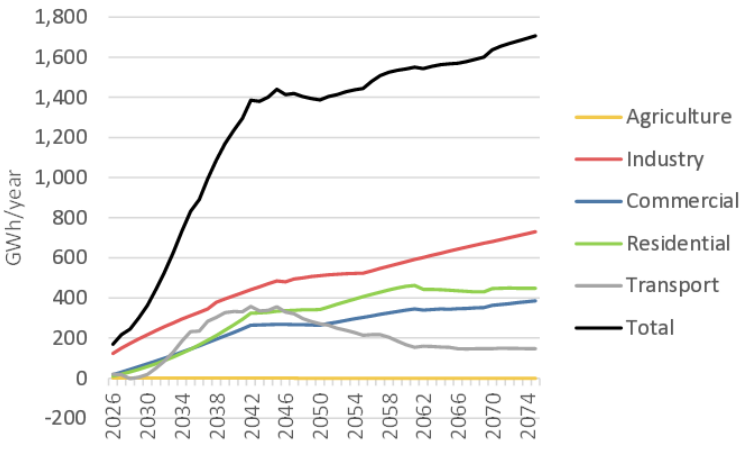
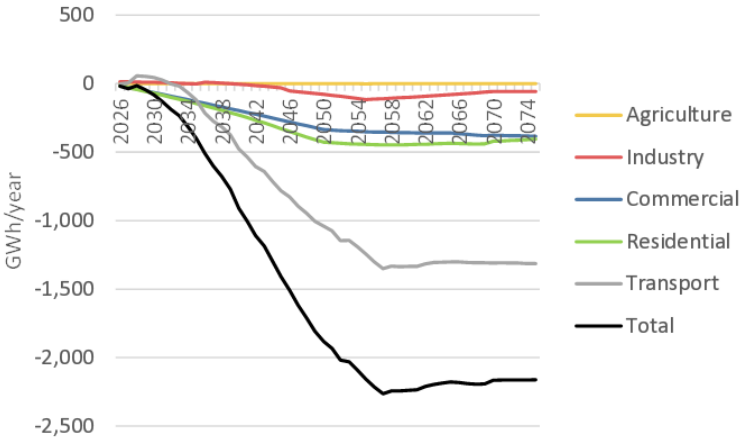


Figure 28: Electricity demand - Fuel Diverse vs. reference



Residential electricity demand

Relative to the reference projection, the four scenarios illustrate how different combinations of urban form, building efficiency, distributed electricity generation and storage, electrification and fuel choice reshape residential electricity demand. All scenarios use the same population growth trajectory; alternative population trajectories are considered only in the sensitivity analysis. The scenarios differ not only in the magnitude of total demand but also in the distribution of demand across end uses, demonstrating how alternative development pathways influence both overall electricity requirements and the composition of household electricity consumption. Reported electricity demand is modelled on a gross basis, meaning that electricity generated and consumed onsite from rooftop solar is not deducted from household demand.

Relative to the reference projection, differences in residential electricity demand across the four scenarios are dominated by changes in water heating. Two effects are particularly important: the electrification of gas water heating and the projected uptake of hot water heat pumps, which are currently relatively rare. Heat pumps are currently far more common in space heating, so there is less variation in the space heating trajectories across scenarios.

In the “Compact and Efficient” scenario, greater electrification increases the number of households using electricity for water heating, but this is more than offset by higher uptake of efficient hot water heat pumps. As a result, electricity requirements for water heating decline despite faster switching away from gas. Electricity demand for space heating is also lower due to increased use of heat pumps and improved building performance.

The “Expansion” scenario results in higher residential electricity demand, particularly for space and water heating. A more dispersed urban form, a greater share of detached housing and slower improvements in building efficiency increase space-heating requirements, while lower uptake of efficient water-heating technologies means electricity use for hot water remains comparatively high.

The “Electricity Stress” scenario produces the largest increase in residential electricity demand. Rapid switching away from gas increases electric water-heating demand, while weaker efficiency improvements and lower uptake of technologies such as hot water heat pumps mean that this additional electricity use is not offset by corresponding efficiency gains. Higher demand across other end uses further increases pressure on electricity generation and network infrastructure.

The “Fuel Diverse” scenario has the lowest residential electricity demand. Rooftop solar uptake is higher than the reference scenario. Hot water heat pumps still become more common, reducing the electricity required for water heating, but there is also less electrification of gas hot water than under the reference. The combination of lower fuel switching and greater water-heating efficiency therefore produces an even larger reduction in electricity demand. More broadly, improved building efficiency and continued use of a wider mix of fuels reduce reliance on grid electricity relative to a predominantly electrification-led pathway.

Figure 29: Residential electricity demand: Compact and Efficient vs. reference

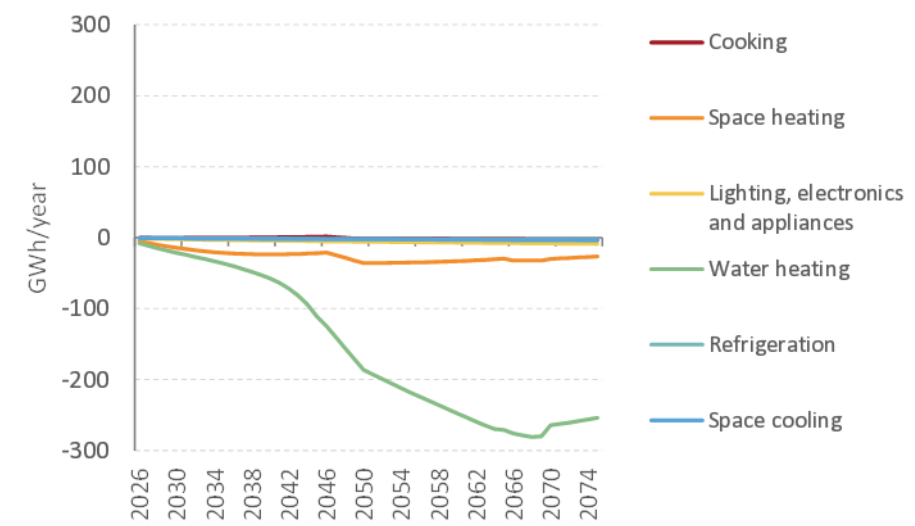


Figure 30: Residential electricity demand: Expansion vs. reference

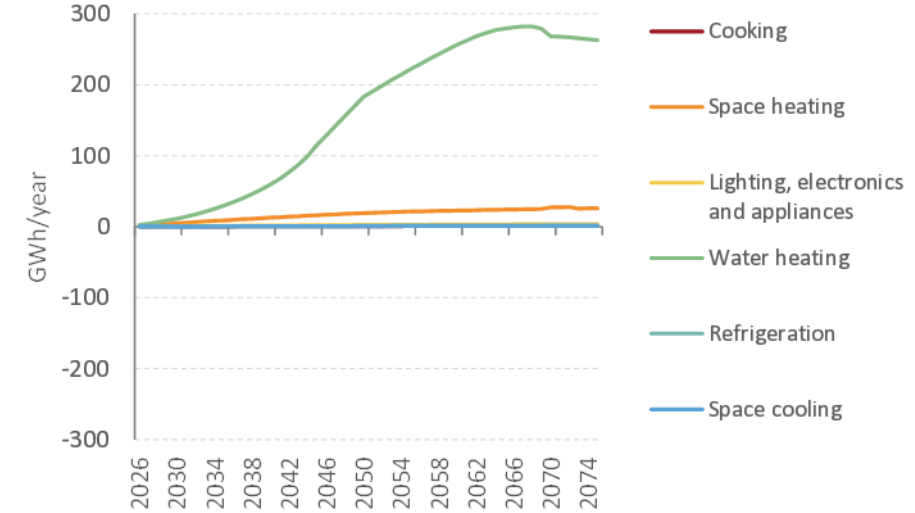


Figure 31: Residential electricity demand: Electricity Stress vs. reference

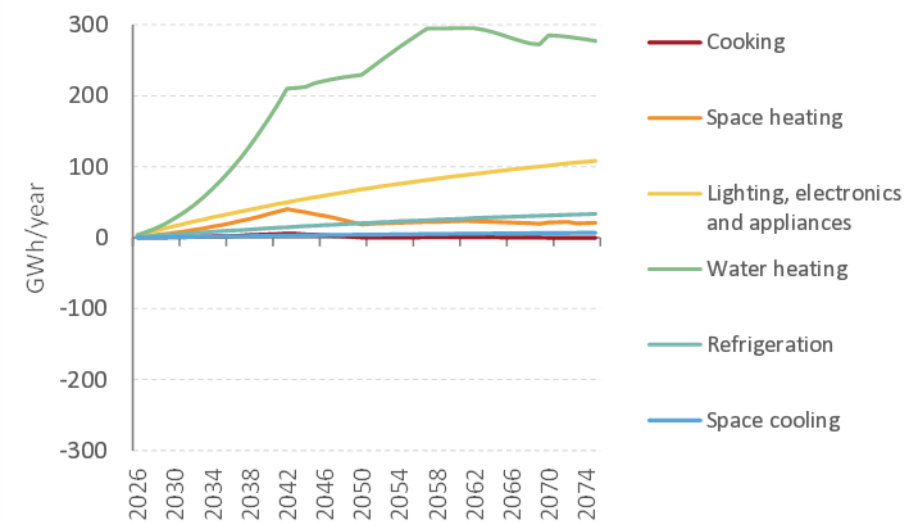
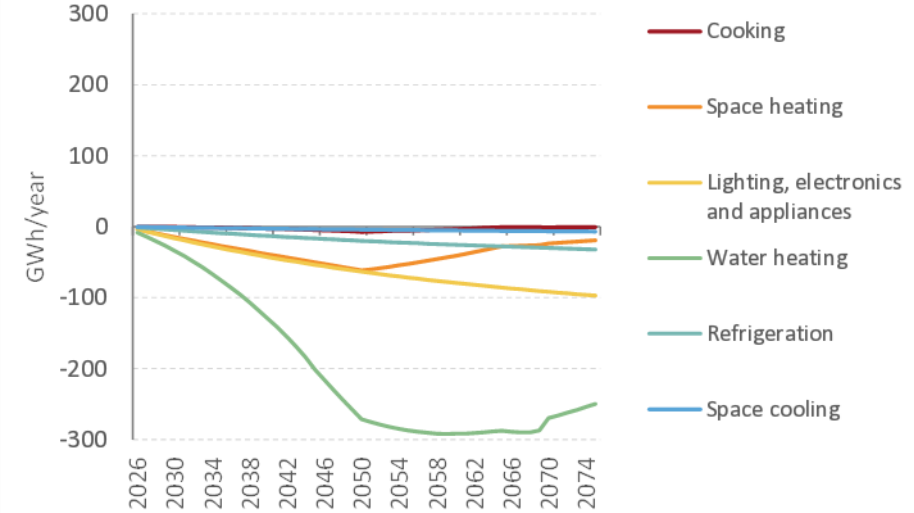


Figure 32: Residential electricity demand: Fuel Diverse vs. reference



Peak demand

Figure 29 to Figure 32 show the modelled change in Auckland's peak electricity demand relative to the reference scenario, disaggregated by sector. The results indicate that transport electrification is the dominant driver of differences in peak electricity demand across the scenarios, while changes in residential, commercial and industrial demand are generally smaller.

The “Compact and Efficient” scenario produces the largest reduction in peak electricity demand. This outcome is driven primarily by lower transport electricity demand resulting from reduced private travel demand and smarter electric vehicle charging behaviour. There are smaller reductions across the residential and commercial sectors reflecting higher energy efficiency and greater demand-side flexibility.

The “Expansion” scenario has peak demand relatively close to the reference as delayed electrification of transport counters the impact of higher transport activity.

“Electricity Stress” generates the largest increase in peak electricity demand relative to the reference, increasing from 1,826 MW in 2026 to 2,800 MW in 2050. Rapid electrification of transport and other end uses, combined with weaker improvements in energy efficiency and demand management, increases peak demand across all sectors, highlighting the potential consequences of electrification occurring without complementary flexibility measures.

In contrast, the “Fuel Diverse” scenario reduces peak electricity demand relative to the reference, with the largest difference occurring in the transport sector due to slower electric vehicle uptake. Smaller reductions are also evident in the residential sector, while industrial and commercial demand remain broadly similar to the reference. Overall, this scenario illustrates how greater reliance on alternative fuels can reduce pressure on Auckland's electricity network, albeit with different implications for emissions and energy security.

Figure 33: Peak electricity demand (MW) - Compact and Efficient vs. reference

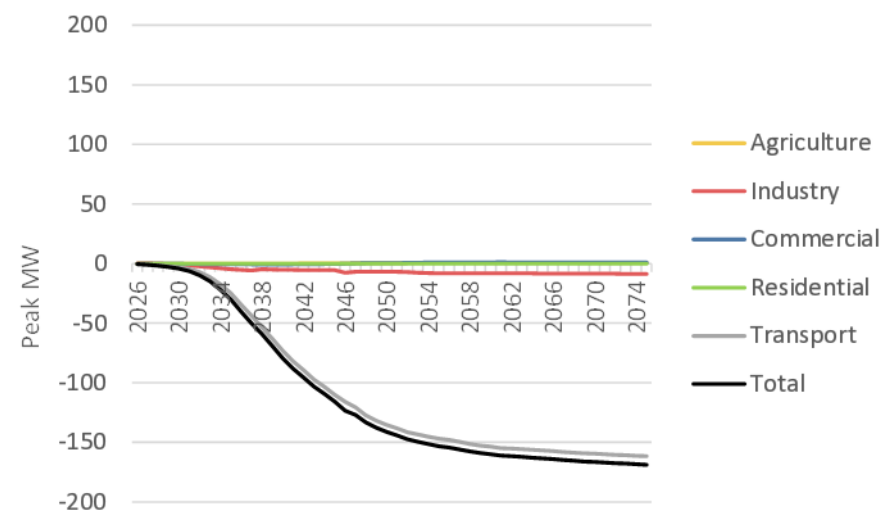


Figure 34: Peak electricity demand (MW) - Expansion vs. reference

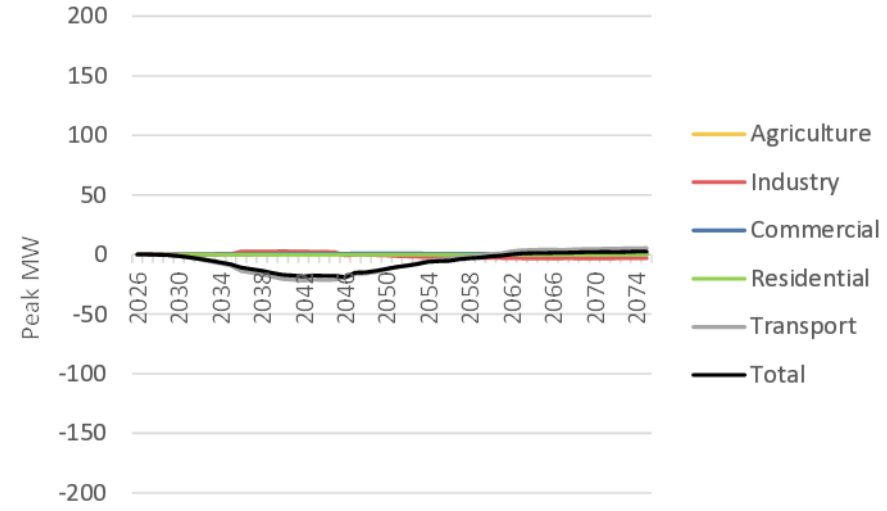


Figure 35: Peak electricity demand (MW) - Electricity Stress vs. reference

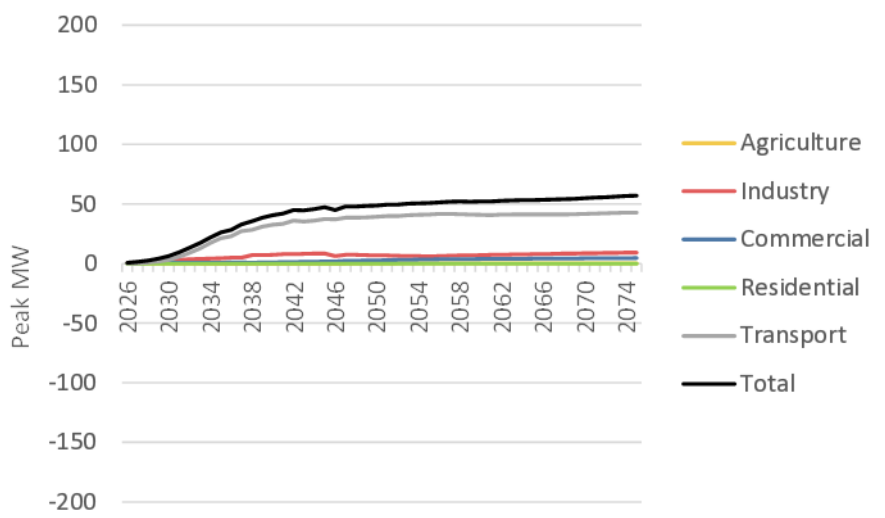
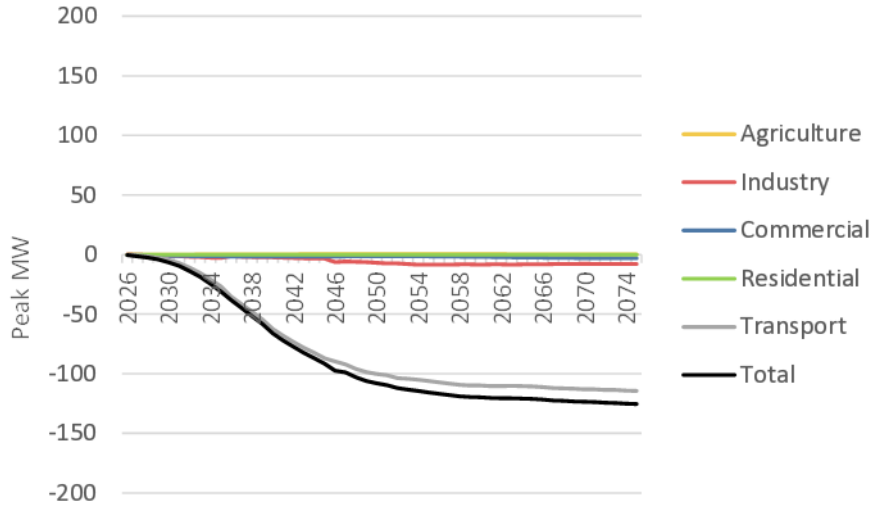


Figure 36: Peak electricity demand (MW) - Fuel Diverse vs. reference



6.2.3 Gas Demand

Figure 37 to Figure 40 show the change in gas demand relative to the reference scenario by end use. Unlike electricity demand, the differences between scenarios are driven primarily by the assumed rate of fuel switching away from gas, with industrial process heat accounting for most of the variation. Although the transition pathways differ markedly before 2055, all scenarios bar “Fuel Diverse” converge with the reference by around 2055 as domestic gas supplies are assumed to be exhausted. “Fuel Diverse” continues to use small amounts of imported LNG beyond this point.

The “Compact and Efficient” scenario results in lower gas demand across most end uses as households and businesses transition away from gas more rapidly. The largest reductions occur in industrial boiler heat and furnace heat, reflecting accelerated fuel switching in process heat. Smaller reductions are also observed for space and water heating as buildings electrify more quickly.

The effects of the “Expansion” scenario are comparatively minor. Changes are measured in terajoules (TJ) rather than petajoules (PJ), reflecting that the scenario does not substantially alter fuel switching behaviour. Instead, the higher gas demand arises primarily from less energy-efficient buildings.

The “Electricity Stress” scenario produces the largest reductions in gas demand. Faster electrification across buildings and industry, together with a more rapid transition away from gas, substantially reduces gas consumption for industrial process heat, particularly boiler and furnace applications. Gas demand for space and water heating also declines more rapidly than in the reference.

In contrast, the “Fuel Diverse” scenario increases gas demand relative to the reference across almost all end uses. Slower electrification and a greater willingness to retain gas for heating lead to higher gas consumption, with the largest increase occurring in industrial boiler heat. Residential and commercial uses also increase, although to a much smaller extent. These results illustrate that the future role of gas in Auckland depends primarily on the pace of fuel switching rather than changes in underlying energy service demand.

Figure 37: Gas demand by end use - Compact and Efficient vs. reference

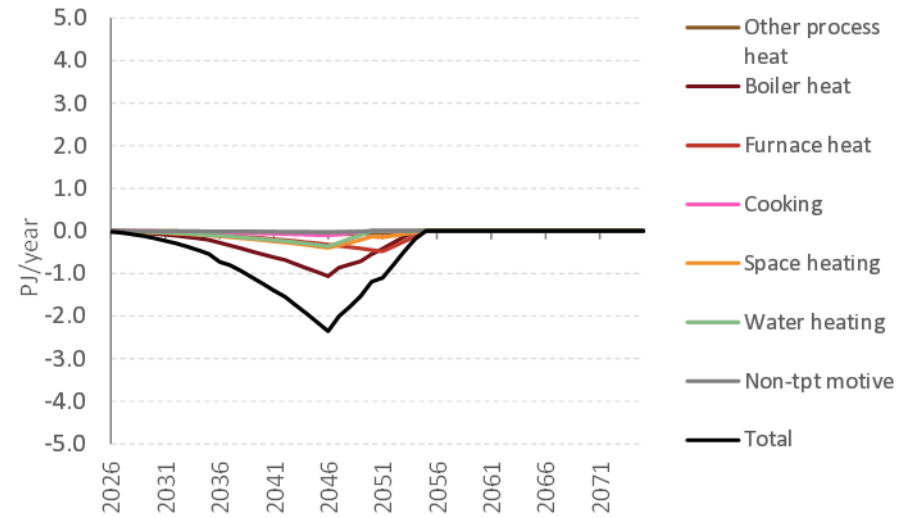


Figure 38: Gas demand by end use - Expansion vs. reference

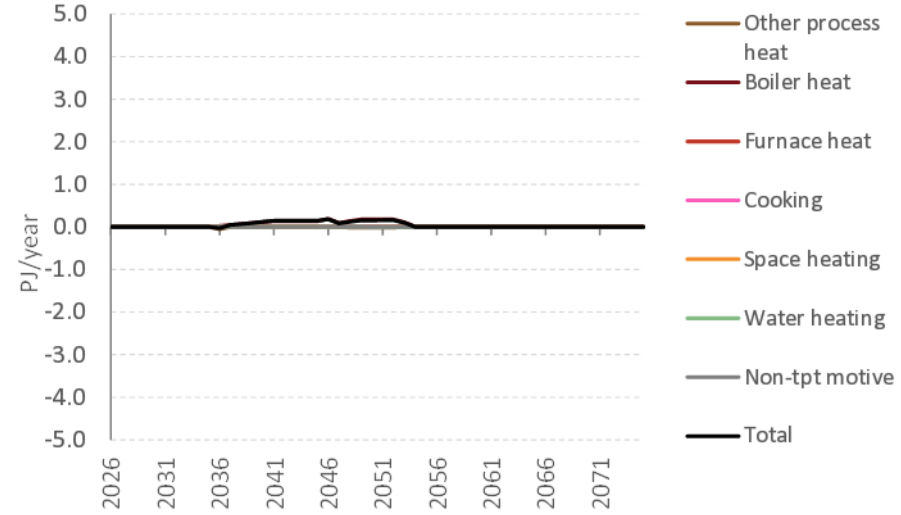


Figure 39: Gas demand by end use - Electricity Stress vs. reference

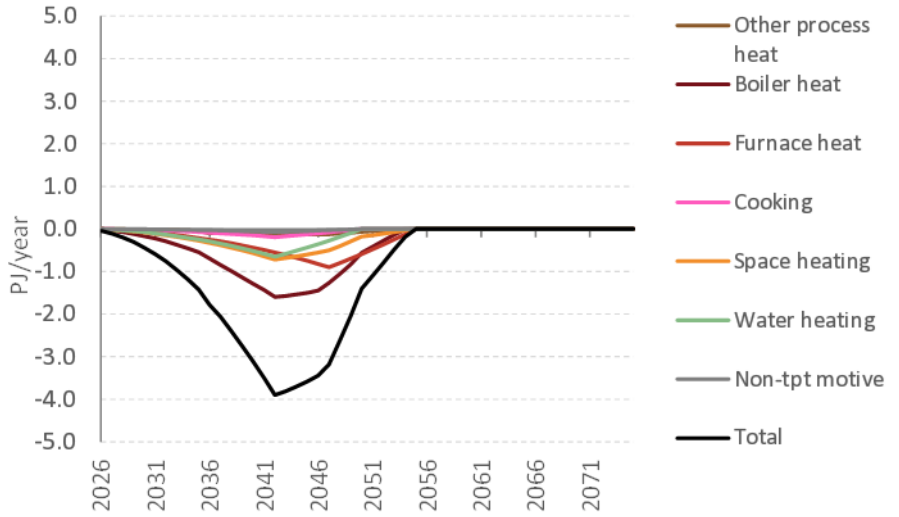
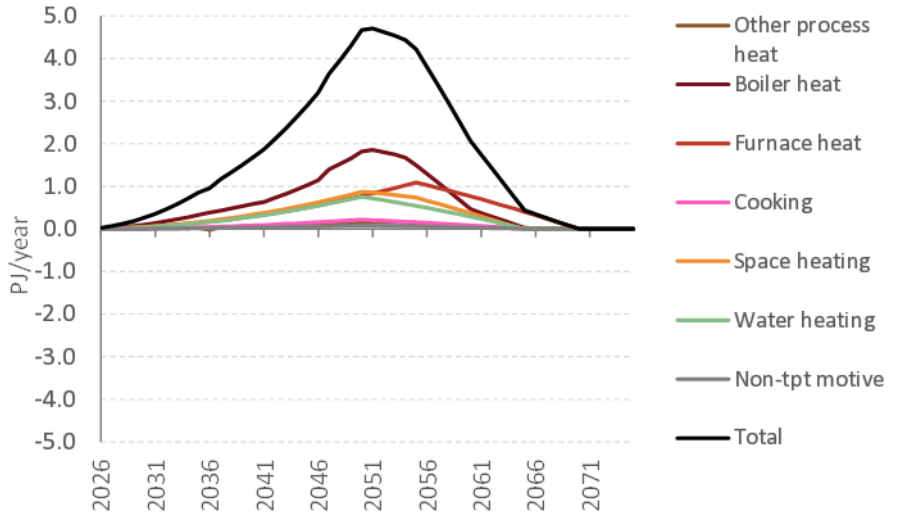


Figure 40: Gas demand by end use - Fuel Diverse vs. reference



6.2.4 Transport Energy Demand

Figure 41 to Figure 44 show the differences in transport energy demand across the scenarios. These differences reflect the interaction of three main drivers: overall transport demand, mode shift between transport modes, and fuel switching within each mode.

“Compact and Efficient” has greater electrification of transport, which reduces petrol and diesel demand, combined with a greater extent of mode shifting, which further reduces demand petrol and also for electricity. Diesel consumption by rail transport is slightly higher due to freight mode shifting to rail.

“Expansion” has less electrification and less mode shifting than the reference, which leads to significantly higher petrol consumption. Rail electricity demand is higher due to increased passenger rail demand with urban expansion, even in the absence of further mode shifting.

The “Electricity Stress” scenario has higher transport electricity demand from light vehicle electrification. Diesel demand changes relatively little, reflecting the more costly economics of heavy vehicle electrification. Rail electricity demand is modestly higher than the reference. Aviation electricity demand is also higher, with batteries increasingly being used for domestic short haul flights, however, the total impact is small.

The “Fuel Diverse” scenario combines greater mode shift towards public and active transport with slower electrification of the light vehicle fleet. As a result, electricity demand from road transport is substantially lower than in the reference, remaining around 5 PJ lower by the end of the modelling period. Petrol and diesel consumption are initially lower than the reference, but increase over time.

Figure 41: Transport energy demand (TJ) – Compact and Efficient vs. reference

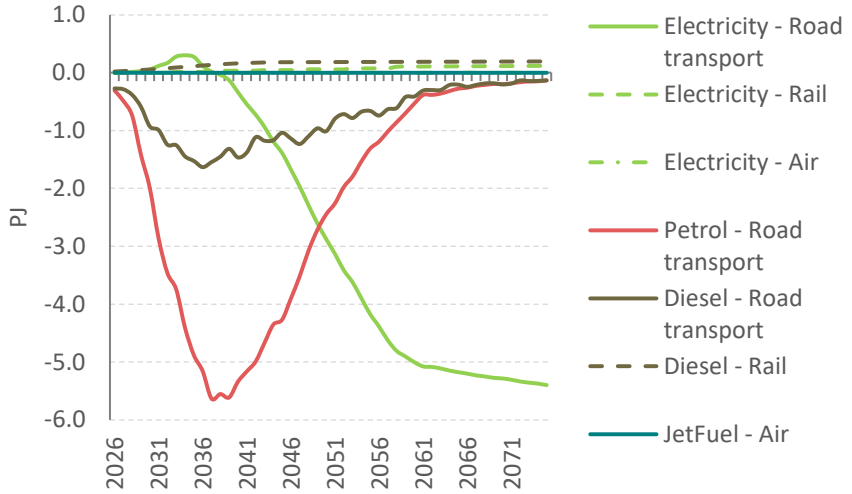


Figure 42: Transport energy demand (TJ) - Expansion vs. reference

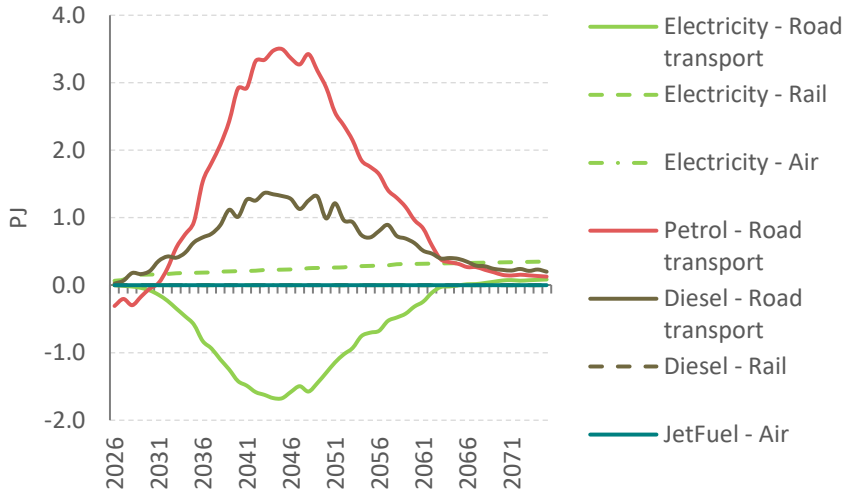


Figure 43: Transport energy demand (TJ) – Electricity Stress vs. reference

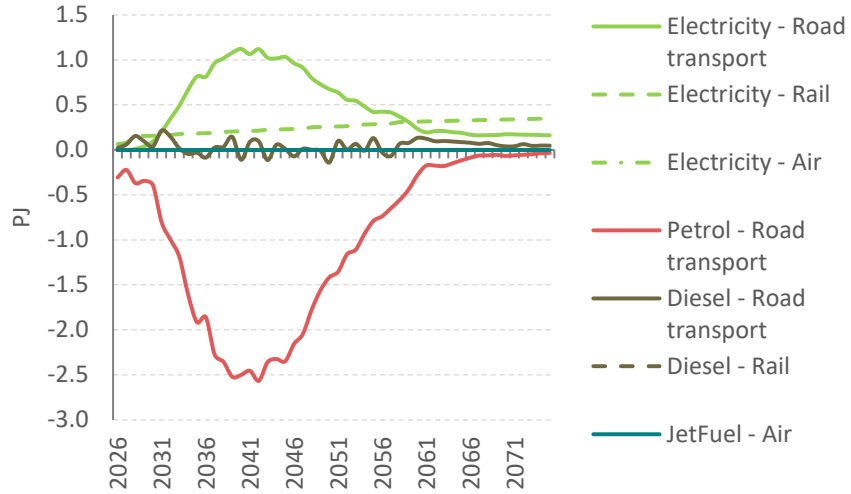
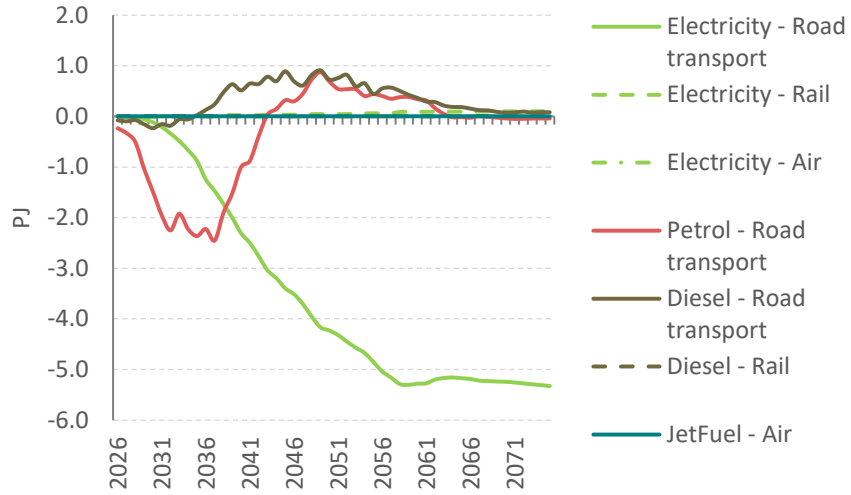


Figure 44: Transport energy demand (TJ) – Fuel Diverse vs. reference



6.2.5 Capital expenditure

The “Compact and Efficient” scenario delivers the largest reduction in capital expenditure, driven primarily by lower private vehicle investment resulting from reduced travel demand and greater use of public and active transport. Small increases in residential and commercial appliance investment reflect faster uptake of more efficient technologies, while lower electricity demand reduces the need for generation and distribution investment.

The “Expansion” scenario has the highest overall capital expenditure of the scenarios considered. Higher underlying demand and more dispersed urban growth increase investment requirements, particularly for local electricity networks. Greater reliance on private transport is also assumed to increase vehicle capital requirements, whether through higher vehicle ownership or more frequent replacement. Generation investment is uneven over time because new generation and firming capacity are added in discrete increments, but from around the 2040s it requires materially more investment in both generation and firming than the reference scenario.

The “Electricity Stress” scenario requires the greatest increase in electricity-related capital expenditure relative to the reference. More rapid electrification substantially increases vehicle investment, while additional spending on electricity generation and local network infrastructure is required to meet higher electricity demand in the absence of as much distributed energy resources, demand flexibility and efficiency. Some investment shifts away from gas infrastructure and fossil fuel appliances as electrification accelerates. Section 6.3 and the appendix expand on implications for electricity networks.

The “Fuel Diverse” scenario reduces overall capital expenditure relative to the reference through lower vehicle investment, despite increased investment in gas appliances and continued expenditure on gas infrastructure. Compared with the electrification-focused scenarios, this pathway shifts investment away from the electricity system and towards maintaining a more diverse mix of energy technologies.

These modelled capital expenditure results do not include the transport infrastructure needed to support changes in travel demand and mode share. As discussed in Section 7.7, Auckland’s current RLTP proposes $63.1 billion of transport expenditure over 2024-2034, while the high-ambition VKT Reduction Programme estimates approximately $20.5 billion of capital expenditure to 2035, although these programmes overlap substantially and include baseline growth, renewal and resilience investment.

Lower private transport demand in Scenarios 1 and 4 results in substantially lower private vehicle capital expenditure, with the estimated reduction larger than the combined differences in energy infrastructure and other appliance investment. This result should, however, be interpreted cautiously. The relationship between private vehicle kilometres travelled and vehicle purchasing is not well understood and reflects the cumulative effect of many household decisions about vehicle ownership. The effective elasticity may differ from that assumed in the modelling, so the estimated magnitude should be treated as indicative of direction rather than a precise projection.

Figure 45: Capital expenditure – Compact and Efficient vs. reference

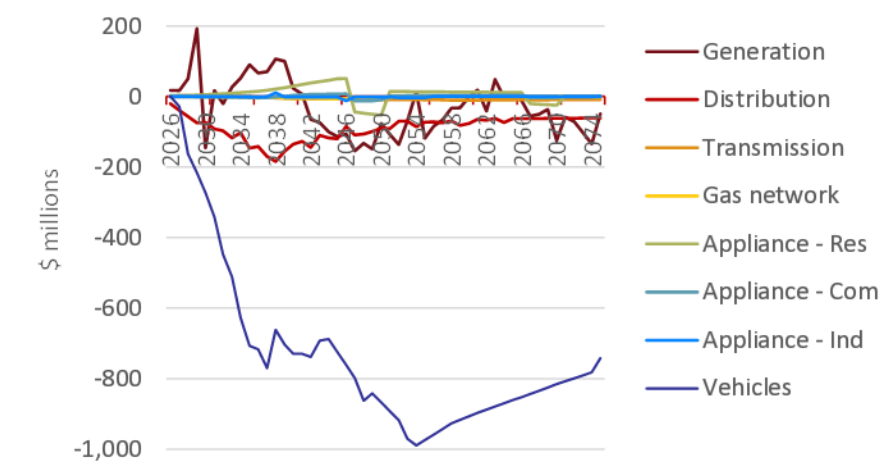


Figure 46: Capital expenditure - Expansion vs. reference

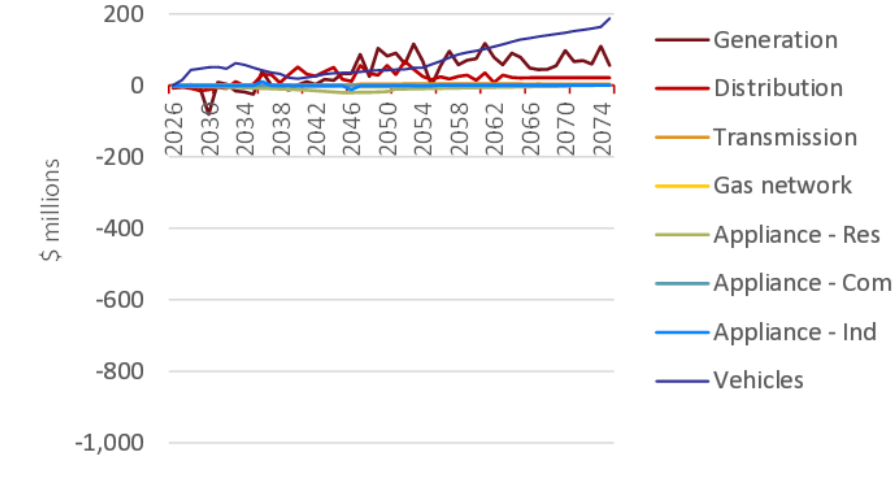


Figure 47: Capital expenditure – Electricity Stress vs. reference

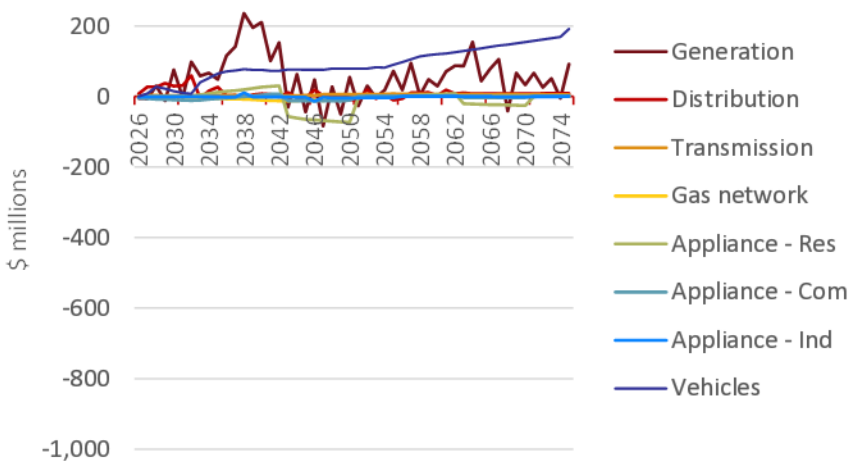
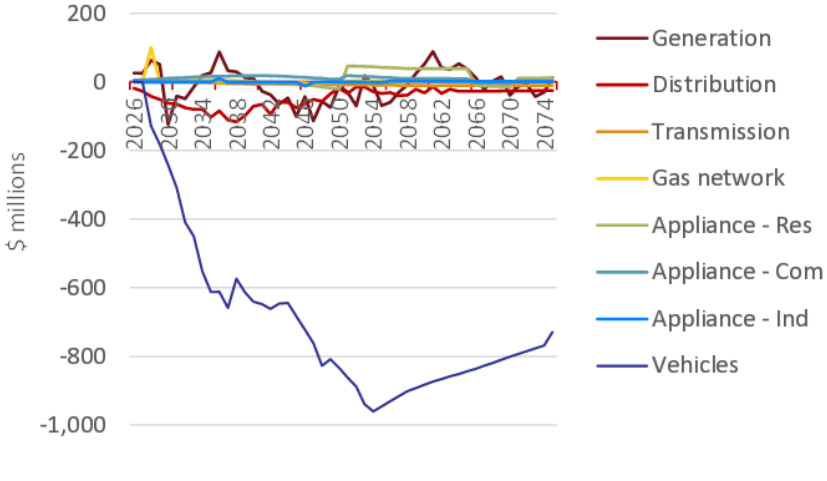


Figure 48: Capital expenditure – Fuel Diverse vs. reference



6.2.6 Operational costs

The difference in operating expenses paints a similar picture. Figure 49 to Figure 52 show the annual difference in operating expenditure (opex) relative to the reference scenario. The largest changes are associated with private vehicle operating costs, expenditure on liquid fuels, and gas network operating costs, while differences in electricity generation, local networks and appliance operating costs are comparatively small. The results reflect changes in transport demand, the pace of electrification, and the extent of fuel switching.

