2024 Asset Management Plan Update

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Introduction

CEO Message

Caroline Ovenstone

> "Proactive investment is needed now, ahead of future demand."

Welcome to our 2024 Asset Management Plan Update (2024 AMP). On behalf of the Alpine team, I am proud to present an AMP that reflects our commitment to empowering our vibrant and thriving communities, now and for the future.

In my introduction to last year's AMP, I spoke about the rapidly changing energy sector and the need to think differently, plan better, and engage more with customers and key stakeholders. Over the past year, we have made great progress.

We have engaged extensively with our customers to better understand their energy needs. We have refined our planning processes and forecasting methodologies to better reflect the investment required to deliver network growth and resilience. Our amalgamation with our subsidiary field service provider NETcon Limited (NETcon) last year is just one example of how we are thinking differently about the opportunities and challenges in front of us.

During the year we contributed to EECA's 2023 'Mid-South Canterbury Regional Energy Transition Accelerator' (RETA) report. This report, together with the Boston Consulting Group's 2022 'The Future is Electric' report, confirms what our planning is showing – proactive investment is needed now, ahead of future demand.

During the year, we have strategically invested in various data sources, including data from the National Institute of Water & Atmospheric Research (NIWA) to enhance our understanding of the risks affecting the resilience and reliability of our network. With an increased understanding of our network's vulnerabilities, we have updated our asset replacement, renewal, and resilience investment plans. These revised plans are designed to proactively address vulnerabilities and bolster the resilience of our network against potential disruptions. Our forecast capital expenditure has significantly increased as a result of our revised plans and reflects our commitment to deliver these plans.

Parts of our network are nearing capacity limits and require large upgrades to deliver forecast growth. We have now included the additional expenditure to deliver these upgrades in our 2024 AMP forecasts. Our increased engagement with our customers has given us more certainty about consumer connection projects driving significant demand, which we have now included in our system growth capital expenditure forecasts.

Delivering this ambitious, but necessary, capital programme over the next ten years also requires increased investment in our digital systems and cyber security. Moving from traditional on-premise solutions, which would have been capital expenditure, to modern cloud-based solutions, has significantly increased our forecast non-network operating expenditure. We will also need an increased investment in our people, and their capabilities, as we deliver this capital programme.

This AMP allows us to prepare our network and our communities for a resilient, zero-carbon future.

About Alpine

As our core business we construct and maintain our electricity distribution network to continue to operate a successful electricity distribution business (EDB). We have 4,374 km of lines and cables, providing an essential service to more than 33,800 homes and businesses, serving approximately 48,500 people across our communities.

This document reflects our updated forecasts of the investment required to deliver a network that enables growth and decarbonisation, supports the connection of distributed generation (DG), is resilient, and delivers the quality of service our customers across South Canterbury expect.

This 2024 AMP acknowledges that providing long-term benefits for our customers and communities requires considerable network developments over the next ten years. This is partly because of the electricity sector's central role in contributing to Aotearoa's goal of a net-zero economy by 2050 through decarbonisation and increased renewable electricity generation; partly because of the widely recognised need for network resilience to climate change and cyber risks; and partly because of the unique makeup of our region and its economic activities.

Our unique region

As a region, South Canterbury is uniquely diverse and complex in electricity needs:

- Land use and economic activities: Dairy, sheep and beef, crop farming, significant food processing and other industrial operations, and high tourism activity in the Mackenzie District.
- Energy demand: Significant industrial process heat requirements combined with seasonal demand driven by irrigation.
- Geography and climate: Stretching from the alpine village of Aoraki/Mt Cook to the temperate coast at the Waitaki River.
- Population spread: One significant urban centre (Timaru) and many smaller towns and villages throughout the region as well as remote rural connections.
- 7 Grid Exit Points (GXPs).

Purpose of AMP update

> "AMP Purpose Statement: Our AMP provides transparency to our stakeholders, customers and our people in relation to how we make investment decisions and how our asset management practices support the decision-making process through the collection and use of data."

In April 2023 we published a comprehensive Asset Management Plan (2023 AMP), which is available on our website www.alpineenergy.co.nz. This 2024 AMP is structured to meet the disclosure requirements set out by the Commerce Commission in the Electricity Distribution Information Disclosure Determination 2012 (ID Determination). We have not duplicated the detailed explanations of our network and asset management planning approaches provided in our 2023 AMP. We encourage readers to refer to our 2023 AMP where greater detail and a glossary of key terms are included.

Our 2024 AMP is limited to providing updates on material changes to our 2023 AMP, including those relating to our network development plans, asset lifecycle management, and delivery plans.

- Chapter 1 provides a summary of how we are managing ongoing uncertainty, change and risk to deliver on our asset management and network development commitments. It provides examples of the strategic initiatives we are undertaking to improve our asset management maturity and support the delivery of our 2024 AMP and strategic outcomes.
- Chapter 2 provides the context for and details of the material changes to our 2023 AMP, including our demand forecasts, network development plans, asset lifecycle management, and delivery plan.
- Chapter 3 is an update of our capital and operational expenditure forecasts for our network for the 10-year planning period and summarises major variances to our capital and operating expenditure from our 2023 AMP.
- The Appendices include our updated Information Disclosure Schedules; forecast capital and operating expenditure, asset condition, forecast capacity and network demand, forecast interruptions and duration, explanatory notes on forecast information, and Directors' certification.

The 2024 AMP relates to our electricity distribution services and covers the planning period from 1 April 2024 to 31 March 2034.

Information Disclosure requirements

Our 2024 AMP is prepared in accordance with the Commerce Commission's ID Determination. The ID Determination requires that we publicly disclose an AMP update prior to 1 April 2024.

The ID Determination requires the AMP update to:

- Identify any material changes to the network development plans disclosed in the last AMP.
- Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP.
- Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b.
- Identify any changes to the asset management practices of the EDB.

We must also publicly disclose:

- the Report on Forecast Capital Expenditure in Schedule 11a
- the Report on Forecast Operational Expenditure in Schedule 11b
- the Report on Asset Condition in Schedule 12a
- the Report on Forecast Capacity in Schedule 12b
- the Report on Forecast Network Demand in Schedule 12c
- the Report on Forecast Interruptions and Duration in Schedule 12d.

Chapter 1

Certainty in uncertain times

Our 2023 AMP identified our key strategic influences.

A year on, we have more certainty about how we will respond to some of these. Developments over the last twelve months highlight their ongoing influence in formulating our 2024 AMP:

- The change of government policy removing Government Investment in Decarbonising Industry (GIDI) funding could influence customer investment decisions. Based on our engagement with our customers, this will not change their decarbonisation decisions, though may affect the timing.
- The change in government policy to remove the clean car discount has resulted in a downturn of electric vehicle (EV) purchases. We expect EV purchases to continue, albeit at a slower rate. We still need to plan to cater for tourists travelling through our region, fleet electrification and the future impact of increased EV penetration on our low-voltage (LV) network.
- Resolutions to the nationwide talent gap in the infrastructure sector are not obvious or immediate. There are ongoing issues attracting talent to our sector and our region.
- In line with models provided by NIWA, we anticipate an increase in climate change-related weather events across our region. However, we do not know where, or when they will hit. We do not know the extent to which our climate will be disrupted in the long term, with global emissions reductions well short of targets.
- The extent to which the Commerce Commission's final decision on our 2025-2030 price-quality path will enable us to fund and deliver a significant step-change in network expenditure will not be known until November 2024.

Strategy-led planning

We have reviewed and updated our purpose and the long-term outcomes we are aiming for. These outcomes underpin the activities of our business now and in the future.

Our purpose: Empowering our vibrant and thriving communities now and for the future

Thriving communities	Electricity for all	Resilient and reliable electricity
Our people and communities are healthy and safe and thriving	**All electricity users can access and use electricity they need**	**Our electricity supply is resilient and adaptive in the face of climate change**
• Reliable electricity supports thriving families and businesses • Our people, communities and environment are healthy and safe	• Electricity is accessible, reliable, and affordable • Customers engage with us to make informed energy choices and access services that meet their needs	• Resilient and reliable electricity infrastructure and services span the needs of localities and generations • Our network adapts to, and stands strong in, the face of climate change

Network and customer insights

Regional Energy Transition Accelerator

The Mid-South Canterbury RETA – Phase One Report, was completed in 2023.[1] It provides a common set of information to organisations considering process heat decarbonisation, or who have the potential to support the transition through scaling up the supply of renewable energy. The report demonstrates that the collective effect of customer decarbonisation will have a significant impact on investment in the region's electricity infrastructure, including how this investment is prioritised and staged.

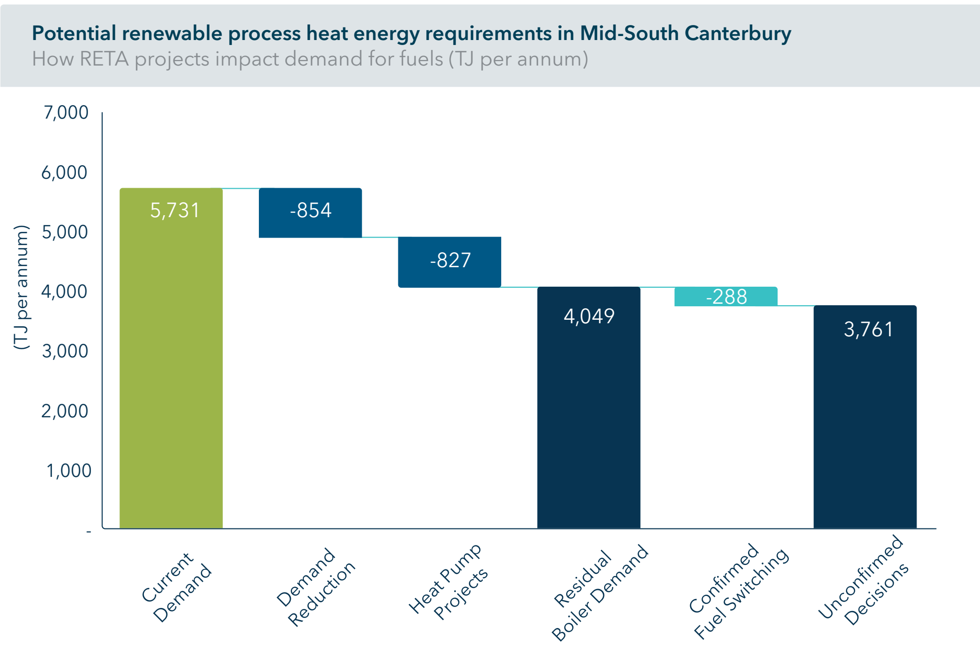

Figure 1: Potential impact of fuel switching on fossil fuel usage, 2022-2037. Source: EECA

[1] Regional Energy Transition Accelerator Mid-South Canterbury – Phase One Report, Energy Efficiency and Conservation Authority, June 2023.

The research used a simple economic criterion to identify at what point a decarbonisation decision would save a business money over the lifetime of investment, based on an assumed future trajectory of carbon prices. It found that by 2025, 75% of potential emission reductions in the region become economic based on this modelling.

While we recognise that there are a lot of other factors influencing individual businesses' decarbonisation plans, this finding is significant for our own investment decisions, and the timing of these. It reinforces our opinion, stated in last year's AMP, that the era of just-in-time investment is over. With limited capacity on parts of our network and the changing economic equation for decarbonisation, we need to get ahead of the demand curve. Our forecast increase in system growth investment, detailed in Chapter 2, reflects this.

