TRANSPOWER

Transmission Planning Report

December 2019

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1 Introduction

Transpower owns, maintains, operates and develops New Zealand's high voltage electricity transmission network (the National Grid).

This Transmission Planning Report (TPR) describes how we assess the adequacy of the transmission network to meet the future needs of users, and identifies potential investments to address demand needs or alleviate expected constraints. The TPR also identifies investment opportunities in the interconnected grid that may improve operation of the grid, reduce losses or enhance market operation.

The Decision Framework is a core part of our transmission planning process. We are also working to develop our understanding of uncertainty in investment planning and regulatory processes, in order to manage it better.

The information in this TPR is based on the New Zealand transmission network as at 30 June 2019 unless otherwise stated.

1.1 Purpose of the Transmission Planning Report

The purpose of this TPR is to provide interested parties with information about:

- the Enhancement and Development[1] (E&D) transmission investments that may be required within the 15 year planning period (2019 to 2034) to address gaps in capability
- the existing and future capability of the National Grid
- our transmission planning processes.

Transparency in respect of our transmission network development processes is important to encourage efficient industry investment decision-making via the timely disclosure of potential grid development needs and options.

1.1.1 Transpower context

Transmission Tomorrow[2] provides Transpower's perspective on the changing environment in which it operates, and how this will impact future requirements for transmission services.

To support our objective of continuing to provide quality transmission services and investing appropriately in long-life assets within a changing environment, we have developed the following Grid strategic goals, which are at the core of our planning strategies and processes.

The TPR provides a transparent publication setting out how we plan for grid E&D (including engaging with stakeholders), and shares progress towards the Grid strategic goals.

- **Service Performance:** The investments proposed in the TPR consider the needs of the interconnected grid and the service performance required by each of our customers, enabling effective cost-service trade-offs to be made. The flexibility in the process for investigating transmission problems or opportunities supports consideration of a broad range of options to meet transmission development needs.
- **Cost Performance:** The changing environment for transmission services requires that we match our investments to grid needs, value the future flexibility some options may provide, and select the 'least-regrets' investment[3]. Our assessment of potential transmission investments gives significant weight to the whole-of-life cost of the assets and the extent to which they enable us to achieve service levels.

1 The E&D portfolio encompasses all investments that change the capability of the transmission grid to provide desired levels of service to our customers. Changing the capability of the grid may be either an increase or decrease in capability.

2 https://www.transpower.co.nz/about-us/transmission-tomorrow/about-transmission-tomorrow

3 A 'least regrets' approach to planning is a prudent approach for the stewardship of an essential service based on long-lived assets.

- **Customers and Stakeholders:** Customers' development plans, preferred service levels and technology choices are central to transmission investment decisions. The TPR describes how customer choices impact transmission investment choices and timing. Sharing investment planning information and processes and working closely with customers and stakeholders ensures best outcomes are achieved, both nationally and regionally.
- **Asset Management Capability:** A key challenge in investment planning is managing uncertainty. The need for and timing of investments is inevitably affected by external factors such as changes in the wider economy and uptake of new technologies. Continuing to improve our understanding of uncertainties that may affect grid development, and being cognisant of their potential impacts is essential to building our asset management capability.

We recently considered a range of future uncertainties affecting the electricity sector – a deeper dive on the issues covered by *Transmission Tomorrow*. Our early findings are set out in *Te Mauri Hiko - Energy Futures*[4]. We outline possible future scenarios and identify some of the possible changes and the challenges we might face as a result of energy sustainability, New Zealand's response to climate change, electrification of some parts of our economy and the uptake of new technologies.

We continue to work to understand the implications of the possible changes and challenges we face, particularly in relation to investment uncertainty (discussed further in Chapter 3) and the impact on our transmission system.

1.1.2 Integrated Transmission Plan

We publish a new Integrated Transmission Plan (ITP) most years as a central part of our engagement with the Commerce Commission and stakeholders. The ITP also satisfies requirements under the Capital Expenditure Input Methodology[5] (Capex IM).

The ITP describes Transpower's business objectives, strategies and our approach to decision-making. It also provides a high-level view of forecast expenditure and service outputs across network development, replacement, refurbishment and maintenance expenditure.

One of the supporting documents of the ITP is a recent TPR. This year we are not required to publish a ITP; our next ITP is due in 2020. Despite this we have published this TPR to provide transparency as our plans and planning evolve.

The TPR as a supporting document to the ITP, provides detailed information on current and potential future E&D investment. This includes both base capex projects (expenditure less than $20 million) and Major Capex Projects (expenditure greater than $20 million).

1.1.3 Regulatory context

Investment funding

Investments, which either increase or decrease the capability of the grid, are categorised as E&D projects.

The grid development plans set out in this TPR (Chapters 6 - 19) are a bottom-up view of possible E&D projects for the next 15 years. Alongside this bottom-up view we consider how uncertainty in our operating environment (e.g. uptake of new technologies, changes in economic conditions and decisions by our customers) may impact overall investment needs. This approach is described in Chapter 3.

Our view of E&D investment needs is a component of our five-yearly regulatory reset proposals, alongside our assessment of reinvestment and operating costs. The Commerce Commission evaluates our proposal as a whole and establishes funding arrangements (baselines, output targets and incentives). Once funding arrangements are established we have flexibility to reprioritise our plans, and increase or decrease overall investment within the regulatory period in response to new information.

4 https://www.temaurihiko.co.nz/

5 http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/transpower-input-methodologies/

The five-yearly process described above excludes any development investments with an expected cost in excess of $20 million. These 'Major Capex Projects' are assessed individually by the Commission.[6]

In our planning processes we classify our transmission network development projects by funding arrangement as summarised in Table 1-4.

Reporting requirements

Every two years, under Part 12 of the Electricity Industry Participation Code, we are required to publish:

- a Grid Reliability Report (GRR), which sets out 10-year forecasts of demand at grid exit points, generation at grid injection points, and whether the National Grid can reasonably be expected to meet (n-1) security requirements, and
- a Grid Economic Investment Report (GEIR), which identifies economic investments (those that create net market benefits) Transpower considers could be made in respect of the interconnection assets.

The TPR fulfils the requirements of the GRR by providing:

- a forecast of demand at each grid exit point over the next 10 years (Chapters 7 - 19)
- a forecast of supply at each Grid Injection Point (GIP) over the next 10 years (Chapters 7 - 19)
- whether the power system is reasonably expected to meet the n-1 criterion at all times over the next 10 years (Asset Capability sections of Chapters 6 - 19).

The Grid Enhancement Approach sections of each regional and backbone TPR chapter fulfil the requirements of the GRR and GEIR by:

- providing proposals for addressing any n-1 issues identified in the assessment of asset capability
- identifying issues impacting the economic operation of the grid, and
- providing proposals to address any issues impacting economic operation of the grid.

The blue 'investment boxes' throughout this TPR, similar to Table 1-1, provide details of our proposals to address identified issues. Where an issue is **not** part of the GEIR it should be considered a GRR issue.

Table 1-1: Example of proposal to address a GRR issue[7]

Project name:	Increase interconnection capacity to Lower Waitaki Valley
Project description:	Waihao grid exit point
Project's state of completion:	Investigation started
OAA level completed:	OAA L3p
Grid need date:	TBA, customer initiated
Indicative cost ($ million):	26
Part of the GEIR?	No

The TPR contains the information required to be published in the GRR and GEIR under Part 12 of the Electricity Industry Participation Code. We have not separately published these reports since 2016.

Under the Commerce Act Information Disclosure (ID) regulations[8], Transpower is also obliged to disclose grid demand and injection information (Schedule G2). The demand and injection information produced for ID is the same as that produced for the GRR.

As noted previously, there is no requirement to publish a TPR this year. We have published this TPR to provide transparency as our plans and planning evolve.

6 Major Capex Projects are included in the proposal for information purposes, but funding is not approved as part of the Commission assessment described here. Instead they are submitted to the Commission individually throughout the regulatory control period as proposals are completed.

7 The classifications used in this table are described in section 11.2.2.

8 Transpower Information Disclosure Determination 2014, paragraph 11 available at http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-information-disclosure/

1.2 Investment process and classification

1.2.1 Investment process

There are two main parts to the investment planning process:

- identifying grid problems and opportunities for changing grid capability, and
- investigating options to resolve these issues through the Decision Framework.[9]

Identifying problems and opportunities for changing grid capability

We use three main inputs to identify grid problems and opportunities.

- The Annual Transmission Planning process: we test the capability of the grid to meet forecast demand and generation needs over the next 15 years. This assesses the ability of the grid to remain in a secure state with any one asset out of service (n-1), from which we can identify potential future upgrades. This process provides the main input to the Decision Framework for E&D investments. The Asset Capability section of each TPR regional or backbone chapter details the results of these studies.
- Customer Developments: when customers require new connections, increase their demand or develop their own networks, changes in the transmission grid may be necessary to ensure acceptable service performance and security of supply. We obtain relevant information from discussion with customers and through the Customer Technical Request (CTR) process. Customer input is discussed in the Grid Enhancement sections of each regional or backbone chapter.
- Asset Feedback: in operating and maintaining the grid, valuable information is obtained on potential transmission problems and opportunities, and the risks associated with current asset capability. Asset Feedback is discussed in the Asset Capability section of each regional or backbone chapter.

While the Annual Transmission Planning process, in particular, has a natural focus on identifying problems, all three of the processes described above may also identify opportunities for grid investment. Opportunities generally involve investment in the interconnected grid that produce net market benefits, such as where they improve operation of the grid, reduce losses or enhance market operation.

All identified problems and opportunities are reviewed and assessed to determine whether there is an investment need.

Applying the Decision Framework

We investigate E&D investment needs and the options to resolve them by applying the Decision Framework. This framework requires us to consider System Needs alongside refurbishment, replacement and maintenance requirements. Where appropriate, we combine individual Needs into collective grid Needs, ensuring that investigations consider interrelated problems and opportunities.

The Grid Enhancement sections of the TPR capture our application of the Decision Framework to E&D System Needs. The outcome is a set of potential investments in each region and on the grid backbone.

As we evolve the TPR, we intend to expand discussions on investments to set out our views of investment uncertainty and the impact of this on investment decision making.

Our investment decision making process is described in more detail in Appendix A.

1.2.2 Project classification

The TPR refers to a large number of current and potential transmission and generation projects. This section explains how we present projects in the TPR in terms of state of completion, regulatory status, identification references and costs.

[9] The Decision Framework is a process that allows us to make effective, consistent, repeatable asset planning decisions that balance risk, service levels and investment. See Appendix A for more information

State of completion

We classify transmission network development projects by their state of completion to provide an indication of the planning stage each one is in.

Table 1-2 lists the completion states with respect to the Decision Framework and Option Assessment Approach.

Table 1-2: State of completion classifications

Status	Definition
Delivery	Projects that have an approved delivery business case and are in the delivery stages.
Committed	Projects that have completed the options assessment stage (gone through a delivery level options assessment) and either: • the investment has obtained approval to proceed, or • Transpower has entered into an investment contract with a specific customer or customers.
Proposed	Projects that are still in the options assessment stage, having gone through a planning level options assessment.
Possible	These projects are in the needs identification stage and have not gone through an options assessment stage. The investments identified are possible options for future grid upgrades, subject to further analysis.

Investigation detail

We use the Options Assessment Approach (OAA) to guide the level of investigation detail undertaken when assessing System Needs. The OAA provides guidance for undertaking a commensurate approach to investigations and options analysis. The expected cost, complexity of analysis and the timing of System Need are all considered when selecting the OAA assessment level.

For issues discussed in the Grid Enhancement Approach sections of this TPR, we have identified the level of analysis already undertaken. As the TPR covers grid problems and opportunities over a 10 to 15-year period, many of the assessments undertaken or underway are ‘planning’ level options analyses. These inform the development plans in this TPR and our financial forecasting. However, preferred solutions from planning level OAA assessments will be reassessed using a detailed delivery level assessment at the appropriate time.

Table 1-3 below provides a high-level description of the OAA classifications, indicating the type of System Needs that fit the criteria for each level.

Table 1-3: Options Assessment Approach classifications

OAA Assessment Level	Investigation Parameters
None	The problem or opportunity has been identified but has not yet been assessed. Costing information is based on judgement and expertise.
1	The asset class strategy prescribes the preferred investment solution. No options assessment is undertaken.
2 – Planning (AL2p)	For investigations with low complexity and / or cost, required within 10 years. Preferred solution informs plan. Investigation revisited before any expenditure.
2 – Delivery (AL2d)	For investigations with low complexity and or cost for delivery. Preferred solution is delivered.
3 – Planning (AL3p)	For investigations with: • Medium complexity and / or cost, required within 10 years • High complexity and medium cost, required after 10 years. Preferred solution informs plan. Investigation revisited before any expenditure.
3 – Delivery (AL3d)	For investigations with: • Medium complexity and or cost, required for delivery • High complexity and medium cost, required for delivery. Preferred solution is delivered.
4 – Planning (AL4p)	For investigations with: • High complexity and cost (<$20 million), required within 10 years. Preferred solution informs plan. Investigation revisited before any expenditure.
4 – Delivery (AL4d)	For investigations with: • High complexity and cost (<$20 million), required for delivery. Preferred solution is delivered.
5 – Delivery (AL5d)	For investigations with a preferred solution expected to cost >$20million, requiring full consultation with stakeholders and individual approval by the Commerce Commission.

Investment type

We classify our transmission network development projects by funding arrangement as shown in Table 1-4.

Table 1-4: Regulatory investment type

Investment type	Definition
Base Capex	Replacement and Refurbishment projects of any value, or Enhancement and Development projects forecast to cost less than $20 million. We have flexibility to reprioritise across base capex, to increase or decrease overall base capex, and to shift between base capex and opex (e.g. procuring demand response to defer investments).
Major Capex Projects	These are individual investment proposals to enhance the Grid which are submitted to the Commerce Commission for approval on a case by case basis. The cost threshold for individual enhancement project approval is $20 million.
Customer-specific	Enhancement projects on assets specific to a customer or group of customers which are agreed and paid for under an investment contract between Transpower and the customer/group of customers.

Project costing

Where investment is required to resolve an identified problem or opportunity, an indicative cost is shown. The indicative costs represent the expected capital cost (in 2019 dollars) to fully implement the indicated solution. Note that the accuracy of costs presented is commensurate with the current level of detail in the investigation. Cost estimates should be relatively accurate for projects in the Delivery or Committed states, but will be highly uncertain for Proposed or Possible projects.

Property and consenting costs have generally not been included because of the uncertainties involved. For some projects, property costs can significantly impact the overall cost.

Cost information generally represents a high level and provisional estimate only and should not form the basis for investment decisions. Interested parties should confirm the adequacy of these cost estimates for themselves or contact us for more detailed information.

Grid enhancement approach investment proposals

The Grid Enhancement Approach in each regional and grid backbone chapter outlines our proposals to address investment needs. The proposals are summarised throughout the chapters in the blue 'investment boxes' similar to Table 1-1.

1.3 Document overview

In this TPR:

- Chapter 2 'Existing National Grid' provides a description of the National Grid's existing configuration, including recently completed projects.
- Chapter 3 'Investment Uncertainties' provides a discussion of how investment drivers may vary over time, the uncertainty this drives in investment decision making and how this impacts Transpower's view of the required funding to undertake E&D transmission investments.
- Chapter 4: 'Enhancement and Development Portfolio' provides an overview of the E&D funding approved through the "Regulatory Control Period 3" process and the mechanisims avaliable for additional funding.
- Chapter 5: 'Major Grid Events' links together the issues raised in Chapters 6 to 19 that are directly related to possible major industry and environmental changes.
- Chapter 6 'Grid Backbone' discusses the grid backbone's ability to accommodate the forecast demand and any identified investment Needs.
- Chapters 7 to 19 'Regional Plans' describe any proposed investment Needs and the transmission capability over the next 15 years for each region's transmission network.

Each regional plan also provides an overview of the existing regional transmission network and any anticipated security issues.

2 Existing National Grid

2.1 National Grid

This chapter provides an overview of New Zealand's existing National Grid as at 30 June 2019. The National Grid comprises:

- the HVAC transmission network
- an inter-island HVDC link.

2.1.1 The AC transmission network

New Zealand's HVAC transmission network supplies all major load centres. It consists of:

- a grid backbone of 220 kV transmission lines stretching nearly the full length of each Island
- a network of 110 kV lines running roughly parallel to the 220 kV system.

The 110 kV lines were the original grid backbone prior to development of the 220 kV grid from the 1950s. Current roles of the 110 kV system are to supply regions not reached by the 220 kV system, and for sub-transmission to substations within a region.

Figure 2-1 and Figure 2-2 show maps of the existing North and South Island transmission networks.

Figure 2-1: New Zealand's North Island transmission network

Figure 2-2: New Zealand's South Island transmission network

2.1.2 The HVDC link

The HVDC link connects the North and South Island transmission networks.

This bi-directional link runs from Benmore in the South Island, to Haywards in the North Island. It comprises a 535 km overhead transmission line between Benmore and Fighting Bay (Marlborough), three 40 km submarine cables across Cook Strait between Fighting Bay and Oteranga Bay, and a further 37 km overhead transmission line to Haywards substation north of Wellington. Both Haywards and Benmore substations have AC/DC converter stations.

Table 2-1 lists the capacities of the existing poles for converting power from AC to DC and DC to AC. Due to cable constraints, total HVDC capacity is less than the sum of converting capacity of the individual poles.

Table 2-1: Converter ratings and pole capacities

Pole	Commissioned	Converter type	Nominal capacity
Pole 2	1991	Thyristor valves	700 MW
Pole 3	2013	Thyristor valves	700 MW
Total possible HVDC transmission capacity			1200 MW

2.1.3 Transmission network asset profile

Table 2-2 provides a summary of our transmission network assets.

Table 2-2: Transmission network assets

Asset description	Detail
HVAC and HVDC transmission line	10,969 route km
Substations, including HVDC	168
HVAC transmission line voltages	220, 110, 66 kV
HVDC transmission line voltage	350 kV
HVDC link capacity	1200 MW
Capacitor banks and filters	61
Transformers (banks)	321
Synchronous condensers	8
Static Var Compensators/STATCOMS	10
Shunt reactors	5
Series reactors	2

2.1.4 Recently completed transmission upgrade projects

Table 2-3 lists the major transmission upgrade projects completed since publication of the previous Transmission Planning Report, in 2018.

Table 2-3: Projects completed since the 2018 TPR

Project name
Installed Bunnythorpe–Mataroa series reactor and circuit overload protection scheme
Upgraded Maraetai 220 kV bus security
Replaced Owhata supply transformers (T1 and T2)
Installed Redclyffe transformer overload protection scheme
Installed new 110 kV bay at Hangatiki to connect The Lines Company's third supply transformer
Replaced Kinleith supply transformer (T9)
Installed inter-phase spacers on critical spans of the Wairakei–Whirinaki A line
Replaced the conductor on the Central Park–Wilton B line

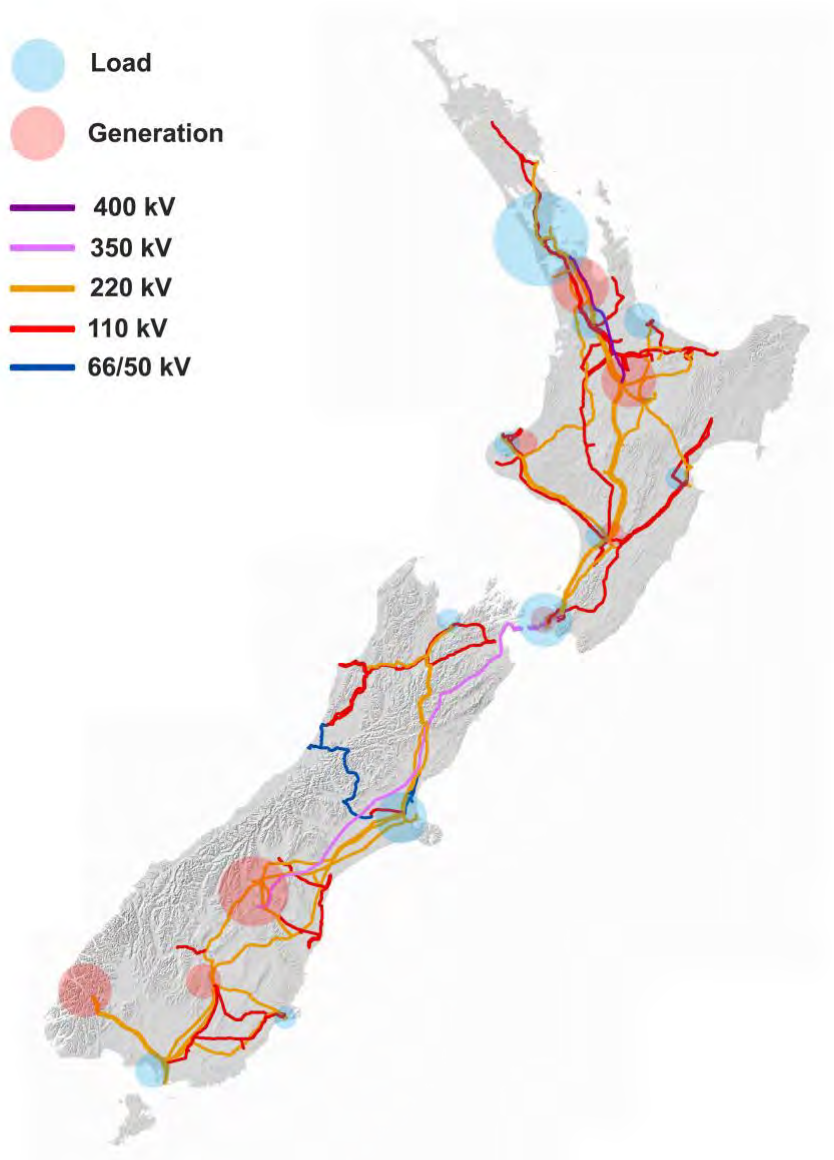
Upgraded the Timaru 220/110 kV interconnection capacity

2.2 Load and generation

New Zealand's transmission network is regarded as narrow and longitudinal, with areas of demand (load) commonly some distance from the areas of significant generation. The transmission network is essential to transport electricity to where it is needed, as well as to balance demand and generation between the Islands.

Figure 2-3 shows a simplified map of load, generation, and our transmission network. Demand and generation assumptions are discussed in more detail in Chapter 3, and the transmission backbone in Chapter 6.

Figure 2-3: Load, Generation and our Transmission network



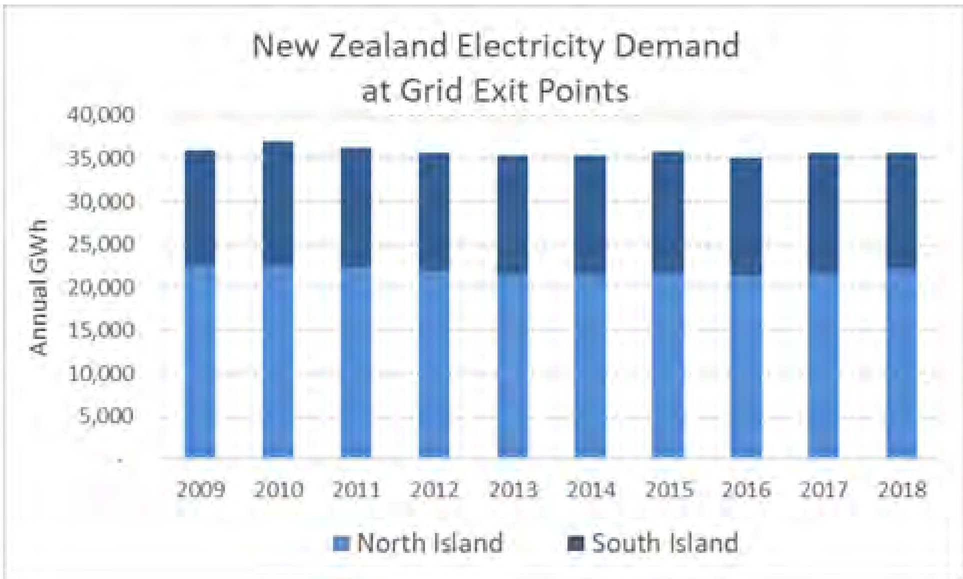
Many of New Zealand's larger population centres are located in the North Island, while a significant amount of hydro generation is located in the South Island.

HVDC power flow is predominantly northward during normal hydrological periods, when available generation exceeds South Island demand. During 'dry' hydrological periods in the South Island, extended southward flow occurs as South Island generators conserve water. Long periods of southward transfers have occurred in recent years.

2.2.1 Historical electricity demand

Figure 2-4: New Zealand Grid Exit Point electric energy deman shows New Zealand's grid exit point electricity demand over the past decade.[1]

Figure 2-4: New Zealand Grid Exit Point electric energy demand (GWh)



Electricity demand (GWh) has been relatively flat over this period compared to the strong growth seen in earlier decades. In recent years, the following factors have put downward pressure on energy demand, offsetting factors that would otherwise drive demand growth:

- some reduction in industrial demand, for example, at the Norske Skog Tasman mill, Pacific Steel, Holcim Cement and (until earlier this year) the Tiwai aluminium smelter
- improvements in household energy efficiency through uptake of more energy efficient appliances and better insulation (causing reduced average residential demand)
- improvements in energy efficiency in the commercial and industrial sectors
- milder winters
- an increase in generation embedded within distribution networks which reduces the demand observed at grid exit points.

1 Grid exit point demand includes distribution network losses but excludes demand supplied by generation embedded within these networks.

2.2.2 Existing grid connected generation

Table 2-4 lists the operating capacities of existing grid-connected generators larger than 10 MW.[2]

Table 2-4: Existing grid-connected generation

Generation plant	Region	Type	Operating capacity in MW	Grid injection point
Glenbrook[1]	Auckland	Cogeneration	74	Glenbrook
Aniwhenua	Bay of Plenty	Hydro	25	Aniwhenua
Kawerau	Bay of Plenty	Geothermal	105	Kawerau
Kawerau Norske Skog	Bay of Plenty	Geothermal	25	Kawerau
Kinleith	Bay of Plenty	Cogeneration	28	Kinleith
Matahina	Bay of Plenty	Hydro	72	Matahina
Wheao/Flaxy	Bay of Plenty	Hydro	24	Rotorua
Aratiatia	Central North Island	Hydro	78	Aratiatia
Mangahao	Central North Island	Hydro	37	Mangahao
Ohaaki	Central North Island	Geothermal	46	Ohaaki
Poihipi	Central North Island	Geothermal	51	Poihipi
Rangipo	Central North Island	Hydro	120	Rangipo
Tararua III[2]	Central North Island	Wind	93	Bunnythorpe
Te Apiti	Central North Island	Wind	90	Woodville
Tokaanu	Central North Island	Hydro	240	Tokaanu
Te Mihi	Central North Island	Geothermal	166	Te Mihi
Wairakei	Central North Island	Geothermal	161	Wairakei
Nga Awa Purua	Central North Island	Geothermal	140	Nga Awa Purua
Ngatamariki	Central North Island	Geothermal	82	Nga Awa Purua
Kaitawa	Hawkes Bay	Hydro	36	Tuai
Piripaua	Hawkes Bay	Hydro	42	Tuai
Tuai	Hawkes Bay	Hydro	60	Tuai
Whirinaki	Hawkes Bay	Diesel	155	Whirinaki
Kapuni	Taranaki	Cogeneration	25	Kapuni
Kiwi Dairy	Taranaki	Cogeneration	70	Hawera
McKee Peaker	Taranaki	Gas - OCGT	100	Motunui Deviation
Patea	Taranaki	Hydro	31	Hawera
Taranaki CC	Taranaki	Gas - CCGT	385	Stratford
Stratford Peaker	Taranaki	Gas - OCGT	200	Stratford
Arapuni	Waikato	Hydro	197	Arapuni
Atiamuri	Waikato	Hydro	84	Atiamuri
Huntly	Waikato	Coal and Gas	500	Huntly
Huntly Unit 5	Waikato	Gas - CCGT	385	Huntly
Huntly Unit 6	Waikato	Gas - OCGT	50	Huntly
Karapiro	Waikato	Hydro	90	Karapiro
Maraetai	Waikato	Hydro	360	Maraetai

2 Installed capacity may differ from operating capacity in some cases.

Mokai	Waikato	Geothermal	112	Whakamaru
Ohakuri	Waikato	Hydro	112	Ohakuri
Waipapa	Waikato	Hydro	51	Maraetai
Whakamaru	Waikato	Hydro	100	Whakamaru
West Wind	Wellington	Wind	143	West Wind
Argyle/Wairau	Nelson/Marlborough	Hydro	11	Argyle
Cobb	Nelson/Marlborough	Hydro	32	Cobb
Coleridge	Canterbury	Hydro	45	Coleridge
Aviemore	South Canterbury	Hydro	220	Aviemore
Benmore	South Canterbury	Hydro	540	Benmore
Ohau A	South Canterbury	Hydro	264	Ohau A
Ohau B	South Canterbury	Hydro	212	Ohau B
Ohau C	South Canterbury	Hydro	212	Ohau C
Tekapo A	South Canterbury	Hydro	30	Tekapo A
Tekapo B	South Canterbury	Hydro	160	Tekapo B
Waitaki	South Canterbury	Hydro	105	Waitaki
Clyde	Otago/Southland	Hydro	432	Clyde
Manapouri	Otago/Southland	Hydro	840	Manapouri
Roxburgh	Otago/Southland	Hydro	320	Roxburgh
Waipori[3]	Otago/Southland	Hydro	84	Halfway Bush

1. This value includes an embedded generating unit with a nominal rating of 38 MW that is operating at a continuous output of 25 MW.
2. Tararua stages I and II are both embedded in local networks.
3. Waipori is partly embedded in the local network.

3 Investment Uncertainties

In the medium to long-term there is considerable uncertainty regarding future demand growth and generation expansion in the New Zealand electricity sector. *In Te Mauri Hiko - Energy Futures*[1], we look ahead and identify some of the possible changes and challenges we might face. Energy sustainability and New Zealand's response to climate change will require a move to a low carbon economy. Electrification of some parts of our economy, which currently use fossil fuels, will likely be an important part of that change. New technologies are emerging and evolving, the electricity sector is evolving, and societal needs and expectations are changing around us. However, how, when and what effect this may have on demand and generation expansion is uncertain.

Following decades of steady electricity demand growth and investment in generation and grid capacity, we have more recently seen a period of flat demand with a slowly evolving generation mix. Uncertainty about the scale and speed of uptake of emerging technologies makes it difficult to accurately predict future growth in grid-supplied electricity and what shape future demand profiles may take. Potential changes to transmission pricing structures and the future path of carbon pricing and other policies are all likely to impact demand for electricity in energy intensive industries.

Generation companies now consistently indicate that future investments will be in renewable generation with geothermal, wind and solar seen as the likely future energy sources. There is uncertainty over the future for thermal generation and the potential closure of some plant.

This chapter discusses demand and generation uncertainties and the approach we have taken in considering them within this TPR.

3.1 Demand

Historical peak demand at grid exit points (GXPs), for regions and for the entire North and South Islands, are key inputs to the planning that underlies the TPR.

In constructing a forecast, we consider the trend in the underlying peak demand, accounting for the uncertainty associated with these trends. We also consider feedback we receive from distribution companies and other large users. This feedback may identify new factories likely to be commissioned and other significant developments within the distribution networks.

This year, for the first time, we have explicitly considered the potential effects of solar photo-voltaic panels, electric vehicles, battery storage, and the electrification of industrial heat processes on future demand. This has required significant development of our forecasting models.

3.1.1 New Zealand peak grid demand

In 2018 we saw peak demand 3.1% higher than the previous year. This illustrates some of the underlying variability in the trend of demand growth.

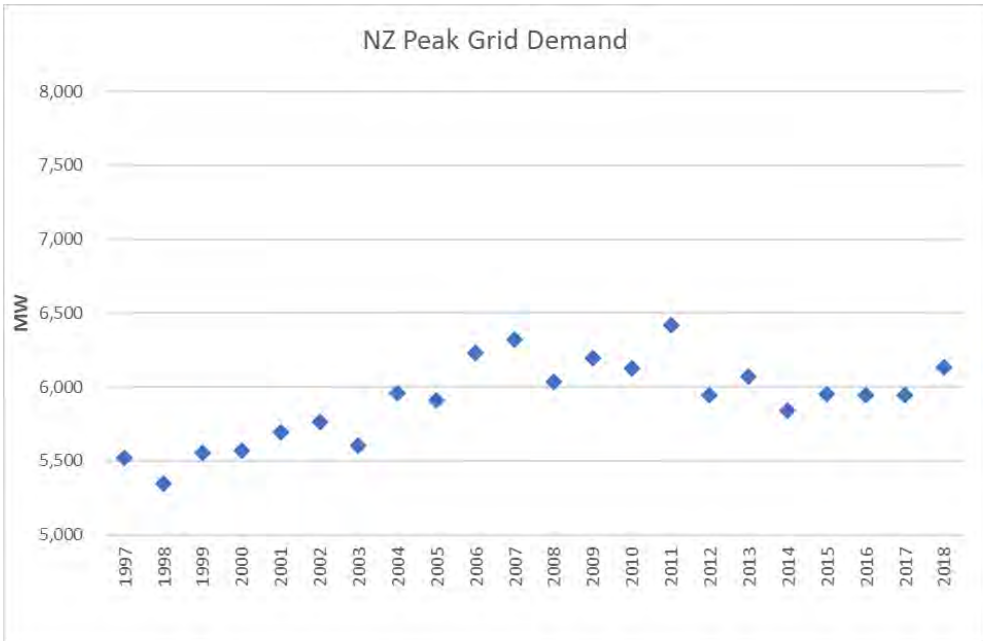
Figure shows New Zealand's peak grid demand[2] since 1997. In the period to 2007, peak demand grew at an average 1.5 per cent per annum, but since then it has plateaued. The exception was 2011, when a new national peak demand record was set in mid-August during an unusual polar weather event that affected the whole country.

Considerable year-to-year variability is evident. In 2018 we saw peak demand 3.1% higher than the previous year. This illustrates some of the underlying variability in the trend of demand growth.

1 https://www.transpower.co.nz/sites/default/files/publications/resources/TP%20Energy%20Futures%20-%20Te%20Mauri%20Hiko%2011%20June%2718.pdf

2 New Zealand Peak Grid Demand is the sum of the Peak Demands at each grid exit point (GXP). The GXP Peak Demand is the maximum demand is the highest grid demand seen at that GXP in any half hour of a calendar year. As such NZ Peak Demand is non-coincident

Figure 3-1: New Zealand peak grid demand (MW)



The relatively flat peak demand seen in recent years is the aggregate result of many factors across all sectors of demand. The growth we would have expected to see as a result of recent strong growth in both population and Gross Domestic Product (GDP) – historically the key drivers of demand – has been largely offset by a combination of factors including:

- an increased uptake of energy efficient lighting and appliances
- an increase in the efficiency of new homes
- with some exceptions, generally milder winters[3]
- an increase in generation embedded within distribution networks, which reduces grid supplied demand
- the current Transmission Pricing Methodology (TPM) which has encouraged load management aimed at reducing regional coincident peak demand, in order to defer or avoid new investment in transmission.
- the success of schemes such as the Upper South Island load management scheme[4] which acts to manage high demand periods.

While the figure above shows national annual peak demand, we also forecast island and regional peak demand, by season. In some of our drier regions there has been strong demand growth as a result of irrigation schemes and dairy production expansion, leading to strong growth in summer peak demand. South Canterbury is a region that has seen these effects and is now summer peaking. The West Coast is also a summer peaking region, where dairying and tourism have contributed to recent summer peak demand growth.

3.1.2 Peak demand forecasting

This year we have adopted a two stage process to construct peak demand forecasts.

In stage 1 we have used both top-down and bottom-up approaches to forecast growth in underlying peak demand, similar to in previous years. For national, island and regional peak forecasts we have used an ensemble of models[5] (trend, econometric, etc.) to produce forecasts based on historical peak values. At a GXP level we have used simpler techniques and have drawn on information, primarily from local

3 This impact is more on total energy (GWh) than on peak demand (MW).

4 http://www.oriongroup.co.nz/customers/load-management-and-hot-water-control/upper-si-load-management.

5 Use of an ensemble approach combines forecasts from different forecasting models, such as trend and econometric models, to derive a forecast of the underlying growth. Our approach derives a distribution for future demand growth that we use to inform the construction of a prudent forecast.

distribution companies, to derive GXP forecasts. We then have reconciled the bottom up GXP forecasts with the top down national, island and regional forecasts to derive the contribution each GXP makes to island and regional peaks.

This year we have added a stage 2 process that considers how the underlying stage 1 forecasts may be affected by an assumed uptake of solar photovoltaic panels, electric vehicles, residential battery storage and the electrification of industrial heat processes. The future uptake of these technologies is still quite unknown but for planning purposes we have assumed market uptakes in line with the NZ Inc. scenario outlined in *Te Mauri Hiko – Energy Futures*.

