Counties Energy

Asset Management Plan

Update 1 April 2022

Energy Reimagined

Contents

1. Introduction

1.1 Executive Summary

This 2022 Asset Management Plan Update (AMP Update) provides updates of our investment plans and asset management practices that have occurred since we published our 2021 Asset Management Plan on 31 March 2021.

Specifically, for this update, in accordance with the Information Disclosure Determination, we have incorporated the following updates to:

- Service levels;
- Material changes to asset management practices;
- Network reliability; and
- Regulatory Schedules:
  - Forecast Capital Expenditure in Schedule 11a;
  - Forecast Operational Expenditure in Schedule 11b;
  - Asset Condition in Schedule 12a;
  - Forecast Capacity in Schedule 12b;
  - Forecast Network Demand in Schedule 12c; and
  - Forecast Interruptions and Duration in Schedule 12d.

Counties Energy Limited (Counties Energy) was rebranded from Counties Power late last year so that our visual identity more accurately reflects our vision of reimagining energy for our customers. Our continued evolution reflects the changing needs of energy consumers today: the adoption of smart technologies to support two-way energy flow, decarbonisation, and community energy schemes that utilise solar and batteries to support electric vehicle charging.

As Counties Energy, we have a proud history spanning almost 100 years, and we remain a safe pair of hands for the community that we serve, while navigating a fast changing energy landscape. In particular, the growing volume of distributed generation requires us to start transitioning from a Distribution Network Operator (DNO) to a more dynamic Distribution Systems Operator (DSO) role to actively manage the network using new technology and real-time data.

Demand on our network continues to experience growth in the Pukekohe, Paerata, Drury, Karaka, Glenbrook and Pokeno areas. This has driven, and continues to drive, our investment in zone substations, capacity upgrades, and reliability improvements.

Our growth forecasts have been updated to reflect the latest information regarding residential and industrial developments in our region. These have resulted in changes to the forecast capital expenditure, with the major change being to the timing of zone substations in the Drury and Pukekohe North areas.

In our 2021 Asset Management Plan, the Pukekohe North zone substation was to be established over FY24–FY26, while the zone substation for the Drury Area (Quarry Road) was to come online in FY32[1]. We now have substantial industrial growth in the Drury area forecast for 2024–2027, while residential load (in the Drury and Pukekohe North regions) is anticipated to gradually come online over the next 10–15 years. This has driven the need for a substation in the Drury Area sooner than anticipated, thus the Quarry Road

1 Whilst the Quarry Road zone substation was being established in FY32, this was only the 22 kV portion. The 110 kV portion of this site needed establishment in the same timeframe as Pukekohe North.

zone substation will now be established by FY26, with the Pukekohe North zone substation being deferred until FY34–FY35. In conjunction with the Quarry Road zone substation, feeder reinforcement is expected to provide additional capacity for anticipated residential loads in the wider Drury and Pukekohe North areas for the next decade.

The forecast for capital expenditure (CAPEX) across the planning period is $438 m, increasing $8.6 m from the 2021 Asset Management Plan forecast. The forecast for operational expenditure (OPEX) across the planning period is $237.5 m, increasing $31 m from the 2021 Asset Management Plan forecast.

The increase in our forecast OPEX reflects our ongoing commitment to embracing new technologies and digitalisation for greater efficiency of network control in order to address decarbonisation and sustainability. Smart technologies such as Advanced Distribution Management System (ADMS), Asset Management and DSO-related platforms will complement our physical infrastructure to ensure we maximise the full potential of these assets.

The changes identified in this AMP Update will ensure we meet the growth in demand from developments and improve the quality of service.

1.2. Period Covered by the 2022 AMP Update

This AMP Update covers the period from 1 April 2022 to 31 March 2032 (planning period).

1.3. Approval Date

This AMP Update was reviewed and approved by the Counties Energy Limited Board of Directors on 22 March 2022.

1.4. Purpose Of This Document

The purpose of the AMP Update is to inform and communicate to our stakeholders the material changes in asset management from our 2021 Asset Management Plan. These changes are provided to reflect our latest demand forecast, which is aligned with the high levels of growth in the area, and accelerate ageing asset renewal and replacement to meet our stakeholder requirements according to our asset management strategy and objectives.

The AMP Update is not intended to be a fully self-contained plan but rather an update to (and should be read in conjunction with) our 2021 Asset Management Plan. Our 2021 Asset Management Plan can be found at www.countiesenergy.co.nz/about/content/regulatory

1.5. Intended Audience

The intended audience for this AMP Update is our stakeholders. This includes our customers, community, shareholders, the Commerce Commission and the Electricity Authority, employees and contractors, and other interested parties.

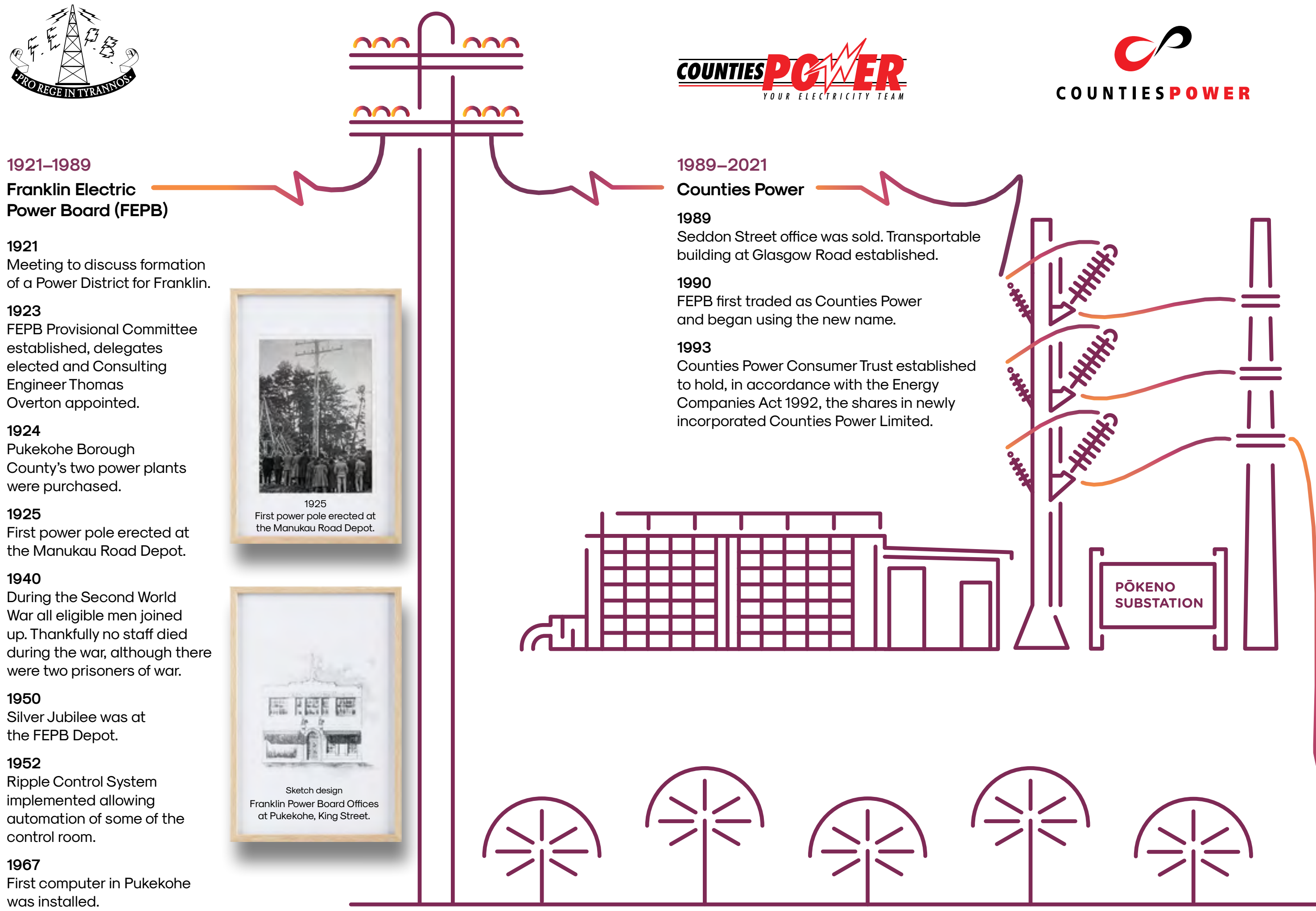

Figure 2-1 Our Evolution

2. Reimagining Energy

2.1 Say Hello to Counties Energy

Last year marked a significant moment in the company's almost 100-year history of distributing electricity to the community as it evolved with a fresh new name and brand – Counties Energy.

From Franklin Electric Power Board to Counties Power, and now to Counties Energy, this evolution reflects the changing needs of energy consumers today, and into the future, with the adoption of smart technologies and increasing need and expectations for decarbonisation from customers.

As one of New Zealand's most progressive energy companies, we're already trusted by thousands of Kiwis to power their busy lives and successful businesses, develop new technology innovations and generate life-changing ideas. Today, with more sustainable technologies and a customer base looking for even greater value for money, we're proactively responding to the needs and wants of our customers.

Over the past year, we've been diving deep into customer journeys, usage and views on the future of energy, alongside our research into the changing state of the energy market. We believe energy can change lives for the better – for the planet, our customers and our communities – so we're putting our insights into action to reimagine energy for the better.

Counties Power wins Premier Award for electricity marketing excellence.

1999
Laws were passed splitting lines companies and retail parts of all New Zealand electricity suppliers.

2019
Counties Power invests in ECL Group.

Counties Power wins 'Network Initiative of the Year' at the Deloitte Energy Excellence Awards.

2020
Counties Power goes live on new substation in Pōkeno.

2021
Counties Power commences $40m network upgrade in eastern region, including a new substation for Bombay.

Counties Power rebrands to Counties Energy.

Now and into the future

For nearly 100 years, we've seen a lot of changes here at Counties. It's brought us to where we are today.

As we enter our next chapter, we celebrate these milestones and start to imagine what the future of energy could hold.

It's an exciting time as we embrace the changes ahead and explore new and innovative ways of working and new ventures to see us through another 100 years to come.

Our new name is Counties Energy

Counties Energy

A new brand for a new era for the business. As you're aware, the world has changed and to stay relevant and thrive we need to change with it.

These days we're more than power – we're a technology and energy business too, and our new name and look reflects this.

As New Zealand transitions to a low carbon future, we see our energy industry changing too – and with that our role as an electricity distribution network.

We need to be as forward-thinking as possible, and fully prepared for what's next.

While moving forward, we acknowledge our proud history and the locals who built the network and served our community by keeping the power flowing. We've been a reliable, safe pair of hands for the communities of South Auckland to the top of the Waikato.

As Counties Energy, we continue to be a safe pair of hands; our new name and logo reflect our new energy journey that focuses on reimagining energy – from smart grid technologies to virtual power plants and community energy schemes that utilise electric vehicle charging, renewable energy and cutting-edge digital technologies.

Our new visual identity is accompanied by a more customer friendly tone of voice. Our reimagined infinity device has been integrated into the new logo, which, along with a gradient of bright new colours, symbolises an exciting and constantly evolving energy future. Our refreshed values (Safety First, Customer Obsessed, Energy Innovators, Always On, and Human Kind) have provided a renewed focus for our people to shape tomorrow, today.

2. Reimagining Energy

2.2 How We're Reimagining Energy

The electricity industry has a big part to play in the transition to a low carbon future. Counties Energy continues to evolve to address challenges of decarbonisation and sustainability as well as embracing new technologies and digitalisation for greater efficiency of network control.

Our job is to manage increasing energy demands on the network utilising new and smarter technologies that enable multi-directional energy flows while maintaining customer choice and quality of supply and providing value for money. Market forces such as the pace of Auckland's growth and the uptake of Electric Vehicles (EVs) has required Counties Energy to begin thinking differently about our role as an energy distribution provider for today and tomorrow.

For a number of years now, we have increased our commitment and capability in smart technologies to reimagine the future of energy. In particular, the growing volume of distributed generation requires us to start transitioning from a Distribution Network Operator (DNO) to a more dynamic Distribution Systems Operator (DSO) role to actively manage the network using new technology and real-time data. More on our emerging DSO strategy can be found in section 2.4.

As a Metering Equipment Provider or MEP, our ability to access real-time meter data for usage levels and power quality aids our understanding of changing trends in consumer behaviour. We can no longer assume that peak demand will remain between 6 and 9 am in the morning and between 5 and 9 pm in the evening with shifting work patterns and more options for people to work remotely. Real-time meter data is crucial in effectively managing the changing consumer behavioural patterns and the subsequent load profiles on the network.

Lowering emissions and creating smaller carbon footprints through sustainable technologies is already an important focus.

Positive changes in producing and using energy are well underway and include:

- Vehicle-to-Grid technology pilot with direct Solar EV Charging capability;
- OpenLoop – EV charging platform; and
- Second-life battery system using retired EV batteries to support the electricity network.

It is important to note that using smart technologies such as Advanced Distribution Management System (ADMS), Asset Management and DSO-related platforms to manage a dynamic network will complement our continued investment in physical infrastructure to ensure we maximise the full potential of these assets. We also expect that, in the future, energy technologies such as microgrids, grid-scale batteries and commercial-scale solar arrays will be part of our physical infrastructure.

Counties Energy is investigating a site south of Port Waikato for a potential future windfarm, with a wind monitoring tower installed in early 2021. While this site is still being evaluated it would most likely be connected to the distribution network using Counties Power's standard single pole 110kV transmission lines back to the Tuakau substation. If the windfarm were to proceed it would provide a significant amount of clean green renewable power for South Auckland.

2.3 Becoming Customer Obsessed

Part of the transition from Counties Power to Counties Energy has been increased focus on the end-customer, especially the need to better understand who our customers are and improve their customer experience (CX). Counties Energy has developed a Customer Strategy consisting of six key pillars to ensure the customer is at the centre of everything we do.

- **Connect Me and Service Me –** these two pillars of the Customer Strategy encapsulate service delivery in the electricity space, ensuring programmes of work to bring us from good to great for improved customer experiences in outages and new connections.
- **Share with Me –** this is the strategy pillar related to customer communications in relation to Counties Energy initiatives and was formed due to customer feedback.
- **Here for Me –** the Community Engagement pillar reflects the important role we play in our community as the sole electricity distributor, with programmes that benefit the community.

Figure 2-2 Our Customer Strategy

- **Innovate for Me –** this pillar reflects the importance of constantly innovating to improve the lives of our customers by staying one step ahead.
- **Get to Know Me –** last but not least; this pillar realises the importance of knowing who our customers are, their pain points, and how we can improve their customer experience. Together with the Innovate for Me pillar, we ensure we meet customers' current needs and innovate for their future needs.

2.4 Becoming Distribution System Operator (DSO) ready

2.4.1 What is a DSO?

There are many definitions of a DSO around the world. The one that most resonates with Counties Energy's vision is the modernisation of the traditional electricity distribution utility. A modernisation focused on adding capabilities of new technologies, granular network intelligence, aggregation, and management of Distributed Energy Resources (DERs). The broadening of the scope allows traditional Distribution Network Operators (DNOs) to enable customers with new energy-related opportunities such as unlocking greater DER enablement, an alternative to traditional network investment and a highly visible, transparent cost-optimal service.

A DER can be any generation, storage or controllable load resource on the electricity distribution network. DERs include solar photovoltaic (PV), wind, batteries, electric hot water cylinders and EV chargers. As a DSO, Counties Energy will (1) connect and signal DERs within its network in an optimal manner that allows for greater uptake of the above technologies, and (2) have a greater awareness of its network, components, loading and performance. These new capabilities will allow Counties Energy to continue providing a modern and cost-effective electricity lines service.

2. Reimagining Energy

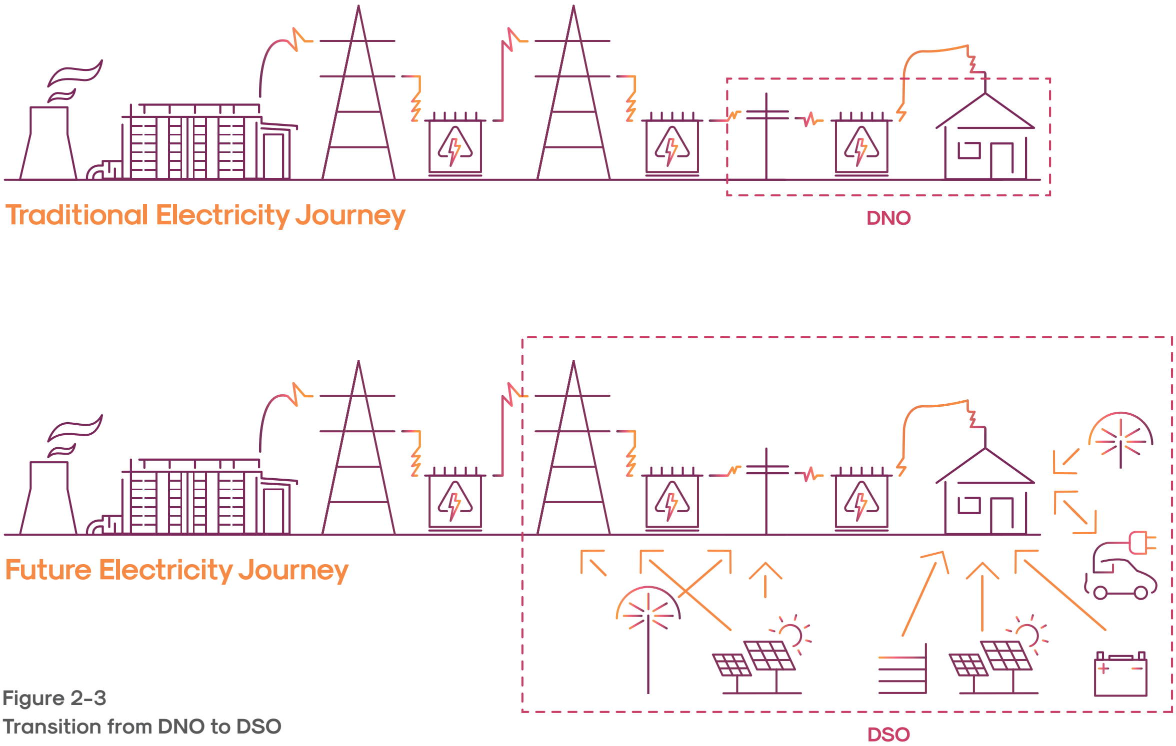

Figure 2-3
Transition from DNO to DSO

2.4.2 How are we going to transform into a DSO?

The transition for electricity distribution businesses to a DSO will require a significant uplift in current capabilities and approach. Some key early areas that we are focusing on are:

Being customer obsessed

As the uptake of DERs such as batteries, EVs and solar continues to grow, the transition of Counties Energy from a DNO to a DSO becomes even more important if we are to meet the changing needs of customers. Customers are demanding greater choice and control around energy generation, usage and renewables. We have to adapt if we are to deliver to customers' needs while ensuring a safe, reliable supply of energy.