South Canterbury Energy Strategy

Building on RETA's collaborative approach, we have led conversations with key stakeholders, including councils and mana whenua, across our region on the development of the South Canterbury Energy Strategy.

To be developed in the next two years, the South Canterbury Energy Strategy will examine long-term energy scenarios and the holistic implications for the region. It will be a resource to support sustainable energy decisions for public organisations and private investors and will inform our future AMPs.

> "We'll make significant progress by working together across government, council, economic development agencies, businesses, and community. And the outlook is positive, with industry in the wider region highly engaged."
>
> Nicki Sutherland Group Business Manager EECA

Proactive Engagement

The RETA project reiterated that, given the pace of change in the electricity industry, we need to proactively engage with customers. Over the past year, we have engaged closely with large industrial customers and developers to better understand the scale and timing of their growth and decarbonisation plans. Through this engagement, we have been able to challenge our growth forecasting assumptions for reasonability. As a result, our confidence in customer demand has increased, enabling us to prepare more robust network investment roadmaps for high-growth areas at Washdyke, South Timaru and Timaru Port areas.

Chapter 2 details the material changes to our AMP resulting from this engagement and our increased confidence in customer projects included in our forecasts.

Customer relationship management

Ongoing management of customer relationships is equally as important as proactive engagement. Our recent investment in a Customer Relationship Management (CRM) system is driving how we collect, manage, and analyse customer data and relationships. It has improved our visibility of future customer projects and will provide a solid data platform, allowing us to proactively manage any network impact, streamline our customer engagement and connection processes, and improve our response to enquiries. With our customer connection process now fully integrated into the CRM, we will continue rolling this out across the business. It will soon include network-related enquiries and requests, automating our network requests, for example, safety disconnections, and close approach and dig requests.

2050 Modelling

Using our recently developed modelling tool, we have applied different load assumptions, including EV penetration, decarbonisation, roof-top solar, and organic growth to provide a 2050 view of potential network needs at a distribution feeder level. Where our network roadmaps support location-specific investment plans, our 2050 modelling ensures these plans account for long-term trends including emerging technology and customer behaviour across our whole network.

Modelling deeper into our medium voltage network, and over a longer period, means we can plan for increased and changing demand, and the potential mitigating impact of non-traditional solutions, like flexibility services, or energy storage systems, such as batteries. This supports informed decision-making and long-term cost savings if we can defer or avoid potentially unnecessary network growth investment.

Network data

With the increase in residential EV charging, and roof-top solar, monitoring load and injection constraints on LV networks is an emerging issue for EDBs. Our investment in SmartCo, a metering equipment provider, and having open access to metering data across over 85% of connections to our network, means we are well-placed to respond to this issue. Utilising smart meter data, through SmartCo's Hiko network insights tool, we can monitor voltage issues, including under and over-voltage incidents on our network. We can now proactively intervene in voltage issues before they become a larger problem for customers or our assets. This data also supports future network development and asset lifecycle planning through evidence-based prioritisation of work.

This is an example of how, through new tools, we are implementing low-cost mechanisms to improve our visibility over our network and analyse data that better informs our investment decisions.

A future-ready business

In 2023 we amalgamated with our subsidiary field services provider, NETcon. The key driver for the amalgamation was to secure the capability to deliver the increase in our network programme and benefit from the commercial efficiencies it will deliver. There are direct savings from the amalgamation and streamlining of our operations. Over the next few years, operational efficiency and productivity will improve. This includes an anticipated rise in productive field staff hours and the consolidation of tasks into an integrated administrative function.

The nationwide talent gap in the infrastructure sector, highlighted in our 2023 AMP, is an ongoing risk to the delivery of our AMP. This risk remains, even after the amalgamation. Expanding our workforce and supporting our contractors' growth is crucial for executing our AMP delivery plan.

Chapter 2 provides more detail on the material change to our service delivery model resulting from the amalgamation and our delivery plan.

Target architecture

Digital technology that reduces costs, improves our understanding of our assets, and supports the efficient and effective delivery of our core services is becoming increasingly important. It is key in facilitating efficient customer service delivery. However, without a solid foundation, we cannot implement or benefit from the efficiencies and insights of these new technologies. Similarly, without investing in resilience, be that network, cyber, or business resilience, new systems or assets may inherit any fragility within our current state.

Initiatives are already underway, and further investment is included in this AMP to support the short-term strengthening of our operating model to deliver long-term digital transformation and resilience.

Our target architecture is a blueprint for our future digital operating platforms. The target architecture has an emphasis on connecting all the touchpoints between different people and different technologies involved in end-to-end processes, also providing a fully integrated work cycle across our amalgamated business.

Our focus for the first two years of this AMP is to replace or strengthen core systems, including our Enterprise Resource Planning (ERP) system and our GIS platform. Once these foundations are in place, we will progress to developing an Enterprise Asset Management (EAM) system. Plans include the integration of electricity-specific systems, beginning with an Advanced Distribution Management System (ADMS).

Dedicated Cyber Security Operations Centre

Like other smaller EDBs, it is a challenge to manage cyber security effectively due to staffing, processes, and technology demands, and the ever-increasing threat of a cyber-attack.

To address this challenge, we have entered a partnership with Vector (New Zealand's largest EDB), leveraging their proven technical solutions and mature cyber security capability. This allows us to focus our teams on core competencies and prioritise key areas.

Together we have implemented a dedicated Cyber security operations centre (SOC). This fully managed IT and OT (Operations Technology) SOC includes network detection and response, OT continuous threat detection, vulnerability management and email security. This partnership has significantly increased our cyber resilience.

Resilience

In early-2024 we developed our Resilience Management Strategy. This strategy supports network and business decision-making alongside our Condition Based Asset Risk Management (CBARM) modelling and our recently developed risk mapping tool. Chapter 2 sets out the material changes to our work programmes and forecast expenditure to increase our network resilience. We are also reviewing our critical spare holdings to increase our responsiveness in emergencies.

We have joined a Canterbury regional resilience project with other lifeline utilities. This collaboration is vital to responding effectively to the increasing risk from severe weather events and cyber-attacks. Our understanding of our role as a lifeline utility and the interdependencies with other utilities and organisations has increased. Collaboration like this is essential to supporting our network resilience planning and delivering on our strategic objective of resilient, reliable electricity for our communities.

Chapter 2

Material changes

This chapter provides an overview of the rationale and drivers for material changes since we developed our 2023 AMP forecasts. It also details the material changes to network development plans, asset lifecycle management plans, expenditure forecasts and our asset management practices.

Forecasting assumptions

Our significant forecasting assumptions and our response to these assumptions remain largely unchanged. These are set out in Section 3 of our 2023 AMP. Changes to these assumptions, which are driving material changes to our 2024 AMP are set out below.

	2023 assumption	2024 assumption	Our Response
Population, household, and economic growth	We assumed population and household growth across South Canterbury will be in line with the most recent growth projections prepared by the Timaru, Mackenzie, and Waimate District Councils. We also assumed that economic development across the region will continue at a modest level and that there will be no significant land use change driving rapid economic growth, or any significant long-term economic decline across the region.	Our total network demand forecasts have increased from the 2023 AMP. We assume that during this AMP period, while the historic relationship between population, household growth and economic growth, and network demand will continue for most of our network, in Washdyke and Timaru in particular, increased demand from a small group of large industrial customers will increase our total network demand as they undertake growth and decarbonisation projects in the next ten years.	The change in our network demand forecast reflects that customer projects previously considered speculative, or beyond the AMP period, are now forecast to proceed within the next ten years. Because of the lack of capacity on certain parts of our network, this AMP includes new system growth projects, and increased customer connection expenditure forecasts. Our updated demand forecasts and the material changes to our system growth projects are included in this chapter.
Asset lifecycle management	In 2023 we assumed that we would use CBARM to inform our asset maintenance, renewal, and replacement. Our work programme and forecasts were prepared in line with this assumption.	While this assumption remains, the data insights gained by applying CBARM across our major asset fleets have changed our response. The development of our Resilience Management Strategy in the past year has also changed how we assess the risk to our assets, as we now have more granular data on our asset exposure to earthquake and climate change-related risk.	By applying CBARM and our Resilience Management Strategy across our major asset fleets, our works programme and expenditure forecasts for Asset Renewal and Replacement (ARR) have changed materially. Our overhead pole, underground cable, distribution substation and underground substation fleet strategies have also been revised and we have increased our expenditure forecasts to reflect the condition, age, and resilience-related risk these fleets are carrying. The material changes to our ARR programmes are included in this chapter.
Service delivery arrangements	Our 2023 AMP assumed we would continue to use NETcon as our main contractor to deliver our AMP work programme, supported by other network-approved contractors.	In October 2023 we amalgamated with NETcon. As a result, we now assume most of our work programme will be delivered by in-house field services. We assume that efficiency gains resulting from the amalgamation and our ongoing process optimisation programme will support some of the delivery of our increased capex work programme, through the elimination of duplicated tasks across the business. We also assume that the amalgamation provides us with more control over the resources we need to deliver the uplift in our work programme which helps mitigate the talent gap the industry is experiencing.	We have identified the deliverability of our AMP work programme as a risk, especially given the increase in capex in the next two years and a nationwide talent shortage in the infrastructure sector. We have updated our AMP Delivery Plan to effectively plan and respond to this risk. A summary of our updated AMP Delivery Plan is included in this chapter.

Network expenditure

Material change – demand forecasts

Our network demand forecasts have been refined since 2023. This is a result of increased confidence in network impacts from forecast customer decarbonisation and growth, mainly in the Washdyke, South Timaru and Timaru Port areas, relevant to our Timaru GXP.