As in past years, we have continued to incorporate the uncertainty resulting from distributed generation. Data supplied by the electricity market's Reconciliation Manager on existing distributed generation enables us to calculate and forecast gross demand supplied by the grid and by distributed generation. From this we derive grid demand forecasts by making suitable assumptions about the generation output we would expect from existing distributed generation at times of regional and island peaks.[6]

For the TPR we use a "prudent" forecast to recognise the significant risks associated with investing too late to address issues on the grid. This year we have continued to use a similar approach as in previous years, representing prudence using a stage 1 forecast with a 10 per cent probability of exceedance for the first seven years of the forecast period (until 2025).[7] Post-2025 we assume that the stage 1 forecasts grow at an expected (or mean) rate of growth. While this approach does add some prudence into the forecasts it does not explicitly add any "prudence" to the assumptions about the uptake rates of new technologies and their operation. We intend to investigate this further in future publications.

3.1.3 Te Mauri Hiko – Energy Futures: NZ Inc Scenario

Our *Te Mauri Hiko – Energy Futures* explores a range of potential futures for the New Zealand electricity industry. In constructing forecasts for the TPR we have focused on aligning our assumptions closely with the Base Case NZ Inc. scenario. This assumes relatively modest uptake of new technologies to 2025, but with relatively rapid uptake from that point. These assumptions have a relatively minor impact on the demand forecasts in most regions until around 2030, which is near the end of the period considered by the TPR. By this point the uptake rates of new technologies are such that they start to materially affect our forecasts. Importantly, in terms of peak demand forecasts we assume some level of "smartness" associated with EV charging and battery operation. The more "smart" they are, the more they act to smooth out demand profiles in such a way that the increase seen in overall energy demand is not directly reflected in the rate of peak demand growth.

We are continuing to refine our assumptions relating to uptake rates of new technologies and expect to engage further with the industry in the near future. The large uncertainty over the rate of uptake is a considerable challenge for investment decision making.

6 Future distributed generation development is discussed within our generation section.

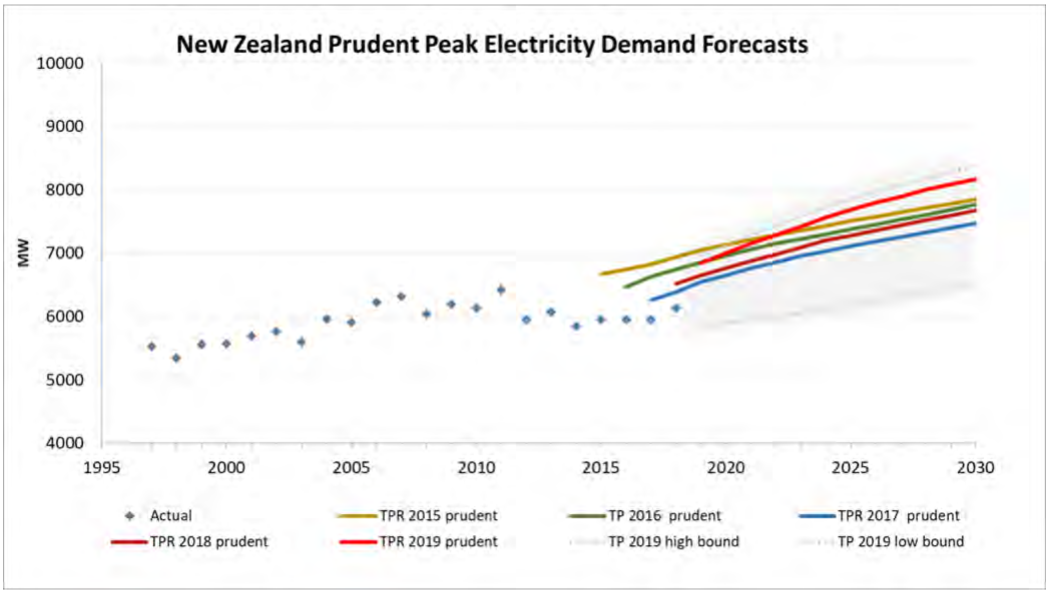
7 This is equivalent to a P90 forecast, in which peak demand has a 90 per cent chance of being less than the prudent forecast. Put another way, we expect actual peak demand to exceed the forecast in just one year in ten.

3.1.4 Island and regional peak demand forecasts

Figure 3-2 shows our latest national peak demand forecast compared to previous forecasts.

Peak demand remained flat over the years 2012-2017 and our forecasts have generally adjusted downward year on year. Last year saw a 3% increase in peak demand (relative to the previous year) and is largely responsible for our forecasts rising this year. The grey region shows the plausible range of growth in underlying demand based on our stage 1 models.

Figure 3-2: Comparison of 2019 TPR prudent peak demand forecast with previous TPR forecasts



3.1.5 Grid exit point forecasts

At a GXP level we seek the views of the local distribution network companies who are well-placed to advise on local near-term growth. In the absence of their advice we employ regression techniques based on historical gross GXP demand.

Local information about expected step increases in demand (for example, a new factory opening) is also incorporated into the forecast. Such additional demands are usually known within the 1-5 year horizon, while on occasion there are reductions in demand over the same period relating to announced plant closures. However, notice of demand changes can be short, making it challenging to reflect in forecasts.

Some of the major step increases in demand identified in the 2019 GXP forecasts include:

- Penrose 33 kV GXP: 12 MW additional load from Auckland Hospital expansion in 2019
- Albany 33 kV GXP: 10 MW Industrial/commercial load in 2026
- Cambridge GXP: Industrial Developments comprising 8.5 MW in 2020 and 9.5 MW in 2024
- Bombay 110kV GXP: rapid build out of the new Drury residential developments sees an additional 6MW expected each year from 2019 to 2023

For more information about specific demand step changes in load in a region, see the relevant regional chapter (Chapters 7-19).

3.1.6 GXP contribution to Island and regional peak forecasts

By combining our top-down regional and island forecasts with our bottom-up GXP forecasts, we calculate the expected contribution of each GXP to regional and island peak demands. These contributions are inputs to regional planning studies. The regional and island peaks will not necessarily occur at the same time as the GXP demand peaks and thus the GXP contributions to region/island peaks are typically less than the GXP peak demand forecast.

3.2 Generation

A period of strong growth in new generation plant occurred over the period from 2009-2014, with more than 1,200 MW of new capacity installed. It is likely that much of this investment was premised on continuing strong growth in demand, as seen in the period to 2007 (refer to Figure), which did not eventuate.

Since 2015 we have seen the closure or announced closure of a significant amount of thermal generation in the upper North Island. Otahuhu B (380 MW) and Southdown (140 MW) have been decommissioned and in August 2015, Genesis Energy has announced its intention to decommission the remaining two Rankine units (500MW total) at Huntly not before 2022.

Such plant retirements can drastically alter power flows on the grid, and in future, retirements may be a primary driver of grid investments.

The existing grid connected generation plant is listed in Chapter 2.

3.2.1 Generation development

New Zealand has abundant renewable resources for development of new generation. Investment in new generation in recent years has been seen as commercially challenging due to flat demand, uncertainties surrounding uptake of solar photovoltaic panels and batteries, and the future of the Tiwai smelter.

Multiple closures of fossil-fuel powered generation, clarification around our Government's stance on renewable electricity, and the expected move toward electrification (of loads currently utilising fossil fuels) should ease uncertainty in the medium-term. As a result, we expect to see a resumption of new renewable generation development within the window of this TPR.

Some recent developments such as Mercury's 222 MW Turitea wind farm in the Manuwatu-Wanganui region, and Tilt Renewables' planned 133 MW wind farm in the Taranaki region are examples of renewed interest in generation development.

Uncertainty over where generation will be developed and the ability (in many cases) of generation companies to commission generation relatively quickly remain challenges for transmission planning.

3.3 Emerging technologies and electrification

As outlined above, and discussed in *Te Mauri Hiko – Energy Futures*, emerging technologies and electrification are expected to significantly affect future demand. Such technologies include electric vehicles, solar photovoltaic panels and battery storage. Electrification also includes the conversion of heating and cooling (in the residential, commercial and industrial sectors) from the use of fossil fuels to electricity. The timing and uptake of these changes will have a significant impact on grid demand and the uncertainty around these presents a challenge to developing medium to long term network plans.

The difficulty for Transpower is that we must make investment decisions now, in assets that we expect to be in service for several decades – beyond 2035.

3.3.1 Overseas experience

Other countries have pursued renewable sources of energy as they have worked to address energy security, sustainability and climate change issues. This has led to significant investment in solar photovoltaics and electric vehicles and, as a result, the costs of solar photovoltaics and battery technologies for domestic (and commercial/industrial) use are reducing quickly.

- The cost of solar photovoltaics panels has decreased at an average rate of 10 per cent per year since 1980[8]. It is now possible to install a domestic 2.7 kW system in New Zealand for $7,500, with module costs expected to continue to drop.
- The cost of batteries is also reducing rapidly, with many forecasters predicting that electric vehicles will be cost competitive with internal combustion vehicles by 2025.[9]

As costs fall, we expect that many New Zealand consumers will find such technologies attractive, and uptake of the technologies will increase significantly over time.

8 http://www.sciencedirect.com/science/article/pii/S0048733315001699?via%3Dihub#sec0095

9 https://about.bnef.com/blog/electric-cars-reach-price-parity-2025/

3.3.2 New Zealand experience

Distribution companies are now actively evaluating the use of these emerging technologies. Some of the technologies provide significant opportunities for distribution companies to improve their own asset management, provide new services to connected customers and pursue commercial growth opportunities. Some emerging technologies used within the distribution network may enable reduced or deferred investment in the transmission network.

For example, whilst electricity demand is expected to grow rapidly over the period 2025-2035, so is the uptake of battery technologies. If batteries are used to provide electricity at peak times of electricity demand, there may not be such a large effect on electricity peak demand, the primary determinant of grid size.

It is expected that some distribution companies will become distributed system operators, managing two way energy flows over their networks. How these distributed system operators and our own System Operations group will interface will need to be established over time, to ensure security of supply to consumers is maintained.

As discussed above, the New Zealand government has indicated a commitment to meet our Paris climate change pledge[10] and in November 2019 the Climate Change Response (Zero Carbon) Amendment Bill[11] completed its path through parliament and came into law. The purpose of this bill is to provide a framework by which New Zealand can develop and implement clear and stable climate change policies that contribute to the global effort under the Paris Agreement. Policies that encourage the uptake of electric vehicles and the further electrification of industry (i.e. substituting electric technologies for coal and gas) have been identified as important elements in achieving that pledge. We have begun to explore the detailed aspects of potential demand growth and will provide more information in future TPR updates.

3.4 Uncertainty and investment planning

The presence of demand, generation and new technology uncertainty makes developing a medium to long-term investment plan challenging. While we forecast the key drivers of investment, and analyse grid issues based on these, we also know that our plans are likely to change as the environment changes and new information comes to light.

3.4.1 Demand

The grid challenges and opportunities presented in the TPR are identified through analysis that compares our demand forecast expectations, generation assumptions and current grid capability. As we investigate grid needs, we consider their sensitivity to different assumptions and also test what is the best option for addressing the need.

Where the investment need or timing is highly uncertain due to demand uncertainty, we may need to change our investment plans at short notice. Flexibility in our plans is preferable to remaining committed to an investment plan that is no longer fit for purpose.

3.4.2 Generation

In this TPR we have considered the uncertainty associated with generation primarily as it relates to investment in the grid backbone, although the impact of any committed generation is also considered at a regional level.

Testing the limits of the grid backbone capability is done by identifying the boundaries of the grid to handle new or changed generation dispatch profiles. We particularly focus on regions known to have significant generation resources. In addition, we seek to test the practical limitations of the grid, helping identify where generation uncertainty may influence grid investment needs.

However, while we do investigate potential grid problems and opportunities, we cannot predict with any certainty that these issues will arise, as generation investment may evolve differently than anticipated. This uncertainty requires us to apply some judgement and agility in the way we construct our investment plans.

10 http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-strategies/consultation-draft-replacement-new-zealand-energy-efficiency-and-conservation-strategy/draft-replacement-nzeec-strategy.pdf

11 https://www.parliament.nz/en/pb/bills-and-laws/bills-proposed-laws/document/BILL_87861/climate-change-response-zero-carbon-amendment-bill

4 Enhancement and Development Portfolio

This chapter updates our view of the investment outlook for the Enhancement and Development (E&D) portfolio. In the time since the 2018 TPR the Commerce Commission has determined our Base Capex funding allowance for E&D projects. It has also provided a funding adjustment mechanism to increase baseline funding under specified circumstances.

We describe the regulatory context in which we work within and the decisions that have been made about RCP3 baseline funding by the Commission. We also describe the mechanism that has been provided to allow for higher levels of funding for E&D.

Customer-funded investments were not included in our RCP3 regulatory submission (for the E&D portfolio or otherwise) as these are funded through a customer investment contract with the customer. Our views of the customer-funded E&D investments that will be required during RCP3 are set out in the relevant regional chapters of this TPR.

We also describe how we intend to report upon our E&D progress in future TPRs throughout the regulatory period.

4.1 Regulatory Context

To determine the development needs of the system the following functions of the grid are considered:

- providing a reliable and resilient electricity supply to consumers
- enabling an efficient energy market, which will result in energy delivered to consumers at least cost.

We also consider the need to provide a transmission system that balances the cost of investment against the benefits gained from that expenditure. These functions are considered in conjunction with the regulatory environment in which we operate. We are regulated by both the Electricity Authority and the Commerce Commission.

4.1.1 Electricity Authority

The Electricity Authority is responsible for ensuring the efficient operation of the wholesale electricity market. We are a market participant and certain provisions of the Electricity Industry Participation Code (EIPC) apply to our operations. The EIPC prescribes Grid Reliability Standards (GRS), being the standards against which the reliability performance of the grid is assessed. The GRS includes:

- an economic (probabilistic) standard for the whole grid
- a "safety net" minimum reliability standard of n-1 for contingencies on the Core grid[1].

We use the GRS to guide our decisions on approving expenditure to resolve E&D System Needs.

4.1.2 Commerce Commission

The Commerce Commission regulates our operating and capital expenditure. The capital expenditure required for E&D investments (excluding customer investments) is governed by the Capex Input Methodology. Each investment is categorised as either a Major Capex Project (MCP) or base capital expenditure, with the latter subject to our independent price path and incentive regime.

[1] The Core grid is defined in the EIPC.

4.2 Our Enhancement and Development Submission - Regulatory Control Period 3

The 2018 TPR was part of our submission for Regulatory Control Period 3. In that document we described two scenarios for the period, to provide a view of high and low system needs. For each scenario the funding levels for the period were estimated. We used a scenario approach rather than a list of projects, due to the uncertainty of E&D needs. Our submission was that the midpoint between these two scenarios would be a suitable level of funding to allow for development during the period. Refer to the 2018 TPR for a comprehensive outline of our approach. Table 4-1 summarises our 2018 E&D capex forecast.

Table 4-1: - Funding Baseline - midpoint

	$ m
High Expenditure Scenario	93
Low Expenditure Scenario	59
Midpoint Baseline	76

4.3 Regulatory Control Period 3 – Enhancement and Development Decision

On 14 November 2019 the Commerce Commission released its final determination on Transpower's Individual Price–Quality Path. The determination allowed for the low expenditure scenario ($59m) rather than the requested midpoint ($76m). The determination established the Price Path Reopener Provisions to enable Transpower to manage uncertainty around E&D expenditure provided the expenditure met certain criteria.

4.3.1 Price Path Reopener Provisions

The Price Path Reopener Provisions[2] allow for us to seek additional funding for projects that arise in E&D that:

- were not reasonably foreseeable at the time of setting the price-quality path, or
- were foreseeable, but the costs and/or timing were uncertain at the time of setting the price-quality path.

This mechanism allows us to seek additional funding in the E&D capex portfolio in circumstances where:

- an allowance for that E&D project was not included in the base capex allowances for the current regulatory period because that E&D project was not forecast to commence in that regulatory period when the Transpower IPP determination was made
- it was either unforeseeable, or was foreseeable but was unknown in its cost and/or timing, that the E&D project was likely to commence during the current regulatory period when the Transpower IPP determination was made
- the project has one or more specific E&D drivers e.g., demand step changes, generation developments or decommissioning

For us to apply for a reopener

- the application must relate to a minimum of two E&D projects that must in aggregate cost at least $20 million, and
- We can demonstrate that the E&D projects are reasonably likely to commence in the regulatory period.

The reopener can only be applied for once during the period. This is at the end of the second regulatory year which will be 2022 for regulatory control period 3.

2 https://comcom.govt.nz/__data/assets/pdf_file/0035/188783/Transpower-Individual-Price-Quality-Path-from-1-April-2010-Companion-paper-to-final-RCP3-IPP-determination-and-information-gathering-notices-14-November-2019.PDF

4.4 Major Capex Projects

A Major Capex Project is an investment with an expected cost greater than $20 million. Table 4-2 details proposed Major Capex Projects, both approved and unapproved. For those currently unapproved, some are under investigation. Others would only be progressed if generation development or significant load changes occurred, stretching the capability of the existing transmission system.

Table 4-2: Approved and Unapproved Major Capex Projects within the Planning Horizon

Region	Project Name	Indicative commissioning	Part of the GEIR?	Status
Approved Major Capex Projects				
Otago / Southland	Lower South Island Reliability	2019	No	In delivery
Otago / Southland	Clutha Upper Waitaki Lines Project (CUWLP)	Generation/load dependent	Yes	Will be progressed if generation/load changes justify the expenditure
Unapproved Major Capex Projects – under investigation				
NI Grid Backbone	Waikato and Upper North Island Voltage Management (WUNI)	2023	Yes	Investigation currently underway
Waikato	Bombay-Otahuhu Regional Investigation	2023-2033 (Multiple Stages)	Yes	Investigation currently underway
Unapproved Major Capex Projects – investigation scheduled for options analysis				
HVDC	HVDC capacity upgrade	Economically driven, potentially aligning with HVDC cable replacement need date	Yes	Investigation currently underway
South Canterbury	Upper South Island voltage stability	Tentatively 2027, dependent on short term demand step changes and/or peak control philosophy changes	No	Investigation to start in 20/21
Unapproved Major Capex Projects – investigation scheduled to confirm Need				
Central North Island	Central North Island transmission capacity	Tentatively 2025-2030, generation and demand dependent	Yes	Preliminary review underway 2019/20

Each Major Capex Project is individually submitted to the Commerce Commission for approval. We endeavour to provide the Commission with indicative timings for submissions to assist with workload planning and expectations.

4.5 Customer Funded Projects

Customer-funded projects are investments covered by a customer investment contract between Transpower and the customer (primarily covers connection assets). As such, these investments are not included in our regulatory submission (for the E&D portfolio or otherwise). The decision to investigate and invest resides with the customer.

We identify and publish n-1 grid issues within the planning time frame in each of the regional chapters (Chapters 7 to 19).

For further information customers are encouraged to contact us.

4.6 Future Enhancement and Development Portfolio Chapters

In future we intend that this chapter will describe the progress of our investments as we move through RCP3. This should give visibility of how the portfolio is developing through the period. It will also indicate if projects that could be part of the Price Path Reopener have come to light.

5 Major Industry Events

Significant step changes in demand and generation can impact multiple aspects of grid security, reliability and operation across multiple locations. We are actively monitoring three potential step changes – further decommissioning of thermal generation in the upper North Island, partial or full closure of the Tiwai Point aluminium smelter, and significant new demand deriving from process heat electrification. Going forward, we will monitor and assess additional possible step changes for which the impact would be significant.

This Chapter describes the three potential changes and explains what investigations have been, or are likely to be, carried out in relation to each. As the step changes will impact our proposed Grid Enhancement Approaches in some areas, we direct the reader to the relevant sections where this impact is discussed (Chapters 6 to 19).

5.1 Upper North Island thermal decommissioning

Since 2012, over 1000 MW of generation capacity has been decommissioned in the Upper North Island and Waikato regions. This generation reduction coupled with the actual and expected demand growth in the Waikato and Upper North Island raises significant voltage stability risks. The potential loss of the two remaining Huntly Rankine units in 2022 further increases this risk.

We published a series of reports since September 2015 examining the potential impacts of reduced thermal generation capacity in the upper North Island. These can be found at:

- https://www.transpower.co.nz/system-operator/information-industry/impact-thermal-generator-decommissioning
- https://www.transpower.co.nz/upper-north-island-generation-decommissioning-report-and-appendices
- https://www.transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation

The main issues raised by the decommissioning of thermal generation are briefly discussed below.

5.1.1 Waikato and Upper North Island voltage stability

Previously published reports forecast dynamic and static voltage stability issues in the upper North Island following the proposed thermal generation decommissioning. Our Waikato and Upper North Island Voltage Management (WUNIVM) project team was established to investigate the investment need, options and timing to mitigate the identified issues.

A long-list consultation document was published in mid-2016 followed by a short-list consultation in mid-2019.[1] A range of submissions were received in both consultations were generally supportive of Transpower's approach assessment of the need, assumptions and approach to the Investment Test to identify a preferred solution.

From the short list consultation feedback, we are refining our analysis to identify a preferred option, with a view to submitting it to the Commerce Commission for approval in December 2019.

For more details of this project refer to our website[2]

1 A long list consultation document identifies a full range of options to meet the need, even if there is no identified proponent, options have not been assessed against specified criteria at this stage. A short list consultation document identifies our short list of investment options for addressing the identified need.

2 https://www.transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation.

5.1.2 Thermal constraints: Future generation development

With existing generation assets, no major thermal constraints are seen on our grid backbone during normal operation. However, for system studies it is necessary to assume generation development, over time, to maintain a balance between demand and generation.

Our system studies assumed generation development occurs either at or south of Whakamaru, or in Taranaki, to highlight the possible thermal constraints that may arise depending on the location of new generation.

5.1.2.1 Upper North Island Transmission constraints

Where our studies assumed upper North Island generation is replaced with new generation development at (or south of) Whakamaru, thermal constraints arise between Whakamaru and Auckland.

The first constraints are on the Hamilton–Whakamaru and Ohinewai–Whakamaru sections of the Otahuhu–Whakamaru C line. This is being investigated in the context of the Otahuhu–Whakamaru A and B lines requiring reconductoring between 2023 and 2030. We will investigate the preferred conductor and system configuration for these line reconductoring projects.

Refer to Chapter 6, Grid Backbone (North Island section), for further discussion of thermal constraint issues.

5.1.2.2 Taranaki 220 kV constraints

Where our studies assumed generation development in the Taranaki region, transmission constraints on the Tokaanu–Whakamaru and Huntly–Stratford circuits were exacerbated. These constraints are most likely to be seen when high generation output in Taranaki coincides with high HVDC north transfer or high generation output in the Wellington region.

The currently committed generation developments in the Taranaki region (Junction Road gas-fired peakers and Waipipi windfarm) are not expected to cause constraints on the Taranaki 220 kV network. The lack of futher generation developments in the region and potential retirement of the Stratford combined cycle generator has resulted in the Taranaki 220 kV constraints being a lower priority. We will continue to monitor future generation develoments in the region.

5.1.2.3 Central North Island 110 kV constraints

The low-capacity 110 kV Bunnythorpe–Mataroa circuit operates in parallel with higher-capacity 220 kV circuits. Chapter 11 includes a discussion about the Bunnythorpe–Mataroa series reactor and special protection scheme investments we recently commissioned to relieve the constraint. Growing loads on the Waikato 110 kV network and the increasing need to export generation out of the Taranaki and Wellington regions will continue exacerbate the Bunnythorpe–Mataroa constraint. We will continue to monitor these drivers and also study the long term approach to the Waikato regional network.

The Arapuni bus split will remain open to facilitate increased power transfer into the upper North Island. (Refer to Chapter 9 for further detail.)

5.1.2.4 Central North Island 220 kV constraints

We recently upgraded the Tokaanu special protection scheme which allows the full thermal capacity of the Tokaanu–Whakamaru circuits to be utilised. We will also investigate if variable line ratings are beneficial for these circuits. If we apply variable line ratings, we will have completed all the possible minor upgrades to maximise transmission capacity on the Central North Island 220 kV network. To further upgrade transmission capacity will require upgrading of primary plant, e.g. transmission line upgrades or a new transmission line.

Transmission constraints south of Whakamaru (Central North Island 220 kV) depend on where new generation is located, its size and the timing of the investment.

Refer to Chapter 6 for further detail on these constraints.

5.1.2.5 Wairakei Ring constraints

New generation connections in the Wairakei Ring area, Eastern Bay of Plenty area and the Hawke's Bay region have the potential to create transmission constraints on the Wairakei Ring.

Due to recent generation connection enquiries in these areas, we are taking a closer look at the Wairakei Ring constraints to determine if investments can be justified to relieve transmission constraints (refer to Chapter 6 for further detail).

5.2 Tiwai Point Aluminium Smelter potential closure

The aluminium smelter, owned by New Zealand Aluminium Smelter Limited, connects to the grid at the Tiwai grid exit point and has a peak load of 632 MW. Potential partial or full closure of the plant has been raised in recent years, but current arrangements mean a minimum 12 month notification must be given of intention to cease operations.

Closure of the smelter will result in an excess of generation in the lower South Island. Transmission of this surplus to other regions of New Zealand would be constrained by the capacities of the South Island grid, the HVDC link, and the North Island grid.

The main transmission issues raised by smelter closure are briefly discussed below.

5.2.1 South Island grid constraints

There will be transmission constraints in sending power from Clutha/Southland to Benmore if operations at the aluminium smelter reduce or cease.

To increase power export from Southland, we will need to increase the capacity of some 220 kV circuits between Roxburgh and Benmore. These constraints were studied as part of the Clutha Upper Waitaki Lines Project (CUWLP). Construction of the new assets identified by the CUWLP work is expected to take three years from an announcement of the smelter's closure (refer to Chapter 6 for more details).

We recently announced the commencement of enabling works such as foundation strengthening to reduce the expected time it takes for Transpower to complete the remaining work identified in CUWLP. These enabling works are funded by external parties.

5.2.2 HVDC capacity constraint

Current northward transfer capacity of the HVDC link is 1,200 MW. The Pole 3 upgrade project completed in 2013 envisaged a 'Stage 3', which would further increase northward transfer capacity to 1,400 MW. However, this addition was not economically justifiable at the time with the aluminium smelter remaining in operation.

Recent condition assessment shows that the existing HVDC submarine cables will approach end of life in approximately 10 years. An investigation is underway to assess the replacement need and options for the HVDC cables. This investigation includes an option to increase the capacity of the HVDC cables beyond the current capacity. Other HVDC-related upgrades needed to achieve 1,400 MW capacity include additional filter banks and dynamic voltage support plant (Refer to Chapter 6, HVDC section).

5.2.3 North Island Grid constraints

Transferring the surplus generation from the lower South Island to the load centres in the upper North Island will exacerbate existing constraints on the North Island 220 kV circuits. The increased power transfer may require investment in the Central North Island, Taranaki, and Wairakei Ring 220 kV circuits to increase capacity.

The constraints likely to be seen are those discussed Chapter 6, Grid Backbone (North Island section).

5.3 Process Heat Electrification

In 2018, we published the *Te Mauri Hiko* white paper to explore possible energy futures. New Zealand – along with much of the rest of the world – is seeking to reduce carbon emissions, and alternative low emissions or emissions-free technologies that may assist with this are maturing. The *Te Mauri Hiko* Base Case estimates that 12 TWh (just over 25 per cent) of New Zealand's projected electricity growth by 2050 will be created by the electrification of industry (process heat).[3] If this type of growth does eventuate, it will present material challenges and opportunities which will need to be considered and addressed by the electricity industry.

Separately, the Ministry of Business, Innovation and Employment (MBIE) publication *Process Heat – Overview Fact Sheet* shows that, in 2016, process heat made up 28 percent of all energy-related greenhouse gas emissions and was the second largest source of energy-related emissions, behind transport.[4] MBIEs publication also identified that around 55 per cent of process heat demand was met by burning fossil fuels, mainly coal or natural gas. As such we expect to see increasing Government and industry focus on encouraging the reduction of emissions by the process heat sector, as well as by the transportation and agriculture sectors.

New Zealand's largely renewable electricity supply presents an attractive solution for decarbonising many of our process heat plants that still burn fossil fuels. Our recent process heat paper *Taking the climate heat out of process heat* presented three case studies of process heat electrification.[5] We expect to see increasing process heat electrification as New Zealand works towards a lower-emission economy.

In recognition of this, it is important that we are proactive in providing process heat plant owners with the information they will need (with respect to transmission) to help with investment decision-making.

This section of the TPR highlights the transmission network implications of the potential electrification of process heat plants. We analysed the dairy manufacturing sector for this purpose as it is the only large industrial heat sector for which there is publicly available information on the size, fuel – mostly coal or gas – and energy use of its boilers. In addition, we know where the plants are connected into the electricity network, often in locations with limited transmission capacity. Where substantial new demand is sought at locations with limited transmission capacity, considerable analysis and planning will be required to ensure that we can provide the required capacity and reliability to consumers, and do so in a cost effective manner. Having as much advance notice as possible also allows us to consider how a particular project might be combined with other planned or possible projects, maximising efficiency of the investments as a whole and benefitting all consumers. Generally we would expect a project of this type to have an elapsed time of 2-5 years from initial notification through to commissioning, depending on the scale of investment.

This section is divided into sub-sections to cover off each region that currently hosts one or more dairy factories. Note: Owners of smaller process heat plants (with electrical capacity of up to a few mega-watts) should seek information from their local distribution network provider in the first instance as, individual plants of that size are not likely to cause issues on the transmission network.

We have not discussed process heat electrification in other industry sectors. However, the issues raised in relation to the dairy sector are considered representative of issues that may affect these other sectors. We welcome early engagement with interested parties to ensure that all involved understand the full impact of process heat electrification.

3 https://www.transpower.co.nz/sites/default/files/publications/resources/TP%20Energy%20Futures%20-%20Te%20Mauri%20Hiko%2011%20June%2718.pdf

4 https://www.mbie.govt.nz/assets/8c89799b73/process-heat-current-state-fact-sheet.pdf

5 https://www.transpower.co.nz/resources/taking-climate-heat-out-process-heat

5.3.1 Northland region

We have identified two large dairy factories in the Northland region. These are supplied via the local distribution company's network from two grid exit points: Maungatapere and Maungaturoto.

5.3.1.1 Maungatapere

Transmission into Maungatapere is on four 110 kV circuits, two of which are the Henderson–Wellsford–Maungaturoto–Maungatapere circuits. The local lines company owns and operates the 110/33 kV transformers and distribution network between Maungatapere and the dairy factory.

Potential issues include:

- There are existing n-1 transmission constraints on the Henderson–Wellsford sections of the Henderson–Wellsford–Maungaturoto–Maungatapere circuits, see section 7.5.4.2. Electrification at sites supplied from Maungatapere will exacerbate this constraint.
- Increased demand in the Waikato and Upper North Island region will exacerbate the voltage issues in the region, see Chapter 6.

As there are already transmission issues supplying Maungatapere, early engagement with Transpower will be essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.1.2 Maungaturoto

Transmission into Maungaturoto is on two 110 kV Henderson–Wellsford–Maungaturoto–Maungatapere circuits, with two 110/33 kV supply transformers at Maungaturoto. The local lines company owns and operates the network between Maungaturoto and the dairy factory.

There is 7-8 MW of headroom before we expect the transformers' n-1 capacity to be exceeded.

Potential issues include:

- There are existing n-1 transmission constraints on the Henderson–Wellsford sections of the Henderson–Wellsford–Maungaturoto–Maungatapere circuits, see section 7.5.4.2. Electrification at sites supplied from Maungaturoto will exacerbate this constraint.
- Increased demand in the Waikato and Upper North Island region will exacerbate the voltage issues in the region, see Chapter 6.

As there are already transmission issues supplying Maugaturoto, early engagement with Transpower will be essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.2 Auckland region

One dairy factory was identified in the Auckland region, supplied via the local distribution company's network from Bombay.

5.3.2.1 Bombay

Transmission into Bombay consists of five low-capacity 110 kV circuits. These circuits supply Bombay and provide through-transmission. The local lines company owns and operates the distribution network to the dairy factory.

Potential issues include:

- There are existing n-1 transmission constraints on the two Bombay–Wiri–Otahuhu circuits, see section 8.5.4.2. Electrification at sites supplied from Bombay will exacerbate this constraint.
- Increased demand in the Waikato and Upper North Island region will exacerbate the voltage issues in the region, see Chapter 6.

In addition, we have already identified the need for major refurbishment of all circuits connecting at Bombay, see section 8.5.1. We are investigating development options and anticipate resolving the collective issues in the Bombay–Otahuhu area within the next few years, see section 8.4.2.3. To ensure our development options provide the necessary service required, parties considering process heat electrification should contact the Bombay–Otahuhu Regional Investigation project team at: https://www.transpower.co.nz/bombay-otahuhu-regional-investigation.

5.3.3 Waikato region

We have identified ten dairy factories in the Waikato region. These are supplied via the local distribution company's network from six different grid exit points: one each from Cambridge, Hinuera, Lichfield, Piako, and Te Awamutu, two from Te Kowhai, and three from Waihou.

5.3.3.1 Cambridge

Transmission into Cambridge is on two 110 kV Hamilton–Cambridge–Karapiro circuits, with two 110/11 kV supply transformers at Cambridge. The local lines company owns and operates the distribution network between Cambridge and the dairy factory.

Potential issues include:

- The peak load at Cambridge already exceeds the supply transformers' n-1 capacity, see section 9.5.4.6.
- Increased demand at Cambridge will increase the need to constrain-on Karapiro generation to maintain n-1 security on the Hamilton–Cambridge–Karapiro circuits, see section 9.5.6.1.
- Increased demand in the Waikato 110 kV network will increase the need to constrain-on local generation to manage the loading on the Hamilton 220/110 kV interconnecting transformer following an outage of the parallel unit, see section 9.5.4.3.
- Increased demand in the Waikato and Upper North Island region will exacerbate the voltage issues in the region, see Chapter 6.

We have committed to investments to lift the Cambridge supply transformers' n-1 capacity to supply some step demand growth in the short term.

We are also working with Waipa Networks to investigate long term supply capacity enhancements for the Cambridge area, see section 9.4.2.7. The opportunity to factor in possible process heat electrification supplied from Cambridge exists if we are formally advised of the plans in time. Enquiries should be directed to Waipa Networks in the first instance.

5.3.3.2 Hinuera

Transmission into Hinuera is on a single 110 kV Hinuera–Karapiro circuit, with two 110/33 kV transformers at Hinuera. Karapiro also connects the Karapiro power station and connects to the rest of the transmission network at 110 kV via a Karapiro–Te Awamutu and two Hamilton–Cambridge–Karapiro circuits. The local network company owns and operates the distribution network between Hinuera and the dairy factory.

Potential issues include:

- The peak load at Hinuera already exceeds the supply transformers' n-1 capacity, see section 9.5.4.10.
- Transmission to Hinuera has n security which means an outage on the Hinuera–Karapiro circuit results in a loss of supply.
- Increased demand at Hinuera or Cambridge will increase the need to constrain-on Karapiro generation to maintain n-1 security on the Hamilton–Cambridge–Karapiro circuits, see section 9.5.6.1.
- Increased demand in the Waikato 110 kV network will increase the need to constrain-on local generation to manage the loading on the Hamilton 220/110 kV interconnecting transformer following an outage of the parallel unit, see section 9.5.4.3.
- Increased demand in the Waikato and Upper North Island region will exacerbate the voltage issues in the region, see Chapter 6.

We are working with Powerco to investigate options to reinforce its network and provide better security of supply. The preferred option is a new 110 kV transmission circuit from Arapuni to Powerco's Putaruru substation, with Powerco upgrading its network between Putaruru and Tirau to provide its customers with n-1 security. Beyond this investment, the 110 kV Hinuera–Karapiro circuit and (during low Karapiro generation scenarios) the Hamilton–Cambridge sections of the Hamilton–Cambridge–Karapiro circuits may affect the ability to electrify process heat loads supplied from Hinuera. Early engagement with Transpower is essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.3.3 Lichfield

Transmission into Lichfield is on two 110 kV Kinleith–Lichfield–Tarukenga circuits. The circuits also connect the Kinleith substation and the Arapuni power station's south-bus to Tarukenga. Vector owns the supply transformers at Lichfield and the distribution network to the dairy factory.

Potential issues include:

- There are already n-1 transmission constraints on the Lichfield–Tarukenga sections of the Kinleith–Lichfield–Tarukenga circuits, see section 9.5.4.2.

Although we have discussed a potential investment to further increase transmission capacity between Lichfield and Tarukenga, this investment would only add 5-6 MVA of capacity. As there are already transmission issues affecting Lichfield, early engagement with Transpower is essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.3.4 Piako

Transmission into Piako is on two 110 kV Hamilton–Piako–Waihou circuits. Two circuits continue (from Waihou) to Waikino and Kopu. The 110 kV circuits between Hamilton and Kopu are collectively known as the Valley Spur. Powerco owns the supply transformers at Piako and the distribution network to the dairy factory.