Creating Greater Low Voltage (LV) Visibility

The investment of capital into the LV network is necessary to prevent impaired performance and requires real-time monitoring of changing consumer consumption and DER injections. Therefore, setting an LV strategy and breaking this into functional components is needed: customer, engineering, network planning, operations, field services and project delivery. Supporting the LV strategy will be the right digital tools and processes to effectively manage granular visibility of the LV network.

Enabling the rapid enrolment of DERs

There are many providers of PV, wind generation, batteries, EV chargers and energy aggregators in the market. We recognise the importance of building strategic partnerships with these providers to unlock value for customers by introducing and trialling initiatives such as:

- a map of our network identifying ideal locations for different types of DERs;
- a demand-based pricing model for residential EV charging; and
- streamlining the new DER connections process online.

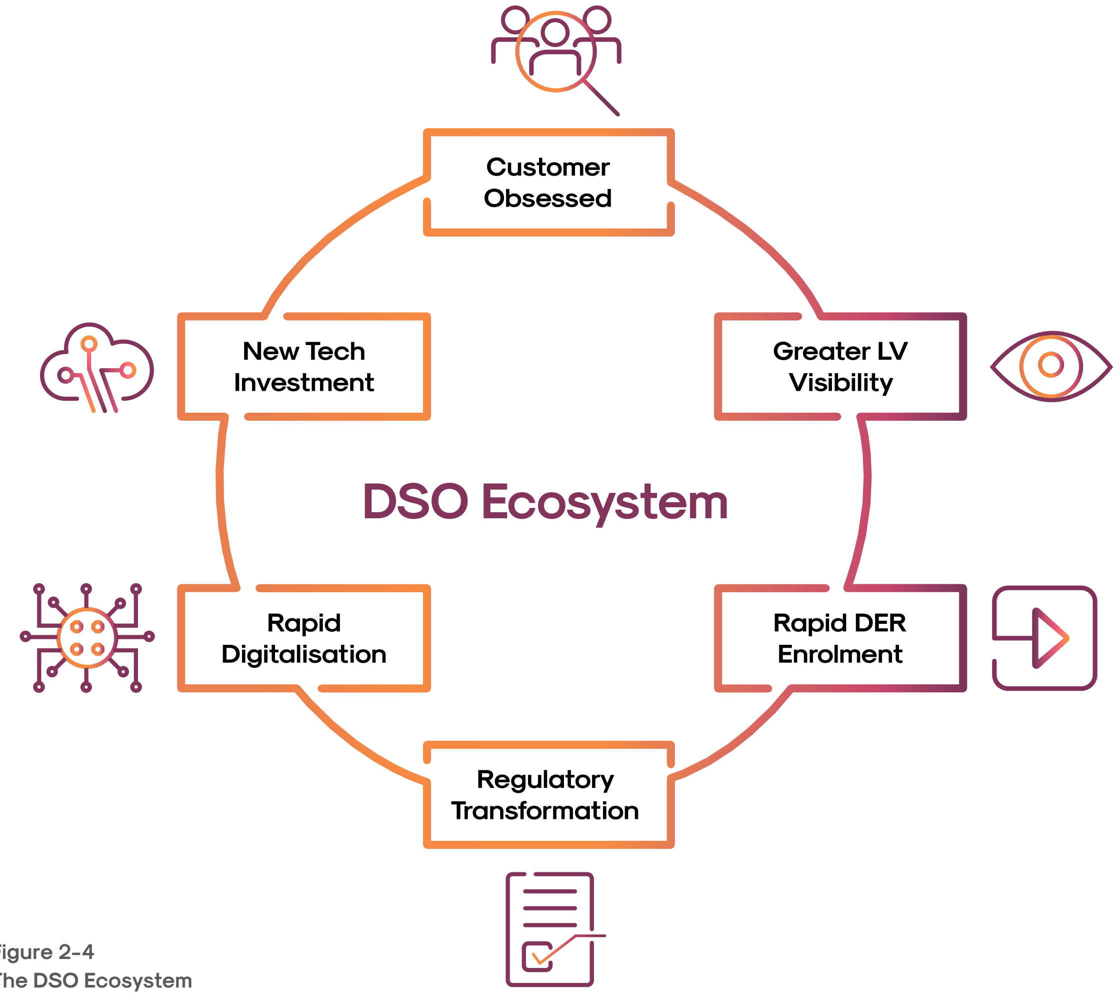

Figure 2-4
The DSO Ecosystem

Regulatory Transformation

Therefore, it is important that Counties Energy works closely with industry partners, other EDBs and government regulatory bodies on innovative and creative step changes required towards a DSO transition.

Rapid Digitalisation

As the boundaries between the physical and digital worlds continue to blur, Counties Energy will continue to invest in digital tools that provide the foundation for greater network granularity and control. This in turn will enhance network reliability, worker safety and precision reinforcement. Key areas of investment will include OpenLoop EV charging platform, ADMS, GIS, Outage Management, Advanced Metering Data Intelligence, Machine Learning, Cyber Security, Data Privacy, Automation, Distributed Energy Resource Management System (DERMS).

Investing in New Energy Technology

Besides enabling DER integration on our network, Counties Energy will consider how best to integrate community PV, battery and smart EV charging solutions. The deferral of traditional investment in larger cables, bigger oil-filled transformers and substations is also an important consideration as we look to new technologies for smarter ways to manage hot water, network control, fault prediction and self-healing networks. These technologies combined with our digital investments will ensure that Counties Energy is at the forefront of a modern utility sector.

2. Reimagining Energy

2.5 Advanced Distribution Management System (ADMS)

Counties Energy will implement GE Digital's ADMS as part of its Digital Utility transformation programme. The ADMS solution, in combination with our existing implementation of GE Digital's Smallworld Electric Office, will drive greater reliability, resiliency and flexibility for our assets through richer multi-source data. Combining the two platforms will enable smarter, sustainable and innovative energy services and solutions that deliver better customer experiences, operational efficiencies, and the ability to manage growth intelligently, ultimately shaping a future-proofed energy platform.

The ADMS solution for Counties Energy combines Supervisory Control and Data Acquisition (SCADA), Distribution Management System (DMS) and Outage Management System (OMS) capabilities. By implementing this solution, Counties Energy will have a single platform to safely interact with its network, control work and share information in real-time and ultimately provide low voltage network visibility.

By integrating ADMS and Electric Office, Counties Energy will be able to provide network operators with an accurate connected single view of the end-to-end network of assets with a fully digital as-built process flowing from the field to Smallworld Electric Office and on to the ADMS. There are also plans to create a rich picture of its network by utilising its smart meter coverage to increase the accuracy of the traditional SCADA high and medium voltage view.

Counties Energy intends to leverage the improved knowledge of our physical assets in new and expansive ways. Advanced analytics can be used to simulate weather impacts, improve storm preparedness and outage response, and understand how the network will behave under different load and future Distribution Energy Resources (DER) growth scenarios.

3. Service Levels

3.1 Customer Service Performance

We engage an external research company to undertake monthly surveys to provide a pulse on customer satisfaction. These surveys target a sample of 50 customers who have interacted with our team throughout the month, and provide insights into when customer expectations have been met or improvement is necessary. The annual customer report, provided in August 2021 for the 12 months prior, yielded the best result since surveys began five years ago.

In 2019, Counties Energy made the decision to deliver our comprehensive customer survey on an annual basis rather than the previous bi-annual programme. In addition, in early 2021, Counties Energy took part in a benchmarking exercise where our results were compared with five other electricity distribution businesses (EDB) in New Zealand. This benchmarking has proved helpful and has facilitated cross-industry collaboration. In our most recent comprehensive customer survey, the main driver of overall satisfaction was value for money, followed by image, reputation and communication.

Building on customer experience is a core focus for Counties Energy. Recently, we have been working with customer groups to explore in detail our planned and unplanned outage customer journeys. This work will provide the basis for any improvement necessary in each respective area.

3.2 Workplace Safety

Counties Energy is committed to "Safety First" and undertaking its business in a way that enables everyone to be healthy, safe and well.

Through the sustained application of the principles, provision and intent of the Health and Safety at Work Act 2015, Counties Energy continues a tradition of strong leadership, and aspirations of continuous advancements, in the area of safety, health and wellness.

Managing the impact of COVID-19 has triggered the business over the past 18 months to put in place additional measures and protocols that keep our people safe and the business running to ensure customers have minimised unplanned disruptions.

3.2.1 Leading Indicators

We continue to monitor, promote and encourage safety observations and safety audits. Additionally, we undertake independent external safety audits to identify areas for continuous improvement.

3.2.2. Lagging Indicators

We continue to review and implement learnings from incident trends and data analysis.

Total recordable injury frequency rate (TRIFR): This measures the total recordable injury frequency rate, which encompasses loss of time, restricted work and medically treated injuries

Lost time injury frequency rate (LTIFR): This measures the total number of lost time injuries and lost days. Our company target for each measure is to reduce to zero.

Our LTIFR and TRIFR reflects one lost time incidents over the past 12 months, a positive reduction from the previous reported period. These incidents were investigated, improvements were implemented with resulting changes, and learnings notified to the business.

We continue to grow and stretch in the safety space by continually considering what we can do differently – the Stop for Safety Day in May was run by the Safety Representatives, demonstrating the increasing maturity of this team.

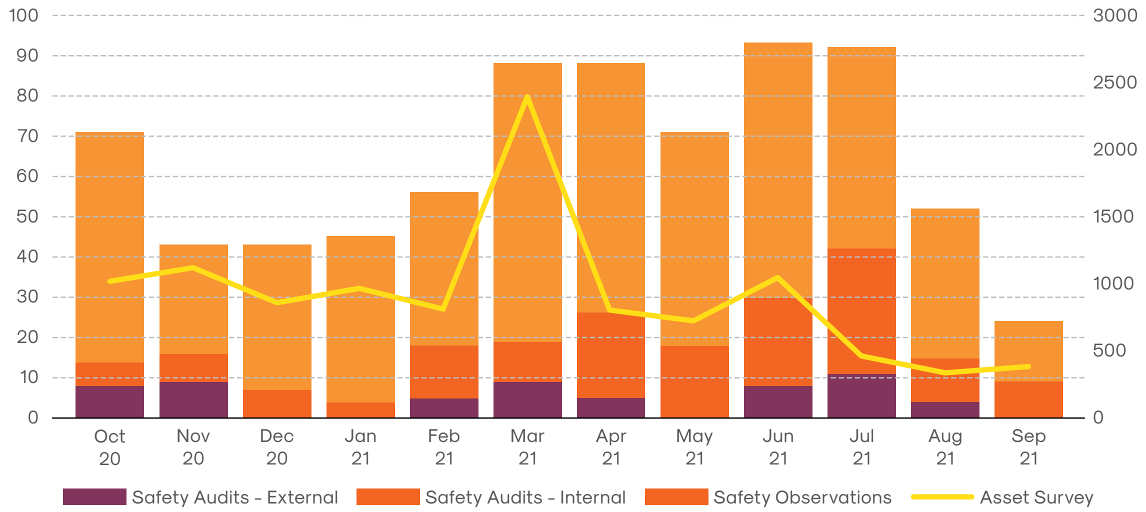

Figure 3-1 Leading Indicators

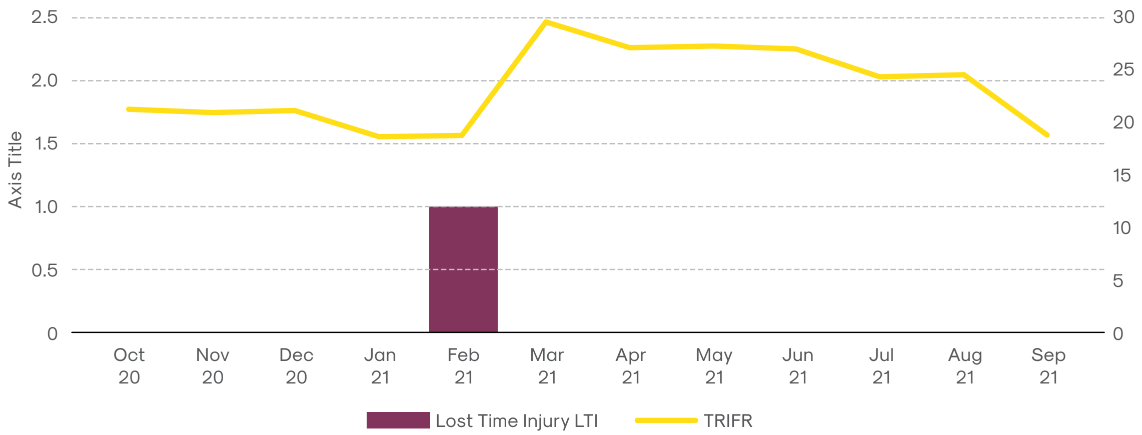

Figure 3-2 TRIFR (Total Recordable Injury Frequency Rate)
– 12 Month Rolling Average (per million hours worked)

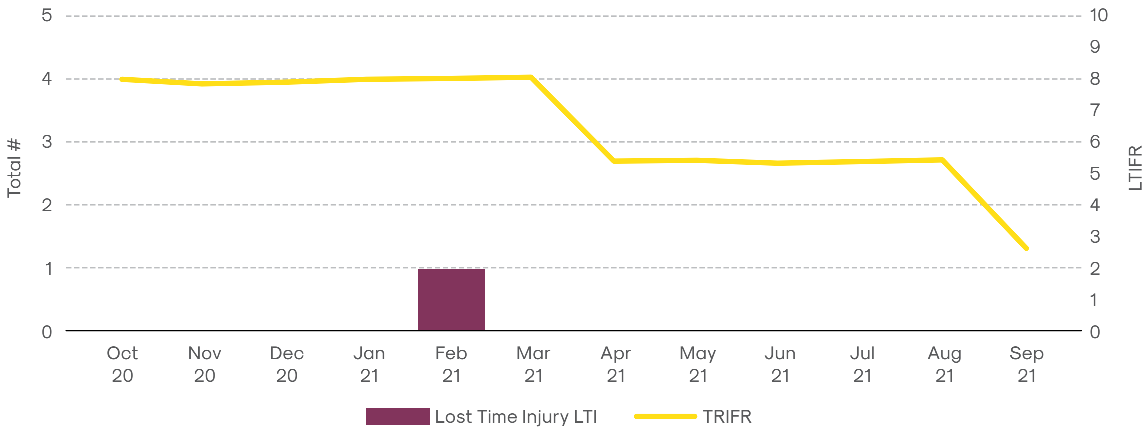

Figure 3-3 LTIFR (Lost Time Injury Frequency Rate)
– All Events – 12 Month Rolling Average (per million hours worked)

3.3 Public Safety Measures and Targets

Our objective is to ensure that our network assets harm no member of the public and that hazards introduced by our network assets are controlled to minimise the risk to be as low as reasonably practicable.

3.3.1 Leading Indicators

Categories for leading public safety indicators include:

- The number of asset inspections and tests undertaken on:
  - High-risk asset categories in the public domain – pillars, transformers, high-voltage switchgear, poles and zone substations;
  - Safety-critical assets – earthing and protection systems; and
  - Assets in special locations – those located around schools, public recreation spaces, commercial and shopping areas.
- The time taken to repair high-risk defects on the network (percentage completed within required timeframes); and
- The number of external stakeholder engagement activities.

3.3.2 Lagging Indicators

Lagging indicators include:

- The number of incidents reported with or without harm; and
- The number of damaged property incidents (consumer premises and network property).

The actual performance for FY20 to FY22 are shown in the table below.

Details	FY20	FY21	FY22 (to end Sep)
Property Damage to Network Assets	249	193	113
Reported Public Injuries from Network Assets	4	1	0

Table 3-1 Actual Performance FY20-FY22

3.4 Network Reliability

3.4.1 Objectives

Our objective is to operate the network to provide a level of performance in line with the price customers are willing to pay, this includes:

- Minimising the number and duration of outages experienced by customers;
- Restoring power as quickly and safely as possible following an unplanned outage, as well as providing effective and prompt communication to keep customers fully informed at all stages of the outage; and
- Providing customers with sufficient notice ahead of planned outages required for maintenance.

3.4.2 Targets

The default price-quality path (known as DPP) applies to regulated electricity distribution businesses (EDB) and is set by the Commerce Commission to ensure that the quality of service provided to customers is not compromised by profit objectives; this is done by setting a cap on total allowable revenue in any regulatory period linked to a set standard of service quality.

As an EDB that is 100% consumer-owned, Counties Energy is exempt from price-quality regulation. However, we recognise that the level of network reliability directly impacts the experience of our customers, and we are committed to closely aligning with the regulatory methodology as far as possible in order to provide the best customer service. This is a core business priority, and is reflected in our key value of “Always On”.

There have been changes made to the rulesets used for our network reliability service levels moving forward:

- **Unplanned outages:** from the FY22 reporting year onwards (starting 01 April 2021), we now use the latest ruleset (DPP3) used by regulated EDBs for the period 1 April 2020 to 31 March 2025.
- **Planned outages:** from the FY23 reporting year onwards (starting 01 April 2022), we will revert to align with the Information Disclosure (ID) method, removing the weighting factors as previously used. For FY23, we also intend to introduce additional reporting metrics to measure and drive improved customer experience in relation to planned outages consistent with our Customer Strategy (refer to Section 2.3).

For more detail on our network reliability philosophy and the changes made, please refer to Section 5.2.

SAIFI and SAIDI targets have been set based on:

- Recent performance of the network
- Research presented to the Counties Energy Board on network reliability
- A forecast of planned outage requirements, which is based on investment programmes (outlined in the Asset Management Plan), and the expected reliability improvements from these investments.

The below tables outline our service level targets from FY21 to FY25, noting the change in methodologies from FY22 onwards.

	(DPP2)	(DPP3)			
Average number of interruptions per Customer (SAIFI)	FY21	FY22	FY23	FY24	FY25
Unplanned	2.700	1.919	1.866	1.772	1.661
Planned	0.300	0.600 *	0.543	0.391	0.393
Total	3.000	2.519	2.409	2.163	2.054

* Note: FY22 planned target is shown by the ID method and is equivalent to 0.300 interruptions with the DPP2 x 0.5 normalisation multiplier applied.