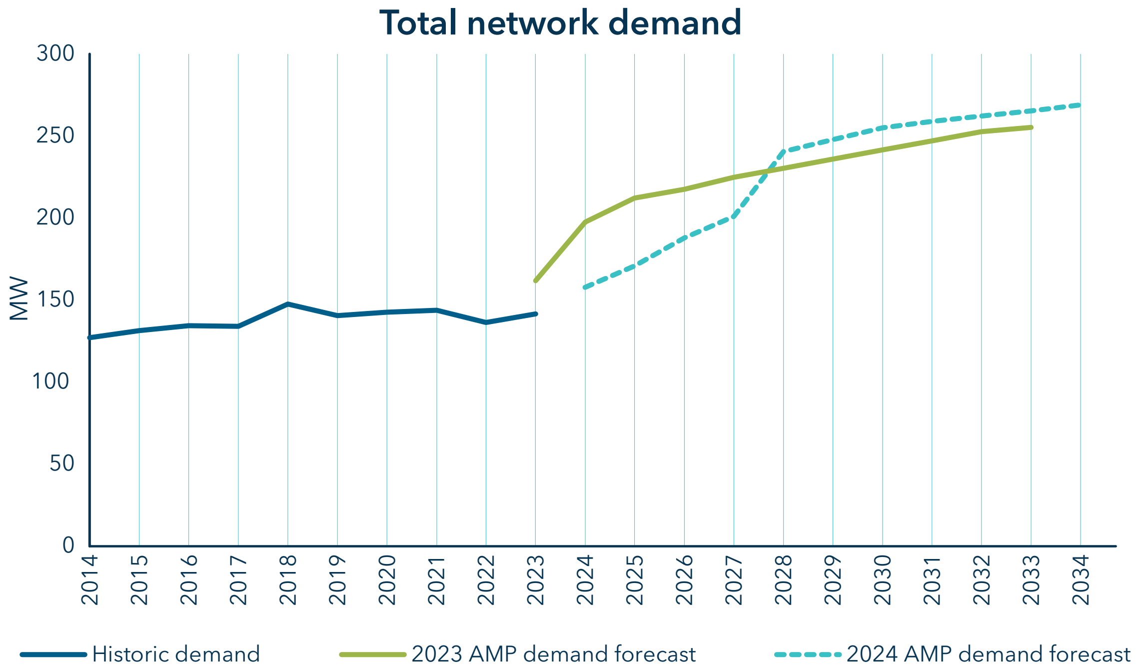

Figure 2: Total network demand forecast

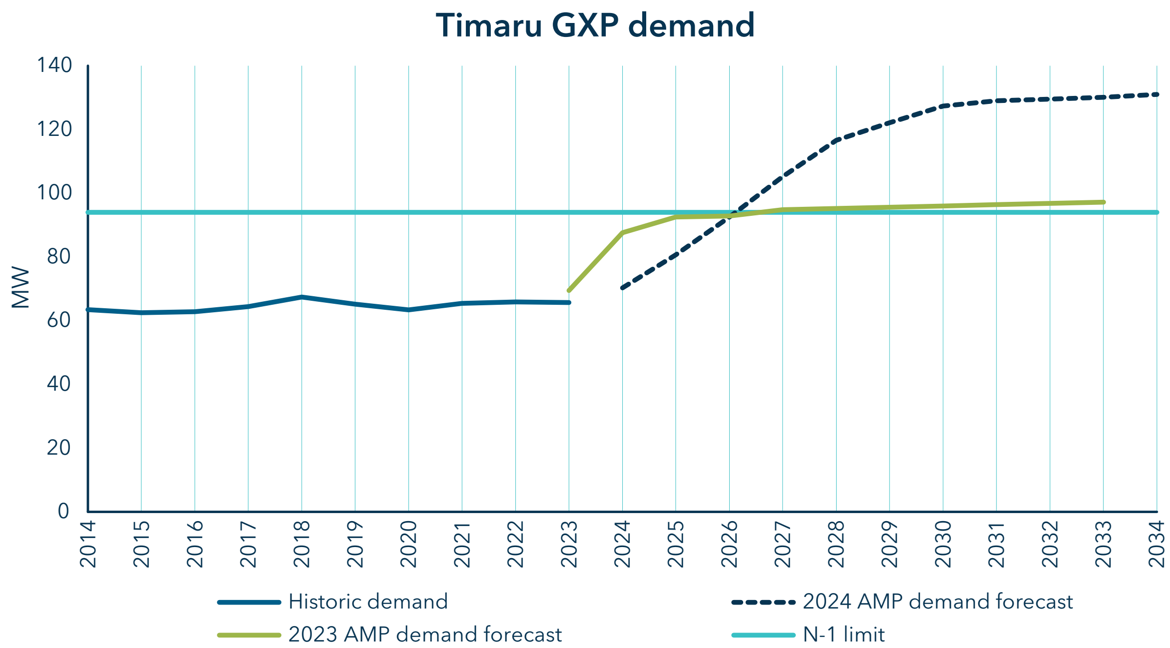

Figure 3: Timaru GXP demand forecast

Material change – system growth projects

Last year, many of the system growth projects included in our 2024 AMP were classified as 'speculative'. The drivers for these projects were investment decisions of individual large industrial customers and the expansion of industrial zones through council planning processes. We did not include projects considered 'speculative' in our 2023 AMP expenditure forecasts.

During the past year, we have developed investment roadmaps for Washdyke, South Timaru and Timaru Port areas. We have engaged closely with key stakeholders, including developers, new and existing industrial customers, and local councils to test and confirm our demand forecasts.

As a result of this work, our long-term network development plans have not changed significantly. However, the timeframes for delivering this work have accelerated, and our expenditure forecasts have increased through improved project scoping, inflationary impacts and increased costs associated with traffic management and civil works. Projects we signalled to be beyond the ten years covered in the 2023 AMP are now required sooner to bolster capacity to meet known and projected customer demand.

We are forecasting an additional 46MW at Washdyke over the next five years, with only 10MW capacity currently remaining. The development of a new 33kV GXP by Transpower (located at the existing Timaru GXP site), is essential for the delivery of our Washdyke roadmap, providing new capacity to this industrial area. To utilise this new capacity, a new 33kV substation is planned for Washdyke in 2025-2026, following the completion of a new 11kV switching station that is currently in construction.

Figure 4: System growth and consumer connections projects planned for Washdyke 2024-2034

Medium-term growth in the South Timaru and Timaru Port area is forecast to add 30MW of demand and Timaru central business district (CBD) development and EV charging growth will add approxiamately 6.5MW of demand. The new Timaru 33kV GXP will free up enough capacity to provide for this forecast growth in Timaru, which will continue to be fed from the 11kV GXP. The installation of new 33kV sub-transmission circuits from the GXP, and upgrades to existing cables planned for 2026 – 2032 will deliver this capacity and additional security to customers, and future-proof our investment should a high-growth scenario arise.

Figure 5: System growth projects planned for Timaru 2024-34

Our system growth expenditure forecast includes $44 million, nearly half our 10-year forecast, to build five new switching stations and substations. In 2023 we forecast $28 million for substation projects. This reflects that, like Washdyke, our other high-growth areas are nearing the end of their current capacity. Significant investment is now required to enable the types of connections our customers are seeking. Improved project scope and pricing, the impacts of inflation, and the supply chain constraints for long lead items have contributed to the forecast increases to our substation developments.

The following table provides a summary of the material changes to our system growth projects planned for the next ten years to meet the demand forecasts set out above.

Project	Change	Driver	Cost	Timing
Timaru 33kV GXP				
Feeder reconfiguration at Timaru 33kV GXP (following Transpower project to build new 33kV GXP at Timaru GXP)	Reforecast expenditure for feeder reconfiguration	Immediate capacity constraints at Washdyke, currently fed off Timaru 11kV GXP. Forecast medium-term capacity constraints for Timaru driven by South Timaru and Timaru Port industrial and commercial growth.	$1M (2023 AMP: $0.4M)	2027
Washdyke system growth projects				
Build new Washdyke 33kV substation	Improved project scoping and expenditure reforecast	Short-term industrial growth and customer decarbonisation.	$10M (2023 AMP: $5M)	2025 - 2026
New West Washdyke substation	Improved project scoping and expenditure reforecast	Medium-term forecast industrial growth and customer decarbonisation.	$15M (2023 AMP: $5M)	2031 - 2033
South Timaru and Timaru Port system growth projects				
Port feeder upgrades	New project	Existing feeder capacity constraints. Feeder upgrades are required for a new Timaru Port switching station. Alignment with Timaru District Council projects to minimise cost and disturbance.	$4.1M (2023 AMP: $1.5M)	2025 - 2026, 2028
New Timaru sub-transmission circuits	Increased project scope	Medium-term capacity constraints are driven by forecast industrial, commercial and EV charging growth in South Timaru, Timaru Port and CBD. The project will improve resilience in urban Timaru.	$16.7M (2023 AMP: $5.2M)	2026 - 2032
Timaru CBD system growth projects				
New Timaru CBD switching station	Expenditure reforecast (previously classified as 'speculative')	Timaru District Council inner city rejuvenation projects and forecast EV growth will result in capacity and security of supply issues in the medium term.	$5M (2023 AMP: $0.4M)	2029 - 2030
Timaru CBD feeder upgrades	New Project	Forecast capacity constraint on older undersized feeders. Alignment with Timaru District Council projects to minimise cost and disturbance.	$6M (2023 AMP: $0)	2025 - 2034
Pleasant Point system growth projects				
Pleasant Point substation rebuild and additional power transformer	Increased project scope and expenditure reforecast (previously classified as 'speculative')	Medium-term forecast growth and existing security of supply issues.	$9.2M (2023 AMP: $1.5M)	2030 - 2031
2023 AMP projects - deferred or removed				
New twin substation in Twizel	Project deferred beyond AMP planning period	Reforecast demand.	$0 (2023 AMP: $1.5M)	-
Twizel mobile substation	Project removed from forecasts	No longer considered prudent.	$0 (2023 AMP: $2M)	-
New Redruth zone substation	Project removed from forecasts	Reforecast demand, project no longer considered prudent.	$0 (2023 AMP: $2.5M)	-

These project changes are driving much of the expenditure forecast variance shown in Figure 6 below.

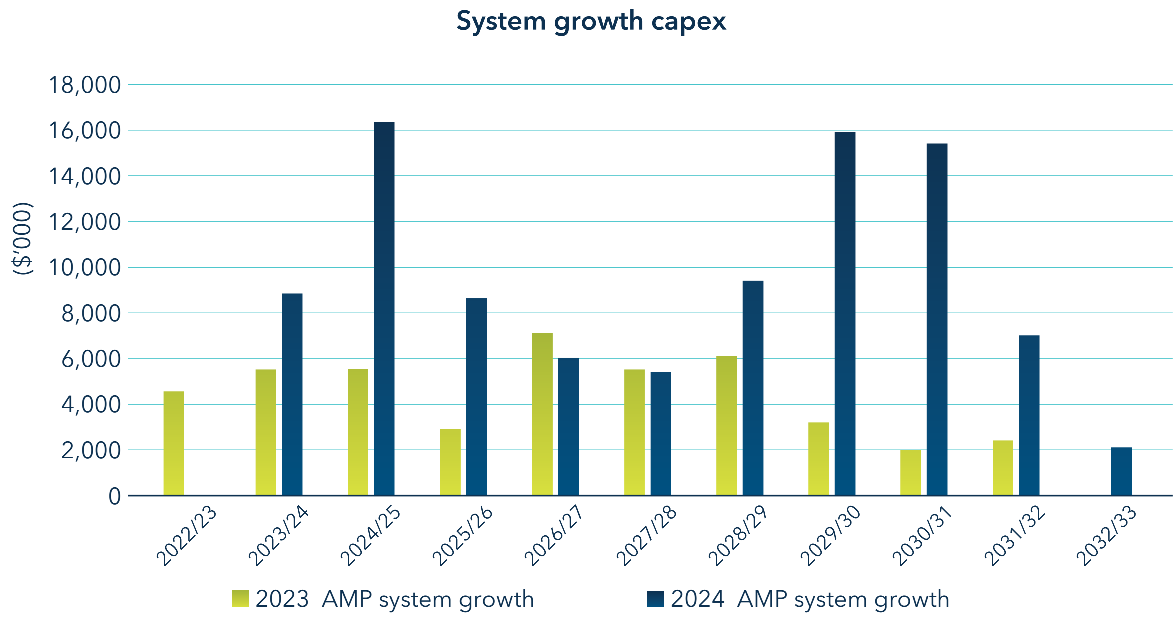

Figure 6: System growth capex forecast

Material change – asset lifecycle management

In line with our Asset Management Policy and our 2023 AMP, we continue to use CBARM to prioritise our ARR programmes.

Our previous forecasts did not include specific capex to address climate change-related network resilience. We have now invested in technology and data analysis to better understand the potential impact of natural hazards and the changing climate across our network. A risk mapping tool has been developed, allowing us to visualise our assets overlayed with environmental data sources, which will be updated annually to highlight changing risks.

Pairing this climate and hazard data with CBARM age and condition indicators has resulted in a modest, but critical step change in expenditure for major asset fleets including overhead poles, underground cables, and distribution substations. Our annual replacement and renewals forecasts for the next three years have increased by $3.5 million on average, compared to our 2023 AMP forecasts.