Potential issues include:

- The Valley Spur peak load already exceeds the n-1 capacity of the Hamilton–Piako–Waihou circuits, see section 9.5.4.4.
- Increased demand in the Waikato 110 kV network will increase the need to constrain-on local generation to manage the loading on the Hamilton 220/110 kV interconnecting transformer following an outage of the parallel unit, see section 9.5.4.3.
- Increased demand in the Waikato and Upper North Island region will exacerbate the voltage issues in the region, see Chapter 6.

We will work with Powerco to determine long term development options to resolve capacity constraints on the Hamilton–Piako–Waihou circuits, see section 9.4.2.4. As there are already transmission issues affecting Piako, early engagement with Powerco and Transpower is essential to ensure the parties involved understand the full impact of process heat electrification

5.3.3.5 Te Awamutu

Transmission into Te Awamutu is on two 110 kV circuits, Karapiro–Te Awamutu and Hangatiki–Te Awamutu (the latter being owned by Waipa Networks), with two 110/11 kV transformers at Te Awamutu. Karapiro and Hangatiki connect to the rest of the transmission network through a number of low capacity 110 kV circuits and hydro power stations. The local lines company owns and operates the distribution network between Te Awamutu and the dairy factory.

Potential issues include:

- The peak load may exceed the supply transformers' n-1 capacity from 2021, see section 9.5.4.15.
- Increased demand at Te Awamutu will increase the need to constrain-on Arapuni-north generation to maintain n-1 security and prevent pre-contingency overloading of the Bunnythorpe–Mataroa circuit during high Taranaki and Wellington generation scenarios, see section 9.5.4.9.
- Increased demand at Te Awamutu will increase the need to constrain-on Karapiro generation to maintain n-1 security on the Hamilton–Cambridge–Karapiro circuits, see section 9.5.6.1.
- Increased demand in the Waikato 110 kV network will increase the need to constrain-on local generation to manage loading on the Hamilton 220/110 kV interconnecting transformer following an outage of the parallel unit, see section 9.5.4.3.
- Increased demand in the Waikato and Upper North Island region will exacerbate the voltage issues in the region, see Chapter 6.

As there are already transmission issues that affect Te Awamutu, early engagement with Transpower is essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.3.6 Te Kowhai

Transmission into Te Kowhai is on the 220 kV Hamilton–Te Kowhai and Taumaranui–Te Kowhai circuits, with two 220/33 kV supply transformers at Te Kowhai. The local lines company owns and operates the distribution network between Te Kowhai and the two dairy factories.

The Te Kowhai 220/33 kV supply transformers have around 35 MW of headroom before we expect the transformers n-1 capacity to be exceeded.

Potential issues include:

- Increased demand in the Waikato and Upper North Island region will exacerbate the voltage issues in the region, see Chapter 6.

There is no existing capacity issue specific to Te Kowhai but the transformer has limited headroom to allow connection of process heat electrification plant. Therefore, early engagement with WEL Networks and Transpower is recommended to ensure that the parties involved understand the full impact of process heat electrification.

5.3.3.7 Waihou

Transmission into Waihou is on two 110 kV Hamilton–Piako–Waihou circuits. Two circuits continue to Waikino and Kopu. The 110 kV circuits between Hamilton and Kopu are collectively known as the Valley Spur. A project is underway to supply Waihou via two new 110/33 kV supply transformers. The local lines company owns and operates the distribution network between Waihou and the four dairy factories.

Potential issues include:

- The Valley Spur peak load already exceeds the n-1 capacity of the Hamilton–Piako–Waihou circuits, see section 9.5.4.4.
- Increased demand in the Waikato 110 kV network will increase the need to constrain-on local generation to manage the loading on the Hamilton 220/110 kV interconnecting transformer following an outage of the parallel unit, see section 9.5.4.3.
- Increased demand in the Waikato and Upper North Island region will exacerbate the voltage issues in the region, see Chapter 6.

We will work with Powerco to determine long term development options to resolve capacity constraints on the Hamilton–Piako–Waihou circuits, see section 9.4.2.4. As there are already transmission issues affecting Waihou, early engagement with Powerco and Transpower is essential to ensure the involved parties understand the full impact of process heat electrification.

5.3.4 Bay of Plenty region

One dairy factory was identified in the Bay of Plenty region, supplied via the local distribution company's network from the Edgecumbe grid exit point.

5.3.4.1 Edgecumbe

Transmission into Edgecumbe is on three high-capacity 220 kV circuits, with two 220/33 kV supply transformers at Edgecumbe. The local lines company owns and operates the distribution network between Edgecumbe and the dairy factory.

Potential issues include:

- The peak load already exceeds the supply transformers' n-1 capacity, see section 10.5.4.3.

One Edgecumbe transformer is due to be replaced based on asset health. We will work with Horizon Networks to determine supply capacity requirements at Edgecumbe. As there are already transmission issues affecting Edgecumbe, early engagement with Transpower and Horizon Networks is essential to ensure that the involved parties understand the full impact of process heat electrification.

5.3.5 Taranaki region

We have identified four dairy factories in the Taranaki region. These are supplied either via the local distribution company's network or behind a generator connection, from four different grid exit or grid injection points: Hawera, Kapuni, Stratford and Wanganui.

5.3.5.1 Hawera

Transmission into Hawera is on the 110 kV Hawera–Stratford and Hawera–Waverly circuits. The Hawera substation supplies Powerco and Beach Energy at 33 kV through two 110/33 kV transformers, and connects Whareroa co-generation and Patea hydro generation at 110 kV. The Whareroa co-generation plant supplies the dairy factory's steam and electricity requirements and exports excess electricity to the grid.

Although the 110 kV system has relatively high capacity, voltage quality is likely to limit the amount of load that can be supplied from Hawera. The worst case scenario is an outage on the Hawera–Stratford circuit which results in Hawera being supplied from a 143 km spur line from Bunnythorpe, see section 12.5.4.4. As there are already transmission issues that affect Hawera, early engagement with Transpower is essential to ensure that the involved parties understand the full impact of process heat electrification.

5.3.5.2 Kapuni

Transmission into the Kapuni co-generation plant is on a single 110 kV Opunake–Kapuni–Stratford circuit. The Kapuni co-generation plant supplies steam and electricity to the Kapuni gas treatment plant and the dairy factory while exporting excess electricity to the grid.

The Opunake–Stratford circuit is rated at 67/79 MVA (summer/winter), offering a reasonably large capacity to facilitate process heat electrification. Kapuni currently only has a single connection (see section 12.5.4.7) to the transmission grid but a second connection can be sourced to improve security of supply. Although there is no existing capacity issue specific to Kapuni, early consultation with Transpower is recommended to ensure the parties involved understand the full impact of process heat electrification.

5.3.5.3 Stratford

Stratford substation is a major transmission node that connects the Taranaki regional network to the rest of the transmission system. Transmission into Stratford consists of five high-capacity 220 kV circuits and two 220/110 kV interconnecting transformers. Stratford has two 110/33 kV supply transformers. The local lines company owns and operates the distribution network between Stratford and the dairy factory.

There are no n-1 constraints identified on the Stratford 110/33 kV supply transformers and there is around 20 MW of headroom remaining before we expect the transformers' n-1 capacity to be exceeded. Although there is no existing capacity issue specific to Stratford, early consultation with Powerco and Transpower is recommended to ensure that the parties involved understand the full impact of process heat electrification.

5.3.5.4 Wanganui

Transmission into Wanganui is at 110 kV on one Wanganui–Waverly and two Bunnythorpe–Marton–Wanganui circuits, with two 110/33 kV supply transformers at Wanganui. The local lines company owns and operates the distribution network between Wanganui and the dairy factory.

Potential issues include:

- The peak load already exceeds the supply transformers' n-1 capacity, see section 12.5.4.9.
- Powerco's distribution network allows some load to be shifted from Wanganui to Brunswick. Brunswick has a single supply transformer which provides only n security. The Brunswick supply transformer is also forecast to become overloaded in the early 2020's, see section 12.5.4.2.

We are working with Powerco on the approach to manage/address the capacity and security of supply issues collectively at Brunswick and Wanganui, see section 12.4.2.2. As there are already transmission issues that would affect electrification of plants supplied from Wanganui, early engagement with Transpower and Powerco is essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.6 Manawatu region

We have identified two dairy factories in the Manawatu region. Both are supplied via the local distribution company's network, from the Linton and Mangamaire grid exit points.

5.3.6.1 Linton

Linton supplied by two 220/33 kV supply transformers. The 220 kV is part of the grid backbone. The local lines company owns and operates the distribution network between Linton and the dairy factory.

Potential issues include:

- The peak load is expected to exceed the supply transformers' n-1 capacity in the early 2020's, see section 11.5.4.4.

The transformers' n-1 capacity is limited by a metering accuracy limit (see section 11.4.2.1) which, when resolved, will add at least 20 MW of headroom. As there are already transmission issues that affect Linton, early engagement with Transpower and Powerco is essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.6.2 Mangamaire

Transmission into Mangamaire is on the 110 kV Mangamaire–Woodville and Mangamaire–Masterton circuits, with two 110/33 kV supply transformers at Mangamaire. Woodville connects to the rest of the transmission network via two low capacity 110 kV Bunnythorpe–Woodville circuits. Masterton connects to the rest of the transmission network via two 110 kV Masterton–Greytown–Upper Hutt circuits and then via two 110 kV Haywards–Upper Hutt circuits. The local lines company owns and operates the distribution network between Mangamaire and the dairy factory.

The Mangamaire 110/33 kV transformers have 8-10 MW of headroom before we expect the transformers' n-1 capacity to be exceeded.

Potential issues include:

- In some extreme operating scenarios, a system split may need to be applied on the Mangamaire–Masterton circuit to prevent 220 kV outages overloading the 110 kV system, putting Mangamaire on n security.
- In some operating scenarios, the n-1 capacity of the Masterton–Greytown–Upper Hutt circuits may be exceeded, see section 14.5.4.1. This can be managed by generation and/or HVDC dispatch, or a system split may need to be applied on the Mangamaire–Masterton circuit, putting Mangamaire on n security.

These methods to manage the 110 kV constraints in the area have been satisfactory to date but will need to be reviewed if significant demand and/or generation changes are expected in the Manawatu and Wellington regions. As there are already potential transmission issues at Mangamaire, early engagement with Transpower and Powerco is essential to ensure that involved parties understand the full impact of process heat electrification.

5.3.7 Marlborough Region

One dairy processing facility was identified in the Marlborough region, supplied via the local distribution company's network from the Blenheim grid exit point.

5.3.7.1 Blenheim

Transmission into Blenheim is on the 110 kV Blenheim–Argyle–Kikiwa and two Blenheim–Stoke circuits, with three 110/33 kV supply transformers at Blenheim. The local lines company owns and operates the distribution network between Blenheim and the dairy factory.

There is at least 30 MW of headroom before we expect the transformers' n-1 capacity to be exceeded.

Potential issues include:

- An increase in demand in the upper South Island will exacerbate the voltage and thermal issues in the region, see Chapter 6.

Although there is no existing capacity issue specific to Blenheim, early consultation with Marlborough Lines and Transpower is recommended to ensure that the parties involved understand the full impact of process heat electrification.

5.3.8 Tasman Region

We have identified three dairy factories in the Tasman region. These are supplied via the local distribution company's network from two grid exit points: two from Stoke 66 kV and one from Stoke 33 kV.

5.3.8.1 Stoke 66 kV

The Stoke 66 kV supply bus will be supplied via two 110/66 kV transformers (a project is underway with completion expected by the end of 2019). The 110 kV is supplied by a 220/110 kV transformer at Stoke and a 220/110 kV transformer at Kikiwa via a 110 kV Kikiwa–Stoke circuit. The local lines company owns and operates the distribution network between Stoke 66 kV and the dairy factories.

There is at least 10 MW of headroom before we expect the transformer's n-1 capacity to be exceeded in a scenario where there is no contribution from embedded generation (the 34 MW Cobb hydro station is embedded in the 66 kV network), see section 15.4.2.3.

Potential issues include:

- An increase in demand in the upper South Island will exacerbate the voltage and thermal issues in the region, see Chapter 6.

Although there is no existing capacity issue specific to Stoke 66 kV, early consultation with Network Tasman and Transpower is recommended to ensure that involved parties understand the full impact of process heat electrification.

5.3.8.2 Stoke 33 kV

Transmission into Stoke is predominantly on two 220 kV Kikiwa–Stoke circuits, with two 220/33 kV supply transformers at Stoke. The local lines company owns and operates the distribution network between Stoke 33 kV and the dairy factory.

Potential issues include:

- The peak load is expected to exceed the supply transformers' n-1 capacity in the early 2020's, see section 15.5.4.
- Increased demand in the upper South Island will exacerbate the voltage and thermal issues in the region, see Chapter 6.

We are currently working with Network Tasman to determine a long term approach to reinforce supply capacity to the Nelson area, see section 15.4.2.2. There is an opportunity to factor in demand resulting from process heat electrification in the network supplied from Stoke 33 kV. Enquiries on process heat electrification in the network supplied from Stoke 33 kV should be directed to Network Tasman in the first instance.

5.3.9 Canterbury Region

We have identified six dairy factories in the Canterbury region. These are supplied via the local distribution company's network from six grid exit points: Culverden 66 kV, Hororata 66 kV, Islington 66 kV, Kimberley, Studholme, and Temuka.

5.3.9.1 Culverden 66 kV

Transmission into Culverden 66 kV supply bus is on two 220 kV Islington–Waipara–Culverden–Kikiwa circuits, via two 220/33 kV transformers and a single 33/66 kV transformer. The local lines company owns and operates the distribution network between Culverden 66 kV and the dairy factory.

Potential issues include:

- The Culverden 66 kV supply bus is supplied by a single transformer resulting in a n security supply, see section 17.5.4.5.
- The peak load is expected to exceed the supply transformers' n-1 capacity in the early 2020's, see section 17.5.4.5.
- Increased demand in the upper South Island will exacerbate the voltage and thermal issues in the region, see Chapter 6.

As there are already transmission issues that affect Culverden 33 kV and 66 kV, early engagement with Mainpower and Transpower is essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.9.2 Hororata 66 kV

Transmission into Hororata is on two 66 kV Hororata–Kimberley–Islington circuits. Two 66 kV Coleridge–Hororata circuits further connect Hororata to the Coleridge hydro station and the West Coast sections of our network. The local lines company owns and operates the distribution network between Hororata and the dairy factory.

Potential issues include:

- A wider voltage agreement with Orion for Hororata 66 kV allows a post-contingent operating voltage of 0.9-1.05 pu. However, in high load/low Coleridge generation scenarios the post-contingent voltage may drop below the agreed level (0.9 pu) and the Hororata–Kimberley–Islington circuits may be loaded above their n-1 capacity, see section 17.5.4.6.
- The Islington 66 kV peak load is expected to exceed the Islington 220/66 kV interconnecting transformers' n-1 capacity in the late 2020's, see section 17.5.4.1.
- Increased demand in the upper South Island will exacerbate the voltage and thermal issues in the region, see Chapter 6.

As there are already transmission issues that affect Hororata 66 kV, early engagement with Orion and Transpower is essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.9.3 Islington 66 kV

Transmission into Islington is predominantly supplied by three 220/66 kV interconnecting transformers. The 220 kV is part of the grid backbone. The local lines company owns and operates the distribution network between Islington 66 kV and the dairy factory.

Potential issues include:

- The peak load is expected to exceed the 220/66 kV interconnecting transformers' n-1 capacity in the late 2020's, see section 17.5.4.1.
- Increased demand in the upper South Island will exacerbate the voltage and thermal issues in the region, see Chapter 6.

As there are already transmission issues that affect Islington 66 kV, early engagement with Orion and Transpower is essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.9.4 Kimberley

Transmission into Kimberley is on two 66 kV Hororata–Kimberley–Islington circuits. Two 66 kV Coleridge–Hororata circuits connect Hororata to the Coleridge hydro station and the West Coast sections of our network. The local lines company owns and operates the distribution network between Kimberley and the dairy factory, including the supply transformers and supply bus.

Potential issues include:

- A wider voltage agreement with Orion at Kimberley allows a post contingent operating voltage band of 0.9-1.05 pu. However, in high load/low Coleridge generation scenarios, the post-contingent voltage may drop below the agreed level (0.9 pu) and the Hororata–Kimberley–Islington circuits may need to be loaded above their n-1 capacity, see section 17.5.4.6.
- The peak load is expected to exceed the 220/66 kV interconnecting transformers' n-1 capacity in the late 2020's, see section 17.5.4.1.
- Increased demand in the upper South Island will exacerbate the voltage and thermal issues in the region, see Chapter 6.

As there are already transmission issues that affect Kimberley 66 kV, early engagement with Orion and Transpower is essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.9.5 Studholme

Transmission into Studholme is on the 110 kV Timaru–Studholme and Oamaru–Studholme–Bells Pond–Waitaki circuits, with two 110/11 kV supply transformers at Studholme. The local lines company owns and operates the distribution network between Studholme and the dairy factory.

Potential issues include:

- Transmission constraints on the Bells Pond–Waitaki section of the Oamaru–Studholme–Bells Pond–Waitaki 1 circuit, see section 18.4.4.1.
- The 2019/20 summer load is expected to exceed the n-1 capacity and continuous rating of both 110/11 kV supply transformers at Studholme, see section 18.4.4.10.
- Increased demand in the upper South Island will exacerbate the voltage and thermal issues in the region, see Chapter 6.

Network Waitaki and Alpine Energy are considering a new grid exit point to take some load off the constrained 110 kV network, see section 18.3.2.1. However, this only deals with the constraint on the Oamaru–Studholme–Bells Pond–Waitaki circuit and not the Studholme supply transformer capacity issue. As there are already transmission issues that affect Studholme, early engagement with Alpine Energy and Transpower is essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.9.6 Temuka

Transmission into Temuka is on two 110 kV Temuka–Timaru circuits, with two 110/33 kV supply transformers at Temuka. The local lines company owns and operates the distribution network between Temuka and the dairy factory.

Potential issues include:

- The load is expected to exceed the n-1 capacity of both the 110/33 kV supply transformers and the Temuka–Timaru circuits, see section 18.4.4.12.
- Increased demand at Temuka will also exacerbate the voltage stability issue for the Timaru area, see section 18.4.4.2.
- Increased demand in the upper South Island will exacerbate the voltage and thermal issues in the region, see Chapter 6.

We are working with Alpine Energy to upgrade capacity to Temuka, see section 18.3.2.8. However, this does not resolve the Timaru area voltage stability issue which we plan to investigate separately once there is greater certainty as to future development plans to resolve capacity issues at Studholme and Temuka. As there are existing transmission issues that affect Temuka, early engagement with Alpine Energy and Transpower is essential to ensure that involved parties understand the impact of process heat electrification.

5.3.10 Central Otago region

One dairy processing factory was identified in the Central Otago region, supplied via the local distribution company's network from the Balclutha grid exit point.

5.3.10.1 Balclutha

Transmission into Balclutha is on the 110 kV Balclutha–Gore and Balclutha–Berwick–Halfway Bush circuits, with two 110/33 kV supply transformers at Balclutha. The local lines company owns and operates the distribution network between Balclutha and the dairy factory.

Potential issues include:

- The load is expected to exceed the n-1 capacity of both the 110/33 kV supply transformers and the two 110 kV circuits, see section 19.5.4.2.
- Increased demand in the lower South Island will exacerbate the transmission capacity issues into the region but will relieve export constraints on lower South Island generation, see Chapter 6.

We are working with PowerNet and other stakeholders to investigation options for reinforcing supply capacity to the Balclutha area, see section 19.4.2.2. As there are already transmission issues that affect Balclutha, early engagement with PowerNet and Transpower is essential to ensure that the parties involved understand the impact of process heat electrification.

5.3.11 Southland region

We have identified four dairy factories in the Southland region. These are supplied via the local distribution company's network from three grid exit points: one each from Edendale and Gore, and two from Invercargill.

5.3.11.1 Edendale

Transmission into Edendale is on the 110 kV Edendale–Invercargill and Brydone–Edendale circuits, with two 110/33 kV transformers at Edendale. Brydone further connects to Gore which has a high capacity interconnection to the 220 kV grid. The local lines company owns and operates the distribution network between Edendale and the dairy factory.

Potential issues include:

- The load at Edendale is expected to exceed the n-1 capacity of the 110/33 kV supply, see section 19.5.4.4.
- The capacity of the Edendale–Invercargill and Brydone–Gore 1 circuits limit the combined load that can be supplied from Edendale and Brydone, see section 19.5.4.1.
- Increased demand in the lower South Island will exacerbate the transmission capacity issues into the region but will relieve export constraints on lower South Island generation, see Chapter 6.

We are working with PowerNet and other stakeholders to identify options for reinforcing capacity to the Edendale area, see section 19.4.2.4. As there are already transmission issues that affect Edendale, early engagement with PowerNet and Transpower is essential to ensure that the parties involved understand the full impact of process heat electrification.

5.3.11.2 Invercargill

Invercargill is supplied by two 220/33 kV supply transformers. The 220 kV is part of the grid backbone. The local lines company owns and operates the distribution network between Invercargill and the dairy factories.

There is at least 35-40 MW of headroom before we expect the transformers' n-1 capacity to be exceeded.

Potential issues include:

- Increased demand in the lower South Island will exacerbate the transmission capacity issues into the region but will relieve export constraints on lower South Island generation, see Chapter 6.

Although there is no existing capacity issue specific to Invercargill, early consultation with Electricity Invercargill and Transpower is recommended to ensure that involved parties understand the full impact of process heat electrification.

6 Grid Backbone

6.1 Introduction

This chapter describes the adequacy of the grid backbone to transfer energy from generators to loads now and in the future, while maintaining a secure grid.

The Grid backbone describes the bulk interconnected transmission system, primarily the 220 kV network, which connects the regions described in Chapters 7 to 19.

We identify potential grid backbone issues by studying the system's capability to meet the forecast growth in demand (see Chapter 3) under a range of system conditions.[1] Generation development scenarios are not explicitly used, other than to note where significant issues may arise if future generation is established in particular regions.[2] Grid upgrades to resolve issues must meet the requirements of the Grid Reliability Standards. Many grid upgrades will also require submission of a Major Capex Proposal to the Commerce Commission for approval.

6.2 North Island grid backbone

The North Island grid backbone comprises the following 220 kV circuits:

- four from Wellington to Bunnythorpe
- three from Bunnythorpe to Wairakei and Whakamaru
- three connecting Wairakei and Whakamaru
- two from Bunnythorpe to Brunswick, then three from Brunswick to Stratford
- two from Stratford to Huntly
- eight into Auckland from Huntly, Ohinewai and Whakamaru.

Power flows on the inter-island HVDC link vary. The net annual power flow is northwards, especially at times of North Island peak demand. However, during light load periods, power may flow southward to conserve South Island hydro storage, especially during periods of low hydro inflows in the South Island.

The existing North Island grid backbone is set out geographically in Figure 6-1 and schematically in Figure 6-2.

To help describe transmission system problems and opportunities on the backbone grid, we split the North Island transmission system into five main areas:

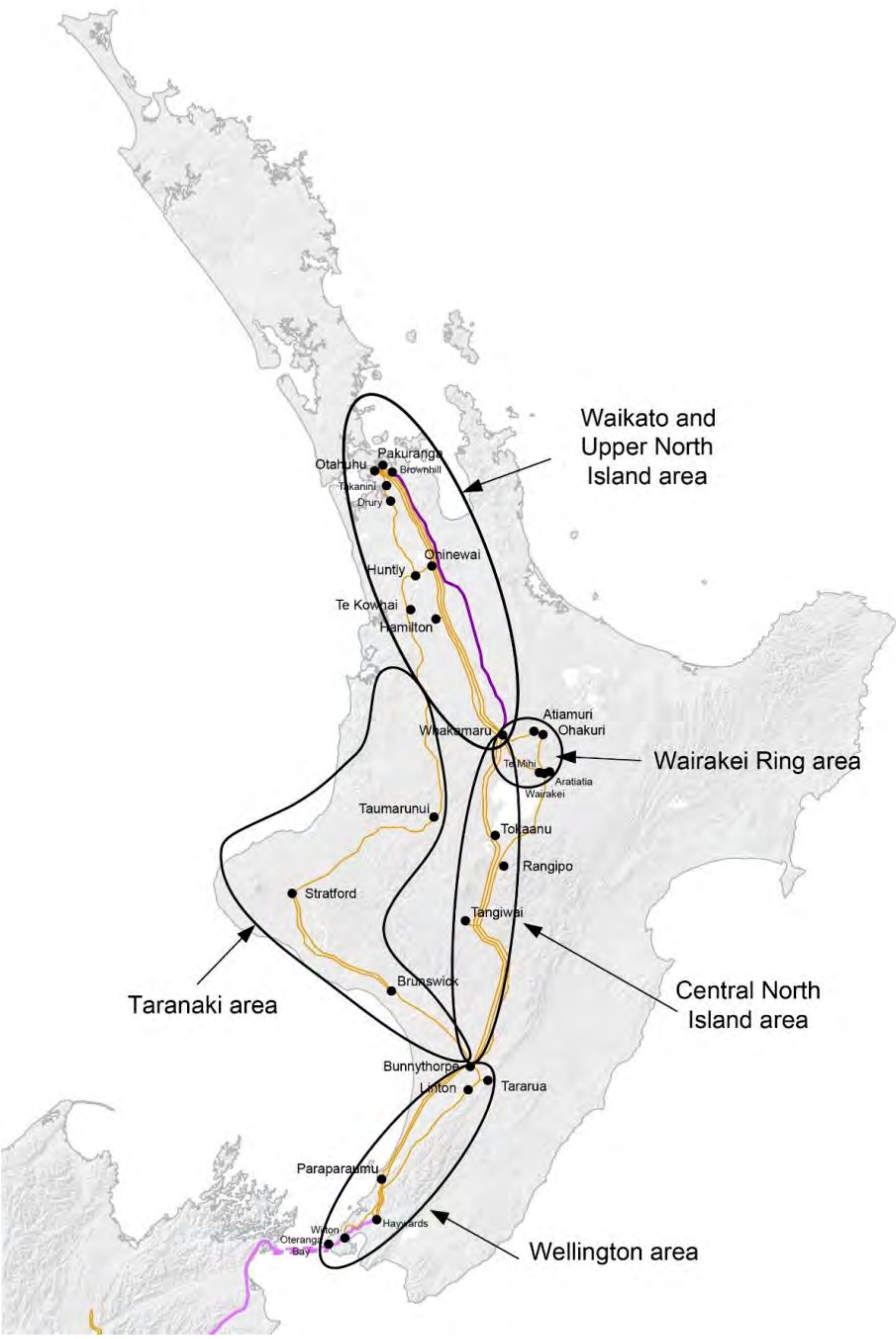
- lower North Island area, which encompasses everything south of Bunnythorpe
- central North Island area, which connects the lower North Island area with Whakamaru and Wairakei

1 System conditions are load and generation patterns that we use to highlight transmission issues we can reasonably expect to occur with currently available information and trends.

2 Additional 'growth generation' is included in our North Island models where it is required to balance load and generation. Refer to section 6.4.4.3.

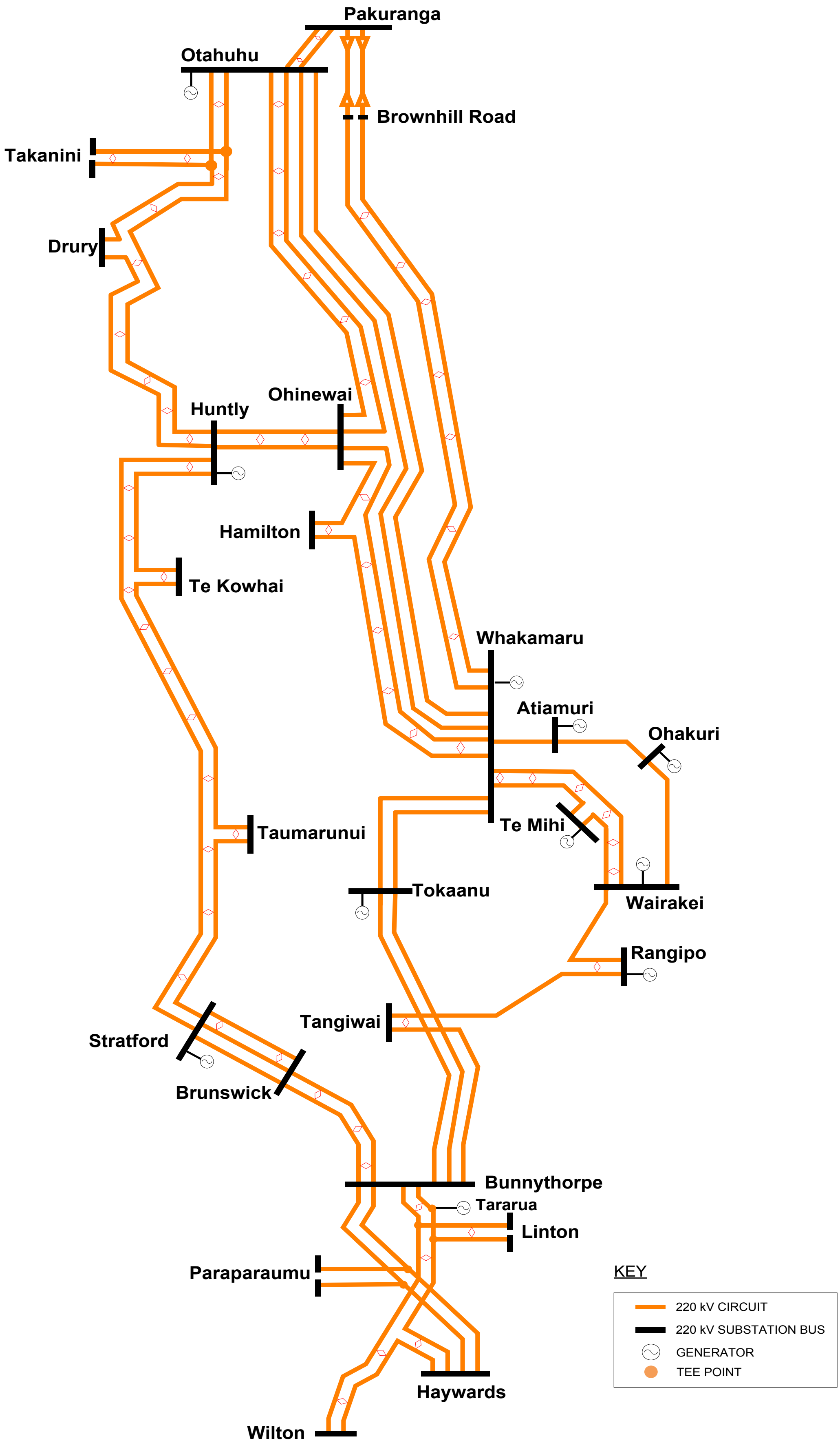
- Wairakei Ring area, which encompasses the 220 kV circuits between Wairakei and Whakamaru connecting the major hydro and geothermal generation in the central North Island, Bay of Plenty and Hawke's Bay regions to the transmission network
- Taranaki area, which encompasses the grid backbone that connects generation in the Taranaki region to the Waikato and Upper North Island (WUNI) and central North Island areas
- WUNI area, which encompasses everything north of Whakamaru, including the Auckland and Northland regions and most of the Waikato region[3].

Figure 6-1: North Island grid backbone map



3 This is the same area that is the focus of the Waikato and Upper North Island Voltage Management project, which is discussed in sections 6.3.2.1 and 6.4.6.1

Figure 6-2: Simplified North Island grid backbone schematic

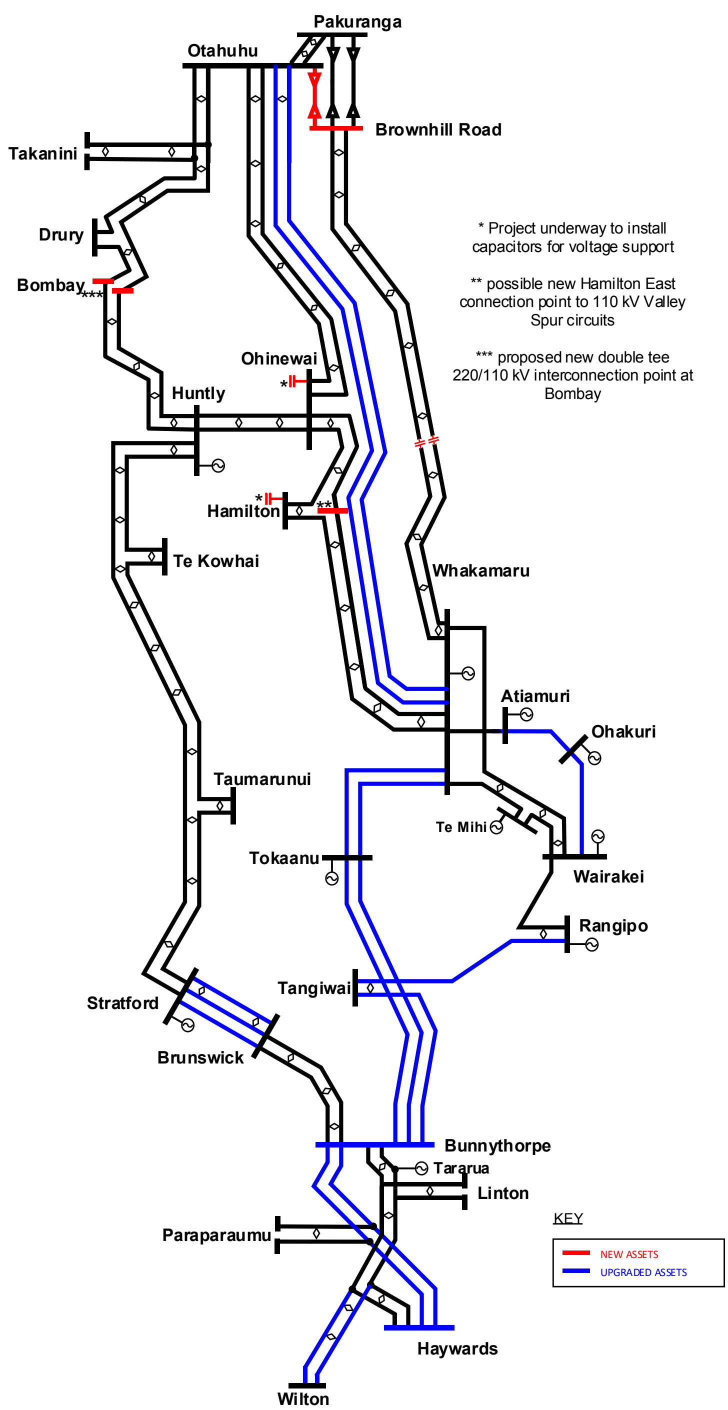


6.3 North Island grid enhancement approach

6.3.1 Possible North Island grid backbone to 2034

Figure 6-3 provides an indication of possible North Island transmission backbone development in the medium-term (the next 15 years). Assets that are new or upgraded within the forecast period (based on potential enhancement approaches set out in the following sections) are shown.

Figure 6-3: Indicative North Island grid backbone schematic to 2034



6.3.2 Enhancement approach

This section provides information about the transmission constraints on the North Island grid backbone that we will investigate or mitigate over the next few years. Constraints not considered at this time include those that only occur:

- for a particular generation development scenario (for example, one where most new generation is located in the Taranaki region)
- towards the end of the forecast period.

Transmission issues likely requiring E&D base capex or Major Capex Proposal (MCP) funded investment in the North Island grid backbone over the next 10-15 years include:

Section number	Issue
6.3.2.10	Transmission constraints north of Whakamaru
6.3.2.2	Wairakei Ring transmission capacity
6.3.2.3	Central North Island and Taranaki transmission capacity
6.3.2.4	High voltage at light load periods

Appendix A describes our Options Assessment Approach (OAA) to identify a range of investment options to address issues and ensure our assets remain fit for purpose into the future. The level of options assessment is commensurate with the level of expenditure.

6.3.2.1 Transmission constraints north of Whakamaru

Waikato and Upper North Island Voltage Management

Since 2015, more than 1,000 MW of generation capacity has been decommissioned in the WUNI) area. The proposed closure of the remaining two Huntly Rankine units in 2022 will reduce generation by an additional 500 MW which, coupled with demand growth in the WUNI area, raises significant voltage stability risks.

Enhancement approach:

The WUNI Voltage Management (WUNIVM) investigation has identified the following investment proposal to maintain voltage stability in the WUNI region:

- static capacitors at Hamilton and Ohinewai (project in delivery under RCP2 base capex)
- dynamic reactive support at Hamilton and Otahuhu
- an automatic load management scheme to manage N-G-1 voltage stability limits
- an automatic capacitor tripping scheme to manage over voltages following some faults (funded under a previously approved Grid Upgrade Proposal)
- preliminary work for series capacitors on the Brownhill–Whakamaru 400 kV-capable line.

Whether there is a need for these investments is highly dependent on the actions of other parties in developing non-transmission solutions, such as new generation in the WUNI area.

The WUNI project is a Major Capex Project and we expect to submit a proposal to the Commerce Commission in the 2019/20 financial year.

Series capacitors on the Brownhill–Whakamaru circuits may be required in the mid 2020's to manage voltage stability and/or address thermal transmission constraints. Doing preliminary work for series capacitors reduces the time from confirming series capacitors are required to commissioning. The procurement and installation of series capacitors would be a separate Major Capital Project proposal submitted to the Commerce Commission.