Table 3-2 SAIFI Service Levels FY21-FY2

3. Service Levels

	(DPP2)	(DPP3)			
Average minutes without electricity per Customer (SAIDI)	**FY21**	**FY22**	**FY23**	**FY24**	**FY25**
Unplanned	140.00	104.29	101.50	96.99	91.89
Planned	90.00	180.00 *	176.15	125.40	127.11
Total	**230**	**284.29**	**277.65**	**222.39**	**219.00**

* Note: FY22 planned target is shown by the ID method and is equivalent to 90.0 minutes with the DPP2 x 0.5 normalisation multiplier applied.

Table 3-3 SAIDI Service Levels FY21-FY25

Our service levels for SAIFI and SAIDI relate to outages originating on the Counties Energy network and do not include outages originating from networks owned by other parties such as Transpower, other EDBs or privately owned service lines. The service levels are also exclusive of the full impact of major events such as extreme weather events.

The table below shows the recent performance against our service levels for FY21 and the first half of FY22 (to the end of September 2021). For FY22 the service levels used are year-to-date linear (ie. half of the full yearly service levels set out in Table 3-2 and Table 3-3 above).

	Average number of interruptions per Customer (SAIFI)		Average minutes without electricity per Customer (SAIDI)	
	FY21 (DPP2)	**FY22 (to end Sep) (DPP3)**	**FY21 (DPP2)**	**FY22 (to end Sep) (DPP3)**
Unplanned				
Service Level	2.700	0.960	140.00	125.40
Actual	2.550	1.427	121.46	82.66
Planned				
Service Level	0.300	0.300	90.00	90.00
Actual	0.220	0.179	69.14	57.17
Total				
Service Level	**3.000**	**1.260**	**230.00**	**142.15**
Actual	**2.770**	**1.606**	**190.60**	**139.83**

* Note: FY22 planned target is shown by the ID method and is equivalent to 90.0 minutes with the DPP2 x 0.5 normalisation multiplier applied.

Table 3-4 Achievement to Service Levels

Full analysis of unplanned outages can be found in Chapter 5.

Our recent performance from FY17–FY21 and forward targets to FY25 are shown below, in Figure 3-4 for SAIFI and Figure 3-5 for SAIDI. This is shown using the DPP3 method for unplanned and ID method for planned across all years to provide a consistent comparison.

Network Planned and Unplanned SAIFI

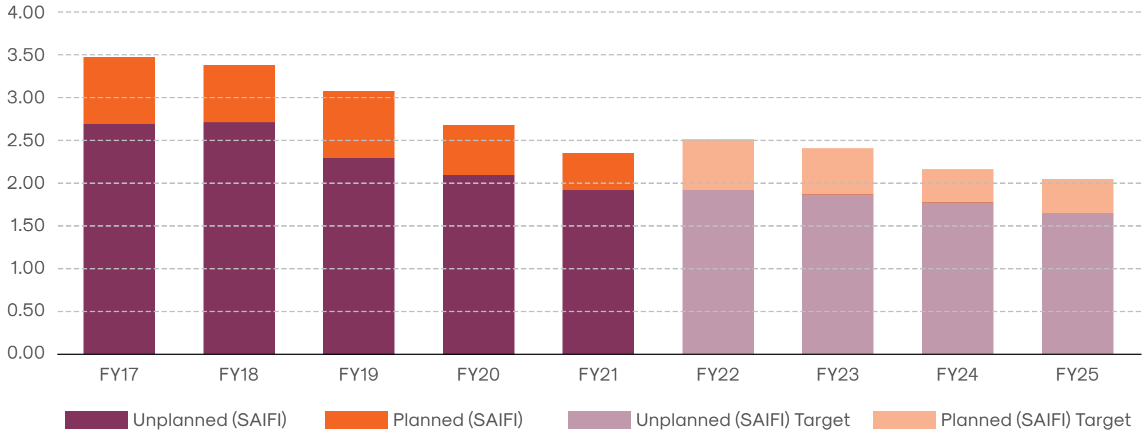

Figure 3-4 SAIFI FY17-FY21 actuals and FY22-FY25 targets

Network Planned and Unplanned SAIDI

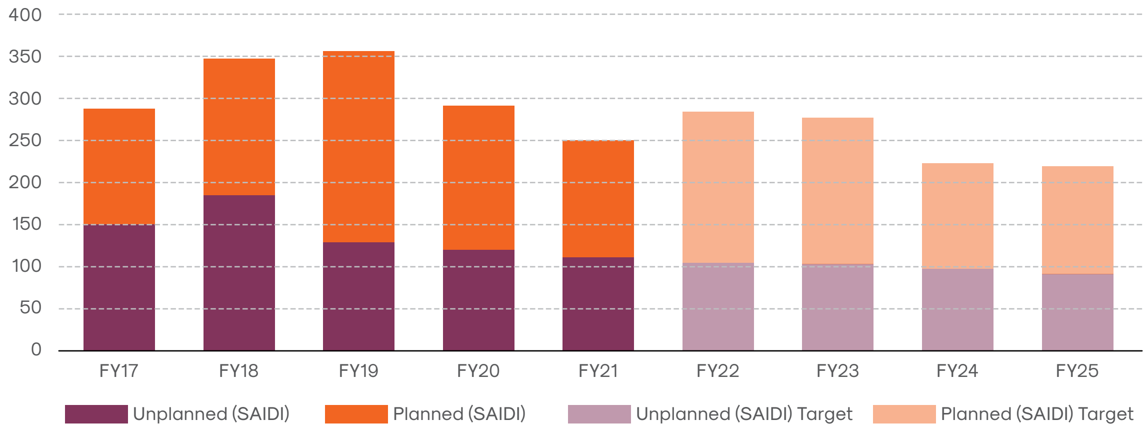

Figure 3-5 SAIDI FY17-FY21 actuals and FY22-FY25 targets

3. Service Levels

3.5 Environmental

3.5.1 Objectives

Counties Energy aims to provide environmental leadership within the community in which we operate. We recognise that environmental protection and sustainability are important issues facing our community now and in the future. With this in mind, we are continually seeking to implement environmental best practice through all stages of the asset life cycle to minimise our environmental impact whilst maintaining compliance with our legal obligations. We have set an environmental and sustainability policy which makes the following commitments:

- Identify all environmental touchpoints, understand their impact on the environment and seek to reduce any negative impacts;
- Provide awareness training and education for our employees;
- Engage likeminded suppliers and contractors; and
- Support community groups to fulfil their environmental ambitions.

The focus for our Counties Energy environmental and sustainability programme is:

- **Engaged employees:** Our goal is to have a highly engaged workforce through employee training, toolboxes, onsite coaching, and recognition and celebration of great environmental achievements. We want everyone to feel comfortable to speak up, concerning environmental and improvement opportunities.
- **Improved systems and governance:** All environmental risks are understood, managed and mitigated. Implement robust reporting and incident management processes, and ensure appropriate actions. We are also working on our sustainable procurement processes, including contractor approval.
- **Sustainability:** We are undertaking a materiality assessment to identify the most important sustainability topics to our business and our community. We have a large focus on carbon, including emissions monitoring and reporting, setting emissions reduction targets and understanding the climate resilience of our assets.

3.5.2 Targets

Emissions

We are committed to reducing our emissions and supporting our community to reduce theirs too. This year we will be measuring and reporting on our greenhouse gas emissions as well as setting emissions reduction targets.

Oil

We are also focusing on a more proactive approach to transformer oil management, including spill response training for staff and protocols to help ensure that leaks are identified and fixed before any discharge to the environment.

Overall, we continue to target reporting and to investigate all environmental incidents and ensuring that improvements are made to minimise the risk of a similar incident in the future.

4. Material Changes to Asset Management Practices

This section details proposed changes in the approach to asset management practices in order to improve our current maturity levels, however, there are no material changes to our current Asset Management Maturity Assessment (AMMAT).

4.1 Vegetation Management

We undertake vegetation management to ensure safety around our network and that network performance meets expectations. Our vegetation management is undertaken primarily in accordance with the Electricity (Hazards from Trees) Regulations 2003 [the tree regulations]. These are prescriptive and transactional, focusing on addressing any vegetation growing close to conductors, but at present do not support us in addressing trees further away from lines (out of zone) that either present a risk of falling through or shedding debris into lines.

Our vegetation programme is risk-based. The likelihood is informed by the analysed results of our Light Detection and Ranging (LiDAR) survey (last completed in early 2020), identifying sections of line where vegetation has been detected near to lines as well as trees which could present a fall hazard, based on their height and distance from the line. The consequence component uses the information from a manual review of all lines across the network, categorising the entire length into (up to) six zones (A to F) based on the customers impacted should a fault occur on the line section. Analysis using these two components has produced a risk-based view of the zone's health in terms of vegetation, which was used to prioritise our five-year proactive vegetation plan, which commenced in FY21. A component of this approach also ensures our 33 kV and 110 kV subtransmission circuits are surveyed annually due to their high criticality.

When working on a zone, we firstly complete a scoping visit to validate the sites identified by LiDAR and any additional sites that have grown closer to the lines since the survey was undertaken. These sites are within the growth limit zones specified in the tree regulations and are treated accordingly. This sees costs for the work allocated as specified in the tree regulations, although we will often liaise with the tree owner to explore whether permanent removal is an appropriate, efficient long-term solution for a particular tree. During the scoping, we also use the opportunity to survey sites with out-of-zone vegetation that poses a risk to the network, such as vegetation likely to shed debris into the lines or those flagged by LiDAR as potential sites where the tree could fall across the lines. For these out of zone sites, an arboricultural assessment is made based on tree species and health. This is used to inform the site's risk assessment, which informs the justification and prioritisation of any required remedial works.

As permanent removal of in-zone trees and remedial works on out of zone trees are outside of the scope of the tree regulations, any remediation possible currently relies entirely on negotiation with the tree owner. This can consume a lot of administrative resources and lead to costs borne by Counties Energy, and therefore all network customers, rather than the tree owner which is otherwise generally the intent of the tree regulations. Out of zone vegetation continues to represent about 65% of our known vegetation related faults, rising even higher during stormy weather conditions. These are industry recognised problems, and it is understood that the Ministry of Business, Innovation and Employment (MBIE) is still working on a full review of the tree regulations, on which progress updates are keenly anticipated.

4.2 Maintenance and Construction Standards

4.2.1 Maintenance Standards

Maintenance and Inspection Standards are currently being reviewed to align with industry best practices and reflect the repeated causes of equipment failure. Further information can be found in section 5.3.

The overhead equipment inspections have been reviewed, with a more prescriptive inspection regime and greater detail included to capture information on known construction issues such as:

- Asset security;
- Asset identification and labelling;
- Connection defects (i.e. incorrect connection type);
- Small component defects (e.g. kingbolts); and
- Uneven line tension.

New inspections will be rolled out through FY23 to the field employees and results integrated into the asset management system for monitoring and rectification planning. It is anticipated that the increased rigour of these inspections will result in a larger quantity of defects found requiring remedial work.

4.2.2 Defect Management

The way in which we score and react to defects has been revised to prioritise better prioritise assets requiring immediate action or management and those which can be planned into larger capital projects over the one- to three-year remediation planning period. Better guidance has been provided to the inspection employees regarding how these scores are applied, and a faults panel reviews high score defects (moderate and above) for action or planning.

In FY23, a new scoring matrix will be introduced, which will consider the chance of failure, the criticality of the asset and contextual factors, using geospatial data such as proximity to high-risk public areas (eg. schools, play areas). This will further refine the risk assessment of the hazards so investment decisions can be made with greater accuracy and defects with an unacceptable safety or performance risk can be addressed in a more efficient timeframe. The new scoring matrix will be aided by implementing new systems in development to enable improved integration between field devices, employees and asset management systems.

4.2.3 Construction Standards

As discussed in the 2021 Asset Management Plan, the revised crossarm standard has now been fully implemented, with delta 2.4 m steel crossarms being our standard construction where possible to minimise clashing issues and increase separation to reduce the risk of debris and wildlife contact. Polymer insulators are now used as standard, except for the existing copper conductor, which will continue to use porcelain post insulators until reconductoring.

The transformer standards, both pole and ground-mounted, have been standardised to minimise lead time and improve our ability to procure stock off the shelf where possible and better respond to high usage levels.

4. Material Changes to Asset Management Practices

4.3 Environmental Management

4.3.1 SF_6 Management

Counties Energy are now a participant in the emission trading scheme (ETS). As part of our commitment to minimise the usage of greenhouse gas emissions, the overhead switchgear standard is currently under revision, and vacuum switches are being trialled to minimise our usage of SF6. It is anticipated that vacuum overhead switches may become the standard where remote control ability is required across the network as old switches are replaced or as new switches are introduced. This will include the automation rebuild programme; refer to section 5.6.4.

The management of SF6 is under review, with updates to our live register recording changes to our inventory held and in-service assets. Additionally, we have renewed our engagement with the disposal and de-gassing delivery partners to ensure our activities are reportable and accurate.

4.4 Asset Risk Management Modelling (ARMM)

The Asset Management investment plans have historically been managed based on age and available performance data with condition information. Counties Energy has commenced the establishment of asset risk models based on the principles and methodology outlined in the publicly available DNO Common Network Asset Indices Methodology, published by the UK regulator. The purpose of this is to better model health, probability of failure, criticality and investment requirements to more adequately make investment decisions for the The AMP.

The ARMM will inform and optimise primary asset groups' capital and operational investment strategies, with an overhead equipment model expected for completion in early 2022.

This model intends to move to a risk-based and information-driven approach to support asset investment planning and maintenance strategy to:

- Inform budget requirements;
- Optimise asset replacement strategy;
- Demonstrate optimisation of investment; and
- Establish a comprehensive asset risk assessment and investment planning process.

4.5 Alignment to ISO55001

Counties Energy aim to align to ISO55001 in its asset management practices. Further work is going into the development and ISO55001 framework to detail where alignment is intended in order to realise the value from our assets. The scope of alignment will be developed through FY23.

Our proposed alignment to the ISO55001 framework will primarily focus on the systems relating to physical assets and was developed to support Counties Energy in:

- Operating assets safely;
- Meeting regulatory and statutory obligations;
- Evaluating business strategies concerning performance, cost and risk profiles; and
- Reducing the cost of managing their assets over their full life cycle.

The framework looks to move an organisation's behaviour into a strategic space, looking at the entire asset life cycle rather than stages in isolation, considering asset systems rather than individual assets and discrete activities, forming an integrated management system.

Adopting components of ISO55001 into Counties Energy's asset management system will take its asset management from isolated assets managed in silos into a holistic system-based approach, strengthening resilience to external and operational risks to better control and mitigate in the long term.

4.5.1 Asset Information

As part of the alignment to ISO55001 and to further develop the AMMAT score in this area, an asset information strategy will be developed to support the performance and condition measures. This will also support the technology solutions by standardising the data convention for network assets.

The asset information strategy will define the approach to the definition, collection, management and reporting of asset information and identify risks, costs, benefits, relevant procedures and processes related to the collection and management of data. It will be consistent with Counties Energy's objectives and supports the day-to-day business decision requirements.

The specific information requirements for each asset group will be defined in the asset fleet strategies and will identify the asset information and data standards, including:

- Asset hierarchy, types and classes;
- Functional attributes of the assets;
- The utilisation of the assets and controls/constraints;
- Performance and condition attributes;
- Defect identification standards;
- Failure modes; and
- Failure consequence.

5. Network Reliability

5.1 Introduction

This section is intended to provide the latest understanding of network reliability as an update to that previously described in Chapter 5 of the 2021 Asset Management Plan. This update includes a detailed update on recent network performance, the latest changes to the management approach and an update on initiatives in progress. Updates to investments relating to Network Reliability can be found in section 5.6.

5.2 Philosophy

Counties Energy recognises the direct effect network reliability has on the experience of customers connected to the network and it is, therefore, a core business priority. Consistent with the approach outlined in previous versions of our Asset Management Plans, engagement with our customers has previously identified that, although improved service levels are desired, there is generally very limited support for increased line charges to support such improvements. It is, therefore, a primary focus of our asset management activities to ensure all expenditure is targeted to achieve the best overall network reliability, recognising that the asset is a long-term one and thus a minimum whole of life approach to costs is usually the most appropriate.

As a consumer-owned EDB, we are obliged to meet Information Disclosure (ID) requirements, although we are exempt from the quality standards of non-exempt EDBs. Nonetheless, we recognise the regulatory regime as a widely consulted and agreed methodology in the industry. As a result, we aim to closely align with the regulatory methodology as far as possible.

In line with the intention outlined in section 5.6.1 of the 2021 Asset Management Plan, our reporting was updated for the start of FY22 (from 01 April 2021), so unplanned SAIFI/SAIDI (class C) is now measured using the latest ruleset used by regulated EDBs for the period 1 April 2020 to 31 March 2025, the third default price-quality path (DPP3). This means we now use the latest DPP3 methodology in all our reporting except where required to report using the Information Disclosure (ID) method. Further detail can be found in section 5.5.2.

Also aligned with the latest DPP methodology, we report separately on unplanned (class C) and planned (class B) SAIFI/SAIDI. This aligns with our understanding of our customer needs, where planned events are preferable to unplanned events. This is because planned events can be undertaken at a time ideally suited to, and with prior notice to, the customer, enabling them to make suitable alternative arrangements. This is in contrast to unplanned events, which have a much greater negative impact on customer experience.

For FY22, we have continued to use the planned normalisation rules from the prior DPP2 ruleset. However, the latest DPP3 planned rules have been updated to incentivise better customer outcomes by highly effective and accurate management of notified planned outages. This methodology utilises reasonably complex mathematical adjustments that result in a number suitable for regulation but would have lower meaningful value to our customers. Therefore, it is intended for FY23 (from 01 April 2022) to implement reporting that achieves the same customer outcomes as the DPP3 planned rules but without replicating the exact methodology. We intend for our reporting of planned SAIFI/SAIDI from FY23 to revert to align with the Information Disclosure (ID) method, removing any weighting factors as previously used but introducing additional reporting metrics to measure and drive improved customer experience.

Consistent with previous Asset Management Plans, we regard the overall operating environment as having changed to such an extent that attempting to extract useful trends using SAIDI, and to a lesser extent SAIFI, using data from before FY17 is unlikely to yield meaningful results.