As well as our increased resilience focus across our maintenance and renewal schedules, we are also reviewing our strategic spare holdings, looking at increased storm hardening of our overhead line network and redesigning parts of our network with high criticality or vulnerable assets. Non-network solutions, including local generation and energy storage to improve resilience and avoid significant expenditure for line replacement are also being considered, especially in remote locations.

The following table provides a summary of the material changes to our ARR work programmes planned for the next ten years to ensure our network is reliable and resilient.

Change	Driver	Cost	Timing
Overhead pole fleet			
Increase annual pole replacement rate from 600 to a minimum of 850	6,170 wooden poles have outlived their CBARM life of 47 years, and 633 concrete poles have exceeded a 68-year lifespan. The need for a robust pole replacement plan is clear and urgent. 9,426 poles on our network have not been inspected in the past 10 years, and 2,465 of these poles have already exceeded their CBARM lifespan. Increasing our pole replacement programme will help reduce the risk currently sitting with this asset fleet and improve network resilience over time.	2025: $8.2M 2026: $9.9M 2027 – 2035: $9.95M p.a. (2023 AMP: $6.5M p.a.)	10-year programme
Underground cable replacement			
Replace at least 1km of aged cable annually	Our XLPE/PVC cable network stretches over 327km, with 5km exceeding an expected 45-year service life. The increasing risk of cable failure from these aged cables and the significant disruption for customers resulting from a failure is driving the increased expenditure.	$10.2M (2023 AMP: $2.6M)	10-year programme
Distribution substation replacement			
Replace at least 124 substations annually to manage the ageing profile effectively	672 substations that have outlived their 50-year CBARM life. This accounts for 11% of our fleet. The ageing substations are prone to oil leaks and potential failure, posing both environmental and reliability risks. The outdated design of these substations adds safety concerns and reduces our resilience to natural hazards.	$28.4M (2023 AMP: $15.6M)	10-year programme
Two-pole substations			
Relocation of high-risk two-pole substations to ground, or strengthen designs	51 of our 182 two-pole substations have exceeded their 50-year CBARM life, requiring a minimum replacement rate of seven per year to manage their ageing profile effectively. Older substations are susceptible to oil leaks, which will pose environmental risks and compromise network reliability. Current design and location make them more earthquake-prone than single-pole or ground-mounted options.	$12.4M (2023 AMP: $4M)	10-year programme
Underground substation renewal			
Relocation of underground substation fleet to above-ground	The underground location of the substations introduces specific risks such as arc flash incidents, electrocution hazards, and delayed emergency response.	$12.6M (2023 AMP: $6M)	6-year programme

These ARR programmes are driving the expenditure forecast variance shown in Figure 7 below.

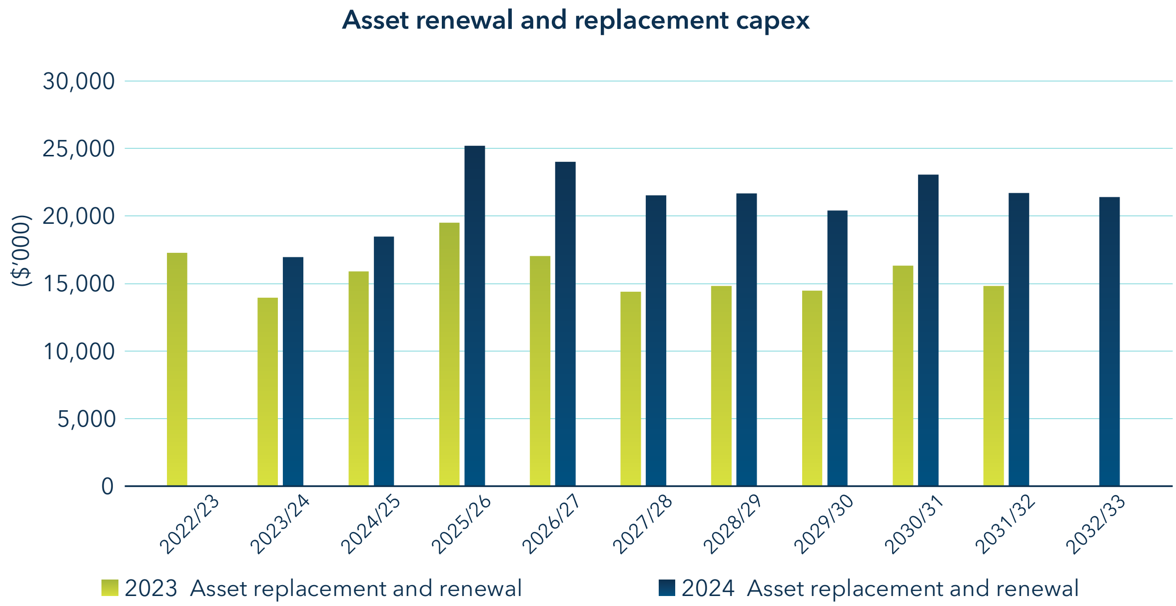

Figure 7: Asset renewal and replacement capex forecast

Material change – consumer connections expenditure forecast

Until recently, consumer connection activity across South Canterbury was relatively steady, aligning with population, household, and economic growth. Our previous forecasts have reflected this assumption.

Decarbonisation and distributed generation have changed the impact individual consumers have on our expenditure forecast. For example, the RETA report estimated $9.75 million of consumer connection expenditure for nine projects with "minor complexity" and a further $11.75 million for three "moderate complexity" connections.[2] We have updated our forecasting methodology to better reflect the impact of changing consumer demand profiles and the significant expenditure associated with these connections.

This change in methodology has resulted in a material increase reflecting the anticipated expenditure on large industrial growth and decarbonisation projects, and the connection of large-scale distributed generation to our network.

Uncertainty remains over the scope, timing, and location of customer-driven work. However, reflecting the increase in large and complex customer connections in our expenditure forecasts better supports our resource and service delivery planning.

Capital contribution revenue

We have made assumptions about the level of capital contribution revenue we will receive by applying our current capital contributions policy to forecast consumer connections expenditure. We intend to review this policy following the communication of the new price path set under the default price-quality (DPP) regulation. Our revenue assumptions may change in future AMPs to ensure we can fund our significant network development and customer-driven work programme. Our capital contribution revenue forecast is detailed in Appendix 1 - Schedule 11a - Report on Forecast Capital Expenditure.

The table below provides a summary of the material changes to our customer connections forecasts over the next ten years.

Consumer Category	Change	Driver	Cost	Timing
Consumer connections forecasts				
Large-scale DG	New category and expenditure forecast	Consumer connection expenditure forecast methodology updated to reflect increased certainty of large-scale DG connections.	$6M (AMP 2023: $0)	2025 – 2034
Large industrial connection	New category and expenditure forecast	Consumer connection expenditure forecast methodology updated to reflect anticipated large industrial connections driving demand growth as reflected in our system growth forecasts.	$23.8M (2023 AMP: $0)	2025 – 2034
Large industrial – Washdyke cabling projects	Increased scope of projects and expenditure reforecast Reclassification from system growth	Washdyke Roadmap completed. Immediate and medium-term capacity constraints and consumer connection requirements are driven by industrial growth and customer decarbonisation. Reclassification of Washdyke cable projects from system growth to consumer connections expenditure to reflect the customer-driven nature of these projects.	$26M (2023 AMP: $11.5M SG)	2026 – 2032

[2] Regional Energy Transition Accelerator Mid-South Canterbury – Phase One Report, Energy Efficiency and Conservation Authority, June 2023, p84-88.

These new consumer categories are driving most of the expenditure forecast variance shown in Figure 8 below.

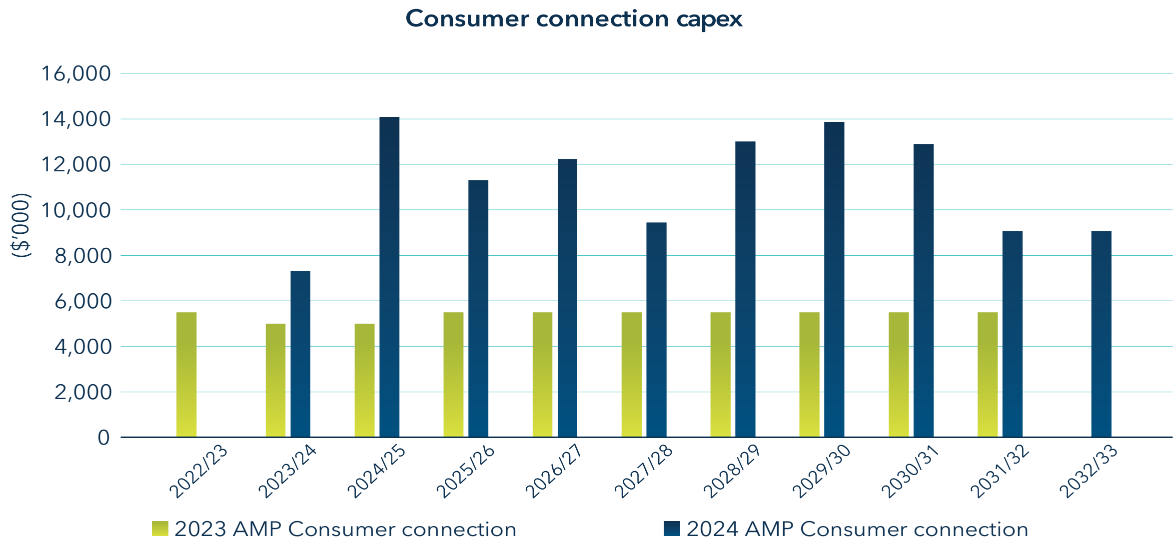

Figure 8: Consumer connection capex forecast

Delivery of our AMP

Material change – service delivery model

Bringing NETcon into our business will result in a long-term, sustainable reduction in the cost of service delivery. We are in the process of integrating field services directly into our workflow processes, including procurement and store management, project management and pricing, and vehicle fleet management.

Examples of efficiencies and process improvements planned include:

- Cost reductions by removing tendering, contracting, and invoicing between two businesses.
- Reduction in time and data errors in the asset inspection process.
- Improved asset information through streamlined communications between field service and asset lifecycle teams.
- Alignment of fault response and control room operations reducing safety risks and improving response efficiency.

AMP delivery plan

The volume of work we are forecasting for the next ten years is materially higher than what we have undertaken in the past. It will take time to build capacity and skills within our teams and our contractors, particularly given the nationwide talent shortage in the infrastructure and construction sectors. Our work programme also includes some large, complex projects that will require specialist skills. Delivering this AMP requires a focused delivery approach.

Our 2024 AMP delivery plan has four central components:

- The amalgamation delivers improved productivity across our work programme.
- Increase in-house capacity and skills over the next three years.
- Strategic partnerships with external contractors and peers to support the delivery of large projects.
- Engagement with other utility providers and councils to identify efficiencies and remove delivery barriers to project delivery.

We are already undertaking initiatives to grow our workforce and increase our ability to deliver including:

- Establishing a new graduate recruitment program.
- Utilising in-house expertise for specialised project and design work and backfilling existing positions.
- Partnering on a 12-month programme with an accredited training institution to support and develop the skillsets of our field crews. Upskilling their capacity and investing in support to mentor a new workforce.
- Going to market for large system growth projects to the wider industry.
- Aligning work with other utility providers, particularly council roading and water services teams, and Transpower to reduce cost.
- Early engagement with interested parties including landowners and councils, particularly where resource consents are required, to reduce potential project delays.