Base Capex investments

Project Name	Waikato and Upper North Island Voltage Management (WUNIVM)
Project description:	WUNI Shunt Capacitors Stage 1 – Hamilton and Ohinewai Capacitors
Project's state of completion	Delivery
OAA[4] level completed:	OAA level 4
Grid need date:	2019
Indicative cost [$ million]:	12
Part of the GEIR?	No

Major Capex investments

Project Name	Waikato and Upper North Island Voltage Management (WUNIVM)
Project description:	Waikato and Upper North Island Voltage Management
Project's state of completion	Possible
OAA level completed:	OAA level 5
Grid need date:	2023
Indicative cost [$ million]:	150
Part of the GEIR?	Yes

Brownhill–Whakamaru transmission

The 400 kV-capable Brownhill–Whakamaru A double circuit line was built with the intention of applying staged upgrades as warranted by demand growth in the upper North Island.

The first stage is to install series compensation on the line while it remains operating at 220 kV. This would address transmission constraints due to system stability (following the WUNI upgrade) and/or thermal capacity north of Whakamaru. Series compensation also reduce system losses, which may justify bringing forward the investment to before the need date for transmission constraints.

The second stage, once transmission constraints are again reached, is a 220 kV bus at Brownhill Road and a third 220 kV cable from Brownhill Road north to Auckland. The 220 kV bus and cable are not required if the series capacitors are installed to reduce losses only, rather than to meet demand growth.

Enhancement approach:

Series compensation will raise the limits on transmission into the WUNI area identified by the WUNIVM project. The cost of series compensation is expected to exceed the $20 million Major Capex Project threshold.

Major Capex investments

Project Name	Brownhill–Whakamaru series compensation
Project description:	Brownhill–Whakamaru series compensation
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2024
Indicative cost [$ million]:	90
Part of the GEIR?	Yes

6.3.2.2 Wairakei Ring transmission capacity

The Wairakei Ring connects the generation rich regions of the central North Island with the high load centres of the upper North Island, Waikato and Bay of Plenty via two 220 kV transmission lines (a single and a double circuit line).

4 OAA is Options Assessment Approach, see Appendix A for further details.

The capacity of the Wairakei–Ohakuri–Atiamuri–Whakamaru circuits may cause a transmission constraint during very high Wairakei Ring area generation. This constraint will worsen if there is a reduction in industrial load in the Bay of Plenty region, or if additional generation is developed around Wairakei or in the Bay of Plenty region (both of which have the potential for a significant increase in geothermal generation), or there is an increase in "through transmission" to the WUNI region due to generation retirement and/or load growth.

Enhancement approach:

We will continue to monitor developments in the region that may trigger the need for investments to relieve the Wairakei Ring constraints. These triggers include generation developments in Wairakei, Kawerau and the Bay of Plenty region. We will investigate investment options as one or more of these triggers emerges.

The limiting circuits have already been thermally upgraded and have variable line ratings applied, so there is no scope to further increase the transmission capacity using these techniques. We are investigating an incremental investment to install a series reactor on the Wairakei–Atiamuri–Ohakuri–Whakamaru line to balance flows on the Wairakei Ring circuits. The next investments, as more triggers emerge, will be major ones involving reconductoring or building a new line, either of which will have a cost in excess of the $20 million Major Capex Project threshold.

Base E&D Capex investments

Project Name	Wairakei Ring transmission constraint
Project description:	Install Atiamuri–Ohakuri series reactor
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	Uncertain, Wairakei area generation dependent
Indicative cost [$ million]:	10
Part of the GEIR?	Yes

6.3.2.3 Central North Island and Taranaki transmission capacity

Central North Island and Taranaki thermal capacity

During high generation in the Wellington (including HVDC north transfers) and Taranaki regions, the Tokaanu–Whakamaru, Bunnythorpe–Mataroa, and Huntly–Stratford transmission circuits limit generation export to the WUNI area.

The limiting constraint depends on which region contributes the highest generation. When generation is highest in the Wellington region, the 220 kV Tokaanu–Whakamaru circuits and low capacity 110 kV Bunnythorpe–Mataroa circuit constrain generation export. When generation is highest in the Taranaki region, the 220 kV Huntly–Stratford circuit constrains generation export.

Enhancement approach:

We have identified a range of smaller investments that will enable us to better utilise the existing assets between Bunnythorpe and the WUNI area:

- possibly apply variable line ratings on the Tokaanu–Whakamaru circuits
- upgrade the Huntly–Stratford line protection and install Huntly 220 kV duplicate busbar protection to remove the static limit on this circuit.

The next generation development in the Taranaki region is likely to trigger the need to upgrade protection on the Huntly–Stratford circuit and Huntly 220 kV busbar to remove the line's branch component limit. We are monitoring triggers such as the proposed Waikato power stations and will consider whether to proceed with this investment once firm proposals emerge.

Once the benefits from the incremental investments described above have been realised, a major investment will likely be required if a combination of the following factors eventuate:

- substantial generation investment in the Taranaki region
- substantial generation investment or load reduction in the Wellington region
- an increase in HVDC north transfer, which may be driven by substantial generation investment or a reduction in load in the South Island.

Possible major investments are reconductoring or new transmission lines.[5] The cost of these investments will be in excess of the $20 million Major Capex Project threshold. We will proceed with a Major Capex Project investigation when plans for development in these areas are more certain.

Base E&D Capex investments

Project Name	Huntly–Stratford transmission capacity
Project description:	Upgrade Huntly–Stratford circuit and Huntly 220 kV duplicate busbar protection
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2022
Indicative cost [$ million]:	2
Part of the GEIR?	Yes

Brunswick–Stratford circuit consolidation

The 220 kV single circuit Brunswick–Stratford B line (Brunswick–Stratford 3 circuit) is due for reconductoring as a risk-based condition replacement.

Enhancement approach:

We are investigating the long term need for this line, including considering the following options:

- dismantling the line
- upgrading the Brunswick–Stratford A line (Brunswick–Stratford 1 and 2 circuits) and dismantling the B line
- reconductoring the Brunswick–Stratford B line.

An outcome of this investigation will be a preferred option and a timeframe for submission of a Major Capital Project to the Commerce Commission.

6.3.2.4 High voltage at light load periods

Waikato and Upper North Island high voltage management

During light load periods, managing high voltages issues in the WUNI area is increasingly difficult. We primarily manage the issue by switching the 400 kV-capable Pakuranga–Whakamaru circuits out of service when there are insufficient reactive power reserves on the available dynamic reactive plant in the area. In a few instances, we have also switched the Huntly–Stratford circuit out of service and one or more 220 kV cable circuits in Auckland.

Although taking circuits out of service is an effective way to control voltages, its application is limited as we must also ensure security of supply to load in the area.

Enhancement approach:

We are currently investigating options to provide voltage support to the WUNI area during peak load periods (see section 6.3.2.1) under the WUNIVM project. The dynamic reactive plant, if implemented, will also increase the capability of the grid to absorb reactive power during light loads and will reduce, but not eliminate, the need to switch circuits.

An alternative option to manage the high voltage issue, if the WUNIVM proposal does not go ahead or is insufficient to address the high voltage, is to install shunt reactors.

[5] The lines have already been thermally upgraded to the maximum practical extent.

Base E&D Capex investments

Project Name	Waikato and Upper North Island high voltage management
Project description:	Waikato and Upper North Island high voltage management - shunt reactor
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2021
Indicative cost [$ million]:	6
Part of the GEIR?	No

6.3.3 North Island grid backbone beyond the planning horizon (2034)

Figure 6-4 provides an indication of the possible North Island transmission backbone development in the longer term (beyond 2034).

6.3.3.1 Increased operating voltages from Whakamaru to Brownhill Road

The operating voltage on the overhead transmission line from Whakamaru to Brownhill Road may be increased to 400 kV. This will also require additional 220 kV cables from Brownhill Road north into Auckland. Ultimately, we may also require a new transmission line from Whakamaru to Auckland, but both of these upgrades are highly dependent on future load and generation growth, and the viability of alternatives.

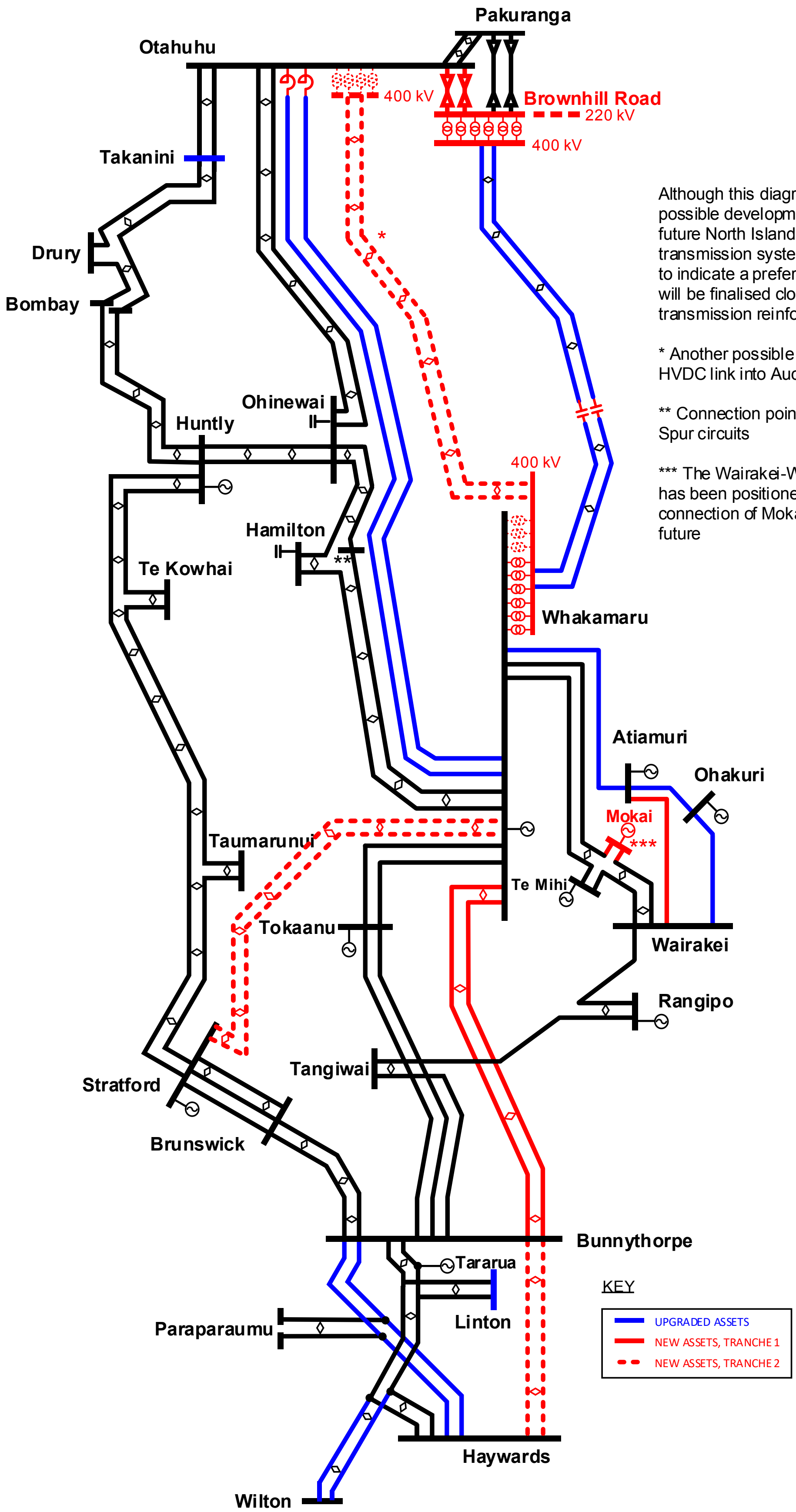
6.3.3.2 Wairakei Ring upgrade options

Upgrade options for the Wairakei Ring include reconductoring part or all of the existing single circuit Wairakei–Ohakuri–Atiamuri–Whakamaru line or replacing it with a new double circuit line. A new double circuit line has the added advantage of increasing security to the Bay of Plenty region during maintenance outages.

6.3.3.3 Transmission capacity north of Bunnythorpe

Transmission capacity north of Bunnythorpe may be increased through the central North Island to Whakamaru and/or through the Taranaki area with a new line from Taranaki to Whakamaru. Ultimately, we may also require a significant increase in transmission capacity from Wellington to Bunnythorpe. These upgrades are highly dependent on significant new generation being developed south of Taupo.

Figure 6-4: Longer-term indicative North Island grid backbone schematic (beyond 2034)



Although this diagram shows a few possible development paths for the future North Island grid backbone transmission system, it is not intended to indicate a preference. Any option will be finalised closer to the date that transmission reinforcement is needed.

* Another possible option is a new HVDC link into Auckland.

** Connection point for 110 kV Valley Spur circuits

*** The Wairakei-Whakamaru C line has been positioned to allow connection of Mokai generation in the future

6.4 North Island asset capability and management

We have assessed transmission capacity and reactive support requirements on the North Island grid backbone for a range of system conditions over the next 15 years. When a problem or opportunity is likely to arise, we examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 6.3) were developed to address problems or opportunities that require action within the forecast period and where investment is a valid option.

6.4.1 Changes since the 2018 Transmission Planning Report

Changes since the 2018 TPR include:

- a higher winter load forecast and a lower summer load forecast
- installed a series reactor and special protection scheme on the Bunnythorpe–Mataroa circuit
- removed the system condition that demonstrated the impact of extremely low upper North Island generation on the 110 kV network as these issues will be addressed with the installation of static capacitors in the Waikato region (see section 6.4.2).

6.4.2 Committed Projects

Projects that are not complete at the time of publication, but which are included in the analysis modelling, are:

- reconductoring of the Bunnythorpe–Haywards A and B lines, programmed for completion by winter 2020
- installation of shunt capacitors at Hamilton and Ohinewai, programmed for completion by winter 2020.

6.4.3 Line conductor reviews and replacements

Table 6-1 lists the major grid backbone line conductor review and replacement projects expected to be undertaken between 2019 and 2034.

Table 6-1: Grid backbone line conductor reviews and replacements 2019 to 2034

Line	Affected circuits	Tentative year	Further information
Bunnythorpe–Haywards A Bunnythorpe–Haywards B	Bunnythorpe–Paraparaumu–Haywards 1 Bunnythorpe–Paraparaumu–Haywards 2	2019-2020 2019-2020	Note 1
Bunnythorpe–Wilton A (Judgeford–Wilton section)	Bunnythorpe–Linton–Wilton 1 Bunnythorpe–Tararua C–Haywards 1 Haywards–Linton 1	2020-2022	Note 2
Bunnythorpe–Wilton A (Bunnythorpe–Judgeford section)	Bunnythorpe–Linton–Wilton 1 Haywards–Wilton 1	2023-2030+	Note 3 Note 4
Brunswick–Stratford B	Brunswick–Stratford 3	2023-2025	Note 3
Otahuhu–Whakamaru A Otahuhu–Whakamaru B	Otahuhu–Whakamaru 1 Otahuhu–Whakamaru 2	2021-2030+	Note 5 Note 3

1. Major Capex Proposal approved by the Commerce Commission.
2. Reconductoring the Judgeford–Wilton section is an approved project.
3. Condition-based intervention is being investigated on these lines. We will potentially submit a Major Capex Project proposal to the Commerce Commission for this work.
4. The Bunnythorpe–Wilton A (Bunnythorpe–Judgeford section) will be reconductored in sections, with phase one expected 2023-2025, and the remainder some time after.
5. The northern-most 5 km section of the Otahuhu–Whakamaru A and B lines are scheduled to be reconductored around 2021, followed by the next 23 km around 2025, and the remainder in the early 2030s.

These line conductors are all approaching risk-based condition replacement criteria, which provides the opportunity to review the circuit capacities and whether they are still required in future. Options providing the greatest net benefit will be implemented, optimising the conductor types and operating temperatures, circuit capacities, losses, the cost of replacing conductors and strengthening towers, market benefits, and future maintenance costs.

6.4.3.1 North Island grid backbone asset feedback register

The Asset Feedback Register includes no entries related to E&D specific to the North Island grid backbone.

6.4.3.2 Bunnythorpe–Haywards A and B line conductor replacement

This is an approved project. The existing Goat conductor is being replaced with Zebra conductor, providing a moderate increase in rating of 45–55 MVA per circuit. Although the project is not complete at the time of publication, the analysis assumes the new line conductor is commissioned.

6.4.3.3 Bunnythorpe–Wilton A line conductor replacement

The project involves reconductoring the Judgeford–Wilton section by 2024, replacing the existing duplex zebra conductor with simplex chukar. The three existing two-terminal circuits Haywards–Linton, Haywards–Wilton and Linton–Wilton will be reconfigured as two new three-terminal Haywards–Linton–Wilton circuits. The analysis referred to in this TPR uses the existing line conductor and circuit configuration until 2023 from which point the grid reconfiguration is assumed to be complete.

6.4.3.4 Brunswick–Stratford B line conductor replacement

Replacement options are being investigated and, if required, a Major Capex Project proposal will be submitted to the Commerce Commission. Options include dismantling the line, upgrading the Brunswick–Stratford A line and dismantling the B line, and reconductoring the Brunswick–Stratford B line. The analysis referred to in this TPR uses the existing line conductor.

6.4.3.5 Otahuhu–Whakamaru A and B line conductor replacement

The project involves reconductoring the northern section (approximately 5 km) of the Otahuhu–Whakamaru A and B lines due to meeting replacement criteria based on asset health condition assessment.

The conductor on the rest of the line will also reach replacement criteria in stages from 2025 to 2030+. We will assess the options for each section as the need arises. Options include reconductoring with a modern equivalent conductor or a larger conductor, or building a new line section and dismantling an existing line section. This will be either part of our RCP4 submission or a Major Capital Project proposal.

This work is closely linked to the WUNIVM Project and the Auckland Strategy. For more details, refer to Chapters 6 and 8, respectively.

6.4.4 Methodology

6.4.4.1 System conditions

A small number of realistically challenging system conditions are used to assess the capability of the existing North Island grid backbone (including the committed projects discussed in section 6.4.2). They provide snapshots to identify transmission constraints that may require minimum or maximum generation limits to avoid overloading the power system following an outage. From these we can identify transmission upgrades that will alleviate the constraints, allowing lower minimum and higher maximum generation limits.

6.4.4.2 Development uncertainty

Until recently, load in the upper North Island was partially supplied by local generation at Otahuhu, Southdown and Huntly. However, upper North Island load growth and the decommissioning of more than 1,000 MW of thermal generation in the WUNI area in the last few years will result in voltage stability and thermal issues in the area.

Decommissioning of the remaining Huntly Rankine units (possibly as soon as 2022) will further increase this impact.

These changes cause considerable uncertainty for transmission planning because more generation is required to meet load. However, it is unclear as yet where new generation development will occur. Therefore, at this stage it is not possible to assess the likelihood and location of future thermal constraints on the North Island grid backbone with any certainty. Also, our preferred option for the WUNIVM project has yet to be considered by the Commerce Commission.

Due to these uncertainties, system analysis beyond 2022 is of limited value. All the results presented below, which deal with the period beyond 2022, should be used with caution.

6.4.4.3 Growth generation

Existing generation is insufficient to supply the forecast load for some system conditions. Additional generation is required to securely supply the forecast load. We model this using 'growth generation'.

Depending on the system conditions, assumed 'growth generation' can exceed:

- 1,800 MW by Winter 2034.
- 500 MW by Summer 2031.

In the North Island we model the growth generation as 50 MW generating units added sequentially at Stratford and Wairakei, as they are centrally located in gas and geothermal rich areas respectively. Growth generation at Stratford is capped to prevent overloading the conductor on the long Huntly–Stratford circuit. Heavily loading this long circuit results in high reactive power absorption, which can lead to unmanageable voltages in the Waikato region.

The system conditions will identify transmission constraints that can occur as a result of the growth generation.

6.4.4.4 Limits in the electricity market

Transmission constraints identified by the system conditions do not always cause minimum or maximum generation limits in the wholesale electricity market. The System Operator's management of a transmission constraint depends on the type of outage that causes the constraint:

- Circuit outages are managed as contingent events requiring pre-contingent management (for example, by using market security constraints to apply a maximum generation limit or pre-contingent load management).
- Other outages (for example, bus-sections) may be managed using pre-contingent or post-contingent actions, depending on the extent and magnitude of the system impact resulting from the outage.

6.4.5 Overview of results

6.4.5.1 Key results for TPR2019

Key findings for the North Island grid backbone are:

- A reduction in thermal generation in the WUNI area will require immediate investment in both dynamic and static reactive support. Reduced generation will also worsen, or bring forward, the transmission constraints into the WUNI area.
- Transmission in the Wairakei Ring area is nearing capacity, despite commissioning of the high capacity Wairakei–Whakamaru C line in 2014. The Wairakei–Whakamaru A line will become a transmission constraint if there is further significant geothermal generation development around Wairakei and/or in the eastern Bay of Plenty.

- The 110 kV Bunnythorpe–Mataroa circuit may limit transmission in the central North Island area. A series reactor and special protection scheme were installed to alleviate (but not eliminate) the transmission constraint.
- The 220 kV Tokaanu–Whakamaru and Huntly–Stratford circuits may cause transmission constraints between Bunnythorpe and the WUNI area.

6.4.5.2 Key differences from TPR2018

Some results for TPR2019 are significantly different to those reported in TPR2018, particularly for system conditions 1 and 2 (sections 6.4.6.1 and 6.4.6.2 respectively). These system conditions have high levels of power flow from Wellington and the lower North Island towards Auckland. Changes that have occurred include:

- We are forecasting substantially more aggressive winter load growth in the Auckland region and less aggressive winter load growth in other regions, due in part to recent observed load growth. We are also forecasting less summer load growth in the Auckland region.
- New generation[6] being connected at Linton (Turitea North wind generator in the Central North Island region) and into the 110 kV Bunnythorpe–Carrington Street circuit (Junction Road, an open cycle gas turbine in the Taranaki region).

The effect of these changes includes:

- The transmission issues identified within the WUNI area in winter occur earlier, mainly due to the increased load forecast.
- Some transmission issues within the Wairakei ring in summer no longer appear in summer due to the reduced load forecast.
- Even with the new generation, the more aggressive forecast for the Auckland region, in particular, results in significant advancement and increase in the amount of growth generation required.
- The committed new generation build all flows north via the central North Island and Taranaki circuits. Therefore, significantly lower limits on the HVDC are required to prevent these circuits from overloading. That is, the new generation is traded off against South Island generation.

6.4.6 North Island grid backbone capability and constraints

The system conditions that provide snapshots of the capability of the North Island grid backbone to transfer energy from generators to the loads while maintaining a secure grid are:

- low WUNI generation and winter peak load (section 6.4.6.1)
- low WUNI generation and summer peak load (section 6.4.6.2)
- HVDC south transfer (winter) (section 6.4.6.3)
- HVDC south transfer (summer) (section 6.4.6.4)
- low eastern Bay of Plenty industrial load (section 6.4.6.5)
- light load (section 6.4.6.6).

6.4.6.1 System condition 1: low WUNI generation (winter peak)

This system condition (SC1) tests the case where thermal generation in the WUNI area is low during a period of high load (winter peak). It represents generation development scenarios where the two remaining Huntly Rankine units are not available during the winter peak and are replaced with 'growth generation' elsewhere in the North Island. The specific assumptions for this system condition are:

- North Island winter peak load
- thermal generation in the WUNI area is limited to one combined-cycle generating unit and one small open-cycle gas turbine at Huntly, unless otherwise noted

6 Since the "freeze date" for the studies, two additional new generation builds were announced. These are the Waipipi wind farm (133 MW) connecting at Waverley, and Turitea South wind farm (103 MW) connecting at Linton. To highlight the impact of transmission constraints, particularly in the central North Island area, we reduce HVDC transfer. These generators will result in HVDC transfers lower than reported.

- high geothermal and hydro generation in the Bay of Plenty, Central North Island and Hawke's Bay regions
- maximum thermal generation in the Taranaki region (including the combined cycle generating station and the gas peaking generators)
- maximum wind generation
- high HVDC north transfer, up to 1,000 MW
- for the thermal analysis, a dynamic reactive power source that provides enough reactive support to maintain the voltage at Otahuhu to 1.02 pu
- generation and load balance is achieved using growth generation at Wairakei and/or Stratford (see section 6.4.4.3 for details).

Transmission constraints are addressed by trading off lower North Island and South Island generation with WUNI area generation.

Studies of this system condition focus on the thermal issues that occur when large amounts of growth generation is transported from remote areas in the lower North Island to Whakamaru and Huntly. In order to prevent major voltage stability problems in the WUNI area (which are specifically covered by the WUNI section) and at the same time avoid extremely high levels of 'growth generation'[7], we assume that Huntly unit 5 is available.

Summary of transmission constraints

Possible transmission constraints include:

- WUNI voltage issues
- constraints north of Whakamaru
- central North Island area constraints
- Taranaki area constraints
- Wairakei Ring area constraints.

The 110 kV and 220 kV circuits in the central North Island area will overload under this system condition. If significant amounts of new generation locates in the:

- Taranaki area, then the Huntly–Stratford circuits will also overload within the forecast period
- Wairakei area, then the Wairakei Ring circuits and some circuits between Whakamaru and Auckland will also overload within the forecast period.

SC1: Waikato and Upper North Island Voltage Management

The WUNI voltage management project analysed the voltage issues in detail and identified, for a scenario where Huntly unit 5 is unavailable:

- the limitation in the WUNI area is voltage stability
- there will be low voltage in the Waikato region, requiring static capacitors to lift the voltage plane
- the Otahuhu–Whakamaru and Hamilton–Whakamaru 220 kV circuits are likely to overload for parallel 220 kV circuit outages.

SC1: North of Whakamaru constraints

The 220 kV Hamilton–Whakamaru and Otahuhu–Whakamaru 1 and 2 circuits may overload from 2024. These overloads could be managed operationally for the forecast period and beyond by increasing generation in the WUNI area.[8]

Transmission constraints will arise on the 110 kV circuits between Otahuhu and Bombay before they appear on the 220 kV transmission system. These constraints are discussed in the Auckland Chapter 8.

Detailed dynamic voltage stability studies identified the need for substantial transmission investment to manage both the dynamic and static voltage stability following the decommissioning of the remaining Huntly Rankine units (currently scheduled to occur in 2022).

7 With Huntly Unit 5 off, extremely high levels of 'growth generation' are required which will result in exaggerated thermal constraints on the transmission system south of the WUNI area.

8 This solution assumes that at Huntly, at least one Rankine generating unit is still available to relieve the overload in addition to the 440 MW combined cycle gast turbine (CCGT) generating unit.

SC1: Central North Island area constraints

The most prominent transmission constraint is the loading on the 110 kV Bunnythorpe–Mataroa circuit. At present, the Bunnythorpe–Mataroa circuit may overload pre-contingency[9] for this system condition, managed by limiting maximum generation in the lower North Island, with the most effective reduction being HVDC north transfer. This is nearly one and a half times as effective as reducing Taranaki generation.

At present, a Tokaanu–Whakamaru circuit may overload following the outage of the other Tokaanu–Whakamaru circuit for this system condition. This transmission constraint is alleviated (but not resolved) by the special protection scheme at Tokaanu.[10] Limits on maximum generation at, or south of, Tokaanu will reduce loading with the most effective place to reduce generation being Tokaanu. This is one and a half to two times as effective as reducing HVDC transfer and between two and two and a half times as effective as reducing Taranaki generation.

In Winter:

- 2020, HVDC north transfer is limited to approximately 890 MW to prevent Bunnythorpe–Mataroa from overloading pre-contingency. Tokaanu–Whakamaru will overload for a parallel circuit outage if Tokaanu generation exceeds around 110 MW with the above HVDC north transfer
- 2024, HVDC north transfer is limited to approximately 470 MW to prevent Bunnythorpe–Mataroa from overloading pre-contingency. Tokaanu–Whakamaru will overload for a parallel circuit outage if Tokaanu generation exceeds around 220 MW with the above HVDC north transfer
- 2034, HVDC north transfer is limited to approximately 415 MW to prevent Bunnythorpe–Mataroa from overloading pre-contingency.

SC1: Taranaki area constraints

At present, a Huntly–Stratford circuit may overload for a parallel circuit outage. The Huntly–Stratford circuit is presently limited to 354 MVA.[11]

In Winter:

- 2020, HVDC north transfer is limited to approximately 860/300 MW[12] to prevent Huntly–Stratford from overloading for a parallel circuit outage
- 2024, HVDC north transfer is limited to approximately 600/45[13] MW to prevent Huntly–Stratford from overloading for a parallel circuit outage
- 2034, HVDC north transfer is limited to approximately 515 MW to prevent Bunnythorpe–Mataroa from overloading pre-contingency with no growth generation at Stratford. HVDC north transfer is limited to 45 MW to prevent Huntly–Stratford from overloading for a parallel circuit outage with 350 MW of growth generation at Stratford.

With the protection limit resolved, the Bunnythorpe–Mataroa and Tokaanu–Whakamaru circuits will overload before a Huntly–Stratford circuit. The Huntly–Stratford circuit overload will only occur if transmission through the central North Island is upgraded. This constraint is most effectively managed operationally, by limiting generation in the Taranaki area. This is one and a half times as effective as reducing HVDC transfer.

SC1: Wairakei Ring area constraints

With growth generation connected near Wairakei:

- the Atiamuri–Ohakuri–Wairakei circuits will overload from 2020 following a Whakamaru 220 kV bus section outage

9 The Bunnythorpe–Mataroa Circuit Overload Protection Scheme at Mataroa reconfigures the grid by opening the 110 kV Mataroa–Ohakune circuit. The operation of this scheme means that the worst case loading on the Bunnythorpe–Mataroa circuit is pre-contingency.

10 The special protection scheme at Tokaanu reconfigures the grid by splitting the 220 kV Tokaanu bus. This redistributes the power flow within the power system, reducing the loading on the in-service Tokaanu–Whakamaru circuit. This scheme always operates for a Tokaanu–Whakamaru circuit or 220 kV Whakamaru bus outage, even if the other Tokaanu–Whakamaru circuit is not overloaded.

11 The circuit's capacity is limited by protection equipment. With this limit resolved, capacity will be 469/492 MVA (summer/winter).

12 These figures are for 0 MW and 350 MW of growth generation at Stratford, respectively.

13 These figures are for 0 MW and 350 MW of growth generation at Stratford, respectively.

- the Atiamuri–Ohakuri– Wairakei circuit will overload from 2020 following a Te Mihi–Whakamaru circuit contingency or a Wairakei–Whakamaru circuit contingency
- by 2023, all existing thermal generation north of Whakamaru[14] is required to be operating to prevent the Atiamuri–Ohakuri circuit from overloading for a Whakamaru 220 kV bus section outage
- by 2024, all existing thermal generation north of Whakamaru[14] is required to prevent the Atiamuri–Ohakuri circuit from overloading for a Te Mihi–Whakamaru circuit outage.
- after 2024, to eliminate post-contingency Atiamuri–Ohakuri overloads, a series reactor was modelled to determine its impact on the transmission network:
  - by 2028, all existing thermal generation north of Whakamaru is required to prevent circuit overloads within the Wairakei ring for both Whakamaru and Wairakei bus section outages.
  - by 2034, all existing thermal generation north of Whakamaru is required to prevent circuit overloads within the Wairakei ring following a Te Mihi–Whakamaru circuit outage.

The transmission constraints caused by the overloads can be most effectively managed operationally by reducing generation injection into the Wairakei 220 kV bus. This is around four times as effective as reducing HVDC transfer.

What next?

Presently, transmission constraints can be managed operationally through generation dispatch in the WUNI area.

We are studying investment options to alleviate or remove the transmission constraints following decommissioning of the remaining Huntly Rankine units. For more specific information on our enhancement approach for the:

- Central North Island 110 kV constraints, see section 6.3.2.3
- transmission capacity between Bunnythorpe and Whakamaru, see section 6.3.2.3
- transmission capacity between Stratford and Huntly, see section 6.3.2.3
- transmission capacity in the Wairakei Ring, see section 6.3.2.2
- transmission capacity into the WUNI area, see section 6.3.2.1

6.4.6.2 System condition 2: low WUNI generation (summer peak)

This system condition (SC2) tests the case where there is low thermal generation in the WUNI area during summer peak load. This is similar to system condition 1, but with summer circuit ratings. It considers the case where the two remaining Huntly Rankine units are not available at summer peak time, replaced with ‘growth generation’ elsewhere in the North Island. The specific assumptions for this system condition are:

- North Island summer peak load in the year the transmission constraint is identified
- thermal generation in the WUNI area is limited to one combined cycle generating unit at Huntly
- maximum geothermal generation in the Bay of Plenty, central North Island and Hawke’s Bay regions
- average summer hydro generation in the Central North Island, Hawke’s Bay, Bay of Plenty and Waikato regions
- low Taranaki generation, with no generation on the Stratford 220 kV bus
- maximum wind generation in the lower and central North Island
- generation and load balance is achieved by increasing HVDC north transfer, up to 1,000 MW. This is followed by growth generation at Wairakei and Stratford (see section 6.4.4.3 for details)
- transmission constraints are addressed by trading off lower North Island and South Island generation with WUNI generation.

[14] This solution assumes all the existing generation at Huntly is available, including retaining two Rankine units beyond 2022.

Summary of transmission constraints

Possible transmission constraints include:

- Central North Island area constraints
- 110 kV constraints
- WUNI area voltage stability
- Wairakei Ring area constraints.

In general, the 220 kV network is more capable of supplying the summer peak load than winter peak load without thermal constraints. Voltage stability limits are expected to bind in the WUNI area once the remaining Huntly Rankine units are decommissioned.

The 110 kV Bunnythorpe–Mataroa circuit in the central North Island may limit the maximum HVDC north transfer.

SC2: Central North Island area constraints

The most prominent transmission constraint is the loading on the 110 kV Bunnythorpe–Mataroa circuit.

There is a series reactor at Mataroa and the Bunnythorpe–Mataroa circuit can be loaded to 100 per cent pre-contingency because there is a special protection scheme to open the Mataroa–Ohakune circuit if the Bunnythorpe–Mataroa circuit overloads post-contingency.

The next limitation on the Bunnythorpe–Mataroa circuit is pre-contingency overloading from around 2026.

From 2020, a Tokaanu–Whakamaru circuit may overload following the outage of the other Tokaanu–Whakamaru circuit. This transmission constraint is managed with the existing special protection scheme at Tokaanu.[10] However, from around 2023 and as HVDC north transfer and the Stratford (growth) generation increases, an outage of a Tokaanu–Whakamaru circuit will operate the Bunnythorpe–Mataroa and Tokaanu special protection schemes.

In summer:

- 2026, HVDC north transfer is limited to around 850 MW to prevent Bunnythorpe–Mataroa from overloading pre-contingency and Tokaanu generation is limited to around 155 MW to prevent Tokaanu–Whakamaru from overloading for a parallel circuit outage
- 2034, HVDC north transfer is limited to 695 MW to prevent Bunnythorpe–Mataroa from overloading pre-contingency. For the specific assumptions for SC2, in particular using the average summer hydro dispatch at Tokaanu, the Tokaanu–Whakamaru circuit loading is above 90 per cent after the Bunnythorpe–Mataroa and Tokaanu–Whakamaru special protection schemes have operated.

Small changes in generation and load assumptions can result in the Tokaanu–Whakamaru circuit overloading, so generation constraints may occur within the forecast period.

SC2: Waikato and Upper North Island voltage stability

Dynamic voltage stability studies have identified the summer peak period as having a lower risk of dynamic voltage collapse than winter peak. The analysis confirmed a voltage stability limit will bind once the remaining Huntly Rankine units are decommissioned, presently scheduled for 2022.

SC2: Wairakei Ring area constraints

The Atiamuri–Ohakuri–Wairakei circuits may overload for a 220 kV Whakamaru bus section outage from around 2029.

What next?

The transmission constraints identified by this system condition are similar to those in system condition 1.

Presently, the transmission constraints can be managed operationally through generation dispatch in the WUNI area.

We are studying investments to alleviate or remove the transmission constraints following decommissioning of the remaining Huntly Rankine units. For more specific information on our enhancement approach for the:

- Central North Island 110 kV constraints, see Chapter 11
- transmission capacity between Bunnythorpe and Whakamaru, see section 6.3.2.3

- transmission capacity between Stratford and Huntly, see section 6.3.2.3
- transmission capacity in the Wairakei Ring, see section 6.3.2.2
- transmission capacity into the WUNI area, see section 6.3.2.1.

6.4.6.3 System condition 3: HVDC south transfer (winter)

This system condition (SC3) tests the case where there is extremely low generation in the South Island, requiring high HVDC south transfer during periods when winter loads in the North Island are relatively high. This system condition represents a 'dry' period in the South Island together with low North Island wind generation. The specific assumptions for this system condition are:

- load is 80 per cent of North Island winter peak load
- thermal generation in the WUNI area is up to 940 MW including all remaining Huntly Rankine units
- maximum geothermal and hydro generation in the Bay of Plenty, central North Island, and Hawke's Bay regions
- maximum thermal generation in the Taranaki region, including the Taranaki combined cycle unit
- no wind generation in the North Island
- high HVDC south transfer up to voltage stability limits
- generation and load balance is achieved using growth generation at Wairakei and Stratford (see section 6.4.4.3 for details)
- transmission constraints are addressed by trading off South Island generation with North Island generation.