We continue to report internally on reliability metrics as described in section 5.4 of the 2021 Asset Management Plan, for which an update is provided below.

5.3 Reliability Metrics

This section presents our reliability metrics from FY17 to FY21, plus the latest FY22 result for the first six months of the year (to 30 September 2021). Commentary is provided relating to the FY21 results.

Consistent with the 2021 Asset Management Plan, these metrics focus on all unplanned events outside of major events, treating any unplanned event that occurs between the start and end of a major event (as defined by the DPP3 methodology) as part of the major event. Although the normalised SAIFI and SAIDI of the major event is recorded as a separate unplanned event category, these unplanned events are otherwise not included in the Events, Customers Affected and Duration (CAIDI) metrics presented below. It should also be noted that as we are now using the updated DPP3 methodology to define the major events, these numbers may have changed relative to previous Asset Management Plans. Further detail can be found on Major Events in section 5.4.

5.3.1 Events

The following table shows the number of events by unplanned event category.

Category	FY17-FY20 Average	FY21	±% (from FY17-20)	FY22 (to 30 Sep)
TYPICALLY SIGNIFICANT CONTRIBUTING CAUSES				
Equipment - Overhead	126	105	-17%	58
Third Party Incident	37	32	-13%	20
Vegetation	36	44	21%	46
No Cause Found	35	61	76%	28
Wildlife	15	13	-12%	9
TYPICALLY MINOR CAUSES				
Equipment - UG / GM / ZS	5	3	-37%	2
Adverse Conditions	5	2	-60%	1
Network Incident	4	2	-43%	3
Total to all categories	**262**	**262**	**0%**	**167**

Table 5-1 Events by Unplanned Category

Overall, this metric is static compared to the preceding internal benchmark period, although with some shifts to be seen in the major categories. Equipment – Overhead, Third-Party Incident and Wildlife decreased in the year relative to the internal benchmark period. The events caused by Vegetation and No Cause Found increased relative to the internal benchmark period.

As discussed in the 2021 Asset Management Plan, internal systems also capture a more detailed cause code per event. However, the quality of this data is variable and for events up to the end of FY21 is presently below the level required to reliably form deep insights into contributing factors to network reliability. A change has been made to data capture processes for events in FY22 onwards and it is expected the increased richness of failure cause information will enable deeper trend analysis from FY22 in the next full Asset Management Plan. Further details on this change are discussed in section 5.5.1.

Equipment Overhead

The distribution of recorded causes of failure in FY21 remains similar to previous years. The top types recorded are failures on jumpers, crossarms, wire (mostly small dimension copper and Aluminium Conductor Steel Reinforced (ACSR)/Swan), drop out fuses and insulators (typically, failed 22 kV pins).

Notable findings and resulting actions recently undertaken included:

- **Jumper/drop out fuses:** Further analysis has since shown that failures recorded as jumper or drop out fuses are typically a failure of the jumper terminations, usually where aluminium conductor has been historically directly terminated into tinned copper terminations leading to galvanic corrosion and eventual failure of the jumper connection over time. This is a network-wide problem on older assets. Identification of this developing failure mode has been added to our maintenance inspections. When one fails, the opportunity is typically taken to replace all connections in the same location with the modern standard construction.
- **Crossarms:** Failures have almost always been on wooden crossarms, typically from mechanical deterioration/rot. This has been seen on crossarms supporting conductors and the 'hanger' arms on which overhead transformers are supported. The design standard for crossarms supporting transformers is being revised to utilise steel rather than wood. The maintenance inspection standards are being updated, so deteriorating wooden crossarms are flagged as a higher risk to be suitably addressed by corrective maintenance.
- **Wire:** Consistent with previous years, two-thirds of recorded wire (conductor) failures are attributed to small (<25 mm2) copper or ACSR (Swan) conductor. These failure-prone conductors are progressively being replaced by the replacement programme – refer section 7.1.2.
- **Insulator:** Most failures are recorded as insulators of a 'pin' design consisting of a porcelain insulator fitted onto a steel pin. Recovery of some failed assets has indicated that this central steel pin has corroded and expanded, causing damage to the porcelain and subsequent electrical failure of the insulator. Our design standards were updated in 2021 to move to a 'post' design of insulator which doesn't require the central steel pin giving greater clearance between live parts and support structures which, it is expected, in time, should also reduce wildlife events.

Third Party Incident

Of the 32 events, 25 were caused by vehicles contacting our poles, four overhead contacts with our lines and three cable strikes. This result for Third-Party Incident benefited from several weeks of COVID-19 alert level restrictions reducing both vehicles and third-party construction activity around our assets.

Vegetation

Of the 44 events, nine are recorded as being caused by tree contact with lines, seven as trees falling through lines and 28 as being caused by debris, of which eight are noted as being caused by bark, with the remainder being broken branches falling across lines. Even with the assumption made that all tree contact events relate to a growth limit zone intrusion, the FY21 results broadly show that only nine of the 44 events (~20%) were caused by tree growth close to lines, and, therefore, within the scope of the tree regulations.

No Cause Found

Past experience indicates that No Cause Found events are typically expected to be caused by vegetation, wildlife, or, less commonly, developing equipment failures that can be initially transient in nature, such as deteriorating insulators and lightning arrestors. As a result, asset management strategies intended to address these categories of events would be expected to have a corresponding effect on No Cause Found events also.

Our operating processes require that, where protection has operated, the network will always be patrolled. This applies even on more remote networks where a subsequent manual reclose attempt successfully restores supply before the patrol is completed. Events are recorded as No Cause Found if no likely evidence of event cause is found, such as:

- Visible recent evidence of event location such as burn marks or electrical arcing activity on either lines or vegetation;

- Localised reports received from persons on site; or
- Notable localised wildlife activity reported around the network at the time of the event.

Typically, we will update the recorded cause of an event up to one month or so after the date of the initial event if evidence is later discovered that indicates a likely cause.

In mid-2021, a review of the design/construction standards was undertaken to standardise larger crossarms and post insulators, aiming to increase clearances and make the network more resilient to wildlife, turbulent winds and smaller vegetation debris. These standards apply to all replacement and development projects, and so we expect to see the network progressively become more resilient over time. This is expected to especially benefit the 22 kV network which, unlike subtransmission circuits operating at higher voltages, has the same design complexities as an 11 kV network but twice the source voltage to initiate an event.

Wildlife

All 13 events were recorded as being caused by birds, a mix of mid-span strikes and events initiated on supporting poles with remains of the bird found in nearly all cases. It is worth noting that remains can be especially difficult to find for cross country lines where the area under the line may be vegetated, wetland or a waterbody, all of which can easily disguise or hide remains. In these cases, the event would likely be recorded as No Cause Found.

5.3.2 Customers Impacted

The following table shows the average numbers of customers impacted by an unplanned event in each unplanned event category.

Category	FY17-FY20 Average	FY21	±% (from FY17-20)	FY22 (to 30 Sep)
TYPICALLY SIGNIFICANT CONTRIBUTING CAUSES				
Equipment - Overhead	211.2	106.7	-49%	175.8
Third Party Incident	355.7	276.2	-22%	244.5
Vegetation	357.7	407.2	14%	317.9
No Cause Found	707.4	396.4	-44%	779.9
Wildlife	895.2	858.0	-4%	684.6
TYPICALLY MINOR CAUSES				
Equipment - UG / GM / ZS	920.7	793.0	-14%	776.0
Adverse Conditions	522.3	58.0	-89%	44.0
Network Incident	1016.3	2351.0	131%	1494.7
Weighted average across all categories	**361.3**	**307.2**	**-15%**	**382.0**

Table 5-2 Customer Impact by unplanned category

This metric has improved for nearly all unplanned event categories in FY21 compared to the internal benchmark period. This is likely due to the continued focus on investment prioritisation by network criticality (for network maintenance, vegetation management and replacement investment) and the improvement yielded from past recloser installations and feeder split projects. It should be noted the bottom three categories correspond to a relatively smaller number of events, which can make this averaging metric very volatile.

Following a review of the benefits of the remaining feeder split projects, it has been found that installation costs are higher than other solutions to improve reliability (refer to section 5.6 for further information). Therefore, effective prioritisation of investment by network criticality remains the key lever expected to impact this metric. This will be less effective on unplanned event categories which are less controllable such as Third-Party Incidents or Wildlife.

5.3.3 SAIFI

The following table shows the SAIFI by each unplanned event category.

Category	FY17-FY20 Average	FY21	±% (from FY17-20)	FY22 (to 30 Sep)
TYPICALLY SIGNIFICANT CONTRIBUTING CAUSES				
Equipment - Overhead	0.626	0.252	-60%	0.224
Third Party Incident	0.311	0.199	-36%	0.108
Vegetation	0.313	0.404	29%	0.322
No Cause Found	0.551	0.542	-2%	0.482
Wildlife	0.306	0.252	-18%	0.135
TYPICALLY MINOR CAUSES				
Equipment - UG / GM / ZS	0.104	0.054	-48%	0.034
Adverse Conditions	0.063	0.003	-96%	0.001
Network Incident	0.065	0.106	64%	0.099
Total to all categories	**2.306**	**1.811**	**-21%**	**1.404**
Major Events	0.157	0.117	-25%	0.023
Total	**2.463**	**1.928**	**-22%**	**1.427**

Table 5-3 SAIFI by unplanned category

SAIFI is a product of the number of events and the customer impact outlined in the sections above. Considering network performance outside of major events, events are static relative to the benchmark, and the average customer impact has decreased. The net result is a decrease in unplanned SAIFI in FY21 relative to the benchmark by ~21%.

The SAIFI contribution from Major Events after normalisation by the DPP3 method is 0.117. Further information on the Major Event result can be found in section 5.4.

The overall SAIFI result for FY21 was 1.928, a 22% decrease from the internal benchmark period.

5.3.4 Duration (CAIDI)

The following table shows the average duration (CAIDI) by each unplanned event category.

Category	FY17–FY20 Average	FY21	±% (from FY17–20)	FY22 (to 30 Sep)
TYPICALLY SIGNIFICANT CONTRIBUTING CAUSES				
Equipment – Overhead	77.9	102.0	31%	103.3
Third-Party Incident	109.0	116.2	7%	131.7
Vegetation	59.2	48.0	-19%	70.8
No Cause Found	42.1	32.1	-24%	27.4
Wildlife	29.7	23.1	-22%	36.3
TYPICALLY MINOR CAUSES				
Equipment – UG / GM / ZS	34.7	8.7	-75%	28.0
Adverse Conditions	57.2	15.7	-73%	249.0
Network Incident	13.1	29.9	128%	21.4
Average across all categories	**61.0**	**52.5**	**-14%**	**57.9**

Table 5-4 CAIDI by unplanned event category

There have been movements up and down within fault categories, but the overall average event duration (CAIDI) has decreased by 14% for FY21 compared to the internal benchmark period. It should be noted the bottom three categories correspond to a relatively smaller number of events, which can make this averaging metric very volatile.

Following a review of network isolation areas enabled by the creation of our SAIDI criticality model, a programme has been added within the upcoming 10-year planning period to install additional switchgear in some key areas, reducing the number of customers affected for an extended repair duration should an unplanned event happen in the area, and, therefore, it is expected to yield an improvement in CAIDI. Further details on this programme can be found in section 5.6.5.

5.3.5 SAIDI

The following table shows the SAIDI by each unplanned event category.

Category	FY17-FY20 Average	FY21	±% (from FY17-20)	FY22 (to 30 Sep)
TYPICALLY SIGNIFICANT CONTRIBUTING CAUSES				
Equipment – Overhead	48.31	25.72	-47%	22.75
Third-Party Incident	34.48	23.07	-33%	14.16
Vegetation	17.89	19.37	8%	22.75
No Cause Found	24.17	17.42	-28%	13.22
Wildlife	8.51	5.80	-32%	4.90
TYPICALLY MINOR CAUSES				
Equipment – UG / GM / ZS	4.10	0.47	-89%	0.96
Adverse Conditions	2.78	0.04	-99%	0.24
Network Incident	0.80	3.18	296%	2.12
Total to all categories	**140.63**	**95.08**	**-32%**	**81.10**
Major Events	5.54	16.25	194%	1.56
Total	**146.17**	**111.33**	**-24%**	**82.66**

Table 5-5 SAIDI by each unplanned category

SAIDI is a product of SAIFI and the Duration (CAIDI) as outlined in the sections above. Considering network performance outside of major events, SAIFI has decreased relative to the benchmark, and the average duration (CAIDI) has also decreased. The net result of this is a decrease in unplanned SAIDI in FY21 relative to the benchmark by 32%.

The SAIDI contribution from Major Events after normalisation by the DPP3 method is 16.25. Further information on the Major Event result can be found in 5.4.

The overall SAIDI result for FY21 was 111.33, a 24% decrease from the internal benchmark period.

5.4 Major Event Periods

5.4.1 Major Event Summary

The following table shows the summary of periods identified in FY21 identified as Major Events.

Number	Major Event Window Start Date / Time	Major Event Window End Date / Time	SAIFI Major Event?	SAIDI Major Event?
1	01/06/2020 08:10	02/06/2020 05:01	**Yes**	No
2	24/06/2020 20:05	25/06/2020 10:28	**Yes**	**Yes**
3	24/07/2020 09:22	25/07/2020 07:03	**Yes**	No
4	08/02/2021 09:47	09/02/2021 15:32	No	**Yes**
5	30/03/2021 04:48	30/03/2021 23:05	**Yes**	No

Table 5-6 FY21 Major Events

5.4.2 FY21 Major Event One

This Major Event was triggered initially by a vegetation event on a feeder. Although the feeder circuit breaker correctly identified the fault, the upstream substation transformer circuit breaker tripped before the feeder circuit breaker could open as intended. This resulted in an outage occurring to approximately one-third of the Tuakau substation. This occurred on 2 June at 04:53 and initially affected 6301 customers. The outage was quickly restored, with the last restoration occurring after nine minutes. The SAIFI value incurred was marginally under the major event trigger threshold; however, when combined with the 24-hour rolling sum of other events in the period, the SAIFI trigger value was met. The other four events in the period consisted of other feeder events; all recorded as caused by Vegetation.

- Major Event Original SAIFI: 0.223 (SAIFI trigger met)
- Major Event Normalised SAIFI: 0.012
- Major Event Original SAIDI: 4.79 (SAIDI trigger not met)
- Major Event Normalised SAIDI: 4.79

Following this event, investigation began looking for the cause of the transformer trip, finding no apparent cause and a successful re-livening. Additional investigation work began looking further into protection settings, suspecting a miscoordination event.

5.4.4 FY21 Major Event Two

This Major Event was very similar to the one described above, initially triggered by a third-party incident event on a feeder. Although the feeder circuit breaker correctly identified the fault, the upstream substation transformer circuit breaker again tripped before the feeder circuit breaker could open as intended. This resulted in an outage occurring to approximately one-third of the Tuakau substation. This occurred on 25 June at 04:40 and initially affected 6249 customers. The outage took up to two hours to restore, with only some customers in the immediate locality of the third-party incident remaining without supply for longer. The SAIFI value incurred was marginally under the major event trigger threshold; however, when combined with the 24-hour rolling sum of other events in the period, the SAIFI and SAIDI trigger values were met. The other three events in the period consisted of feeder events recorded as caused by No Cause Found, Equipment Overhead and another Third-Party Incident elsewhere on the network.

- Major Event Original SAIFI: 0.162 (SAIFI trigger met)
- Major Event Normalised SAIFI: 0.010
- Major Event Original SAIDI: 15.32 (SAIDI trigger met)
- Major Event Normalised SAIDI: 0.65

Similar to the previous event, no apparent cause for the transformer trip was found, with the unit being successfully re-livened. However, further priority was put onto the protection investigation and transformer testing was scheduled to establish the presence of underlying condition issues with the transformer that may be causing the trip for through-fault events.

5.4.4 FY21 Major Event Three

This Major Event was triggered by the failure of the zone substation earthing transformer at Tuakau zone substation, related to the transformer that had tripped twice before in previous major events. Again, this caused an outage to approximately one-third of Tuakau substation. This occurred on 25 July at 07:03, and initially affected 6369 customers, taking up to 28 minutes to restore. The SAIFI value incurred was marginally under the major event trigger threshold; however, when combined with the 24-hour rolling sum of other events in the period, the SAIFI trigger value was met. The other two events in the period consisted of other feeder events recorded as Wildlife and Equipment Overhead elsewhere on the network.

- Major Event Original SAIFI: 0.161 (SAIFI trigger met)
- Major Event Normalised SAIFI: 0.006
- Major Event Original SAIDI: 4.73 (SAIDI trigger not met)
- Major Event Normalised SAIDI: 4.73

On this occasion, site inspection found evidence of an internal failure of the earthing transformer, which required replacement.

5.4.5 FY21 Major Event Four

This Major Event was triggered by a feeder fault on our Beach Road feeder, which occurred on 09 February at 08:42, initially affecting 2365 customers and taking up to 167 minutes to restore. This is one of our largest feeders (by connected customer), almost entirely underground and subject to significant network development in the area. Follow up investigation found that despite the large number of connected customers, the functionality of remote-controlled (automation) equipment lacked fault indication ability to our control room, the presence of local fault indicating devices were not recorded in our systems, our field crews patrolling the line weren't fully aware of the revised feeder layout following recent network development, and the decision to not attempt a manual reclose in an urban area was the correct one. After a full patrol, the event was recorded as No Cause Found. A number of improvement actions were initiated, including a survey of local fault-indicating equipment for inclusion into our systems to give visibility for future events and a plan to create fault response plans for our major feeders.

The SAIDI value incurred was marginally under the major event trigger threshold; however, when combined with the 24-hour rolling sum of other events in the period, the SAIDI trigger value was met. The other five events in the period consisted of other feeder events recorded as caused by No Cause Found, Vegetation and Equipment Overhead elsewhere on the network.

- Major Event Original SAIFI: 0.077 (SAIFI trigger not met)
- Major Event Normalised SAIFI: 0.077
- Major Event Original SAIDI: 9.12 (SAIDI trigger met)
- Major Event Normalised SAIDI: 0.65

5.4.6 FY21 Major Event Five

This Major Event was triggered by a feeder fault on our Cape Hill feeder, which occurred on 30 March at 05:45, initially affecting 2403 customers. However, further customers were impacted during restoration, with the total number reaching 6388 unique customers impacted over the course of 80 minutes. Like the event the month before on Beach Road, this is one of our largest feeders (by connected customer), almost entirely underground and investigation reinforced the learnings raised from the previous event. The cause was identified as an underground cable fault, although retrieval of the failed asset indicated this was caused by reasonable damage to the external sheath, likely from an underground directional drill at some point in the past, and the event was recorded as Third-Party Incident.