Asset management maturity

We are continuing our asset management maturity journey with the improvement initiatives identified in our 2023 AMP. Our focus in preparing this AMP update has been on revising our planned network projects and programmes. This has not resulted in any changes to the asset management practices that would affect the Schedule 13 Report on Asset Management Maturity disclosure. Our 2025 AMP will include an independent assessment of our asset management maturity.

Non-network expenditure

Material change – non-network opex

Investment in digital

We are investing significantly in digital products that support and improve our core functions. The specific projects set out in Chapter 9 of our 2023 AMP have not changed materially in nature. However, we have now fully scoped the target digital architecture and capabilities we need to deliver on our asset management objectives.

We are currently dependent on legacy systems, many of which are out of support and pose single points of failure and security risks. To address these risks, our focus for the first two years of this AMP is to replace or strengthen core systems, including our ERP system and our GIS platform. Once these foundations are in place, we will progress to developing an EAM system. Plans include the integration of electricity-specific systems, beginning with an ADMS by the end of 2026.

This digital investment programme will move us from largely on-premises systems to cloud-based services (otherwise referred to as 'software as a service' (SaaS)). This results in a material change to our forecasts with expenditure shifting from non-network capex to non-network opex.

Our legacy environment inhibits our ability to deliver efficient and streamlined services to our customers. Our digital investment program will mitigate single points of failure and security risks and equip us for a more resilient, agile, and customer-centric future.

Cybersecurity continues to be a focus, due to the increasing cyber risk landscape. Our forecasts reflect enhanced system security to reduce network vulnerability. By partnering with Vector, we are ensuring quality system security cost-effectively.

The table below summarises the material changes in our non-network opex.

Project	Change	Driver	Cost	Timing
		Investment in TA		
Target technology and data architecture programme	Forecast increase in operating expenditure due to increased scope of the programme.	We have multiple legacy systems that are no longer fit for purpose and prevent us from implementing electricity-specific systems, including an advanced distribution management system (ADMS).	$3M p.a. (2023 AMP: $1.6M p.a.)	10-year programme
Cyber security	Reforecast expenditure	The increase in cloud-based solutions and cyber-attacks globally, paired with the business expansion resulting from our amalgamation have driven the reforecast of our cyber security programme.	$5.3M (2023 AMP: $2.9M)	10-year programme
Investment in Software as a Service (SaaS) solutions	Moving from aged on-premise IT systems to SaaS products and improved cost forecasts.	The treatment of the costs to invest in SaaS solutions as opex instead of capex, following Generally Accepted Accounting Principles and improved project cost forecasts.	$16.6M (2023 AMP: $18.9M included in non-network capex)	1 – 5-year programme

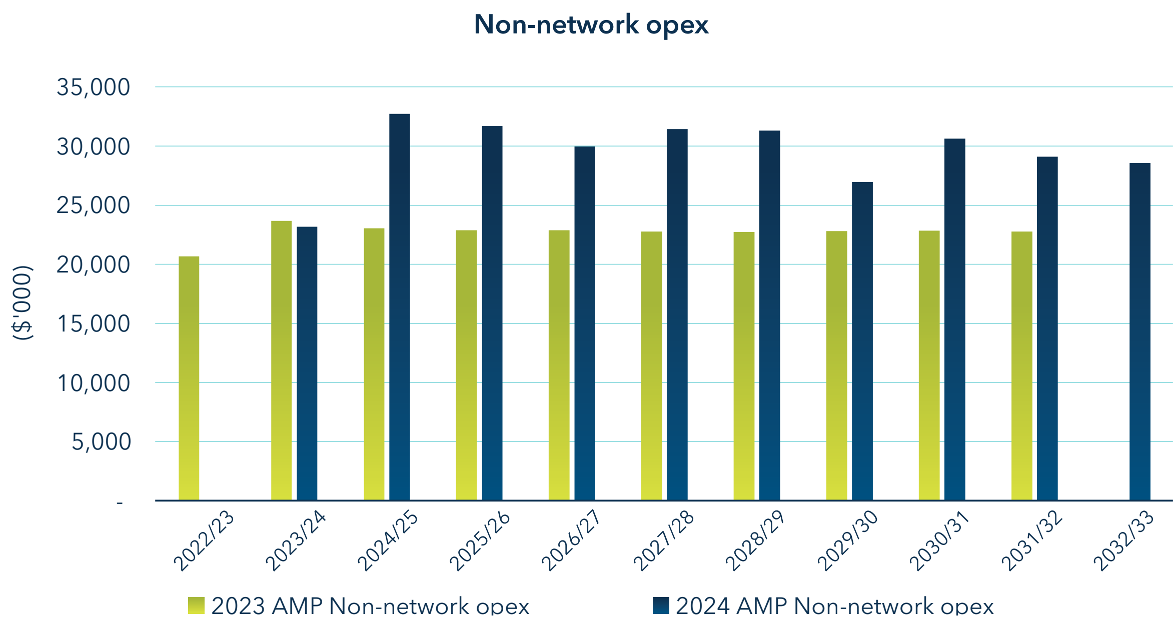

Figure 9: Non-network opex forecast

Chapter 3

Expenditure forecast overview

This chapter details our capex and opex forecasts for the next 10-year planning period. It provides a high-level comparison with our forecasts included in the 2023 AMP, highlighting how our investment plan has evolved over the past year to both grow and strengthen our network and business to meet our customers' needs.

Material changes from our 2023 AMP capex and opex forecasts are discussed.

Forecasts are presented in the 2024 prices (constant prices) and reflect those included in the Report on Forecast Capital Expenditure (Appendix 1 – Schedule 11a) and Report on Operating Expenditure (Appendix 2 – Schedule 11b). The forecast expenditure is based on the best information available at the time of publishing our 2024 AMP.

Network expenditure

Network capex

Network capex includes expenditure across the following categories:

- System growth
- Asset renewal and replacement
- Consumer connections
- Asset relocations
- Reliability, safety, and environment.

We have forecast a total network capex programme of $450 million over the 10-year planning period. The expenditure profile is punctuated by costly substation and switching station developments in 2026 and 2030-2031 required to increase capacity across the network.

Increases in our system growth, asset renewal and replacement, and consumer connection forecasts have the biggest impact on our overall capex variance. The material changes to projects and programmes within these categories are set out in Chapter 2.

At an aggregated level, the main drivers for forecast increases in capex are:

- Updated forecasting methodology and improved project scoping and pricing, particularly for large projects like substation builds. These forecasts are based on actual cost comparisons for projects underway in the last year.
- Increases to system growth and consumer connection forecasts following of the development of the Washdyke and South Timaru and Timaru Port roadmaps. System growth has increased by $50 million and consumer connections have increased by $59 million. We have increased confidence in demand forecasts and consumer connection activity for these industrial areas following customer engagement and additional network development studies.
- Asset renewal and replacement forecasts have increased by $56 million, reflecting greater investment in network resilience and a strategic approach to slow the ageing of our asset fleets.
- The significant increase in inflation levels has impacted all expenditure categories.

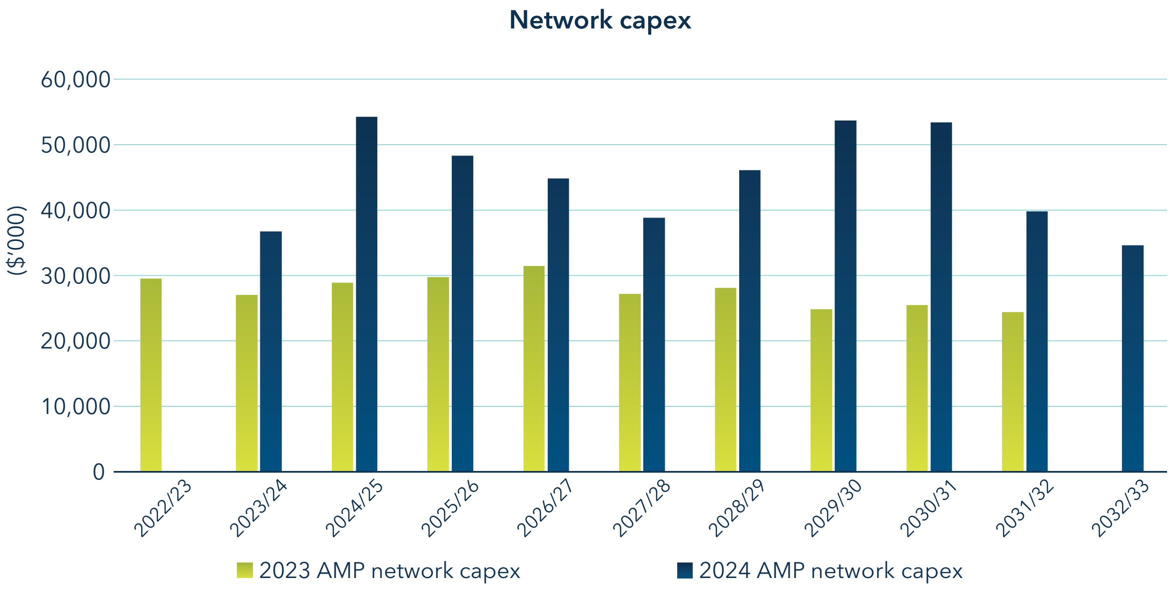

Figure 10: Network capex forecast

Network opex

Network opex includes expenditure across the following categories:

- Service interruptions and emergencies
- Vegetation management
- Routine and corrective maintenance
- Asset renewal and replacement

We have forecast a total network opex programme of $74 million over the 10-year planning period. Our forecasts have not changed materially since our 2023 AMP. A $4 million variance is a result of increased labour costs for fault response and vegetation management.

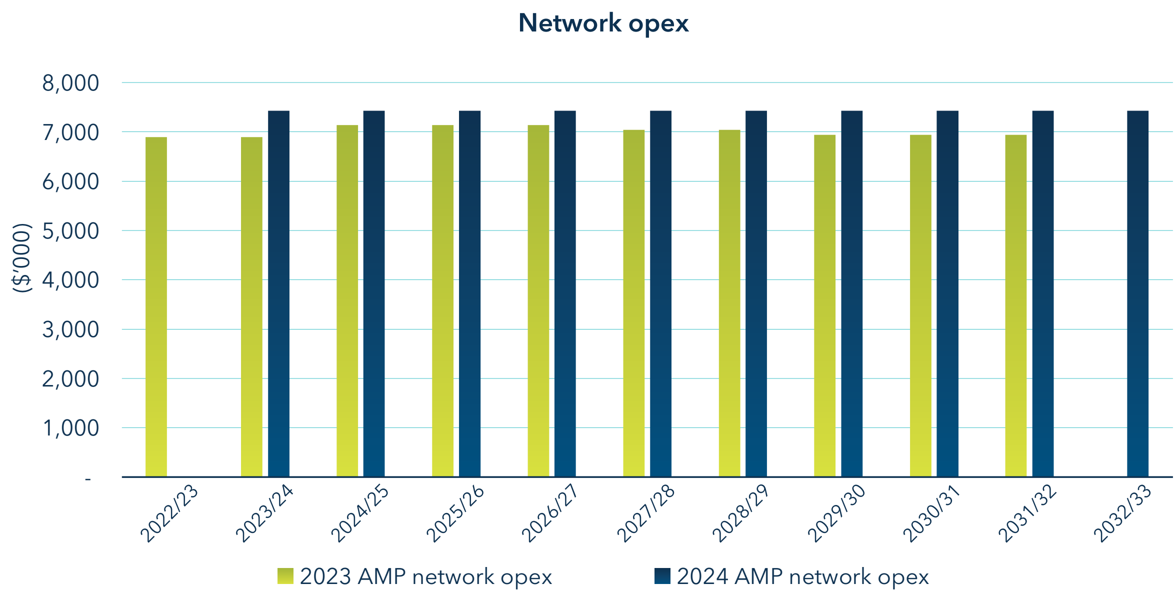

Figure 11: Network opex forecast

Non-network expenditure

Non-network capex

Our 2024 AMP includes $8.5 million of non-network capex. This is a decrease of $18 million from our 2023 AMP. This variance reflects a shift from forecasting capital expenditure for on-premise digital systems, to operating expenditure for SaaS solutions.