The “Compact and Efficient” scenario delivers the largest reductions in operating expenditure relative to the reference. Lower transport demand reduces private vehicle operating costs, while faster electrification substantially reduces expenditure on more costly and inefficient fossil fuels during the transition period. Electricity system operating costs change relatively little.

The “Expansion” scenario results in higher operating expenditure than the reference, primarily because slower electrification maintains higher expenditure on liquid fuels. Vehicle maintenance costs are also higher due to a higher proportion of travel by private vehicle.

The “Electricity Stress” scenario produces a mixed pattern of operating expenditure. Faster electrification reduces spending on liquid fuels, but these savings are partly offset by higher gas network operating costs and increased private vehicle operating costs associated with higher private road transport demand. Most differences diminish over time as the energy system converges towards the reference pathway.

The “Fuel Diverse” scenario shifts operating expenditure away from electricity and towards fossil fuels. Slower electrification increases expenditure on liquid fuels and gas network operations, while private vehicle operating costs remain below the reference because greater mode shift reduces vehicle travel. As with the other scenarios, most differences narrow towards the end of the modelling period as the energy system adjusts to the long-term transition away from domestic natural gas and internal combustion vehicles.

Figure 49: Operating expenditure: scenario 1 vs. reference

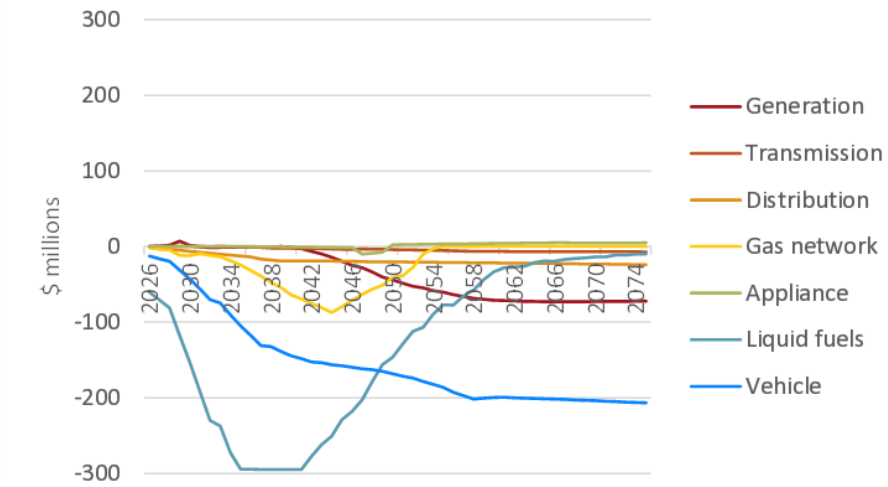


Figure 50: Operating expenditure: Expansion vs. reference

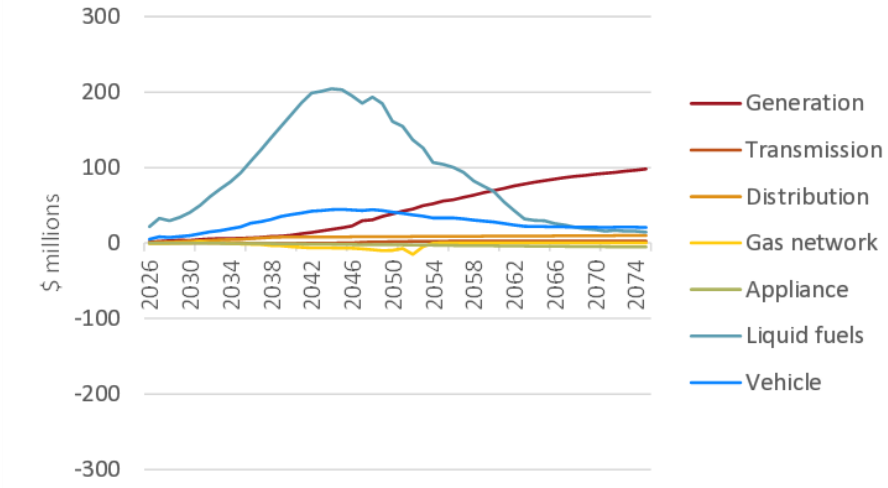


Figure 51: Operating expenditure: Electricity Stress vs. reference

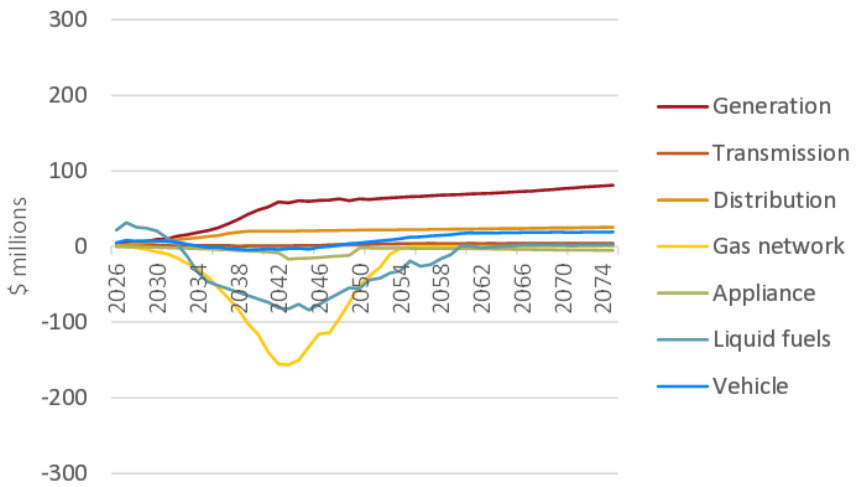
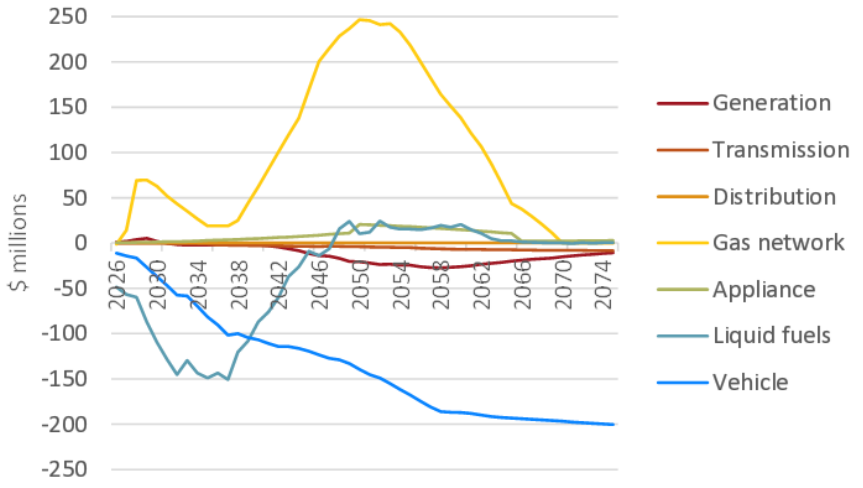


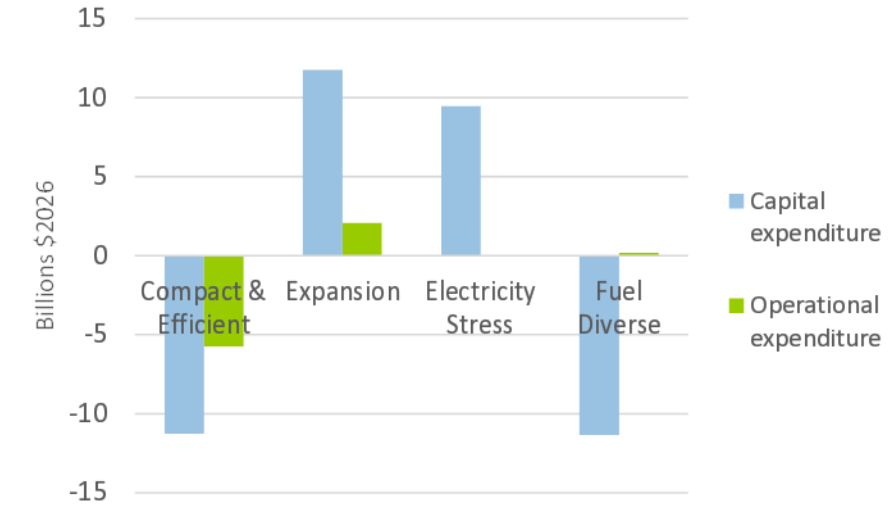
Figure 52: Operating expenditure: Fuel Diverse vs. reference



Over the period from 2026 to 2035, the scenarios produce markedly different impacts on total capital and operating costs relative to the reference (Figure 53). “Compact and Efficient” reduces both capital and operating expenditure. “Expansion” increases both, with higher demand requiring substantially more capital investment as well as higher ongoing operating expenditure.

“Electricity Stress” also results in significantly higher capital expenditure, while operating expenditure remains almost unchanged from the reference. “Fuel Diverse” has lower capital expenditure over this period, driven mainly by lower private vehicle travel and reduced requirements for electricity infrastructure. Its operating expenditure is slightly higher than the reference, however, and this gap widens beyond 2035 as continued reliance on higher-cost fuels becomes more significant. These estimates do **not** include costs of the LNG import terminal assumed to operate in this scenario.

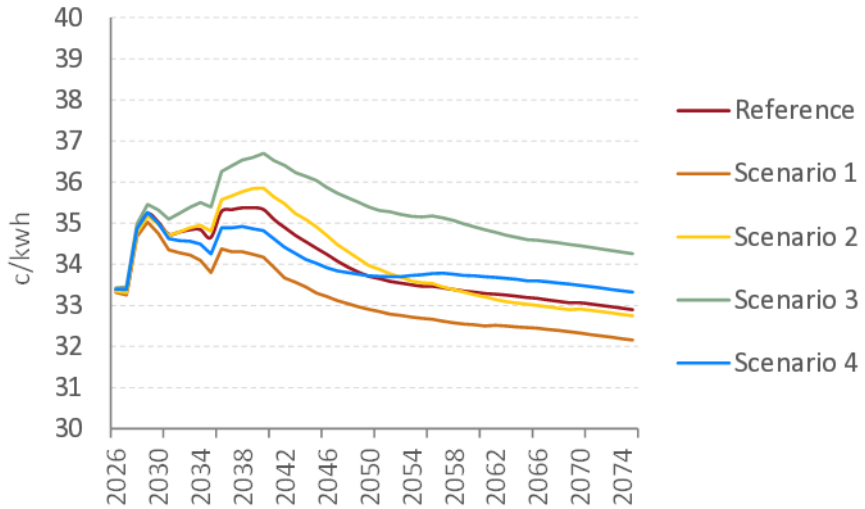
Figure 53: Overall impact on costs to 2035 vs. reference



6.2.7 Energy prices

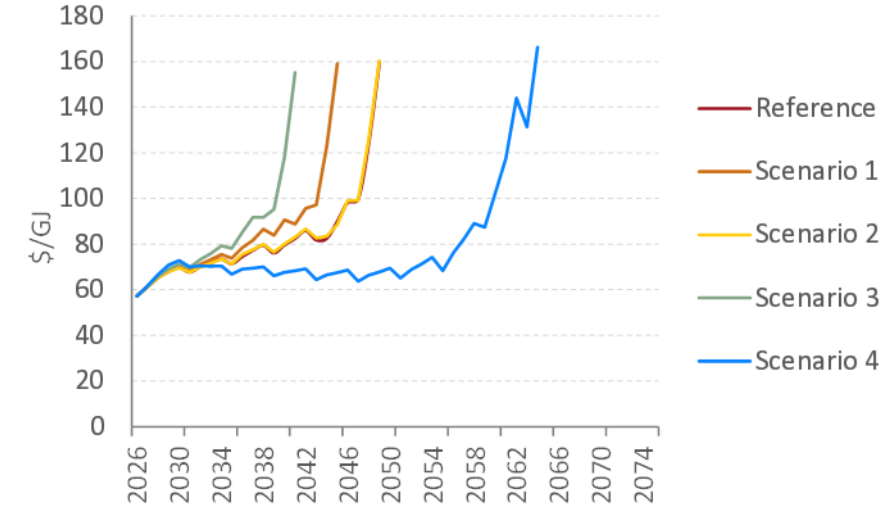
Residential electricity prices diverge across the scenarios primarily because of differences in electricity demand growth, peak demand and the resulting network investment requirements. The “Compact and Efficient” scenario produces the lowest prices over the longer term, reflecting relatively low demand growth due to energy efficiency and successful peak load management. The “Electricity Stress” produces the highest prices because both overall electricity demand and peak demand grow strongly, requiring greater investment in generation and network capacity. The “Expansion” scenario has lower overall demand growth from electrification, but weaker management of peak demand still drives relatively high network costs. The “Fuel Diverse” scenario has lower prices in the near term due to slower electrification, but prices are higher later as electrification and associated network requirements catch up over time.

Figure 54: Retail electricity price by scenario (c/kwh)



Retail gas prices rise sharply as the customer base contracts and the largely fixed costs of operating the gas network are recovered from fewer users. The reference, Compact and Efficient, Expansion, and Electricity Stress scenarios use the same wholesale gas assumptions, so differences in retail prices between these scenarios are driven by the different rates at which customers leave the network. Faster switching away from gas produces a more rapid increase in costs for those who remain. The "Fuel Diverse" scenario delays this dynamic because LNG imports extend the availability of gas and slower electrification retains customers on the network for longer. However, as the relative economics of electrification become increasingly favourable, gas demand still eventually declines sharply.

Figure 55: Retail gas price by scenario ($/GJ)



6.2.8 Emissions

Figure 56 to Figure 59 shows the difference in greenhouse gas (GHG) emissions relative to the reference scenario, disaggregated by fuel. The differences arise primarily from three factors: changes in the rate of fuel switching between fossil fuels and electricity or biomass, changes in underlying energy demand (particularly for transport), and, to a lesser extent, differences in the emissions intensity of electricity generation resulting from changes in the national generation mix.

The "Compact and Efficient" scenario delivers the largest emissions reductions relative to the reference. Faster electrification of transport, buildings and industry substantially reduces emissions from petrol, diesel and gas. At the same time, transport mode shifting decreases overall electricity demand so emissions from electricity are also lower.

The "Expansion" scenario has the highest overall emissions. Lower energy efficiency and weaker mode shift keep petrol and diesel consumption higher than under the more efficient scenarios, while greater energy demand also limits reductions in gas use. Electricity emissions increase initially as greater electrification raises demand, producing a short-lived spike. However, this effect diminishes over time as additional renewable generation comes online, flattening the increase in electricity emissions and leaving a relatively small net reduction in overall emissions compared with the reference.

The "Electricity Stress" scenario increases electricity emissions substantially relative to the reference as rapid electrification and higher underlying transport demand drive greater electricity consumption. However, these increases are eventually offset by lower petrol and gas emissions resulting from accelerated fuel switching. From the late 2060s the gap reduces as electricity demand growth slows and converges with the reference.

The "Fuel Diverse" scenario produces the opposite pattern. Slower electrification reduces electricity-sector emissions relative to the reference but results in higher emissions from gas and petrol, as fossil fuels continue to play a larger role in transport and heating.

Figure 56: GHG emissions (kt CO_2-e) – Compact and Efficient vs. reference

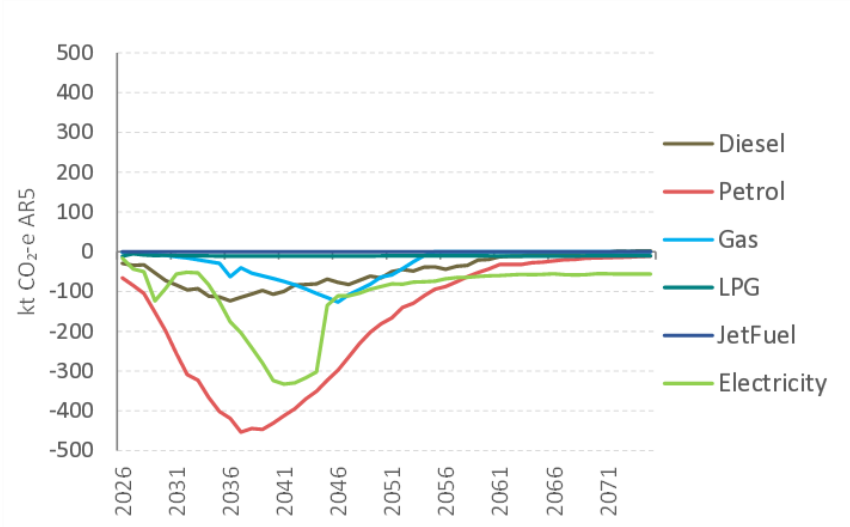


Figure 57: GHG emissions (kt CO_2-e) - Expansion vs. reference

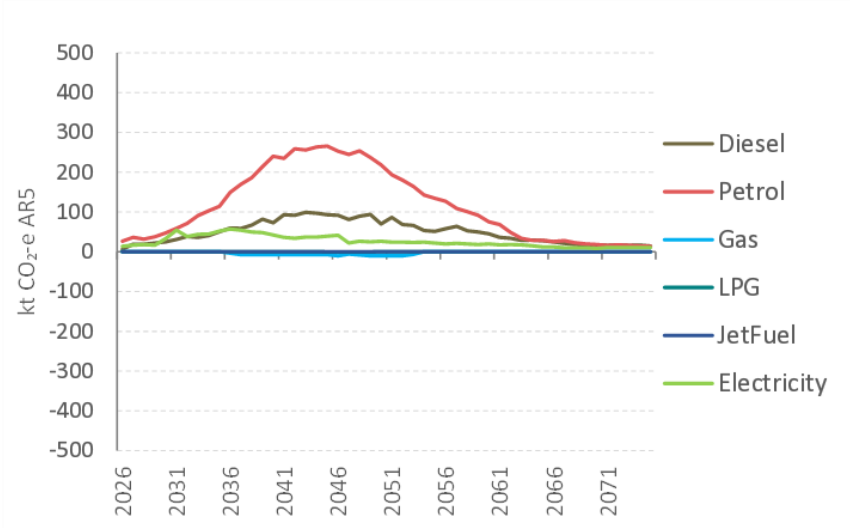


Figure 58: GHG emissions (kt CO_2-e) – Electricity Stress vs. reference

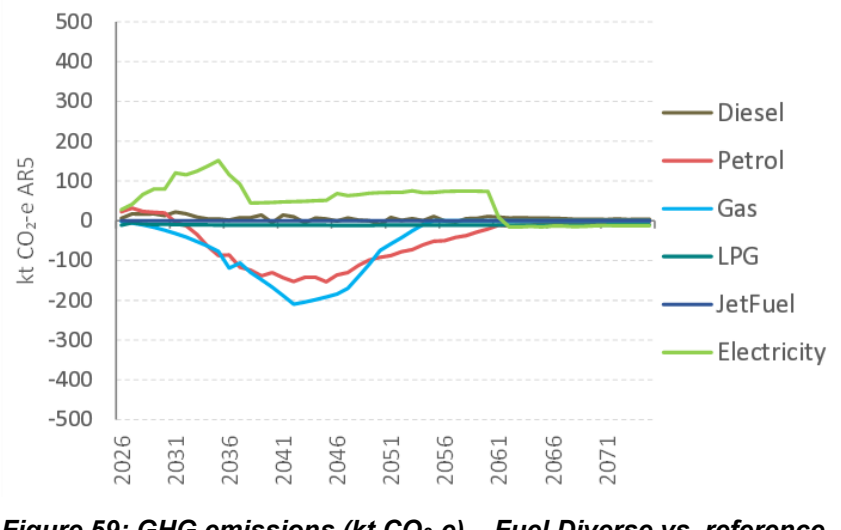
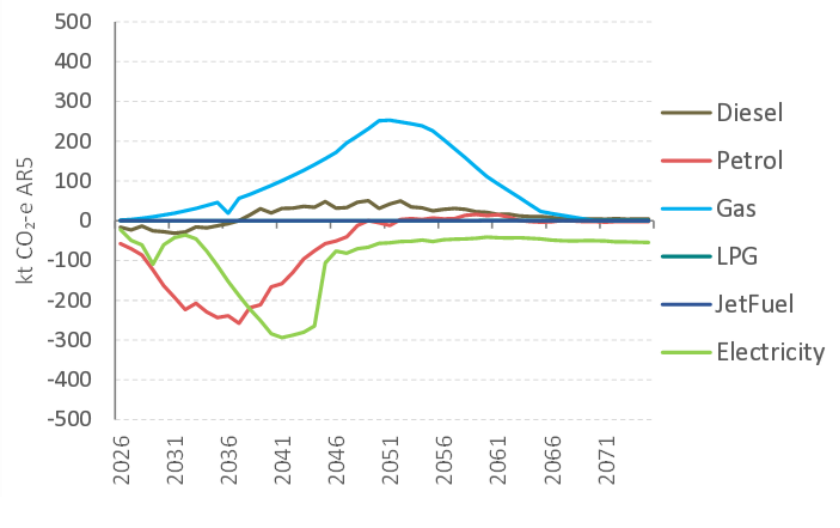


Figure 59: GHG emissions (kt CO_2-e) – Fuel Diverse vs. reference



6.2.9 Key insights: the pace of electrification matters less than how it is implemented.

Looking across the four scenarios, three assumptions account for most of the differences in the results:

- The pace of electrification
- Improvements in energy efficiency and smart load management
- The extent to which people shift away from private vehicles.

Urban form matters because it influences all three, affecting both transport demand and the amount of energy needed to provide the same services.

The strongest overall outcomes are achieved in the “Compact and Efficient” scenario. Compact urban development reduces travel demand, while higher building efficiency and uptake of smart demand management, and greater use of public and active transport reinforce the benefits of electrification. The combined effect is lower energy demand, lower peak electricity demand, lower emissions, and the lowest capital and operating costs of any scenario. In other words, reducing demand efficiently lessens the need for additional infrastructure and operating expenditure.

At the other end of the spectrum, the “Expansion” scenario shows the penalty associated with more dispersed growth. Longer travel distances and less efficient buildings increase energy demand across the economy. Delaying electrification avoids some capital expenditure in the short term, but this saving is gradually outweighed by higher fuel costs and persistently higher emissions, coupled with poor demand management increasing the network build requirements materially above what they could have been if smart demand solutions had been implemented.

The “Electricity Stress” scenario reinforces a different lesson. Electrification can reduce fossil fuel use quickly, but it does not eliminate the need for investment or action elsewhere. Without stronger efficiency improvements or demand-side flexibility, electricity demand grows rapidly, peak loads rise, and considerably more generation and network capacity is required. Of the four scenarios, this places the greatest strain on Auckland's electricity system.

The “Fuel Diverse” scenario takes a different approach again. Slower electrification keeps electricity demand and network investment well below the reference, particularly when combined with greater transport mode shift. However, this comes at the cost of retaining gas and liquid fuels for longer, with imported LNG needed after domestic gas production is exhausted.

A consistent finding across the modelling is that the benefits of electrification depend on the context in which it occurs. Electrification delivers much better outcomes when it is accompanied by smart demand management, efficient buildings and a transport system that reduces reliance on private vehicles. Simply electrifying more end uses, without addressing demand management shifts pressure from fossil fuels onto the electricity system rather than removing it.

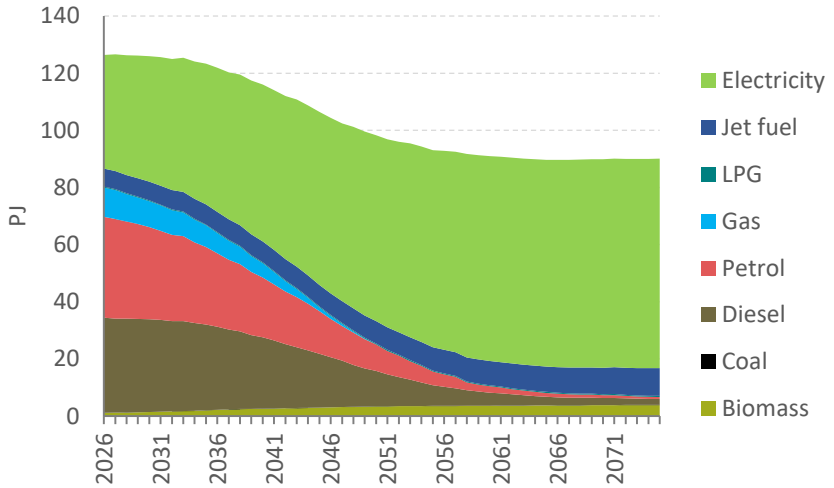
Finally, these scenarios are not intended to represent different economic growth paths. With the exception of transport mode shift and improvements in energy efficiency, the underlying demand for residential, commercial and industrial energy services is held constant across all scenarios. Faster population or economic growth would increase total energy demand, infrastructure requirements and emissions under every scenario, while slower growth would reduce them. The relative differences between the scenarios, however, would be expected to remain much the same.

6.3 Revised outlook with Plan Change 120 projections

6.3.1 Total energy demand

The shift towards services is expected to reduce energy demand for industrial processes compared with the original reference scenario. However, employment is not always a reliable indicator of energy demand for electricity-intensive activities such as data centres. This revised reference scenario has higher electricity demand due to the higher growth projections for commercial activity, and faster electrification of transport than was previously the case.

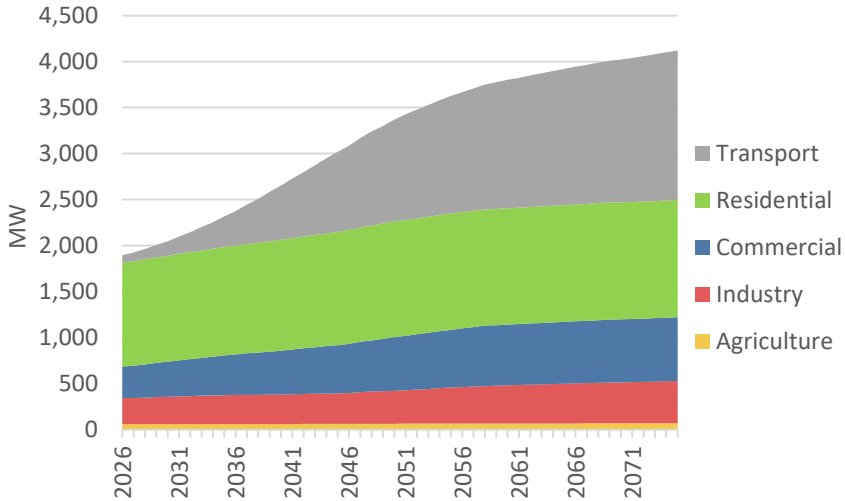
Figure 60: Revised reference total energy demand by fuel type



6.3.2 Electricity demand

The overall impact of the dwelling changes is initially more electricity demand due to more dwellings in the 2030s. These have a low heating energy demand and a higher cooling demand than existing housing stock. By 2050, however, the overall net effect is slightly less peak residential demand than under the previous reference scenario. The revised projections of EV uptake and efficiencies have significantly increased transport electricity demand, and commercial demand has also increased. The overall effect is an increase from 3200 MW in 2075 in the previous reference to 4100 MW in the revised scenario.

Figure 61 - Revised reference peak electricity demand.

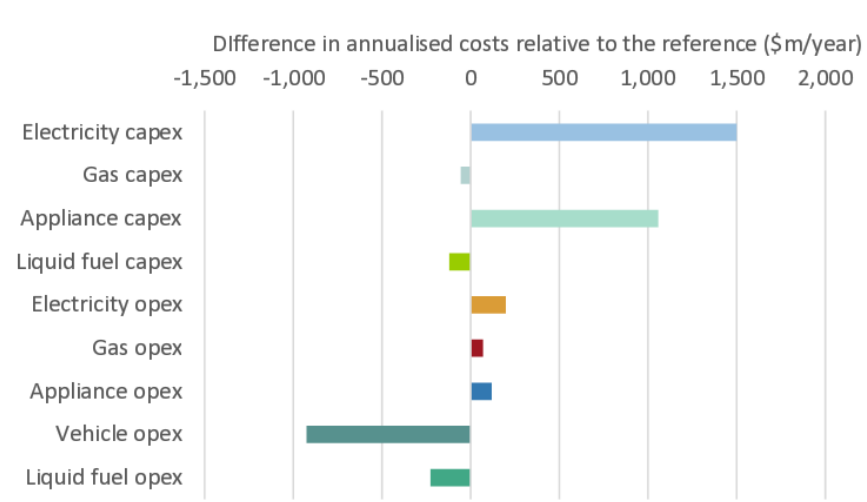


6.3.3 Capital and operating expenditure

The updated PC120 scenario produces several differences in energy-related costs compared with the previous reference (Figure 62). Electricity operating and capital expenditure are both higher, reflecting stronger household and economic growth and the associated increase in electricity demand. Appliance costs also rise because more dwellings are expected to be built, some of which are assumed to connect to gas and will therefore require replacement appliances as the gas network transitions towards 2050. Gas operating expenditure is higher due to stronger growth in commercial

sectors that use gas, while pipeline capital expenditure is lower because this additional demand is more geographically concentrated. In transport, revised EV uptake assumptions reduce expenditure on liquid fuels and vehicle operating costs. However, as the transport modelling has not yet been completed, the implications for the total number of private vehicles remain uncertain. Vehicle and transport capital expenditure are therefore excluded from the comparison at this stage.

Figure 62 – Expenditure to 2050 vs. reference

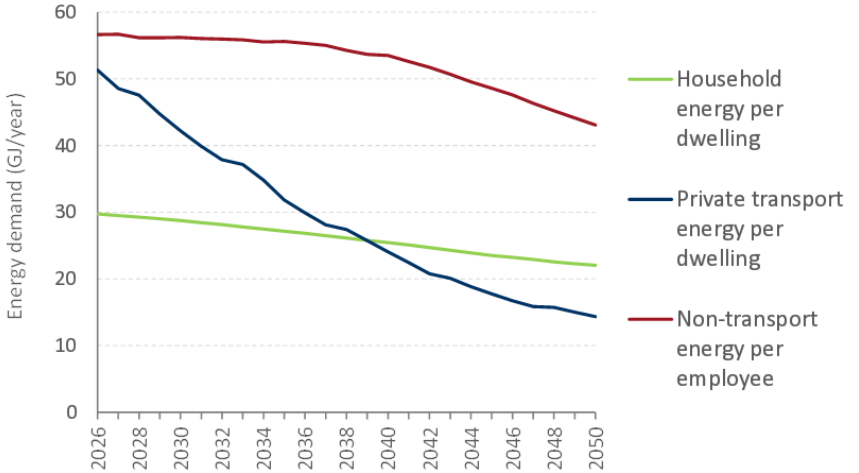


6.4 Energy intensity

As Auckland grows, its total energy demand is projected to increase much slowly than the number of households and employees.

Energy demand per dwelling and employee is expected to fall between 2026 and 2050. The largest change is in private transport, where energy use per dwelling falls by around 73% to 15GJ per year. Some of this comes from a shift towards public and active transport, but much of the reduction is due to the uptake of electric vehicles. Petrol and diesel vehicles waste a large proportion of their energy as heat so electric transport demands less energy overall.

Figure 63: Energy intensity per dwelling and employee - PC120 scenario



Household energy use also falls, from around 30 GJ to 22 GJ per dwelling per year. This reflects smaller average dwelling sizes, switching away from gas, and more efficient heat pumps for space and water heating.

Non-transport energy use per employee declines more gradually, from around 57 GJ to 43 GJ, due to efficiency improvements, electrification of industrial heat, and a shift in Auckland's economy towards less energy-intensive sectors. However, growth in energy-intensive industries such as data centres offsets these improvements and could reverse the downward trend under an “Electricity Stress”-type future.

6.5 Emissions

Residential emissions change very little, as the increase in dwelling numbers is largely offset by smaller floor areas and the greater efficiency of multi-unit housing. Emissions from industry and electricity generation are slightly higher, but these increases are more than offset by stronger EV uptake, resulting in an overall emissions reduction of 4% (around 200 kt per year) by 2050 relative to the previous reference. However, the transport results remain uncertain until Auckland Council completes its transport modelling.

6.5.1 Key insights

The PC120 scenario reflects stronger household and economic growth, alongside a shift towards smaller, more compact dwellings. While this urban form is closer to the Compact and Efficient scenario, PC120 retains broadly business-as-usual assumptions for electrification, transport mode shift and demand management.

Despite higher growth, residential energy demand increases relatively little, as smaller dwellings and a greater share of multi-unit housing offset much of the additional demand. Commercial and industrial energy demand is higher, reflecting the revised economic growth projections.

The higher EV uptake in 2026 is projected to have long-term impacts on the vehicle fleet and future fuel costs, while also increasing electricity demand. However, these results remain uncertain until the updated transport modelling is completed.

Electricity capital and operating costs are projected to be higher than in the previous reference, although more concentrated development may reduce some infrastructure requirements.

PC120 therefore provides an updated reference outlook rather than replacing the alternative scenarios. Although its urban form is more compact than the previous reference scenario, outcomes resembling Electricity Stress or Fuel Diverse remain possible under the revised growth projections.

7 Infrastructure Requirements and Network Implications

As New Zealand transitions away from fossil fuels to renewable energy, there will be significant infrastructure challenges – but of a diametrically opposite nature depending on whether the infrastructure is associated with renewables or fossil fuels.

For electricity, the challenge won't just be to build renewable generation at a fast enough pace, but also to ensure that the transmission and distribution wires can be built in time to accommodate the potentially significant demand growth associated with electrifying transport, heating, and new sources of demand such as data centres. This network expansion will also need to be supported by smart demand arrangements that avoid unnecessary peaks in demand.

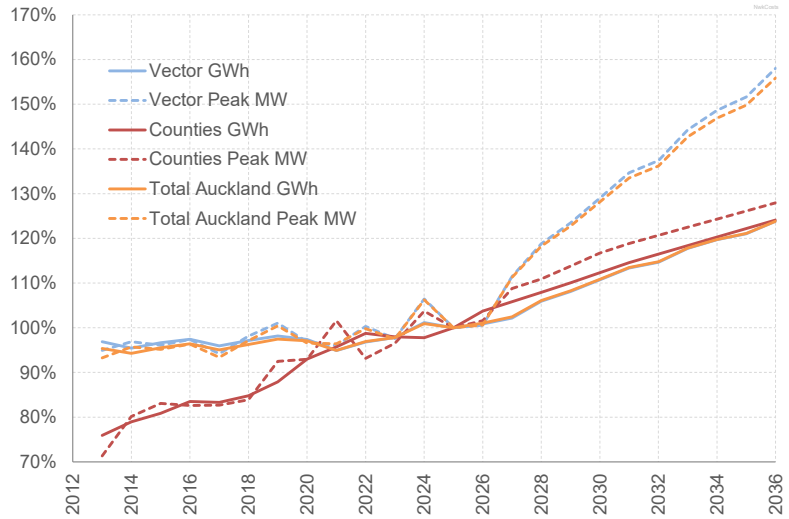
For gas and petrol / diesel networks, the challenge will be ensuring the decline in demand is managed in a way that the remaining users don't face excessive price increases, while maintaining safe and reliable services throughout the transition. This challenge is likely to be more pronounced for reticulated gas, where geographically fixed infrastructure must continue to be maintained as costs are spread across fewer customers, alongside eventual decommissioning costs. Liquid fuel supply chains are comparatively adaptable, as terminals, distribution networks and retail facilities can be consolidated as demand declines.

There is an equity consideration here, in that those consumers for whom it is harder to electrify will face progressively higher prices from remaining on the fossil networks. Low-income households may be disproportionately represented in these groups, as they are less able to afford the upfront capital investment to purchase electric vehicles or heat pumps, even though such investments are likely to deliver strongly positive rates of return. Households in rental properties are likely to face additional barriers to install electric appliances to switch away from gas heating.

7.1 Electricity Network Requirements

As Figure 64 below shows, both of Auckland's electricity distributors – Vector and Counties Energy – are projecting significant demand growth over the next eleven years.

Figure 64: Change in demand relative to 2025[8]



Vector, in particular, is projecting that peak demand growth will grow at a much faster pace than average annual demand growth.

[8] Values up to and including 2025 are actuals, taken from the Information Disclosures (IDs) published by the Commerce Commission. The values to 2031 are the projections from the lines companies published in the IDs. The values from 2032 to 2036 are based on the asset management plans (AMPs) published by each lines company, using the relationships derived between the published AMP and ID numbers for the years 2026 to 2031. The Total Auckland lines are virtually the same as the Vector lines because Vector is so large – accounting for ~93% of the total Auckland area demand.

This growth in peak demand is important because it is peak demand growth that is the principal demand-related driver of network costs. Transpower is also projecting significant demand growth over the coming years for Auckland.

As Figure 65 to Figure 68 show, this demand growth is driving significant network investment in both distribution and transmission. This growth-driven investment also comes at a time when there is a significant need to undertake replacement and renewal of assets that are coming to the end of their life.