The SAIFI value incurred was marginally under the major event trigger threshold; however, when combined with the 24-hour rolling sum of other events in the period, the SAIFI trigger value was met. The other four events in the period consisted of other feeder events recorded as caused by Third-Party Incident, No Cause Found and Equipment Overhead elsewhere on the network.

- Major Event Original SAIFI: 0.165 (SAIFI trigger met)
- Major Event Normalised SAIFI: 0.012
- Major Event Original SAIDI: 5.42 (SAIDI trigger not met)
- Major Event Normalised SAIDI: 5.42

5. Network Reliability

5.5 Methodology Improvement for the Management of Reliability

5.5.1 Improved Capture of Events

An improved structure for recording unplanned events was implemented in June 2021, with events dating back to the start of FY22 (from 01 April 2021) reviewed and updated with the latest categorisation. The improved categorisation breaks each unplanned event category further into a cause and a sub-cause. It is hoped this will enable a more accurate analysis of the contributing causes of a network reliability result to be confidently presented in later versions of this Asset Management Plan. The implementation also saw us bring the recording of part-phase (known to us as weak power) and momentary (< 1 minute), typically due to auto-reclose, outages into the same centralised outage recoding system even though these types of events are not presently counted in our disclosed network performance figures or reliability metrics presented earlier in this plan. Having them in the same system will enable future reporting on these aspects of network reliability and provide the full reliability picture to inform other asset management activities.

Events are recorded by our Network Operations Centre (NOC), with a weekly event review meeting held between network operators, field teams, engineers and asset managers to review the events, validate the accuracy of captured events and capture any lessons learnt or required improvement actions. Work is still progressing on the enhancements to the tablet system used by our reactive teams, which will capture further information against the work order on the causes of events, improved information on the consequences of failure and photographs, all of which can be used to improve our knowledge of the unplanned events and therefore improve our asset management activities. It is planned this enhancement will go live in mid-2022.

5.5.2 DPP3 Methodology

The start of FY22 saw us change to the latest DPP3 methodology to normalise for major events in all internal management reporting; network reliability for unplanned events is reported separately to planned events. The latest normalisation method now uses a rolling 24-hour period to trigger the major event, with normalisation applied per 30-minute period rather than a calendar day approach as before. Boundary values have been defined from the 10-year (FY10–FY19) benchmark period, with the SAIFI boundary value calculated as 0.1441 and the SAIDI boundary value 8.319.

5.5.3 Reliability Metric Targets

FY22 saw the introduction of internal targets for each of the five reliability metrics (unplanned events, customers impacted, SAIFI, duration [CAIDI] and SAIDI, as described in section 5.4 of the 2021 Asset Management Plan). These targets have been set relative to FY21 performance and are being used on a published internal dashboard to compare year-to-date performance against these targets. For future years it is intended the targets will be set and utilised in a similar manner based on an understanding of the six-year trend (FY17–FY22) that will by then be available, the improved accuracy of events captured from FY22, whilst also considering the expected performance improvement of planned investment/initiatives.

For the next full Asset Management Plan, it is planned to publish these targets and update the narrative of the reliability analysis to compare performance to target rather than solely to performance against a prior period.

5.5.4 Reliability Standards by Customer Type

It is recognised that measuring network reliability on SAIFI/SAIDI has the disadvantage that the metrics are averaged across all network-connected customers. There are likely to be extremes within this, where customers supplied from reliable urban networks may go years between interruptions. The converse is true for customers on long remote rural networks where multiple interruptions can occur during a single year.

This initiative was considered in 2021, however, it was established that the present way the events are captured does not enable such reporting. The increased data capture and subsequent changes to the recording system to achieve this reporting would be too significant, considering these systems are intended to be superseded by the planned implementation of an advanced distribution management system (ADMS) which is expected to be implemented before the end of FY25.

That said, it is intended to achieve a similar outcome by instead leveraging the capabilities of our smart meter population, discussed further below.

5.5.5 Leverage of Smart Meter Data

We recognise our fortunate position of having access to the data available from our smart meters installed across the vast majority of our network, providing around 95% Installation Control Point (ICP) coverage. This data has been driving improvements in customer experience for several years now, for which we are proud to have won multiple industry awards.

From a reliability perspective, work is presently progressing to analyse the power-down events reported by the smart meters. The intention is to compare the total outage view against the recorded SAIFI/SAIDI view, this being the known impact of events on the HV distribution network. The difference between the two should be a reasonably accurate view of the potential SAIFI/SAIDI attributable to events on the low voltage network or private service lines. It is also hoped the smart meter data, being inherently at a customer (ICP) level, will give insights into the distribution of customer experience from a network reliability viewpoint, that is, understand the range of experience from best to worst served customers. Once gained, this insight will further refine asset management activities to benefit our customers' experience.

5. Network Reliability

5.6 Material Changes to Reliability, Safety and Environment

The material changes in capital expenditure are in the following areas:

- SCADA Radio Equipment upgrade now has an Automation Rebuild component which has moved to reliability;
- Addition of Recloser Air Gap programme;
- Addition of Network Isolation Point Improvement programme;
- Site-specific projects identified for FY23 to address known quality or reliability issues; and
- Removal of remaining feeder split projects from the planning period.

The overall effect of these changes can be seen below.

2021 vs 2022 Reliability, Safety and Environment CAPEX Summary in Constant Price

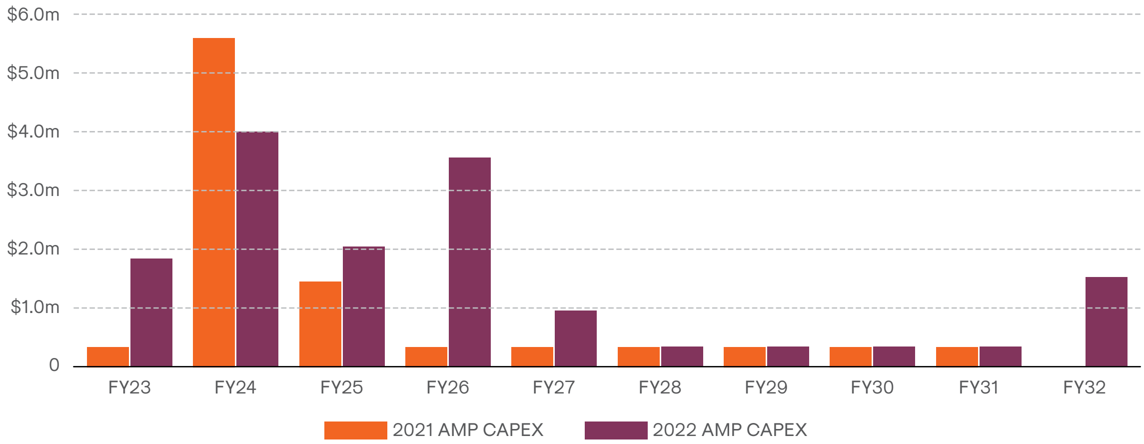

Figure 5-1 Reliability, safety and environment variation from AMP2021 (constant $)

The specified projects in FY23 – FY27, in conjunction with other network investments which also are expected to improve reliability, are expected to enable achievement of our reliability objectives. For this reason, significant investment is not presently identified in the second half of the planning period. This may be revised in the future versions of this Asset Management Plan as objectives or network reliability measures require.

A summary of material changes can be seen below.

Feeder / Area	AMP2021 Financial Year	AMP2021 Estimated Cost ($000s)	Updated Financial Year	Updated Estimated Cost ($000s)	Commentary
Cape Hill Feeder Split	FY24	2,571	Removed	Removed	Refer below 5.6.1
Install cable and new RMU to reduce customer numbers on Hingaia feeder	FY25	1,097	Removed	Removed	
Pukekohe Hill Feeder UG	FY24	1,132	Removed	Removed	Refer below 5.6.2
Power Quality Compliance	FY23	350	FY23	640	Refer below 5.6.3
Automation Rebuild	New Programme		FY24-26	5,200	Refer below 5.6.4
Network Isolation Point Improvement	New Programme		FY24-27	2,190	Refer below 5.6.5
Recloser Air Gap	New Programme		FY23-26	280	Refer below 5.6.6
Anchor Factory Rehabilitation	New project		FY23	547	Refer below 5.6.7
Beach Road Feeder Undergrounding	New project		FY23	586	Refer below 5.6.8

Table 5-7 Reliability, safety and environment material changes

5.6.1 Feeder Split Projects

The two remaining feeder split projects within the upcoming planning period on Cape Hill and Hingaia feeders require a reasonable amount of new network cable to be installed. Additionally, Hingaia is subject to considerable network development in the area, and the feeder configuration is likely to change significantly within the 10-year planning period. A justification review has shown that the cost/benefit ratio is higher than other comparable improvement projects outlined in this section. For this reason, these projects have been removed from the 10-year planning period.

5.6.2 Pukekohe Hill Undergrounding

The planned undergrounding of a section of Pukekohe Hill feeder along Kitchener Road has been removed from the 10-year planning period due to increased costs. A justification review shows that the cost–benefit ratio is higher than other comparable improvement projects outlined in this section. In addition, it is expected that other reliability programmes, specifically the Automation Rebuild (refer 5.6.4), will benefit the network reliability experienced by customers all across the network, including those supplied from the Pukekohe Hill feeder.

5.6.3 Power Quality Compliance

An additional $290,000 has been added to FY23 to address known site-specific issues by installing additional distribution transformer capacity. A default budget of $350,000 remains unchanged for all other years in the planning period.

5.6.4 Automation Rebuild

Although indicated as a new programme, this programme is formed from a split of the SCADA Radio Equipment upgrade project (refer to section 7.1.3). As a result, this does not increase the overall programme, although it does result in a $5.2 m shift in cost allocations from 'Asset replacement and renewal' to 'Reliability, safety and environment' for this AMP Update.

The number of field devices such as overhead or ground-mounted switchgear with remote control and indication abilities, colloquially referred to as 'automation', has progressively grown on our network over many years. Initially begun as a strategic roll-out, the policy later evolved. For the last several years, all newly installed field devices have been installed with automation functionality. As a result, beyond the initial deployment, the penetration of automation has not been even across the network, with areas of high investment from renewal or growth drivers seeing higher volumes of installed automation whilst other areas remained relatively lower.

Analysis completed in 2021 indicated that instead of replacing the obsolete and near end-of-life radio equipment in all existing locations, a greater overall benefit to network reliability could be achieved by considering sites strategically network-wide. Our recently developed Network Criticality Model enabled this analysis and was triggered by the replacement driver on the SCADA radio network.

This approach would likely see some sites removed on feeders with an existing high penetration of automation, instead placing new additional sites on feeders that, at present, have less. Initial analysis completed on close to 90% of the network has indicated that taking a strategic placement approach for the same investment could see the SAIDI saved annually increase by 10–15% compared to replacing all existing sites like-for-like.

At present, we have reallocated the full cost of what was originally a programme of replacement for all sites into a strategic automation rebuild. Further analysis, scope determination, feeder prioritisation and design is intended to start in FY23, but at present, the intent is to invest this budget as optimally as possible to provide an even penetration network-wide, with an overall benefit 10–15% greater than experienced now with the existing population in terms of SAIDI benefit to customers.

5.6.5 Network Isolation Point Improvement

Analysis completed in 2021, enabled by our recently developed Network Criticality Model, compared the existing as-built network to our previously published security criteria requiring no more than 300 customers to be connected to a switching segment (i.e. between switching devices). The results showed 16 places on the network exceeded this requirement, 12 of which could be improved by installing additional switching devices. The other four likely require further investment, such as a second supply circuit into an area. Further analysis was then undertaken to consider the network lengths of each section. This showed that some sections could stretch for relatively long distances, in some cases up to 10 km, between switching devices, despite having less than 300 connected customers. With SAIFI (and therefore SAIDI) being a function of the number of faults as well as impacted customers, the model highlighted that focusing on customer numbers alone did not drive an outcome as optimal as considering customer numbers and network length.

Based on the modelled results, it was recommended to install new switching devices onto the network for which an allowance of $2.19 m has been made from FY24 to FY27.

5.6.6 Recloser Air Gap

Counties Energy has a fleet of reclosers in service across the network. Although these are a range of designs, almost all utilise vacuum interrupters for the circuit breaker with either solid or gas insulation. It has been identified that approximately half of these are currently installed 'hard-tapped', that is, there is no other device other than the vacuum interrupter if the recloser is called upon as a point of isolation. Engineering investigation undertaken in 2021 guided an operational decision to no longer rely solely on vacuum interrupters as a point of isolation. This programme has included an allowance to install additional solid links in-series with the existing reclosers that do not already have them, enabling these recloser sites to continue to be used as a point of isolation and avoid additional customer impact from needing to take wider outages.

5.6.7 Anchor Factory Rehabilitation

The Anchor Factory feeder from Pukekohe zone substation supplies the areas north and west of Pukekohe, including Paerata, Paerata Rise and Helvetia. Between February and August of 2021, the feeder protection operated nine times, with each occasion either recorded as caused by Wildlife or No Cause Found. Some temporary reconfiguration works were undertaken in May to remove most customers from the section of network appearing to cause the problems and reduce the impact of any subsequent events. Since then, detailed patrols have been completed, including an aerial survey. Initial results from this have shown that although there are no health or condition concerns with any of the assets in the section, a reasonable number of poles are built to older 22 kV construction standards which provide less clearance between conductors and, therefore, are more susceptible to faults caused by birds or vegetation debris. Therefore, this project has been added for FY23 to rebuild some of the critical sections of this feeder.

5.6.8 Beach Road Feeder Undergrounding

Over the last few years, recent development has seen the majority of the remaining overhead sections of the Beach Road feeder from the Opaheke zone substation converted to an underground network, particularly in the Rosehill and Park Estate areas. Eight spans (~600 m) of overhead line remain at the feeder's start, part of which will require undergrounding due to a customer-initiated relocation project. This project is an allowance to underground the remainder of this short section of this feeder.

6. Innovation and New Technology

The Technology and Digital programme of work at Counties Energy is increasing at pace as the organisation digitises and embraces complex new technologies to deliver greater value to its customers and stakeholders and prepare for a low-carbon, electric future. This work programme reflects the organisation's growth as one of the fastest growing EDBs in New Zealand, with a trajectory towards transforming to be one of the smartest DSOs in New Zealand.

Counties Energy is investing in key areas of its core operations as part of its Digital Utility Strategy programme. This programme initially focuses on upgrades of key platforms such as Advanced Distribution Management System (ADMS), Maximo – Enterprise Asset Management system, Cloud Data and Integration platform, and OT/IT cyber security upliftment (part of the Cyber Security strategy). With some of the existing platforms and software tools coming to the end of life, Counties Energy is investing in the next phase of Technology and Digital capabilities that will prepare the business for a smarter energy future.

6.1 Adopting New Clean Energy Technologies

Advanced technologies provide a foundational step forward on Counties Energy's transformational journey to an innovation-led, low carbon future. By keeping Counties Energy ahead of the digital curve, we will transform our service delivery to include diverse energy choices and offerings that customers are seeking.

6.1.1 Smart EV Charging with OpenLoop

Transportation is the largest polluter worldwide, with many governments recognising that electrification of transportation (supplied by renewable energy sources) is key to meeting carbon reduction targets.

New Zealand's Climate Change Commission has submitted findings that show homes with EVs on average spend up to 25% less on energy in comparison to those with petrol vehicles.

The limiting factor for many households and commercial businesses to transition to EVs is the upfront cost of an electric vehicle, which on average are 60% more expensive in comparison to an internal combustion vehicle. To encourage this transition, some governments have introduced subsidies to accelerate EV uptake. In New Zealand, for example, the Clean Car Discount (launched in July 2021) of up to $8,625 for a new Battery Electric Vehicle (BEV) has helped to make EVs a more attractive option.

Other influencing factors include:

- The surging price of petrol and diesel has reached record highs in 2021 and is expected to continue rising;
- The introduction of a carbon tax in Auckland, by Auckland Council; and
- The implementation of the Clean Car Standard where vehicle importers with a lower carbon footprint are rewarded with credit and those with a high carbon footprint are penalised.

These factors will contribute towards the uptake of EVs nationwide in the coming years.

Electricity distribution networks were not designed to take on this additional EV charging load if it were to all occur simultaneously. However, by using smart EV charging, we can manage peak demand while ensuring EVs are charged in a managed and dynamic way depending on the available capacity on the network within a given timeframe.

By pursuing smart charging and enrolling our customers' EV chargers onto our digital platforms, we will seek to avoid expenditure to reinforce the electricity network that may otherwise be required due to simultaneous EV charging. Platforms like OpenLoop will provide further benefits as we learn to better manage changing demand profiles on the network.

With the support of Energy Efficiency and Conservation Authority (EECA) co-funding, we are also researching new EV charging technologies such as Vehicle-to-Grid technology, which enables EV owners to discharge the energy from their EVs back to the grid during network peaks or emergencies.

6.1.2 Second-life EV Battery Systems

With the large uptake of EVs worldwide, old EV batteries being stockpiled at the end of their life is becoming an issue.

At Counties Energy, we plan to give these batteries a new lease of life on our electricity network. We are currently trialling these batteries as network DERs to regulate power quality, shave energy peaks and as a buffer energy source for High Power EV charging to reduce the stress on the network.

These battery systems are typically cheaper and hold potentially up to 80% of their original charge – whilst not as useful in an EV, they may be useful on our network as a substitute to traditional network solutions.

We are also investigating how these batteries can be used for large scale community storage applications, such as backup energy sources for remote locations on our network, and to assist in the integration of distributed or centralised community PV. By utilising Second-life EV Battery systems in this manner, we can potentially defer the need for infrastructure upgrades.

6.1.3 Virtual Power Plants (VPPs) and Microgrids

As greater distributed renewable generation and storage is hosted on the network, an area of opportunity arises to provide a greater level of energy service by being able to create Virtual Power Plants (VPPs) and Microgrids to serve key customer segments, such as customers in remote communities as well as new energy-efficient housing developments.

6.1.4 Low Voltage (LV) Networks – Hosting Capacity

It is expected the new technologies such as EV charging, PV and batteries will mostly connect at the LV level of the electricity network. This will require a shift in the approach to planning and operation of these networks, which in turn will require asset information data of a higher quality than is presently available. A key part of this planning shift is to form an understanding of hosting capacity. This is the understanding of the capacity of the LV networks to host or absorb the uptake of EV and PV technologies before network congestion may begin to occur. This may occur with low uptakes of new technologies in some areas of relatively weaker network.