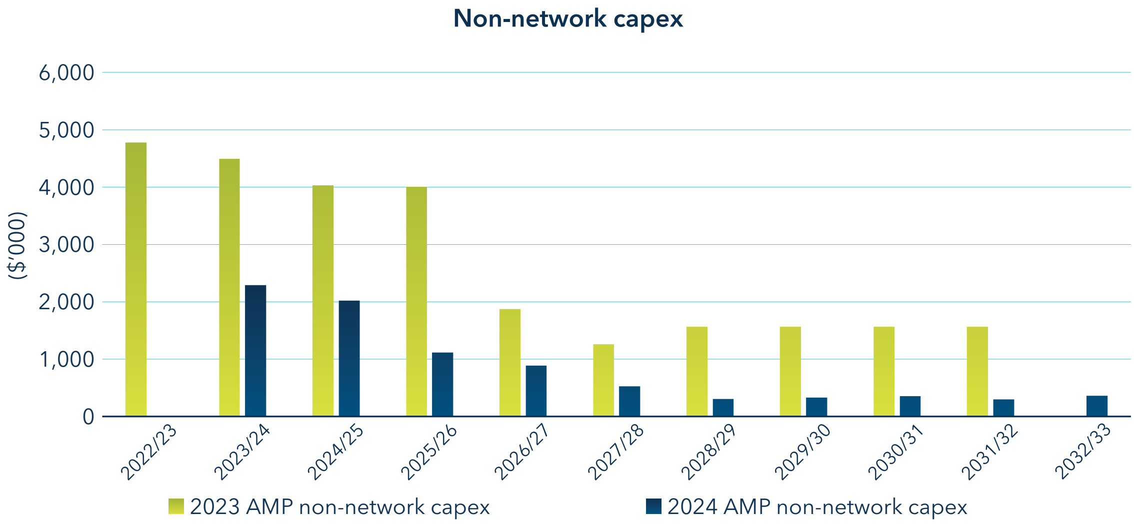

Figure 12: Non-network capex forecast

Non-network opex

Non-network opex includes across two categories:

- System operations and network support
- Business support.

We have forecast total non-network opex of $310 million over the 10-year planning period. An increase of $68 million in business support opex from our previous forecast is driven by increased investment in digitisation and cyber security and the shift from capex to opex for SaaS solutions. We have also forecast higher personnel costs in system operations and network support and business support, reflecting the need to increase capacity and capability across the business.

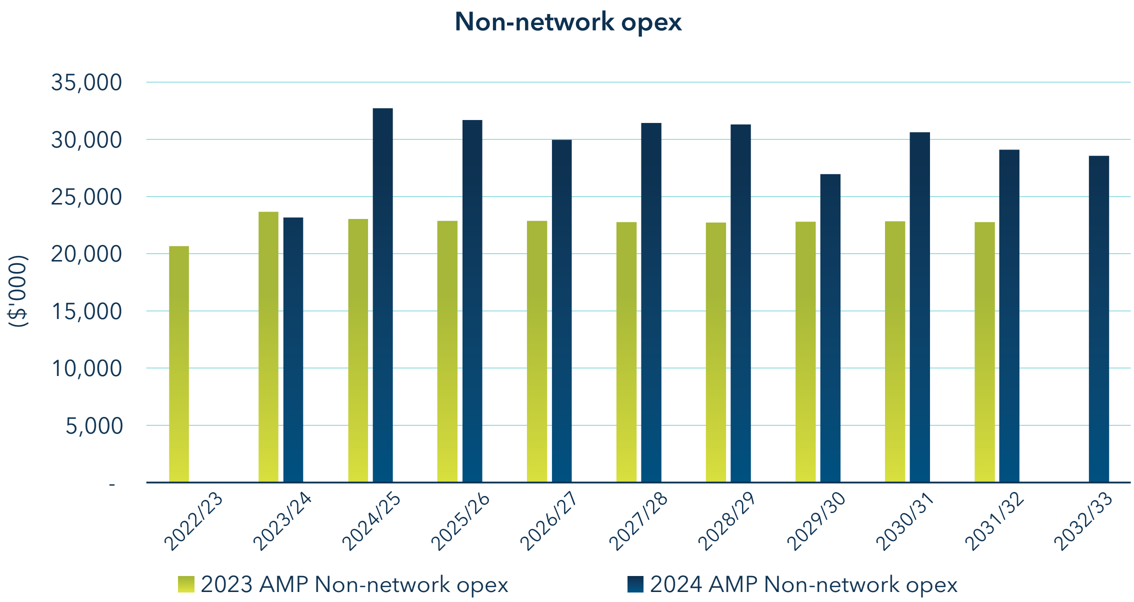

Figure 13: Non-network opex forecasts

Appendices

Appendix 1:

Schedule 11a. Report on forecast capital expenditure

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2024 – 31 March 2034

7 8	for year ended	Current Year CY 31 Mar 24	CY+1 31 Mar 25	CY+2 31 Mar 26	CY+3 31 Mar 27	CY+4 31 Mar 28	CY+5 31 Mar 29	CY+6 31 Mar 30	CY+7 31 Mar 31	CY+8 31 Mar 32	CY+9 31 Mar 33	CY+10 31 Mar 34
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	4,921	7,310	14,418	11,827	13,050	10,266	14,423	15,702	14,891	10,685	10,899
11	System growth	1,653	8,840	16,748	9,033	6,441	5,885	10,440	18,005	17,788	8,254	2,534
12	Asset replacement and renewal	16,149	16,968	18,903	26,368	25,599	23,403	24,037	23,103	26,613	25,556	25,706
13	Asset relocations	146	250	1,792	470	746	218	222	226	231	235	240
14	Reliability, safety and environment:											
15	Quality of supply	-	-	-	-	-	-	-	1,698	-	-	-
16	Legislative and regulatory	-	800	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	1,286	2,535	3,676	2,833	1,962	2,458	2,008	2,048	2,089	2,131	2,174
18	**Total reliability, safety and environment**	**1,286**	**3,335**	**3,676**	**2,833**	**1,962**	**2,458**	**2,008**	**3,746**	**2,089**	**2,131**	**2,174**
19	**Expenditure on network assets**	**24,155**	**36,703**	**55,537**	**50,532**	**47,799**	**42,229**	**51,131**	**60,783**	**61,612**	**46,861**	**41,553**
20	Expenditure on non-network assets	2,235	2,292	2,066	1,165	948	568	341	375	408	352	437
21	**Expenditure on assets**	**26,390**	**38,995**	**57,602**	**51,696**	**48,748**	**42,797**	**51,472**	**61,158**	**62,020**	**47,212**	**41,990**
22												
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	3,670	6,625	11,228	8,586	10,011	8,416	10,707	12,477	12,351	9,684	9,878
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
27	**Capital expenditure forecast**	**22,720**	**32,370**	**46,374**	**43,110**	**38,737**	**34,381**	**40,765**	**48,682**	**49,668**	**37,528**	**32,112**
29	Assets commissioned	20,569	31,284	42,823	42,351	35,623	34,057	37,013	47,566	48,301	37,019	30,506
32		**$000 (in constant prices)**										
33	Consumer connection	4,921	7,310	14,080	11,313	12,238	9,438	13,000	13,875	12,900	9,075	9,075
34	System growth	1,653	8,840	16,355	8,640	6,040	5,410	9,410	15,910	15,410	7,010	2,110
35	Asset replacement and renewal	16,149	16,968	18,460	25,220	24,005	21,515	21,665	20,415	23,055	21,705	21,405
36	Asset relocations	146	250	1,750	450	700	200	200	200	200	200	200
37	Reliability, safety and environment:											
38	Quality of supply	-	-	-	-	-	-	-	1,500	-	-	-
39	Legislative and regulatory	-	800	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	1,286	2,535	3,590	2,710	1,840	2,260	1,810	1,810	1,810	1,810	1,810
41	**Total reliability, safety and environment**	**1,286**	**3,335**	**3,590**	**2,710**	**1,840**	**2,260**	**1,810**	**3,310**	**1,810**	**1,810**	**1,810**
42	**Expenditure on network assets**	**24,155**	**36,703**	**54,235**	**48,333**	**44,823**	**38,823**	**46,085**	**53,710**	**53,375**	**39,800**	**34,600**
43	Expenditure on non-network assets	2,235	2,292	2,017	1,114	889	523	307	332	353	299	363
44	**Expenditure on assets**	**26,390**	**38,995**	**56,252**	**49,446**	**45,712**	**39,345**	**46,392**	**54,042**	**53,728**	**40,099**	**34,963**

Schedule 11a. Report on forecast capital expenditure continued

46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses	193	-	-	-	-	-	-	-	-	-	-
48	Overhead to underground conversion	-	50	1,550	250	500	-	-	-	-	-	-
49	Research and development	-	-	-	-	-	-	-	-	-	-	-
52 53	for year ended	**Current Year CY 31 Mar 24**	**CY+1 31 Mar 25**	**CY+2 31 Mar 26**	**CY+3 31 Mar 27**	**CY+4 31 Mar 28**	**CY+5 31 Mar 29**	**CY+6 31 Mar 30**	**CY+7 31 Mar 31**	**CY+8 31 Mar 32**	**CY+9 31 Mar 33**	**CY+10 31 Mar 34**
54	**Difference between nominal and constant price forecasts**	**$000**										
55	Consumer connection	-	-	338	515	813	828	1,423	1,827	1,991	1,610	1,824
56	System growth	-	-	393	393	401	475	1,030	2,095	2,378	1,244	424
57	Asset replacement and renewal	-	-	443	1,148	1,594	1,888	2,372	2,688	3,558	3,851	4,301
58	Asset relocations	-	-	42	20	46	18	22	26	31	35	40
59	Reliability, safety and environment:											
60	Quality of supply	-	-	-	-	-	-	-	198	-	-	-
61	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
62	Other reliability, safety and environment	-	-	86	123	122	198	198	238	279	321	364
63	**Total reliability, safety and environment**	**-**	**-**	**86**	**123**	**122**	**198**	**198**	**436**	**279**	**321**	**364**
64	**Expenditure on network assets**	**-**	**-**	**1,302**	**2,199**	**2,977**	**3,406**	**5,046**	**7,073**	**8,237**	**7,061**	**6,953**
65	Expenditure on non-network assets	-	-	48	51	59	46	34	44	54	53	73
66	**Expenditure on assets**	**-**	**-**	**1,350**	**2,250**	**3,036**	**3,452**	**5,080**	**7,117**	**8,291**	**7,114**	**7,026**