Figure 65: Vector historical (to 2025) and planned capital expenditure[9]

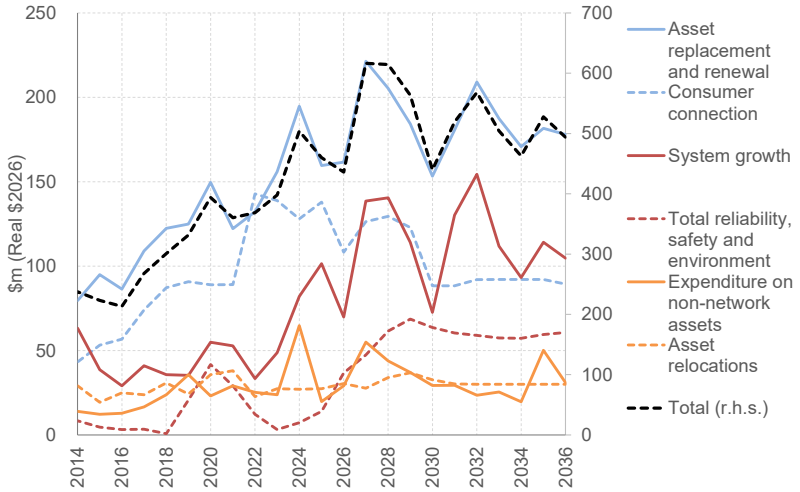


Figure 66: Counties historical (to 2025) and planned capital expenditure[6]

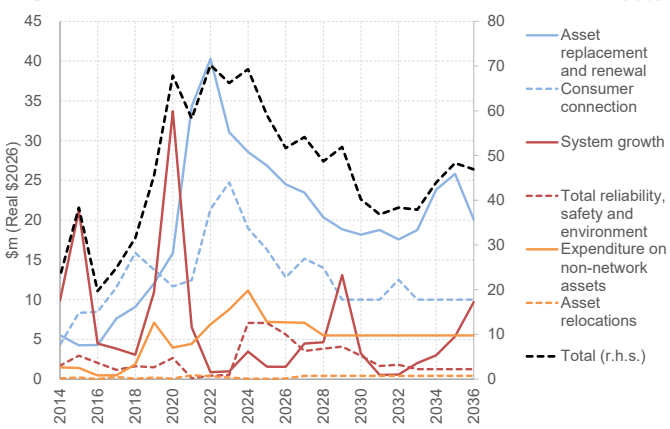
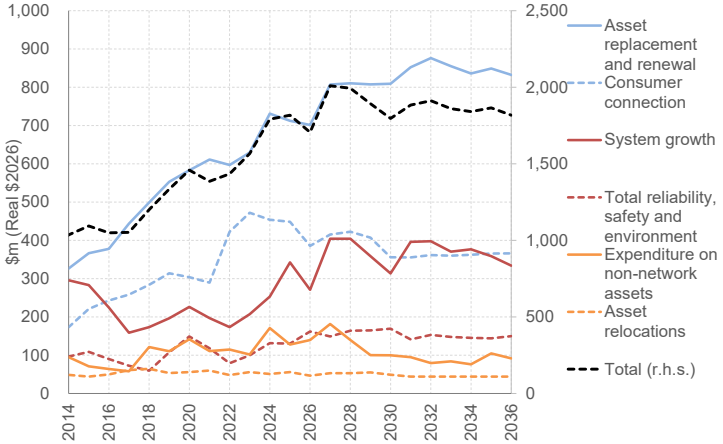


Figure 67: All NZ distributors' historical (to 2025) and planned capital expenditure[10]



[9] Source: Concept analysis of latest Commerce Commission information disclosures
10 Source: Concept analysis of latest Commerce Commission information disclosures

Figure 68: Transpower historical (to 2024) and projected capital expenditure[11]

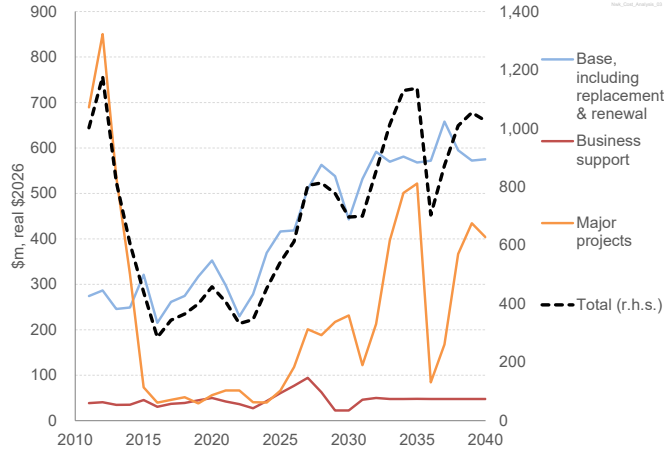
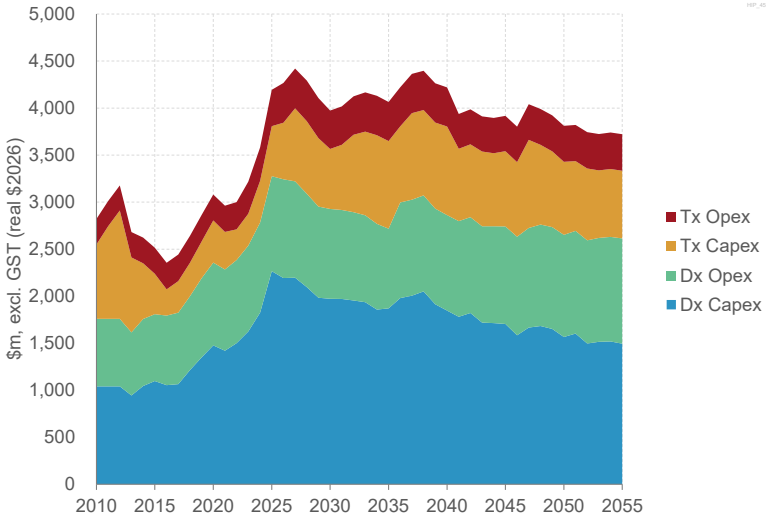


Figure 69: Historical and projected total NZ network capital expenditure – area graph



To assess what the effect of demand growth will mean for network expenditure and future consumer bills out to 2050, we used Concept's ENZ model. This takes the latest projections from the electricity distributors and Transpower, and projects forward beyond the end of such projections based on a model of the various drivers of network capex and opex. It also has a model that replicates the Commerce Commission's approach to determining the revenue that network companies are allowed to recover from consumers, along with a consumer group cost allocation model to project the consequent network prices and consumer bills.

11 Source: Concept analysis based on Transpower's 2025 ITP Schedule

Figure 70: Historical and projected total NZ network capital expenditure – line graph

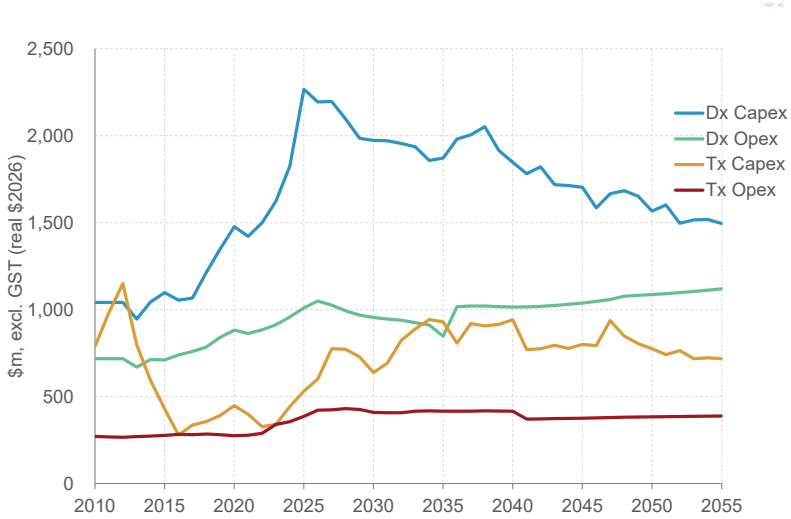


Figure 69 shows that annual network expenditure has grown by ~80% over the past decade, but that it is likely to level off at this higher level for the coming years.

This growth in expenditure, coupled with an increase in network companies' regulatory-assessed WACC[12] due to rising interest rates is giving rise to a real increase in network prices for consumer groups – as shown by Figure 71. However, from 2030 prices should level off and even decline for residential consumers.[13]

Figure 71: Historical (to 2025) and projected network prices

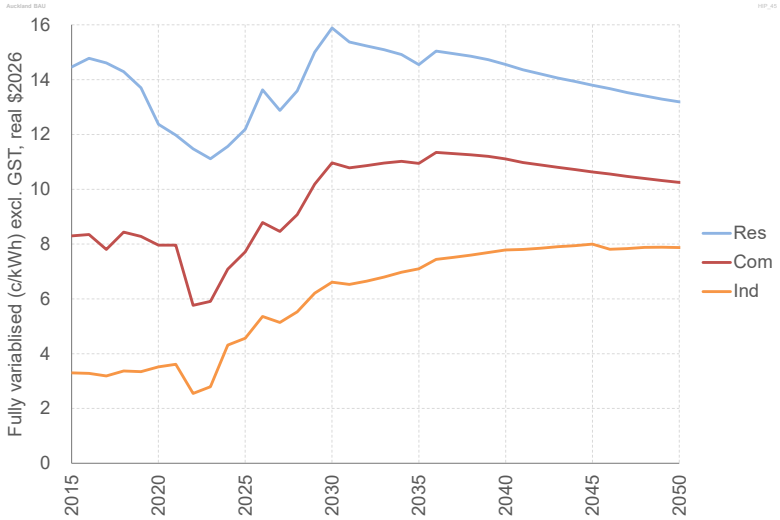


Figure 72 and Figure 73 subsequently show what this means for the average household electricity bill. For these graphs we have excluded the effect of households getting electric vehicles to get a like-for-like comparison across time.

As can be seen, in real terms, household bills are projected to rise by approximately 19% by 2029 from their low point in 2023, but then level off, such that the average household electricity bill in 2050 is projected to be barely different to that in 2010, despite the massive investment in generation and networks to meet the growing demand.

This relatively small change in electricity prices is because, while the dollar spend is going up, the energy consumption (MWh) across

[12] In simple terms, a company's weighted average cost of capital (WACC) is a measure of the rate of return they can earn on their assets.

[13] The difference in the general pattern of projected network price changes between residential, commercial, and industrial consumers is partly due to variations in the proportions of transmission and distribution charges, but also due to our projections assuming that network cost allocation approaches will progressively move to allocate costs more in proportion to the underlying drivers of such costs, including through the operation of the current transmission pricing methodology (TPM).

which this spend is recovered is growing by a similar amount, so on a $/MWh basis there is relatively little change.

Figure 72: Historical (to 2025) and projected composition of average household electricity bill (excluding charging EVs) – area graph

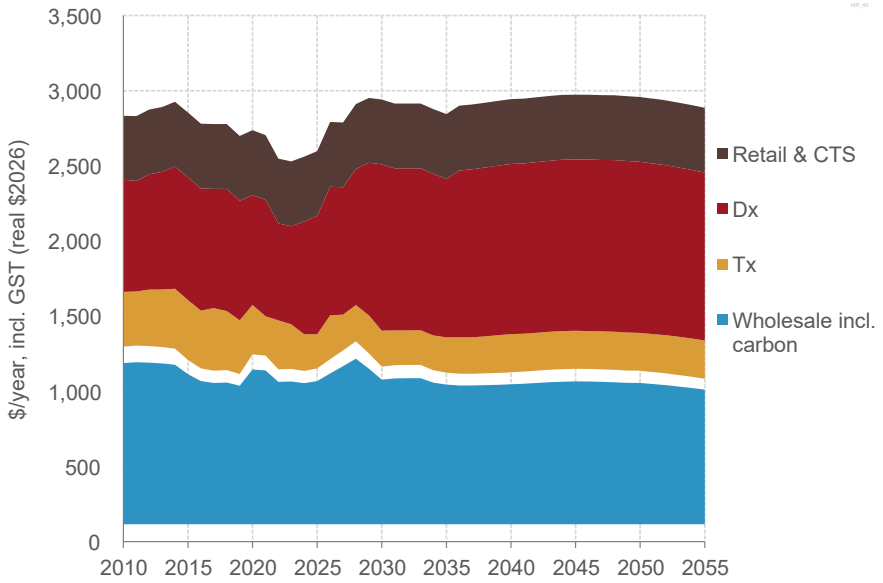


Figure 73: Historical (to 2025) and projected composition of average household electricity bill (excluding charging EVs) – line graph



7.2 Distribution Network Requirements

The Auckland distribution networks will need to accommodate substantial growth in peak electricity demand. The scale and timing of required investment will depend less on total annual electricity consumption than on how much additional demand coincides with network peaks. Analysis in Appendix C estimates that the demand-driven component of Auckland distribution network costs is approximately $126 per additional peak kW per year, highlighting the value of measures that reduce or shift peak demand.

The implications will vary across the region. Vector's network serves most of urban Auckland and faces increasing pressure from electrification, data centres, commercial development and new connections, while Counties Energy is experiencing rapid growth with uncertain timing in the southern growth corridor.

Further detail on the methodology, distribution-network cost estimates and implications of peak demand is provided in Appendix C.

7.3 Transmission Network Requirements

Auckland's growing electricity demand will also require continued investment in the national transmission network. However, the drivers of transmission investment differ from those of local distribution networks. Distribution investment is strongly influenced by local peak demand, whereas a substantial share of transmission investment is required to connect new generation and transport electricity across the country. As a result, growth in annual electricity consumption can require additional transmission investment even where demand flexibility limits growth in Auckland's system peak.

The Appendix C analysis estimates that the peak-demand-driven component of transmission costs is approximately $22 per additional peak kW per year in 2026 dollars. This is substantially lower than the corresponding distribution-network estimate because only around 22% of transmission costs are estimated to be driven by peak demand. The remainder reflects factors including generation connections, the volume and location of electricity transported, and other system infrastructure.

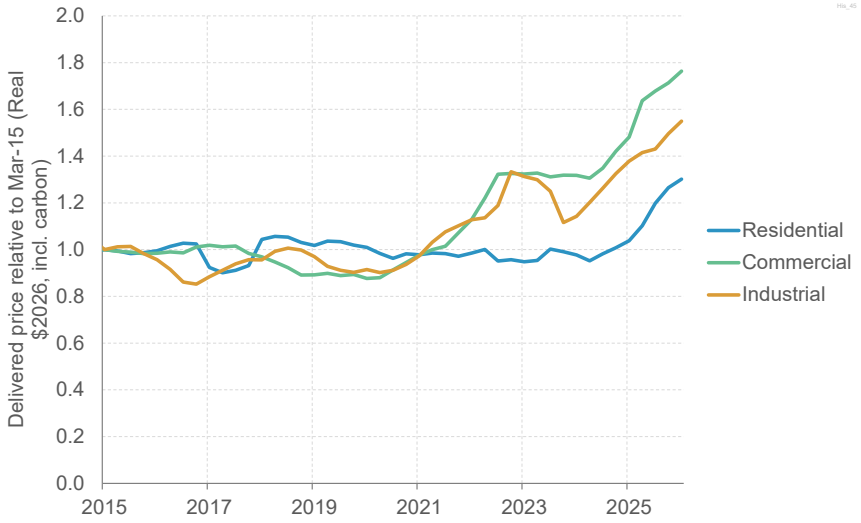
7.4 Gas Infrastructure

Figure 11 shows that gas use declines to zero by the mid-50s in the base scenario. This is due to the progressive depletion of New Zealand's gas reserves, which are not replaced by an LNG import terminal. During that period, the cost of gas is projected to increase, including:

- The wholesale price of gas, as pricing is effectively driven by a rationing dynamic, rather than the cost of supply, with prices progressively moving up the demand curve for gas, with gas consumers' willingness to pay being driven by the cost of switching to alternatives. Ultimately, the wholesale price of gas is capped by the cost of the best alternative – being the cost of switching to LPG, not LNG. LNG is never a cheaper option because of the high cost of the terminal being spread over what, by international standards, is a relatively small demand in New Zealand.
- The gas transmission and distribution charge, which increases as the volume of gas on the pipeline decreases. This is because the costs of maintaining and operating the gas pipelines are largely fixed, and so fixed costs recovered over declining volumes results in rising prices.
- The gas retail cost-to-serve costs, as the fixed charge elements of maintaining systems and processes to service gas consumers gets spread across progressively fewer customers.

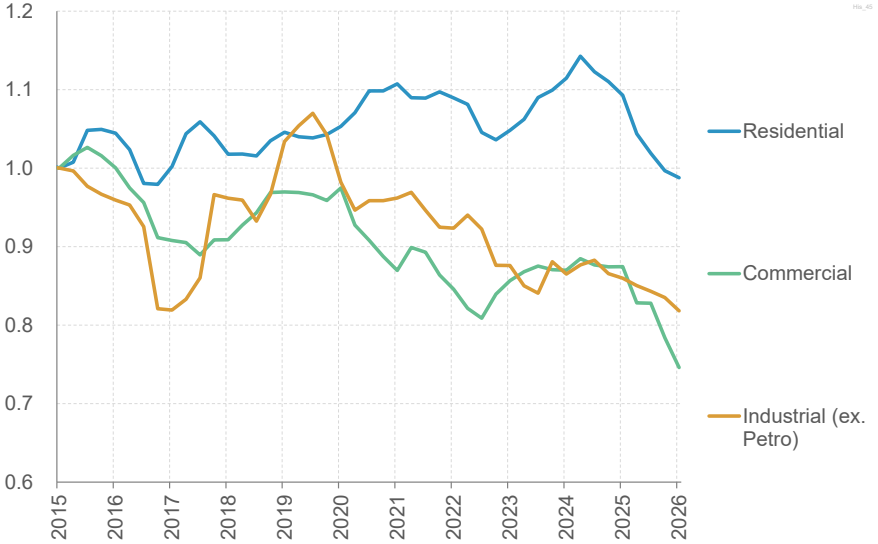
These price rises will come on top of already significant price rises for gas consumers, as indicated by Figure 74.

Figure 74: Rolling 4-quarter average price of gas in New Zealand for different consumer classes relative to the beginning of 2015



The effects of these price rises are already starting to be seen in changing gas demand as shown in Figure 75.

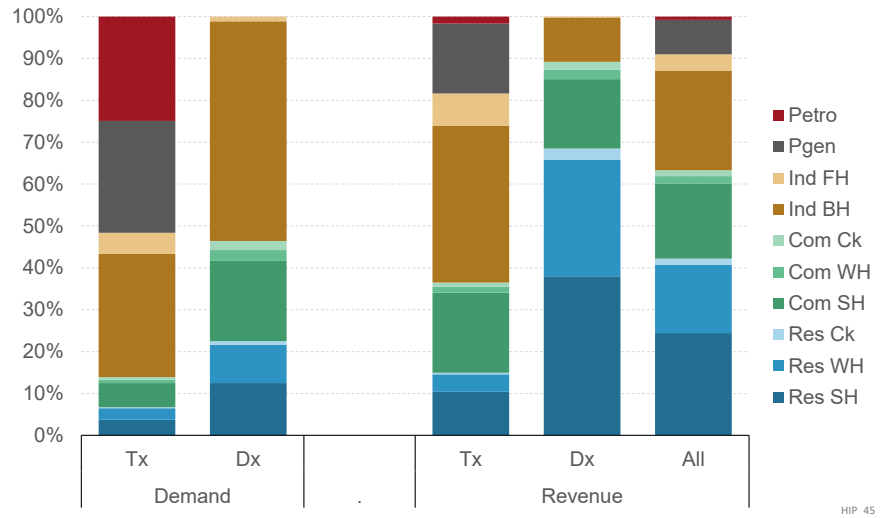
Figure 75: Change in New Zealand gas demand relative to the beginning of 2015 – rolling 4-quarter average



Of particular significance is the recent reductions in residential and commercial consumers over the past couple of years – an annualised rate of reduction of ~8%. This is because, as illustrated in Figure 76, while such consumers are not large in terms of the overall volume of gas flowing through New Zealand's pipes, they are the biggest contributor to funding these pipes.

A 10% reduction in demand will, all other things being equal, result in approximately a 10% increase in pipeline prices for remaining customers.

Figure 76: Estimated split of 2025 pipeline demand and revenues



Source: Concept analysis of EECA, MBIE, GIC, and Firstgas data

Accordingly, the future economic viability of pipelines is critically dependent on the extent to which residential consumers continue to use gas for space heating (SH) and water heating (WH) – the two principal uses of gas for households – with cooking (Ck) accounting for a much smaller share.

For transmission pipelines (Tx), the dominant contributor is industrial process heat, with boiler heat (BH) used for raising low or intermediate process heat in the form of hot water or steam accounting for the vast majority of this segment. High temperature furnace heat (FH) accounts for a much smaller component of this segment. That said, residential and commercial demand accounts for one-third of transmission pipeline revenues, so the fortunes of these two segments will have a material effect on the transmission pipeline charges for industrial consumers.

The projected steady increase in gas prices has significant implications for Auckland's gas-using households and businesses.

7.4.1 Gas for households

The good news for households is that electricity is the most economic fuel choice for all new-build situations, and for most households considering switching away from gas.

For the minority of households for whom it is currently not cost-effective to switch away from gas (predominantly households with gas central heating that would incur significant make-good costs from de-installing their gas appliances), the economics of switching to electricity will progressively improve of time. This is because our central projection is that in ten years' time, even if carbon prices do not rise, the cost of pipeline gas for household space and water heating will have risen by ~33%, whereas the electricity cost of such heating services will have *fallen* by ~11%[14].

In addition to energy prices having this structural shift, there have been significant changes in space and water heating technologies. Heat pump costs and efficiencies have improved significantly over the past couple of decades – not just for space heating, but also for water heating – and are projected to continue to improve over the coming decades. In contrast, no such improvements are projected for gas appliances.

[14] Much of this reduction in the cost of electricity for space and water heating is because of a projected move to more cost-reflective prices for electricity distribution.

The non-price 'quality' aspects of the gas and electric options have also changed:

- Space heating heat pumps also offer space cooling services in summer – something that is becoming increasingly valued as summer temperatures rise.
- Modern water cylinders are mains-fed, resulting in exactly the same water pressure as for instant gas water heaters. Plus, externally located water cylinders at the side of a house (typically where an instant gas boiler would be located) can offer large quantities of hot water – more than enough for a household with teenagers (!) – without taking up interior space.

Lastly, changes in electricity generation have altered the emissions implications of switching from gas to electricity. A couple of decades ago, switching from gas to electric heating would have had relatively small (although beneficial) emissions impact as much of the increased electricity demand would have been met by increased fossil-fired generation. Now, as New Zealand is rapidly moving to a very high percentage of renewable generation, additional demand is predominantly met with additional renewable generation, be it on the grid or household rooftop solar. Not only is this beneficial from an emissions perspective, but it means that the extent to which the price of using electric appliances for heating are orders of magnitude less sensitive to future changes in carbon price than the price of using gas appliances.

Electricity is the most economic choice for new-build situations

Electricity is always the cheapest option for space and water heating in new-build situations. This result is robust even against the most extreme (and in our view, implausible) combination of low future gas prices and high future electricity prices. Electricity running costs for heating are so much lower due to a combination of:

- Lower variable charges (ie, the c/kWh charge of being supplied with gas or electricity).
- Superior efficiencies in the case of heat pumps.
- Not requiring any incremental fixed charges (ie, the $/day charge) for electricity supply as such, but needing to pay these charges for gas. In other words, all households will need electricity anyway, whereas consumers can avoid the fixed charges for gas by choosing electricity for their heating provision.

As Table 5 shows, a household can save approximately $17,300 over fifteen years by choosing a heat pump for space heating in a new-build situation rather than pipeline gas. Although resistance electric heaters have a much lower up-front cost, their lower efficiency means they are a more expensive option than heat pumps over their lifetime.

Note: For gas, the up-front cost includes the cost of a gas connection, and the annual running costs assume some of the fixed charges for gas will be 'shared' by a gas water heater. If the house only has gas space heating, the annual running costs for gas will be even greater.

Table 5: Space heating costs for typical medium-sized new-build house[15]

Option	Upfront cost ($)	15 yr average annual running cost ($/yr)	Total over 15 yrs ($)	Total benefit relative to gas ($)
Gas	10,160	1,220	28,460	
Heat pump	6,400	320	11,200	17,260
Resistance	1,260	990	16,110	12,350

GBC Misc_03

Table 6 shows that households can save approximately $15,900 over fifteen years from choosing a heat pump for water heating in a new-

[15] Costs include GST – as do all the other tables in this section on household heating costs.

build situation. As for space heating, the higher up-front costs of the heat pump are outweighed by the superior efficiency compared to a standard resistance electric water cylinder.

Table 6: Water heating costs for typical medium-sized new-build house

Option	Upfront cost ($)	15 yr average annual running cost ($/yr)	Total over 15 yrs ($)	Total benefit relative to gas ($)
Gas	6,740	1,500	29,240	
Heat pump	8,280	340	13,380	15,860
Resistance	3,180	830	15,630	13,610

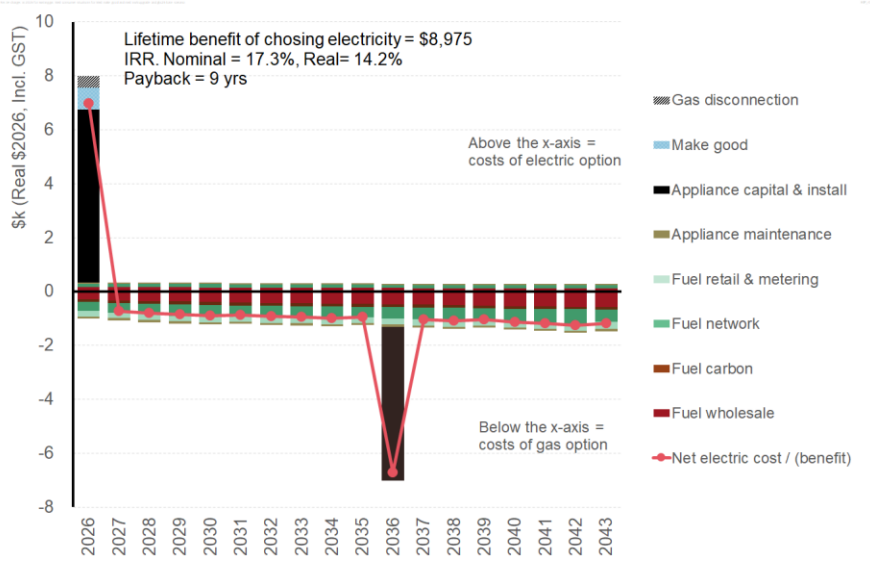
For households that already have gas, it pays to switch away from gas in most cases

The evaluation is slightly more complex for households that currently have gas for space or water heating:

- The capital costs of their existing gas heater are 'sunk'. Therefore, only the operating and the future costs of replacing the gas appliance should be considered. This future cost will effectively be a lot less for a gas appliance that could carry on operating for many years compared to one that will need replacing in the next year or so.
- There will likely be some 'make good' costs associated with removing an existing gas appliance (eg, plastering and painting where a space heater has been removed). These vary according to household circumstances. If a house is being re-decorated anyway, the costs can be small.
- A small minority of large households) may also incur the costs of increasing the capacity of their electricity network connection; going from one phase to two or three phase.
- Households may face a charge for disconnecting from the gas network.

The pattern of cashflows is illustrated in Figure 77 which shows the cash-flows for switching away from gas space heating to a heat pump for an average "medium heat-load" household that would need to replace their gas heater in 10 years' time.

Figure 77: Cash-flow for switching away from gas space heating to a heat pump for an average "medium heat-load" household that would need to replace their gas space heater in 10 years' time in a mid fuel price scenario



Initially, the household needs to spend ~$7,650 to purchase and install the heat pumps, undertake make-good repairs (some re-plastering and painting), and pay to disconnect from the gas network.[16]

[16] This assumes some of the disconnection costs are shared with water heating.

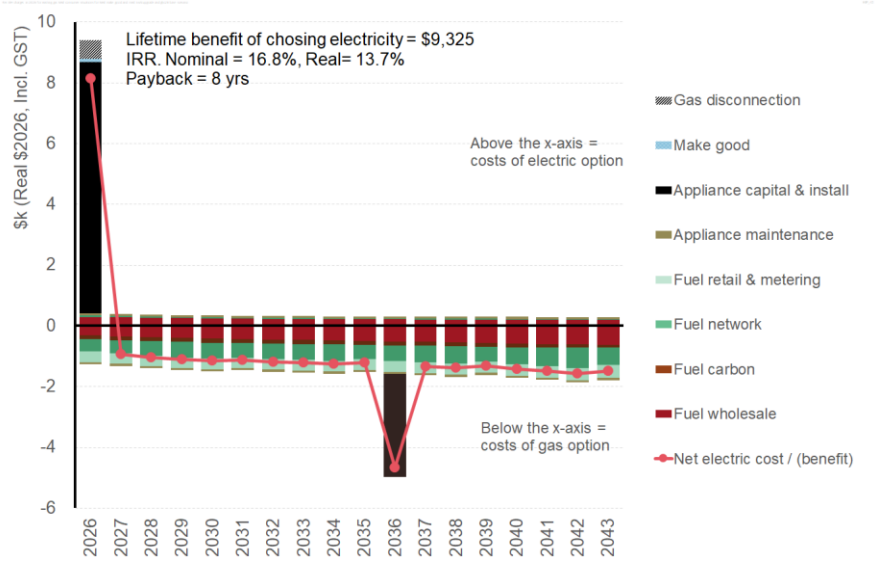
Offsetting this, are ongoing fuel savings of ~$875 per year plus the avoided $5,715 cost of replacing a worn-out gas appliance with a new gas appliance in year 10. Overall, the investment delivers a healthy 17% return and will increase the household's wealth by ~$9,000 over the 15-year period of evaluation.

If a gas space heater is close to being needed to be replaced anyway, the savings are even greater – a 36% return if the gas heater would need replacing within one year. Likewise, if the household only has gas for space heating, the savings from switching away will be greater still.

That said, it should be noted that in a small minority of cases – typically large houses with gas central heating with a combination of: relatively new gas heating and which would incur significant make-good costs and significant electricity network connection upgrade costs – it may not be currently cost-effective to switch away from gas. However, this is very much the minority of cases.

Figure 78 shows the same cashflow equation for a household that installs a heat pump water heater, but would otherwise need to replace their gas water heater in year 10.

Figure 78: Cash-flow for switching away from gas water heating to a heat pump for an average "medium heat-load" household that would need to replace their gas space heater in 10 years' time in a mid fuel price scenario



This too delivers a similar level of net financial benefit and ~17% return. Likewise, if the gas water heater is close to needing to be replaced anyway, the returns will be even greater – 24% if the gas heater needs replacing within one year.

Furthermore, unlike space heating, there are virtually no situations where it is not profitable to switch away from gas for water heating. Make-good costs are typically much lower and, where an instantaneous gas water heater is replaced with an external electric cylinder, may be negligible. Electric water heating can also be managed using timers, smart controllers or ripple control to avoid increasing peak electricity demand and reduce the likelihood of network upgrade costs.

Box 1: Should I wait until my appliance needs replacing?

If a gas appliance needs replacing anyway, it is almost always the case that it will be cost-effective to switch to an electric option. The average rate of return on the investment for the switch is estimated to be between 20% to 50% depending on customer circumstance.

If a gas appliance has several years of life left, a household might maximise their value by waiting until 'just before' it needs replacing. The scale of benefit from waiting is greatest if the gas appliance is relatively new, as the present value from postponing the up-front cost of the electricity option outweighs the lost benefit from not enjoying lower running costs earlier. If the gas appliance only has a few years left, the benefit from waiting is relatively small.

The big caveat to the 'wait-until-replacement-is-needed' strategy, is that it is not possible to predict exactly when a gas appliance will need replacing. If a gas appliance suddenly stops working, it is generally much quicker to replace it with another gas appliance than switch to electricity. Thus, unless households are prepared to wait the several days (potentially weeks) without heating or hot water while an electricity appliance is installed at short notice following a gas breakdown, it is worth pro-actively switching to electricity ahead of time where practicable, thereby avoiding any disruption.

Furthermore, as Figure 77 and Figure 78 have demonstrated, switching to electricity 'now' rather than waiting till the gas appliance anyway needs replacing 'later', is not a bad investment. It is just that if you can fine tune the timing of switching to coincide with the timing when the gas appliance would anyway need replacing, you can achieve even greater value – subject to the risks of waiting too late.

Also, for households with more than one gas appliance (eg, space and water heating), if there is anyway a need to replace one appliance, the economics of switching out the other appliance at the same time also substantially improve.

While Figure 77 and Figure 78 show the pattern of costs and savings from switching away from gas in an intuitive sense, they only show them for one consumer situation. However, the relative economics of gas versus electricity can change depending on factors such as:

- The size of a consumer's heat load.
- The extent to which a consumer may require an electricity network connection upgrade.
- Which electric option is chosen – a heat pump or a standard resistance electric heater.

Figure 79 and Figure 80 below enables such a comparison across all these different consumer situations in terms of continuing with gas versus switching to electricity (either heat pump ('HP') or resistance ('Resist') electric heating) for household space heating, and water heating, respectively. For a small to medium household the cost of switching to either heat pump or resistance are lower than staying with gas, even using the highest assumption for make-good costs. For a large household, heat pump is the lowest cost **unless** both make-good and network connection upgrade costs are at the highest end of the plausible range.

Figure 79: Stay vs. switch costs for residential <u>space heating</u> for the reference scenario

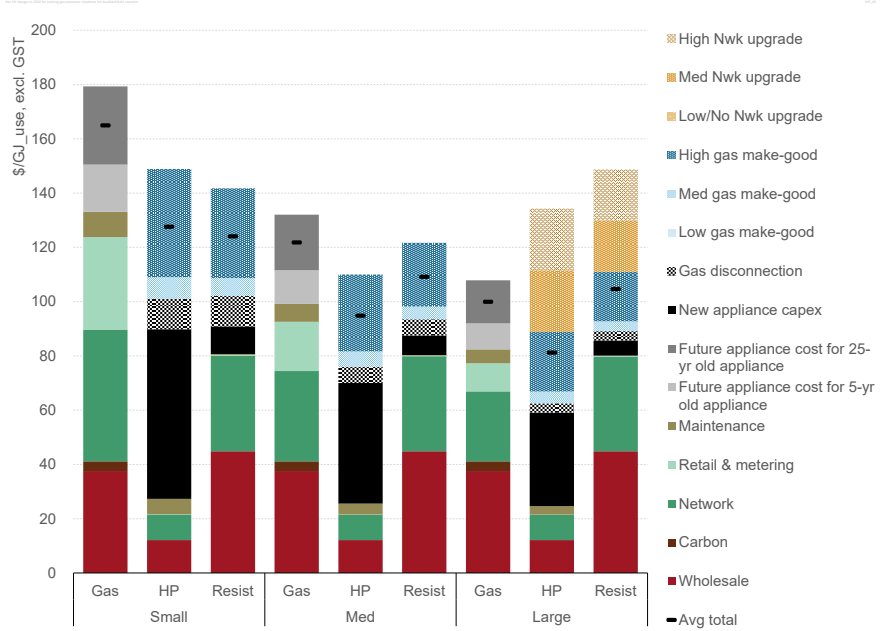
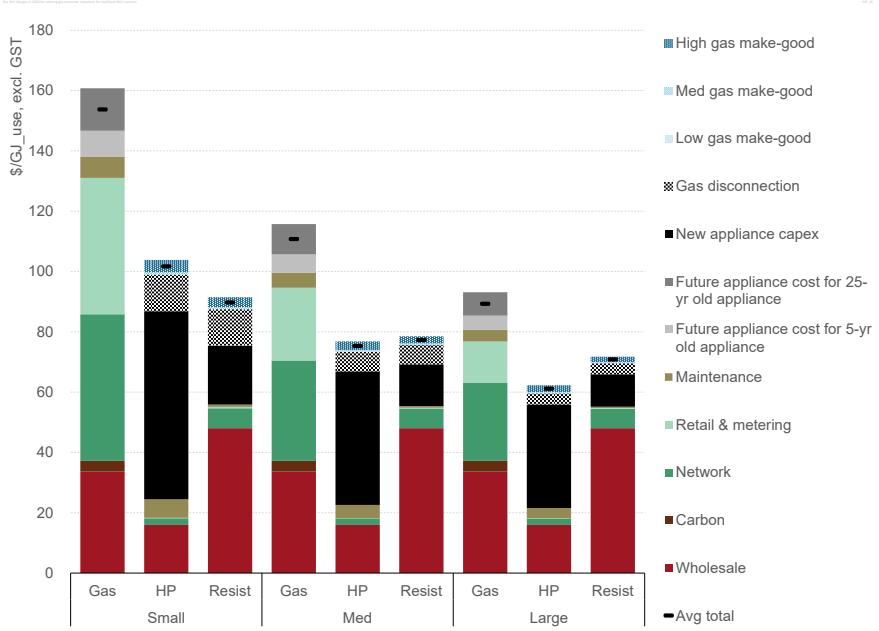


Figure 80: Switch-away costs for residential <u>water heating</u> for the reference scenario



The graphs show the average *lifetime* cost per GJ of providing *useful* heat.

The italicisation of 'lifetime' and 'useful' is because, to enable true like-for-like comparisons between options, it is necessary to take account of the fact that:

- The cost of heating a home is comprised of some costs that occur as up-front lump sums (eg, the cost of installing an appliance), some which occur as regular fixed costs (eg, network, and retail & metering), and some that vary with the amount of heat provided (eg, carbon costs, some network costs and fuel – which is marked as 'wholesale' in this graph).

- There are variations in the amount of heat required for different households.
- There are variations in the efficiency (a.k.a. coefficient of performance, or 'COP'[17]) of the appliances used to provide such heat.

These aspects mean it is necessary to:

- Amortise the capital costs over the lifetime of the up-front lump sums to arrive at a $/yr cost recovery requirement.
- Spread any annual capital recovery or fixed costs over the annual GJ of useful heat required by the household situation.
- Factor the cost of the variable fuel, carbon, and network charges by the appliance COP.
- Weight the variable costs by the expected discount-weighted average of such costs over the lifetime of the investment. For example, if it is expected that wholesale prices are going to rise over the next twenty years, it is necessary to calculate the average price over the twenty years, but with the early years weighted more than later years using an appropriate discount rate.[18]

The graph also highlights there are many different elements to the cost of heating a home:

- **The wholesale fuel costs.** This is the non-carbon cost of gas or the wholesale electricity generation cost. The reason there is such a difference between the heat pump and resistance heating options despite both using the same-priced electricity is because the COPs are so different, with heat pumps being much more efficient.
- **The carbon cost.** For electricity, this is effectively incorporated within the wholesale cost but is split out for gas.
- **Network costs:**
  - For gas, this includes both the variable charge and the recovery of fixed charges. The recovery of fixed charges gives rise to the network cost of gas being higher for households with small heating loads compared to large heating loads, because in small heating loads the fixed costs are being spread over a relatively small amount of useful heat.
  - For electricity, only the variable charges are included. This is because a home will require electricity (and incur the associated fixed charges) irrespective of their heating choice, whereas gas is an entirely discretionary fuel.
- **Retail & metering costs** are largely recovered via fixed charges – hence the variation for gas consumers between households with small and large heating loads. Furthermore, such costs are not incrementally incurred for electricity heating choices because, like network charges, homes will anyway require electricity, irrespective of their heating choice.
- **Maintenance costs** associated with servicing the heating appliance. While this is likely to be incurred every five to ten years, the cost shown is the annual average, spread over the useful heating load.

[17] Efficiency is often referred to as 'coefficient of performance' (COP). A typical gas heater has a COP of approximately 78% (in real world use conditions), a resistance space heater has a COP of 100%, whereas a space heating heat pump has a COP of approximately 360% - Ie, because it is heating the home using the ambient heat from outside, it produces 3.6 times the amount of useful heat than it consumes as electricity.
[18] For this analysis a 5% real discount rate has been used, being a reasonable reflection of most household's real cost of capital.

- **Up-front capital costs** of purchasing and installing the appliance. Although the up-front costs of installing an appliance for a household with a small heating load will be less than for a large heating load, such costs do not scale directly with the size of heating load. This results in the cost per GJ of useful heat being larger for households with small heating requirements than those with large heating requirements.

  Consumers with existing gas appliances don't need to purchase a new gas appliance, whereas switching to electric heating will incur the full cost of the new appliance. However, gas appliances do wear out and will eventually need replacing. Accordingly, the charts show the present value of the future cost of a household replacing a worn-out gas appliance with another gas appliance for two situations: A household with a five-year-old gas appliance, and one with a twenty-five-year-old appliance. As can be seen, the present value of the future cost of replacing a relatively new appliance is a lot less than for an old appliance which will soon need replacing anyway. In addition to discounting the future cost, it is assumed that replacing a worn-out gas appliance with another gas appliance will result in a 20% saving in the cost compared to a new-build situation.