Counties Energy started a review of hosting capacity in 2021, aiming to understand the hosting capacity of the LV networks. We are doing this in conjunction with a modelling partner who has provided their services to many organisations across New Zealand. It is intended this will eventually be information that we could share to assist our customers as well as use to inform and prioritise our future network investment. This review is making use of our visibility of the smart meter information we have for over 95% of connected customers, which can provide some key insights around load consumption along with some voltage information.

Initial experiences in this review have highlighted a need for improved LV network asset data. We are currently working through this challenge for the next phase of this programme.

6.1.5 DER Visualisation Tools

Integrating new DERs on our network requires visualisation software to help us understand both the positive impacts and the risks to be mitigated when installing such technology. Creating a digital twin of DER assets and virtually simulating scenarios will enable such visualisations. The findings from these tools are used to create different options, which inform and justify capital expenditure on the network.

7. Renewal and Maintenance

The material changes to our renewal and maintenance are predominantly due to increases in defect management funding, following maintenance reviews and inspection outcomes. Further detail of this can be found in Section 4 and throughout this Chapter. Increases in defect management activities have also impacted the scopes of replacement projects and have impacted budget requirements or timeframes.

The material changes in capital expenditure are in the following areas:

- Defect and Low Line Management;
- Karaka Protection Strategy; and
- Barber Road Substation, including a reduction in subtransmission estimates.

7.1 Material Changes to the Lifecycle Asset Management

The expenditure and material changes can be seen below;

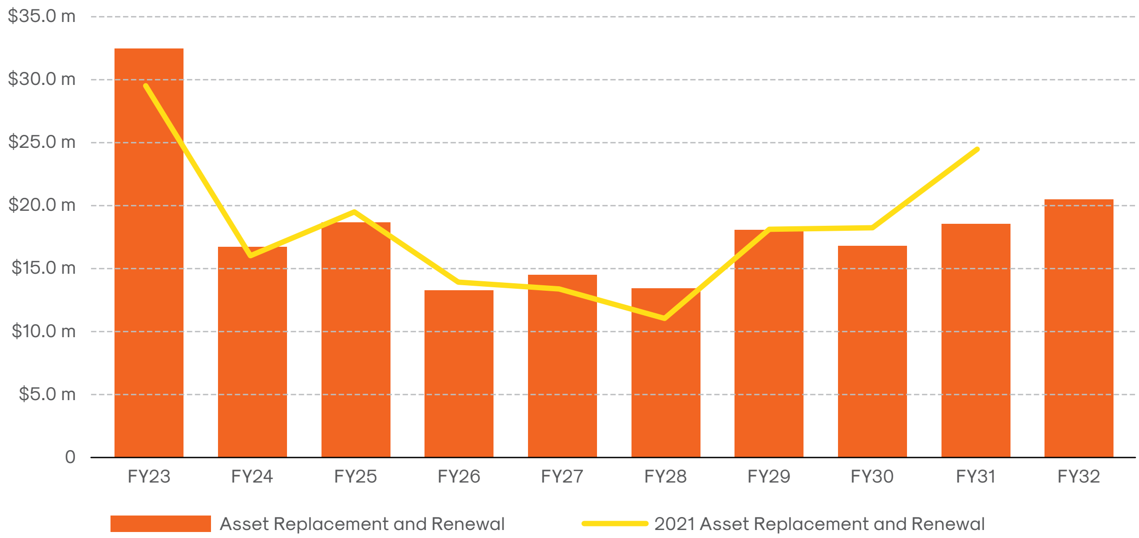

Figure 7-1 2021 vs 2022 Asset Renewal and Replacement CAPEX Summary in Constant Price

7.1.1 Defect Management and Low Lines

Analysis of the network defects, including the outputs of Light Detection and Ranging surveys (LiDAR) and aerial surveys, has resulted in the requirements of an additional $1.0 m per annum for overhead defect and low line remediation. This also considers the elevated defect rate of service lines that undergo ownership transfer to Counties Energy. The number of outages resulting from overhead equipment failure remains high, although it is improving compared to the benchmark period (refer to section 5.3.1 Events for further detail). To address this, there have been revisions to the defect management process and hazard scoring criteria to better prioritise based on the likelihood of failure, risk to public safety and risk to network performance.

The additional budget allocation allows us to respond to the high-risk defects as they arise through the routine inspections and rectify more areas of the network where historical construction issues are impacting performance, such as connector types or inadequate crossarm construction.

More prescriptive and detailed inspection standards, particularly for overhead equipment, are likely to increase known defects and allow us to proactively address the types of issues resulting in network outages, as discussed in section 5.3.2. This increase in known defects, resulting from each feeder survey, results in more extensive investment to rectify and ensure improved performance in those areas.

Areas of increased focus in the defect remediation management system include:

- SAIDI and Public Safety Factors of the work area;
- Known component issues such as inadequate jumper connections;
- Areas where span length or crossarm size and construction may be causing poor performance; and
- Areas of high pollution.

Detail on the revised standards and defect management tools can be found in section 4.2.

Feeder / Area	AMP2021 Financial Year	AMP2021 Estimated Cost ($000s)	Updated Financial Year	Updated Estimated Cost ($000s)	Commentary
Overhead Line Renewal – Defect Remediation	FY23-FY31	3,000	No change	4,000	Increased budget for defect remediation projects.
Te Toro – HV Backbone Rehabilitation	New Project	New Project	FY23	1,430	High defect rate identified in FY22 inspections and high rate of asset failure. Conductor and Pole condition adequate.
LiDAR Flights	FY24/27/30	500	FY24/27/30	No change to budget; reclassified to Opex	Reallocated to Operational Expenditure; ongoing maintenance cost.

Table 7-1 - Defect Management material changes

Capitalised Maintenance

Capitalised maintenance has increased from $950 k per annum to $1.3 m per annum. Also, allowance for the three yearly LiDAR flights has been transferred to Operational Expenditure as part of ongoing maintenance; more detail can be found in section 9.2.

7.1.2 Aged Conductor Replacement Programme

The copper and swan programmes continue to progress well, and high population urban and school areas are largely complete. Overall, the net impact on the budget is minimal. The programme continues to undergo refinement based on asset condition, public safety risks and contextual factors such as high pollution areas. The programme is undergoing review using asset health modelling; more detail can be found in section 4.4.

Swan Replacement Programme

Following a programme review against updated geospatial information, some project timings have been adjusted. Additionally, the scopes of works continue to be refined to more detailed and specific work areas. Some of these changes come from development works impacting the scope of works, such as Drury and Drury Hills, where network development and the Barber Road feeder works are being undertaken.

Feeder / Area	AMP2021 Financial Year	AMP2021 Estimated Cost ($000s)	Updated Financial Year	Updated Estimated Cost ($000s)	Commentary
Drury Hills	FY23	1800	FY33	1800	Deferred due to significant development in area.
Waiuku West – Cornwall Road	FY24	565	FY23	216	Reduced scope due to defect remediation previously undertaken in the area.
Pakington – Wymer Road/Reid Road	FY27	2,322	FY24	1210	Reduced scope due to defect remediation previously undertaken in the area. Schedule change due to proximity to high pollutant area, affecting asset life expectancy
Drury Feeder	FY24	3,603	FY33	3,603	Deferred due to development in the area.
Hingaia – Oakland Road	New Project	New Project	FY24	640	Residual overhead in a subdivided residential area.
Hingaia – Pararekau Road	New Project	New Project	FY24	1195	Improves reliability by creating a link to Beach Road feeder.

Table 7-2 - Swan Replacement programme changes

Copper Replacement Programme

Feeder	AMP2021 Financial Year	AMP2021 Estimated Cost ($000s)	Updated Financial Year	Updated Estimated Cost ($000s)	Commentary
Bombay SH1	FY23	1,160	FY24	860	Deferment to allow for additional reliability scoping requirements, highly complex project requires additional planning and coordination with key stakeholders.
Pakington (Glenbrook Station Road) CU replacement	FY27	1,454	FY25	1,313	Defect remediation required in the area, refinement of cost estimate.
Seagrove Road Copper replacement	FY28	1,400	FY25	1,567	Refinement of cost estimate.
Waiuku South – Waiuku Road	New Project	New Project	FY25	1,723	Backbone copper, to align with Glenbrook Station Road replacement.

Table 7-3 - Copper replacement material changes (constant dollars)

7.1.3 Other Fixed Systems

Karaka Protection

Due to learnings from the Pukekawa and Tuakau relay replacement projects, resource requirements and delivery staging, the Karaka relay replacement projects have been rescheduled.

Loading and clearance restrictions on the overhead structures relating to the proposed fibre route have resulted in an increase in the budget and a delay to FY23. This work is required before commissioning the relay replacement works, now scheduled for completion in FY24, following protection strategy and installation design in FY23.

Feeder	AMP2021 Financial Year	AMP2021 Estimated Cost ($000s)	Updated Financial Year	Updated Estimated Cost ($000s)
Karaka Sub to Glenbrook install fibre	FY22	500	FY23	1,800
Karaka Protection design	New Project	New Project	FY23	300
Karaka 8 relay replacement – rollover	FY22	510	FY24	580
Karaka 33 kV and TX Micom Relay Replacement (incl. Glenbrook End)	FY22	500	FY24	380

Table 7-4 Karaka protection material changes (constant dollars)

SCADA Communication Systems

Feeder	AMP2021 Financial Year	AMP2021 Estimated Cost ($000s)	Updated Financial Year	Updated Estimated Cost ($000s)
SCADA Radio Equipment Upgrade	FY23–26	9,000	FY23–24	3,800

Note: This project commenced in FY22 and the budget for the current financial year is excluded from the above.

Table 7-5 SCADA Communication Systems material changes (constant dollars)

The SCADA Radio Equipment upgrade has been split into two sections. The replacement project is primarily concerned with the communications backbone. Field devices for remote control and indication are covered under the 'Automation rebuild' reliability initiative, as described in section 5.6.4.

7. Renewal and Maintenance

7.1.4 Barber Road Substation

Subtransmission Works

Feeder	AMP2021 Financial Year	AMP2021 Estimated Cost ($000s)	Updated Financial Year	Updated Estimated Cost ($000s)	Commentary
Bombay-Ramarama Tower line rebuild	FY24/25	9,000	FY23	2,000	Reduced budget. The current route is being retained and refurbished.

Table 7-6 Barber Road Subtransmission material changes (constant dollars)

Feeder Works

The Barber Road substation feeder works have been reprioritised to better work staging when converting to 22 kV. As a result, some work scheduled to be completed in FY23 will be completed in FY22.

Further information regarding the Barber Road substation works can be found in Chapter 8 Network Development.

Feeder	AMP2021 Financial Year	AMP2021 Estimated Cost ($000s)	Updated Financial Year	Updated Estimated Cost ($000s)	Commentary
Pinnacle Hill North (Copper Replacement)	FY22	815	FY23	815	Deferred due to staging.
Bombay Road (Copper Replacement)	FY23	1,386	FY22	Due Completion FY22	Brought forward due to staging.
Great South Motorway Crossing (Copper Replacement)	FY23	182	FY22	Due Completion FY22	Brought forward due to staging.
Barber Road North (Copper Replacement)	FY23	936	FY22	Due Completion FY22	Brought forward due to staging.
Pinnacle Hill South (Swan Replacement)	FY22	380	FY23	2,241	Deferred due to staging.
Hillview Road South (Swan Replacement)	FY23	1,225	FY22	Due Completion FY22	Brought forward due to staging.
Paparata Road East (Swan Replacement)	FY23	549	FY22	Due Completion FY22	Brought forward due to staging.
Razorback Puketutu Intersection	FY23	123	FY22	Due Completion FY22	Brought forward due to staging.

Table 7-7 - Barber Road feeder material changes (constant dollars)

7.2 Material Changes to the Capitalised Maintenance

Capitalised maintenance allowance has increased from $955 k to $1.3 m to reflect better the change in how we deal with reactive faults, replacing whole assets or significant components. This increase aligns with the volume of capitalised maintenance activities we currently experience.

The business rules which determine what work is capitalised have recently been reviewed and revised to ensure that the capitalisation of new assets occurs when required.

8. Network Development

8.1 Material Changes to Network Development

The material changes to our network development plans have resulted from lower than expected increases in demand observed during 2021 compared to what had been forecast previously and the subsequent improvements we have made to our demand forecast. This, combined with Council plan changes in the area, has resulted in a reprioritisation of projects.

The network is experiencing continued growth. While the most significant increase has been in residential properties, the growth in industrial and commercial properties also continues. As of October 2021, there were 45,982 ICPs (an increase of 2.8% year on year [YoY]) connected to the Counties Energy network with a maximum demand of approximately 141 MW and annual delivered energy of 640.5 GWh the year ending 31 March 2021 (an increase of 3.6% YoY).

For the 2021 winter, however, our peak demand was 129 MW (a decrease of 8% YoY). This is due primarily to improvements in load control, which have resulted in reduced peaks despite higher volumes of energy and record national peaks during winter 2021. Furthermore, this peak reduction YoY is reflective of COVID-19 impacts. We have observed increased peaks for residential feeders and a decrease in commercial feeders. This is primarily related to behaviour changes with remote working becoming more common and the impact of lockdowns on retail and commercial outlets. A breakdown of the ICP type and delivered GWh is shown in the table below.

	ICPs	Delivered GWh (FY21)
Direct Supply	9 (0% YoY)	114.8 (+14.8% YoY)
Time of use	174 (+1.75% YoY)	115.6 (+1.2% YoY)
Commercial	7,332 (+2.2% YoY)	114.3 (+5.5% YoY)
Domestic	38,467 (+2.9% YoY)	295.7 (+5.3% YoY)
Total	**45,982 (+2.8% YoY)**	**640.5 (+3.6% YoY)**

Table 8-1 ICP breakdown and delivered GWh

Domestic ICP growth reflects the focus on providing housing in targeted areas within the wider Auckland region. Subdivisions in the Pukekohe, Paerata, Drury, Karaka, Glenbrook and Pokeno areas continue to see strong growth in customer numbers.

Industrial connection requests have continued to grow. This includes significant expansion at Watercare's Waikato Water Treatment Plant in Tuakau and several new requests from the Drury South industrial precinct.

Our forecasts are based on current growth trends and information at hand. Taking these into consideration, we updated our assumptions for our demand forecasting. The potential impact of new technology (including DG and EVs) and climate change continue to be monitored. The present load forecast for the whole network is shown below in Figure 8-1. This is shown alongside the corresponding forecast from the 2021 Asset Management Plan.

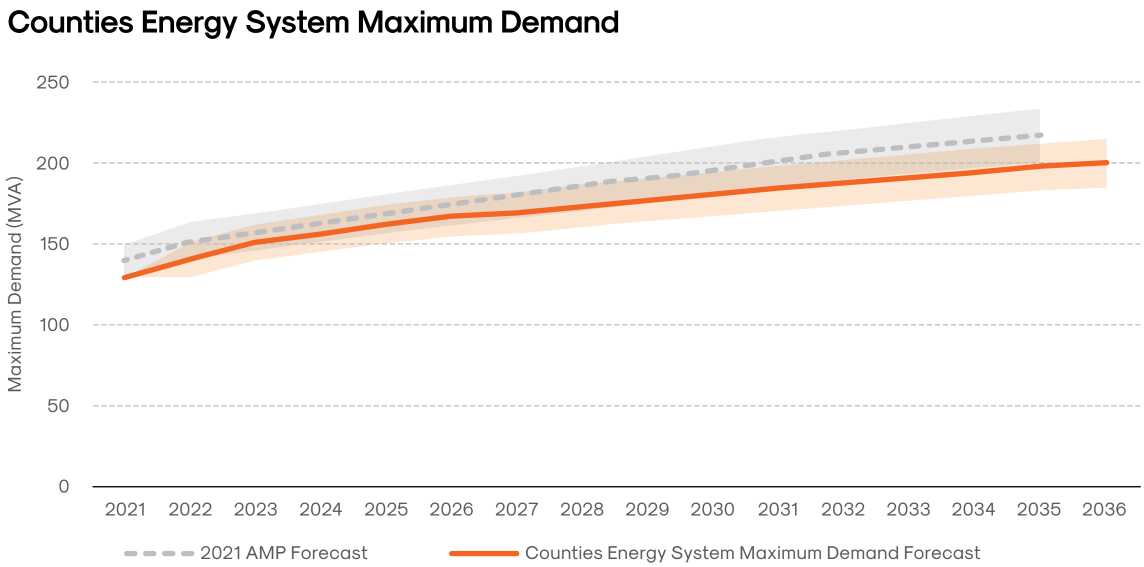

Figure 8-1 Winter system maximum demand forecast

Figure 8-2 below shows the 10-year network development CAPEX forecast compared to the 2021 Asset Management Plan. No significant new major network development projects are expected within the planning period. However, we have reprioritised our system growth projects, resulting in an overall decrease of $3.5 m in network development capital expenditure for the planning period YOY.

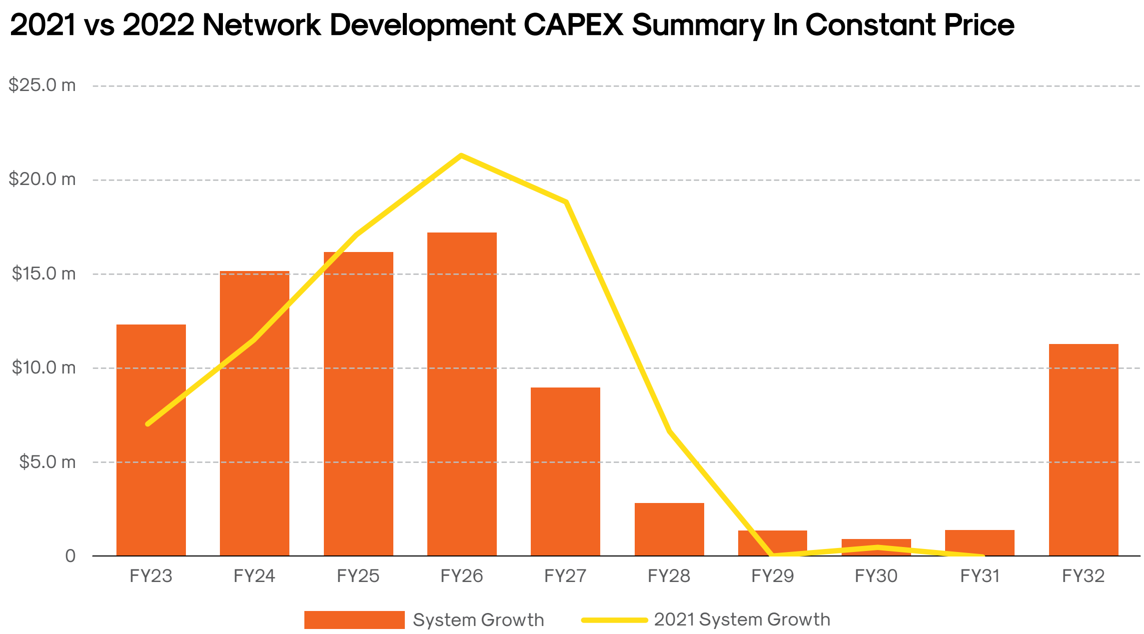

Figure 8-2 Network development CAPEX forecast

8.2 Material Changes to the Network Development Programme

The main changes to the network development programme are outlined below.