Schedule 11a. Report on forecast capital expenditure continued

72	for year ended	Current Year CY 31 Mar 23	CY+1 31 Mar 24	CY+2 31 Mar 25	CY+3 31 Mar 26	CY+4 31 Mar 27	CY+5 31 Mar 28
73	**11a(ii): Consumer Connection**						
74	*Consumer types defined by EDB**	**$000 (in constant prices)**					
75	Large Industrial	1,843	1,120	7,230	5,513	6,438	3,688
76	Commercial	666	960	1,080	1,200	1,200	1,200
77	Subdivision	842	1,200	1,350	1,500	1,500	1,500
78	Irrigation	404	320	315	300	300	250
	Residential	988	1,200	1,350	1,500	1,500	1,500
	Large Distributed Generation	-	1,500	1,500	-	-	-
	HV Alterations	158	320	360	400	400	400
	LV Alterations	20	40	45	50	50	50
79	Switchgear	-	650	850	850	850	850
80	**include additional rows if needed*						
81	**Consumer connection expenditure**	**4,921**	**7,310**	**14,080**	**11,313**	**12,238**	**9,438**
82	*less* Capital contributions funding consumer connection	3,670	6,625	10,965	8,213	9,388	7,738
83	**Consumer connection less capital contributions**	**1,251**	**685**	**3,115**	**3,100**	**2,850**	**1,700**
84	**11a(iii): System Growth**						
85	Subtransmission	26	-	500	-	-	1,500
86	Zone substations	1,425	3,780	7,980	2,530	2,530	1,500
87	Distribution and LV lines	21	-	400	-	-	-
88	Distribution and LV cables	35	2,210	6,460	4,560	2,960	1,660
89	Distribution substations and transformers	12	2,300	400	1,000	-	-
90	Distribution switchgear	67	300	300	300	300	300
91	Other network assets	67	250	315	250	250	450
92	**System growth expenditure**	**1,653**	**8,840**	**16,355**	**8,640**	**6,040**	**5,410**
93	less Capital contributions funding system growth	-	-	-	-	-	-
94	**System growth less capital contributions**	**1,653**	**8,840**	**16,355**	**8,640**	**6,040**	**5,410**
95							
98	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
99	Subtransmission	9	-	-	1,000	-	-
100	Zone substations	3,738	220	110	4,010	3,310	410
101	Distribution and LV lines	7,572	8,398	8,980	9,480	9,980	9,980
102	Distribution and LV cables	1,528	1,690	1,900	1,860	1,960	1,850
103	Distribution substations and transformers	1,903	5,465	5,995	6,365	6,780	7,050
104	Distribution switchgear	1,351	1,195	1,475	2,505	1,975	2,225
105	Other network assets	48	-	-	-	-	-
106	**Asset replacement and renewal expenditure**	**16,149**	**16,968**	**18,460**	**25,220**	**24,005**	**21,515**
107	*less* Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
108	**Asset replacement and renewal less capital contributions**	**16,149**	**16,968**	**18,460**	**25,220**	**24,005**	**21,515**

Schedule 11a. Report on forecast capital expenditure continued

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2024 – 31 March 2034

111							
112	for year ended	Current Year CY 31 Mar 24	CY+1 31 Mar 25	CY+2 31 Mar 26	CY+3 31 Mar 27	CY+4 31 Mar 28	CY+5 31 Mar 29
113	**11a(v): Asset Relocations**	**$000 (in constant prices)**					
114	*Project or programme**						
115	Distribution Cable	-	50	1,550	250	500	-
116	Distribution Substations	-	-	-	-	-	-
117	Transformer	146	200	200	200	200	200
118							
119							
120	**include additional rows if needed*						
121	All other project or programmes - asset relocations	-	-	-	-	-	-
122	**Asset relocations expenditure**	**146**	**250**	**1,750**	**450**	**700**	**200**
123	*less* Capital contributions funding asset relocations	-	-	-	-	-	-
124	**Asset relocations less capital contributions**	**146**	**250**	**1,750**	**450**	**700**	**200**
128	**11a(vi): Quality of Supply**						
129	*Project or programme**	**$000 (in constant prices)**					
130	Generation	-	50	-	-	-	-
131							
132							
133							
134							
135	**include additional rows if needed*						
136	All other projects or programmes - quality of supply	-	-	-	-	-	-
137	**Quality of supply expenditure**	**-**	**-**	**-**	**-**	**-**	**-**
138	*less* Capital contributions funding quality of supply	-	-	-	-	-	-
139	**Quality of supply less capital contributions**	**-**	**-**	**-**	**-**	**-**	**-**
143	**11a(vii): Legislative and Regulatory**						
144	*Project or programme**	**$000 (in constant prices)**					
145	Distribution Line	-	800	-	-	-	-
146							
147							
148							
149							
150	**include additional rows if needed*						
151	All other projects or programmes - legislative and regulatory	-	-	-	-	-	-
152	**Legislative and regulatory expenditure**	-	800	-	-	-	-
153	less Capital contributions funding legislative and regulatory	-	-	-	-	-	-
154	**Legislative and regulatory less capital contributions**	-	800	-	-	-	-

Schedule 11a. Report on forecast capital expenditure continued

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
154							
155	for year ended	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29
157	**11a(viii): Other Reliability, Safety and Environment**						
158	*Project or programme**	**$000 (in constant prices)**					
159	Automation	3	140	100	200	200	200
160	Communication	57	200	200	200	200	200
161	Distribution Cable	563	750	1,450	1,000	250	1,000
162	Distribution Substations	-	335	-	-	-	-
	Distribution Switchgear	255	710	710	710	710	710
	Load and Voltage Control	81	50	150	150	150	150
	Load Control	-	-	600	-	-	-
	Ripple Plant	2	350	280	450	330	-
163	Zone Substation Metering	-	-	100	-	-	-
164	**include additional rows if needed*						
165	All other projects or programmes - other reliability, safety and environment	325	-	-	-	-	-
166	**Other reliability, safety and environment expenditure**	**1,286**	**2,535**	**3,590**	**2,710**	**1,840**	**2,260**
167	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
168	**Other reliability, safety and environment less capital contributions**	**1,286**	**2,535**	**3,590**	**2,710**	**1,840**	**2,260**

Schedule 11a. Report on forecast capital expenditure continued

170 171	for year ended	Current Year CY 31 Mar 24	CY+1 31 Mar 25	CY+2 31 Mar 26	CY+3 31 Mar 27	CY+4 31 Mar 28	CY+5 31 Mar 29
172	**11a(ix): Non-Network Assets**						
173	**Routine expenditure**						
174	*Project or programme**	**$000 (in constant prices)**					
175	Cyber security	-	110	-	-	-	-
176	Site Security	60	-	-	-	-	-
177	Emergency spares	-	350	1,300	850	600	100
179	**include additional rows if needed*						
180	All other projects or programmes - routine expenditure	1,114	482	229	264	289	423
182	**Routine expenditure**	**1,114**	**942**	**1,529**	**1,114**	**889**	**523**
183	**Atypical expenditure**						
184	*Project or programme**						
185	Transformer load visibility	-	-	-	-	-	-
186	Enterprise Content Management	586	-	-	-	-	-
187	Digital	498	-	-	-	-	-
188	Property	37	1,000	488	-	-	-
189	Branding	-	260	-	-	-	-
190	**include additional rows if needed*						
191	All other projects or programmes - atypical expenditure	-	90	-	-	-	-
192	**Atypical expenditure**	**1,121**	**1,350**	**488**	**-**	**-**	**-**
193							
194	**Expenditure on non-network assets**	**2,235**	**2,292**	**2,017**	**1,114**	**889**	**523**

Schedule 11b. Report on forecast operational expenditure

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2024 – 31 March 2034

7 8	for year ended	Current Year CY 31 Mar 24	CY+1 31 Mar 25	CY+2 31 Mar 26	CY+3 31 Mar 27	CY+4 31 Mar 28	CY+5 31 Mar 29	CY+6 31 Mar 30	CY+7 31 Mar 31	CY+8 31 Mar 32	CY+9 31 Mar 33	CY+10 31 Mar 34
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,815	2,209	2,262	2,310	2,356	2,403	2,451	2,500	2,550	2,601	2,653
11	Vegetation management	795	1,550	1,587	1,621	1,653	1,686	1,720	1,754	1,789	1,825	1,861
12	Routine and corrective maintenance and inspection	2,918	3,330	3,410	3,482	3,551	3,622	3,695	3,769	3,844	3,921	3,999
13	Asset replacement and renewal	382	342	350	358	365	372	379	387	395	403	411
14	**Network Opex**	**5,910**	**7,431**	**7,609**	**7,769**	**7,925**	**8,083**	**8,245**	**8,410**	**8,578**	**8,749**	**8,924**
15	System operations and network support	9,900	11,932	12,468	12,168	12,444	12,598	12,805	13,096	13,394	13,607	13,871
16	Business support	13,282	20,800	19,987	19,175	21,066	21,432	17,125	21,570	20,209	20,012	20,315
18	**Non-network opex**	**23,183**	**32,732**	**32,455**	**31,344**	**33,510**	**34,030**	**29,930**	**34,666**	**33,604**	**33,619**	**34,186**
19	**Operational expenditure**	**29,093**	**40,163**	**40,064**	**39,113**	**41,435**	**42,113**	**38,174**	**43,075**	**42,181**	**42,369**	**43,110**
22		**$000 (in constant prices)**										
23	Service interruptions and emergencies	1,815	2,209	2,209	2,209	2,209	2,209	2,209	2,209	2,209	2,209	2,209
24	Vegetation management	795	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550
25	Routine and corrective maintenance and inspection	2,918	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330	3,330
26	Asset replacement and renewal	382	342	342	342	342	342	342	342	342	342	342
27	**Network Opex**	**5,910**	**7,431**	**7,431**	**7,431**	**7,431**	**7,431**	**7,431**	**7,431**	**7,431**	**7,431**	**7,431**
28	System operations and network support	9,900	11,932	12,176	11,639	11,669	11,582	11,541	11,572	11,603	11,557	11,550
29	Business support	13,282	20,800	19,518	18,341	19,754	19,703	15,435	19,060	17,508	16,997	16,916
31	**Non-network opex**	**23,183**	**32,732**	**31,694**	**29,980**	**31,423**	**31,285**	**26,976**	**30,632**	**29,111**	**28,554**	**28,466**
32	**Operational expenditure**	**29,093**	**40,163**	**39,125**	**37,411**	**38,854**	**38,716**	**34,407**	**38,063**	**36,542**	**35,985**	**35,897**
33	**Subcomponents of operational expenditure (where known)**											
36	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
37	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
38	Research and Development	-	-	-	-	-	-	-	-	-	-	-
39	Insurance	454	628	629	629	629	629	629	629	629	629	629
41	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
45	**Difference between nominal and real forecasts**	**$000**										
46	Service interruptions and emergencies	-	-	53	101	147	194	242	291	341	392	444
47	Vegetation management	-	-	37	71	103	136	170	204	239	275	311
48	Routine and corrective maintenance and inspection	-	-	80	152	221	292	365	439	514	591	669
49	Asset replacement and renewal	-	-	8	16	23	30	37	45	53	61	69
50	**Network Opex**	**-**	**-**	**178**	**338**	**494**	**652**	**814**	**979**	**1,147**	**1,318**	**1,493**
51	System operations and network support	-	-	292	530	775	1,016	1,264	1,524	1,791	2,050	2,321
52	Business support	-	-	480	857	1,345	1,773	2,237	2,576	2,779	3,104	3,500
54	**Non-network opex**	**-**	**-**	**773**	**1,387**	**2,120**	**2,789**	**3,501**	**4,100**	**4,570**	**5,154**	**5,821**
55	**Operational expenditure**	**-**	**-**	**951**	**1,725**	**2,614**	**3,441**	**4,314**	**5,078**	**5,716**	**6,473**	**7,314**