- **Some costs which only apply to the electricity options:**
  - Removing a gas appliance will likely require some 'make-good' costs, such as plastering and painting where a gas heater used to be. There is likely to be significant variation between such costs, hence the high / medium / low values. These costs are likely to be minor for water heating but more significant for space heating.
  - Households will likely incur a cost to disconnect from the gas network. For this evaluation we have conservatively assumed $750. We note that overseas jurisdictions have started to introduce measures to cap these costs (eg, Victoria has capped gas disconnection costs at ~A$235, compared to the ~A$1,000 to $2,500 consumers were charged previously).
  - Potential electricity network connection upgrade costs – ie, moving from the typical one-phase connection to a two-phase connection. Very few houses will require such an upgrade – hence it only appears for the large heating load situation, and even then, only a minority of such large heating load households will require such an upgrade. Furthermore, there can be some variation in the cost incurred if an upgrade is required. This gives rise to the variation between low to high network cost upgrades.

The dashed mark 'Avg total' shows the weighted average total costs incurred across the different housing situations. In the case of new-build space heating, this takes account of the likelihood of a house requiring a network connection upgrade.

The key take-away from the results shown in Figure 79 and Figure 80 are that the majority of households who currently use gas can make material savings by switching away to electricity.

That said, there are some households for whom the economics of switching away from gas to electricity currently do not stack up. This applies to those households with a combination of:

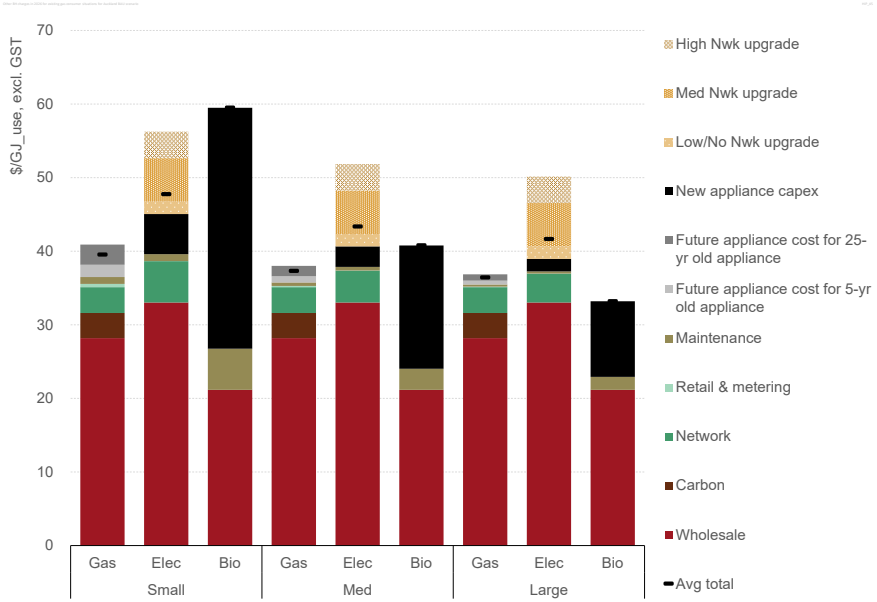
- A fairly new gas appliance that won't need replacing for at least another fifteen years.
- High make-good costs from removing the existing gas appliance – this is mostly an issue for space heating in some housing situations.
- High network connection upgrade costs – this is only an issue for space heating in a small number of houses with large heating loads.

However, such households are very much in the minority, predominantly being large houses with gas central heating for space heating.

7.4.2 Gas for industry

Whereas the economics of switching from gas to electricity are compelling for the vast majority of households and small businesses, the same is not necessarily true for industrial users. Industrial electrification may involve heat pumps, electric boilers or other technologies depending on process requirements. EECA's RETA analysis recommends an integrated approach in which businesses first pursue energy efficiency and demand-reduction opportunities before fuel switching, thereby reducing the size and cost of replacement equipment and associated network upgrades. This integrated pathway can materially improve the overall economics of switching away from gas, but has not been explicitly modelled in this study. To illustrate, the following chart shows the cost of gas versus alternatives for industrial boiler heat consumers.

Figure 81: Relative economics of fuel options for industrial boiler heat in 2026 for the reference scenario



One of the key takeaways from Figure 81 compared with Figure 79 and Figure 80 is that the wholesale + carbon cost dominates the cost for such users. This is because industrial users have very high load factors for their operation – typically using their boilers for ~65% of the time. This contrasts with ~10% load factors for households using their heating appliance. Coupled with significant economies of scale, this makes the appliance capital and maintenance costs of industrial boilers significantly less on a $ per GJ of useful heat basis compared with industrial heaters.

Similarly, significant economies of scale and high utilisation results in much lower network costs (gas pipeline or electricity wires).

This dynamic makes it generally more costly for industrial users to switch from gas to alternatives. While high temperature heat pumps

are available for some industrial heating requirements (and which can deliver lower electric heating costs than shown in Figure 81), in most cases there will still be a significant requirement for raising primary heat in a way that can't be satisfied by a heat pump.

Using a standard electric boiler (the 'Elec' option shown in Figure 81) results in a high wholesale cost of electricity. While electro boilers are themselves relatively low-cost options, in many cases switching to an electric option will require a significant and costly network upgrade.

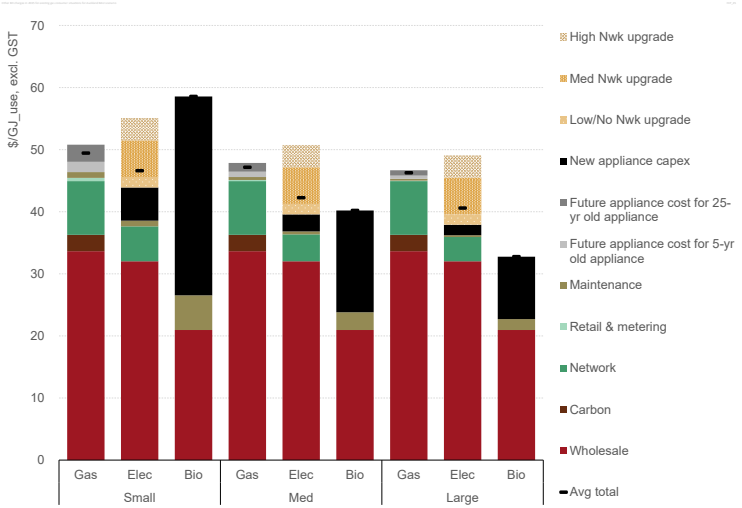
Biomass is a cheaper fuel relative to electricity – although there can be material variation depending on site-specific factors such as distance from the source of biomass – but the costs of the boilers themselves are significantly more expensive. Furthermore, biomass supply requires supply chains that have yet to fully mature, creating a 'chicken-and-egg' barrier to large scale uptake. An industrial consumer will be unwilling to make an investment in a biomass boiler unless they have confidence that there will be long-term supply of biomass. Conversely, a biomass supplier will be unwilling to make the long-term commitment to enable such supply unless they have confidence of a long-term market for their biomass. That said, this infant technology barrier is starting to be overcome, with scale being developed in a number of regions.

The economics of switching away from gas for industry will progressively improve

There are two factors that are likely to make the economics of industrial users switching away from gas progressively more compelling.

The first is the continued decline in New Zealand's gas reserves which will progressively push up wholesale gas and pipeline prices. At the same time, electricity prices are not projected to increase materially – and may even fall. Figure 82 shows the same comparison as in Figure 81 but in ten years' time – ie, the outlook for industrial consumers in 2035, rather than 2026.

Figure 82: Relative economics of fuel options for industrial boiler heat in 2035 for the reference scenario



As can be seen, the higher gas wholesale prices and pipeline charges improve the relative economics of gas versus alternatives – particularly for the largest gas users.

The second factor that could improve the economics of switching away from gas is a change to the carbon prices faced by consumers.

The carbon prices used for the analysis in Figure 81 and Figure 82 assume a continuation of the low (~$50/t$CO_2$) prices currently emerging from the emissions trading scheme (ETS). Figure 83 and Figure 84 are the equivalent graphs except that they use the Treasury's High scenario for the shadow price of carbon.

Unsurprisingly, the higher carbon prices significantly improve the economics of switching away from gas.

Figure 83: Relative economics of fuel options for industrial boiler heat in 2026 for high carbon price scenario

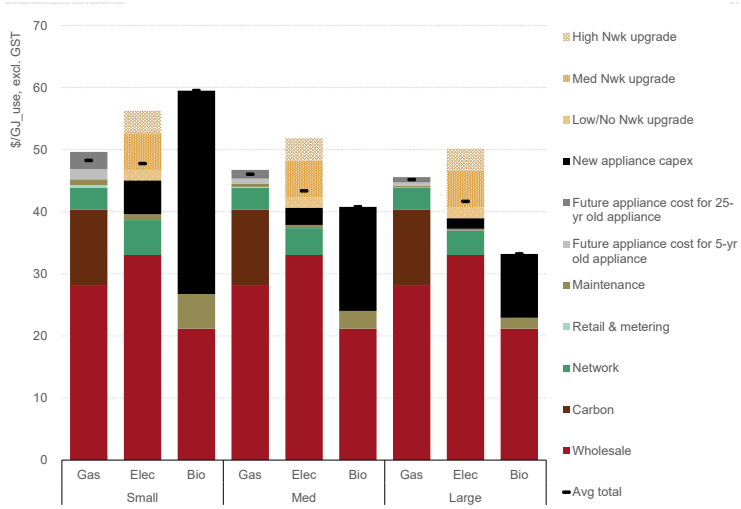
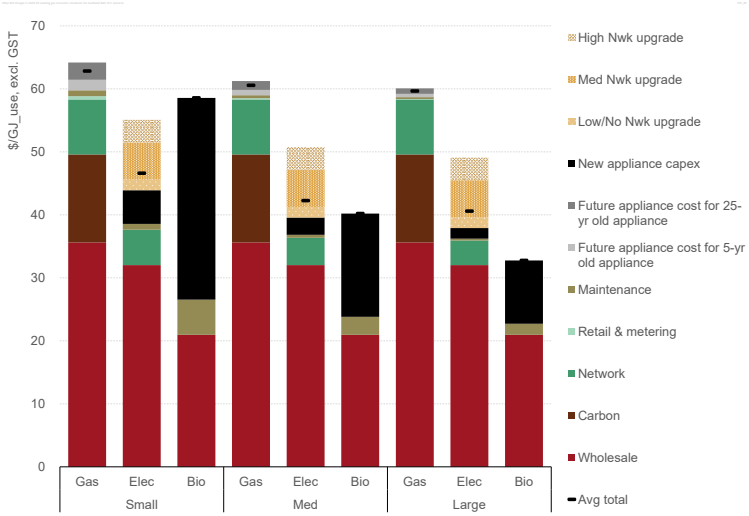


Figure 84: Relative economics of fuel options for industrial boiler heat in 2035 for high carbon price scenario



Given that the Treasury's high carbon price scenario is what the Climate Change Commission projects as being the marginal cost of meeting our emissions reduction target, it is the best reflection of the price signal New Zealand should be sending its emitters to deliver the least-cost transition – at least in a way that doesn't result in large areas of sheep-and-beef farmland being covered in pine trees for the purposes of carbon sequestration.

If, as is currently the case, New Zealand doesn't send such a price signal, we are likely to get worse economic outcomes.

Furthermore, it should be noted that the high carbon price scenario is that which is consistent with the current legislated emissions reduction target: net-zero emissions (excluding biogenic methane) by 2050 and beyond. However, the Climate Change Commission's latest advice is that to be consistent with New Zealand's international commitments to limit climate change, New Zealand should adopt a target of net *negative* 20 $MtCO_2e$ by 2050 *including* international

transport emissions. The marginal abatement cost with such a target would necessarily be higher than is currently reflected in the High carbon price scenario.

"But hang on, I'm an industrial gas user and I'm struggling to get contracts for gas at any price."

The above analysis implicitly assumes that industrial gas users can continue to use gas while it is economic for them to do so. However, we are aware that an increasing number of industrial gas users are struggling to recontract for gas as their current contracts expire.

Detailed analysis of this issue is beyond the scope of this report, but it is a topic that we analyse in some detail in our gas market forecast report.[19]

In brief, the key conclusions from that analysis were that this is largely due to Methanex (New Zealand's largest gas user by far) having contracted forward for large quantities of gas out to the end of 2029 to an extent that can't be satisfied by projected production from New Zealand's existing gas fields and also meet the demands from other gas users. As our analysis in that report demonstrates, the best option for New Zealand would be for Methanex to trade its gas entitlements to higher-value gas users – such as industrial consumers using gas for process heat – but that there are significant barriers to such economically rational outcomes to occur, including poor gas contract price discovery under current gas market arrangements.

Additionally, our separate report identifies that the Methanex contracts are likely having a suppressing effect on additional gas drilling out to 2029, in that much of the additional gas that is brought forward by such drilling would be sold to Methanex at prices that are significantly below the market value of gas. As such, the gas field operators appear to be (rationally from their financial incentives) postponing some drilling until after 2029.

Although these issues are transitory in nature, that is small comfort for an industrial gas user that is struggling to get firm gas supply contracts for the next three to four years and instead having to increasingly procure their gas from a series of short-term contracts or the spot market.

Again, resolving this issue is beyond the scope of this report. However, our separate gas report identified that rushing into an LNG terminal to remedy the situation is unlikely to be the best decision and would likely instead impose significant costs (of the order of $6bn) on the New Zealand economy.

And what about the industrial users that need a high temperature flame that can't be provided by electricity or biomass?

The analysis set out in Figure 81 to Figure 84 is for industrial users who raise their heat via a boiler to create low to intermediate temperature heat. This accounts for the majority of industrial process heat requirements: EECA's energy end-use database indicates that on a national basis, industrial heat raised by boilers accounts for over 85% of gas demand for industrial process heat.

However, there are some industrial gas users for whom electro boilers or biomass are not practicable options. For example, those industrial gas users who require a high temperature flame in kilns, furnaces, direct burners, and the like – what we collectively refer to as 'furnace heat'. According to EECA's energy end-use database these uses account for some 15% of industrial process heat, with some located in Auckland – Visy glass being a prime example.

Our analysis indicates that the best option for these users as NZ gas reserves decline is to transition to LPG or diesel. The optimal

[19] "2026 Gas Market Outlook". Available on subscription. For details, email simonc@concept.co.nz.

approach would likely to be to initially develop dual fuel capability (ie gas and LPG, or gas and diesel) as this allows for switching between fuels depending on relative prices at any moment in time.

That is not to say this will be a cheap fuel option. Users will likely be facing ex-carbon prices for diesel or LPG in the approximately $30/GJ range. This is substantially higher than the ~$10/GJ price (in real 2026 dollars) that industrial users typically paid for gas in the last decade.

However, the days of such cheap gas are long gone. Gas pricing is extremely opaque in New Zealand. This is a problem that is driving poor outcomes for industrial gas consumers and which, in our view, could be significantly improved by requiring the kind of anonymised contract price disclosure that has been required in the electricity market for many years. Nonetheless, it appears that industrial consumers currently seeking to re-contract are likely to be paying ~$20/GJ – a 100% increase relative to the previous decade.

This pricing is not being driven by a cost of supply, but by a rationing dynamic where scarce gas is priced up to the marginal consumer's willingness to pay. As gas fields continue to decline, this rationing dynamic will lead to progressively higher prices from steadily moving up a gas demand curve whose slope is driven by the various gas users' cost of switching to alternatives (ie, their willingness to pay). This will help ration remaining gas for the highest value gas users for as long as possible – with the furnace heat industrial users being foremost among this group.

Eventually prices should be capped at the cost of alternative fuels such as diesel or LPG – ie, approximately $30/GJ.

Our assessment is that LNG is not going to be a cheaper option for New Zealand. It is likely that LNG could be procured on the international market and shipped to New Zealand for approximately $18 to $22/GJ during 'normal' (ie, non-geopolitical crisis) conditions. Due to the current US-Israel-Iran war, prices are at least 50% above that, and reached even higher levels during the early years of the start of the Russia Ukraine war.

On top of this are the costs of the receiving LNG import infrastructure. The fixed costs of the infrastructure are likely to be between $75 to $200m per year – depending on how large the facility is, and how resilient it is to bad sea conditions – both of which will affect how cheaply New Zealand can source the type of 'flexible' gas required to meet New Zealand's highly variable demand needs due to large dry-year/wet-year swings in thermal power generation. (Ie, a 'cheap' import infrastructure option will likely make the cost of landed LNG – and its value to the system – worse.)

Our analysis indicates that the required throughput from the terminal will be of the order of 1 to 5 PJ a year – and quite possibly even less – due to New Zealand's existing gas fields being able to continue to supply most (if not all) of our gas needs (ex-Methanex) for many years.

Recovering the $75-200m across 1 to 5 PJ a year gives a terminal cost recovery of between $15/GJ to $200/GJ.

On top of this will be the variable operating costs of a floating storage and regasification unit (FSRU) of ~$2/GJ, and the costs of pipeline charges – currently only ~$2/GJ, but projected to rise significantly as pipeline volumes fall.

All up, the likely range of delivered LNG prices is between $37/GJ to $226/GJ.

This is in excess of the cost of fossil alternatives such as diesel or LPG, and considerably in excess of the cost of switching to electricity or biomass for the majority of users for whom such options are practicable.

There have been some proposals for the fixed costs of the LNG terminal to be recovered from electricity consumers either directly or indirectly. While this may be good for some industrial gas users who avoid paying for this infrastructure, it is clearly not good for electricity

consumers, and 'hiding' the costs in this way will inevitably lead to poor fuel choice decisions and worse economic outcomes for New Zealand as a whole.

If New Zealand goes down the route of procuring an LNG terminal and signing up for long-term LNG supply contracts, the adverse economic harm can be minimised by ensuring that the costs of LNG are recovered from those that use it – ie, all gas consumers.[20]

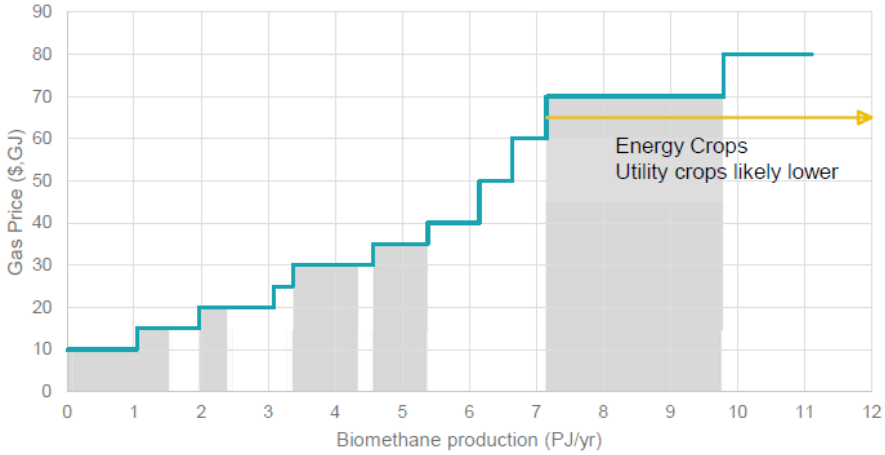
7.4.3 Biomethane

Some commentators suggest biomethane as an alternative way to manage the decline in New Zealand's gas fields.

To examine the extent to which this may be the case, we used our ENZ model in fully dynamic mode, whereby fuel choices are driven by the relative costs of the fuels taking account of the finite nature of New Zealand's gas fields and the consequent rationing effect on prices as reserves decline. In this mode, using the base assumptions results in a pattern of residential, commercial, and industrial switching that is very close to the assumed patterns of declining gas demand for the reference scenario – as previously illustrated in Figure 11.

Within the model there is a biomethane cost-supply curve, with the base assumption for such a curve being that developed by woodbeca for the Gas Industry Company[21], reproduced as Figure 85 below.

Figure 85: Biomethane cost-supply curve



Note: grey columns indicated the quantities based on the case studies

For each modelled future year, the model takes up biomethane to the extent that it is cost-effective to do so. Thus, as the wholesale price of gas rises, the model progressively develops biomethane consistent with the biomethane cost-supply curve.

Eg, if wholesale gas prices rise to $25/GJ, an amount of biomethane is assumed to be developed consistent with the $25/GJ point on the cost-supply curve, taking account of the relative carbon intensities of the two fuels and the assumed carbon price for the scenario.

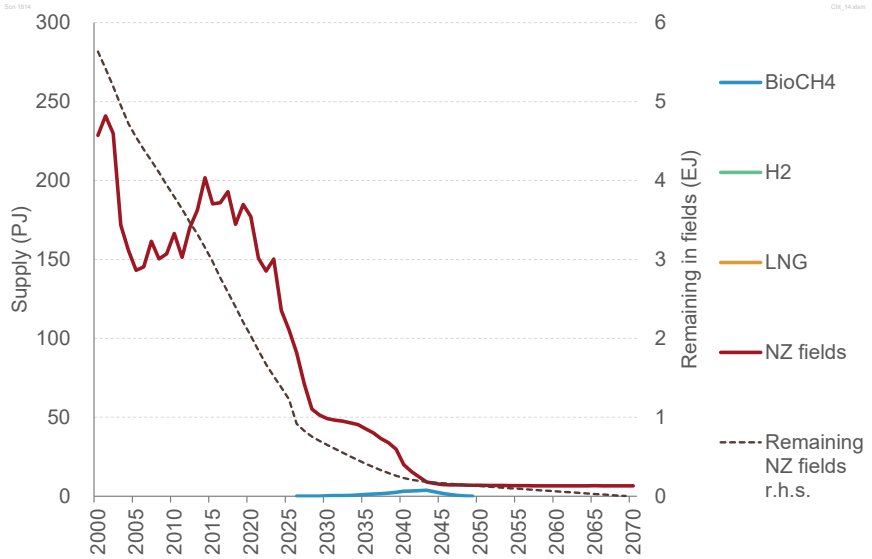
Developing biomethane slows the depletion of recoverable gas reserves. An LNG terminal, by supplying imported fossil gas, would do the same.

However, using the base assumptions, as illustrated in Figure 86 below, there is relatively modest uptakes of biomethane in the Base

[20] The argument put forward by some that the main users of an LNG terminal will be the electricity generators and therefore it is appropriate to recover the costs from them is specious. To the extent that gas-fired generators procure LNG it will reduce the amount of gas they need to procure from NZ gas producers which will free up such gas for other gas users. Ie, at the margin, every gas consumer will be directly or indirectly 'using' the LNG terminal.
[21] Source: https://www.gasindustry.co.nz/assets/CoverDocument/Gas-Transition-Plan-Biogas-Research-Report-February-2023.pdf

scenario, with little effect on the time when consumers transition away from pipeline gas. Fundamentally, this is because there is very little biomethane at costs that are lower than pipeline gas or the costs from switching to electricity or biomass alternatives.

Figure 86: Base scenario gas supply and remaining resources



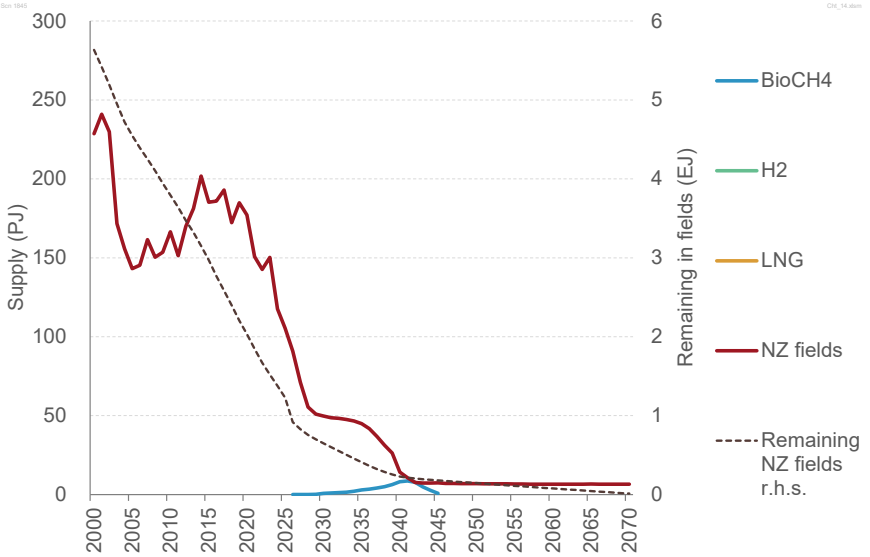
What if biomethane were cheap and plentiful?

To test whether much larger, cheaper biomethane supply would change the outcomes, we ran a 'Cheap Biomethane' scenario with twice the available volume at 75% of the price. We regard these as extremely optimistic assumptions because:

- Biomethane costs are mostly feedstock costs, so it lacks the scope for the big technology-driven cost reductions other renewables have enjoyed.
- In many cases there are more cost-effective measures to utilise organic waste and reduce greenhouse gas emissions, such as composting or electricity generation (for landfill or sewage treatment plants).
- Some of the assumptions in the woodbeca curve appear not to be borne out in practice.[22]

Nonetheless, despite these (in our view) optimistic assumptions, Figure 87 illustrates that the higher amounts of biomethane uptake in this scenario only marginally prolongs pipeline gas use.

Figure 87: Gas supply and remaining field resources as per Base assumptions except Cheap Biomethane



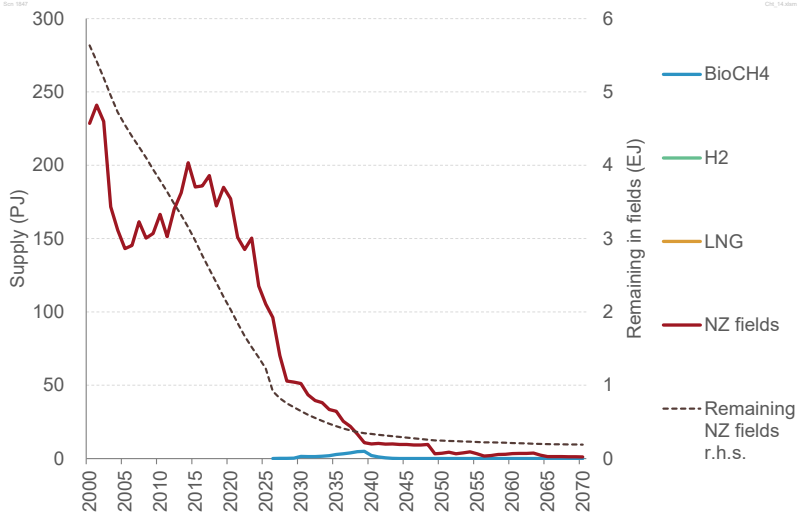
[22] For example, the volumes of Auckland food waste collected for the Reporoa anaerobic digestion plant — which feeds the gas pipeline network — are materially below projections, hurting the scheme's already very expensive economics.

What if biomethane were cheap and plentiful and carbon emissions expensive?

Because biomethane is proposed as a decarbonisation pathway, we ran a scenario combining the Cheap Biomethane assumptions with the energy sector facing carbon prices at Treasury's recommended high estimate for the shadow price of carbon. The logic: if biomethane is a cost-effective way to decarbonise, a high carbon price should overcome any barrier created by carbon prices being too low.

However, as Figure 89 below show, exposing market participants to a high carbon price results in a much more rapid transition away from pipeline gas to alternatives such as electricity and (solid) biomass, and there is relatively little biomethane uptake.

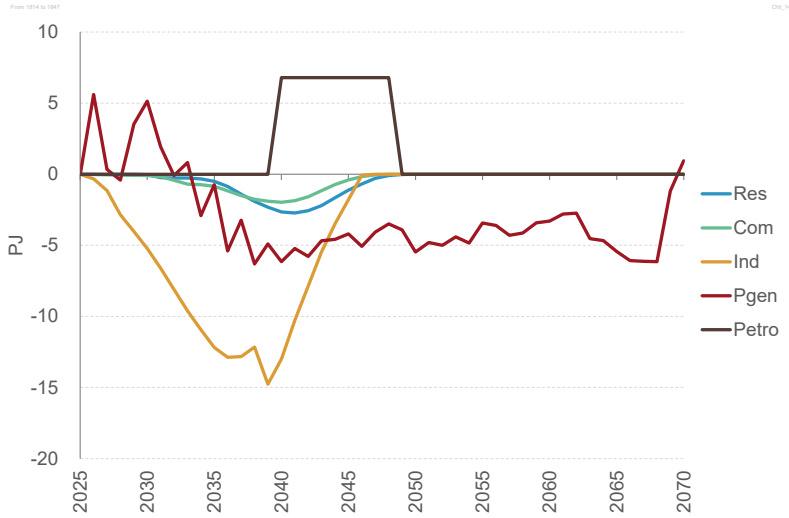
Figure 88: Gas supply and remaining resources as per Base assumptions except Cheap Biomethane + High carbon price



This is because, even at double the available biomethane, the volume is still small relative to pipeline-gas demand. The high carbon price on the fossil component of pipeline gas outweighs any benefit from the lower-emission biomethane component, so switching accelerates.

As Figure 89 below shows, the only sector with higher pipeline gas demand in this scenario is petrochemicals. This is gas sold to the fertiliser producer Ballance, which the Industrial Allocation mechanism shields from the high carbon price. Because non-petrochemical consumers switch away faster because of the high carbon price, more gas is freed up for petrochemical production.

Figure 89: Change in gas demand going from Base scenario to Cheap biomethane + High Carbon Price



Biomethane summary

Given its small physical potential and high cost, it is hard to see biomethane delivering a sustainable long-term future for pipeline gas — and certainly not one that lowers energy costs for New Zealand's gas consumers.

If cost-effective opportunities to develop biomethane and inject it into pipelines arise over the next couple of decades, all well and good —

though our provisional view is that alternative uses for the bio-feedstock will often be more cost-effective. For example:

- Electricity generation using biogas at landfills or waste-water treatment plants.
- Composting rather than anaerobic digestion for waste organic matter.
- And if circumstances make anaerobic digestion more cost-effective than composting, direct use of the biogas in an industrial gas facility rather than upgrading the biogas to biomethane to inject into a pipeline.

7.4.4 Gas price impacts for consumers

The forces facing New Zealand's gas sector all point to rising prices:

- A progressively rising wholesale gas price driven by a rationing dynamic as New Zealand's gas fields decline.
- Potentially higher carbon charges if future government reforms of the ETS result in emitters facing prices that are more consistent with the cost to New Zealand of such emissions rather than the current low ~$50/tCO$_2$ prices.
- Rising pipeline charges as the largely fixed costs of maintaining and operating the pipeline network are recovered from a declining consumer base.
- Rising retail cost-to-serve costs as the fixed costs of maintaining metering and billing systems are recovered over declining gas consumer numbers. This dynamic is only really material for residential consumers for whom retail cost-to-serve costs are a significant component of their overall gas bill.

All of this comes on the back of already material price rises over the past five years as illustrated in Figure 90.

Figure 90: Change in rolling 4-quarter average gas prices relative to 2015

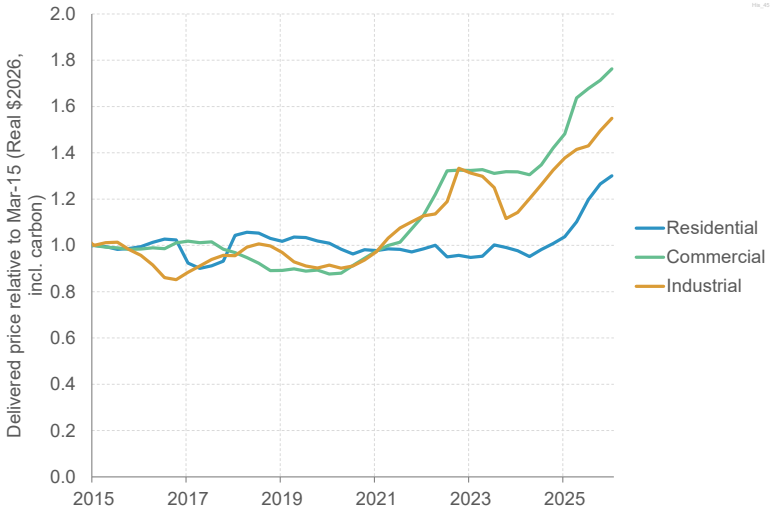


Figure 91 and Figure 92 show the modelled impact on the average residential gas consumer's bill over the period of the projection.

Figure 91: Historical and modelled average residential gas consumer's bill – area graph

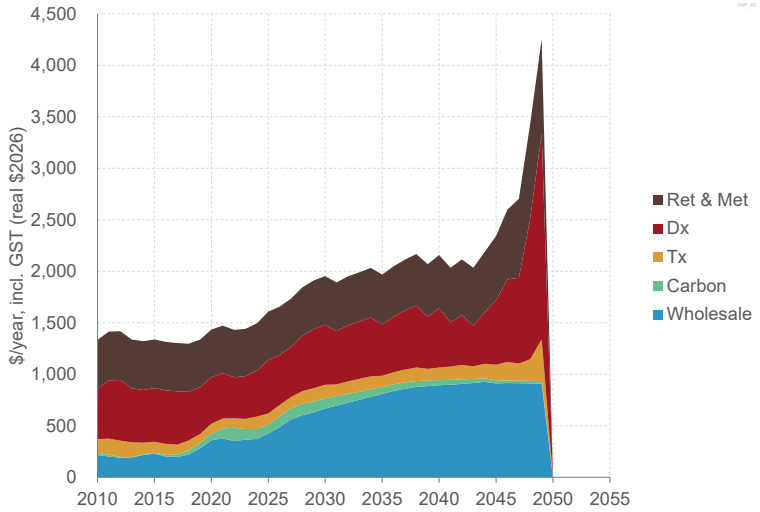
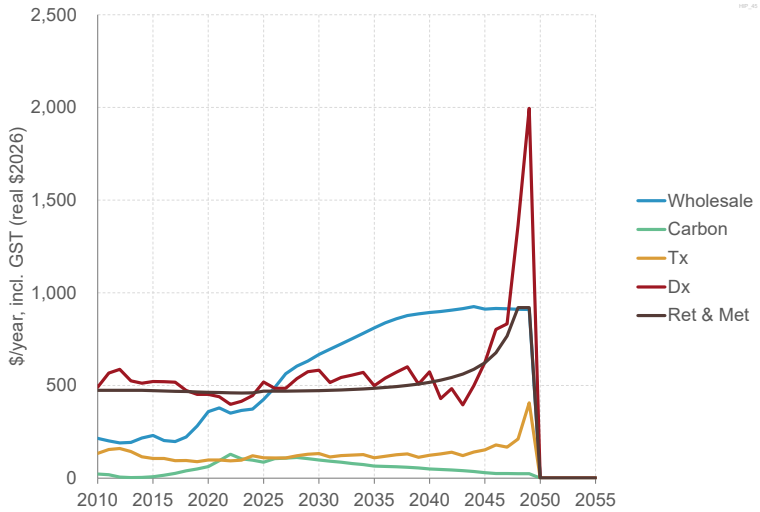


Figure 92: Historical and modelled average residential gas consumer's bill – line graph



The first and most obvious takeaway from Figure 91 and Figure 92 is that those households that remain on gas are likely to have significant bill increases over the coming decades.

This raises some equity issues in that, while the analysis set out in section 7.4.1 earlier demonstrates that households will generally save a lot of money from switching away from gas (and increasingly so as time goes on and gas prices rise, while electricity prices largely remain flat), there will be some households for whom switching to electricity will be difficult. It is likely that low-income households will be disproportionately affected in this category in that:

- If they own their house, they tend to find it significantly harder to raise the up-front capital to invest in electric heating options.
- Low-income households are much more likely to rent their homes and thus face the significant tenant-landlord problems for such investments. Ie, landlords would be the party who would make the investment, but the tenants would be the ones who would enjoy the lower energy bills, and the landlords are usually unable to increase rents to a level that reflects the value of this benefit. We estimate there are approximately 40,000 rented properties that have gas in the Auckland region.

The second takeaway from the figures is that pipeline charges aren't projected to materially increase until later decades. However, it should be appreciated that this is due to the assumption that as pipeline demand starts to fall below a certain level, pipeline companies will start to reduce the capital investments in maintaining the pipelines. This reduced capital spend (as illustrated in the figures below), coupled with the assumption of accelerated depreciation, results in a relatively flat profile of pipeline prices until the last five to ten years where demand has really fallen to very low levels and pipelines need to start to recover decommissioning costs. At this point, pipeline charges start to rise exponentially.

Figure 93: Whole-NZ pipeline costs – area chart

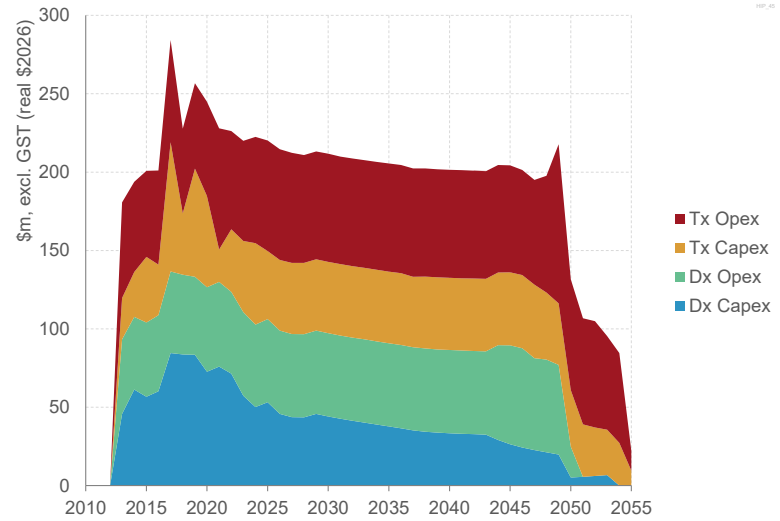
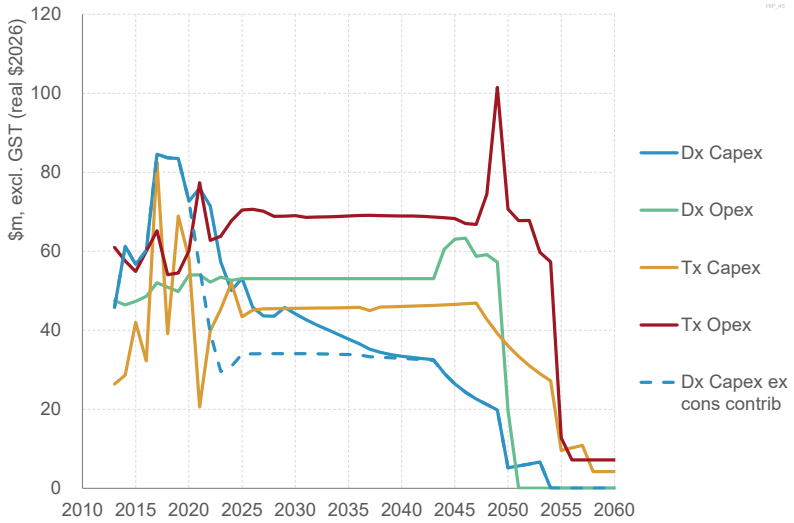


Figure 94: Whole-NZ pipeline costs – line chart



It is potentially the case that the significant decline in pipeline capital expenditure couldn't happen to the same extent as assumed for this modelling exercise.

Figure 91 and Figure 92 also show a similar pattern of increase for gas retail cost-to-serve costs in the last decade of gas consumers being on the network. This assumes what proportion of retail cost-to-serve costs are variable on a number of customers basis, and what are fixed. For this modelling exercise it is assumed that ~19% of current total cost-to-serve is for recovery of fixed costs. The proportion may be higher or lower than that, with associated increases or decreases in price rises in the latter years of the projection.