The HVDC control system prevents voltage stability issues by automatically reducing HVDC transfer, if required, following a power system fault. The reduction in HVDC transfer depends on how many circuits, transformers, synchronous condensers and filters are available in the lower North Island. The largest reduction will occur for 220 kV bus faults at Bunnythorpe or Haywards. The reduction in HVDC transfer also limits thermal issues within the North Island grid backbone.

The transmission constraints arising from these assumptions are based on the capacity of the existing grid.

Summary of transmission constraints

Possible transmission constraints include:

- 110 kV regional constraints
- Haywards HVDC power limits
- central North Island area 220 kV constraints
- lower North Island area 220 kV constraints
- Brunswick–Stratford constraints.

The 110 kV and 220 kV circuits in the central and lower North Island areas will overload during the forecast period under this system condition. There are also likely to be low voltages in the central North Island driven by low voltage at the Bunnythorpe 220 kV bus.

Some transmission constraints are managed by the HVDC control system as described above.

SC3: 110 kV regional constraints

From 2020, the 110 kV Bunnythorpe–Woodville circuits may overload following an outage of the 220 kV Haywards–Linton or Bunnythorpe–Linton circuits for HVDC south transfer above about 530 MW.

Low voltages may occur in the central North Island during a Bunnythorpe 220 kV bus outage when there is HVDC south transfer. Waipawa is likely to be the first supply bus to fall below 0.95 pu. Other supply buses with voltages outside the acceptable voltage operating range include Brunswick, Wanganui, Mataroa, and Marton.

SC3: Haywards HVDC power limits

The maximum pre-contingency HVDC south transfer is about:[15]

- 780 MW in 2020, with Wellington load of about 440 MW (assuming no generation injection into the Wellington 110 kV network)
- 725 MW by 2025, with Wellington load of about 490 MW
- 650 MW by 2034, with Wellington load of about 540 MW.

SC3: Central North Island area 220 kV constraints

If the majority of 'growth' generation is connected in the Wairakei area from 2020, the:

- Rangipo–Tangiwai circuit may overload during an outage of a Stratford, Bunnythorpe or Tokaanu 220 kV bus, or an outage of a Bunnythorpe–Tokaanu circuit, for HVDC south transfer above about 240-340 MW
- Bunnythorpe–Tangiwai circuit may overload during an outage of a Stratford, Bunnythorpe or Tokaanu 220 kV bus, or an outage of a Bunnythorpe–Tokaanu circuit, for HVDC south transfer above about 280-365 MW
- Bunnythorpe–Tokaanu circuits may overload during an outage of a Bunnythorpe 220 kV bus, the other Bunnythorpe–Tokaanu circuit, or the Rangipo–Tangiwai circuit, for an HVDC south transfer above about 330-470 MW
- Rangipo–Tangiwai circuit may overload pre-contingency for HVDC south transfer of more than about 485 MW.

By 2025, the:

- Rangipo–Tangiwai circuit may overload during an outage of a Bunnythorpe or Tokaanu 220 kV bus, or an outage of a Bunnythorpe–Tokaanu circuit, for HVDC south transfer above about 180-260 MW
- Bunnythorpe–Tangiwai circuit may overload during an outage of a Tokaanu 220 kV bus or an outage of a Bunnythorpe–Tokaanu circuit, for HVDC south transfer above about 220-300 MW.

By 2034, the:

- Rangipo–Tangiwai circuit may overload during an outage of a Bunnythorpe or Tokaanu 220 kV bus or a Bunnythorpe–Tokaanu circuit, for HVDC south transfer above about 80-150 MW
- Bunnythorpe–Tangiwai circuit may overload during an outage of a Tokaanu 220 kV bus or an outage of a Bunnythorpe–Tokaanu circuit, for HVDC south transfer above about 150-200 MW.

These transmission constraints, which can be managed operationally by increasing or reducing generation in the Taranaki area and the South Island, depend on the amount of generation at Rangipo. If Rangipo generation is reduced and traded off with increased generation:

- north of Rangipo, the HVDC south transfer can be increased by less than 1 MW for every 1 MW reduction at Rangipo
- in the Taranaki area, the HVDC south transfer can be increased by more than 4 MW for every 1 MW reduction at Rangipo.

SC3: Lower North Island area 220 kV constraints

From 2020:

- the Bunnythorpe–Paraparaumu Tee circuits may overload during an outage of a parallel 220 kV circuit, for HVDC south transfer above about 565 MW.

We are currently reconductoring the Bunnythorpe–Paraparaumu–Haywards circuits and this is due for completion by 2020. The above analysis assumed this reconductoring has been completed.

15 These limits are set by HVDC power limits, reactive reserve limits may result in lower values.

There is also a transmission constraint due to dynamic voltage stability for HVDC south transfer. After the Bunnythorpe–Paraparaumu–Haywards circuits are reconductored, the thermal transmission limit due to the capacity of the Bunnythorpe–Paraparaumu–Haywards circuits and the dynamic voltage stability limit are similar.

SC3: Brunswick–Stratford constraints

Transmission capacity out of the Taranaki region during HVDC south transfer is limited by the capacity of the 220 kV Brunswick–Stratford circuits. The maximum achievable transfer is dependent on the amount of 'growth generation' in the Taranaki region.

The maximum HVDC south transfer to prevent a Brunswick–Stratford circuit from overloading for a parallel circuit outage is more significantly influenced by 'growth generation' than by load growth. The maximum possible HVDC transfer :

- varies between 500 and 600 MW with no Taranaki growth generation
- is 100 MW with 350 MW of Taranaki growth generation.

Adding 1 MW of Taranaki growth generation reduces the HVDC south transfer limit by around 2 MW.

As discussed previously, Taranaki generation can be increased to resolve central North Island constraints, but only to the point where the Brunswick–Stratford constraint becomes more critical than the central North Island constraints.

What next?

In the short term, the transmission constraints described above can be addressed by dispatch of additional generation in the lower North Island area or South Island.

We consider that the existing Bunnythorpe–Woodville special protection scheme is sufficient to manage the Bunnythorpe–Woodville issue for the forecast period and have not planned any investments to change this.

In the medium to long term, the central North Island regional low voltage constraints will be alleviated (but not completely removed) when the existing supply transformers are replaced (due to risk-based condition replacement), as the replacement transformers will have on-load tap changers.

We consider that the HVDC controls are sufficient to manage dynamic voltage stability in the lower North Island area for the forecast period, we have not planned any investments to change this.

In the longer term, we may consider transmission upgrades to alleviate or remove the transmission constraints. For more specific information on our enhancement approach for the:

- transmission capacity between Whakamaru and Bunnythorpe, see section 6.3.2.3
- transmission capacity between Stratford and Bunnythorpe, see section 6.3.2.3
- limiting 220 kV Bunnythorpe bus section outage, see Chapter 11.

6.4.6.4 System condition 4: HVDC south transfer (summer)

This system condition (SC4) tests the case with extremely low generation in the South Island requiring high HVDC south transfer close to the time of summer peak load. Similar to system condition 3, it represents a dry period in the South Island with low wind generation in the North Island. The specific assumptions for this system condition are as follows:

- load is 80 per cent of North Island summer peak load
- thermal generation in the WUNI area is up to 940 MW including all remaining Huntly Rankine units
- maximum geothermal and hydro generation in the Bay of Plenty, Central North Island, and Hawke's Bay regions
- low Taranaki generation, with no generation on the Stratford 220 kV bus
- no wind generation in the lower and central North Island
- high HVDC south transfer up to voltage stability limits
- generation and load balance is achieved using Huntly (to the extent it is available), followed by growth generation at Stratford and Wairakei (see section 6.4.4.3 for details).

Summary of transmission constraints

Possible transmission constraints include:

- 110 kV regional constraints
- 220 kV thermal overloads.

Thermal issues arise before HVDC voltage stability runback levels. This means that the most onerous Bunnythorpe and Haywards 220 kV bus outages can occur with relatively high HVDC south transfer.

SC4: 110 kV regional network

The Bunnythorpe–Woodville circuits may cause a transmission constraint during south transfer for an outage of the parallel circuit. This transmission constraint is managed by the existing special protection scheme at Woodville.[16] The Bunnythorpe–Woodville circuits may also cause a transmission constraint for HVDC south transfer exceeding 420 MW (in 2020) for a 220 kV bus outage. This transmission constraint is not addressed by the special protection scheme at Woodville. The issue can be managed if there is generation at Te Apiti and/or by temporarily reconfiguring the grid to split the 110 kV system.

SC4: 220 kV thermal overloads

With increasing HVDC south transfer, the 220 kV circuits reach their thermal capacities in the following order:

- Rangipo–Tangiwai, which may constrain for an outage of a Bunnythorpe–Tokaanu circuit, a Bunnythorpe bus section, or a Haywards bus section, for HVDC south transfer exceeding approximately 130-280 MW
- Bunnythorpe–Tangiwai, which may constrain for an outage of a Bunnythorpe bus section, a Bunnythorpe–Tokaanu circuit, or a Haywards bus section, for HVDC south transfer exceeding approximately 200-370 MW
- Bunnythorpe–Tokaanu, which may constrain for an outage of a Bunnythorpe bus section, a parallel circuit, a Tangiwai bus section, a Bunnythorpe–Tangiwai circuit, or a Haywards bus section, for HVDC south transfer exceeding approximately 270-580 MW
- Bunnythorpe–Paraparaumu–Haywards, which may constrain for a Bunnythorpe bus section outage for HVDC south transfer exceeding approximately 430 MW
- Rangipo–Tangiwai (pre-contingency), which will constrain for pre-contingency HVDC south transfer exceeding 290 MW.

What next?

In the short term, these transmission constraints can be addressed with additional generation dispatched in the lower North Island or South Island.

We consider that the Bunnythorpe–Woodville special protection scheme is sufficient to manage the central North Island 110 kV issue for the forecast period, and we have not planned any other investments.

In the longer term, we may consider transmission upgrades to alleviate or remove the transmission constraints. For more specific information on our enhancement approach for the:

- transmission capacity between Whakamaru and Bunnythorpe, see section 6.3.2.3
- limiting 220 kV Bunnythorpe bus section outage, see Chapter 11.

6.4.6.5 System condition 5: low eastern Bay of Plenty industrial load

This system condition (SC5) tests the effect on the grid backbone of high generation export from Kawerau. It represents a summer peak period where there is low thermal generation in the WUNI area, high generation in the eastern Bay of Plenty, and no industrial load at Kawerau. The specific assumptions for this system condition are:

- North Island summer peak load, with all directly connected industrial load on the Kawerau 110 kV and 220 kV buses turned off

16 The special protection scheme at Woodville detects an outage of a Bunnythorpe–Woodville circuit and if the other circuit is overloaded, it reconfigures the grid by opening the Mangamaire–Woodville circuit at Woodville. If the overload remains, the scheme will also reduce Te Apiti generation. This prevents power from flowing to the Wellington area through the lower capacity 110 kV network.

- Kawerau–T13 is replaced with a new transformer bank identical to the existing Kawerau–T12[17]
- thermal generation in the WUNI area is limited to one combined cycle generating unit at Huntly
- maximum geothermal generation in the Bay of Plenty and central North Island regions
- hydro generation at average summer dispatch levels, with the exception of Matahina and Aniwhenua, which are operating at 100 per cent of capacity
- low Taranaki generation, with no generation on the Stratford 220 kV bus
- maximum wind generation in the lower and central North Island
- generation and load balance is achieved using HVDC north transfer.

Summary of transmission constraints

Possible transmission constraints include:

- 110 kV regional constraints
- 220 kV Bay of Plenty network
- Atiamuri–Ohakuri constraints
- other transmission constraints.

The 110 kV network between Kawerau and Owhata may overload for parallel 220 kV circuit outages. Special protection schemes exist to address these overloads, though their operation may cause the Atiamuri–Ohakuri circuit to exceed its summer rating.

SC5: 110 kV regional network

A number of contingencies will result in 110 kV circuit thermal overloads (see Chapter 10 for more information). A number of special protection schemes will operate to remove overloaded 110 kV circuits: the special protection scheme on the Edgecumbe–Owhata circuit[18] is most relevant to the grid backbone.

SC5: 220 kV Bay of Plenty network

The 220 kV Bay of Plenty circuits that may overload are the:

- Edgecumbe–Kawerau 3 or Kawerau–Ohakuri circuit, which may overload for an outage of the other circuit, for Kawerau generation of more than 250 MW, particularly if the special protection scheme on the 110 kV Edgecumbe–Owhata circuit operates
- Edgecumbe–Kawerau 3 circuit, which may also overload for an Atiamuri–Ohakuri circuit outage, for Kawerau generation of more than 265 MW.

See Chapter 10 for more information about these transmission constraints.

SC5: Atiamuri–Ohakuri constraints

The Atiamuri–Ohakuri circuit may overload for:

- an Edgecumbe–Kawerau 3 circuit outage followed by operation of the Edgecumbe–Owhata special protection scheme, for Kawerau generation of more than 240 MW in 2020, 180 MW in 2025, and 170 MW in 2034
- an Edgecumbe 220 kV bus outage followed by operation of the Edgecumbe–Owhata special protection scheme, for Kawerau generation of more than 280 MW in 2020, 220 MW in 2025 and 210 MW in 2033
- a Kawerau 220 kV bus outage followed by operation of the Edgecumbe–Owhata special protection scheme, for Kawerau generation of more than 240 MW in 2020, 180 MW in 2025, and 170 MW in 2034.

SC5: Other transmission constraints

The following transmission constraints are not specifically caused by high generation export and no industrial load at Kawerau but do eventuate under system condition 5. The transmission

17 An alternative to this development is to enable the existing Kawerau–T13 Overload Protection Scheme, which reduces Kawerau 110 kV generation if Kawerau–T13 overloads and Kawerau–T12 is out of service. However, this system condition is intended to highlight constraints on the grid backbone, which the special protection scheme does not illustrate.

18 The Edgecumbe–Owhata special protection scheme detects an overload on the Edgecumbe–Owhata 2 circuit, and then reconfigures the grid by opening the Edgecumbe–Owhata 2 circuit.

constraints occur later in the forecast period, as HVDC transfer requirements increase. These are the same transmission constraints identified in system condition 1 and 2, in particular:

- The 110 kV Bunnythorpe–Mataroa circuit may overload during some central North Island 220 kV outages (this will be managed with the special protection scheme that opens the Mataroa–Ohakune circuit if the Bunnythorpe–Mataroa circuit overloads). Pre-contingent overloads may also occur later in the forecast period. This can be most effectively managed by limiting HVDC transfer north.
- The 110 kV Otahuhu–Wiri Tee circuits may exceed their minimum summer variable line rating[19] for an outage of the other Bombay–Wiri–Otahuhu circuit, or for a Hamilton 220 kV bus section outage.
- A Tokaanu–Whakamaru circuit may overload for an outage of the other Tokaanu–Whakamaru circuit. This will be managed with the existing special protection scheme at Tokaanu.[20]

What next?

In the short term, these transmission constraints can be managed operationally by limiting generation on the Kawerau 110 kV bus during low industrial load periods.

In the longer term, we may consider transmission upgrades to alleviate or remove the transmission constraints. For more specific information on our proposed approach for:

- increasing the 220 kV capacity out of Kawerau, see Chapter 10
- increasing the capacity in the Wairakei Ring, see section 6.3.2.2.

6.4.6.6 System condition 6: light load

This system condition (SC6) tests the effect of low load on the grid backbone. It represents a realistic summer night light load period and is designed to highlight high voltage issues. The specific assumptions for this system condition are:

- North Island trough summer night load
- thermal generation in the WUNI area is limited to one combined cycle generating unit at Huntly
- maximum geothermal generation in the Bay of Plenty, central North Island and Hawke's Bay regions
- low hydro generation, with many stations having only one unit in service, the exceptions being Arapuni, Maraetai, Rangipo, and Tokaanu
- no Taranaki area generation
- low wind generation in the Wellington region and no wind generation in the Central North Island region
- low HVDC north transfer of 140 MW representing low levels of South Island hydro generation.
- generation and load balance is achieved by altering Whakamaru generation.

Summary of transmission constraints

Possible transmission constraints include:

- WUNI area high voltages
- Te Kowhai and Taumarunui high voltage
- lower North Island area high voltages.

19 Variable line rating has a different line rating for every two-hour period. If an outage coincides with the minimum two-hour rating and peak summer load, the circuit may overload.

20 Assuming the special protection scheme at Tokaanu is in service reduces the reliance on generation in the WUNI area. However, because of high minimum generation requirements at Arapuni, a high level of generation at Karapiro is also assumed to balance water flow between power stations.

The main concern during light load periods is high post-contingency voltages. These are dependent on load, power factor and voltage profile across the North Island. The voltage profile can be maintained at around 1.0 pu at most generating stations. However, this requires generation and North Island dynamic reactive plant to absorb a high level of reactive power pre-contingency, limiting the available response to a post-contingency event.

SC6: Upper North Island area high voltages

Keeping the WUNI area voltages within acceptable limits with all circuits in service requires high levels of reactive power absorption from available units at Huntly and dynamic reactive plant in the region at Penrose, Albany and Marsden. If this reactive power absorption is not available or is insufficient, circuits such as Pakuranga–Whakamaru 1 and/or 2 are removed from service to maintain voltages.

SC6: Te Kowhai and Taumarunui high voltage

If a 220 kV Huntly–Te Kowhai circuit outage occurs at light load periods, the Te Kowhai and Taumarunui 220 kV bus voltages can exceed 1.10 pu. This is more likely to occur when generation is unavailable in the Taranaki region as there are no means to absorb the excess reactive power. The extent of the high voltages at Te Kowhai and Taumarunui also depends on the response from the two generating stations embedded at Te Kowhai (Te Rapa and Te Uku).

SC6: Lower North Island high voltages

Keeping the lower North Island area voltages within acceptable limits with all circuits in service requires high levels of reactive power absorption from the Haywards synchronous condensers at light load times. HVDC transfer may also be limited for harmonic performance if the number of filters must be reduced to prevent high voltages.

What next?

At present, the high voltages are managed via operational measures including removing circuits from service, (particularly in the WUNI area), and in more severe cases by constraining on bringing on generators in the region.

In the short-term, we consider the operational measures we have identified are sufficient to manage the high voltage issue in Taumarunui, Te Kowhai, and the lower North Island area.

In the medium-term, our proposed investments to resolve voltage stability issues in the WUNI area, as discussed in section 6.3.2.4, will also assist in resolving overnight high voltage issues. The investments are expected to reduce, but not remove, the need to switch out circuits.

In the longer-term, we expect the high voltage issue to worsen. A variety of factors exacerbate the high voltage issue including the use of long transmission cables (particularly in the Auckland region), an increasing amount of distribution network being converted to underground cables, and load characteristics becoming generally more capacitive. We will continue to monitor the high voltage issue and investigate further options as the need arises.

6.5 South Island grid backbone

The South Island grid backbone comprises the following 220 kV circuits:

- three from Islington to Kikiwa
- four from Twizel and Livingstone to Islington
- nine between Twizel and Livingstone, which connect six large Waitaki Valley hydro generation stations and the HVDC link
- three from Roxburgh to Twizel and Livingstone
- four from Roxburgh to Invercargill and North Makarewa (two of which run via Three Mile Hill)
- nine connecting Manapouri and Tiwai to Invercargill and North Makarewa.

The existing South Island grid backbone is set out geographically in Figure 6-5 and schematically in Figure 6-6.

The South Island grid backbone is connected to the North Island via the inter-island HVDC link. This allows power to be exchanged between the two islands. Typically, the net annual power flow is northwards; this is particular frequent during North Island peak demand periods. However, during light load periods, power may flow southward, conserving South Island hydro storage, especially during periods of low hydro inflows in the South Island.

To help describe transmission system issues and opportunities on the grid backbone we split the South Island transmission system into three major areas:

- Clutha Upper Waitaki Valley area, which encompasses the transmission system between the Clutha area (Clyde and Roxburgh) and the Waitaki Valley area (Twizel and Livingstone)
- Upper South Island area, which encompasses everything north of the Clutha Upper Waitaki Valley area
- Lower South Island area, which encompasses everything south of the Clutha Upper Waitaki Valley area. Within the Lower South Island area, we also refer to the area south of Invercargill and North Makarewa as the Southland area.

Figure 6-5: South Island grid backbone map

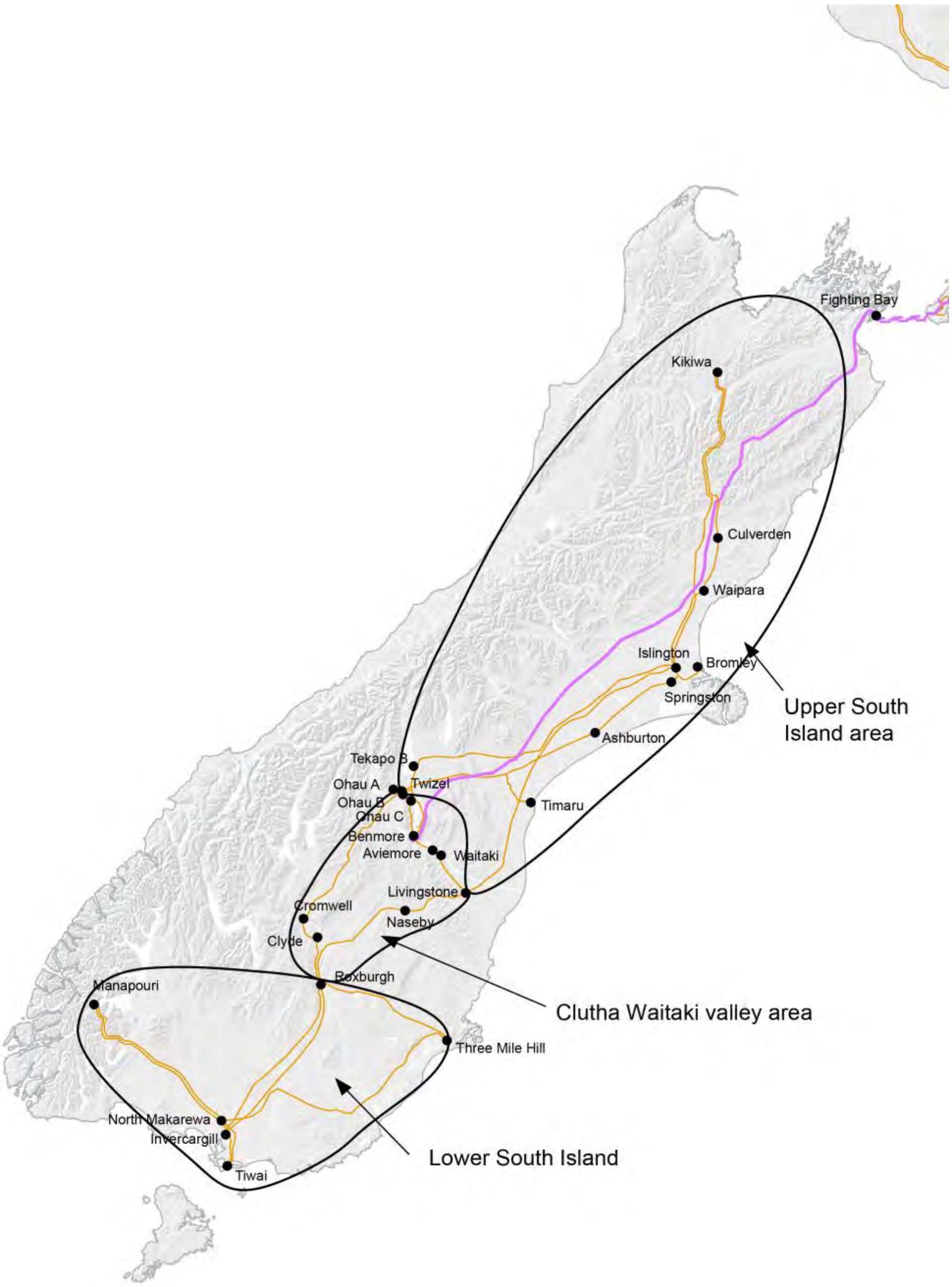
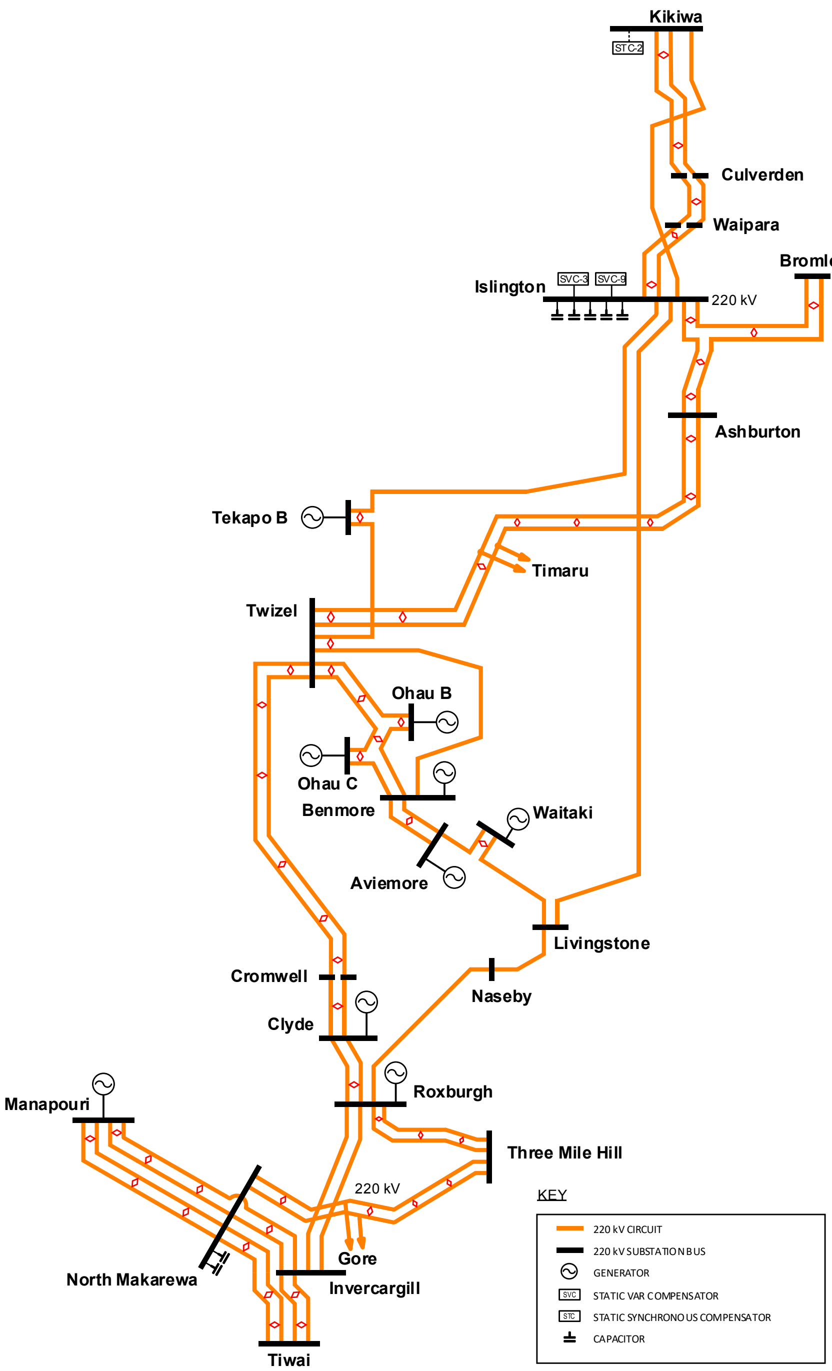


Figure 6-6: South Island grid backbone schematic

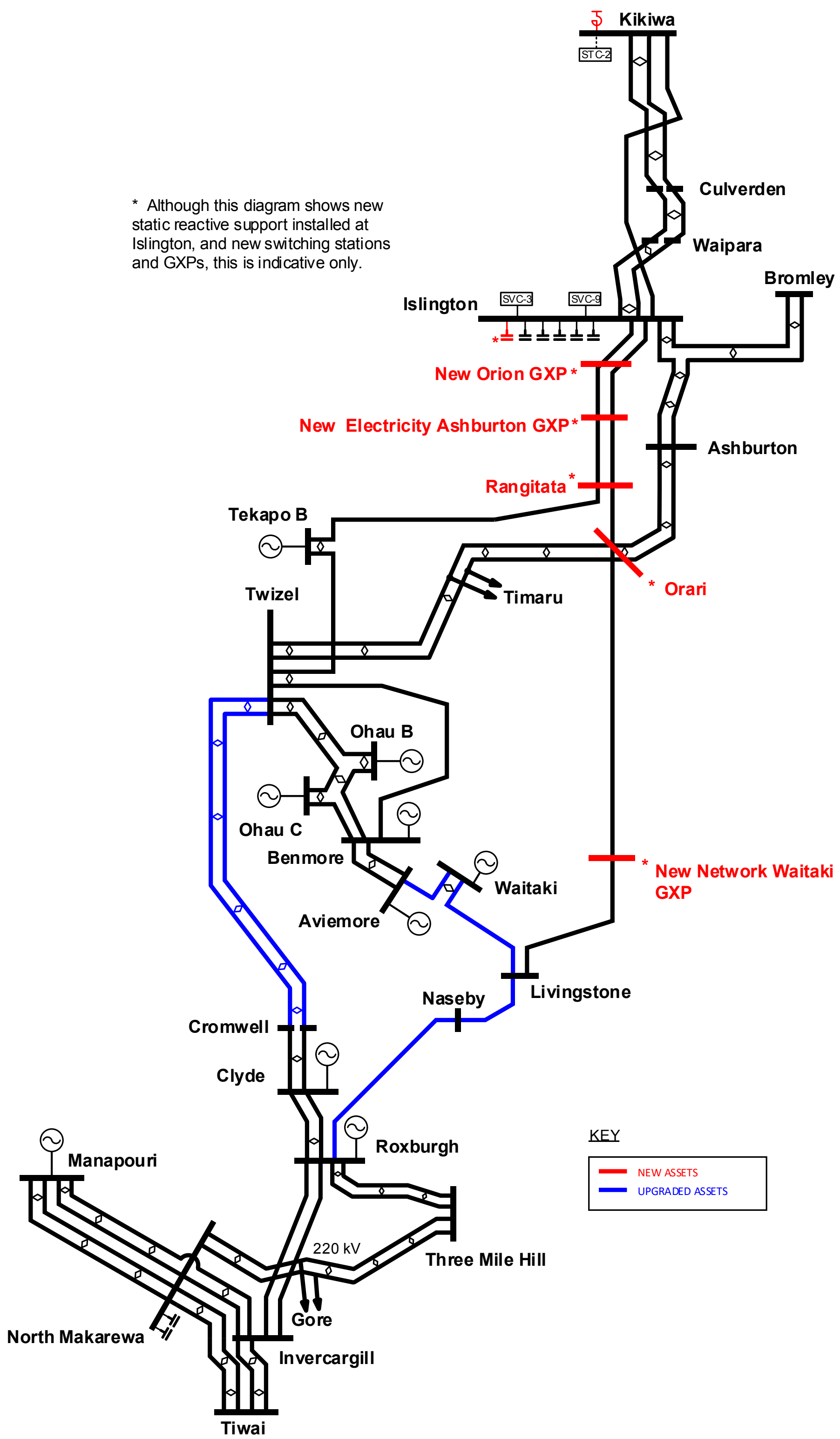


6.6 South Island grid enhancement approach

6.6.1 Possible South Island grid backbone to 2034

Figure 6-7 provides an indication of possible South Island transmission backbone development in the medium term (the next 15 years). New assets and upgraded assets (based on potential enhancement approaches set out in the following sections) are shown.

Figure 6-7: Possible South Island grid backbone schematic in 2034



6.6.2 Enhancement approach

This section provides information about the transmission constraints we will investigate or mitigate over the next few years.

Transmission issues likely requiring E&D base capex or Major Capex Project (MCP) funded investment in the South Island grid backbone over the next 10-15 years include:

Section number	Issue
6.6.2.1	Upper South Island transmission capacity
6.6.2.2	Otago-Southland and Waitaki Valley transmission capacity
6.6.2.3	Upper South Island high voltage during light load

6.6.2.1 Upper South Island transmission capacity

The Upper South Island is a major load centre (dominated by Christchurch load) with very little local generation. Almost all load in this part of the South Island is supplied from the Waitaki Valley, making it heavily reliant on the transmission system. This reliance on imported power from the Waitaki Valley makes it essential that we:

- maintain sufficient voltage support equipment and ensure voltage stability limits are not exceeded
- ensure there is sufficient thermal capacity.

Upper South Island voltage support

There are few synchronous generators in the upper South Island, so we have an extensive fleet of reactive support equipment in the area to maintain voltage stability and quality. As demand in this part of the South Island grows, we need to ensure that there continues to be sufficient voltage support equipment in the area.

We studied the upper South Island voltage stability issue extensively and have an investment programme over the next 10-15 years to address the forecast issues. Our preferred options for the next investment phases are:

- sectionalising the 220 kV circuits from the Waitaki Valley to Islington by bussing them at new switching stations at Orari and Rangitata
- installing additional reactive support equipment, towards the end of the forecast period.

The Commerce Commission approved the enabling works for the Orari and Rangitata switching stations. Enabling work consists of developing the detailed design for the works and procuring the necessary designations, easements, and property. This work is currently underway.

Due to changing land use in the region and the use of central pivot irrigation, we consider it is economically prudent to secure the necessary property rights for the switching stations now. This will ensure the option of building new switching stations is feasible in the future and reduce lead times for delivery of the project when it is needed. Once the enabling work is completed, the timing of the build phase will be confirmed. The build phase will require separate approval from the Commerce Commission as a Major Capex Project.

Enhancement approach:

- We are currently reviewing the need date for the Orari and Rangitata switching stations build phase due to changes in forecast demand. Once the need date is determined we will:
  - determine the need and timing of Islington SVC3 refurbishment (to be funded under base capex replacement and refurbishment). See section 6.7.4 for further discussion
  - schedule the build phase for Orari and Rangitata and submit a Major Capex Project proposal to the Commerce Commission for approval.
- upper South Island voltage stability will be an ongoing issue due to the lack of synchronous generation in the area. We will monitor the need for additional reactive support as load in the area continues to grow.

Major Capex investment

Project Name	Upper South Island voltage stability
Project description:	Build Orari and Rangitata switching stations, bussing 220 kV circuits from the Waitaki Valley
Project's state of completion	Possible
OAA level completed:	AL 4p
Grid need date:	2027
Indicative cost [$ million]:	$72
Part of the GEIR?	No

Waitaki Valley to Christchurch transmission capacity

In addition to the voltage constraints, the upper South Island load is also forecast to exceed the thermal n-1 summer transmission capacity between the Waitaki Valley and Islington from 2028. The thermal capacity is limited by a Timaru–Twizel circuit section overloading for an outage of the other Ashburton–Timaru–Twizel circuit.

Enhancement approach:

- The Orari and Rangitata investment to resolve the voltage stability issue will also increase thermal transmission capacity into Christchurch.
- We will investigate longer-term options to increase the n-1 thermal transmission capacity closer to the need date, likely to be beyond the forecast period (see section 6.6.3).

6.6.2.2 Otago-Southland and Waitaki Valley transmission capacity

A significant portion of the South Island's generation is in the Otago-Southland region. The region is connected to the Waitaki Valley by three 220 kV circuits (Clyde–Cromwell–Twizel 1 and 2 and Livingstone–Naseby–Roxburgh 1).

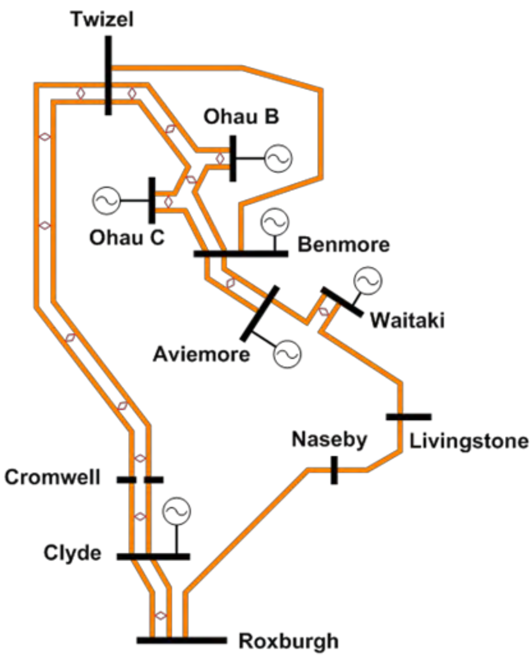
Much of the region's substantial hydro generation is consumed locally by the Tiwai Point aluminium smelter which operates year round. Other major load centres include Dunedin and Invercargill.