Appendix 3:

Schedule 12a: Report on asset condition

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2024 – 31 March 2034

7			Asset condition at start of planning period (percentage of units by grade)									
8												
9	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
10	All	Overhead Line	Concrete poles / steel structure	No.	-	0.04%	31.74%	32.38%	35.84%		3	0.50%
11	All	Overhead Line	Wood poles	No.	1.36%	5.88%	50.14%	15.46%	27.16%		3	3.00%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	8.85%	25.26%	36.63%	29.26%		3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	0.29%	4.79%	94.92%		4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km							N/A	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							N/A	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km							N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	10.53%	5.26%	31.58%	52.63%		3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	100.00%		4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	5.26%	-	26.32%	15.79%	52.63%		4	5.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	24.24%	16.67%	12.12%	-	46.97%		3	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	19.75%	12.35%	18.52%	1.23%	48.15%		3	5.00%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	100.00%		3	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	100.00%		4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	26.67%	-	-	-	73.33%		3	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	23.53%	76.47%		3	-
35												

Schedule 12a: Report on asset condition continued

36	Asset condition at start of planning period (percentage of units by grade)												
37													
38	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	7.14%	7.14%	14.29%	71.43%		3	4.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.32%	40.11%	19.46%	15.31%	24.80%		3	2.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	-	100.00%	-	-	-		3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.29%	0.29%	0.72%	14.30%	84.40%		3	0.50%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	2.20%	80.27%	17.53%		3	-
45	HV	Distribution Cable	Distribution Submarine Cable	km							N/A	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	9.38%	35.94%	54.69%		3	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	4.85%	-	14.55%	16.36%	64.24%		3	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	14.79%	5.65%	4.94%	22.70%	51.91%		3	5.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	37.70%	9.84%	-	-	52.46%		3	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	3.32%	15.49%	25.44%	12.39%	43.36%		3	2.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.05%	30.03%	27.92%	23.61%	17.38%		3	1.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.45%	16.99%	22.45%	31.66%	28.44%		3	1.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	60.29%	39.71%		4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.							N/A	
55	LV	LV Line	LV OH Conductor	km	0.43%	28.80%	49.38%	16.73%	4.67%		3	2.00%
56	LV	LV Cable	LV UG Cable	km	0.53%	0.78%	4.67%	57.45%	36.57%		3	1.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km							N/A	
58	LV	Connections	OH/UG consumer service connections	No.							N/A	
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	2.00%	0.45%	13.14%	65.03%	19.38%		3	2.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	2.33%	-	37.21%	44.19%	16.28%		3	5.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	21.43%	-	32.14%	46.43%		3	-
62	All	Load Control	Centralised plant	Lot	1.16%	16.67%	18.60%	22.09%	41.47%		3	16.00%
63	All	Load Control	Relays	No.							N/A	
64	All	Civils	Cable Tunnels	km							N/A	

Appendix 4:

Schedule 12b: Report on forecast capacity

7 **12b(i): System Growth - Zone Substations**

9	Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
10	Albury (ABY)	4	-	N	-	-	-		No constraint within +5 years	Meets Alpine security standard
11	Old Man Rage (OMR)	0	-	N	-	-	-		No constraint within +5 years	Balmoral sub decommissioned in 2019
12	Bells Pond (BPD)	14	20	N-1	-	72%	20	94	Transformer	T1 installed FY18/19, T2 to be upgraded to provide N-1 security of supply
13	Clandeboye 1 (CD1)	14	20	N-1	-	69%	20	73	Transformer	Orari new GXP in 2026/2027 due to forecast to growth
14	Clandeboye 2 (CD2)	20	25	N-1	-	79%	25	220	Transformer	Orari new GXP in 2026/2027 due to forecast to growth
15	Cooney's Road (CNR)	5	-	N	1.8/0.8/0.6*	-	-	-	No constraint within +5 years	Meets Alpine security standard
16	Fairlie (FLE)	3	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
17	Geraldine (GLD)	7	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
18	Haldon Lilybank (HLB)	1	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
19	Pareora (PAR)	9	15	N-1	-	61%	15	66	No constraint within +5 years	Meets Alpine security standard
20	Pleasant Point (PLP)	5	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
21	Rangitata (RGA)	10	10	N-1	-	102%	10	110	Subtransmission circuit	Line capacity constraint, sufficient 11 kV backup in place
22	Studholme (STU)	14	10	N-1	-	141%	10	158	Transpower	Transpower two 11 MVA transformers, load shedding/shift required
23	Tekapo Village (TEK)	5	-	N	-	-	15	88	Transformer	Upgrade of transformer and the Temuka substation option of constructing a "twin" substation/switching station to provide N-1 security of supply
24	Temuka (TMK)	13	25	N-1	-	51%	25	57	No constraint within +5 years	Meets Alpine Security standard
25	Timaru 11/33 kV (TIM)	15	-	N	-	-	-	-	No constraint within +5 years	Loads to be transferred to Timaru 33kV GXP in 2026/2027
26	Twizel Village (TVS)	4	-	N	-	-	-	-	No constraint within +5 years	Options being assessed to upgrade installed firm capacity
27	Unwin Hut (UHT)	1	-	N	-	-	-	-	No constraint within +5 years	Meets Alpine security standard
28	Washdyke	-	-	-	-	-	54	75	No constraint within +5 years	We are forecasting an additional 46 MW at Washdyke over the next five years, with very little headroom remaining in the 11kV distribution network in the area. The development of new 33kV GXP by Transpower (located at the existing Timaru GXP site), is essential for the delivery of our Washdyke roadmap, providing additional capacity into this industrial area through an upgraded 33kV sub-transmission system. To utilise this new capacity, a new 33kV substation is planned for Washdyke in 2025-2026, following the completion of a new 11kV switching station that is currently in construction
29										

Schedule 12c: Report on forecast network demand

Company name: Alpine Energy Ltd
AMP planning period: 1 April 2024 – 31 March 2034

7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*	**Number of connections**					
9 10	for year ended	**Current Year CY 31 Mar 23**	**CY+1 31 Mar 24**	**CY+2 31 Mar 25**	**CY+3 31 Mar 26**	**CY+4 31 Mar 27**	**CY+5 31 Mar 28**
11	*Consumer types defined by EDB**						
12	Large Scale Distributed Generation	-	-	1	-	-	-
13	Large Industrial Connections	-	2	5	3	5	4
14	Commercial (medium/small)	7	10	10	11	11	10
15	Irrigation	5	6	5	6	5	4
	Residential	130	137	137	138	138	138
16	Subdivision	38	44	44	44	45	44
17	**Connections total**	**180**	**199**	**202**	**202**	**204**	**200**
18	**include additional rows if needed*						
22	**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23	Number of connections made in year	128	131	134	138	140	143
24	Capacity of distributed generation installed in year (MVA)	0.8	0.7	30.8	1.0	0.9	0.9
25	**12c(ii) System Demand**						
27	**Maximum coincident system demand (MW)**						
28	GXP demand	147	162	174	209	216	223
29	*plus* Distributed generation output at HV and above	7	7	13	13	14	14
30	**Maximum coincident system demand**	**154**	**169**	**187**	**222**	**229**	**236**
31	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
32	**Demand on system for supply to consumers' connection points**	**154**	**169**	**187**	**222**	**229**	**236**
33	**Electricity volumes carried (GWh)**						
34	Electricity supplied from GXPs	830	916	983	1,179	1,218	1,258
35	*less* Electricity exports to GXPs	22	19	66	62	50	34
36	*plus* Electricity supplied from distributed generation	34	35	88	90	92	93
37	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
38	**Electricity entering system for supply to ICPs**	**842**	**932**	**1,006**	**1,207**	**1,260**	**1,317**
39	*less* Total energy delivered to ICPs	812	899	971	1,165	1,215	1,267
40	**Losses**	**30**	**32**	**35**	**42**	**45**	**50**
41							
42	**Load factor**	**62%**	**63%**	**61%**	**62%**	**63%**	**64%**
43	**Loss ratio**	**3.5%**	**3.5%**	**3.5%**	**3.5%**	**3.6%**	**3.8%**

Schedule 12d: Report forecast interruptions and duration

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8							
9	for year ended	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28
10	**SAIDI**						
11	Class B (planned interruptions on the network)	100.0	100.0	100.0	100.0	100.0	100.0
12	Class C (unplanned interruptions on the network)	91.9	91.9	91.9	91.9	91.9	91.9
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.70	0.70	0.70	0.70	0.70	0.70
15	Class C (unplanned interruptions on the network)	1.20	1.20	1.20	1.20	1.20	1.20

Appendix 7:

Schedule 14a: Mandatory explanatory notes on forecast information

Schedule 14a

Company name: Alpine Energy Limited

For Year Ended 31 March 2024

Schedule 14a - Mandatory Explanatory Notes of Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015))

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

This Schedule is mandatory EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is part of the audited disclosure information, and so is not subject to the assurance requirements specified in Section 2.6.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a).

The nominal dollars capital expenditure forecast for 31 March 2024 represents the forecast actual capital expenditure for the year ending 31 March 2024. The constant price for 31 March 2024 represents the forecast values as per the prior year AMP.

To derive the capital expenditure in nominal dollar terms, the constant price forecasts (using 2025 real dollars) were inflated by 2.4% for 2026, 2.1% for 2027, and 2.0% for the other years, based on forecasts by ANZ and the Reserve Bank of New Zealand (RBNZ). To derive the ten-year forecast, 2.4% for 2026, 2.1% for 2027, and 2.0% for the other years, as conservative inflationary rates. Therefore, the difference between nominal and constant expenditure forecasts is an inflationary impact of 2.4 in 2026, 2.1% in 2027, and 2.0% in other years.

Commentary on difference between nominal and constant prise operational expenditure forecasts (Schedule 11b).

The nominal dollars operational expenditure forecast for 31 March 2024 represents the forecast actual operational expenditure for the year ending 31 March 2024. The constant price for 31 March 2024 represents the forecast values as per the prior year AMP.

To derive the operational expenditure in nominal dollar terms, the constant price forecasts (using 2025 real dollars) were inflated by 2.4% for 2026, 2.1% for 2027, and 2.0% for the other years, based on forecasts by ANZ and the Reserve Bank of New Zealand (RBNZ). To derive the 10-year forecast, 2.4% for 2026, 2.1% for 2027 and 2.0% for the other years, as conservative inflationary rates. Therefore, the difference between nominal and constant expenditure forecasts is an inflationary impact of 2.4% for 2026, 2.1% for 2027, and 2.0% in other years.

Appendix 8:

Schedule 17: Certification for year-beginning disclosures

We, Warren McNabb and Melissa Clark-Reynolds, being directors of Alpine Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Alpine Energy Limited prepared for the purposes of clauses 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Alpine Energy Limited's corporate vision and strategy and are documented in retained records.

Director	Director
28 March 2024	28 March 2024
Date	Date

24 Elginshire Street, Washdyke, Timaru 7940 **P.** 0800 66 11 77 **www.alpineenergy.co.nz**