Lastly, Figure 91 and Figure 92 show the carbon component of residential consumers' bills rising then *falling* towards the latter half of the projection. However, both are due to assumptions that could be materially wrong:

- Firstly, it assumes that carbon prices faced by emitters (and thus incorporated within gas prices) remain at the low $\$50/tCO_2$ level. If prices were to rise to the estimated cost of emissions to New Zealand, the carbon price could be many multiples of this $50 value.
- The model is dutifully developing biomethane on the basis of the assumed cost-supply curve illustrated in Figure 85 on page 92 previously. Thus, as gas demand falls and wholesale gas prices rise, the proportion of biomethane is modelled as growing ever larger – with the consequence that the carbon component of prices will reduce. However, as set out in section 7.4.3, our analysis suggests that the biomethane cost-supply curve is highly optimistic. Furthermore, some of the sources of biomethane involve capital investment that would need to be recovered over twenty or so years. This is not consistent with the pattern of gas demand declining to zero.

What about LNG's potential impact on consumer prices?

If New Zealand were to go down the path of committing to an LNG terminal and long-term supply contracts, it would certainly alter gas prices. However, whether it decreased or *increased* gas prices to consumers depends on how the costs of the import infrastructure are recovered.

If the costs of the terminal are recovered from gas users via a $/GJ fee based on the throughput of the terminal (ie, the basis on which the costs of all energy assets are reflected in their impact on gas or electricity prices currently), the price of gas could rise substantially.

If the costs of the terminal are recovered by 'smearing' them via a levy on all gas sold in New Zealand, the wholesale price of gas could still rise above what would otherwise have been the case.

If the costs of the terminal are instead recovered from electricity consumers (including via an approach which charged the electricity generators who would then pass on the increased costs of generation through electricity prices), then wholesale prices for gas consumers would likely not rise as much as is reflected in Figure 91 and Figure 92. In turn, this may reduce the rate of gas demand decline and therefore push out the timing of increases in pipeline charges.

Pipeline regulatory challenges

As gas demand continues to decline, it will become increasingly hard for pipeline companies (and the Commerce Commission who regulates what they are allowed to charge consumers) to determine when they can start the process of scaling back stay-in-business pipeline capex and starting to recover decommissioning costs.

Once that point is reached and decisions are taken to reduce pipeline stay-in-business capex and recover decommissioning costs, it is likely to be a one-way process that is hard to reverse.

Two key challenges relate to:

- The equity issues from those harder-to-electrify consumers facing ever increasing bills.
- The likelihood of a significant proportion of pipeline costs not being recovered from consumers, particularly the decommissioning costs incurred in the last decade or so.

In relation to sources of cost recovery, the options are remaining gas consumers, pipeline shareholders, and/or taxpayers or local ratepayers.

There are tricky trade-offs with some of these choices. For example, an approach which predominantly sought to recover costs from remaining consumers may trigger the very 'death spiral' that could result in significant under-recovery, as well as having significant equity issues.

It is probably the case that some combination of recovery from all three groups would deliver the best outcome.

Enabling a gas transition for consumers

It is beyond the scope of this report to analyse in detail the various policy options to address the challenge of transition consumers away from gas supplies that are likely to become ever more scarce and costly, but the key elements to achieving the least painful transition are likely to be:

- Clearly signal the direction of travel for pipeline gas as a matter of regional and/or national policy.
- Provide support to consumers switching away from gas – be it informational/educational and/or financial.
- Work with the trades that will support consumers in switching away from gas and support the gas industry-related trades to transition.

- Use planning codes and building standards to discourage new gas connections.
- Ensure gas pipeline regulation supports an orderly transition.

Clearly signalling to consumers the direction of travel and ultimate destination for pipeline gas is important, including a move to a total transition away over the next two to three decades. This will help consumers make well-informed choices when they come to make fuel choice decisions. Placing greatest emphasis on early switching for households and small commercial businesses is likely to deliver the greatest benefit to New Zealand, as it will help ration scarce gas for the highest-value gas users, particularly industrial process heat users.

Some key parties are starting to indicate that an eventual wind-down is the likely destination for pipeline gas, including gas distributor Vector and the Commerce Commission, although without specifying a likely timeframe. However, other pipeline companies and GasNZ – the industry association – are still promoting pipeline gas as a good choice for consumers.

The Government's position appears to remain that pipeline gas has a long-term future, albeit with much smaller volumes. However, recent initiatives such as the "Home Energy Fund," a Ratepayer Assistance Scheme (for rooftop solar, batteries, insulation, heat pumps, efficient electrical appliances, and other energy resilience improvements) which can help consumers pay to switch away from gas, are sending signals that could be interpreted as running contrary to this position.[23]

Providing support to consumers will be necessary to overcome the barriers associated with switching away from gas. For households, the Ratepayer Assistance Scheme is a useful start. However, targeted additional measures for rental properties and low-income households are likely to be required to deliver the best outcomes for this segment of consumers. Some form of well-designed financial assistance for these consumers, and potentially other householders, could deliver a good cost-benefit ratio.

For businesses, EECA is running a number of programmes to help businesses choose and implement the best options for switching away from gas. Expanding these initiatives, including well-designed financial support in some instances, will likely deliver positive returns for New Zealand. There is also likely to be merit in helping hard-to-electrify industrial users implement dual-fuel capabilities with LPG or diesel.

Working with the trades has been shown overseas to be a key ingredient for a successful transition. This could include investing in retraining programmes for new electric heating appliances, providing specific support for gas fitters, and enabling self-certification for qualified installers.

Planning codes and building standards should be used to make electric systems, within efficient buildings, the default option over time. A heavy-handed ban approach is likely to make the programme less durable. Policies that have worked well, and garnered broad public support, have started with the low-hanging fruit of new-build properties and progressively increased the scope of mandated options as electric technologies steadily become the default for consumers' energy requirements.

Pipeline regulation will also need to deliver good outcomes. This includes:

- Continuing with accelerated depreciation of capital.
- Starting to recover decommissioning costs early.
- Regulating disconnection charges so that they don't become a barrier to consumers making the best fuel choice.

[23] Home Energy Fund | National Party

Much of this falls within the remit of central government to initiate. However, Auckland Council can play an important role in terms of:

- Clearly signalling (eg, through the Auckland Plan) that a move to electrify households and small businesses is Auckland's desired end goal.
- Using its planning codes to progressively signal and facilitate a move to an electrified Auckland. Eg, through prohibiting new sub-divisions being reticulated with gas.
- Helping implement Ratepayer Assistance Schemes to transition away from gas.
- Expanding the programmes it currently has (in some cases in conjunction with Vector and other parties such as Ecobulb) helping vulnerable households understand their best energy choices and (in some cases) providing financial support.
- Having a programme to progressively switch away from gas heating (and improve the energy efficiency) for the buildings that are part of Auckland Council's property portfolio.

Vector and Counties Energy are also likely to be key stakeholders that can help deliver the best outcomes for Auckland. Key actions include:

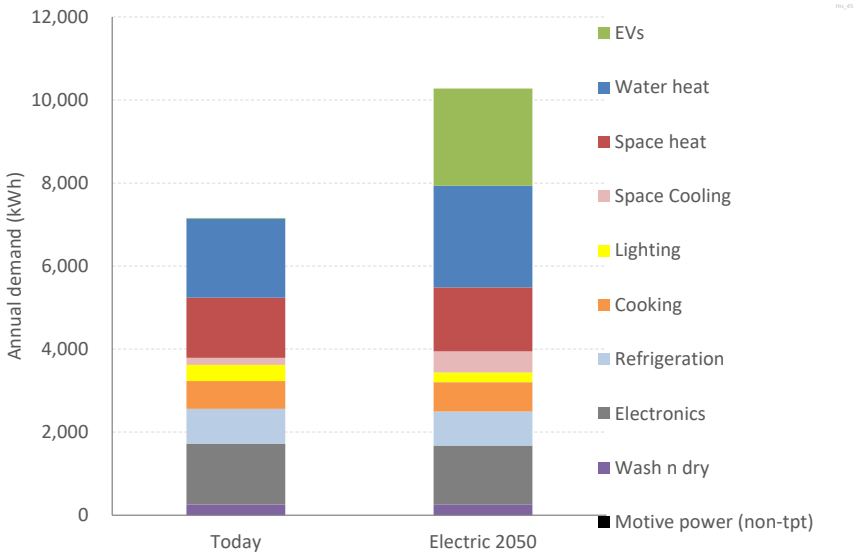
- Ensuring their electricity tariffs are cost-reflective so that they don't artificially signal that using electricity results in higher network costs than is actually the case – for example, ensuring that those costs that aren't driven by the level of demand are recovered through fixed charges. Our estimate is that, on average, approximately 60% of the costs of network provision are driven by factors other than demand.
- Using their engagement with Auckland's consumers (from households through to large industrial consumers) to provide information about the best energy choices they can make – including Vector signalling the likely end state for pipeline gas for Auckland.
- Working with parties such as Council to help deliver programmes aimed at switching away from gas.

7.5 Distributed Energy Resources

7.5.1 Demand response

As Figure 95 below shows, the electrification of home heating and transport will result in significant average household electricity demand growth.

Figure 95: Annual electricity demand from average NZ household[24]

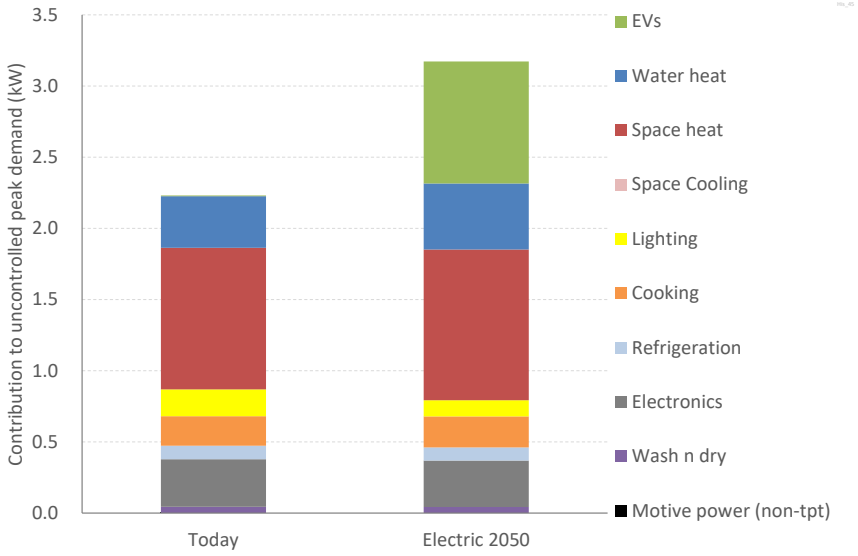


The pattern of when these different appliances are used will determine the effect on the peak electricity demand – which is generally around 6pm on a cold winter evening.

Figure 96 shows that if demand from these appliances were to simply follow the pattern of use – in the case of EVs, people typically plugging in their car to charge when they get home from work – there would be a large increase in peak demand (~ 42% in this analysis).

This would exceed network capacities in many cases, requiring costly network upgrades.

Figure 96: Uncontrolled coincident peak demand



An example of the scale of cost, is that if it required capacity upgrades of approximately 40%, it would increase consumers' bills in the long run by approximately $65 per year and require capital investment of approximately $1.6bn.[25]

[24] Source: Concept analysis based on EECA and MBIE data. Although this is for the average New Zealand household, we consider it to broadly representative of the average Auckland household. The change in mix is due to the combined effect of fuel switching and varying degrees of improvement in energy efficiency for the different end-uses. The progressive switch to LEDs is why the amount of electricity used for lighting falls by 2050.

[25] Key assumptions: LRMC of capacity-driven network expansion = $145/kW/yr. Average NZ household after-diversity peak demand = 2.25 kW. Capital cost recovery over 35 years at 6%.

The good news is that many of these appliances are capable of being controlled at times of peak in a way that doesn't materially alter the end-use service they are providing.

For example, a hot water cylinder can be turned off for a few hours, but the water inside will remain hot. Heat pumps can have their thermostat setting reduced. Dishwashers or washing machines can have their wash postponed.

An EV has two potential ways it can reduce peak demand:

- Shifting charging away from peak periods – sometimes referred to as 'V1G.'
- Injecting power back into the grid at times of peak – this is known as vehicle-to-grid or 'V2G.'

Figure 97 shows the practical maximum level of controllability at peak for the different end uses, taking account of the extent to which they can be controlled without causing a material loss of service. For example, it would not be practicable to completely turn off space heaters during a peak demand period, but it should be possible to turn them down a bit – we've assumed a 15% reduction in space heating demand is achievable during these peak periods.

In contrast, the heating element for a hot water cylinder can be completely turned off during a peak period, as can EV chargers, as both can postpone their recharging (of heat, or battery) till later in the evening / night.

And V2G has an enormous theoretical potential peak delivery as:

- At 6pm there is a very large number of vehicles at home (or at their commercial premises for business vehicles).
- They have a significant maximum potential kW delivery whereas, in contrast, there would be significant variation in the level of demand drawn by the various vehicles due to variations in how full their batteries were.

Figure 97: Practical maximum level of controllability for end-uses

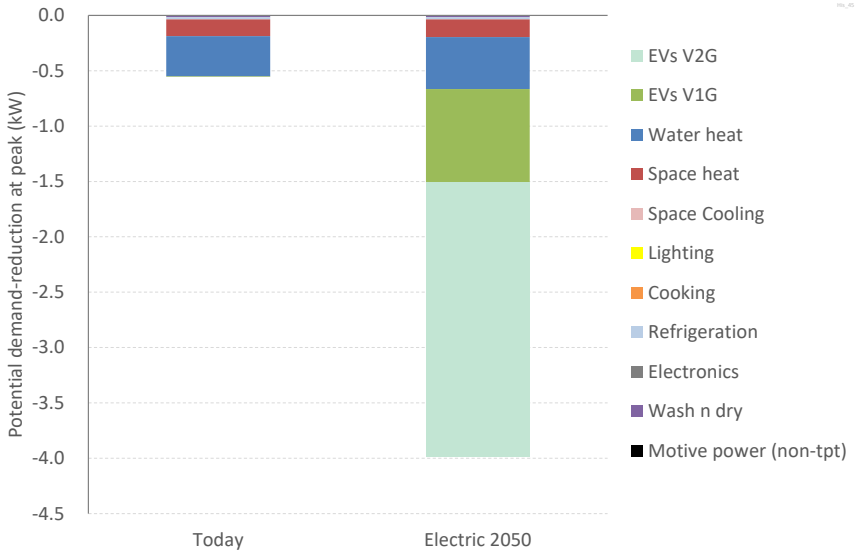
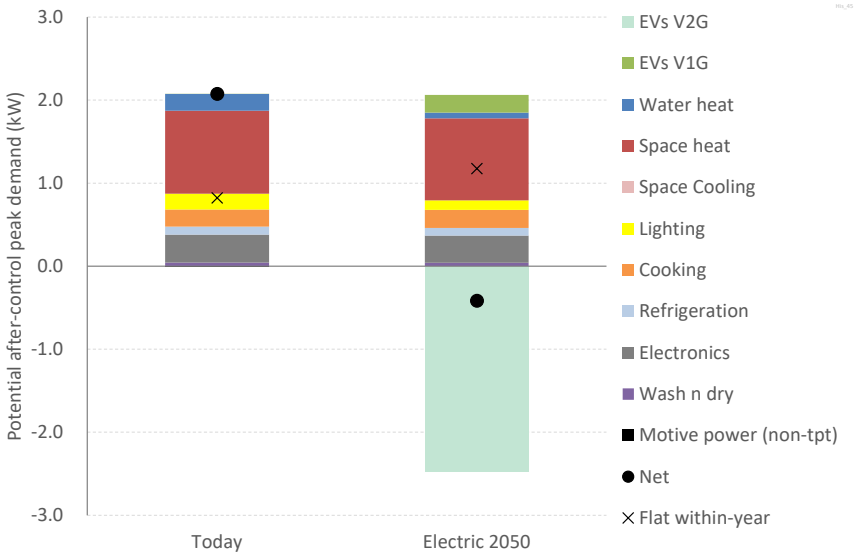


Figure 98 shows the (slightly ridiculous) example of the change in net after-control peak demand between today and 2050 if every device were controlled to the extent shown in Figure 97 – the net figure being shown as a black dot.

Also shown for comparison (the 'x' mark) is the demand that would occur if the annual demand of each appliance were spread evenly over every hour of the year.

Figure 98: Theoretical maximum change in net after-control peak demand



We say this is a "ridiculous" example as the net peak demand is *negative*. However, it highlights the enormous potential from smart load management.

It also highlights that there are only two types of appliance that really matter from a smart load management perspective: EVs, and hot water cylinders.

This has significant implications for the design of arrangements to harness this potential.

Due to the significant uncertainty over when peak periods occur, it is impractical for most consumers (both households and businesses) to monitor system conditions and control their devices.

Far more practicable is to grant control to a third-party (typically the electricity network company or electricity retailer) to undertake such control in return for a lower tariff (or receive payment in the case of V2G).

The design of network tariffs from the likes of Vector and Counties will be important regarding how much of this potential can be unlocked.

Some parties have suggested that tariffs that vary across the day and year would be the key to unlocking this potential. While such time-of-use tariffs may be appropriate for helping encourage customers to change their behaviours somewhat (eg, postponing starting the dishwasher until later at night), we think they are inappropriate for harnessing the potential for highly controllable devices such as EVs and hot water cylinders.

For these, we believe *type-of-use* tariffs are the most appropriate. Eg, a cheaper tariff for your hot water cylinder in return for granting your network or retailer the rights to control it at times of peak.

In a similar vein, we believe highly granular locational prices (eg, Vector varying the network price in different parts of Auckland based on the extent each area required capacity upgrades) are unnecessarily precise and will be less effective (and less durable from a public acceptance perspective) than a common tariff across the Auckland area that sends the right price signal on average over time.

7.5.2 Rooftop solar

One of the options that Auckland has for meeting its future energy needs is developing rooftop solar. However, our analysis indicates that rooftop solar is unlikely to represent a high-priority use of scarce public resources. Where Auckland Council or other public agencies are considering financial support for energy initiatives, those resources are likely to deliver greater system-wide benefits if directed towards more economic measures, such as energy efficiency, demand flexibility, transport interventions, or enabling infrastructure.

This does not imply that rooftop solar is not worthwhile for private households or businesses, whose investment decisions will depend on their own circumstances and preferences. The next section considers how these conclusions change when rooftop solar is combined with battery storage, including the implications of higher battery attachment rates for system value.

Why are people installing rooftop solar?

Many households and businesses install rooftop solar due to the bill reductions that they enjoy from installing solar.

The bill reductions are particularly attractive to many due to current electricity tariffs (or charges) not being "cost-reflective," which results in the bill reductions often being greater than the reductions in electricity system costs for supplying them with electricity services. Key issues are:

- Costs that don't change with demand being recovered through the variable charge, rather than the fixed charge. Policy instruments such as the low-fixed charge (which is now being unwound) have been a key driver of this.
- Non-time-of-use tariffs. The costs of supplying electricity are significantly greater in winter and in the early-morning and early-evenings – Ie, peak demand periods. However, the tariffs for supplying most electricity consumers don't vary by time of day or year. Accordingly, the price consumers are charged for electricity consumed in the middle of the day in summer is much greater than the underlying cost of supplying such electricity – and vice versa for winter evening periods.

Although households with solar avoid paying for some of the costs of supplying them with electricity, these costs don't go away. Instead, lines companies and retailers increase their average prices with the result that costs are shifted from solar-owning power users onto non-solar-owning power users. Given that there are far fewer solar owners in the poorest income deciles, there is an adverse distributional impact from rooftop solar uptake.

The Electricity Authority is currently implementing measures to require networks and retailers to move to more cost-reflective tariffs, which should progressively reduce this problem.

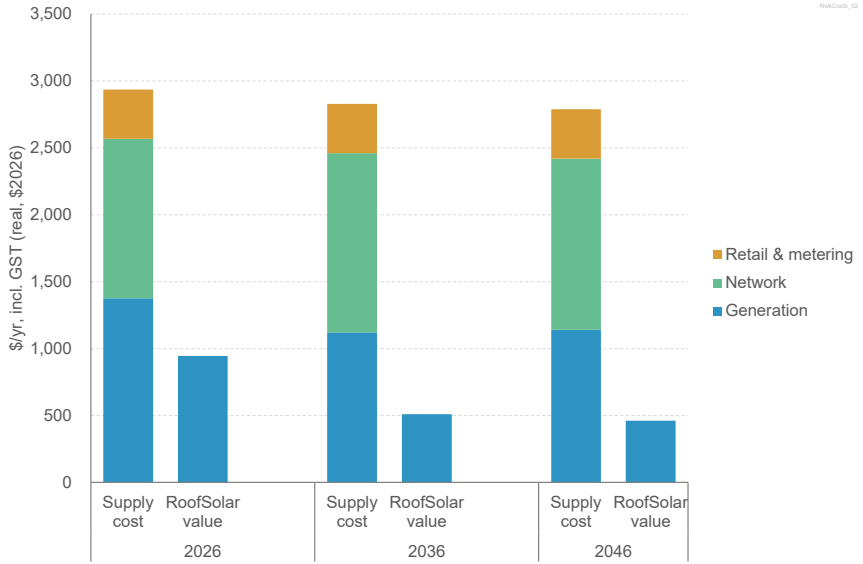
What are the system impacts of rooftop solar?

To illustrate why public funding for rooftop solar may deliver relatively limited system-wide benefits, Figure 99 shows the breakdown of a typical Auckland household electricity bill now and in the future. This is for a household that consumes 7,000 kWh/yr (the current Auckland average) and based on current tariffs in Vector's area. The bill is split into the main three components associated with supplying households with electricity:

- Generation – being the costs of building and operating the various power stations around the country.
- Network – being the costs of building and operating the transmission and distribution networks to bring the power from power stations to peoples' homes.
- Retail & metering – being the cost of providing billing and metering services.

Also shown is how much of these costs in providing electricity services to the household would be reduced if the household installed a 5 kW rooftop solar panel. ***Note that we are referring here to whole-of-electricity system costs, rather than charges faced by consumers.***

Figure 99: Breakdown of typical Auckland electricity bill, plus value that rooftop solar would provide



The first key take-away from Figure 99 is that the principal system cost avoided when a household installs rooftop solar is the cost of electricity generation that would otherwise have been supplied from the grid. The household may also reduce the retail charges and retailer margin it pays on electricity no longer purchased from the grid. However, these are largely transfers rather than avoided resource costs: the underlying costs of retailing, metering and billing generally remain and may need to be recovered through other charges or from other customers. Rooftop solar may also introduce additional administrative and metering requirements for retailers associated with measuring and settling exported electricity.

Furthermore, rooftop solar **on its own** is unlikely to avoid a large share of network costs. A substantial proportion of the costs of providing network services are relatively fixed and are not driven by changes in electricity consumption. These include the costs of towers, poles, trenches, transformers, wires and the ongoing operation of the network. On average, more than 60 per cent of electricity network costs are not directly driven by demand.

The remaining demand-related network costs are primarily driven by demand at times of network peak, rather than by total annual electricity consumption. In New Zealand residential areas, peak demand typically occurs on cold winter evenings, when rooftop solar output is low. Rooftop solar without storage therefore provides limited value in reducing the network capacity required to meet peak demand. This changes when solar is paired with batteries, as discussed in the next section.

The second key take-away from Figure 99 is that the value of avoided generation costs is projected to reduce over time. This is because there is projected to be significant development of utility-scale solar (large scale solar farms), plus continued development of rooftop solar. As solar generation becomes more prevalent, electricity will increasingly be abundant during sunny daytime periods and relatively scarce at other times. This is expected to reduce wholesale electricity prices during periods when rooftop solar is generating, lowering the value to the electricity system of each additional unit of solar generation. This analysis concerns the underlying economic value of generation rather than the electricity price faced directly by households, which is generally based on retail tariffs rather than contemporaneous spot prices.

From an electricity system perspective, the modelled value of rooftop solar alone is therefore lower than its installation cost. Thus, a typical 5 kW system will currently cost ~$10,000 (incl. GST). However, the value it provides in terms of reducing the need for building and operating utility-scale power stations is projected to be only ~$8,000.

This indicates that rooftop solar is not as cost-effective as utility-scale generation. The capital costs of rooftop solar are estimated to be approximately 14% higher than utility-solar, due to utility solar enjoying significant economies of scale.

In addition, the annual output per kW_{AC} of utility solar can be over one-third greater than rooftop solar, due to a combination of single-axis tracking and oversizing the panels relative to the inverter.

These cost advantages of utility solar significantly outweigh the benefit of reduced network losses of rooftop solar of ~7%.

Overall, this results in rooftop solar costing as much as ~65% more per kWh of electricity generated than utility solar.

Solar and an Equitable Energy Transition

The higher relative cost does not mean that rooftop solar has no role in Auckland's energy future. Distributed solar can reduce household electricity bills, improve resilience when paired with batteries, and contribute to local generation. And, if consumer electricity tariffs evolve appropriately, solar uptake need not result in network and retail cost recovery being shifted onto non-solar-owning consumers.

As Auckland's electricity demand grows through transport electrification and industrial fuel switching, solar can also reduce pressure on parts of the distribution network when combined with demand response, smart EV charging and battery storage. The value of rooftop solar therefore depends not simply on how much electricity it produces indiscriminately, but when it produces it and how well it is integrated with other flexible technologies. Distributed energy resources are likely to deliver the greatest value when coordinated rather than operating independently (EECA, 2026).

Rooftop solar can also support broader social objectives. While uptake has traditionally been concentrated among households and businesses able to afford the upfront investment, shared solar schemes, community energy projects, public housing installations and innovative financing arrangements can broaden access to lower-cost electricity. In this way, distributed solar can help reduce energy hardship and contribute to a more equitable energy transition (Brent et al., 2025).

The scenario analysis reinforces this distinction. Both the “Compact and Efficient” and “Electricity Stress” scenarios assume higher rooftop solar uptake than the Reference case. However, only “Compact and Efficient” combines solar with higher battery attachment, demand flexibility and energy efficiency, resulting in substantially greater system value. In the “Electricity Stress” scenario, higher solar uptake provides benefits for participating households but delivers fewer system-wide benefits because it is less closely integrated with complementary technologies. This highlights that rooftop solar is most effective when deployed as part of an integrated distributed energy system rather than as a standalone technology.

Box 2: Sharing community renewable energy

Māniaroa Marae, near Mōkau on the South Waikato coast, demonstrates how community energy models can extend the benefits of rooftop solar beyond the building where it is installed. The marae's solar photovoltaic system generates more electricity than it requires during much of the day. Through a pilot involving local electricity sector partners, surplus generation is shared with nearby households, reducing electricity costs while making better use of locally generated renewable energy.

During the first three months of operation, the system generated 8,405 kWh of electricity, with 87% of this shared among five participating households. The households saved around $100 per month on electricity bills. The project demonstrated that existing network infrastructure can support local energy sharing when enabled by appropriate commercial arrangements.

Implications for Auckland: Community energy initiatives demonstrate how distributed energy can support a more equitable energy transition. While rooftop solar alone is unlikely to meet Auckland's future electricity needs, innovative approaches to sharing locally generated renewable electricity could help reduce energy hardship, improve community resilience and broaden access to the benefits of decarbonisation.

Source: www.ena.org.nz/our-work/news/tlc-case-study-sharing-community-renewable-energy



7.5.3 Batteries

An increasing number of households are installing home batteries, almost always in conjunction with a solar panel installation.

The advantage to the household is that the battery charges with ‘excess’ solar power (any solar output above what home appliances are using at a given moment) during the middle of the day, then discharges during the (generally higher-priced) evening period. This reduces the power the property needs to draw from the grid at those more expensive evening peak times.

Reducing consumption at times of evening peaks will genuinely reduce network costs over the long term, as it will reduce the amount of network capacity that needs to be built.

However, this benefit is solely due to the battery, not the combination of solar plus battery. This is because the peak capacity that networks are built to meet is typically for an extreme weather event of several days of very cold weather. If those cold days are also cloudy, there would be very little sunshine for a solar panel to fill up the battery.

However, batteries could still be able to help in such situations as they can fill up with power from the grid during lower demand periods (nighttime and middle of the day) to release during peak demand periods (morning and evening peaks).

The reason that batteries make sense in conjunction with solar for households at the moment is due to the non-cost-reflective tariffs that are in place, thereby causing cost-shifting to households without such appliances. As networks and retailers move to more cost-reflective tariffs, this excess benefit to the households will eventually disappear, and the value they receive from their solar and/or battery will be roughly equal to the value they bring to the wider system in terms of reducing the need to build generation or network assets.

As battery costs have declined, they can be cost-effective options to avoid or postpone the need to increase grid capacity as well as

reduce the need to call upon expensive generation or demand curtailment in the wholesale market for electricity.

This value should increasingly be reflected in cost-reflective prices to consumers. However, it is not known whether these prices will be enough to cover the costs of household batteries, because there may be more cost-effective options to provide such services, particularly:

- Utility batteries. These range from enormous batteries connected to the transmission grid, to pole-mounted batteries connected to the lower-voltage parts of the distribution networks. Our evaluation is that pole-mounted and/or other forms of utility batteries in distribution networks could be the most cost-effective type of battery as:
  - They enjoy economies of scale relative to household batteries.
  - They can reduce distribution network costs (unlike the transmission-connected batteries that sit "upstream" of the distribution network).
  - They can potentially be redeployed by the distribution company around their network as conditions change, thereby maximising the benefit per kWh of battery capacity deployed. This contrasts with household batteries which would be spread all around the network, including places where there are no capacity constraints.
- Vehicle-to-grid technologies that harness the capability to discharge batteries sitting within electric vehicles. As the following section sets out, V2G has enormous potential and could be very cheap since they can be flexed like home batteries but essentially come for "free" with the purchase of a new electric car.

Over time the value that home batteries should receive should be equal to the avoided cost of these other options to provide the battery services. If (as is almost certainly the case) these other options are cheaper it would not be cost-effective to install household batteries.

There is some additional value that home batteries provide households, in that they provide resilience against power cuts. For rural communities that are generally subject to more frequent interruptions than urban households, this benefit alone could justify the cost of the battery, even if the returns from installing the battery are not greater than the cost of the battery.

7.5.4 Vehicle-to-grid

As the analysis in section 7.5.1 above sets out, there is huge potential for V2G to reduce peak network demand. Although most EVs currently on New Zealand's roads don't have V2G capability, many models are being developed worldwide which can provide this capability, alongside suitably compatible EV charging devices.

Concept recently studied the potential benefits of V2G[26], which identified that the economic value from V2G could be up to:

- $2,000/year per car.
- $10,000/year for trucks.
- $25,000/year in the case of special heavy vehicles that are seasonal in their usage, such as dairy tankers.

However, for this value to be realised relies on the systems and processes to be developed to coordinate this significant potential resource. This is something that is being pursued by the Electricity Authority in conjunction with the electricity network companies and retailers.

[26] "Powerful potential – New Zealand's vehicle-to-grid opportunity", September 2025. Available here: https://www.concept.co.nz/uploads/1/2/8/3/128396759/v2g_in_nz_v2.0.pdf

7.6 Technology options and emerging opportunities

Auckland's energy transition will be supported by a combination of established technologies, technologies that are commercially available but not yet widely deployed, and options that remain uncertain or are likely to have specialised applications. These include:

- High-efficiency heat pumps (established).
- Heat-pump water heating (established).
- Ground- and water-source heat systems (commercially available).
- Thermal storage (emerging).
- Managed electric vehicle charging (commercially available but yet to be widely established).
- Vehicle-to-grid (V2G) – emerging and becoming commercially available.
- Hydrogen – emerging.
- Biofuels and renewable liquid fuels – emerging.
- Biogas and renewable gases – emerging.

The purpose of this section is not to predict which individual technologies will succeed. Technology costs, commercial models, consumer preferences and regulatory arrangements are likely to change substantially over the period to 2050. Instead, it identifies how different technologies could contribute to the broader outcomes considered in the modelling and what their development means for Auckland's energy strategy.

7.6.1 Relationship with the modelling results

The modelling does not separately specify the uptake of every technology described in this section. Instead, the scenarios use technology-agnostic assumptions about the rate of ongoing energy-efficiency improvement, fuel switching and smart load management. This enables the modelling to assess the system-level effects of achieving better energy performance without requiring assumptions about the exact combination of equipment, software and operating practices used to deliver it.

The technologies discussed below can therefore be understood as potential mechanisms for delivering the modelled assumptions:

- Energy-efficiency improvements can be delivered through better-performing buildings, more efficient appliances and industrial processes, heat-pump water heating, heat recovery and higher-efficiency heating and cooling systems.
- Smart load management can be delivered through controlled hot-water heating, thermal storage, managed electric vehicle charging, batteries, automated building-management systems, industrial demand response and, potentially, vehicle-to-grid services.

- Fuel switching can be delivered through direct electrification, heat pumps, electric boilers, biomass, biofuels and renewable liquid fuels, biogas and renewable gases, hydrogen or combinations of these options.

The scenario results should not therefore be interpreted as excluding technologies that are not individually named in the model. Rather, the results show the value of the outcomes those technologies may deliver. The modelling finds that electrification produces substantially better outcomes when it is accompanied by strong efficiency improvements and smart demand management. Efficient technologies reduce annual energy consumption, while flexibility reduces the generation and network capacity required to meet peak demand. Together, these effects reduce capital investment, operating costs and exposure to electricity-system constraints.

7.6.2 Efficient low-temperature heating and hot water

Heat pumps are likely to play an important role in the transition away from gas for space heating, water heating and lower-temperature commercial and industrial heat. They transfer heat from the surrounding air, ground or water rather than producing all required heat through combustion or electrical resistance. This means they can provide several units of useful heat for each unit of electricity consumed.

Heat-pump water heaters are particularly relevant because water heating represents a significant and relatively predictable energy load across homes, businesses and public facilities. Wider uptake could reduce annual energy consumption while creating a controllable source of thermal storage. Water can be heated outside periods of peak electricity demand and stored for later use, provided service quality and public-health requirements are maintained. Heat-pump water heating therefore has potential to contribute to both the energy-efficiency and smart load-management assumptions in the scenarios.

Box 3: Exploring geoheat at Glen Innes Pool

Glen Innes Pool and Leisure Centre illustrates how replacing ageing gas equipment can create an opportunity to reconsider both the fuel and heating technology used in a Council facility. The centre has three heated pools and substantial year-round demand for pool water heating, space heating and hot water, with estimated annual thermal demand of approximately 2.1 GWh, a relatively stable load and a required supply temperature of around 45°C, making it well suited to heat-pump technology.

A proposal prepared for Auckland Council compares the existing gas boiler with air-source and water- or ground-source heat pumps. It estimates that a water- or ground-source system could reduce annual purchased energy from 2.47 GWh of gas to 0.46 GWh of electricity, with indicative annual energy-cost savings of around $157,000. Potential heat sources include groundwater, a nearby surface water body or a closed-loop borefield.

A detailed feasibility assessment would be required to confirm the available heat source, consenting requirements, capital cost, network connection implications, operating savings and emissions reductions. Nevertheless, the example demonstrates the value of examining energy alternatives before replacing ageing gas assets and shows how Auckland Council can use its facilities, procurement and asset-renewal programme to test technologies that may have wider application across pools, hospitals, schools and other buildings with stable low-temperature heat demand.



Industrial and commercial heat pumps can also recover heat from refrigeration, wastewater, ventilation systems or other processes that would otherwise discharge low-temperature heat into the environment.

Ground-source and water-source heat pumps, sometimes described collectively as geoheat or geoexchange systems, draw heat from the ground, groundwater or surface water. They can maintain more stable performance than air-source systems because ground and water temperatures fluctuate less than outdoor air temperatures. However, their suitability is highly site-specific. Their viability depends on load size and consistency, available land or water resources, geological and hydrological conditions, consenting requirements, construction costs and the ability to integrate the system into existing buildings.

These systems are therefore unlikely to provide a single region-wide solution. They may nevertheless be attractive for facilities with large and stable heating loads, such as swimming pools, hospitals, campuses, retirement villages, hotels and some industrial sites. The EECA RETA report also identifies ground-source systems, direct geothermal resources, gaseous biofuels and wastewater heat recovery as options that may suit particular Auckland sites but were not explicitly included in its main electricity and biomass pathways (EECA, 2025).

7.6.3 Flexible electricity use and V2G

Smart hot-water control, batteries, thermal storage and managed EV charging can shift electricity demand away from constrained periods. These technologies have limited effects on annual electricity use but can reduce the generation and network capacity required to meet peak demand by moving usage out of peak periods and smoothing it out.

Demand-side flexibility could reduce national peak electricity demand by approximately 1,700 to 1,900 MW (EECA, 2026). This includes flexibility from hot water, batteries, commercial buildings, industrial processes and transport charging.

Managed EV charging, or V1G, is likely to be the most immediate transport opportunity. It can prevent EV charging from adding unnecessarily to evening demand. Vehicle-to-grid, or V2G, could eventually allow vehicles to export electricity during constrained periods, but its contribution will depend on compatible vehicles and chargers, battery warranties, consumer participation and market arrangements.

Auckland's strategy could therefore prioritise managed-charging capability in new charging infrastructure while continuing to monitor and test V2G. Council fleets, public transport charging and Council facilities could provide suitable demonstration opportunities.

7.6.4 Hydrogen and alternative fuels

Hydrogen, biofuels, biogas, renewable gases and biomass may have roles where direct electrification is difficult, including some high-temperature industrial processes, heavy freight, aviation and shipping. Their potential contribution is less certain and will depend on fuel costs, supply chains, infrastructure, emissions performance and competition for limited renewable resources.

Sustainable aviation fuel (SAF) may be one of the more important options for reducing aviation emissions, particularly for medium- and long-haul flights where direct electrification is unlikely to be practical. SAF includes renewable liquid fuels produced from biological feedstocks or through synthetic fuel pathways. SAF is partly represented in the modelling. The BAU scenario includes very gradual SAF uptake from 2035, consistent with national projections. The "Compact and Efficient" and "Electricity Stress" scenarios also include some uptake of battery-electric aircraft. Aviation therefore remains largely dependent on liquid fuels, but the modelled results already incorporate limited substitution by SAF and electricity.

These fuels should not be treated as general substitutes for natural gas, petrol or diesel. The more robust approach is to prioritise energy efficiency and direct electrification where practical, then reserve alternative fuels for applications with few credible alternatives such as aviation. Auckland's Transport Emissions Reduction Pathway similarly treats hydrogen and biofuels as possible options for difficult transport applications rather than substitutes for reducing travel demand or electrifying suitable vehicles.

7.7 Transport infrastructure

Transport infrastructure requirements vary materially across the scenarios because the scenarios change both the amount of travel and the modes and fuels used to provide it. A dispersed, high-travel future requires more road capacity, maintenance, parking, fuel distribution and geographically dispersed EV charging infrastructure. A compact, lower-travel future requires greater investment in public transport, walking and cycling, interchanges and road-space reallocation, but can reduce the need for additional road capacity and lower pressure on both electricity and liquid-fuel systems.

The Auckland Regional Land Transport Plan 2024-2034 (RLTP) provides the appropriate planned-investment baseline. It proposes a $63.1 billion programme over ten years, including $14.5 billion for public transport services, $13.3 billion for maintenance, operations, renewals and resilience, $11.7 billion for rapid transit and rail, $17.0 billion for state highway improvements, $1.8 billion for other public transport, $1.6 billion for local roads and optimisation, and $868 million for walking and cycling (Auckland Regional Transport Committee, 2024). The programme requires around $40.8 billion from the National Land Transport Fund, substantially more than the funding expected to be available. These figures therefore represent Auckland's proposed transport programme rather than a fully funded commitment.

The RLTP should not be interpreted as a cost of the energy transition. Most of the programme would be required to accommodate population and economic growth, renew ageing assets, improve safety and resilience, and operate existing services regardless of the energy scenario. For this report, the RLTP is treated as the baseline against which scenario-specific additions, changes in timing, and avoided investments should be considered.