Substation	Project	AMP2021 Financial Year	AMP2021 Estimated Cost ($000s)	Updated Financial Year	Updated Estimated Cost ($000s)
Barber Road	Great South Road 22 kV conversion	FY22	2,225	FY23	2,687
	Kaiaua voltage support	New project	New project	FY30	400
	New feeder	New project	New project	FY31	1,410
Karaka	Te Hihi voltage regulator	FY22	360	FY26	360
	Karaka 33 kV line rating study	New project	New project	FY27	400
Kingseat	Land procurement	FY22	3,050	FY24	2,050
	33 kV line preliminary design	FY22	500	FY23	No change
	33 kV line construction	FY26	1,856	FY27	No change
Opaheke	110 kV bus at substation	FY32	4,000	FY25	No change
Pokeno	New feeder	New project	New project	FY29	1,410
Pukekohe North	Land procurement	FY22	2,750	FY23	2,750
	Build 110/22 kV substation with a single 110 kV line	FY24–FY25	27,000	FY34–FY35	No change
	New feeders	FY26	3,000	FY34	No change
Quarry Road	Build 110/22 kV substation	FY32	6,500	FY26	No change
	Substation design	New project	New project	FY23	200
Tuakau	New feeder	New project	New project	FY24	753
Waiuku	33 kV line upgrade – design	New project	New project	FY23	200
	33 kV line upgrade – stage 1	New project	New project	FY24	797
	33 kV line upgrade – stage 2	New project	New project	FY28	1158
	New feeder	New project	New project	FY27	753

Table 8-2 Network Development Programme – material changes

8.2.1 Barber Road Zone Substation (Ramarama and Mangatāwhiri)

The timing for the 22 kV conversion of the Great South Road feeder has been updated to align with the workstreams associated with establishing the new Barber Road 110/22 kV substation. The cost estimate has been updated following a detailed design.

A new project for voltage support on the Kaiaua Feeder for FY30 has been created. Furthermore, a placeholder has been created in FY31 for a new feeder for offloading the existing Pukekohe East Feeder if load growth necessitates.

8.2.2 Kingseat Zone Substation

Land procurement is in progress; however, we anticipate this purchase's cash flow in FY24, pending due diligence investigations. Timings for 33 kV works have been updated to align with the substation build.

8.2.3. Opaheke Zone Substation

The 110 kV bus installation at the Opaheke Zone Substation has been brought forward to align with the Quarry Road 110/22 kV Zone Substation development.

8.2.4. Pokeno Zone Substation

A placeholder has been created in FY29 for a new feeder for supporting industrial growth in the region if load growth necessitates.

8.2.5. Pukekohe North Zone Substation

The timing for the Pukekohe North Zone Substation has been deferred, largely resulting from alternative supply options for the load centre of Paerata Rise and the introduction of a new 22 kV zone substation at Quarry Road.

8.2.6. Quarry Road Zone Substation

The establishment of the Quarry Road 110/22 kV Zone Substation has been brought forward to FY26, primarily to support the development and anticipated loads in the Drury area. Secondary drivers support the existing Opaheke Zone Substation and provide additional capacity into the Paerata Rise development. This substation enables deferment of the Pukekohe North Zone Substation.

8.2.7. Tuakau Zone Substation

A placeholder has been created in FY24 for a new feeder for supporting industrial growth in the region if load growth necessitates.

8.2.8. Waiuku Zone Substation

New projects have been introduced to upgrade the 33 kV Glenbrook–Waiuku East line to address capacity constraints. Furthermore, a placeholder was created in FY27 for a new feeder to support industrial growth in the region if load growth necessitates.

9. Expenditure

This section details the changes to Capital and Operational expenditure; detail of the drivers behind these changes can be found in the related disclosure category sections;

- Section 5.6 Material Changes to Reliability, Safety and Environment;
- Section 7.1 Material Changes to the Lifecycle Asset Management; and
- Section 8.1 Material Changes to Network Development.
- Drivers for the Non-Network Material changes can be found in;
- Chapter 2 Reimagining Energy; and
- Chapter 6 Innovation and New Technology.

9.1 Material Changes to Schedule 11a Capital Expenditure

The forecast for capital expenditure (CAPEX) across the planning period is $438 m, increasing $8.6 m from the 2021 Asset Management Plan forecast.

The network CAPEX forecast is $389 m over the 10-year planning period, a reduction of $2.6 m from the 2021 Asset Management Plan forecast.

Non-network CAPEX forecast is $49 m over the 10-year planning period, an increase of $11 m due to our commitment to invest in digital technology. Further detail can be found in Chapter 6.

9.2 Material Changes to Schedule 11b Operational Expenditure

The forecast for operational expenditure (OPEX) across the planning period is $237.5 m, increasing $31 m from the 2021 Asset Management Plan forecast.

Network operational expenditure increased by $8.5 m over the 10-year planning period. This increase in predominantly in Routine Maintenance and Service Interruptions. Further detail can be found throughout this chapter.

Non-Network operational expenditure has increased $22.6 m, predominantly in business support due to the increase in IT support requirements, for detail refer to section 9.2.4.

Figure 9-3 shows material changes in network expenditure, primarily in the Preventative and Corrective space. In FY23, there is also an increase due to some corrective work which has been highlighted through asset activities, this will be discussed later in this section. There is also an increase in the Service Interruptions and Emergency operational budget. Further detail on this can be found in Section 9.2.1.

There is additional expenditure resulting from the maintenance requirements of the new substation at Pokeno and ongoing maintenance reviews, refinement and improvements across the network. The review of Maintenance and Inspection practices is further discussed in section 4.2 Maintenance and Construction Standards.

2021 vs 2022 Schedule 11a – Capital Expenditure In Constant Price

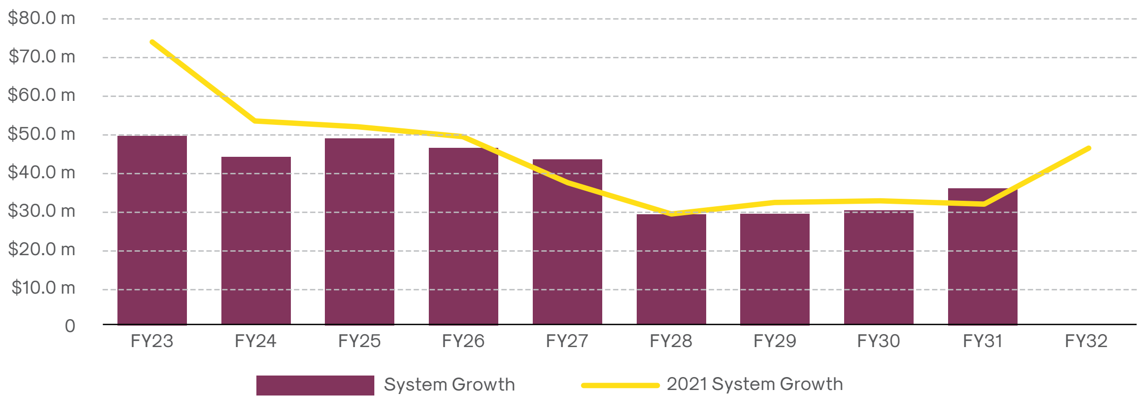

Figure 9-1 2021 vs 2022 Schedule 11a – Capital Expenditure in Constant Price

Ten-year Planning Period CAPEX Forecast in Constant Price

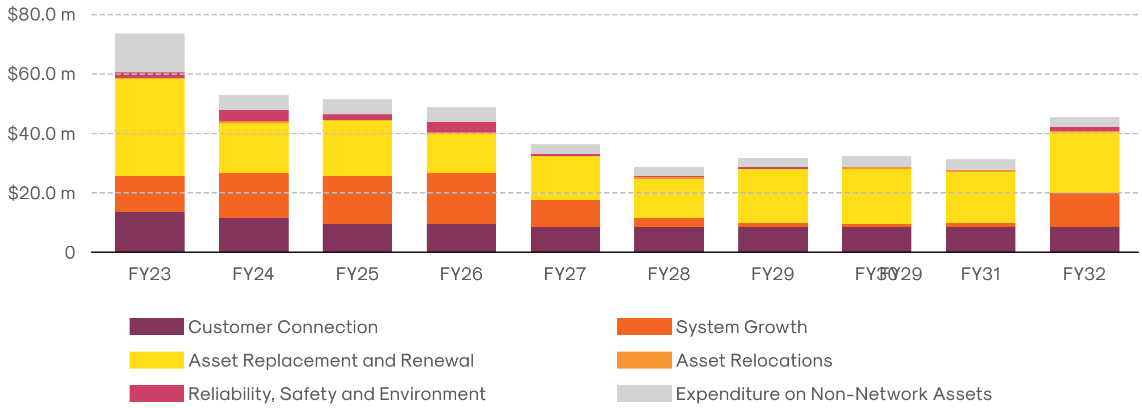

Figure 9-2 Ten year CAPEX forecast in Constant Price

FY23 Network Operational Expenditure Changes (Breakdown) In Constant Price

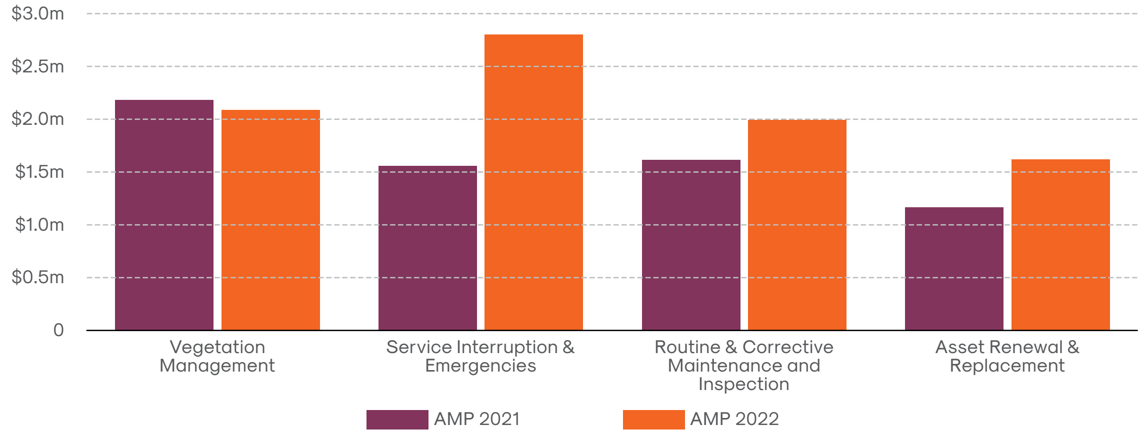

Figure 9-3 - FY23 AMP2021 vs AMP2022 Network Operational Expenditure (Breakdown) In Constant Price

FY23 Non-Network Operational Expenditure Changes (Breakdown) In Constant Price

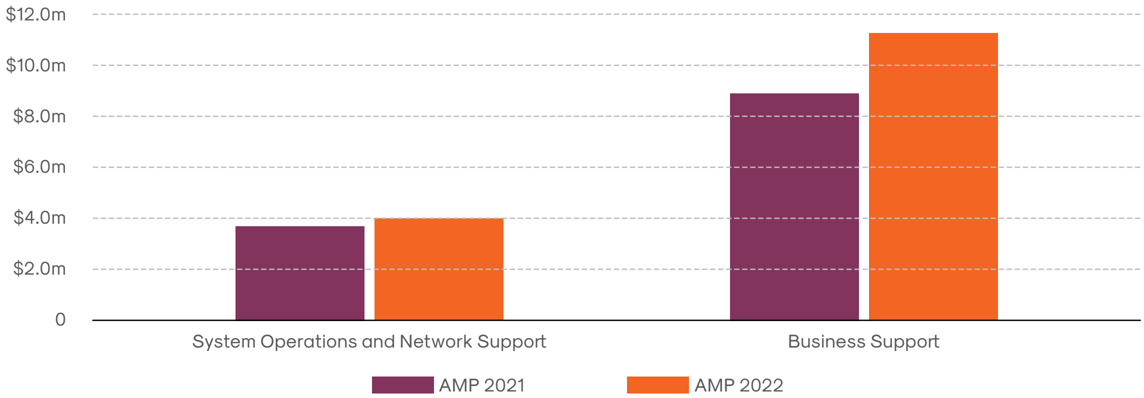

Figure 9-4 FY23 AMP2021 vs AMP22 Non-network OPEX (constant dollars)

9. Expenditure

9.2.1 Service Interruptions and Emergencies Material Changes

Costs relating to the management of faults increased moderately in FY22 compared to plan. Initial investigation has indicated this is a combination of several factors such as a minor volume shift of jobs to outside of core hours, additional resources required for both safety and training reasons, and a minor increase overall in work volume. This full work volume is made up of both HV faults and LV faults, as well as other services, such as public safety services. A step-change increase has been added from FY23 in line with the increase observed in FY22. This step-change remains in place for the rest of the planning period, although work will begin in FY23 to further quantify the reasons for the increase and identify opportunities for efficiency, which can then be reflected in future versions of this Asset Management Plan.

9.2.2 Routine and Corrective Maintenance OPEX Material Changes

Subtransmission Cable

Additional 110 kV cable maintenance at Pokeno Substation has resulted in an increased operational budget of $20 k, including monthly, annual and five-yearly inspections.

FY23 has an additional allowance for training to deliver this maintenance in house.

Distribution Lines and Conductor

An additional $500 k budget is allowed for in FY24, FY27 and FY30 for ongoing LiDAR surveys. There is also an annual allowance for aerial surveys to improve our condition information and continuing management of poles, crossarms and conductor.

There is also an allowance for ongoing aerial photography and condition assessment of the poles and conductor; this is both LiDAR and aerial photography to allow us to continue to monitor the condition of our assets through the use of technology.

Distribution Transformers

The distribution transformers maintenance regime has been reviewed and aligned with industry best practices. It includes greater detail regarding earth testing and, as such, requires a more significant investment due to additional time requirements.

Other System Fixed Assets

A review of the communication system maintenance has highlighted additional maintenance activities and has resulted in an additional operational cost of $320 k. This includes additional base station maintenance, fibre maintenance and repeater stations.

Public safety services

Public Safety Service allowance has doubled, from $50 k to $100 k; this is to reflect the high volume of requests Counties Energy receive to support our community safely, such as:

- High Load Requests;
- Safety Stand-overs;
- B4UDig investigative work; and
- Safety Disconnect.

9.2.3 Asset Replacement and Renewal OPEX Material Changes

Subtransmission Lines

An additional allowance in FY23 is made in the corrective budget for the following operational activities:

- Earth bond repairs;
- Dismantle of the abandoned Bombay to Tuakau subtransmission line; and
- Additional maintenance and inspection of the Mill Road 110 kV line.

Additionally, $20 k has also been included to remedy ground clearance issues on one of the Bombay to Opaheke subtransmission lines. This will de-energise the 33 kV line and utilise those lines on the middle and top crossarms for the 110 kV line.

Distribution Transformers and Switchgear

Additional budget is allowed for remedial repairs and other corrective work to extend the operational life expectancy of mid-life (H3) assets; an allowance of $37 k per annum has been applied to FY23–FY25.

Other System Fixed Assets

A budget of $180 k has been allowed to review and update the protection settings on the Tuakau and Pukekawa feeders.

9.2.4 Non-Network OPEX Material Changes

Business Support

Counties Energy is one of the fastest growing electricity distribution business in New Zealand. Along with experiencing an unprecedented period of continued growth, Counties Energy understands that it needs to start preparing for the role it will play in the future where there will be a smart, renewable and flexible low carbon energy system. By transitioning to a digitally enabled and data-driven network, we will facilitate the rapid integration of new energy technologies such as EVs, batteries and small scale renewable generation whilst ensuring greater operational efficiency and enriched customer experiences.

For a number of years now, we have increased our commitment and capability in smart technologies to reimagine the future of energy. In particular, the growing volume of distributed generation requires us to start transitioning from a DNO to a more dynamic DSO role to actively manage the network using new technology and real-time data to make network interventions.

As such, our forecast operational expenditure for Business Support has increased from 15% to 15.3% of net lines revenue ($19 m) over the ten year planning period. This expenditure is primarily focused on building capability to support the preparation of our transition to a DSO, especially in the areas where we have little to no capability today – such as ADMS, Digital Enterprise Asset Management System, Cloud Data and Integration platform to enable our data insights and analytics strategy. Further detail on these systems can be found in Chapters 6.