The combination of hydro generation and a very large continuous load in the region means the need for transmission into, and out of, the region is very susceptible to local hydrology. During 'dry' hydro conditions the transmission system is constrained by the need to import power from the Waitaki Valley (including HVDC south transfers) while in 'wet' hydro conditions it is constrained by the need to export power to the Waitaki Valley (including HVDC north transfers).

- The Clutha-Upper Waitaki Lines Project (CUWLP) is an approved suite of projects to increase transmission capacity between the Clutha area and the Waitaki Valley. The first tranche of CUWLP has been completed. The second tranche of CUWLP, which is yet to commence, involves:
- thermally upgrading the Cromwell–Twizel circuit sections
- duplexing the Livingstone–Naseby–Roxburgh circuits
- duplexing the Aviemore–Benmore 1 and 2 circuits.

Figure 6-8 shows the circuits between Roxburgh and Twizel following completion of both tranches of CUWLP.

Figure 6-8: 220 kV circuits between Roxburgh and Twizel after CUWLP upgrade



Circuit	Summer/Winter rating
Aviemore–Benmore–1 and 2	609/671 MVA[1]
Aviemore–Waitaki–1	609/671 MVA
Livingstone–Waitaki–1	609/671 MVA
Livingstone–Naseby–1	609/671 MVA[1]
Naseby–Roxburgh–1	609/671 MVA[1]
Clyde–Cromwell–Twizel–1 and 2	561/617 MVA[1]
Clyde–Roxburgh–1 and 2	709/781 MVA
Benmore–Twizel–1	404/493 MVA
Benmore–Ohau B–1	558/614 MVA
Ohau B–Twizel–3	694/764 MVA
Benmore–Ohau C–2	558/614 MVA
Ohau C–Twizel–4	694/764 MVA

[1] The timing to upgrade these circuits will periodically be reviewed. The summer/winter rating for these circuits prior to upgrade is:

- 202/246 MVA for Aviemore–Benmore–1 and 2, Roxburgh–Naseby–Livingstone–1, and
- 385/470 MVA for Cromwell–Twizel–1 and 2.

The primary justification for the second tranche work is to increase transmission capacity for power flow from the Otago-Southland region to the Waitaki Valley. This will be required if there is a significant increase in generation or reduction in load in the region. The second tranche of the CUWLP will also substantially increase transmission capacity for southward power flow from the Waitaki Valley to Otago-Southland, for periods of low generation in the Otago-Southland region.

We periodically review the need to implement the second tranche of CUWLP. We do not currently consider there is sufficient certainty regarding new generation or load reductions in the Otago-Southland region to justify proceeding with the work.

The Roxburgh Export Overload Protection Scheme (REOLPS) provided a small increase in generation export capacity from the Otago-Southland region. The scheme is designed to reconfigure the grid post-contingency in two stages, first by splitting the Roxburgh 220 kV bus and if necessary, opening a Roxburgh-Three Mile Hill circuit to eliminate loop flow.

Enhancement approach:

To enable us to optimise the timing for the second tranche of CUWLP in response to changes in market conditions we have:

- Completed the detailed design for the Livingstone–Naseby–Roxburghduplexing and Cromwell–Twizel thermal upgrade. We will review our decision about whether to proceed with these upgrades as new information becomes available.
- We also identified some lower-cost investments that incrementally increase the transmission capacity between the lower South Island and the Waitaki Valley. We will investigate if it is justifiable to implement some or all of these lower cost incremental upgrades which include:
  - installing a Naseby–Roxburgh series reactor, coupled with the Cromwell–Twizel thermal upgrade, or
  - implementing changes to special protection schemes, and;
  - installing a special protection scheme on the Aviemore–Benmore circuits.

Base E&D Capex investments

Project Name	Benmore–Roxburgh transmission capacity
Project description:	Naseby–Roxburgh series reactor and Cromwell–Twizel thermal upgrade[21]
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2020
Indicative cost [$ million]:	10
Part of the GEIR?	Yes

Project Name	Aviemore–Benmore circuit special protection scheme
Project description:	Install Aviemore–Benmore circuit overload protection scheme[22]
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2020
Indicative cost [$ million]:	0.5
Part of the GEIR?	Yes

Major Capex investments

Project Name	Clutha Upper Waitaki Lines Project (second tranche)
Project description:	Cromwell–Twizel thermal upgrade, Roxburgh–Naseby–Livingstone duplexing, and Aviemore–Benmore special protection scheme.
Project's state of completion	Possible
OAA level completed:	AL 4p
Grid need date:	Uncertain, Otago-Southland generation or load dependent
Indicative cost [$ million]:	$93.5 ($20m for Cromwell–Twizel transmission thermal upgrade, $73m for Roxburgh–Naseby–Livingstone duplexing, $0.5m for Aviemore–Benmore special protection scheme)
Part of the GEIR?	Yes

6.6.2.3 Upper South Island high voltage during light load

The load in the upper South Island is not dominated by heavy industrial loads, making it highly changeable throughout the day, with very low loads overnight, especially in summer. There are long transmission lines into the area and little generation. The long transmission lines produce significant amounts of reactive power during light load periods (increasing the voltage) and there is little generation to absorb reactive power (to reduce the voltage).

We currently resolve the high voltage issue in the upper South Island by switching off the 220 kV Islington–Kikiwa 1 circuit and, on occasion, the Islington–Livingstone 1 circuit overnight when load in the area is low. This operational measure significantly reduces the amount of reactive power produced without compromising security of supply (n-1 security) to our customers.

There are no other circuits in the region that can be switched off during light load without compromising security of supply. On some light load occasions, especially when the HVDC is operating in round-power mode (where filter banks need to be in service), we have needed to bring on generation units at Benmore to absorb the excess reactive power from the grid. It is becoming increasingly difficult to manage high voltages using operational measures and we are now nearing the end of operational options.

21 Note that this thermal upgrade may be undertaken as an incremental measure, or alternately included in the Clutha Upper Waitaki Lines Project (Stage 2)

22 Note that this special protection scheme may be implemented as an incremental measure, or alternately included in the Clutha Upper Waitaki Lines Project (Stage 2)

The most economic investment to resolve the voltage stability issue in the upper South Island is to reduce the impact of an outage (by sectionalising transmission lines), rather than installing more dynamic reactive support equipment as discussed in Section 6.6.2.1. Therefore are no synergies between the investment to control high voltages during light load and investments to maintain voltage stability during peak load in the upper South Island.

Enhancement approach:

- We investigated a range of investment options to increase the capability of the grid to absorb excess reactive power during light load periods, to prevent grid over voltages. We have a project underway to install a new shunt reactor at Kikiwa on the 110 kV bus.

Base E&D Capex investments

Project Name	Upper South Island high voltage
Project description:	Install a 50 Mvar shunt reactor at Kikiwa
Project's state of completion	Approved
OAA level completed:	AL 3d
Grid need date:	November 2019 (expected)
Indicative cost [$ million]:	4.3
Part of the GEIR?	No

6.6.3 South Island grid backbone beyond the planning horizon (2034)

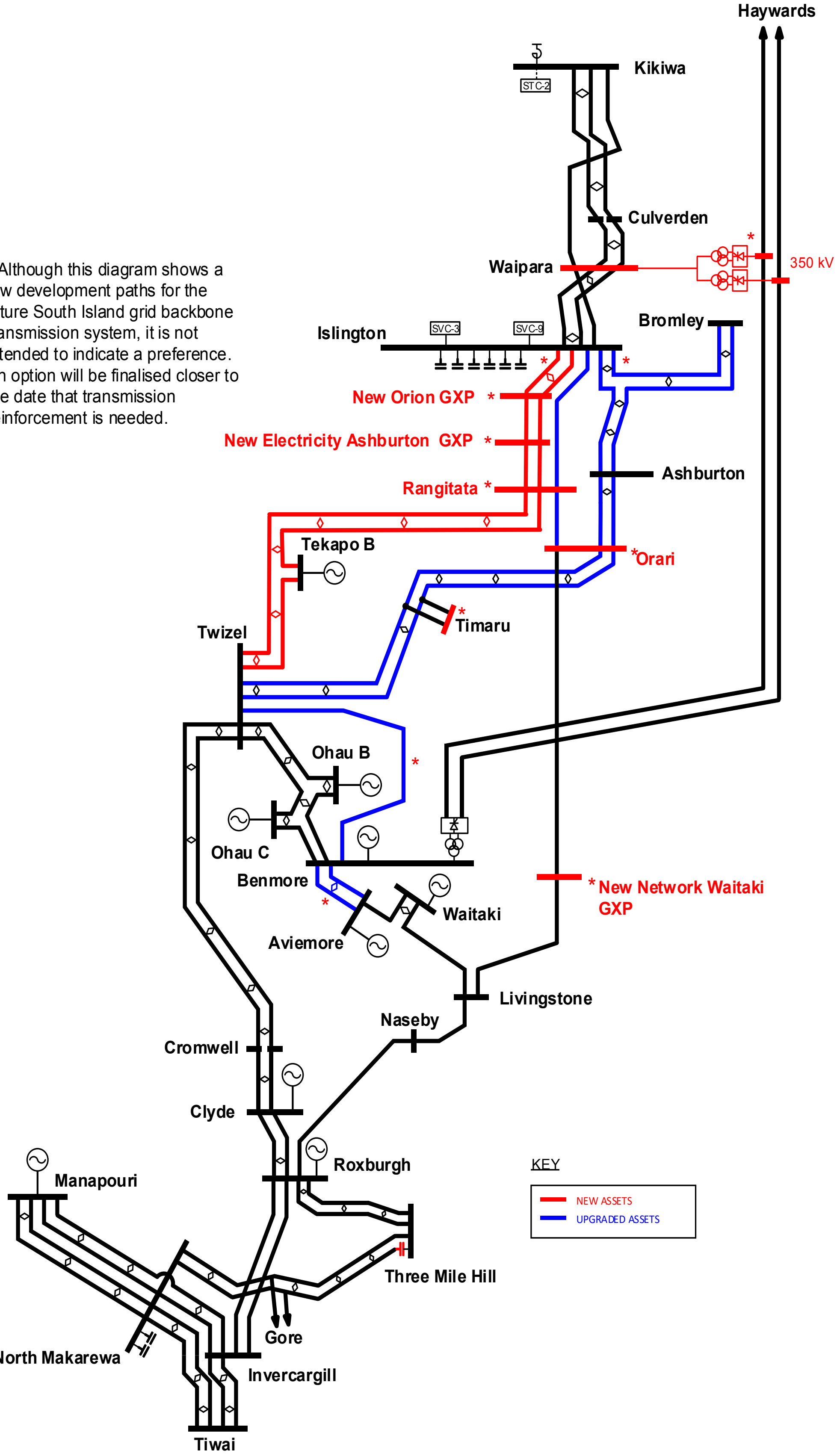
Figure 6-9 provides an indication of the possible South Island transmission backbone development in the longer-term (beyond 2034).

Additional transmission capacity upgrades into Christchurch will likely be required just beyond the end of the forecast period. This can be achieved by one or more of the following options:

- reconductoring existing 220 kV lines into Christchurch
- an HVDC tap-off from the existing HVDC line north of Christchurch
- a new transmission line to Islington (which can be built in stages) terminating at Orari (if built) or Ashburton.

The preferred option will be determined closer to the need date.

Figure 6-9: Longer-term indicative South Island grid backbone schematic (beyond 2034)



* Although this diagram shows a few development paths for the future South Island grid backbone transmission system, it is not intended to indicate a preference. An option will be finalised closer to the date that transmission reinforcement is needed.

6.7 South Island asset capability and management

We have assessed transmission capacity and reactive support requirements on the South Island grid backbone for a range of system conditions over the next 15 years. When an issue or opportunity is likely to arise, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 6.6) have been developed to address issues or opportunities that require action within the forecast period and where investment is a valid option.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk based replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process)

6.7.1 Changes since the 2018 Transmission Planning Report

Changes since the 2018 TPR include:

- installation of two 220/110 kV interconnecting transformers at Gore
- Ashburton–Timaru–Twizel thermal constraint no longer observed due to lower demand forecast.

6.7.2 Committed Projects

There are no committed projects that may not be completed at the time of publication, but which are included in the analysis modelling. However, the analysis assumes Islington–SVC3 remains reliably available and will be refurbished.

6.7.3 Line conductor replacements

No line conductor replacements are expected in the South Island backbone circuits during the forecast period, based upon risk-based condition assessment.

6.7.4 South Island grid backbone asset feedback

The Asset Feedback Register includes the following entries related to E&D that are specific to the South Island grid backbone:

- To review the economic justification for Islington–SVC3.

6.7.4.1 Review the need for Islington–SVC3

Issue

Islington–SVC3's electronic components are nearing end-of-life. However, our operations team is heavily reliant on SVC3 to maintain voltages during both peak and light load periods.

In addition, SVCs take a long time to repair for some fault types. For example, SVC9 was recently forced out of service for an extended period due to component failure, and SVC3 provided some redundancy.

What next?

We are investigating voltage stability in the upper South Island during peak loads. This investigation will take into consideration the future need for Islington–SVC3. See section 6.6.2.1 for our enhancement approach.

We are also considering the economics of providing n-1 capacity while an SVC is out of service.

6.7.5 Methodology

6.7.5.1 System conditions

A small number of realistic but challenging system conditions are used to assess the capability of the existing South Island grid backbone. They provide snapshots to identify transmission constraints that may require minimum or maximum limits to be applied to generation and/or load to avoid overloading the power system following an outage. From these system conditions, we can identify transmission upgrades that may be justified to alleviate the constraints, allowing lower minimum and higher maximum limits for generation and load.

6.7.5.2 Limits in the electricity market

Transmission constraints identified by the system conditions do not always cause minimum or maximum generation limits in the wholesale electricity market. The System Operator's management of a transmission constraint depends on the type of outage that causes it:

- Circuit outages are managed as contingent events requiring pre-contingent management (for example, by using market security constraints to apply a maximum generation limit, or by pre-contingent load management).
- Other outages (for example, bus-sections) may be managed using pre-contingent or post-contingent actions, depending on the extent and magnitude of the system impact resulting from the outage.

6.7.6 Overview of results

Key findings for the South Island grid backbone include:

- Transmission capacity to the upper South Island is first limited by a voltage stability constraint, and later by thermal constraints on the Ashburton–Timaru–Twizel circuits.
- Transmission of generation from the lower South Island area to the Waitaki Valley is first limited by the capacity of the Livingstone–Naseby–Roxburgh circuit, and later by the thermal capacity of the Cromwell–Twizel sections of the Clyde–Cromwell–Twizel circuits.
- The limit on transmission from the Waitaki Valley to the lower South Island area depends on the generation source. With high Waitaki Valley generation, the Livingstone–Naseby–Roxburgh circuit sets the transmission capacity limit. With high HVDC south transfers, the Aviemore–Benmore circuits set the limit, followed by the Benmore–Twizel circuit.
- Transmission out of the Waitaki Valley will then be limited by Benmore–Twizel circuit capacity. Transmission capacity into the Southland area will be limited by voltage stability in the area and later, by the thermal capacity of the Invercargill–Roxburgh circuits.
- During light load periods, the high voltage issue in the upper South Island area is becoming increasingly difficult to manage. The installation of a 50 Mvar reactor at Kikiwa will provide some relief. However, further measures may be needed if the high voltage issue persists.

6.7.7 South Island grid backbone capability and constraints

System conditions are load and generation patterns we use to highlight transmission issues we can reasonably expect to occur, given currently available information and trends. The analysis under each of the system conditions provides a snapshot of the capability of the South Island grid backbone to transfer energy from generators to the loads while maintaining a secure grid. The four system conditions we anticipate we could reasonably encounter in the South Island are:

- low upper South Island generation (see section 6.7.7.1)
- high lower South Island generation (see section 6.7.7.2)
- low lower South Island generation (see section 6.7.7.3)
- light load (see section 6.7.7.4).

6.7.7.1 System condition 1: low upper South Island generation

This system condition (SC1) examines the effect of extremely low generation in the upper South Island area during a forecast prudent South Island regional summer peak load period. It is designed to highlight transmission issues into the upper South Island from the Waitaki Valley area. Although the upper South Island has relatively little generation compared with its load, generation still has a noticeable effect on transmission constraints. The specific assumptions for this system condition are:

- South Island regional prudent peak load
- low generation in the upper South Island
- high generation in the Clutha, Upper Waitaki Valley and lower South Island areas
- generation and load balance is achieved using the HVDC.

The transmission constraints arising from these assumptions are based on existing grid capacity.

Summary of transmission constraints

There is insufficient transmission capacity to supply upper South Island loads within the forecast period under this system condition. The transmission capacity is constrained by voltage stability from 2027 and by transmission thermal capacity from 2028.

SC1: voltage stability constraints

Voltage stability within the upper South Island area is influenced by:

- reactive power losses
- reactive power demand due to load composition (in particular the proportion and type of motor load)
- generation level in the upper South Island.

Reactive support for the upper South Island is provided by:

- two SVCs[23] at Islington
- a STATCOM at Kikiwa
- grid backbone capacitor banks at Islington
- regional grid capacitor banks at Islington, Bromley, Southbrook, Blenheim, Stoke, Greymouth and Hokitika
- regional and embedded generation in the upper South Island
- Waitaki valley generation.

Previous voltage stability studies identified a need date of winter 2022. We revisited the voltage stability studies using updated forecasts and the need date has moved out to summer 2027. The outages that may cause a voltage stability constraint at peak load periods are:

- Ashburton–Timaru–Twizel circuit, from summer 2027
- Islington bus section A,[24] from winter 2028.

Any new generation or demand-side load management within the upper South Island will improve voltage stability. Depending on the amount, this may defer or replace the need for transmission investment.

SC1: transmission thermal constraints

An outage of an Ashburton–Timaru–Twizel circuit will cause the Timaru–Twizel section of the other Ashburton–Timaru–Twizel circuit to overload from summer 2028 (with prudent South Island regional summer peak load).

What next?

The upper South Island voltage stability issue has been extensively studied and we have an investment programme over the next 10-15 years to address the forecast issues. Refer to section 6.6.2.1 for our enhancement approach.

23 Islington SVC3 is due for major refurbishment.

24 An Islington bus section A outage disconnects the Islington–Tekapo B circuit and Islington–T7 (220/66 kV) transformer.

6.7.7.2 System condition 2: high lower South Island generation

This system condition (SC2) tests the case where there is either significant new generation developed or a significant reduction in load in the lower South Island area (south of Roxburgh). It represents a South Island peak load period with very high generation in the lower South Island and is designed to highlight issues with northward transmission through the Clutha to the Waitaki Valley area. The excess power not consumed within the South Island is assumed to be exported to the North Island via the HVDC link. The specific assumptions for this system condition are:

- forecast 2020 South Island peak summer load for summer transmission constraints and forecast 2020 South Island peak winter load for winter transmission constraints
- high generation from the Clutha hydro system and moderate generation from the Waitaki, Ohau, and Tekapo hydro systems
- high HVDC north transfer of up to 1,200 MW
- generation and load balance is achieved by trading off generation south of Roxburgh with generation in the North Island.

Summary of transmission constraints

Possible transmission constraints include:

- Livingstone–Naseby–Roxburgh constraint
- Clyde–Cromwell–Twizel constraint.

The identified constraints are highly sensitive to the generation assumptions, especially at Clyde and Roxburgh.[25] Generation constraints in the lower South Island do not occur frequently with current load and generation levels, but will become frequent if:

- a significant reduction in load occurs
- a significant amount of new generation is developed in the area to supply future demand growth or replace retiring stations in the North Island.

SC2: Livingstone–Naseby–Roxburgh transmission constraint

In most normal operating scenarios, the capacity of the Livingstone–Naseby–Roxburgh circuit constrains the maximum generation export from the lower South Island.

The Livingstone–Naseby–Roxburgh circuit operates in parallel with two higher-capacity Clyde–Cromwell–Twizel circuits, and will overload for a Clyde–Cromwell–Twizel circuit outage if northward transfer from the lower South Island exceeds approximately 625 MW in summer and 795 MW in winter[26] (with both stages of the Roxburgh Export Overload Protection scheme operating).

SC2: Clyde–Cromwell–Twizel transmission constraint

The Clyde–Cromwell–Twizel circuits are usually next to constrain the maximum generation export from the lower South Island, the limiting factor being the Cromwell–Twizel sections, which have a lower capacity than the Clyde–Cromwell sections.

The Cromwell–Twizel section will overload for an outage on the other Clyde–Cromwell–Twizel circuit if generation export from the lower South Island exceeds approximately 700 MW in summer and 855 MW in winter (with both stages of the Roxburgh Export Overload Protection scheme operating).

What next?

These transmission constraints are presently managed operationally by limiting the maximum generation in the Southland area.

Refer to section 6.6.2.2 for our enhancement approach, including the second tranche of CUWLP.

25 The generation at Roxburgh has the biggest effect on export limits from the lower South Island as the Roxburgh Export Overload Protection Scheme effectively splits the generating station into two, with one side connected to the Clyde–Roxburgh circuits and the other side connected to the Naseby–Roxburgh circuits. The export limit will decrease if more Roxburgh generation is connected to the same side as the Naseby–Roxburgh circuits.

26 These limits are the pre-contingency power flows measured across the Naseby–Roxburgh circuit and Clyde–Cromwell sections so they include generation from Clyde and Roxburgh.

6.7.7.3 System Condition 3: low lower South Island generation (summer)

This system condition (SC3) tests the impact of low generation in the lower South Island (south of Clyde). It represents a South Island summer peak load period with low lower South Island area generation and is designed to highlight the transmission issues into the Southland area from both the Waitaki Valley and Roxburgh. The power required to meet load comes from either generation in the Waitaki Valley or in the North Island (via HVDC southward flow). The specific assumptions for this system condition are:

- South Island 2020 summer forecast peak load
- low generation at Clyde and Roxburgh
- high HVDC southward flow
- generation and load balance is achieved by trading off generation south of Clyde with generation in the North Island or Waitaki Valley.

Summary of transmission constraints

The transmission constraints differ depending on if the balance of generation is supplied from:

- high Waitaki Valley generation
- high HVDC southward flow, or
- high Clutha generation.

With the present levels of load and generation in the lower South Island, transmission constraints for power flow into the region do not occur frequently. However, transmission constraints into the lower South Island could occur frequently if there is a significant increase in load or reduction in generation in the area.

SC3: low generation south of Clyde

With relatively high Waitaki Valley generation, low generation south of Clyde, and either northward or low southward HVDC transfer:

- the Livingstone–Naseby–Roxburgh circuit will overload for a Clyde–Cromwell–Twizel outage if lower South Island import[27] exceeds approximately 460 MW
- the Aviemore–Benmore circuit will overload for an outage on the other Aviemore–Benmore circuit if lower South Island import exceeds approximately 725 MW.

SC3: low South Island generation

With low generation across the South Island and very high levels (up to 800 MW) of HVDC south transfer:

- an Aviemore–Benmore circuit will overload for an outage of the other Aviemore–Benmore circuit if southward HVDC transfer exceeds approximately 570 MW
- the Benmore–Twizel 1 circuit will overload for a Ohau B–Twizel 3 outage if southward HVDC transfer exceeds 800 MW.

SC3: low Manapouri generation

With low Manapouri generation:

- voltage stability in the Otago-Southland region sets the minimum number of generating units required at Manapouri[28]
- an Invercargill–Roxburgh circuit will overload for an outage of the other Invercargill–Roxburgh circuit.

What next?

These transmission constraints into the lower South Island can be managed operationally by requiring minimum levels of generation in the region.

The second tranche of CUWLP will significantly increase southward transmission thermal capacity (see section 6.6.2.2 for more information).

We will continue to monitor transmission constraints into the lower South Island and investigate investment options as the need arises.

27 This limit is the pre-contingency power flow measured across the Livingstone–Naseby circuit and Cromwell–Twizel sections.

28 The maximum import limit is calculated by reducing Manapouri generation, therefore the voltage stability limit binds first as generating units are taken out of service, reducing the amount of voltage support available in the Southland area.

6.7.7.4 System Condition 4: light load

This system condition (SC4) tests the effect of low load on the grid backbone. It represents a realistic summer night light load period and is designed to highlight possible high voltage issues. The specific assumptions for this system condition are:

- minimum South Island summer night load
- very low HVDC transfers.

Summary of transmission constraints

The main concern during light load periods is high post-contingency voltages, particularly in the upper South Island area. The high voltages are dependent on load power factor and voltage profiles across the South Island.

SC4: upper South Island high voltage

The load north of the Waitaki Valley is not dominated by heavy industrial loads, making it highly variable throughout the day with very low loads overnight, especially in summer. There are long transmission lines into the upper South Island that produce significant amounts of reactive power during light load periods (increasing the voltage) and there is little generation to absorb reactive power (to reduce the voltage).

Over the years, the high voltage issue has continued to worsen, so we have increasingly needed to switch off transmission lines overnight to manage the issue. A variety of factors have exacerbated the high voltage issue such as an increasing proportion of distribution networks being undergrounded[29] and the load characteristics generally becoming more capacitive.

Three dynamic voltage control plants north of the Waitaki Valley can be used to control voltages by absorbing reactive power during light load periods:

- two SVCs at Islington
- one STATCOM at Kikiwa.

Their combined reactive power absorption capacity is 185 Mvar. Generation in the Waitaki Valley can also be used to absorb some reactive power; this reduces loading on the SVCs at Islington but has very little effect further north.

What next?

We are installing a 50 Mvar reactor at Kikiwa to help reduce overnight high voltages in the area. We will continue to monitor the situation to identify any additional investments that may be required. Refer to section 6.6.2.3 for our enhancement approach.

6.8 HVDC link

The High Voltage Direct Current (HVDC) link connects the North and South Islands, providing:

- the North Island with access to the South Island's significant hydro generation capacity, which can be important for supplying the North Island during peak winter periods
- the South Island with access to the North Island's thermal generation, which is important for supplying the South Island during dry hydrological periods.

The HVDC link reduces the need for extra generation investment in each island, facilitates price competition between all generation sources, and plays an important part in managing renewable energy sources.

6.8.1 HVDC link configuration

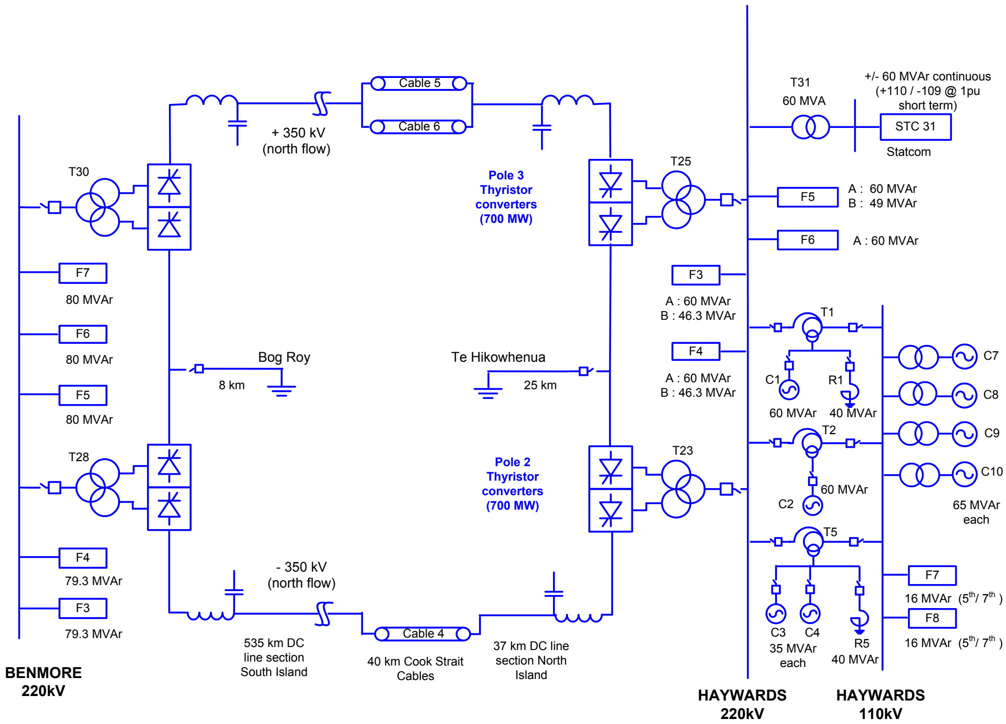
Figure 6-10 shows a simplified schematic of the HVDC link, which comprises:

- two ± 350 kV thyristor bipole converters (Pole 2 and Pole 3), each rated 700 MW, with converter stations and protection and control systems at Benmore in the South Island and Haywards in the North Island
- two 350 kV bipolar transmission lines. These comprise a 535 km length from Benmore to Fighting Bay (on the shore of Cook Strait in the South Island) and a 37 km length from Haywards to Oteranga Bay (on the shore of Cook Strait in the North Island)

29 Cables are naturally more capacitive than overhead lines. Therefore, they produce more reactive power during light loads.

- three 350 kV, 500 MW, 40 km long undersea cables, with cable terminal stations at Fighting Bay and Oteranga Bay
- a land electrode at Bog Roy near Benmore in the South Island and a shore electrode at Te Hikowhenua near Haywards in the North Island
- AC filters to reduce harmonic distortion and provide static reactive support at both Benmore and Haywards
- eight synchronous condensers and a STATCOM at Haywards to supplement the dynamic reactive support available from the AC transmission system.

Figure 6-10: Existing HVDC link schematic

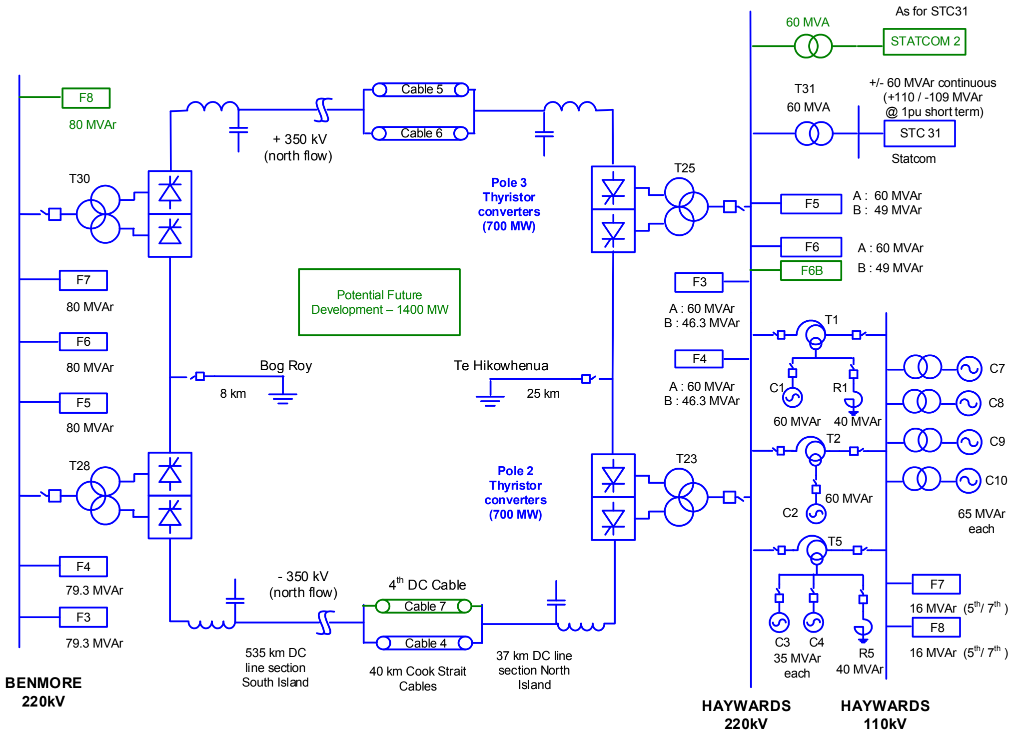


6.9 HVDC link enhancement approach

6.9.1 Possible future HVDC link to 2034

Figure 6-11 shows a simplified diagram for a possible expansion of the HVDC link to 1,400 MW north capacity. This configuration is based on potential enhancement approaches set out below.

Figure 6-11: Possible future HVDC link configuration



6.9.2 Enhancement approach

This section provides information about the transmission constraints and condition-based risks we will investigate or mitigate over the next few years.

Only one issue that likely require E&D base capex or Major Capex Project funded investment in the HVDC link over the next 10-15 years has been identified. This is the HVDC link's submarine cable strategy, reliability, and capacity increase (section 6.9.2.1).

6.9.2.1 HVDC link cable strategy, reliability, and capacity increase

There is an ongoing investigation that covers several issues that could impact the HVDC submarine cables. The issues are being considered together because of the high cost and long lead times associated with any works involving submarine cables.

The investigation covers the following elements:

- Analysis of the risk-based condition of the existing cables. We are reviewing their condition and will use this information to develop a strategy to manage the condition-based risks, including the timing of cable replacement.
- HVDC link reliability requirements. The current focus of the HVDC link is on energy transfer, but future use may primarily be to provide reliability of supply to the North Island. We will consider the future reliability requirements of the HVDC link, and in particular the submarine cables, given the potentially very long repair time of a cable fault.

A possible expansion of the HVDC link involves increasing its capability to 1,400 MW northward capacity. This could be required if the large amounts of power needed to be transferred to the North Island due to a significant load reduction or significant generation increase in the South Island, or if the HVDC was required to provide reliability of supply to the North Island.

This expansion would involve installing:

- an additional (fourth) submarine cable, and expanding the cable stations
- additional filters at both Benmore and Haywards
- additional dynamic reactive support at Haywards.

Timing for our investigation is driven by the need for information on the risk-based condition of the cables (to support strategy development), and to develop a plan to address the possibility of either significant load reduction or significant generation increase in the South Island.

Enhancement approach:

- We have started our initial investigation to determine a cable development strategy to address issues that may occur within the next 10 years.
- If we determine that there is an economic need for a capacity upgrade this will be a Major Capex Proposal and form part of the GEIR. If both cable replacement and an upgrade are warranted, the works will be co-ordinated.

Major Capex investments

Project Name	HVDC cable strategy, reliability and capacity increase
Project description:	Possible capacity increase, risk-based replacement of existing cables, and improve link reliability.
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	Uncertain. Dependent on significant changes in load and/or generation in the South Island and condition of existing cables
Indicative cost [$ million]:	$300 for cable replacement, $150 (additional) for capacity increase.
Part of the GEIR?	Yes

6.10 HVDC link asset capability and management

This section provides existing capability idetails for the HVDC link and sets out significant upcoming work on the HVDC link.

6.10.1 Changes since the 2018 Transmission Planning Report

There have been no changes related to the HVDC capability since the 2018 TPR.

6.10.2 HVDC capacity

The nominal rating of the Pole 2 converter is 560 MW, with a continuous overload of 700 MW. However, the nominal end-to-end capacity of Pole 2 is limited to 500 MW by the rating of the single HVDC cable connected to the pole.

The nominal rating of the Pole 3 converter is 700 MW, with a continuous overload of at least 770 MW within the design ambient temperature range with all cooling systems available. Two 500 MW HVDC cables are connected to Pole 3, so the nominal end-to-end capacity is 700 MW.

The HVDC overhead transmission line has a nominal rating of 700 MW per pole.

The HVDC link as a whole has a capacity of up to 1,000 MW in balanced 500/500 MW bipole operation and up to 1,200 MW[30] in unbalanced 500/700 MW bipole operation.

To reduce the system reserves required to cover a trip of Pole 3, the HVDC link controls were modified. When this control is used, Pole 2 is usually limited to 420 MW. Pole 3 then meets the rest of the bipole capability, so 1,000 MW is sent as 420/580 MW and 1,200 MW is sent as 420/780 MW.

30 This capacity is not always available. Power transfer may be limited by the capacity of the AC transmission systems in the North and South Islands (see sections 6.4 and 6.7, respectively, for more information). In particular, maximum south transfer capability varies significantly with demand in the Wellington region because of AC system limitations or lack of offered instantaneous reserves.

Issue

The announced retirement of the remaining Huntly Rankine units in 2022 may result in an increased need to transfer power from the South Island to the North Island at times of high North Island load (to the extent that South Island generation is not required to meet South Island load).

Following upgrades in the HVAC networks in the South and North Islands, the HVDC link's capacity will limit the ability to transfer power to the North Island. This will increase the risk of spilling from the South Island hydro lakes which can have a significant opportunity cost to New Zealand.

What next?

The HVDC submarine cables are also nearing their risk-based condition replacement criteria. We will coordinate our investigation for the cable's risk-based condition replacement and the need to upgrade the HVDC link's capacity. See section 6.9.2.1 for our approach.

6.10.2.1 HVDC reserves

The HVDC link capacity can be limited by the availability of instantaneous reserves in the AC system to cover for a pole or bipole outage. In bipole operation, if one pole fails the remaining pole can increase its power transfer to provide partial or full self-cover depending on pre-fault power flow on the remaining pole. No self-cover is possible when only one pole in service or for a bipole trip.

To assist with the reserve cover, both Pole 2 and Pole 3 have short-term ratings higher than their nominal ratings.