7.7.1 Mode shift and lower vehicle travel

The "Compact and Efficient" and "Fuel Diverse" scenarios assume lower private vehicle travel and stronger public and active transport. Delivering these outcomes requires infrastructure and service investment. Auckland's Vehicle Kilometres Travelled Reduction Programme (2024) estimates that a package capable of reducing light-vehicle VKT by 29% by 2035 would require $20.5 billion of capital expenditure at the P50 confidence level, rising to $28.8 billion at P95. It would also require cumulative additional operating expenditure of $4.9-$5.1 billion over 2025-2035 and approximately $1.0-$1.05 billion per year once fully operating (AECOM, 2024). These estimates are un-escalated, and the report indicates escalation could add approximately $0.5 billion to the P50 capital estimate.

The largest cost component is public transport. The VKT programme estimates $13.4 billion of public transport capital expenditure at P50, including $9.1 billion for enabling infrastructure and $3.7 billion for speed and reliability improvements. It also estimates $6.5 billion for active modes, comprising $2.6 billion for cycling connectivity, $1.2 billion for walking connectivity, $1.5 billion for crossings, $519 million for mobility hubs and parking, and $479 million for low-traffic neighbourhoods. Travel demand management measures account for a smaller $604 million of capital expenditure but are important because the evidence indicates that infrastructure, pricing, parking management, land-use policy and behaviour-change measures are more effective when implemented as a coordinated package.

These figures should be treated as an indicative upper-bound programme for a rapid, high-ambition VKT reduction pathway, rather

than as costs that can be directly assigned to the “Compact and Efficient” and “Fuel Diverse” scenarios. The AECOM estimates are gross programme costs and were not developed as a funding-gap analysis against the RLTP or Long-term Plan. There is probably much overlap with existing planned transport investments, especially rapid transit, bus priority, walking and cycling, and public transport services, while more compact urban form and lower VKT could also avoid or defer some future roading expenditure. Determining the net additional funding requirement would require project-level reconciliation with funded and unfunded transport programmes, including distinguishing expenditure required for growth and asset renewal from expenditure specifically additional to achieve the modelled mode shift.

Greater walking and cycling are expected to provide both physical and mental health benefits through increased physical activity. Using the NZTA monetised benefit values (NZ Transport Agency Waka Kotahi, 2026) for walking and cycling, the present value of these health benefits over the ten-year period from 2027 to 2036 is estimated to be around $21.5 million higher in the Compact and Efficient and Fuel Diverse scenarios relative to the reference. By contrast, the Expansion and Electricity Stress scenarios have around $8 million lower health benefits from active transport.

7.7.2 Electric vehicle and public transport charging infrastructure

Higher electric vehicle uptake shifts infrastructure requirements from liquid-fuel distribution towards household, workplace, public, fleet, bus-depot and ferry-terminal charging. Total installed cost is not simply the price of the charger. It includes electrical design, switchboards, transformers, cabling and trenching, civil works, communications, parking or depot modifications, consent and electricity-network connection costs.

The Ministry of Transport notes that connection costs can be prohibitively high and inconsistent across distribution businesses, and that large connections can take more than a year where network reinforcement is required (Ministry of Transport, 2024a).

For residential and destination charging, a useful New Zealand benchmark is approximately $3,000 to $4,000 for a standard wall-mounted charger including installation. Costs can be higher where a switchboard, service main or shared-building electrical system must be upgraded[27]. At the other end of the spectrum, many households may be able to meet their normal charging needs using an existing three-pin connection, with EECA indicating that slow overnight charging can add around 100 km of range over ten hours. The appropriate level of investment therefore depends not simply on EV uptake, but on the extent to which faster and smarter charging provides value through convenience, peak management and participation in electricity flexibility services.

The modelling does not separately prescribe a particular uptake rate for smart wall chargers, vehicle-to-grid charging or other individual flexibility technologies. Instead, demand management is represented as a single scenario parameter capturing the aggregate effect of a range of measures, including smart EV charging, time-of-use response, controlled hot-water heating, household and commercial batteries, vehicle-to-grid capability, and industrial demand response. The “Compact and efficient” scenario with stronger demand management therefore implicitly assumes greater uptake and more effective coordination of these technologies.

Public charging requires a different cost and delivery model. The Government's current planning benchmark is a nationwide network of 10,000 public charge points by 2030, equivalent to approximately one public charger for every 60 electric vehicles. Budget 2023 provided $95 million of government co-investment over 2023/24 to 2025/26, while the Ministry expected private investment to fund a

[27] www.eeca.govt.nz/insights/case-studies-and-articles/rest-and-recharge-ev-charging-at-accommodation/

substantial share of total costs[28]. A simple population-share allocation would imply roughly 3,400 public charge points ($32 million) in Auckland if the national network were distributed in proportion to Auckland's population.

Auckland's largest identifiable charging commitments are for public transport. The RLTP allocates $47.1 million to regional bus-charging infrastructure, $138.6 million to regional commercial bus depots that include charging infrastructure, and $10.5 million to electrification of the Ti Rakau Drive depot. Together these programmes represent $196.2 million of bus-depot and charging-related investment, although the $138.6 million depot programme includes land, buildings and other depot works as well as chargers. The RLTP also allocates $281.6 million to Stage 1 of ferry decarbonisation, including new vessels and charging and wharf infrastructure at Downtown, Hobsonville Point and Half Moon Bay, with minor wharf works at Bayswater and Beach Haven. It is therefore a bundled programme rather than a standalone charging estimate (Auckland Transport et al., 2024).

NZTA's zero-emission bus economics study provides additional parameters for scenario costing (Heuser et al., 2024). Its baseline assumes one depot charger per battery-electric bus, but allows a ratio of one charger for every two buses where battery capacity and scheduling permit. The study assumes annual maintenance of approximately $26,000 for a fast charger, compared with zero separately identified annual maintenance for a depot charger in its model, and reports battery-electric bus purchase costs of about $605,000 for a two-axle rigid bus to $953,333 for a three-axle double-decker. The expected technical life for DC fast chargers is eight to ten years, implying that chargers installed during the 2020s may require replacement within the scenario period (Parry et al., 2025).

Electricity-network costs can be comparable with, or larger than, charging equipment costs at constrained sites. The network-cost analysis in Appendix 1 estimates that an additional sustained megawatt of Auckland peak demand imposes approximately $126,000 per year of transmission and distribution capital costs. On that basis, a 20 MW unmanaged charging peak across major depots and fast-charging hubs would imply approximately $2.5 million per year of additional annualised network cost, while shifting that demand away from the system peak could avoid much of this requirement. This illustrates why smart residential charging, depot charging outside the evening peak, load sharing between charge points and flexible connection agreements are central infrastructure assumptions rather than minor operating details. Vector's asset planning and operational trials similarly emphasise controlled charging for buses, ferries and households as a way to defer reinforcement (Vector Limited, 2026).

The “Electricity Stress” scenario has the greatest charging and electricity-network requirement because it combines high EV uptake with high transport demand, weak mode shift and limited demand flexibility. It would require the fastest rollout of public charging, the most extensive depot and fleet connections, and the greatest allowance for local distribution reinforcement. The “Compact and Efficient” scenario also has high EV uptake, but lower VKT and stronger managed charging reduce both the number of public charging sessions and the contribution of EV charging to peak demand. The “Expansion” scenario requires a more geographically dispersed charging network, increasing land, connection and charger maintenance costs per vehicle served. The “Fuel Diverse” scenario has lower near-term charging expenditure but retains petrol, diesel and alternative-fuel infrastructure for longer.

For scenario costing, charging expenditure should therefore be reported in four separate blocks: privately funded residential and workplace charging; publicly accessible light-vehicle charging; bus, ferry and municipal-fleet charging; and electricity-network connection

[28] www.transport.govt.nz/area-of-interest/environment-and-climate-change/supercharging-ev-infrastructure

and reinforcement. The RLTP's $196.2 million of identifiable bus charging and depot programmes and the bundled $281.6 million ferry programme provide an Auckland-specific near-term baseline. Additional public light-vehicle charging should be estimated from the required number and type of charge points, while network costs should be linked to incremental coincident peak demand rather than annual electricity consumption.

Overall, the identifiable charging-related expenditure discussed above could be in the range of $500 million to $800 million, including public light-vehicle charging, bus depot and charging programmes, ferry decarbonisation infrastructure, and potentially substantial private residential charging investment. This range is indicative rather than a comprehensive system cost, as some programmes bundle charging with vehicles, depots or wharf works, while workplace, fleet and network reinforcement costs are not fully captured. The corresponding benefits of this investment are reflected elsewhere in the scenario analysis through lower costs for fuel, and, where charging is effectively managed, lower electricity network capital requirements.

7.7.3 Road, freight and resilience infrastructure

The “Expansion” scenario is likely to have the highest whole-of-system transport infrastructure cost. More dispersed development increases road kilometres, intersections, bridges, drainage, lighting and maintenance obligations, while also making high-frequency public transport more expensive to provide. Longer journeys increase vehicle energy use and require a wider network of public charging and liquid-fuel facilities. Although some road investment remains necessary in every scenario, the relevant comparison is between investment that maintains and optimises the existing network and investment that expands capacity materially to accommodate additional vehicle travel.

Freight infrastructure is required under all scenarios because Auckland's port, airport, distribution centres and industrial areas serve both the regional and national economy. Near-term requirements are likely to include improved route reliability, consolidation and logistics facilities, charging or alternative-fuel infrastructure for commercial fleets, and sufficient access to liquid fuels for vehicles that are slower or more difficult to electrify. Freight charging may create large, concentrated electricity loads and should therefore be coordinated with the location of industrial growth and available network capacity.

7.7.4 Rail infrastructure for freight mode shift

Auckland’s metropolitan passenger rail network is already largely electrified, with the Papakura–Pukekohe extension completing the main remaining section. So, the principal incremental cost associated with different scenarios is likely to arise from increased freight and passenger volumes, including additional track capacity, terminals, signalling, rolling stock and maintenance, rather than from further electrification within Auckland.

Electrification of the wider Golden Triangle between Auckland, Hamilton and Tauranga could create Auckland-related costs, particularly for traction power and interface works south of Pukekohe, freight yards, locomotive facilities and network connections. However, this would be a national inter-regional investment rather than an Auckland-only one.

The “Compact and Efficient” and “Fuel Diverse” scenarios assume that a greater share of Auckland freight is carried by rail rather than road. This would reduce diesel use, road congestion and heavy-vehicle infrastructure pressure, but it would require investment in rail capacity, reliability, terminals and rolling stock. KiwiRail estimates that one freight train can carry approximately the same load as 54 trucks, while rail freight produces around 60 per cent fewer emissions per tonne than heavy road freight. In 2024/25, rail displaced more than one million truck journeys nationally. These benefits depend on sufficient network capacity and reliable access to freight terminals (KiwiRail, 2025a).

The principal Auckland constraint is not simply whether freight locomotives are electric. Freight and metropolitan passenger trains share much of the same network, particularly between Wiri, Westfield and the central isthmus. KiwiRail's Auckland Rail Programme Business Case identifies Wiri to Westfield as a critical bottleneck where passenger and freight movements converge, and concludes that additional tracks are required to provide reliable capacity (KiwiRail & Auckland Transport, 2024).

The full 30-year Auckland rail programme is estimated to cost between $21 and $28 billion. This includes metropolitan passenger improvements as well as freight-enabling works, including additional tracks between Westfield and Pukekohe, the Avondale-Southdown corridor, junction grade separation, signalling, power supply, stations, rolling stock, depots and maintenance facilities. The full programme should therefore not be attributed to freight mode shift alone (WSP, 2023).

Near-term investment already included in the Rail Network Investment Programme provides part of the baseline. Almost $1 billion has been approved for major rail improvements over 2024 to 2027, principally metropolitan projects. Nationally, existing government rail investment also includes $1.6 billion for replacement locomotives, shunts and wagons and modernisation of mechanical depots. Some of this rolling-stock investment would support Auckland freight growth, although KiwiRail does not provide an Auckland-specific allocation (KiwiRail, 2025b).

For scenario costing, an indicative $2 billion to $5 billion Auckland freight-rail allowance to 2050 could be applied to both Scenarios 1 and 4. This is a screening assumption rather than a KiwiRail estimate. It represents an approximate freight-related share of the wider Auckland rail programme and would cover:

- Additional track and junction capacity.
- Freight-terminal and port access improvements.
- The freight-related component of Avondale–Southdown.
- Signalling, passing loops, yards and maintenance access.
- Additional locomotives and wagons.
- Land, consenting and resilience works.

The "Compact and Efficient" scenario would be more likely to justify the upper part of the range if compact growth, strong public transport use and freight mode shift occur together, since passenger and freight services would compete for scarce network capacity. "Fuel Diverse" could use a similar central estimate because its lower road-freight energy demand still relies on rail infrastructure, even though private-vehicle electrification is slower. However, this scenario may retain more diesel rail operation unless locomotive electrification or alternative low-emissions traction is separately assumed.

Box 4: Golden Triangle rail electrification

A future opportunity for low-emissions freight

The Golden Triangle rail corridor linking Auckland, Hamilton and Tauranga is New Zealand's busiest freight corridor, connecting the country's largest city with major industrial centres and the Port of Tauranga. Rail is substantially more energy efficient than road freight and electrifying this corridor has been identified by KiwiRail as a potential long-term opportunity to reduce diesel consumption and lower freight emissions.

Electrifying the corridor would allow around 55% of KiwiRail's freight task to be hauled using electric traction when combined with the existing electrified North Island Main Trunk. The proposal would reduce diesel consumption, lower freight emissions and provide customers with a low-carbon freight option, while creating infrastructure that could also support future inter-regional passenger rail services. Electrification would require significant investment in rail infrastructure, traction power supply and electric locomotives.

Implications for Auckland: a combination of overhead electrification and battery-electric locomotives would create new electricity demand and require careful planning of supporting network capacity. This illustrates that transport decarbonisation extends beyond vehicles to include the electricity infrastructure needed to support them, reinforcing the importance of coordinated planning between transport and energy networks.



7.7.5 Petrol and diesel infrastructure

Petrol and diesel demand declines in all transition scenarios, but the infrastructure cannot be withdrawn at the same pace as fuel use. Much of the capital invested in terminals, storage facilities, distribution assets and service stations is already sunk. However, these assets continue to incur operating, maintenance and renewal costs, some of which are relatively insensitive to throughput. As fuel volumes decline, these remaining costs are spread across fewer litres sold, potentially increasing unit distribution costs and encouraging consolidation of terminals, distribution networks and retail sites. Service-station sites might be repurposed as EV charging and mobility hubs, although fast charging has somewhat different land, connection and dwell-time requirements from liquid-fuel retailing.

The main issue is the need to manage the contraction of the system while maintaining resilience for freight, emergency services, remote communities and the remaining internal combustion vehicle fleet. The national Fuel Security Plan will also require minimum stockholding and resilience measures during the transition (Ministry of Business, Innovation and Employment, 2025)

The “Fuel Diverse” and “Expansion” scenarios retain the greatest dependence on liquid-fuel infrastructure. The “Compact and Efficient” scenario reduces fuel demand fastest through lower VKT and stronger mode shift, while the “Electricity Stress” scenario replaces a greater share of liquid fuel infrastructure with charging and electricity network capacity. Across all scenarios, early coordination is preferable to unmanaged decline, especially where the closure of a terminal, depot or service-station network could reduce regional fuel resilience before alternatives are fully available.

7.7.6 Indicative scenario implications

Business-as-usual. Committed RLTP projects, renewals, gradual charging rollout and staged fleet electrification. The $63.1 billion

RLTP is the relevant baseline envelope, subject to funding availability. The principal risk is that underfunding and delayed delivery leave mode shift insufficient to offset the demands of population growth.

Compact and Efficient. High public transport and active mode investment, bus priority, interchanges and managed charging, with less need for new road capacity. This scenario could require a substantial share of the VKT programme envelope, although much would overlap with the RLTP and would be partly offset by avoided road and vehicle costs. Benefits depend on coordinated land-use, service, pricing and parking measures.

Expansion. Road expansion, dispersed maintenance, longer public transport routes, more parking, widespread charging and continued fuel infrastructure. This is likely to have the highest whole-of-system transport infrastructure requirement, although the available plans do not quantify the incremental cost of dispersed growth.

Electricity Stress. Large-scale private and fleet charging, depot connections and electricity network reinforcement, alongside continued road pressure. It has the highest transport-related electricity infrastructure cost, with unmanaged charging creating network peaks and network connection bottlenecks.

Fuel Diverse. Strong public and active transport, slower EV charging rollout, and longer retention of liquid fuel and alternative fuel infrastructure. Near-term charging costs are lower, but maintaining multiple fuel systems may increase total transition cost and prolong exposure to fuel price and emissions risks.

Overall, the “Compact and Efficient” scenario is not transport infrastructure-light. It redirects investment from accommodating additional private vehicle travel towards higher capacity and more energy efficient modes. Its whole-of-system cost may nevertheless be lower than the “Expansion” and “Electricity Stress” scenarios because it reduces vehicle ownership and use, avoids some road expansion, lowers exposure to fossil fuels and moderates electricity network requirements. The available cost evidence supports reporting transport infrastructure costs as an indicative range, rather than adding the full RLTP or VKT programme cost to the modelled energy system capital expenditure.

7.7.7 Indicative Infrastructure Investment Needs

Table 7: Indicative order-of-magnitude cost differences to 2035 ($ billion)

Cost component	Compact and Efficient	Expansion	Electricity Stress	Fuel Diverse
Public transport, walking and cycling	+$8 to $15bn	$ 0 to $3bn	$0 to $2bn	$6 to $12bn
Rail rolling stock, power and capacity	$1 to +$4bn	$0.5 to $3bn	$0.2 to $1bn	$1 to $4bn
Roads, intersections and parking	-$3 to −$7bn	$5 to +$11bn	$2 to $5bn	−$2 to -$5bn
EV chargers and charging sites	$0.3 to $0.8bn	$0.4 to $1.2bn	$0.8bn to +$2.0bn	−$0.2 to −$0.7bn
Electricity distribution	$0 to $0.4bn	$0.2 to $0.8bn	$0.8 to $2.0bn	−$0.1 to −$0.4bn
Liquid-fuel infrastructure	−$0.2bn to $0	$0 to $0.3bn	$0.2bn to $0	$0.2 to $0.7bn

7.8 Summary of infrastructure requirements

The scenarios illustrate that Auckland will require substantial energy and transport infrastructure investment under any plausible future, but the scale and composition of that investment differ considerably. The key determinant is not simply total energy use, but where demand occurs, how strongly it contributes to peak electricity demand, and the extent to which efficiency, flexibility and distributed energy resources can make better use of existing infrastructure.

The Compact and Efficient scenario has the lowest overall infrastructure burden. Although electrification proceeds more quickly, greater energy efficiency, managed demand and distributed

resources moderate electricity peaks, while compact urban development reduces the need for road expansion and dispersed network infrastructure. Transport investment shifts towards public and active transport rather than accommodating more private vehicle travel.

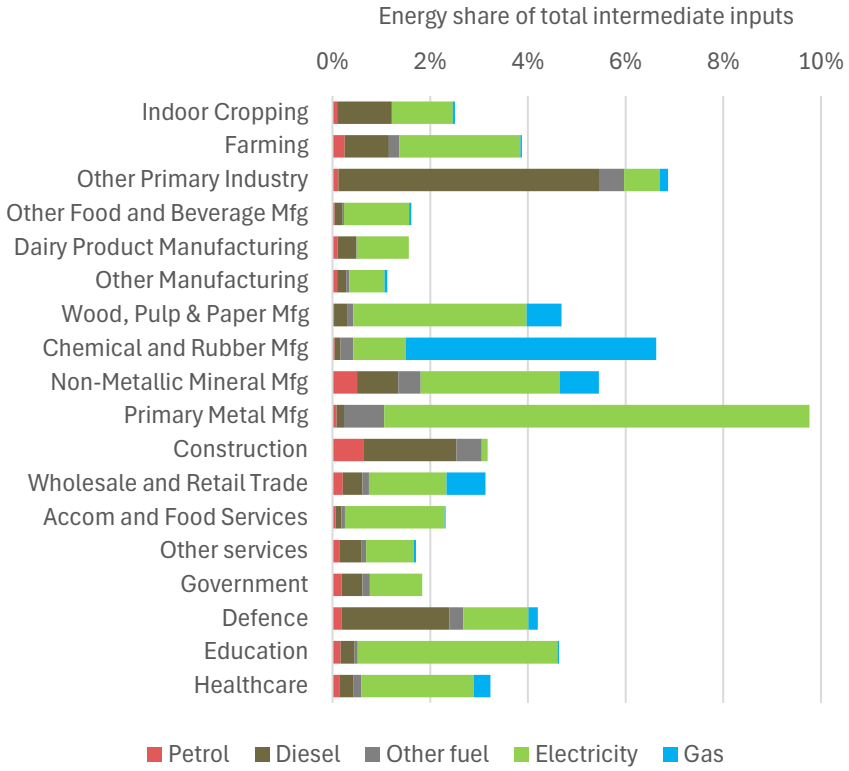
The Expansion scenario is the most infrastructure-intensive overall. Dispersed development increases road, transport and local network requirements, while higher travel demand and lower efficiency increase the amount of infrastructure required to serve a growing population. The Electricity Stress scenario places the greatest pressure specifically on electricity infrastructure, with rapid electrification, large new loads and limited flexibility producing higher peak demand and bringing forward generation, transmission and distribution investment. In contrast, Fuel Diverse reduces near-term electricity infrastructure requirements but retains gas and liquid-fuel infrastructure for longer, prolonging exposure to fuel-supply, network-viability and transition risks.

8 Industry sector impacts

This section examines how changes in Auckland's energy system may affect different parts of the economy. It begins by considering energy's share of each industry's intermediate inputs, as this provides an indication of industries' direct exposure to changes in fuel and electricity costs. Industries with higher energy input shares are more likely to face material pressure on operating costs, margins, prices and investment decisions from rising energy costs, although the ultimate effects will depend on their ability to improve efficiency, switch fuels, pass costs on to customers and/or absorb them through lower margins.

The 2024 Stats NZ supply-use tables indicate that energy generally represents a relatively small share of total intermediate inputs across most industries (excluding transport) nationally. The highest shares are in primary metal manufacturing, at 10%, followed by other primary industries and chemical and rubber manufacturing, at 7%. Electricity is the largest energy input for many sectors, while gas is particularly important for chemical and rubber manufacturing, wood, pulp and paper manufacturing, and non-metallic mineral manufacturing. Diesel is more prominent in primary industries, construction and defence. As these are national averages, the energy cost structure of Auckland industries may differ depending on the regional mix of firms, technologies and fuels used.

Figure 100: Energy input intensity by industry group

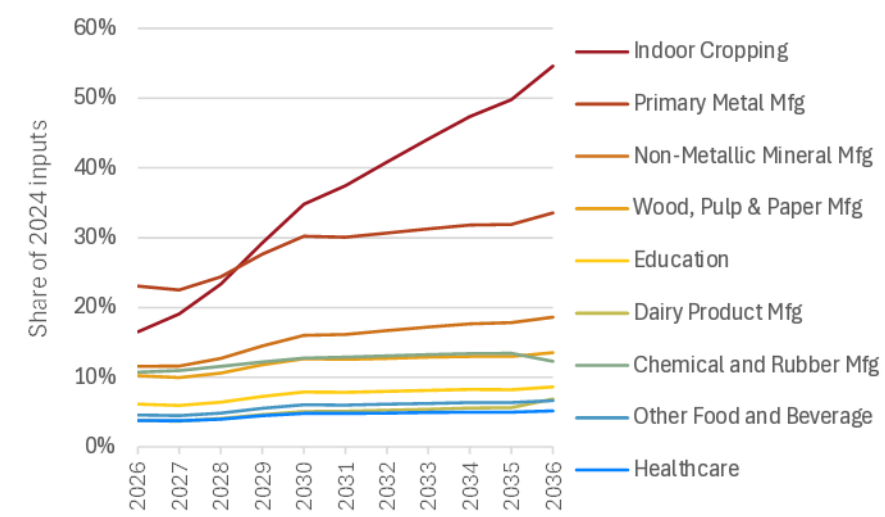


To assess how each scenario could change sectoral energy cost exposure, an indicative energy cost burden was calculated by applying the projected change in fuel use and fuel prices to each industry's current energy expenditure, while holding total intermediate inputs constant at their 2024 value. This isolates the effect of changes in energy demand, fuel switching and prices from wider changes in industry output or input use, for which Auckland-specific projections are not available. The result shows whether

energy costs would become more or less significant relative to the industry's current cost base.

The analysis focuses on electricity and gas because these fuels are central to the (stationary) energy transition, whereas changes in liquid fuel use are addressed mainly through the transport analysis in this report. Figure 101 shows the nine sectors with the highest estimated electricity and gas cost burdens relative to their 2024 intermediate input base.

Figure 101: Constant-structure electricity & gas cost burden



Primary metal manufacturing starts from a high base and increases further. However, the largest increase occurs in indoor cropping, where the electricity capacity required for electrification was based on the greenhouse conversion opportunities identified in EECA's Auckland RETA work. Annual electricity consumption was estimated from these power capacity requirements using a 15% capacity factor, reflecting the predominantly seasonal and winter-focused nature of greenhouse heating. The large increase in energy cost burden highlights a significant affordability challenge for glasshouse operators.

The scale of the estimated increase does not necessarily mean that glasshouse production would cease. Domestic growers benefit from some protection against imported competition because fresh produce is costly to transport and subject to biosecurity restrictions. This may provide some capacity to pass higher heating costs through to produce prices. Nevertheless, the increase represents a material affordability and competitiveness challenge.

Non-metallic mineral manufacturing also experiences a material increase in its estimated energy cost burden, driven particularly by glass production. Glass furnaces require continuous, very-high-temperature heat and have fewer viable alternatives to gas than conventional boiler applications. Glass manufacturing may have greater capacity than some trade-exposed industries to absorb or pass through higher energy costs because glass products are heavy and costly to transport, favouring production close to domestic customers.

Wood, pulp and paper, and chemical manufacturing also face an increase and are hard-to-abate emissions intensive industries that could be vulnerable as gas supply declines, particularly without targeted support. Biomass may provide an alternative for some process heat because wood-processing residues are already widely used within the sector, although those residues also have competing uses and Auckland's available biomass supply becomes increasingly constrained under the EECA RETA pathways.

For most other sectors, the estimated electricity and gas burden remains below 10% of the 2024 intermediate input base. This suggests that the direct effect of stationary energy cost changes is likely to remain relatively modest for much of Auckland's economy, although individual firms will still face significant transition costs for new equipment and/or connection upgrades.

9 Household Distributional Impacts

9.1 Transport

This section examines how the transport energy scenarios affect households across different income groups. Understanding these distributional impacts is important because transport accounts for a larger share of expenditure for lower income households, and differences in vehicle ownership, travel behaviour, and the pace of electric vehicle uptake mean that the costs and benefits of the energy transition are unlikely to be shared evenly.

The Household Expenditure Survey published by Statistics NZ shows that high income households spend a lot more on transport in absolute terms. However, transport including purchase of vehicles accounts for a similar share of total household expenditure across income groups (15% to 18%).

Lower income households are more likely to be in car-dependent neighbourhoods (Welch, 2026). As a result, public transport use tends to follow an inverse U-shaped relationship with income, with middle income households making the greatest use of it.

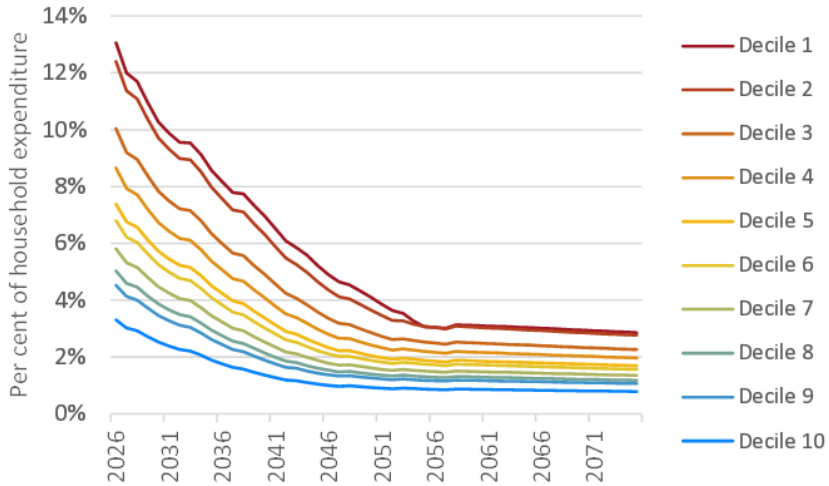
As the light vehicle fleet electrifies under the reference scenario, household expenditure on transport fuel and vehicle maintenance falls substantially. These savings arise because electric vehicles have lower fuel and maintenance costs than internal combustion vehicles.

The transition to electric vehicles is not expected to occur evenly across income groups. Consistent with technology-adoption theory, uptake is modelled as an S-shaped diffusion process in which different household groups have different adoption thresholds rather than simply following the same trajectory with a fixed time lag. Lower income households are less likely to own, or to be considering the purchase of, an electric vehicle (Kaviani et al., 2025). In the reference scenario, high income households reach around 90% EV penetration by 2050, whereas the lowest income households reach only around 20% over the same period. However, as used electric vehicles progressively enter the second-hand market, adoption among lower income households accelerates, with the final stages of the transition also increasingly driven by the declining availability of ICE vehicles entering the new and used vehicle markets. EV penetration therefore approaches universal levels by 2060.

As the light vehicle fleet electrifies under the reference scenario, household expenditure on transport fuel and vehicle maintenance falls substantially.

Although EV uptake is slower among lower income households, the eventual financial benefits are proportionally greater because transport costs make up a larger share of their budgets. The cost for fuel and vehicle maintenance falls from around 13% of current low-income household expenditure to below 4% by 2050, representing a substantial improvement in affordability.

Figure 102: Vehicle fuel and maintenance costs as a proportion of household expenditure by income decile

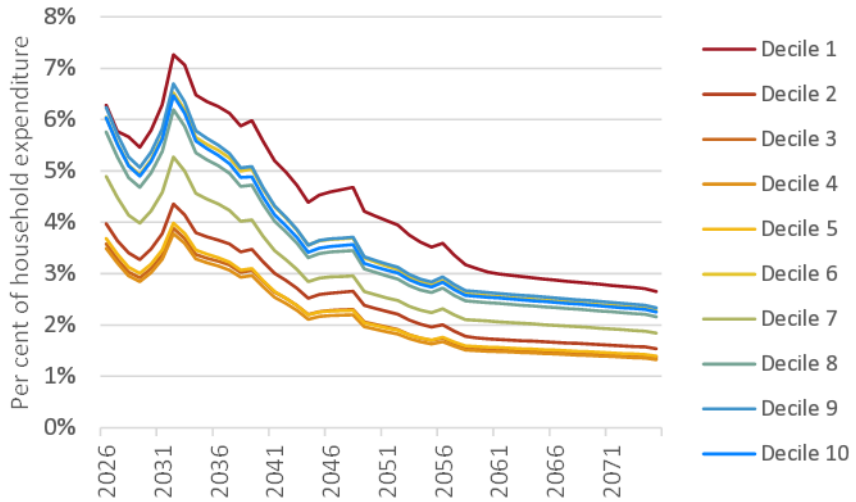


The 2024 baseline vehicle purchase expenditure by household income group is based on the Statistics NZ Household Expenditure Survey, rather than estimated by the model. HES reports average vehicle-purchase expenditure of approximately $2,700 per year for the lowest-income household group, equivalent to around 6% of household expenditure, compared with approximately 3.5% for households in income deciles 4 to 6. The model therefore preserves the observed HES expenditure pattern at the starting point and projects it forward using assumptions about EV uptake, vehicle prices and mode shift.

Under the reference projection, vehicle purchase costs increase during the early 2030s as EV uptake accelerates and EVs still have a price premium over ICE vehicles. New EVs are expected to reach purchase-price parity with comparable new ICE vehicles earlier, around 2030, but this transition will take longer in the used-vehicle market, which accounts for around half of light-vehicle entries into the New Zealand fleet (New Zealand Ministry of Transport, 2026). Even where headline emissions standards are comparable with relevant overseas markets, weaker compliance charges or enforcement could prolong the availability of cheap, inefficient ICE vehicles in New Zealand.

From the late 2030s onwards, weighted average EV purchase costs are projected to decline in real terms. For the lowest income households, annual vehicle purchase expenditure peaks at around $3,000 in 2033 before falling to approximately $1,200 (in real terms) by 2050.

Figure 103: Vehicle purchase costs as a proportion of household expenditure by income decile



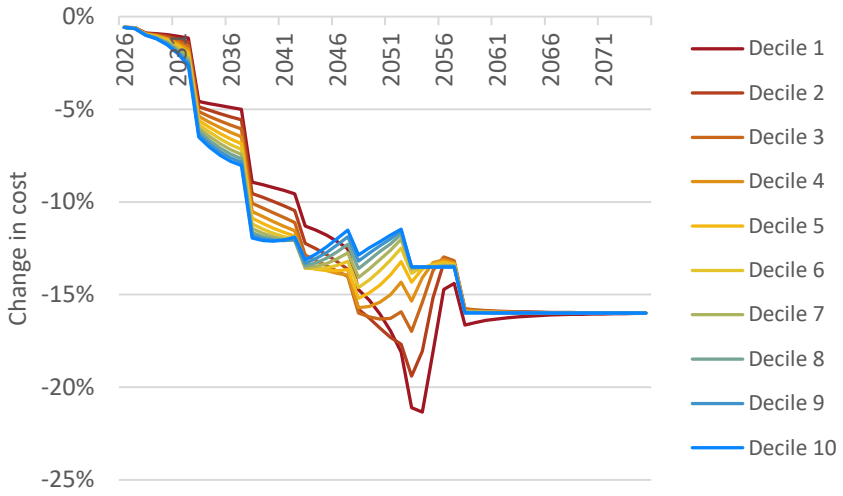
9.1.1 Alternative scenarios

The “Compact and Efficient” scenario results in lower transport costs for both low- and high-income households.

Accelerated EV uptake further lowers fuel and maintenance costs, particularly for middle-to-high income households that adopt EVs earlier. Low-income households are still slower to adopt EVs but may experience significant cost savings by the 2040s. Meanwhile, expanded access to high-quality public transport provides lower income households with greater opportunities to substitute away from private vehicle travel.

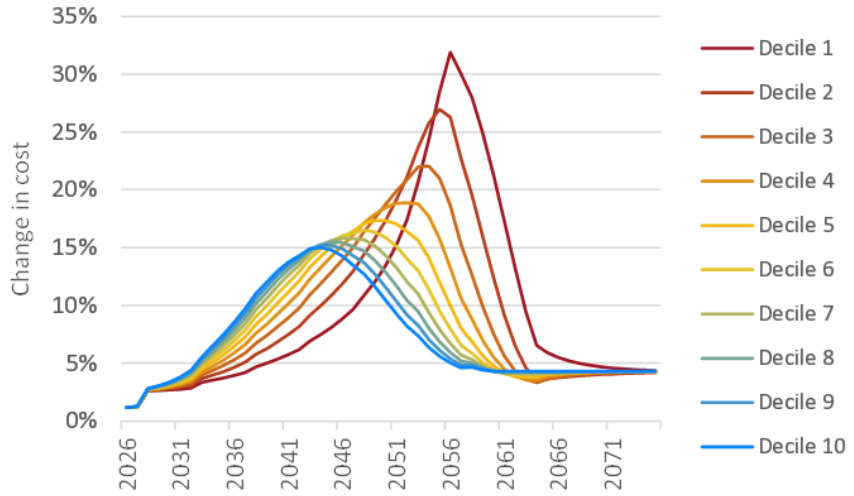
By 2060, vehicle maintenance and fuel costs are around 16% lower for all income groups in scenario 1.

Figure 104: Difference in vehicle fuel and maintenance costs: Compact and Efficient scenario versus reference



In the "Expansion" scenario transport costs are generally higher than the reference. The impact on lower income households is most pronounced in the 2050s, reflecting the foregone benefits of fleet electrification and public transport investment that would otherwise have substantially reduced transport costs. The scenario is internally consistent because both EV adoption and public transport use are modelled with income-specific propensities, with higher VKT reflected in vehicle operating and maintenance costs.

Figure 105: Difference in vehicle fuel and maintenance costs: scenario 2 versus reference



In the "Electricity Stress" scenario, which combines rapid electrification with only limited transport mode shift, the effects of these two changes differ across income groups. Faster EV uptake reduces transport costs primarily for higher income households, while lower income households see little benefit until the 2050s. In the "Fuel Diverse" scenario, which places greater emphasis on mode shift and less on electrification, low-income households benefit more than high income ones from expanded public transport access, more than offsetting the slower pace of fleet electrification.

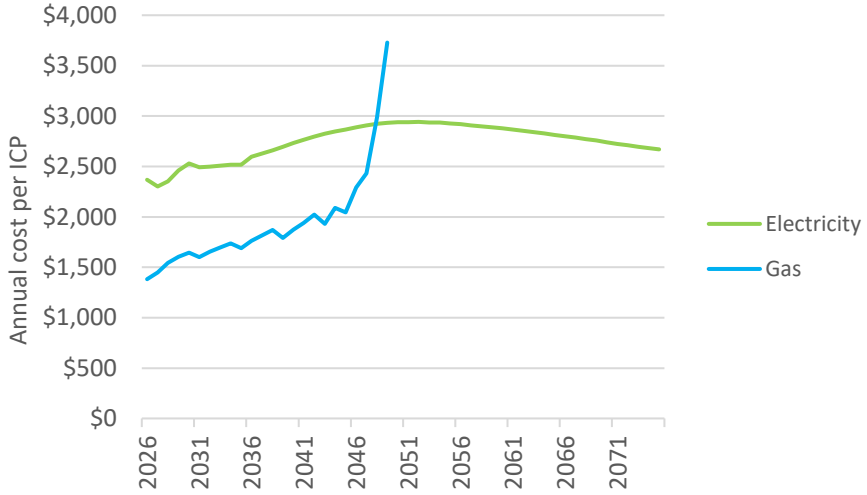
The "Compact and Efficient" and "Fuel Diverse" scenarios also have significantly lower **average** vehicle purchase costs, as the shift to public transport is assumed to result in households needing fewer or even no vehicles. The "Expansion" scenario has the highest average vehicle purchase costs for households.

9.2 Household energy bills

The financial impact on households' energy bills will vary depending on whether they are connected to the gas network, their capacity to switch to electric appliances as gas prices increase, and to a lesser extent, the energy efficiency of their home.

Under the reference scenario, the average gas bill per connection that continues to have gas increases as fixed network costs are recovered from a shrinking customer base (Figure 106). Average electricity bills initially increase as households electrify but then plateau before declining in real terms as the cost of renewable generation and electricity storage continues to fall, and electricity network investment costs are spread over a greater usage base. The figure excludes transport energy costs, as these were presented in the previous section. It also does not include the costs to electrify appliances, which were discussed in section 7.4.1.

Figure 106: Reference average non-transport energy spend per year per residential ICP



Overall, electrification of heating and transport will deliver lower costs of delivering heat and transport to households compared with a delayed electrification pathway in which households remain on gas for longer.