10.1. Schedule 11a Capex Forecast

Company Name	Counties Energy	
AMP Planning Period	1 April 2022 – 31 March 2032	

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
9	**11a(i): Expenditure on Assets Forecast**	$000 (in nominal dollars)										
10	Consumer connection	18,000	14,000	12,360	10,609	10,927	10,130	10,433	10,746	11,069	11,401	11,743
11	System growth	905	12,287	15,553	17,067	18,754	10,086	3,259	1,683	1,167	1,786	14,736
12	Asset replacement and renewal	42,068	32,447	17,335	19,552	14,454	16,301	15,572	21,510	22,892	21,778	26,761
13	Asset relocations	300	300	309	318	328	338	348	358	369	380	391
14	Reliability, safety and environment:											
15	Quality of supply	350	1,772	4,035	2,101	3,803	1,103	406	418	430	443	1,998
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	-	70	72	74	76	-	-	-	-	-	-
18	**Total reliability, safety and environment**	350	1,842	4,107	2,175	3,879	1,103	406	418	430	443	1,998
19	**Expenditure on network assets**	61,623	60,877	49,664	49,722	48,342	37,958	30,019	34,716	35,927	35,788	55,629
20	Expenditure on non-network assets	12,548	15,022	5,066	5,220	5,379	3,505	3,639	3,778	3,923	4,074	4,230
21	**Expenditure on assets**	74,171	75,899	54,730	54,942	53,721	41,462	33,658	38,494	39,850	39,862	59,859
22												
23	*plus* Cost of financing	184	279	255	278	301	232	179	201	204	198	301
24	*less* Value of capital contributions	20,500	15,000	12,731	11,255	11,941	11,401	11,743	12,095	12,458	12,832	13,217
25	*plus* Value of vested assets											
26												
27	**Capital expenditure forecast**	53,855	61,177	42,254	43,965	42,082	30,293	22,093	26,600	27,596	27,228	46,943
28												
29	Assets commissioned											
30		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
32		$000 (in constant prices)										
33	Consumer connection	18,000	14,000	12,000	10,000	10,000	9,000	9,000	9,000	9,000	9,000	9,000
34	System growth	905	12,287	15,100	16,088	17,162	8,961	2,812	1,410	948	1,410	11,294
35	Asset replacement and renewal	42,068	32,447	16,830	18,430	13,227	14,484	13,433	18,014	18,614	17,192	20,510
36	Asset relocations	300	300	300	300	300	300	300	300	300	300	300
37	Reliability, safety and environment:											
38	Quality of supply	350	1,772	3,917	1,980	3,480	980	350	350	350	350	1,531
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	-	70	70	70	70	-	-	-	-	-	-
41	**Total reliability, safety and environment**	350	1,842	3,987	2,050	3,550	980	350	350	350	350	1,531
42	**Expenditure on network assets**	61,623	60,876	48,217	46,868	44,240	33,725	25,894	29,074	29,212	28,252	42,635
43	Expenditure on non-network assets	12,548	15,022	4,919	4,921	4,923	3,114	3,139	3,164	3,190	3,216	3,242
44	**Expenditure on assets**	74,171	75,898	53,136	51,788	49,162	36,839	29,033	32,238	32,402	31,467	45,877
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											
50												
51		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
53	**Difference between nominal and constant price forecasts**	$000										
54	Consumer connection	-	-	360	609	927	1,130	1,433	1,746	2,069	2,401	2,743
55	System growth	-	-	453	980	1,591	1,125	448	274	218	376	3,442
56	Asset replacement and renewal	-	-	505	1,122	1,227	1,818	2,139	3,496	4,279	4,586	6,251
57	Asset relocations	-	-	9	18	28	38	48	58	69	80	91
58	Reliability, safety and environment:											
59	Quality of supply	-	0	118	121	323	123	56	68	80	93	467
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	0	2	4	6	-	-	-	-	-	-
62	**Total reliability, safety and environment**	-	0	120	125	329	123	56	68	80	93	467
63	**Expenditure on network assets**	-	0	1,447	2,854	4,102	4,233	4,124	5,642	6,715	7,537	12,994
64	Expenditure on non-network assets	(0)	-	148	300	456	391	500	614	733	858	988
65	**Expenditure on assets**	(0)	0	1,594	3,154	4,559	4,624	4,624	6,256	7,448	8,395	13,982
66												

11a(ii): Consumer Connection

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
*Consumer types defined by EDB**		$000 (in constant prices)					
Urban residential		9,000	7,000	6,000	5,000	5,000	4,500
Urban commercial		3,600	2,800	2,400	2,000	2,000	1,800
Rural residential		3,060	2,380	2,040	1,700	1,700	1,530
Rural commercial		2,340	1,820	1,560	1,300	1,300	1,170
**include additional rows if needed*							
Consumer connection expenditure		18,000	14,000	12,000	10,000	10,000	9,000
less Capital contributions funding consumer connection		20,500	15,000	12,600	10,500	10,500	9,450
Consumer connection less capital contributions		(2,500)	(1,000)	(600)	(500)	(500)	(450)

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	-	6,950	797	-	1,856	2,256
Zone substations	635	2,500	13,550	15,500	13,500	2,000
Distribution and LV lines	-	2,687	-	588	1,086	3,952
Distribution and LV cables	-	150	753	-	-	753
Distribution substations and transformers	270	-	-	-	720	-
Distribution switchgear	-	-	-	-	-	-
Other network assets	-	-	-	-	-	-
System growth expenditure	905	12,287	15,100	16,088	17,162	8,961
less Capital contributions funding system growth						
System growth less capital contributions	905	12,287	15,100	16,088	17,162	8,961

11a(iv): Asset Replacement and Renewal

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
		$000 (in constant prices)					
Subtransmission		250	2,150	50	50	50	50
Zone substations		12,772	2,350	350	2,050	50	50
Distribution and LV lines		16,991	19,728	11,290	11,790	11,112	12,374
Distribution and LV cables		3,788	569	900	500	500	500
Distribution substations and transformers		400	400	400	400	450	450
Distribution switchgear		3,357	960	960	960	960	960
Other network assets		4,510	6,290	2,880	2,680	105	100
Asset replacement and renewal expenditure		42,068	32,447	16,830	18,430	13,227	14,484
less Capital contributions funding asset replacement and renewal							
Asset replacement and renewal less capital contributions		42,068	32,447	16,830	18,430	13,227	14,484

11a(v): Asset Relocations

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
*Project or programme**		$000 (in constant prices)					
Asset Relocations		300	300	300	300	300	300
**include additional rows if needed*							
All other project or programmes - asset relocations							
Asset relocations expenditure		300	300	300	300	300	300
less Capital contributions funding asset relocations							
Asset relocations less capital contributions		300	300	300	300	300	300

11a(vi): Quality of Supply

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
*Project or programme**		$000 (in constant prices)					
Automation Rebuild		-	-	1,700	1,000	2,500	-
Network Isolation Point Improvement		-	-	300	630	630	630
Other		350	1,772	1,917	350	350	350
**include additional rows if needed*							
All other projects or programmes - quality of supply							
Quality of supply expenditure		350	1,772	3,917	1,980	3,480	980
less Capital contributions funding quality of supply							
Quality of supply less capital contributions		350	1,772	3,917	1,980	3,480	980

10.1. Schedule 11a Capex Forecast (continued)

Company Name	Counties Energy
AMP Planning Period	1 April 2022 – 31 March 2032

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
135		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	**$000 (in constant prices)**					
139							
140							
141							
142							
143							
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory						
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory						
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							
150		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	**$000 (in constant prices)**					
153	Other		70	70	70	70	-
154							
155							
156							
157							
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment						
160	**Other reliability, safety and environment expenditure**	-	70	70	70	70	-
161	*less* Capital contributions funding other reliability, safety and environment						
162	**Other reliability, safety and environment less capital contributions**	-	70	70	70	70	-
163							
164		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169	Land and buildings	2,362	482	450	450	450	450
170	Digital strategy	3,035	5,636	4,126	4,086	4,046	2,266
171	Other non-network assets	243	444	343	385	427	398
172							
173							
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure						
176	**Routine expenditure**	5,640	6,562	4,919	4,921	4,923	3,114
177	**Atypical expenditure**						
178	*Project or programme**						
179	Head office site and building upgrade	6,908	8,460	-	-	-	-
180							
181							
182							
183							
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure						
186	**Atypical expenditure**	6,908	8,460	-	-	-	-
187							
188	**Expenditure on non-network assets**	12,548	15,022	4,919	4,921	4,923	3,114

10.2. Schedule 11b OPEX Forcast

Company Name	Counties Energy
AMP Planning Period	1 April 2022 – 31 March 2032

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
9	**Operational Expenditure Forecast**	$000 (in nominal dollars)										
10	Service interruptions and emergencies	2,400	2,800	2,923	3,051	3,170	3,295	3,424	3,558	3,682	3,809	3,941
11	Vegetation management	2,000	2,090	2,153	2,217	2,284	2,352	2,423	2,496	2,570	2,648	2,727
12	Routine and corrective maintenance and inspection	1,415	2,097	2,696	2,279	2,375	3,053	2,598	2,720	3,463	2,983	3,134
13	Asset replacement and renewal	930	1,628	1,231	1,034	896	1,099	907	934	1,146	989	1,027
14	**Network Opex**	6,745	8,615	9,002	8,581	8,725	9,799	9,352	9,708	10,861	10,429	10,829
15	System operations and network support	3,656	3,868	4,084	4,312	4,552	4,806	5,074	5,357	5,655	5,970	6,303
16	Business support	8,973	10,684	11,551	11,682	12,051	12,432	12,825	13,231	13,650	14,083	14,530
17	**Non-network opex**	12,628	14,552	15,635	15,994	16,603	17,238	17,899	18,588	19,306	20,053	20,833
18	**Operational expenditure**	19,373	23,167	24,637	24,575	25,328	27,037	27,251	28,295	30,166	30,483	31,662

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
21		$000 (in constant prices)										
22	Service interruptions and emergencies	2,400	2,800	2,838	2,876	2,901	2,927	2,954	2,980	2,994	3,007	3,021
23	Vegetation management	2,000	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090
24	Routine and corrective maintenance and inspection	1,415	2,097	2,618	2,148	2,173	2,713	2,241	2,278	2,816	2,355	2,402
25	Asset replacement and renewal	930	1,628	1,195	975	820	976	782	782	932	781	787
26	**Network Opex**	6,745	8,615	8,740	8,089	7,984	8,706	8,067	8,130	8,831	8,233	8,300
27	System operations and network support	3,656	3,868	3,965	4,064	4,166	4,270	4,377	4,486	4,598	4,713	4,831
28	Business support	8,973	10,684	11,214	11,011	11,028	11,046	11,063	11,081	11,099	11,117	11,136
29	**Non-network opex**	12,628	14,552	15,179	15,076	15,194	15,316	15,440	15,567	15,697	15,830	15,967
30	**Operational expenditure**	19,373	23,167	23,919	23,164	23,178	24,022	23,507	23,697	24,528	24,063	24,266
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	540	567	595	625	656	689	724	760	798	838	880

37 * Direct billing expenditure by suppliers that direct bill the majority of their consumers

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
40	for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
41	**Difference between nominal and real forecasts**	$000										
42	Service interruptions and emergencies	-	-	85	175	269	367	470	578	688	802	921
43	Vegetation management	-	-	63	127	194	262	333	406	480	558	637
44	Routine and corrective maintenance and inspection	-	-	79	131	202	340	357	442	647	628	732
45	Asset replacement and renewal	-	-	36	59	76	123	125	152	214	208	240
46	**Network Opex**	-	-	262	493	740	1,093	1,285	1,578	2,030	2,196	2,529
47	System operations and network support	-	-	119	248	386	536	697	871	1,057	1,257	1,472
48	Business support	-	-	336	671	1,023	1,386	1,762	2,150	2,551	2,966	3,394
49	**Non-network opex**	-	-	455	918	1,409	1,922	2,459	3,021	3,608	4,223	4,866
50	**Operational expenditure**	-	-	718	1,411	2,149	3,015	3,744	4,598	5,638	6,419	7,396

10. Schedules

10.3. Schedule 12a Asset Condition

Company Name **Counties Energy**

AMP Planning Period **1 April 2022 – 31 March 2032**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	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
7					Asset condition at start of planning period (percentage of units by grade)							
8												
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	0.07%	5.31%	18.56%	34.99%	41.07%	0.00%	3	3.95%
11	All	Overhead Line	Wood poles	No.	8.71%	10.58%	22.48%	2.87%	55.32%	0.06%	3	9.90%
12	All	Overhead Line	Other pole types	No.	-	24.36%	7.69%	2.56%	56.41%	8.97%	3	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	4.73%	-	64.97%	9.64%	20.66%	-	3	4.74%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	5.24%	-	-	-	94.76%	-	4	5.24%
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	12.99%	-	87.01%	-	3	-
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	-	-	-	-	100.00%	-	4	-
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.	50.00%	33.33%	-	-	16.67%	-	3	33.33%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	75.00%	25.00%	-	4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	16.67%	-	50.00%	33.33%	-	4	33.33%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	76.67%	3.33%	13.33%	6.67%	-	-	3	50.00%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	100.00%	-	4	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	11.76%	88.24%	-	4	11.76%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	9.38%	16.67%	12.50%	34.38%	27.08%	-	3	11.46%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	N/A	-
35												

Company Name: **Counties Energy**

AMP Planning Period: **1 April 2022 – 31 March 2032**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	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
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	5.88%	23.53%	11.76%	23.53%	35.29%	-	3	17.65%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.04%	11.83%	31.56%	34.04%	20.52%	0.00%	3	4.10%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	-	N/A	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.14%	0.17%	2.91%	23.77%	72.45%	0.55%	3	0.13%
44	HV	Distribution Cable	Distribution UG PILC	km	-	13.24%	24.65%	55.22%	6.89%	-	3	55.80%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	33.50%	66.50%	-	4	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	7.14%	21.43%	38.10%	33.33%	-	3	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	11.18%	13.67%	18.36%	25.58%	30.25%	0.94%	3	6.55%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	-	N/A	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2.06%	3.24%	8.24%	30.29%	55.59%	0.59%	3	6.62%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	3.26%	11.97%	30.70%	41.67%	12.06%	0.34%	3	7.50%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.82%	2.88%	30.48%	39.55%	25.64%	0.62%	3	3.49%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	13.33%	86.67%	-	4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1.05%	2.42%	31.05%	40.21%	24.53%	0.74%	4	-
55	LV	LV Line	LV OH Conductor	km	-	0.19%	0.75%	92.46%	6.29%	0.32%	3	8.34%
56	LV	LV Cable	LV UG Cable	km	0.59%	0.74%	1.09%	45.91%	49.92%	1.76%	3	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	1.01%	0.02%	10.54%	88.38%	0.05%	3	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	-	-	-	3	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	0.70%	11.27%	6.34%	27.46%	54.23%	-	3	52.11%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	100.00%	-	-	-	3	96.90%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	84.22%	15.78%	-	-	3	-
62	All	Load Control	Centralised plant	Lot	-	-	33.33%	33.33%	33.33%	-	3	26.24%
63	All	Load Control	Relays	No.	4.59%	30.03%	0.47%	63.78%	1.13%	-	3	5.52%
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

10. Schedules

10.4. Schedule 12b Capacity Forecast

Company Name **Counties Energy**
AMP Planning Period **1 April 2022 – 31 March 2032**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

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

sch ref	*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
9	Opaheke	27	40	n-1	7	67%	40	99%	No constraint within +5 years	
10	Pokeno	9	40	n-1	10	23%	40	58%	No constraint within +5 years	
11	Pukekohe	38	60	n-1	8	63%	60	71%	No constraint within +5 years	
12	Tuakau	17	40	n-1	5	42%	40	52%	No constraint within +5 years	
13	Ramarama	7	5	n-1	5	147%	40	42%	Transformer	Ramarama Substation will be decommissioned and replaced by Barber Rd substation in 2022
14	Mangatawhiri	8		n	5	-			Transformer	Mangatawhiri Substation will be decommissioned and replaced by Barber Rd substation in 2022
15	Waiuku	16	20	n-1	5	78%	20	99%	No constraint within +5 years	
16	Karaka	13	20	n-1	2	63%	20	81%	No constraint within +5 years	
17	Maioro	9	9	n	3	100%			Other	Maioro Substation firm capacity is subject to commercial agreement with the major customer on site for new investment in the 5-year period.
18						-				
19						-				
20						-				
21						-				
22						-				
23						-				
24						-				
25						-				
26						-				
27						-				
28						-				

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

10.5. Schedule 12c Demand Forecast

Company Name: **Counties Energy**

AMP Planning Period: **1 April 2022 – 31 March 2032**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7		**12c(i): Consumer Connections**						
8		*Number of ICPs connected in year by consumer type*			**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
11		*Consumer types defined by EDB**						
12		Standard domestic	516	458	470	481	493	506
13		Low user domestic	684	607	622	638	654	670
14		Mass market business	13	11	12	12	12	13
		Time of use business	65	57	59	60	62	63
15		Distributed Streetlights	13	11	12	12	12	13
16		Direct Charge	-					-
17		**Connections total**	1,291	1,145	1,174	1,203	1,233	1,264
18		**include additional rows if needed*						
19		**Distributed generation**						
20		Number of connections	200	220	240	260	280	300
21		Capacity of distributed generation installed in year (MVA)	2	2	2	2	2	2
22		**12c(ii) System Demand**						
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24		**Maximum coincident system demand (MW)** — for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
25		GXP demand	120	130	140	146	152	157
26	*plus*	Distributed generation output at HV and above	9	10	10	10	10	10
27		**Maximum coincident system demand**	129	140	150	156	162	167
28	*less*	Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29		**Demand on system for supply to consumers' connection points**	129	140	150	156	162	167
30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	628	657	670	687	704	721
32	*less*	Electricity exports to GXPs	-	-	-	-	-	-
33	*plus*	Electricity supplied from distributed generation	47	49	50	51	53	54
34	*less*	Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35		**Electricity entering system for supply to ICPs**	675	706	720	738	756	775
36	*less*	Total energy delivered to ICPs	643	673	686	703	721	739
37		**Losses**	32	33	34	35	36	36
38								
39		**Load factor**	60%	57%	55%	54%	53%	53%
40		**Loss ratio**	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%

10.6. Schedule 12d Reliability Forecast

Company Name	**Counties Energy**
AMP Planning Period	**1 April 2022 – 31 March 2032**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	180.0	176.2	125.4	127.1	147.2	155.7
12	Class C (unplanned interruptions on the network)	104.3	101.5	97.0	91.9	87.6	87.6
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.60	0.54	0.39	0.39	0.45	0.48
15	Class C (unplanned interruptions on the network)	1.92	1.87	1.77	1.66	1.57	1.57

10.7. Schedule 14a Voluntary Explanatory Notes

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8. Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)
2. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
The difference between nominal and constant prices reflects inflation of 3% per annum

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

In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
The difference between nominal and constant prices reflects inflation of 3% per annum.

11. Director's Certificate

11.1. Schedule 17 Certificate for Year-Beginning Disclosures

Clause 2.9.1

We, Vernon John Dark and Hamish William Stevens being directors of Counties Energy certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Counties Energy's prepared for the purposes of clauses 2.4.1, 2.6.1, 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 Counties Energy's corporate vision and strategy and are documented in retained records.

Vernon John Dark
(Director)

Hamish William Stevens
(Director)

Certified this 22nd day of March 2022

Counties Energy

Location:
14 Glasgow Road,
Pukekohe, Auckland, 2120
New Zealand

Postal Address:
Private Bag 4,
Pukekohe 2340,
New Zealand

Phone: 0800 100 202
Email: info@countiesenergy.co.nz
Web: www.countiesenergy.co.nz