6.10.2.2 Transient overvoltage

There will be a temporary or transient overvoltage (TOV) following a bipole trip. The transient recovery voltage is limited at Haywards by the synchronous condensers and STATCOM. However, at times, HVDC power transfer may need to be limited to prevent an excessive transient recovery voltage following a bipole trip.

6.10.2.3 HVDC power limits

The HVDC controls will automatically reduce HVDC capability (i.e. apply power limits) for equipment outages in the North and South Island AC transmission systems to:

- ensure stable operation of the HVDC link
- ensure harmonic performance requirements are met
- prevent AC system over voltages during fault events
- reduce or prevent overloading of AC transmission system circuits.

6.10.2.4 HVDC controls

The HVDC controls will automatically reduce HVDC transfer for certain system conditions. These runbacks are usually 100 MW reductions in the power transfer and are initiated when reactive power margins have been eroded, when AC system voltages are below the required levels for a sustained period, or when AC system equipment overloading is detected.

The HVDC controls also allow the transfer of reserves through the national instantaneous reserves market and of frequency keeping between the North and South Islands.

The HVDC controls are flexible, and additional control functions can be implemented in future if required. However, extensive testing will be required before any new control features are implemented. To assist with this, we have a Real Time Digital Simulator (RTDS) to represent the AC transmission system, interfaced to a complete spare HVDC control hardware suite.

6.10.3 HVDC significant upcoming work

We look for opportunities to integrate our capital project and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Significant upcoming work[31] proposed for the HVDC link during the next 15 years that may significantly impact related system issues or connected parties is discussed below.

6.10.3.1 HVDC undersea cable condition-based risk assessment

Issue

The existing undersea cables are expected to reach replacement criteria in the mid to late 2020's. Cable failures will reduce HVDC capacity and take an extended time to repair or replace.

What next?

We will coordinate our investigation into the cables' condition-based risk and our investigation into a possible increase in the HVDC link's capacity. See section 6.9.2.1 for our approach.

6.10.3.2 HVDC Pole 2 mid-life replacement of selected components

Issue

The Pole 2 valve base electronics system, fibre optic cables, and snubber capacitors will reach their 30 year life span[32] in 2022, which is also close to the mid-life of Pole 2. It is necessary to replace these end of life components as operating them beyond their recommended life will increase the risk of failures, impacting the reliability and availability of the HVDC link.

Due to extensive outage requirements, this work must be undertaken prior to the planned decommissioning of North Island thermal generation (scheduled for 2022).

What next?

The mid-life replacement of selected components in Pole 2 will occur in summer 2020. The Pole 2 outage will be coordinated with the HVDC line reconductoring (section 6.10.3.3).

A second tranche of work is proposed for during the next 5-10 years to upgrade some of the oil-filled HVDC bushings and capacitors associated with Pole 2.

6.10.3.3 Oteranga Bay–Haywards–A line reconductoring

Issue

The conductors on a section of the Haywards–Oteranga Bay transmission line will reach our risk-based condition replacement criteria within the next 3-5 years. Failure of the conductors will cause an unplanned outage and disruption to the electricity market, as well as presenting a safety risk.

What next?

This reconductoring project has been approved and is currently in the delivery stage.

6.10.3.4 HVDC controls replacement

Issue

The HVDC control systems have a shorter life span (around 15-20 years) than the main HVDC converter equipment because of obsolescence. At least one full replacement of the control systems is required during the life of the converter equipment. The HVDC controls and protection for Pole 2 – excluding the valve-based electronics for thyristor control – were replaced in 2013. The Pole 3 controls and the bipole control systems were installed in 2013.

What next?

We will investigate the need and timing for the replacement of the control systems, which is likely to be necessary in 10-15 years.

31 This may include replacement of the asset due to its risk-based condition assessment.

32 The life span of these components is recommended by the manufacturer.

7 Northland Regional Plan

7.1 Regional overview and transmission system

The Northland region load includes a major industrial load (oil refinery) at Bream Bay, and loads at smaller regional centres.

The existing transmission network for the Northland region is set out geographically in Figure 7-1 and schematically in Figure 7-2

Figure 7-1: Northland region transmission

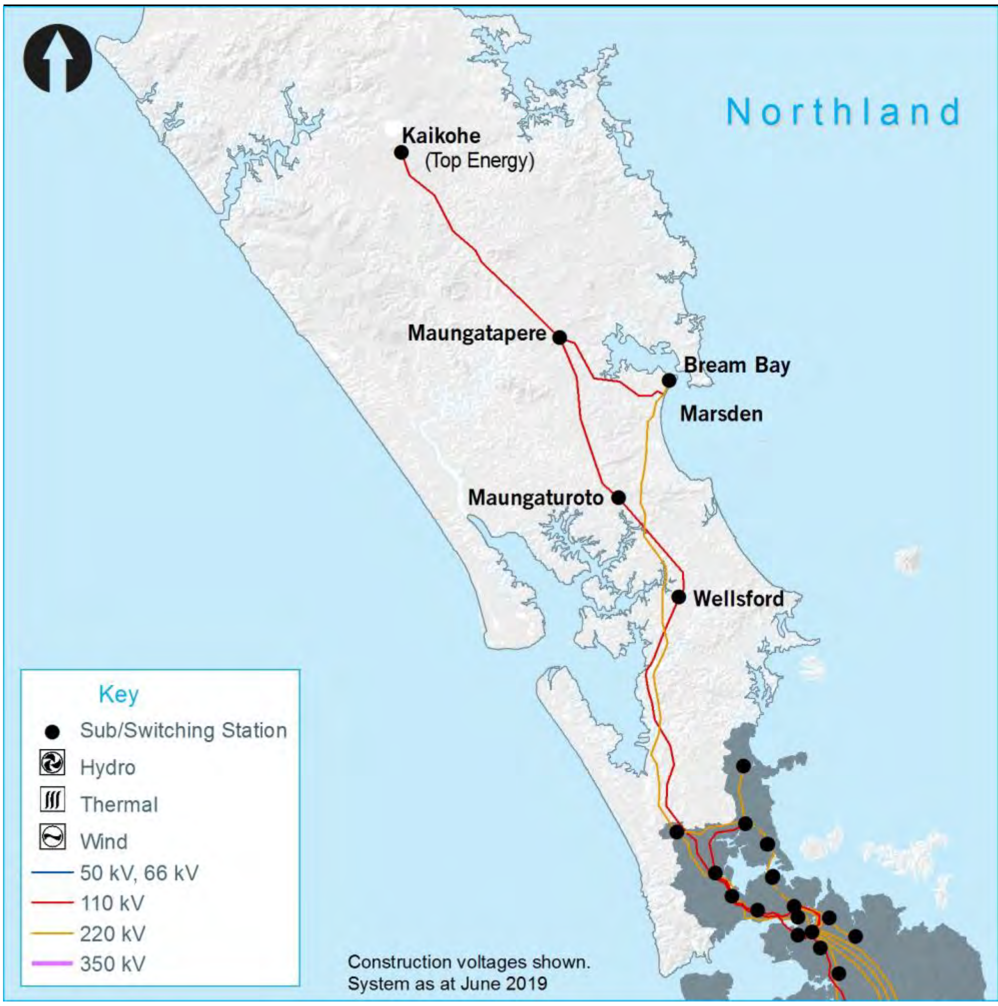
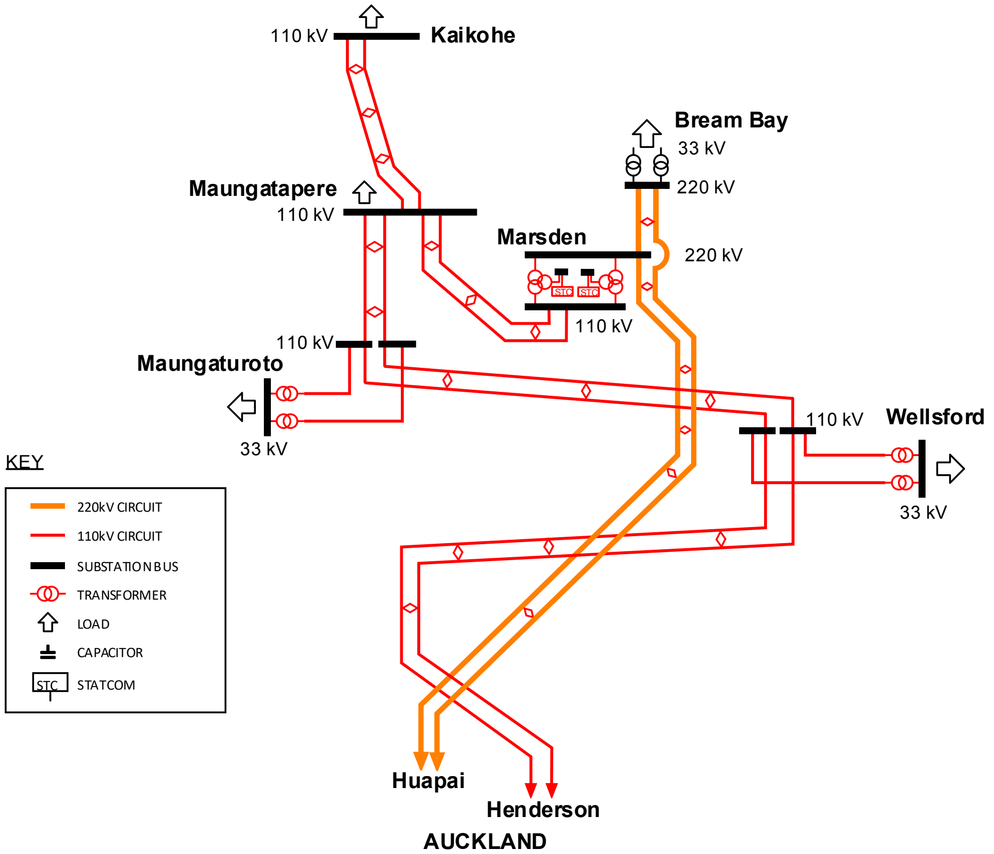


Figure 7-2: Northland region transmission schematic



7.1.1 Transmission into the region

The Northland region is supplied by a 220 kV double-circuit line from Huapai and a 110 kV double-circuit line from Henderson. These circuits are effectively in parallel.

As generation capacity in Northland is well short of that needed to meet local demand, most of the region's electricity demand is imported from the central North Island, through the Auckland region.

7.1.2 Transmission within the region

Within Northland, the transmission system can be further broken down to two sub-regions.

The high capacity 220 kV double-circuit line from Huapai to Marsden and Bream Bay defines one of the sub-regions. Voltage support is provided by two static synchronous compensators (STATCOMs) at Marsden, connected on the tertiaries of the two 220/110/11 kV interconnecting transformers.

The second sub-region is around Maungatapere, supplied mainly through the 110 kV double-circuit Marsden–Maungatapere line. There is also a low capacity double-circuit Henderson–Maungatapere line, with substations at Wellsford and Maungaturoto. From Maungatapere there is a 110 kV double-circuit line to Kaikohe. Voltage support for this sub-region is provided by capacitors within the distribution network at Kaitaia and Kaikohe.

The 220 kV and 110 kV networks in the Northland region are interconnected by two 220/110/11 kV interconnecting transformers at Marsden .

7.2 Northland demand

The Northland regional peak demand[1] is forecast to grow by an average of 0.6 per cent per annum over the next 15 years, from 273 MW in 2019 to 300 MW by 2034. This is less than the national growth rate of 1.2 per cent per annum.

Table 7-1 sets out forecast peak demand (prudent growth[2]) at each grid exit point over the forecast period.

Table 7-1: Forecast annual peak demand (MW) at Northland grid exit points to 2034

Grid exit point	Power Factor	Peak demand (MW)											
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Bream Bay	0.98	55	57	57	60	61	61	60	58	56	55	53	45
Kaikohe[1]	0.96[2]	51	60	63	65	64	63	63	63	64	63	63	54
Maungatapere	0.98	125	127	129	129	130	130	131	133	134	134	135	135
Maungaturoto	1.00	21	21	21	21	22	22	23	23	23	24	24	24
Wellsford	1.00	42	42	43	43	45	47	47	50	52	55	56	54

1. The customer has adviseds that there are various developments in an advanced state of execution that it expects will add up to 9 MW of load to the Kaikohe GXP between 2019-2020.
2. This is a leading power factor.

7.3 Northland generation

The Northland region's current generation capacity is approximately 39 MW. As this is less than is required to meet local demand the deficit is imported through the National Grid.

Table 7-2 lists the generation forecast for each grid injection point for the forecast period. This includes all known and committed generation stations including those embedded within the relevant local lines company's network (Vector, Northpower or Top Energy).[3]

Further generation may be developed during the period but is not sufficiently advanced to be included in our forecasts. (Refer to section 7.5.7 for more information on potential new generation.)

Table 7-2: Forecast annual generation capacity (MW) at Northland grid injection points to 2034 (existing and committed generation)

Grid injection point (location/name if embedded)	Generation capacity (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Bream Bay (Marsden Diesel)	9	9	9	9	9	9	9	9	9	9	9	9
Kaikohe (Ngawha)[1]	25	25	53	53	53	53	53	53	53	53	53	53
Maungatapere (Wairua)	5	5	5	5	5	5	5	5	5	5	5	5

1. Top Energy has publicly announced plans to expand its generation capacity at Ngawha by 28 MW by 2021.

1 For discussion on demand forecasting see Chapter 3, section 3.1.

2 Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

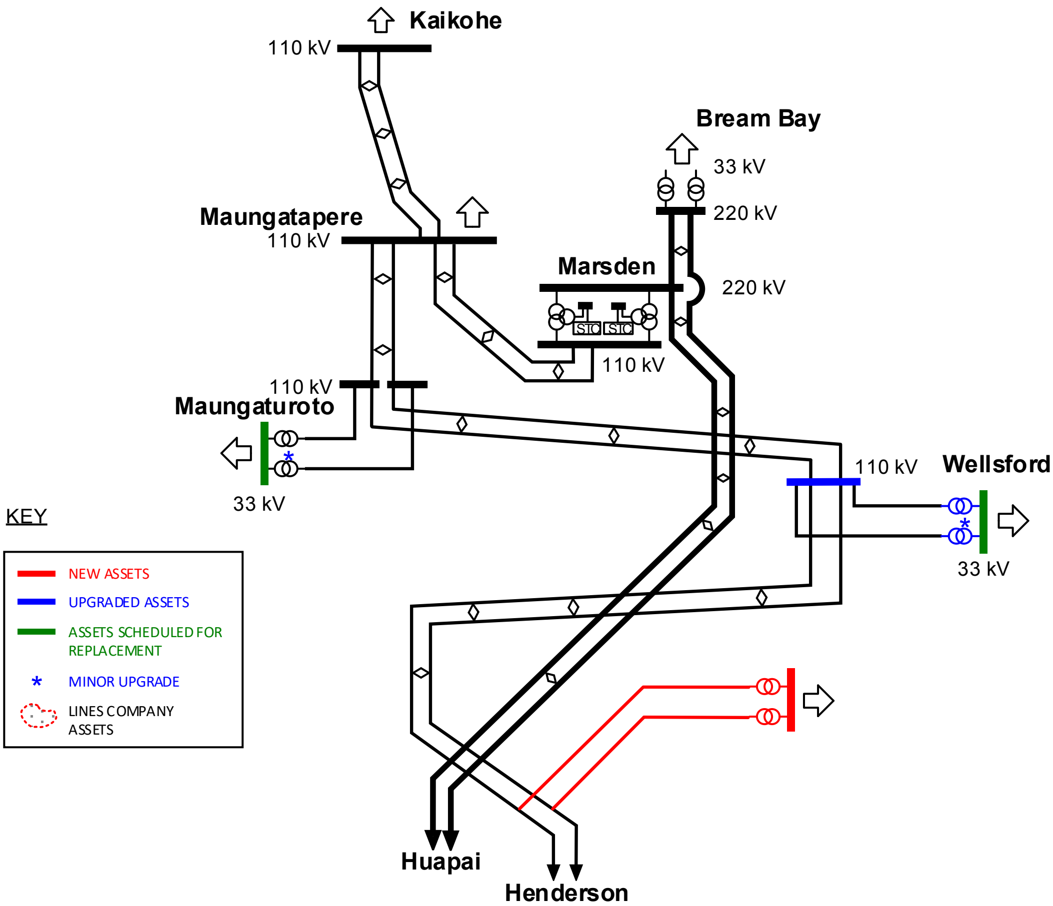
3 Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

7.4 Grid enhancement approach

7.4.1 Possible future Northland transmission configuration

Figure 7-3 shows the possible configuration of Northland transmission in 2034. New assets, upgraded assets, and assets scheduled for replacement within the forecast period (based on potential enhancement approaches set out in the following sections) are shown.

Figure 7-3: Possible Northland transmission configuration in 2034



7.4.2 Enhancement approach

Our approach seeks to ensure secure transmission into and within the Northland region into the future. Through the E&D process, we assess transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified issues and opportunities we take into account uncertainty in future demand, generation and technological developments.

The Northland region, together with the Auckland and Waikato regions, share the transmission network to the Central North Island. Due to the decommissioning of thermal generation in the Auckland and Waikato regions, there is a need to invest in voltage support to ensure voltage stability is maintained on the grid backbone. The Waikato and Upper North Island (WUNI) Project is undertaking short-list consultation on investment options to maintain voltage stability in these regions (see Chapter 6).

Transmission issues likely requiring E&D or Customer funded investments in Northland over the next 10-15 years include:

Section number	Issue
7.4.2.1	Wellsford supply capacity
7.4.2.2	Henderson–Wellsford transmission capacity

7.4.2.1 Wellsford supply capacity

Peak load at Wellsford is forecast to exceed the n-1 capacity of the supply transformers from 2019.

Enhancement approach:

- In the short term, the overload can be managed operationally within Vector's network. We will replace the bushings of the existing transformers to extend their life.
- We will discuss longer term upgrade options with Vector, for when the lack of n-1 capacity can no longer be managed operationally. One option is to install larger transformers at Wellsford. Alternatively, a possible new grid exit point between Henderson and Wellsford may offer more economic benefit. Either of these options will ensure sufficient capacity is available for the forecast period.
- An upgrade of the Wellsford supply transformers and/or a new grid exit point will also require an upgrade of the Henderson–Maungatapere line protection and/or the installation of line circuit breakers at Wellsford and/or Maungaturoto.

Customer investments

Project Name	Wellsford supply capacity
Project description:	Replace Wellsford–T1 and T2 with larger units
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	To be determined through discussion with the customer
Indicative cost [$ million]:	7
Part of the GEIR?	No

Base E&D Capex investments

Project Name	Upgrade protection scheme Henderson–Wellsford–Maungaturoto–Maungatapere
Project description:	Protection scheme upgrade (may require switchgear upgrade)
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2024
Indicative cost [$ million]:	4
Part of the GEIR?	No

7.4.2.2 Henderson–Wellsford transmission capacity

During regional peak load periods, an outage of a Henderson–Wellsford–Maungatoroto–Maungatapere circuit will cause the Henderson–Wellsford section of the remaining circuit to exceed its winter rating from 2026.

Enhancement Approach:

- To reduce the reliance on generation being available at Ngawha to resolve the transmission constraint, we can install a special protection scheme (SPS) to open the Henderson–Wellsford–Maungatoroto–Maungatapere circuit(s) at the Maungatapere end when there are overloads on the Henderson–Wellsford sections of these circuits. The SPS would remove the through-transmission on the low capacity 110 kV Henderson–Wellsford circuits which causes the overloads. The SPS would also provide some regional security during outages of other circuits in the area, and allow higher level load to be restored following an extended outage of the parallel 220 kV double-circuit line or the 110 kV double-circuit Marsden–Maungatapere line.

- The SPS will be installed in 2022 to coincide with a planned end of life protection replacement.

Base E&D Capex investments

Project Name	Henderson–Wellsford transmission capacity
Project description:	Install SPS on the Henderson–Wellsford–Maungatoroto–Maungatapere circuits
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2022
Indicative cost [$ million]:	0.5
Part of the GEIR?	No

7.5 Asset capability and management

We have assessed the transmission capacity and reactive support requirements in the region for the next 15 years. When an issue or opportunity exists, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 7.4.2) have been developed to address issues or opportunities that require action within the forecast period and where investment is justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk-based asset replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

7.5.1 Northland significant upcoming work

We integrate our capital project and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Table 7-3 lists the significant upcoming work[4] proposed for the Northland region during the next 15 years that may significantly impact related system issues or connected parties.

Table 7-3: Proposed significant upcoming work

Description	Tentative year	Linkages to E&D issue
Henderson–Maungatapere A conductor replacement	2032	7.5.4.2
Maungaturoto 33 kV outdoor to indoor conversion	2023-2025	none
Wellsford 33 kV outdoor to indoor conversion	2023-2025	none
Wellsford–T1 and T2 bushing replacement	2020-2021	7.5.4.4

4 Condition-based replacement of the asset is included in this list.

7.5.2 Northland asset feedback

The Asset Feedback Register includes the following entry related to E&D that is specific to the Northland region.

- Future of Kaitaia 33 kV binary switched capacitor.

7.5.2.1 Future of Kaitaia 33 kV binary switched capacitor

Issue

We divested the Kaitaia substation and the 110 kV Kaikohe–Kaitaia transmission line to Top Energy but retained ownership of the 33 kV binary switched capacitors at Kaitaia to provide reactive support to the Northland region. The maintenance and operation of these capacitors is relatively expensive as the site is far from our northern-most substation. In addition, the capacitors are sited on Top Energy's property so that we require its cooperation to facilitate maintenance and servicing.

What next?

We are studying the reactive support requirements for the upper North Island under the WUNI project (see Chapter 6). This work will give us a better understanding of future reactive power requirements in the region, so we can determine the future need for the Kaitaia 33 kV binary switched capacitors.

7.5.3 Changes since the 2018 Transmission Planning Report

Table 7-4 lists the specific issues that are either new or no longer relevant within the forecast period (relative to our previous Transmission Planning Report).

Table 7-4: Changes since the 2018 TPR

Issues	Change
Generation at Maungatapere, and Maungatapere–Maungataroto	New study completed

7.5.4 Northland transmission capability

Table 7-5 summarises identified issues that may affect the Northland region over the next 15 years. In each case we have detected a condition that would constrain the network capacity if action were not taken. Each issue is discussed in more detail below.

This transmission capability section reports whether the Grid can be reasonably expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, makes up the Grid Reliability Report (GRR).

Table 7-5: Northland region transmission issues – regional/site by grid exit point

Section number	Issue
Regional	
7.5.4.1	Upper North Island voltage instability for grid backbone contingencies
7.5.4.2	Henderson–Wellsford 110 kV transmission capacity
Site by grid exit point	
7.5.4.3	Kaikohe–Maungatapere 110 kV transmission capacity
7.5.4.4	Wellsford supply transformer capacity

7.5.4.1 Upper North Island voltage instability for grid backbone contingencies

Issue

As demand in the Auckland and Northland regions grows, voltage stability margins will deteriorate to the point where several generators and circuit contingencies on the grid backbone can cause voltage problems within the Northland region.

What next?

We are currently undertaking short-list consultation on our suggested approach to adding additional reactive power support requirements in the Waikato and Auckland regions to maintain voltage stability margins (see Chapter 6, WUNI project). Any investments made under the WUNI project will also resolve voltage stability issues in the Northland region.

7.5.4.2 Henderson–Wellsford 110 kV transmission capacity

Issue

There is a 110 kV double-circuit line Henderson–Wellsford–Maungatoroto–Maungatapere in parallel with a higher capacity 220 kV double-circuit line Huapai–Marsden–Bream Bay. These circuits supply all of the Northland region's load. The 110 kV circuits have a:

- total nominal installed capacity of 111/136 MVA (summer/winter).
- n-1 capacity of 56/68 MVA (summer/winter).

During regional peak load periods, an outage of a Henderson–Wellsford–Maungatoroto–Maungatapere circuit will cause the Henderson–Wellsford section of the remaining circuit to exceed its winter rating from 2026.

In addition, an outage of the 220 kV Huapai–Marsden circuit will cause the Henderson–Wellsford sections of both Henderson–Wellsford–Maungatoroto–Maungatapere circuits to exceed their winter capacity from 2028.

What next?

The commissioning of new generation at Ngawha will defer the issues from 2022 to the above stated dates. Transmission investments are also a possibility, refer to 7.4.2.2 for our proposed approach.

7.5.4.3 Kaikohe–Maungatapere 110 kV transmission capacity

Issue

Two 110 kV Kaikohe–Maungatapere circuits supply Kaikohe providing:

- total nominal installed capacity of 129/158 MVA (summer/winter).
- n-1 capacity of 63/77 MVA (summer/winter)[5].

The 25 MW Ngawha (geothermal) generation station is embedded behind the Kaikohe supply bus.

When Ngawha is not generating during peak load periods the Kaikohe load will exceed the n-1 winter capacity of the Kaikohe–Maungatapere circuits by 4 MW in 2019, increasing to 33 MW by 2034 (seeTable 7-6).

Table 7-6: Kaikohe-Maungatapere 110 kV transmission line overload forecast

Circuit/grid exit point	Transmission line overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Kaikohe	4	5	20	24	29	30	30	31	31	32	32	33

What next?

The existing capacity of the Ngawha generation is sufficient to ensure the Kaikohe–Maungatapere circuits remain within their n-1 capacity until 2021. Following the commissioning of the new generation at Ngawha, the maximum capacity of Ngawha will defer the Kaikohe–Maungatapere n-1 capacity issue beyond the forecast period.

We have no plans at present to upgrade the capacity on the Kaikohe–Maungatapere circuits. We will investigate investment options when the customer (Top Energy) requests a capacity increase.

5 The two Kaikohe–Maungatapere circuits have different ratings: Kaikoke–Maungatapere 1 has a summer/winter rating of 63/77 MVA and Kaikahe–Maungatapere 2 has a summer/winter rating of 66/80 MVA.

7.5.4.4 Wellsford supply transformer capacity

Issue

Two 110/33 kV transformers supply Wellsford's load, providing:

- total nominal installed capacity of 60 MVA.
- n-1 capacity of 37/39 MVA (summer/winter).

Peak load at Wellsford is forecast to exceed the n-1 winter capacity of the transformers by 4 MW in 2019, increasing to approximately 19 MW by 2031, then reducing to about 17 MW by 2034 (seeTable 7-7). The reduction later in the period is due to our underlying assumptions regarding uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid during peak demand periods.

Both existing transformers comprise three single-phase units. There is no spare unit on site.

Table 7-7: Wellsford supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Wellsford	4	4	4	5	7	9	10	13	14	18	18	17

What next?

In the short term, the overload can be managed operationally within Vector's network. Refer to section 7.4.2.1 for our proposed approach.

7.5.5 Northland bus security

This section presents issues arising from the outage of a single bus section rated at 66 kV and above for the next 15 years.

Bus outages disconnect more than one power system component (for example, other circuits, transformers, reactive support or generators). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

Table 7-8: Northland region transmission issues – bus security

Section number	Issue
7.5.5.1	Transmission bus security
7.5.5.1	Marsden bus security
7.5.5.1	Wellsford bus security
7.5.5.1	Maungatapere bus security

7.5.5.1 Transmission bus security

Table 7-9 lists bus outages that cause voltage issues or a total loss of supply. Generators are included only if a bus outage disconnects the whole generation station or causes a widespread system impact. Supply bus outages, typically 11 kV and 33 kV, are not listed.

Table 7-9: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Marsden 110 kV	-	-	Henderson–Wellsford circuit sections overloading	Note 1
Marsden 220 kV	-	-	Henderson–Wellsford circuit sections overloading Marsden low voltage Bream Bay low voltage	Note 2
Wellsford 110 kV	-	-	Wellsford supply transformer overloading Henderson–Wellsford circuit section overloading	7.5.4.4 Note 3
Maungaturoto 110 kV	-	-	Wellsford supply transformer overloading Henderson–Wellsford circuit section overloading	7.5.4.4 Note 3
Maungatapere 110 kV	-	-	Maungatapere–Kaikohe 1, Maungatapere–Kaikohe 2, overloading	Note 4

1. A 110 kV bus section outage at Marsden disconnects an interconnecting transformer and a 110 kV circuit to Maungatapere. This may cause the Henderson–Wellsford sections of both low capacity Henderson–Wellsford–Maungatoroto–Maungatapere circuits to overload.
2. A 220 kV bus section outage at Marsden disconnects one of the high capacity 220 kV circuits to Marsden and a interconnecting transformer. This may cause both 110 kV Henderson–Wellsford circuit sections to overload and low voltages at Marsden and Bream Bay.
3. The Henderson–Wellsford–Maunaturoto–Maungatapere circuits do not have line circuit breakers at Wellsford and Maungaturoto; a bus outages at Wellsford or Maungatoroto disconnects the entire Henderson–Wellsford–Maunaturoto–Maungatapere circuit which may cause the remaining Henderson–Wellsford circuit section to overload.
4. A bus section outage at Maungatapere disconnects one of the circuits supplying Kaikohe, which overloads the other ciruit.

7.5.6 Other regional items of interest

7.5.6.1 North of Huapai transmission security

Issue

The Huapai switching station comprises three circuit breakers:

- one on each of the 220 kV circuits connecting Marsden and Bream Bay
- a shared circuit breaker for the two incoming 220 kV circuits from Albany and Henderson.

If the shared circuit breaker fails to trip following an incoming 220 kV circuit fault, both the outgoing circuits will trip, leaving the entire load north of Huapai supplied by the low capacity 110 kV Henderson–Maungatapere circuits. This may result in a loss of supply to the Northland region, depending on the region's load at the time.

What next?

We have investigated this issue and found that that investments to increase the security level are not economically justified. We will continue to monitor this issue and will consider enhancing the Huapai bus security if there are synergies with other future developments.

7.5.6.2 Regional transmission security during maintenance of a 220 kV circuit

Issue

During maintenance of one of the 220 kV Huapai–Bream Bay circuits, system operations splits the 110 kV network, by opening the Henderson–Maungatapere circuits at Maungatapere. This is done to cover against the possible contingency of the other 220 kV circuit, which could cause voltage collapse in the Northland region. The 110 kV split puts the region on n security.

NorthPower and Vector have indicated that they would like us to study other possible options that could help to maintain n-1 security during this type of maintenance operation.

What next?

It is expected that this issue will be resolved with the proposed solutions to the Henderson–Wellsford 110 kV transmission capacity and the Wellsford supply transformer capacity issues. Refer to section 7.5.4.2 and 7.5.4.4 for our proposed approach.

7.5.6.3 Supply security during maintenance of a 110 kV Henderson–Maungatapere circuit

Issue

The Henderson–Maungatapere double-circuit line supplies Wellsford and Maungaturoto. There are no line breakers at either of the two substations so if one circuit is out for maintenance and the other trips, there will be loss of supply at these two sites.

As the line is relatively long, maintenance outages occur relatively frequently, which results in the load being on n security for relatively long periods of time.

What next?

From experience on other similar parts of the transmission system, investments to increase security to Wellsford and Maungaturoto are unlikely to be economic. The customers (NorthPower or Vector) have not requested a higher security level.

7.5.7 Northland generation proposals and opportunities

This section details relevant regional issues that may affect generation proposals under investigation by developers and in the public domain, or other generation opportunities. The impact of committed generation projects on the grid backbone is discussed separately in Chapter 6.

The maximum generation that can be connected depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

7.5.7.1 Maximum regional generation

The following maximum generation estimates assume a light North Island load profile and high output from existing generation in the region (Ngawha generating 53 MW).

For generation connected at the Maungatapere 110 kV bus, the maximum generation that could be injected under n-1 conditions is approximately 300 MW. Generation would be constrained by one Marsden interconnector when the other interconnector is out of service.

For generation connected at the Huapai 220 kV bus, the maximum generation that could be injected under n-1 conditions is approximately 560 MW. This constraint is due to the Henderson–Huapai 1 circuit overloading when the Albany–Huapai 1 circuit is out of service. This may increase to 750 MW if a substation equipment constraint on this circuit is removed.

7.5.7.2 Generation injection at Maungatapere

Generation of approximately 300 MW could be connected to the Maungatapere 110 kV bus. It may be possible to install approximately 500 MW generation if some equipment at substations is replaced, and the Marsden interconnection capacity is upgraded.

7.5.7.3 Generation connected to the 110 kV Henderson–Maungatapere line

There is a 110 kV double-circuit line from Henderson to Wellsford, Maungaturoto, and Maungatapere. Each circuit is rated at 56/68 MVA (summer/winter). Generation up to a total of 90 MW on either circuit could be connected. This would not be provided at n-1 and would likely require a generation runback scheme or similar arrangement.

Generation transmitted towards Maungatapere forms part of the generation injection limit into Maungatapere.

7.5.7.4 Generation connected to the 220 kV Huapai–Marsden line

The 220 kV double-circuit line from Huapai (north of Auckland) to Marsden and Bream Bay is the main connection to the Northland region. One circuit is predominantly a simplex conductor (rated at 333/370 MVA) while the other is a duplex conductor (rated 666/740 MVA[6]).

Generation could be connected along this line, not just at existing substations. Maximum generation of between 300 MW and 500 MW may be possible depending on which circuit generation was connected into, with the simplex Bream Bay–Huapai conductor being the limiting component. New generation elsewhere in the Northland region would reduce this limit.

7.5.7.5 Generation connected to the 220 kV bus at Marsden

For generation connected at the Marsden 220 kV bus, the maximum generation that could be injected under n-1 conditions is approximately 600 MW. The constraint is due to the Bream Bay–Huapai1 circuit overloading for an outage of the Albany–Huapai–Marsden line.

7.5.7.6 Generation connected to the 110 kV bus at Marsden

For generation connected at the Marsden 110 kV bus, the maximum generation that can be injected under n-1 conditions is approximately 275 MW. The constraint is due to one Marsden interconnecting transformer overloading for an outage of the parallel transformer.

6 The actual circuit rating is limited to 457 MVA at present due to some substation equipment. As this is relatively easy and inexpensive to replace in the context of generation connection, this limit is ignored for the purposes of this discussion.

8 Auckland Regional Plan

8.1 Regional overview and transmission system

The Auckland region has some of the highest load densities in New Zealand, coupled with relatively low levels of local generation.

The existing transmission network for the Auckland region is set out geographically in Figure 8-1 and schematically in Figure 8-2.