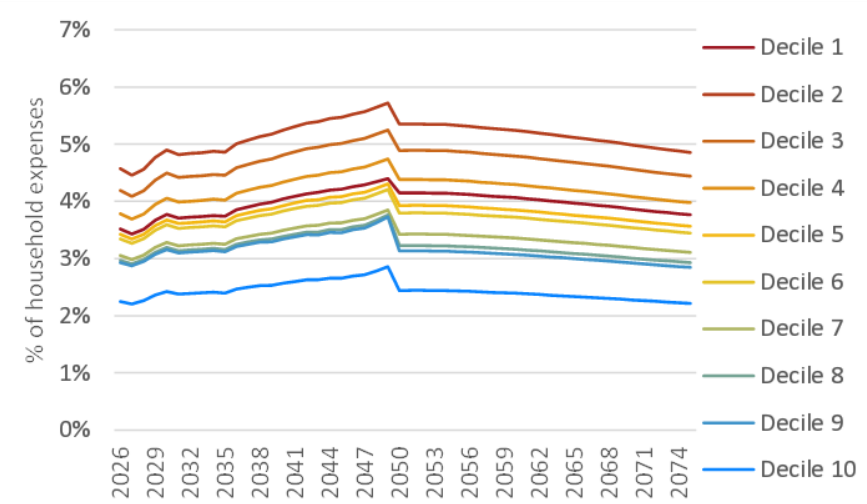
Lower-income households are less likely to have existing gas connections. Average household expenditure on gas rises markedly with income (New Zealand Infrastructure Commission Te Waihanga, 2023). The distribution of residential gas connections across income deciles is therefore assumed to be proportional to average household gas expenditure.

However, low-income households that do have gas are more likely to have difficulty switching to electricity because they have lower access to capital, credit, information and home ownership rates (EECA, 2025). Replacing gas hot water with electric typically requires an upfront investment of around $4,000 for resistance electric or

$8,000 for a heat-pump water heater. Even where low-income households can switch from gas, they may have no choice but to install or accept an inefficient non-heat-pump appliance that locks them into materially higher electricity bills for the long term.

Figure 107 shows that households in the lowest income decile currently spend on average around 4.5% of their total expenditure on electricity and gas. This share rises to approximately 5.5% during the gas transition, before settling at around 5% once electrification is complete.

Figure 107: Household energy costs as a proportion of household expenditure by income decile



These averages, however, mask substantial variation within the income group. Low-income households that remain connected to gas and are unable to electrify could face much larger increases, potentially more than doubling their household energy bills as fixed gas network costs are spread across a shrinking customer base. This creates a material risk of energy hardship.

Some households may respond to rising reticulated gas prices by switching to bottled LPG rather than electrifying. This would allow continued use of gas appliances but may require appliance conversion or replacement, installation of compliant cylinders and regulators, and ongoing cylinder-delivery costs. Bottled LPG is therefore treated as a potential transitional or niche alternative rather than a widespread long-term substitute for reticulated gas.

Although the alternative scenarios alter the timing of increases and decreases in household energy bills, they do not change the underlying affordability challenge. Supporting low-income households through the gas transition is likely to require targeted interventions, including assistance with appliance replacement and electrical upgrades, protections for renters, and measures to avoid vulnerable households becoming the last remaining customers on the gas network. Recent work by the New Zealand Green Building Council similarly highlights the upfront capital barriers faced by lower-income households and the case for targeted support for efficient electric technologies and home retrofits (NZGBC, 2025).

Box 5: Case study: Home retrofits

Efficiency benefits extend beyond energy savings

A Vector and EECA study in 2022 used smart meter data to assess the effects of insulation and heat-pump retrofits in Auckland homes. Insulation reduced electricity consumption, with the largest savings occurring during cold weather and peak-demand periods. Savings were greater in higher-consuming and owner-occupied homes than in rental properties. Heat-pump installation did not reduce measured electricity consumption overall, but the study did not measure the impact on other fuels.

The findings show that retrofit benefits extend beyond annual electricity savings. Insulation can reduce winter peak loads and ease pressure on Auckland's electricity network, while heat pumps can improve thermal comfort and reduce exposure to cold, damp conditions. These wellbeing gains may be especially important for households that previously restricted heating because of cost.

Tenants and lower-income households may have the greatest potential health and comfort benefits but are often less able to finance improvements or influence landlord investment. Targeted subsidies, landlord incentives and accessible financing may therefore be needed to ensure that retrofit benefits are shared widely.

Implications: Higher retrofit rates may deliver their greatest value through warmer, healthier homes and lower winter peak demand, rather than large reductions in annual electricity use.



10 Strategic Implications

The preceding chapters have explored how Auckland's energy system could evolve under a range of plausible futures. While the scenarios differ in their assumptions regarding urban development, transport demand, technology uptake and fuel choices, they reveal several strategic insights that are consistent across multiple futures.

These implications extend beyond the immediate findings of the modelling. They highlight where Auckland faces structural challenges, where current planning approaches may need to evolve, and where early action is likely to deliver the greatest long-term value. Rather than identifying a preferred scenario, they identify the underlying issues that decision-makers should consider regardless of how the future unfolds.

10.1 Auckland's greatest challenge is managing the pace of the transition

Public debate often focuses on whether New Zealand will generate enough electricity to support widespread electrification. The scenario analysis suggests that Auckland's more immediate challenge is likely to be managing the speed and coordination of the transition itself, which often transcends the bounds of the electricity system and broader energy system.

Across all scenarios, households, businesses and infrastructure providers face decisions about replacing vehicles, industrial equipment, heating systems and network assets over the coming decades. The “Reference” and “Electricity Stress” scenarios demonstrate that delaying these decisions does not eliminate the need for investment; instead, it compresses investment into a shorter period, increasing pressure on electricity networks, supply chains, skilled labour and capital.

This suggests that transition capacity (the ability of institutions, markets and infrastructure providers to deliver change in a coordinated manner) may become a more significant constraint than energy availability alone.

10.2 Auckland's largest future energy decisions will be made outside traditional energy sectors

One of the clearest findings from the scenario analysis is that future energy demand is strongly influenced by decisions made outside the energy sector.

The scenarios show that urban form, housing density, transport investment, freight patterns, and the location of employment have a profound influence on future energy consumption. Compact urban development consistently reduces transport energy demand, lowers infrastructure requirements, and improves the efficiency of electricity and public transport investment. Conversely, dispersed growth increases vehicle travel, (transport and electricity) network expansion and long-term infrastructure costs.

The PC120 results reinforce the importance of urban form. Despite stronger projected household growth, the shift towards smaller and more compact dwellings offsets much of the additional residential energy demand. However, PC120 also shows that compact development alone does not deliver the full benefits of the Compact and Efficient scenario, which also assumes faster electrification, greater transport mode shift and stronger demand management.

This reinforces the need to integrate energy considerations into land-use planning, transport planning, and infrastructure sequencing. Energy demand should be viewed not simply as something to forecast, but as an outcome that can be shaped through strategic planning decisions.

10.3 Auckland's electricity resilience depends on connectivity, not self-sufficiency

As electricity becomes increasingly central to Auckland's economy, resilience will become an increasingly important consideration alongside affordability and emissions reduction. Some recent assessments have highlighted Auckland's dependence on electricity imported from outside the region, prompting questions about whether greater local generation should become a strategic objective.

The evidence reviewed for this study suggests that resilience is better understood in terms of the diversity, redundancy and adaptability of the wider electricity system than the amount of generation located within Auckland itself. The region benefits from strong transmission connections to a geographically diverse portfolio of generation across the Upper North Island, including hydro, geothermal, wind, solar and thermal generation. This diversity reduces reliance on individual assets and provides multiple pathways for maintaining supply during outages or periods of system stress.

However, greater local generation also involves trade-offs. Auckland could use substantial areas of land for grid-scale solar, but that may not be the best use of that land or the lowest-cost way to improve resilience. Local generation therefore needs to be considered alongside options such as transmission investment, storage, demand flexibility, and energy efficiency.

The principal resilience challenge for Auckland is therefore not achieving greater electrical self-sufficiency but ensuring that the electricity system can continue to accommodate rapid demand growth while maintaining reliable and affordable supply. This places increasing importance on transmission and distribution investment, demand flexibility, energy efficiency, and distributed energy resources working together as complementary components of a resilient energy system.

Case Study: New Zealand Sugar Company

Industrial electrification through heat recovery

Chelsea refinery in Birkenhead illustrates how industrial decarbonisation can be achieved by improving process efficiency before undertaking large-scale fuel switching. Rather than replacing its gas-fired process heat system outright, the refinery invested in a Mechanical Vapour Recompression (MVR) evaporator that captures waste vapour from the sugar refining process, compresses it, and reuses it as a heat source. This substantially reduces the need for new steam generation while increasing production efficiency. The project was expected to reduce natural gas use by around 10%, achieve lifetime emissions reductions of approximately 32,700 tonnes CO_2-e, and demonstrate how electrification and energy efficiency can be implemented together.

Since commissioning, EECA reports that the new MVR system has exceeded expectations. The technology is around seven times more energy efficient than the previous thermal vapour recompression system, reduces gas consumption by about 10%, improves syrup concentration and downstream processing, and avoids around 2,000 tonnes of CO_2-e each year. The project has also increased plant throughput and provided confidence to pursue further decarbonisation opportunities.

Key insight: This example illustrates a central finding of this report: the pace of electrification matters less than how it is implemented. Reducing energy demand first can lower both business costs and network investment requirements.



The strategic implication is that resilience should be considered as a system property rather than an asset-specific objective. Local renewable generation, battery storage, network reinforcement, demand response and regional transmission all contribute different resilience benefits. Policies that support a balanced portfolio of these measures are likely to provide greater long-term resilience than an approach focused primarily on maximising local generation within Auckland.

10.4 Market structure is secondary to the outcomes Auckland needs

Debate about electricity market structure can become a focal point when concerns arise about electricity prices, investment or security of supply (Auckland Business Chamber & Northern Infrastructure Forum, 2026). However, the more important issue for Auckland is whether market and regulatory arrangements deliver the outcomes the region requires: timely investment in generation and networks, effective coordination of supply and demand, access to connections, efficient demand flexibility and appropriate mechanisms for managing risk. Recent analysis by Concept Consulting (2026) emphasises improving information, incentives and contracting arrangements rather than treating structural or administrative reform as a substitute for effective market coordination (Concept Consulting, 2026).

The region's emerging challenges are strongly associated with coordinating rapid electricity demand growth with generation, transmission and distribution investment, while making greater use of demand response and other flexible resources. These challenges remain under any plausible electricity market structure.

10.5 Energy efficiency should be viewed as infrastructure investment

The analysis demonstrates that reducing energy demand through efficiency can be as valuable as increasing energy supply.

Across the alternative scenarios, improvements in building efficiency, transport mode shifting and demand management reduce peak electricity demand, delay network augmentation and lower long term system costs. These benefits extend beyond reduced energy bills to include avoided investment in substations, distribution upgrades and generation capacity.

This changes the way energy efficiency should be considered. Rather than being viewed solely as an emissions reduction measure or household and business bill reduction initiative, energy efficiency represents an investment that can reduce future infrastructure requirements while improving affordability and system resilience.

10.6 The gas transition is primarily a coordination challenge

Declining domestic gas supply is widely recognised, but the scenario analysis suggests that the greatest risks arise from the way the transition is managed rather than from declining supply alone.

Households, businesses and infrastructure providers make investment decisions independently, yet those decisions affect the viability and cost of the wider gas network. As customers disconnect, remaining users face increasing network costs, creating the potential for a self-reinforcing cycle of declining demand and rising prices – the so-called 'death spiral'.

The modelling indicates that greater certainty around transition pathways can reduce these risks by enabling more orderly equipment replacement, infrastructure planning and investment decisions. This suggests that Auckland's gas transition should be viewed as a

coordinated economic transition rather than simply a technical fuel substitution exercise.

10.7 Flexibility is as important as network capacity

Flexibility should be treated as a network planning option alongside conventional capacity upgrades.

PC120 enables denser development, which could improve infrastructure utilisation, but will also concentrate electricity demand growth in particular locations.

Scenarios incorporating greater demand flexibility, distributed generation, battery storage and managed electric vehicle charging achieve lower peak demand despite substantial electrification. This reduces pressure on transmission and distribution infrastructure and provides greater resilience during periods of high demand or supply disruption.

Internationally, electricity systems are increasingly recognising demand flexibility as an infrastructure resource. The findings suggest Auckland can similarly reduce future investment requirements by treating flexible demand, distributed energy resources and consumer participation as integral components of the energy system rather than optional additions.

10.8 Growth creates both Auckland's greatest opportunity and its greatest challenge

As New Zealand's largest and fastest-growing urban economy, Auckland is likely to experience many aspects of the energy transition earlier and at greater scale than other regions.

Population growth, commercial development, housing construction and industrial activity all contribute to increasing energy demand. While this places greater pressure on infrastructure investment, it also creates opportunities to deploy new technologies, improve infrastructure utilisation and capture economies of scale that may not be available elsewhere.

The higher electricity expenditure under the PC120 scenario is not just a cost, but an investment that supports a larger economy.

This reinforces the importance of Auckland-specific planning. National policies provide an essential framework, but the timing, location and scale of Auckland's infrastructure requirements are sufficiently distinct to warrant regional analysis and coordinated planning.

10.9 The transition requires a different approach to planning

Perhaps the most significant implication of this study is that Auckland is managing a long-term transition between energy systems.

Historically, energy planning focused on forecasting demand and providing sufficient supply, often within silos pertaining to individual energy vectors like electricity, liquid fuels and gas. The scenario analysis shows that future supply and demand need to be considered together. Decisions that reduce or shift demand can avoid or defer costly investment in generation and networks, while the cost and availability of supply can also affect whether electrification and other demand-side changes are economic. Planning each side independently risks either over-investment in infrastructure or discouraging beneficial changes in energy use.

This requires a shift from planning individual asset types towards a more integrated approach across electricity, gas, transport, buildings, businesses and consumers. It also requires greater collaboration between Auckland Council, infrastructure providers, central government, regulators and the private sector than has traditionally been necessary.

11 Actionable pathways for Auckland's Energy Transition

Given the analysis, what should Auckland actually do?

No single intervention can deliver a resilient, affordable and low-emissions energy system for Auckland. Electrification can reduce fossil-fuel use, but unmanaged electrification can increase peak demand and bring forward costly network upgrades. Distributed solar can reduce electricity imported into the region, but it cannot by itself meet winter peaks or maintain supply through prolonged periods of low solar output. Biomass can provide an alternative for some industrial process heat requirements, but regional supply, transport, space and air quality constraints limit its application. Vehicle electrification reduces emissions and exposure to oil prices, but it does not address congestion, urban sprawl, or the infrastructure costs associated with high levels of vehicle travel.

Auckland's pathway must therefore combine demand reduction, compact urban development, transport mode shift, energy efficiency, electrification, demand flexibility, distributed energy, and a managed transition away from fossil gas. These interventions need to be designed as a package because decisions in one part of the system affect costs and options elsewhere. For example, land-use decisions influence transport demand, infrastructure utilisation, and building energy use; building efficiency affects electricity peaks; and the timing of electrification affects network investment requirements.

Responsibility for delivering this transition is distributed. Auckland Council has significant influence through spatial planning, district planning, infrastructure sequencing, transport governance, procurement, its property portfolio, public information and convening. Auckland Transport has direct influence over transport services, road-space allocation and travel demand. Central government and regulators control many of the principal energy market, gas transition, building regulation and transport pricing settings. Transpower, Vector, and Counties Energy are responsible for electricity infrastructure, while businesses and households make many of the investment and technology choices that ultimately determine demand. The recommendations below consequently focus on high-impact and feasible actions, clearly distinguishing between measures Auckland Council can lead and those that require partnership or national action.

11.1 Guiding principles

The following principles underpin the recommendations:

- **Reduce energy demand through efficiency before expanding supply**. Energy efficiency, compact urban form, lower vehicle travel, and better utilisation of existing infrastructure should be considered before committing to additional generation or network capacity. Efficient demand reduction can lower consumer costs, defer infrastructure expenditure and reduce exposure to future supply constraints. It should be treated as an infrastructure investment rather than solely as an emissions or cost saving initiative.
- **Prioritise investments that deliver multiple benefits.** Priority should be given to measures that improve affordability, resilience, productivity, and emissions outcomes simultaneously. Examples include improving building performance, expanding public and active transport, managing electric vehicle charging, reducing industrial energy waste, and developing distributed energy in locations where it can alleviate network constraints.
- **Avoid locking in future stranded assets.** Long-lived investments should be assessed against plausible future energy pathways rather than only current conditions. New fossil gas connections, inefficient buildings, car-dependent development and infrastructure that cannot adapt to changing fuels, demand patterns or climate change could impose avoidable transition costs on future users.

- **Improve flexibility alongside electrification.** Electrification should be accompanied by managed charging, storage, demand response, and commercial arrangements that reward consumers for shifting demand.
- **Sequence infrastructure ahead of demand where justified.** Electricity, charging and transport infrastructure can take many years to plan, consent and construct. Investment should occur early where future demand is sufficiently certain and where delay would constrain housing, industrial development or decarbonisation.

  Sequencing generation in tandem with load growth is a particularly topical example. Market forces will tend to incentivise new generation to be built in response to the demands of large loads such as data centres. For example, Fonterra recently signed a Power Purchase Agreement with New Zealand electricity market new entrant ANZA Power. Fonterra's supply will be backed through the construction of ANZA Power's planned 30 MW (AC) Somerton solar farm, which is located between Fonterra's Darfield and Clandeboye manufacturing sites in the South Island. Darfield and Clandeboye are two coal-dependent sites that Fonterra is working on decarbonising.

  However, the prospect of very large and rapid load growth through data centres has resulted in governments and regulators worldwide seeking further assurances that such load growth will be backed through new generation. This could come in the form of an "additionality" requirement in the permitting regime for data centres, requiring new generation to be developed in step with new data centre load. Permitting authorities may even require that some level of such generation come from renewable sources.

  in Australia, the Australian Energy Market Commission (AEMC) has provided four key recommendations to the energy minister regarding data centres, including requirements to offset consumption using certificates linked to new renewable generation under the Renewable Electricity Guarantee of Origin (REGO) scheme and to contract for firming capacity that offsets the intermittency of renewable generation.[29]
- **Maintain affordability and equity.** The transition should not leave low-income households, renters, small businesses or the last remaining gas consumers carrying disproportionate costs. Financial assistance, consumer protection and accessible alternatives will be needed where households or businesses cannot independently fund efficient appliances, building upgrades or fuel switching.
- **Build resilience into long-lived infrastructure.** Infrastructure planning should account for climate hazards, supply disruption, technology change and uncertainty about the pace of electrification. Resilience should include physical robustness, diversity of supply, operational flexibility and the ability to adapt assets as circumstances change.

11.2 How the scenario modelling informs the pathway

The scenario modelling does not identify a single forecast of Auckland's energy future. Instead, it shows how different combinations of land-use development, transport demand, energy efficiency, electrification, flexibility and fuel switching affect infrastructure requirements, operating costs, emissions and transition risks.

The results indicate that Auckland should ideally seek to move towards the characteristics of the "Compact and Efficient" scenario.

[29] Data centre advice to ECMC | AEMC.

This scenario combines lower transport demand, more efficient buildings, faster fuel switching and greater demand flexibility. It produces the largest emissions reductions and operating cost savings relative to the reference, while moderating the electricity infrastructure consequences of electrification.

The PC120 scenario suggests that Auckland's updated growth projections are already moving towards a more compact urban form. However, the scenario keeps broadly business-as-usual assumptions for electrification, transport mode shift and demand management. Achieving the wider benefits of Compact and Efficient would therefore still require changes beyond those associated with urban development.

The pathway must also remain robust if Auckland develops differently. The “Expansion” scenario requires more dispersed transport and energy infrastructure and produces weaker emissions improvement outcomes. The “Electricity Stress” scenario shows the risks of rapid electrification without corresponding investment in efficiency, distributed energy and flexible demand. The “Fuel Diverse” scenario reduces near-term electricity pressure but prolongs exposure to gas availability, liquid fuel prices, residual emissions and the costs of maintaining multiple energy systems.

The recommendations therefore have three functions:

- Move Auckland towards the “Compact and Efficient” pathway, particularly through compact growth, transport mode shift, building efficiency, managed electrification and distributed energy.
- Implement actions that perform well across all scenarios, including energy efficiency, demand flexibility, infrastructure coordination, consumer protection and avoiding stranded assets.
- Prepare contingent responses if Auckland begins tracking towards “Expansion” or “Electricity Stress” outcomes. Monitoring should identify these changes early enough for infrastructure plans, funding priorities and policy settings to be adjusted.

Table 8: Scenario implications for action

Scenario	Principal implication from the modelling	Actionable response
Reference	Electricity demand and peak demand continue to grow, while the gas transition proceeds gradually and transport outcomes remain dependent on national technology uptake and existing investment plans.	Improve coordination beyond current plans; accelerate efficiency and flexibility; prepare an orderly gas transition; and monitor whether existing transport and network programmes are keeping pace with growth.
Compact and Efficient	Lower vehicle travel, stronger public and active transport, efficient buildings, distributed energy and smarter load management reduce total energy demand and moderate electricity peaks despite faster electrification. Auckland's energy requirements are delivered at the lowest cost of all the scenarios.	Treat this as the preferred direction. Prioritise compact growth, public and active transport, building retrofits, managed charging, rooftop solar and batteries, and the completion of the gas transition.
Expansion	Dispersed growth increases travel, energy demand and the cost of serving homes and businesses. It requires more road, charging, electricity network and fuel infrastructure with the associated higher costs, and leaves Auckland with weaker emissions outcomes.	Use the Future Development Strategy, infrastructure sequencing and transport investment to avoid this pathway. Where outward growth proceeds, require stronger building performance, early infrastructure coordination and local charging and electricity network plans to limit its additional costs.
Electricity Stress	Rapid electrification combined with weak efficiency and flexibility produces the greatest pressure on peak demand, electricity network connections and electricity infrastructure, and associated higher costs. Unmanaged vehicle and fleet charging creates particular risks.	Accelerate managed charging, demand response, storage and flexible connections; coordinate major new loads; bring forward justified transmission and distribution upgrades; and target efficiency programmes in constrained areas.
Fuel Diverse	Lower electrification reduces near-term electricity pressure, but continued gas and liquid fuel use increases exposure to supply, price, gas network viability and emissions risks. Maintaining several parallel fuel systems may also increase total transition costs.	Do not treat this as a long-term destination. Maintain short-term resilience for consumers that cannot immediately electrify, but prevent new fossil fuel lock-in, establish a clear gas exit pathway and use biomass or emerging fuels where they provide a credible site-specific alternative.

11.3 Auckland Council's role

11.3.1 Planning

Auckland Council's most important contribution is to integrate energy into decisions that shape long-term demand. The Future Development Strategy should explicitly consider the electricity, transport and other infrastructure implications of alternative growth patterns. Development should be prioritised in locations that can be efficiently served by existing or planned infrastructure and where residents have practical access to employment, services and public transport. This is consistent with the Future Development Strategy's emphasis on compact, infrastructure-efficient growth and coordination between land use and investment.

District planning can help prevent new development from locking in inefficient or high-risk energy choices. Council could investigate, subject to legal advice and alignment with national policy, whether new subdivisions should be prevented from extending reticulated gas networks. At a minimum, planning provisions should ensure that new development is designed to operate efficiently without gas and that space, electrical capacity and wiring are available for electric heating, cooking, water heating, solar generation and vehicle charging. The objective should be to make efficient electric development the practical default while avoiding poorly designed requirements that impose unnecessary costs.

Infrastructure sequencing should bring Auckland Council, Auckland Transport, Transpower, Vector and Counties Energy together before growth areas are committed. The PC120 results reinforce this need for coordination, with stronger growth and a greater share of multi-unit housing concentrating additional electricity demand in existing urban areas. Structure plans and major plan changes should identify likely electricity demand, transport energy requirements, charging needs and the timing of network investment. Where substantial electricity upgrades are required, Council should consider how land access, road corridors, consenting and infrastructure coordination can reduce costs and lead times.

Transport planning should give greater priority to bus lanes, connected cycling networks, walking access and development around frequent public transport. More compact development and better alternatives to private vehicles reduce both transport fuel consumption and the future electricity demand associated with replacing a large, heavily used fossil fuel vehicle fleet. Auckland's transport pathways identify safe, connected networks, destination infrastructure and safer speed environments as complementary requirements for increasing walking and cycling.

11.3.2 Economic Development

Auckland Council's Economic Development Office which procured this research can drive medium to longer term outcomes through the acceleration of investment in future-focused industries that consider and integrate cleaner, more efficient energy sources at the outset.

This department is responsible for supporting existing businesses to transition to more efficient energy resources while still remaining competitive, attracting innovation and investment in energy solutions that solve some of Auckland's key challenges, as well as thought leadership within the Auckland Council group on the important role of energy in a thriving economy.

This can be through place-based energy transition testbeds where new technologies, business models and system configurations can be trialled in real world conditions, and mission-led innovation projects focused on specific regional energy challenges. Insights from these are then able to be formally used to drive policy and strategy for Auckland Council and its partners to actively shape system settings.

With responsibilities for future workforce development, these insights can support the case for development of jobs and training opportunities that will support the future energy economy.

Māori-led energy initiatives and alternative ownership or delivery models may also create wider benefits, including stronger local economic participation, greater energy resilience and improved community outcomes.

11.3.3 Other transport measures

Council and Auckland Transport should continue to investigate congestion charging as a means of improving network efficiency, reducing peak-period vehicle travel, and funding better alternatives. Any scheme should be introduced alongside credible public transport and active mode options and include measures to address impacts on households with limited alternatives.

Targeted lower-speed environments should be used where they materially improve safety and enable walking, cycling and micromobility. Lower posted speeds are most effective when accompanied by street design, traffic calming and reallocation of road space, rather than relying solely on signage. Auckland's Transport Emissions Reduction Pathway identifies safe speeds as part of the package required to support active travel and reduce deaths and serious injuries.

Secure bicycle parking should be treated as part of the transport network. Council should expand destination facilities at council buildings, town centres, libraries, transport interchanges and other high-use sites. Facilities should reflect the volume and duration of parking expected and can include secure cages, covered stands, charging for e-bikes and space-efficient double-stacked systems where demand and building configuration support them.

Council could investigate area-based measures that encourage cleaner and more efficient transport, particularly in locations with high traffic volumes and exposure to air pollution. International examples include low-emission zones, which use vehicle emissions standards and charges to discourage higher-emitting vehicles from entering specified areas. London's Ultra Low Emission Zone (ULEZ) is an example that led to reductions in traffic-related emissions (Greater London Authority, 2025). Any Auckland application would need to reflect New Zealand's legislative and regulatory settings, but Council could assess whether similar approaches could support emissions reduction, air quality and mode-shift objectives.

11.3.4 Funding

Auckland Council could support implementation of the Ratepayer Assistance Scheme for energy efficiency and electrification (mooted by the current government as the "Home Energy Fund," with variants being proposed by other political parties), subject to the final national design and enabling legislation. The scheme could allow eligible property owners to spread the cost of solar panels, efficient electric appliances, insulation and other approved improvements over a longer period. Council should advocate for a design that includes consumer protections, quality standards and accessibility for households that face the greatest financial barriers.

The scheme will not address all equity issues. Renters, low-income owner-occupiers and households unable to take on additional repayments may require targeted grants or other forms of assistance. Council should work with central government, EECA, community organisations, and energy providers to ensure financing mechanisms do not primarily benefit households already able to invest.

11.3.5 Council investment and procurement

Auckland Council should adopt a portfolio-wide energy transition plan for its property and infrastructure assets. This should prioritise energy efficiency, replacement of fossil-fuel equipment at the end of its useful life, demand management and resilience. Forward planning would allow upgrades to be coordinated with normal renewals rather than undertaken as emergency replacements.

Public buildings should be used as visible demonstrations of practical transition measures. Priority actions include improving thermal and electrical efficiency, installing destination chargers where there is a

clear public or fleet need, and providing secure bicycle parking, changing rooms and other end-of-trip facilities for Council employees and visitors.

Procurement can extend Council's influence beyond its own assets. Bus, waste collection, maintenance, construction and other service contracts should progressively include requirements or evaluation criteria for low emissions vehicles, energy efficiency and credible transition plans. Requirements should be signalled early enough for suppliers to plan fleet replacement and supporting infrastructure. Auckland's existing transport pathway identifies procurement requirements as a practical mechanism for accelerating electric vehicles and low-emissions public transport (Auckland Council, 2022). Auckland Transport has already shown considerable leadership (to great success) along these lines by targeting a zero tailpipe emissions bus fleet by 2035, no further procurement of diesel buses for public routes, and passing these requirements on to its bus operators.

Demonstration projects should test measures that may later be scaled, including managed fleet charging, solar and battery systems at community facilities, flexible electricity connections, neighbourhood energy initiatives and integrated charging hubs. Projects should have clear learning objectives and publish results on costs, utilisation and performance.

11.3.6 Convening

Council should establish a continuing partnership forum that brings together electricity transmission and distribution companies, Auckland Transport, gas infrastructure providers, central government, major users, developers, mana whenua and community representatives. Its purpose should be practical coordination rather than general engagement. It should identify infrastructure hotspots, major connection requirements, sequencing conflicts, workforce constraints and decisions that require escalation to national agencies.

Council should coordinate with central government on matters where regional outcomes depend on national settings, including electricity market arrangements, building regulation, transport funding, congestion charging, gas network regulation and household transition assistance.

Industry collaboration should initially focus on locations or sectors where several businesses face similar transition decisions. Coordinated planning can allow network providers to assess combined demand, identify shared infrastructure options and reduce the risk that firms make incompatible or poorly sequenced investments. EECA's Auckland RETA analysis similarly identifies coordination between industrial sites and network providers as important where the combined effect of electrification influences the timing and cost of network upgrades (EECA, 2025).

11.3.7 Information

Council could facilitate the sharing of spatial information on expected growth, electricity constraints, planned network investment, major charging demand, gas use and industrial transition requirements. Data should be sufficiently detailed to inform planning while protecting commercially sensitive and personal information.

Public information should help households and businesses understand likely future energy choices, available assistance and the implications of replacing gas or liquid fuel equipment. Information should be coordinated with EECA, electricity distributors, electricity retailers and consumer organisations so that messages are consistent and consumers are not directed towards assets that may become costly or difficult to use.

A public monitoring dashboard should report progress against the indicators in Section 11.8 and explain significant changes. Reporting should distinguish between trends Council can directly influence and outcomes mainly determined by national policy or market conditions.

11.3.8 Advocacy

Auckland Council should advocate for national regulation that supports timely electricity investment, efficient connections, flexible demand and fair allocation of transition costs. National settings should allow infrastructure providers to invest before constraints become severe where the benefits of doing so are sufficiently robust across plausible futures.

Electricity market advocacy should focus on outcomes rather than prescribing a particular market structure. The priorities for Auckland are arrangements that improve long-term investment confidence, reward demand flexibility, enable distributed resources to provide network and system services, and protect consumers from inefficient cost shifting.

Gas transition advocacy should seek a clear national direction, transparent information for consumers, fair treatment of remaining gas users and a credible approach to network depreciation, disconnection and eventual decommissioning costs. An unmanaged decline could expose remaining consumers to rising charges and create incentives for further disconnection, increasing both equity and asset stranding risks.

11.4 Quick wins (0-5 years)

The first five years might concentrate on actions that improve information, reduce immediate demand, use existing Council powers and prepare for larger investments. These are no-regrets actions that are justified under every future energy scenario.

1. Establish the Auckland energy transition partnership and agree a rolling regional implementation programme.
2. Incorporate electricity capacity, gas-transition risk, and transport energy requirements into the Future Development Strategy, structure planning, and infrastructure sequencing processes.
3. Undertake a spatial audit of road reserves, parking facilities and other Council-controlled land to identify suitable sites for public and fleet electric vehicle charging. Priority should be given to locations that support apartments, commercial fleets, public transport, community access or known gaps in private charging provision.
4. Require new or renewed Council contracts for waste collection and other suitable vehicle-based services to include low-emissions fleet requirements and charging or fuelling plans. Requirements should reflect vehicle availability and whole-of-life costs and should be signalled in advance of procurement.
5. Continue implementing energy audits and transition plans for Council buildings, including energy-efficiency improvements, replacement of fossil-fuel equipment, destination charging, secure bicycle parking and end-of-trip facilities.
6. Support implementation of the Ratepayer Assistance Scheme and develop complementary assistance for low-income households and rental properties.
7. Develop a coordinated public information programme on energy efficiency, electric appliances, gas replacement, rooftop solar, batteries and managed charging.
8. Identify priority industrial clusters and major sites where fuel-switching decisions may require coordinated electricity-network investment, flexibility or shared infrastructure.
9. Develop regional standards and procurement templates for managed charging, solar, batteries and flexible electricity demand in Council projects.
10. Establish baseline measures for monitoring indicators and publish an initial regional energy dashboard.

11. Review district plan provisions affecting electricity infrastructure, electric vehicle charging, renewable generation, walking and cycling facilities, and new fossil gas connections.
12. Advocate, with NZGBC and other partners, for stronger disclosure of building energy performance at the point of sale or lease, including wider use of NABERSNZ for commercial buildings and an appropriate equivalent for homes.
13. Investigate whether preferential consenting, development incentives or other Council processes could encourage higher-performance residential development, including Homestar-certified.
14. Work with industry and training providers to upskill plumbers, electricians and other building-services trades about efficient electric alternatives.
15. Engage with banks and other finance providers on ways verified building energy performance could be reflected in mortgage products, retrofit finance or other lending incentives.

11.5 Medium-term priorities (5-15 years)

The medium term is likely to contain the most intensive period of transition. Gas availability and network viability risks may become more pronounced while transport, building and industrial electrification increase electricity demand. Actions shift from pilots and planning to coordinated delivery at scale. The following actions have two purposes: moving Auckland towards the “Compact and Efficient” scenario, and building contingency capacity if actual conditions begin to resemble “Expansion” or “Electricity Stress.” The recommended priorities are:

1. **Direct growth towards infrastructure-efficient locations.** Council should use spatial planning and infrastructure sequencing to concentrate development in areas that can be efficiently served by existing or planned transport, electricity and other infrastructure. Plans should be updated as development patterns, technology uptake and peak demand become clearer.
2. **Support and enable building retrofits.** Council should improve its own buildings, support retrofit and financing programmes where feasible, target assistance towards lower-income households and renters, and advocate for stronger national standards and funding. Retrofit support should encourage insulation, efficient electric systems, smart controls and suitable distributed energy technologies.
3. **Expand energy efficient transport options.** Auckland Transport should continue improving frequent public transport, bus priority, cycling connections, walking networks and low emissions fleets. Council should also support travel demand measures where statutory authority, funding and viable alternatives are available.
4. **Enable coordinated charging infrastructure.** Council should use transport planning, parking management, consenting, procurement and Council-controlled land to support charging provision. It should work with network providers, charging operators and major users to encourage managed charging and avoid unnecessary peak-demand pressure.
5. **Support industrial transition delivery.** Council should convene businesses, EECA, network providers and central government to help align efficiency projects, fuel-switching plans, major connections and infrastructure requirements. Technology and investment decisions would remain with businesses and energy providers.
6. **Support an orderly gas transition.** Council should avoid increasing gas dependence through its own assets and planning decisions, prepare Council facilities for declining gas availability, provide clear regional information, and advocate for coordinated national arrangements for consumer switching and residual network costs.

7. **Facilitate alignment between network investment and non-network solutions.** Council should share growth and land-use information, coordinate with Transpower and electricity distributors, and support flexibility, storage, managed demand and distributed energy where these may reduce or defer conventional network investment. Responsibility for network investment decisions remains with the relevant infrastructure providers.

11.6 Long-term system shifts (15-25 years)

By the 2040s and around 2050, the objective should be to have moved beyond a collection of individual transition projects to a substantially different regional energy system:

1. **Enable a more flexible electricity system.** Council should support managed charging, batteries, thermal storage, distributed generation and demand response through its planning, procurement, property portfolio and partnership activities. It should also advocate for pricing and market arrangements that reward consumers for providing flexibility.
2. **Manage the residual phase of the gas transition.** By this stage, the transition away from widespread fossil-gas use should be largely complete. Council's role should be to minimise any remaining gas reliance in its own assets, support affected households and businesses where practical, and advocate for an equitable approach to residual users, network repurposing and decommissioning.
3. **Improve building energy performance.** Council should continue to improve the efficiency of its own buildings, support retrofit programmes, target assistance towards energy-burdened households where funding allows, and advocate for stronger national building standards. It can also encourage higher voluntary performance through procurement, partnerships and demonstration projects.
4. **Integrate transport, energy and land-use planning.** Auckland's spatial and transport planning should reduce travel distances and improve access by public transport, walking and cycling. Council should align growth planning, charging infrastructure, transport investment and information on electricity-network capacity as closely as possible.
5. **Enable proven emerging technologies.** Council should monitor new technologies, remove avoidable local barriers, support trials and adopt proven options within Council assets where they provide clear value. These may include vehicle-to-grid services, advanced storage, smart-grid technologies, low-emissions freight solutions and community energy models.
6. **Strengthen the resilience and adaptability of Council-controlled infrastructure.** Council assets and services should be designed to withstand climate hazards and adapt to changing technologies and demand. Council should also work with infrastructure providers to support backup arrangements for critical services and improve coordination across energy, transport and land-use systems.

11.7 Partnership opportunities

Delivery should be organised around the decisions and assets controlled by each partner, rather than around a single Council-led programme.

- **Central government and regulators.** Partnership is required on electricity market reform, gas transition policy, building regulation, transport pricing, infrastructure funding, household assistance and consumer protection. Auckland Council should provide regional evidence and clearly communicate where national settings are creating barriers to timely action.
- **Auckland Transport and NZ Transport Agency Waka Kotahi.** These organisations should work with Council on public transport investment, walking and cycling networks, congestion

management, charging infrastructure, fleet transition and integration of transport with growth planning.

- **Transpower.** Coordination should focus on Auckland's long-term demand outlook, major grid investments, resilience, industrial connections and the implications of different regional growth and electrification pathways. Council can help by sharing growth information, coordinating corridors and land access, and ensuring that planning decisions recognise electricity requirements.
- **Vector and Counties Energy.** Partnership should cover growth planning, connection forecasts, flexibility, charging, distributed energy, consumer information and targeted programmes in constrained locations. Council can help by sharing growth information, coordinating corridors and land access, and ensuring that planning decisions recognise electricity requirements.
- **Gas infrastructure providers and national gas institutions.** Engagement should focus on the likely pathway for gas demand, the treatment of new connections, information for consumers and businesses, network cost recovery and eventual decommissioning.
- **EECA.** EECA is a natural partner for industrial energy assessments, process heat transition, building efficiency, consumer information, flexible demand and the design of financial or technical assistance.
- **Mana whenua.** Partnership with mana whenua should extend from consultation to co-design and, where appropriate, ownership of initiatives. Opportunities may include community energy, marae resilience, distributed generation, skills development and investment models that reflect Māori aspirations and tikanga.
- **Businesses, developers and industry associations.** Council should work with these partners on major connection requirements, industrial transition clusters, efficient new development, charging infrastructure, workforce needs and demonstration projects. Early communication can reduce the risk of simultaneous projects competing for equipment, contractors and network capacity.
- **Community organisations and finance providers.** These organisations can help reach households that are poorly served by conventional information or lending channels. They may also support collective purchasing, community energy, targeted retrofit programmes and trusted consumer advice.
- **Education and training providers.** Universities, wānanga, polytechnics and industry training organisations should help build the workforce required for electrical, building performance, charging, network and industrial transition projects.

11.8 Monitoring progress

Auckland Council should establish a concise set of indicators that show whether the regional transition is improving energy affordability, resilience and emissions outcomes. Indicators should be reported at least annually where data permit and reviewed every three to five years to determine whether actions or targets need to change.

Actual outcomes should be benchmarked against the updated PC120 reference projection but also checked against the other scenarios. Where indicators diverge materially from the preferred pathway, Council and partner agencies should review whether actions, investment sequencing or targets need to change. The following Table 9 describes a suggested set of indicators.

Table 9: Proposed transition monitoring indicators

Area	Indicator
Public transport	Proportion of residents and jobs within convenient walking distance of frequent public transport; service coverage, frequency and reliability.
Electricity use	Total Auckland electricity demand, demand per resident and demand by major sector.

Peak demand	Regional and sub-regional electricity peak demand, including the contribution of managed and flexible loads.
Network readiness	Connection lead times, forecast constraint locations, major upgrade timing and capacity made available through flexibility.
Gas transition	Total gas demand, number of active connections, disconnections, new connections and the distribution of demand between households, commercial users and industry.
Electric vehicles	Light and heavy electric vehicle uptake, public charging availability, fleet charging capacity and the proportion of charging that is managed.
Rooftop solar and batteries	Installed capacity, number of systems, geographic distribution and participation by lower-income households and community organisations.
Urban form	Dwelling growth, share of multi-unit housing, average dwelling floor area.
Building performance	Number and proportion of buildings retrofitted, energy use intensity, fossil fuel equipment replacement and measures of indoor environmental quality where available.
Transport behaviour	Mode share, vehicle kilometres travelled per capita, walking and cycling activity and household access to low-cost transport alternatives.
Emissions	Transport, electricity and stationary energy emissions, reported separately to avoid changes in grid emissions obscuring changes in regional energy use.
Affordability	Household electricity, gas and transport energy expenditure as a share of income, disconnection or hardship indicators, and differences across household groups.
Council leadership	Council operational energy use, fleet emissions, building retrofit progress, renewable generation and procurement-related emissions.

Regional averages should be supplemented with distributional and spatial analysis. An improvement in average household energy costs could conceal worsening hardship for particular communities, while adequate regional electricity capacity could conceal local constraints affecting growth or industrial investment. Monitoring should therefore identify outcomes by location, income, tenure and other relevant characteristics where data and privacy requirements allow.

The monitoring framework should inform action rather than serve only as public reporting. Significant divergence from the expected pathway should trigger review. Examples include faster-than-expected gas disconnections, growth in unmanaged peak electricity demand, delayed network upgrades, falling public transport accessibility or increasing household energy hardship.

11.9 Overall pathway

The pathway can be summarised as a sequence of “prepare”, “scale” and “complete.”

During the first five years, Auckland should establish governance and monitoring, integrate energy into spatial planning, reduce immediate demand, use Council procurement and assets to demonstrate change, and prepare coordinated plans for charging, industrial electrification and gas transition.

Over the following five to fifteen years, the focus should move to delivery at scale. This includes building retrofits, public and active transport, managed charging, electricity network investment, flexible demand, industrial fuel switching and support for households and businesses moving away from gas.

Over the final fifteen to twenty-five years, Auckland should consolidate the system transition. The desired outcome is a compact and accessible city supported by a high-performance building stock, a mature flexible electricity system, substantially reduced fossil gas use and infrastructure that is resilient to climate, supply and technology risks.

This pathway does not depend on accurately forecasting a single future. It prioritises measures that perform well across a range of plausible futures and retains the ability to adjust the timing and scale of investment as new information emerges.

The pathway can also be summarised using two dimensions: the timing of action and Auckland Council's degree of influence relative to the action's system-wide impact. The temporal sequence is "prepare", "scale" and "complete", while the 2×2 framework in Table 10 distinguishes actions Council can lead directly from those requiring partnership, advocacy or enabling support.

Table 10: Classification of actions by system-wide impact, Auckland Council influence and implementation timeframe

	Lower Council influence	Higher Council influence
High system impact	***Partner and advocate*** **Quick wins (0-5 years)** • Establish an Auckland energy partnership. • Support transition finance and household assistance. • Coordinate industrial transition planning. • Advocate for stronger building energy-performance disclosure • Work with industry and training providers to upskill trades. **Medium term** • Expand managed EV charging. • Coordinate and support industrial fuel switching. • Advocate for and coordinate an orderly gas transition. • Facilitate coordination on network upgrades and flexibility. **Long term** • Support the development of a flexible electricity system. • Support an orderly and equitable exit from fossil gas.	***Lead and prioritise*** **Short term** • Integrate energy into spatial and infrastructure planning. • Review planning rules affecting energy infrastructure and gas connections. • Establish regional monitoring. • Investigate preferential consenting for high performance development **Medium term** • Direct growth to infrastructure-efficient locations. • Support and enable building retrofits. • Expand public and active transport. • Introduce travel demand measures. **Long term** • Integrate transport, energy and land-use planning. • Advocate for stronger national building standards and support higher voluntary performance. • Build resilient and adaptable infrastructure.
More targeted impact	***Monitor and enable*** **Short term** • Provide public energy information. • Engage with banks on finance incentives for efficient homes and retrofits **Medium term** • Enable biomass for suitable industrial uses. **Long term** • Monitor and enable uptake of emerging technologies.	***Implement and demonstrate*** **Short term** • Enable EV charging on Council land and road reserves. • Use low emissions procurement. • Council building audits and end-of-trip facilities. • Develop standards for solar, batteries and managed charging. • Investigate preferential consenting **Medium term** • Scale successful Council pilots. **Long term** • Maintain Council assets as demonstration projects.

12 Conclusions

Auckland's energy transition is already underway, but its eventual cost, pace and distributional effects are not predetermined. Decisions made over the next decade about urban growth, transport, buildings, electricity infrastructure, gas and industrial investment will shape the region's energy requirements well beyond 2050. The central conclusion of this study is that Auckland will achieve better outcomes by managing these interactions as a regional system rather than addressing each fuel, sector, or infrastructure network separately.

12.1 Key Findings

The scenarios demonstrate that there is no single inevitable pathway for Auckland. Population and economic growth increase the need for energy services in every future considered, but the amount of energy required, the fuels used and the resulting infrastructure pressures depend substantially on choices about urban form, transport, efficiency, electrification and flexibility.

The Reference pathway would continue the gradual shift towards electricity while leaving several important risks unresolved. Electricity demand and peak loads would grow, the decline of gas would require increasing numbers of consumers to make replacement decisions, and transport would remain materially exposed to imported liquid fuels. Moderate improvements in technology and efficiency would not on their own resolve the need for greater infrastructure coordination.

The updated PC120 reference shows that stronger household and economic growth does not necessarily lead to a proportional increase in energy demand. Smaller dwellings and a greater share of multi-unit housing help offset the additional residential demand, while changes in the economy affect the distribution of energy use across sectors. However, the scenario retains broadly business-as-usual assumptions for electrification, transport mode shift and demand management. The results therefore distinguish between the benefits of compact development and those that depend on system changes.

The "Compact and Efficient" scenario offers the most favourable overall direction. It shows that Auckland can support population and economic growth while moderating total energy demand through more efficient buildings, lower vehicle travel, greater use of public and active transport, distributed energy and smarter management of electricity demand. It is not an infrastructure-light pathway, but it directs investment towards assets and services that provide broader economic, accessibility, affordability and emissions benefits.

The alternative scenarios illustrate the consequences of failing to coordinate the transition. "Expansion" increases the energy and infrastructure required to serve a more dispersed city. "Electricity Stress" shows that rapid electrification can create significant peak demand and connection pressures when efficiency, distributed resources and flexibility do not develop at the same pace. "Fuel Diverse" reduces some near-term electricity pressures but prolongs dependence on gas and liquid fuel systems, leaving Auckland more exposed to supply uncertainty, price volatility, residual emissions and the costs of maintaining parallel infrastructure. The key distinction is therefore not simply between faster and slower electrification. It is between a coordinated transition and one in which energy demand, infrastructure and technology adoption develop out of sequence.

Consistent with the philosophy underpinning Transpower's Te Kanapu programme, Auckland should prioritise measures that perform well across multiple plausible futures rather than relying on a single forecast. These include improving energy efficiency, enabling flexible demand and distributed energy resources, coordinating land use with infrastructure investment, reducing barriers to timely network expansion and avoiding new dependence on assets that may become stranded. Te Kanapu similarly uses scenarios to identify low-regrets investments that remain valuable across uncertain future conditions while preserving the ability to adapt as demand and technology change (Transpower, 2026).

The findings also reinforce that responsibility for Auckland's energy future is distributed. Auckland Council can strongly influence the location and form of growth, transport options, infrastructure sequencing, procurement and the performance of its own assets. It cannot independently determine electricity generation, energy market regulation, gas policy or private investment. Successful implementation will require sustained collaboration with central government, regulators, Auckland Transport, Transpower, Vector, Counties Energy, EECA, businesses, mana whenua, and community organisations.

12.2 Strategic Messages

Auckland's largest energy decisions are not confined to the energy sector. Land use and transport decisions determine travel requirements, building types, infrastructure utilisation and the location of future electricity demand. The PC120 reference scenario reinforces this finding. Integrating energy considerations into spatial planning is therefore likely to have greater long-term value than addressing infrastructure constraints only after development has occurred.

Managing the pace and sequencing of change matters as much as the final technology mix. Electrification is likely to be central to Auckland's transition, but poorly coordinated electrification could increase costs and delay connections. Efficiency improvements, demand flexibility, distributed energy and timely network investment need to develop alongside fuel switching.

Reducing demand through efficiency can substitute for part of the required infrastructure expansion, as can demand flexibility. Building performance, compact growth, lower vehicle travel and efficient industrial processes can reduce the generation, transmission, distribution and charging capacity required to provide the same services. Energy efficiency should consequently be treated as an infrastructure option, not merely as a consumer or climate initiative.

Electricity resilience does not require Auckland to become energy self-sufficient. Auckland will continue to depend heavily on the national electricity system. Its resilience will come from strong transmission and distribution connections, diverse national generation, flexible demand, distributed resources and appropriate backup for critical services. Local solar, batteries and community energy can strengthen this system, but they do not remove the need for timely investment in national and regional networks.

The gas transition requires an orderly end state. Uncertainty about future gas availability and network viability risks delaying business investment while increasing costs for consumers who remain connected. A clear transition framework is needed so that households and firms can plan replacement investments, infrastructure providers can manage declining demand, and residual costs are not unfairly concentrated on the last users.

Council could also work to minimise long-term exposure to gas-network risks by investigating whether planning provisions can restrict the extension of reticulated gas networks into new developments - subject to legal advice and alignment with national policy.

Affordability and equity are conditions for a successful transition. Many efficient electric technologies offer lower lifetime costs but require upfront investment. Without suitable financing, assistance and protections, lower-income households, renters and small businesses may be unable to participate and could remain exposed to increasingly costly legacy fuels and assets.

Debate about electricity market structure should not distract from the more immediate issues affecting Auckland's energy future. Changes to ownership or market arrangements may influence particular outcomes, but Auckland's key challenges are securing timely investment in generation and networks, improving demand flexibility and efficiency, managing the gas transition, and coordinating energy with land use and transport. These priorities remain important under

a wide range of national market structures and are more directly relevant to the levers available to Auckland Council.

Auckland should pursue the “Compact and Efficient” direction while remaining prepared for other outcomes. The preferred pathway provides a strategic destination, not a prediction. Plans should retain sufficient flexibility to respond if actual trends begin to resemble “Expansion”, “Electricity Stress” or “Fuel Diverse” conditions.

12.3 Next Steps

12.3.1 Further analysis

This report provides a regional framework for decision-making rather than a detailed implementation or investment plan. Further work should progressively translate the scenario findings into location-specific and organisation-specific decisions.

Incorporating the results of Auckland Council's updated transport modelling, particularly the implications for private vehicle travel, fleet size, transport infrastructure costs and emissions would help resolve some of the remaining uncertainty in the PC120 reference scenario.

Priority areas include more detailed spatial analysis of electricity demand, network constraints and major future loads; refinement of infrastructure costs and delivery timeframes; assessment of the distributional effects on different households, businesses and communities; and coordinated transition planning for major industrial gas users. Further analysis should also examine how the preferred pathway interacts with specific growth areas, transport programmes, electricity network investment plans and the potential emergence of large discrete loads such as data centres.

Detailed business cases will still be required before significant expenditure is committed by the responsible organisations. These should test conventional infrastructure against efficiency, flexibility and other non-network alternatives, account for uncertainty in demand, and identify how costs and risks should be allocated among beneficiaries.

Further analysis could integrate the scenarios with macroeconomic or system dynamics models to assess wider effects on productivity, household welfare, industry competitiveness, investment and employment, while capturing feedback loops between land use, infrastructure, prices and technology uptake.

12.3.2 Monitoring indicators

Auckland Council should establish the monitoring framework described in section 11.8 and assign responsibility for collecting and reporting each indicator. Actual outcomes should be benchmarked against the trajectories projected under the scenarios, rather than assessed only against fixed targets.

Annual reporting should identify whether Auckland is moving towards the “Compact and Efficient” pathway or displaying early signs of “Expansion”, “Electricity Stress” or “Fuel Diverse” outcomes. A more comprehensive review every three to five years should assess whether changes are required to policies, investment sequencing, partnerships or targets. Monitoring should function as an early-warning and decision-support system, not simply as retrospective reporting.

12.3.3 Future updates

The scenario analysis should be updated as new information becomes available. Important triggers include revised population and land use projections, changes to national energy and climate policy, updated electricity and gas outlooks, new network asset management plans, major industrial investments and material changes in technology costs.

Updates should retain a consistent core set of scenarios where possible so that changes over time can be distinguished from changes in modelling assumptions. New scenarios or sensitivities

can be added where developments materially alter Auckland's outlook. The report should also be reviewed alongside future versions of the Future Development Strategy, Regional Land Transport Plan and Council long-term planning processes so that energy implications are incorporated into decisions as they are made.

The transition will extend across several investment and political cycles. Auckland does not need certainty about every aspect of its 2050 energy system before acting. It does, however, need a durable direction, clear institutional responsibilities and a process for adjusting decisions as evidence changes. By pursuing low-regrets actions now, monitoring the pathway and coordinating investment across sectors, Auckland can reduce the risk of costly constraints while creating a more secure, affordable and lower-emissions energy system.

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APPENDICES

A 2050 Sankey diagrams for scenarios

Figure 108: Compact and Efficient Sankey showing 2050 energy use in terajoules by source, sector, and end use

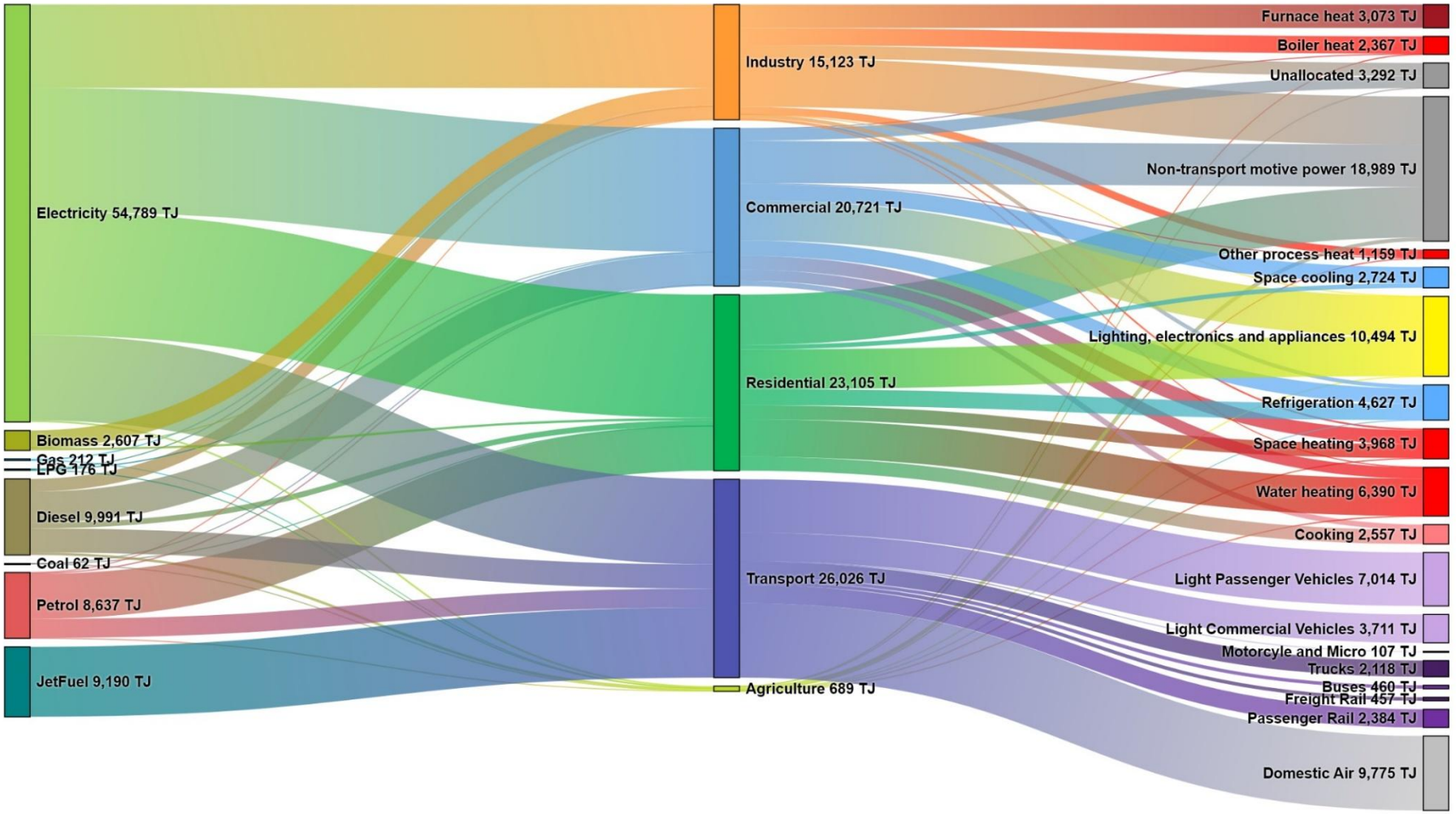


Figure 109: Expansion Sankey showing 2050 energy use in terajoules by source, sector, and end use

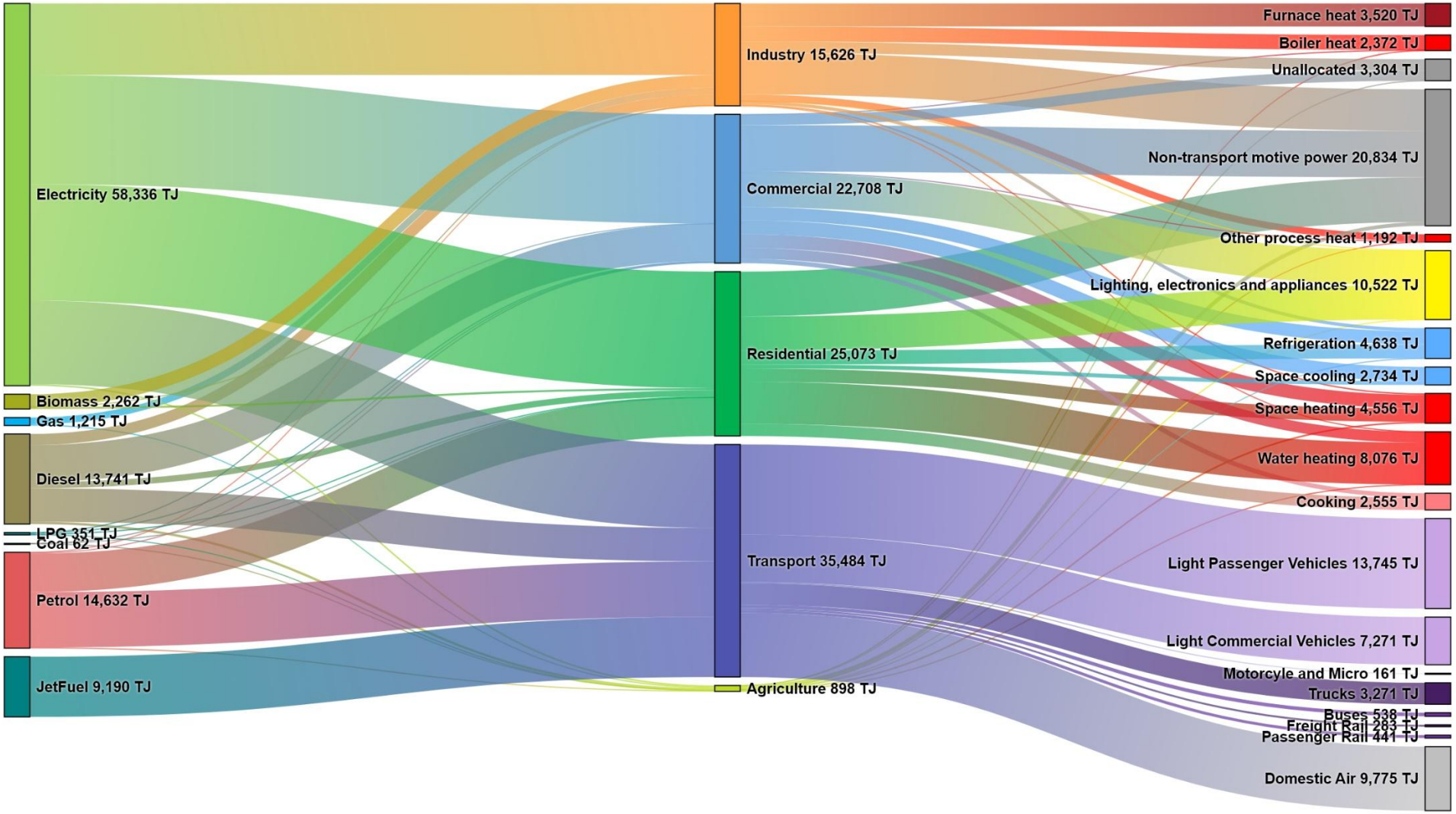


Figure 110: Electricity Stress Sankey showing 2050 energy use in terajoules by source, sector, and end use

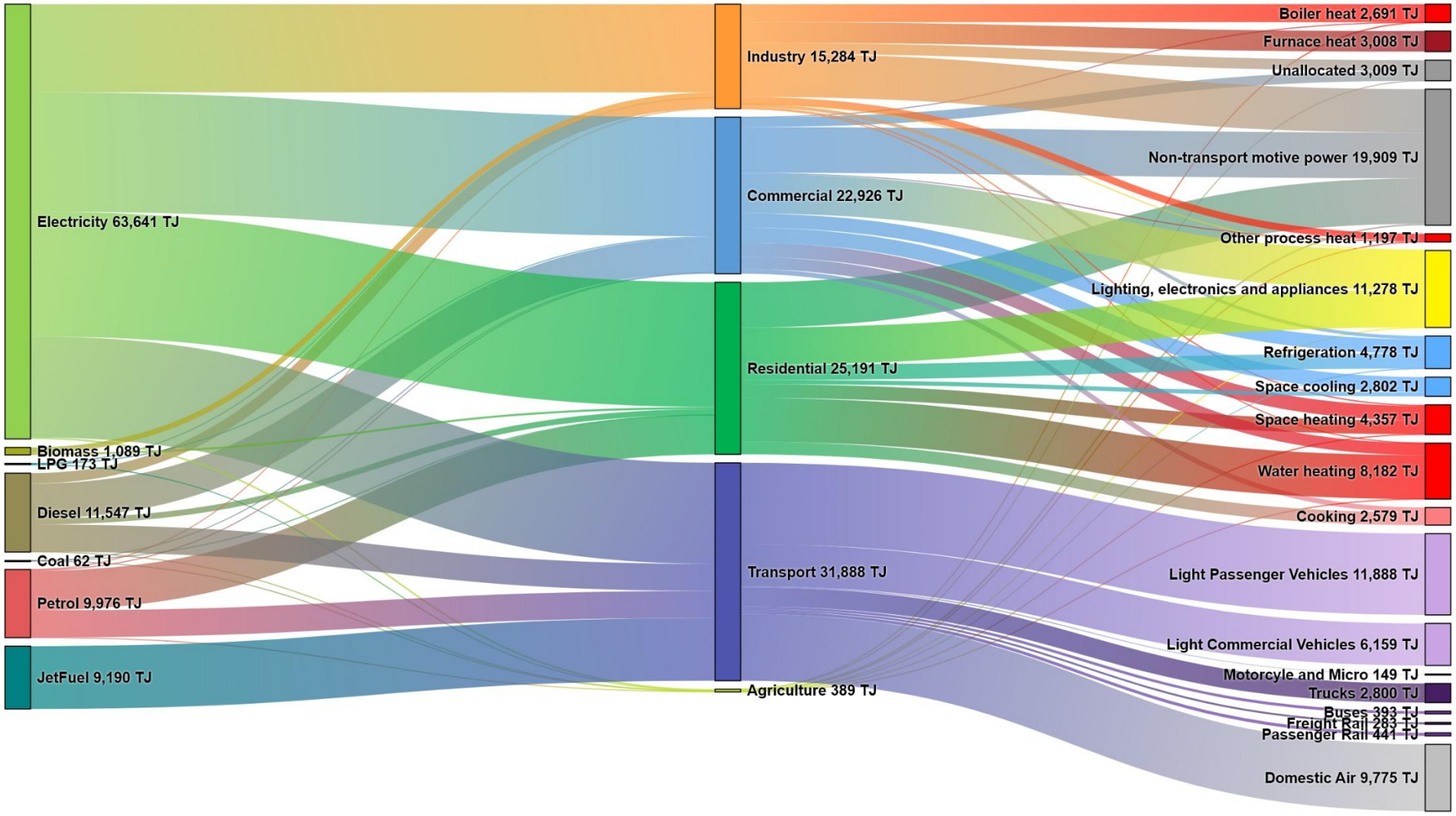
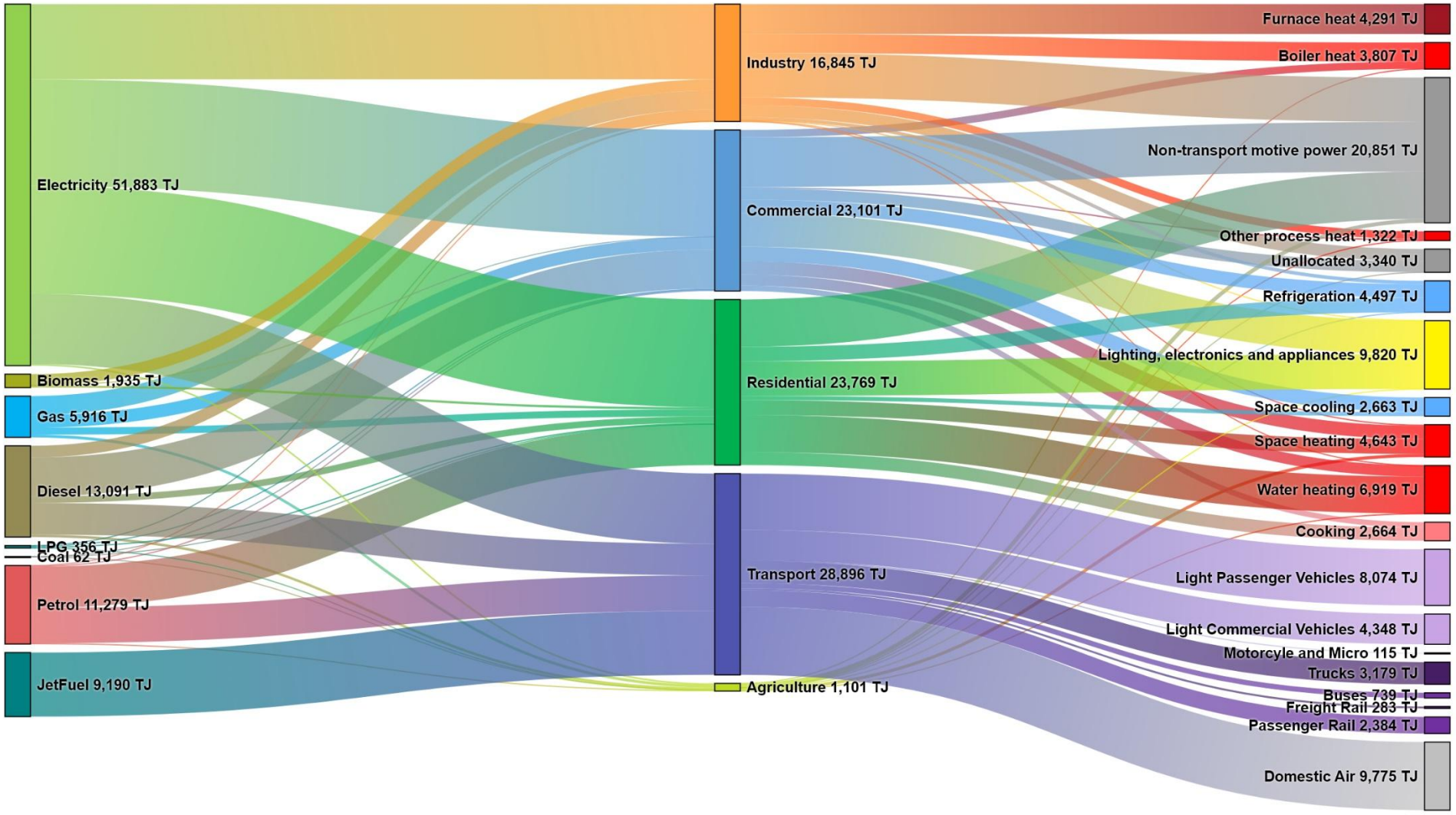


Figure 111: Fuel Diverse Sankey showing 2050 energy use in terajoules by source, sector, and end use



B Costs of electricity network expansion

B.1. Distribution networks

We have estimated the demand-driven costs of expanding Auckland's distribution networks to be approximately $126/kW/yr.

In other words, in the long run, the costs of each extra MW of peak demand on a distribution network will result in an increase in costs of: 1 MW x $126/kW/yr = $126,000/yr.

This represents the value that could be achieved if arrangements to deliver 'smart' demand outcomes were able to reduce the average peak MW demand on a sustained basis.

The derivation of this $126/kW/yr value is as follows.

The annual Commerce-Commission reported non-Opex revenue requirement was summed across all EDBs for each year from 2013 to 2024, inclusive – ie, the annual revenue for a year less the Opex spend for that year.

This covers the return on capital, return of capital (ie, depreciation) and tax cost for a distributor's asset base. Depreciation reduces the asset base, while capital expenditure adds to the asset base. The asset base is revalued annually for inflation, with an offsetting adjustment to revenue. This captures the accumulated impact of all capital spend not recouped through up-front contributions (ie, capital or in-kind contributions), including:

- The portion of new connection costs not recovered up-front.
- Building new network capacity to meet system growth, including due to connection growth or growth in per-connection peak demand.
- Renewing / replacing existing network assets that have reached the end of their economic life.
- Other capital investments, including re-locating network assets, reliability/safety/environment costs, and non-network assets.

For each historical year the values were adjusted for CPI so that all values are in 2024-dollar terms.

These annual capital costs were divided by the sum across all distribution networks of the reported peak demand values for each year. The average across the resultant $/kW values for each of the twelve historical years is approximately $240/kW/yr.

This represents a reasonable first-order estimate of the annualised capital costs of an 'average NZ' distribution network built to meet current levels of average consumer peak demand.

However, not all of the costs of building a network are driven by the level of demand. A significant proportion of the costs are independent of demand.

For example, the costs of poles or trenches are driven by the km of coverage, not by the MW capacity of the lines run along such poles or trenches.

Likewise, there are fixed costs associated with transformers and lines, such that the costs of such assets do not scale directly in proportion to their MW capacity plus, in the case of lines, km coverage is also a significant driver.

In this respect, $/kW is just one metric to consider the costs of electricity networks. Equally, $/km is another useful metric, or $/connection. All are useful metrics, but none are complete explanatory metrics of the drivers of network costs.

The Christchurch electricity network, Orion, has undertaken analysis[30] estimating that approximately 55% of the capital costs of

[30] Taken from Table 24 of 2025 pricing methodology found here: https://www.oriongroup.co.nz/assets/Our-story/Pricing/Orion-pricing-methodology-2025.pdf

their network are driven by peak demand (39% system peak demand, and 16% local peak demand for individual LV networks).

Assuming this 55% is broadly representative of the extent to which NZ distribution networks are driven by demand, multiplying the $240/kW/yr figure by 55% gives a value of $132/kW/yr.

A couple of cross-checks have been performed to determine whether this value is likely to be broadly representative.

1) the equivalent value for Orion's network is $140/kW/yr. This takes their quoted $102/kW/yr for system peak-driven long-run costs, and scales this up to account for the local peak-driven costs quoted by Orion.
2) the annualised $240/kW/yr cost was converted into an up-front cost of $3,704/kW. This 'de-annualisation' assumed that average network capital costs were annualised over a 45-year life using a 6% real discount rate (giving a 6.5% annualisation factor). This $3,704/kW compares with a quoted replacement cost per kVA of $3,228 from Orion.

These cross-checks suggest that the value is broadly representative.

It should be noted that the cost of building a network is likely to be different for different network situations. Thus, relatively higher levels of network undergrounding, or relatively fewer ICPs per km of network, is likely to increase the cost of building a network to meet the average per kW demand for that network.

Conversely, networks that have lower levels of undergrounding, or more ICPs per km of network, will tend to have lower $/kW costs. This is illustrated by Figure 112 and Figure 113 showing the variation between networks of the average non-opex revenue on a per peak kW and per km basis, respectively.

Figure 112: Average non-Opex revenue per peak kW

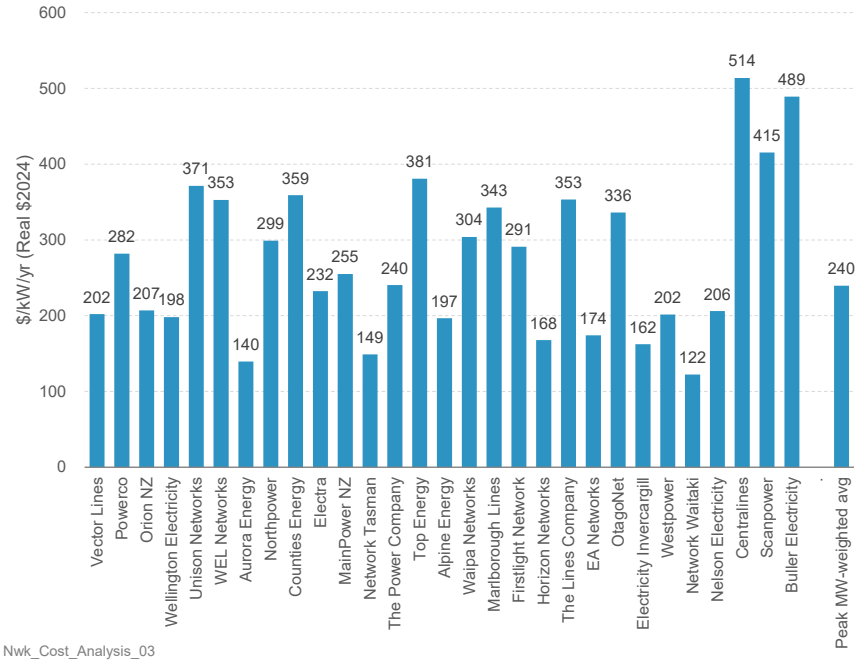
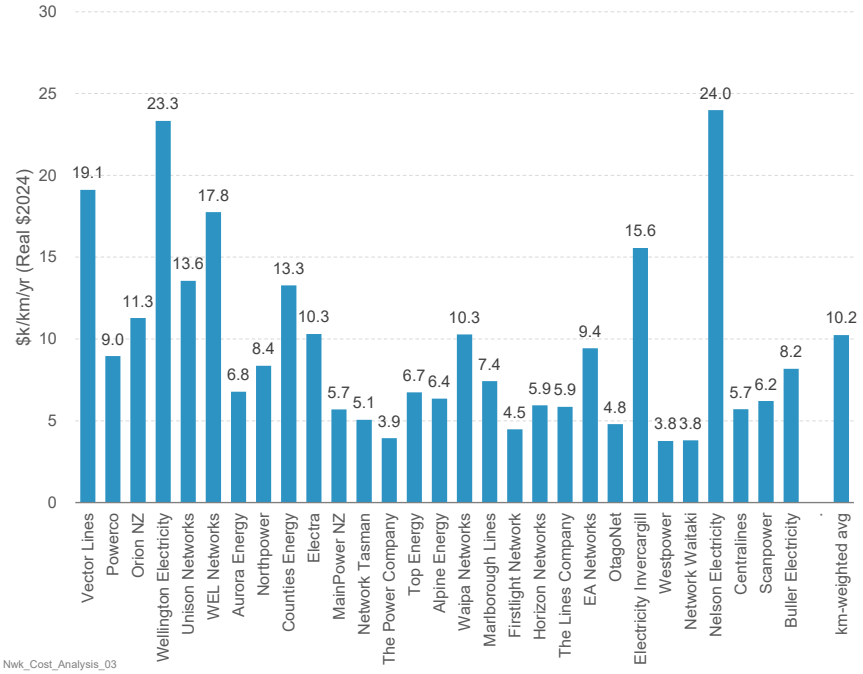


Figure 113: Average non-Opex revenue per km



The variation seen between networks is driven by their circumstances. The *demand-driven* components of such costs may not vary by as much. In other words, a dense network with relatively little undergrounding may have the *proportion* of costs driven by demand being higher than 55%, whereas a sparse network or one with higher levels of undergrounding may have the *proportion* of demand driven costs being lower than 55%, but the *$/kW* value of the demand-driven component of costs may be much more similar between networks.

This is because the demand-driven component of costs principally relates to the sizing of transformers and the capacity of lines, the variation of which with size is broadly the same across networks, whereas the costs of the infrastructure in which to install these assets varies much more significantly across network situations.

Based on all of the above, it is considered that $132/kW/yr is a reasonable estimate of the NZ-wide average distribution network costs of peak demand.

To create an Auckland specific value, we have adjusted the $132/kW/yr value by pro-rating based on the values for Vector and Counties in Figure 112, weighted by their relative demand sizes, relative to the $240/kW/yr whole-NZ value. This comes to $118/kW/yr. Inflating this 2024 value to 2026 dollars brings it to $126/kW/yr.

B.2. Transmission network

A similar exercise has been undertaken to evaluate the likely costs of peak demand on the transmission network. Thus, for the ten years of Information Disclosures by Transpower from 2015 to 2024:

- The non-opex revenue requirement was calculated, factored by the relevant CPI escalator to be in 2024 dollars.
- This was factored by the proportion allocated to distribution networks for 2024 (approximately 75%). This is intended to only consider Transpower's costs driven by EDBs, as opposed to generators or grid-connected large industrial consumers.
- This was divided by the Maximum Peak demand (MW) from distributor offtake GXPs.

The average of this value was $97/kW/yr – in contrast to the $240/kW/yr estimated for EDBs.

However, as with EDBs, not all the costs of building the transmission network are driven by peak demand. Indeed, whereas a value of 55% was used for EDBs, it is considered that a significantly smaller

percentage of Transpower costs are driven by peak demand. This is for two main reasons:

- Firstly, a significant amount of the capital costs of the transmission network are driven by the need to build assets to connect and transport the power from all the various generators (hydro, wind, solar, geothermal, thermal) that are built around the country. Thus, there is a considerable annual *GWh* driver, rather than peak MW, to this aspect of demand-driven transmission cost drivers. This is different to distribution networks. For example, consider a scenario where annual GWh demand was to grow by 50%, say, but smart demand management meant that peak MW demand did not grow.
  - There would still be a significant capital expenditure requirement for Transpower to build assets to connect and transport the power from all the new generators that would need to be built to meet this demand
  - In contrast, there would be little demand-driven requirements to invest to upgrade distribution networks.

  As a working assumption, we have assumed this GWh demand driver will halve the peak MW component of the transmission network demand driver compared to distribution networks.
- Secondly, the capital costs of the system operator more than doubles the proportion of non-network capital expenditure for Transpower compared to the EDBs – ie, it is 19% compared to 8% for EDBs.

Overall, this results in the proportion of transmission costs driven by peak demand falling from 55% to 22%. The resulting average peak demand-driven costs of transmission are $21/kW/yr, compared with $132/kW/yr for distribution networks. In 2026 dollars, this transmission cost is $22/kW/yr.