Figure 8-1: Auckland region transmission network

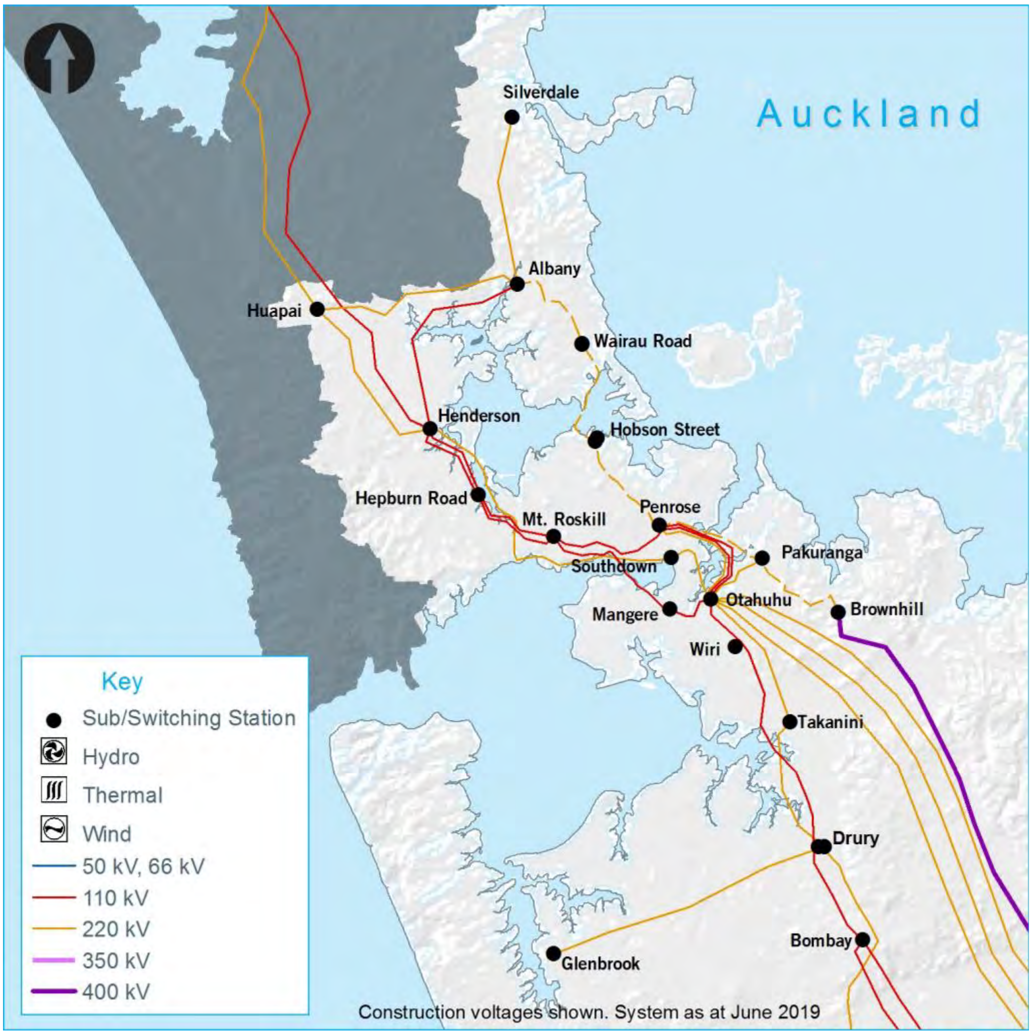
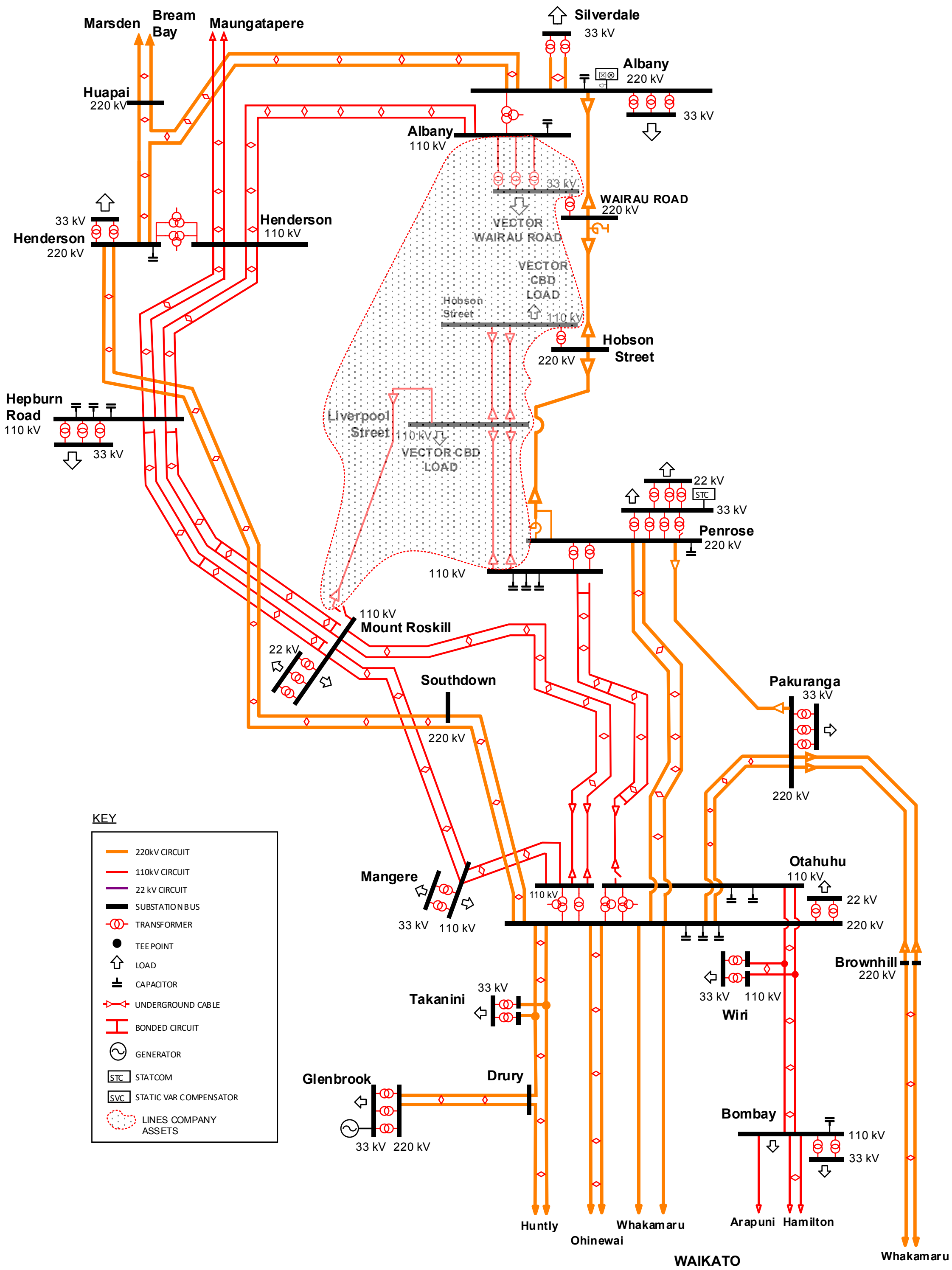


Figure 8-2: Auckland region transmission schematic



8.1.1 Transmission into the region

Approximately 95 per cent of peak electricity demand in the Auckland and Northland regions is supplied by generation located south of Bombay. Transmission enables supply of this electricity into and through the Auckland region.

We have eight high capacity 220 kV circuits into Auckland from Whakamaru (the generation-rich centre of the North Island), Huntly and Taranaki. Voltage support is needed to ensure stability, and this is provided by static capacitors at the Henderson, Hepburn Road, Albany, Otahuhu, Penrose, and Bombay substations, and a shunt reactor at Wairau Road substation. The dynamic reactive support at Albany, Penrose and Marsden helps to maintain voltage stability for outages of circuits supplying Auckland or outages of a major generation unit near the Auckland region.

8.1.2 Transmission and distribution networks within the region

The Auckland transmission network distributes power within the region and provides through-transmission to the Northland region. It consists of three layers: the 220 kV network, the 110 kV network, and the 110 kV distribution system owned by Vector.

220 kV transmission network

There are two high capacity 220 kV rings. One connects Otahuhu, Pakuranga and Penrose, providing security and capacity into the region. The other, from Otahuhu and Penrose through the Henderson, Albany, Wairau Rd and Hobson Street substations, provides security to central Auckland, the North Shore and the Northland region by establishing diverse transmission routes to the substations supplying these areas.

110 kV transmission network

The 110 kV transmission network is split into two halves at Otahuhu.

One half has 220/110 kV interconnecting transformers at Otahuhu, Penrose and Hobson Street. The Otahuhu and Penrose transformers may be connected through the 110 kV Otahuhu–Penrose 2 circuit, which operates in parallel with the 220 kV Otahuhu–Penrose double circuit line (although Otahuhu–Penrose 2 is normally open[1]). The 110 kV network also connects to the Waikato region via a Bombay–Wiri–Otahuhu double circuit line, with power flow generally southward from Otahuhu.

The other half of the 110 kV network has 220/110 kV interconnecting transformers at Otahuhu, Henderson and Albany. Two double-circuit 110 kV lines connect Otahuhu, Mangere, Mt Roskill, Hepburn Rd and Henderson. One double-circuit line connects Henderson to Albany. These 110 kV lines operate in parallel with the 220 kV Otahuhu–Henderson–Albany double-circuit lines. Power flow is generally into Mt Roskill from both south (Otahuhu) and north (Henderson).

110 kV distribution network

Vector's 110 kV distribution network operates in parallel with the 220 kV transmission network between Penrose and Hobson Street.

Vector supplies the Auckland CBD load from its Liverpool Street, Hobson Street and Quay Street substations. Vector can also supply the CBD from the Mt Roskill substation via a 110 kV underground circuit to its Liverpool Street substation. However, this is normally split and is only used to enable maintenance outages.

1 The 110 kV Otahuhu–Penrose circuit is usually open to improve the balance of power flow into the Auckland CBD between Penrose and Hobson Street.

8.2 Auckland demand

The Auckland regional peak demand[2] is forecast to grow by an average of 1.5 per cent per annum over the next 15 years, from 2,166 MW in 2019 to 2,712 MW in 2034. This exceeds the national average growth rate of 1.2 per cent per annum.

Table 8-1sets out forecast peak demand (prudent growth[3]) for each grid exit point over the forecast period.

Table 8-1: Forecast annual peak demand (MW) at Auckland grid exit points to 2034

Grid exit point	Power factor	Peak demand (MW)											
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Albany 33 kV	0.99	170	172	176	180	183	187	191	195	196	198	200	195
Bombay 33 kV[1]	0.99	17	19	0	0	0	0	0	0	0	0	0	0
Bombay 110 kV[1]	0.99	110	115	140	147	158	162	165	168	171	173	174	176
Glenbrook 33 kV[2] (clean bus)	0.98	73	75	78	79	80	81	82	83	84	84	84	83
Glenbrook - NZ Steel (dirty bus)	0.98	125	125	125	125	125	125	125	125	125	125	125	125
Henderson	1.00	149	157	167	176	184	194	202	209	216	227	229	224
Hepburn Rd	0.99	171	176	182	187	192	198	199	200	201	201	200	181
Hobson Street[3]	0.99	113	114	116	118	120	122	125	131	131	132	133	140
Mangere 33 kV	0.99	128	132	133	135	138	141	143	145	146	148	150	154
Mangere 110 kV	0.90	20	20	20	20	20	20	20	20	20	20	21	24
Mt Roskill 22 kV	0.98	125	126	128	129	130	131	132	136	140	143	145	141
Mt Roskill 110 kV[4]	1.00	70	71	72	71	72	73	74	77	80	83	84	82
Otahuhu	1.00	73	74	75	75	76	77	77	78	78	79	79	79
Pakuranga	0.99	177	179	182	184	185	187	188	189	191	192	194	190
Penrose 22 kV	0.98	56	57	58	60	60	61	62	63	63	64	65	68
Penrose 33 kV	0.99	322	329	332	340	340	343	351	350	350	351	351	352
Penrose 110 kV - Liverpool Street[3]	0.99	113	114	116	118	120	122	125	131	131	132	134	146
Silverdale	1.00	102	104	107	110	112	115	118	122	124	127	128	125
Southdown 25 kV	1.00	6	6	6	6	6	6	6	6	6	6	6	6
Takanini	1.00	145	147	150	153	156	158	161	162	165	167	168	162
Wairau Rd	1.00	153	157	159	161	161	163	164	166	168	170	173	186
Wiri	0.98	105	108	110	111	113	116	118	119	121	124	125	127

1. Bombay 33 kV load will shift to the Bombay 110 kV bus in 2020.
2. This is the Glenbrook 33 kV load on the clean bus with no contribution from the generation connected directly onto the 33 kV bus at Glenbrook.
3. The 50/50 load split between Hobson Street and Penrose–Liverpool Street is an estimate only. The Vector and Transpower networks between these grid exit points are operated in parallel.
4. This includes the Kingsland feeders only.

2 For discussion on demand forecasting see Chapter 3, section 3.1.

3 Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

8.3 Auckland generation

Generation capacity in the Auckland region is currently approximately 150 MW. This excludes any embedded solar (PV) generation, which was approximately 20 MW in Auckland at the time of publication.[4] Auckland generation is less than the region's peak demand, with the deficit imported through the National Grid.

Table 8-2 lists the generation forecast for each grid injection point for the forecast period. This includes all known existing and committed generation stations including those embedded in local lines companies' networks (Vector or Counties Power).[5]

Further generation may be developed during the period but is not sufficiently advanced to be included in our forecasts (refer to section 8.5.8 for more information on potential new generation).

Table 8-2: Forecast annual generation capacity (MW) at Auckland grid injection points to 2034 (existing and committed generation)

Grid injection point (location/name if embedded)	Generation capacity (MW)											
	2019	**2020**	**2021**	2022	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2034**
Albany (Rosedale[1])	3	3	3	3	3	3	3	3	3	3	3	3
Bombay (Hampton Downs Landfill)	4	4	4	4	4	4	4	4	4	4	4	4
Bombay (Greymouth power Co., Contact Energy)	2	2	2	2	2	2	2	2	2	2	2	2
Glenbrook[2]	112	112	112	112	112	112	112	112	112	112	112	112
Mangere (Watercare Mangere)	7	7	7	7	7	7	7	7	7	7	7	7
Otahuhu (Greenmount Landfill[3])	1	1	1	1	1	1	1	1	1	1	1	1
Penrose (Auckland Hospital)	4	4	4	4	4	4	4	4	4	4	4	4
Silverdale (Redvale[4])	12	12	12	12	12	12	12	12	12	12	12	12
Takanini (Whitford Landfill)	3	3	3	3	3	3	3	3	3	3	3	3

1. Rosedale generation is limited to approximately 1 MW due to insufficient gas at the site. This amount is not expected to rise significantly within the next few years.
2. This value includes an embedded generating unit with a nominal rating of 38 MW. However, its continuous output is approximately 25 MW.
3. Information from Envirowaste website. Landfill is closed and presently produces 1 MW. This is expected to reduce over time.
4. Installed capacity is 12 x 1 MW machines.

4 Electricity Market Information (EMI), Installed distributed generation trends, https://www.emi.ea.govt.nz/Retail/Reports/GUEHMT?FuelType=solar&RegionType=MAIN_CENTRE&Show=Capacity&_si=p|3,v|3

5 Only generators with capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

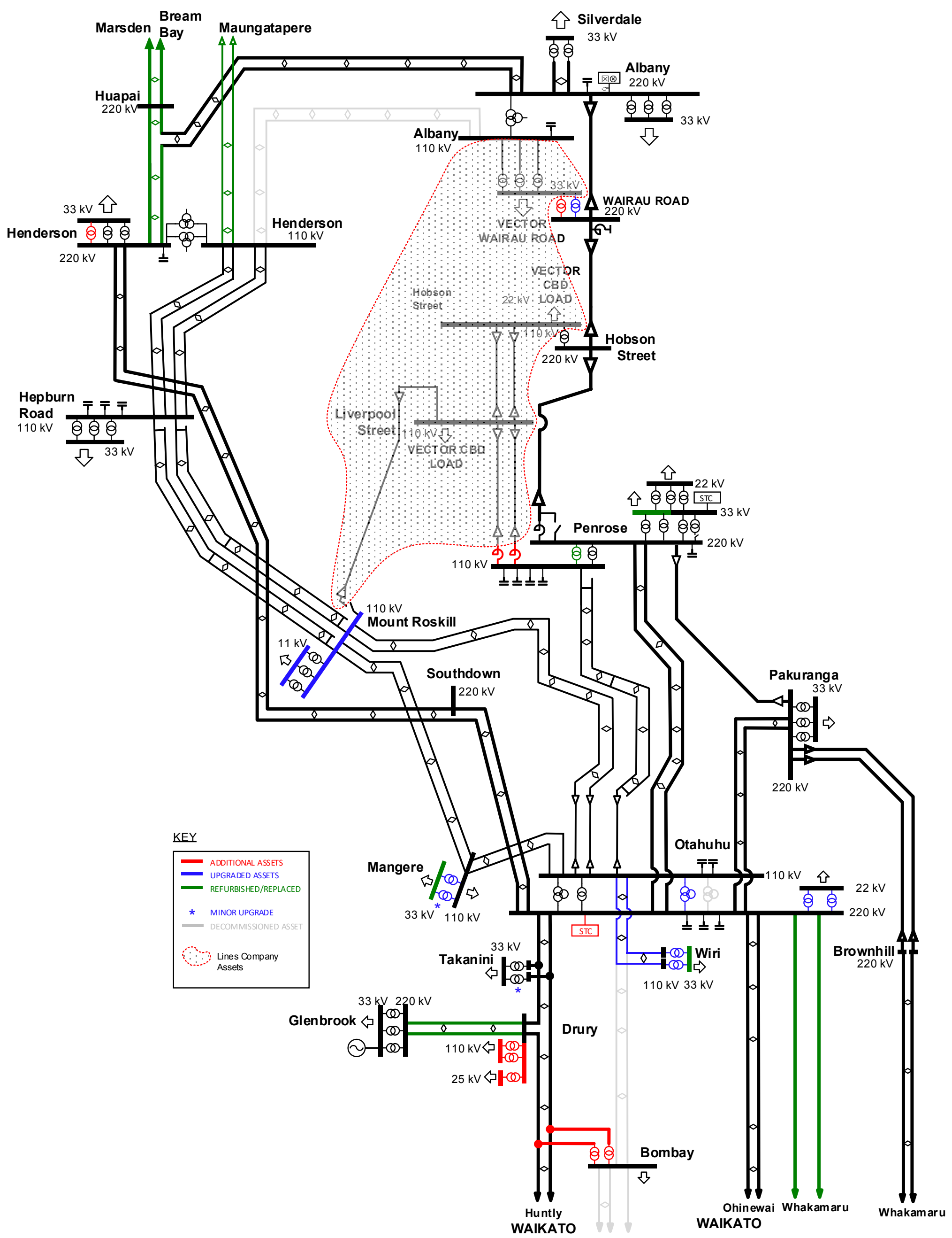
8.4 Grid enhancement approach

8.4.1 Possible future Auckland transmission configuration

Figure 8-3 shows the possible configuration of Auckland transmission in 2034. New assets, upgraded assets, and assets scheduled for replacement within the forecast period (based on potential enhancement approaches set out in the following sections) are shown.

While we include sections of Vector's network for clarity, we are making no statement about Vector's future development plans.

Figure 8-3: Possible Auckland transmission configuration in 2034



8.4.2 Enhancement approach

Our approach seeks to ensure secure transmission into and within the Auckland region into the future. Through the E&D process we have assessed transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified issues and opportunities we take into account uncertainty in future demand, generation and technological developments.

A number of intersecting issues impact transmission infrastructure in Auckland. These include the need for major refurbishment work on our transmission lines across Auckland, customer projects to facilitate development in housing and transport, the Auckland Unitary Plan[6] and forecast population growth for the Auckland region. We have developed a long-term strategy[7] for Auckland that will enable us to coordinate this work, ensuring consistency and avoiding costly rework. Each development will still be subject to the required public consultation and regulatory approval closer to the need date.

While a long-term approach has been developed under the Auckland Strategy project, the actual timing of transmission investments will be reviewed regularly. This ensures timing remains optimal given ongoing changes in load and generation in the Auckland and Northland regions, as well as development of products and technologies such as demand response and energy storage.

The Auckland, Northland and Waikato regions all rely on the same transmission network links to the central North Island. The decommissioning of thermal generation in the Auckland and Waikato regions has caused a need to invest in voltage support to ensure voltage stability is maintained on the grid backbone. The Waikato and Upper North Island (WUNI) Project is looking at investment options to maintain voltage stability in these regions (see Chapters 6 and 9).

We are committed to install a total of 250 Mvar of shunt capacitors for reactive support in the Waikato region to levelise the transmission voltage profile across the grid backbone. This will minimise reactive power exchange between regions, and increase active power transfer capacity into the upper North Island and Waikato regions.

Other investments that are not yet committed include additional dynamic reactive support equipment in the Auckland and Waikato regions in conjunction with a demand management scheme, and in the longer term, series capacitors to support voltage stability in these regions.

Transmission issues that are likely to require E&D or customer-funded investments in Auckland over the next 10-15 years are:

Section number	Issue
Regional	
8.4.2.1	Albany–Henderson A line conductor end of life
8.4.2.2	Auckland CBD 220/110 kV interconnection capacity
8.4.2.3	Bombay–Wiri–Otahuhu transmission
8.4.2.4	Otahuhu–Penrose transmission capacity
Site by grid exit point	
8.4.2.5	Drury point of supply for KiwiRail
8.4.2.6	Henderson supply capacity
8.4.2.7	Mangere supply capacity
8.4.2.8	Otahuhu supply capacity
8.4.2.9	Takanini supply capacity
8.4.2.10	Wiri supply capacity

6 The Unitary Plan contains rules for development including what can be built and where it can be built (see http://unitaryplan.aucklandcouncil.govt.nz/).

7 The Auckland Strategy looked at the requirements for electricity transmission within and across Auckland up to and beyond 2050 (see https://www.transpower.co.nz/keeping-you-connected/auckland-strategy/our-auckland-strategy).

8.4.2.1 Albany–Henderson A line conductor end of life

The conductor on the 110 kV Albany–Henderson A line requires removal in the near-future due to deteriorating condition. The line crosses urban Auckland and replacing the conductor is expected to have a number of challenges.

Enhancement approach:

- We assessed a full range of options for the future of this line, including:
  - replacing the conductor with the modern equivalent
  - replacing the conductor with conductor of a different rating
  - decommissioning and removal of the line
  - replacing the overhead line with an alternative such as a 220 kV line or an underground cable.

Our assessment considered the cost of each option in terms of Vector's development plans as well as Transpower's.

Our preferred option is to decommission and remove the 110 kV Albany–Henderson A line. To maintain operability and security levels some additional investment will be required, including:

- upgrading the branch rating of the 220 kV Henderson–Huapai 1 circuit to enable outages by either rerating disconnector 514 at Henderson or bringing forward its replacement (Base Capex Replacement and Refurbishment funded), and
- upgrading the branch rating of the Wairau Rd T7 220/33 kV transformer to retain n-1 transformer security to all of the Wairau Rd load (customer's internal project).

8.4.2.2 Auckland CBD 220/110 kV interconnection capacity

Ten 220/110 kV transformers[8] supply the 110 kV network in the Auckland region. Three of these transformers, Otahuhu T2 and T4, and Penrose T10, are due for risk-based condition replacement.

Enhancement approach:

- There is a committed project to replace the Penrose–T10 transformer with a new transformer
- There is a committed project to replace OtahuhuT2 and T4 with one new transformer.

Following the replacement of T2 and T4, the Otahuhu 110 kV bus split can be closed, so that the three 220/110 kV transformers at Otahuhu are operating in parallel. This, along with the replacement of Penrose–T10, will provide a high level of security to central Auckland and the Auckland CBD.

Base E&D Capex investments

Project Name	Penrose–T10 risk-based condition replacement
Project description:	Replace Penrose–T10 with a new 220/110 kV, 250 MVA, 15% impedance transformer
Project's state of completion	Committed
OAA level completed:	AL 3d
Grid need date:	2019
Indicative cost [$ million]:	7
Part of the GEIR?	No

8 The ten 220/110 kV transformers in the Auckland region are:
- Albany–T4 (200 MVA, 5%)
- Henderson–T1 and T5 (200 MVA, 5%)
- Otahuhu–T3 and T5 (250 MVA, 15%), Otahuhu–T2 (100 MVA, 5%) and Otahuhu–T4 (200 MVA, 5%)
- Penrose–T6 (250 MVA, 15%) and Penrose–T10 (200 MVA, 5%)
- Hobson Street–T12 (250 MVA, 15%).

Project Name	Otahuhu–T4 risk-based condition replacement
Project description:	Replace Otahuhu–T4 with a new 220/110 kV, 250 MVA, 15% impedance transformer. Remove Otahuhu–T2
Project's state of completion	Committed
OAA level completed:	AL 3d
Grid need date:	2020
Indicative cost [$ million]:	6
Part of the GEIR?	No

8.4.2.3 Bombay–Wiri–Otahuhu transmission

Capacity constraints

The Wiri and Bombay loads are supplied via two 110 kV Bombay–Wiri–Otahuhu circuits and three 110 kV circuits from the Waikato region. Power generally flows from both the Otahuhu and Waikato ends into Wiri and Bombay. During low generation in the Waikato 110 kV system, more power flows from Otahuhu to Wiri and Bombay, potentially exceeding the n-1 capacity of the Otahuhu–Wiri section. We investigated this issue in the context of other related 110 kV issues in the Waikato and Central North Island regions (refer to Chapter 6, Grid Backbone, North Island section).

We implemented variable line rating on the Otahuhu–Wiri Tee sections in 2015 to provide additional capacity and defer major investments. In addition, an increase in 220/110 kV transformer impedance at Otahuhu (refer to section 8.4.2.2) will reduce power flow southward from Otahuhu.

However, there is potential for n-1 capacity issues on the circuits during peak load periods from 2019.

Condition assessment

Condition assessment indicates that the conductor on the Bombay–Otahuhu A line (Bombay–Wiri–Otahuhu 1 and 2 circuits) is reaching end-of-life and intervention is needed by 2023. South of Bombay, the Bombay–Meremere A line conductor (a short section of the Arapuni–Bombay circuit) is estimated to reach end of life in 2025. The Hamilton–Meremere B and Meremere–Takanini A lines (Bombay–Hamilton 1 and 2 circuits) are expected to remain in a satisfactory state until around 2030 but require extensive refurbishments[9] if they are retained beyond then.

Enhancement approach

We are in the final stages of our options assessment as part of a Major Capital Expenditure Proposal. Our analysis shows that all the leading options to address both the constraint and condition issues (discussed above) involve installing two 220/110 kV transformers at Bombay.

Our investigation indicates that the most economic approach is to:

- Install two 220/110 kV transformers at Bombay connecting to the double-circuit 220 kV Huntly–Otahuhu A line, then
- Reconductor the 110 kV line between Otahuhu and Wiri
- Dismantle the 110 kV line between Bombay and Wiri
- Dismantle the Bombay–Hamilton 1 and 2 circuits (Hamilton–Meremere B and Meremere–Takanini A lines), and
- Bus the 110 kV Arapuni–Bombay 1 circuit at Hamilton and dismantle the section between Hamilton and Bombay (Bombay–Meremere A and Hamilton–Meremere A lines).

Transmission constraints on the Waikato and Central North Island 110 kV systems will be relieved (but not eliminated) by removal of the 110 kV Bombay–Hamilton 1 and 2 circuits and connection of the Arapuni–Bombay circuit into Hamilton. This will reduce dependence on Waikato 110 kV generation to relieve transmission constraints (refer to Chapters 6 and 9, respectively, for discussion of constraints on the Grid Backbone and in the Waikato region). It will also reduce power flows on the low-capacity Bunnythorpe–Mataroa 110 kV circuit (refer to Chapter 11).

Although our preferred option is not yet approved, we are undertaking detailed design and preliminary work including environmental and consenting work. Proceeding with this work now

9 Planned refurbishments of the Hamilton–Meremere B and Meremere–Takanini A lines were cancelled due to the high likelihood of them being dismantled as part of out developments between Bombay and Wiri. The estimated expenditure of ~$14 million is no longer included in our our business plan.

will ensure we are able to commission the transformers at Bombay in time to remove the ageing conductor in 2023.

Prior to investment, operational measures such as generation constraints and load management may be required to avoid exceeding the n-1 transmission limit between Otahuhu and Wiri.

Major Capex Investment

Project Name	Bombay–Otahuhu regional investigation
Project description:	Install two 220/110 kV transformers at Bombay Reconductor Otahuhu–Wiri line
Project's state of completion	Possible
OAA level completed:	AL 4P
Grid need date:	2023
Indicative cost [$ million]:	40
Part of the GEIR?	No

Base E&D Capex investments

Project Name	Partial removal of Arapuni–Bombay line
Project description:	Bus the Arapuni–Bombay line at Hamilton and remove the Hamilton–Bombay section
Project's state of completion	Possible
OAA level completed:	AL 3P
Grid need date:	2025
Indicative cost [$ million]:	5.5
Part of the GEIR?	No

Project Name	Removal of Bombay–Wiri section of Bombay–Otahuhu line
Project description:	Following the installation of 220/110 kV transformers at Bombay and reconductoring of the Otahuhu–Wiri section of the Bombay–Otahuhu line, remove the Bombay–Wiri section
Project's state of completion	Possible
OAA level completed:	AL 4P (part of the Bombay–Otahuhu conductor condition investigation)
Grid need date:	2023
Indicative cost [$ million]:	TBC
Part of the GEIR?	No

Project Name	Removal of the Bombay–Hamilton line
Project description:	Decommission and remove the 110 kV Bombay–Hamilton line
Project's state of completion	Possible
OAA level completed:	AL 3P
Grid need date:	2030
Indicative cost [$ million]:	6
Part of the GEIR?	No

8.4.2.4 Otahuhu–Penrose transmission capacity

The peak load on transmission circuits into Penrose (Otahuhu–Penrose 5 and 6, Pakuranga–Penrose 3) is forecast to exceed their n-1 capacity by 2021.

Enhancement approach:

Presently the reactor in the 220 kV Penrose–Hobson Street cable is normally bypassed. It can be put into service when the load requires it, reducing loading on the circuits into Penrose.

The Auckland CBD load is supplied from Penrose and Hobson Street, with Penrose supplying the majority of the load due to system impedances. With the reactor switched into service, the increased impedance will result in almost the entire CBD load being supplied from Penrose. This will place more load on Vector's 110 kV Penrose–Liverpool Street cables, and additional changes may be required to improve the balance between Hobson Street and Penrose. Possible options include:

- splitting the Penrose 110 kV bus, so that each cable is supplied by one 220/110 kV transformer, or
- installing series reactors to increase the impedance of each Liverpool St–Penrose cable.

We will discuss development options and timing with Vector.

Customer investments

Project Name	Otahuhu–Penrose transmission capacity
Project description:	Rebalance load flows into Penrose and the CBD
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2021
Indicative cost [$ million]:	TBC
Part of the GEIR?	No

8.4.2.5 Drury point of supply for KiwiRail

KiwiRail is extending the electrification of the Auckland train network south, and requires a new point of supply in the Drury area.

Enhancement approach:

- We are investigating the development of our Drury switching station as a site for a 220/50 kV supply transformer for KiwiRail.

Customer investments

Project Name	New Drury GXP for KiwiRail
Project description:	Install a 220/50 kV transformer at Drury
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	Customer initiated
Indicative cost [$ million]:	8.5
Part of the GEIR?	No

8.4.2.6 Henderson supply capacity

Peak load at Henderson is forecast to exceed the n-1 winter capacity of the two supply transformers from 2019. Significant load growth is forecast for Henderson over the next 15 years as West Auckland is developed to meet housing demand.

Enhancement approach:

- In the short-term, Vector is able to manage this operationally by shifting load between Henderson and Hepburn Rd.
- In the medium-term, a third 220/33 kV supply transformer can be installed at Henderson to increase the n-1 capacity. The newly installed 33 kV switchboard made provision for a third supply transformer. We will discuss development options, investment requirements and timing with Vector.

Customer investments

Project Name	Henderson supply capacity
Project description:	Install third 220/33 kV supply transformer at Henderson
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	Customer initiated
Indicative cost [$ million]:	TBC
Part of the GEIR?	No

8.4.2.7 Mangere supply capacity

Peak load at Mangere is forecast to exceed the n-1 winter capacity of the transformers from 2019.

Enhancement approach:

- In the short-term, this issue can be managed operationally.
- We will investigate an increase of the protection limits on the supply transformers to provide n-1 capacity until 2021. We will coordinate this investment with the Mangere 33 kV outdoor to indoor conversion, currently planned for completion prior to winter 2020.

Further development options will be discussed with Vector.

8.4.2.8 Otahuhu supply capacity

Peak load at Otahuhu already exceeds the n-1 winter capacity of the supply transformers, and this is forecast to increase slowly.

Enhancement approach:

- In the short-term, Vector can manage this issue by controlling the load.
- Both supply transformers are due for risk-based condition replacement in 2020-2022. We plan to replace (base capex replacement and refurbishment) the supply transformers with 80 MVA units, which will provide sufficient capacity for the forecast period.

8.4.2.9 Takanini supply capacity

The peak load at Takanini is forecast to exceed the n-1 capacity of the Takanini supply transformers from 2022.

Enhancement approach:

- The capacity of the Takanini supply transformers is limited by metering accuracy. Removing this limit will increase the n-1 transformer limit to beyond the forecast peak load.

8.4.2.10 Wiri supply capacity

The peak load at Wiri is forecast to exceed the n-1 capacity of the transformers from 2020. The peak load at Wiri is also forecast to exceed the n-1 winter capacity of the Wiri–Wiri Tee section from 2019.

Towards the end of the forecast period, Wiri–T1 is also due for risk-based condition replacement.

Enhancement approach:

- In the short-term, this issue can be managed operationally.
- The preferred option is to replace the existing Wiri–Wiri Tee line with a higher capacity line. Despite being short in length, this line traverses a motorway, which will complicate an otherwise simple project. This work will be completed as part of the Bombay–Wiri–Otahuhu project (refer to section 8.4.2.3).

We will discuss longer term investment options for the supply transformer capacity with Vector.

8.5 Asset capability and management

We have assessed the transmission capacity and reactive support requirements in the region for the next 15 years. When an issue or opportunity exists, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 8.4.2) have been developed to address issues or opportunities that require action within the forecast period and where investment is justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk-based asset replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

8.5.1 Auckland transmission system significant upcoming work

We integrate our capital project and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Table 8-3 lists the significant upcoming work proposed for the Auckland region over the next 15 years that may significantly impact related system issues or connected parties.

Table 8-3: Proposed significant upcoming work

Description	Tentative year	E&D Issue
Albany–Henderson A conductor replacement	2020-2022	None
Bombay–Meremere A conductor replacement	2024-2025	8.5.4.2
Bombay–Otahuhu A conductor replacement	2022-2023	8.5.4.2
Glenbrook deviation conductor replacement	2030	None
Henderson–Maungatapere A conductor replacement	2032	7.5.4.2
Henderson–Marsden A conductor replacement	2027-2028	None
Mangere 33 kV outdoor to indoor conversion	2019-2020	8.5.4.6
Otahuhu–T4 220/110 kV transformer replacement, T2 decommissioning Otahuhu supply transformers' risk-based condition replacement	2018-2019 2020-2022	8.5.4.3 8.5.4.7
Otahuhu–Whakamaru A and B Otara section conductor replacement	2020-2024	None
Penrose–T10 220/110 kV transformer risk-based condition replacement Penrose replace 22 kV switchboard Penrose exit old control and relay room	2019-2020 2019-2020 2019-2023	None None None
Takanini supply transformer T5 refurbishment	2025-2026	None
Wiri 33 kV outdoor to indoor conversion Wiri–T1 supply transformer risk-based condition replacement	2020-2021 2029-2031	8.5.4.9 8.5.4.9

8.5.2 Auckland asset feedback

The Asset Feedback Register includes no entries related to E&D specific to the Auckland region.

8.5.3 Changes since the 2018 Transmission Planning Report

Table 8-4 lists the specific new issues and those that are no longer relevant within the forecast period (relative to our previous Transmission Planning Report).

Table 8-4: Changes since the 2018 TPR

Issues	Change
Takanini supply transformer capacity	New issue. A metering accuracy limit results in a lower branch capacity than was forecast last year.
Mount Roskill supply transformer capacity	Removed. Supply transformer replaced with higher capacity unit.

8.5.4 Auckland transmission capability

Table 8-5 summarises identified issues that may affect the Auckland region over the next 15 years. In each case, we have detected a condition that would constrain the network capacity if action were not taken. Each issue is discussed in more detail below.

This transmission capability section reports whether the Grid can reasonably be expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, makes up the Grid Reliability Report (GRR).

Table 8-5: Auckland region transmission issues – regional / site by grid exit point

Section number	Issue
Regional	
8.5.4.1	Albany–Henderson 110 kV transmission capacity
8.5.4.1	Bombay–Wiri–Otahuhu 110 kV transmission capacity
8.5.4.2	Otahuhu interconnecting transformer capacity
8.5.4.3	Otahuhu–Penrose transmission capacity
Site by grid exit point	
8.5.4.4	Henderson supply transformer capacity
8.5.4.5	Mangere supply transformer capacity
8.5.4.6	Otahuhu supply transformer capacity
8.5.4.7	Penrose supply transformer capacity
8.5.4.8	Takanini supply transformer capacity
8.5.4.9	Wiri supply transformer capacity

8.5.4.1 Albany–Henderson 110 kV transmission capacity

Issue

The Albany–Henderson A line conductor has been assessed as requiring removal, due to condition, by 2022. With the Wairau Rd load now partially supplied from the 220 kV Hobson St–Wairau Rd–Albany cable, the need for the Albany–Henderson A line has reduced.

What next?

The issue affects the security of supply to Wairau Rd. To a lesser extent it also impacts our ability to get maintenance outages on the Hobson St–Wairau Rd cable. Refer to section 0 for our enhancement approach.

8.5.4.2 Bombay–Wiri–Otahuhu 110 kV transmission capacity

Issue

The Wiri load is supplied via a double hard tee connection to the two 110 kV Bombay–Wiri–Otahuhu circuits, with the:

- Bombay–Wiri Tee section of each circuit rated at 62/76 MVA (summer/winter)
- Otahuhu–Wiri Tee section of each circuit rated at 92/101 MVA (summer/winter)
- Wiri–Wiri Tee section of each circuit rated at 92/101 MVA (summer/winter).

In 2015, variable line rating was applied to the 110 kV Otahuhu–Wiri Tee section of the circuits. This provides a minimum of 12/17/20 per cent additional capacity (summer/shoulder/winter), depending on the month and time of day.

Following the application of variable line rating, three further issues continue to affect the Bombay–Wiri–Otahuhu transmission capacity:

- Peak load at Wiri is forecast to exceed the n-1 winter capacity of the Wiri–Wiri Tee section from 2019.
- An outage of the 110 kV Bombay–Wiri–Otahuhu 1 circuit can overload the Otahuhu–Wiri section of the parallel circuit from 2019. This is most problematic during periods of low Waikato 110 kV generation as that results in more power flow from Otahuhu to Bombay.
- A 110 kV bus section outage at Otahuhu that disconnects Otahuhu–T4 and Bombay–Wiri–Otahuhu 1 and 2 will overload the Bombay–Wiri Tee 2 section and the Bombay–Hamilton 1 and 2 circuits. It may also lead to low voltages or voltage collapse at Wiri and Bombay. The overload occurs due to unequal load sharing of the Wiri supply transformers as the transformers have different impedances and the Wiri 110 kV bus is split.

What next?

The issues will be managed operationally in the short term. We are investigating options to resolve the Otahuhu–Wiri transmission constraint. Refer to section 8.4.2.3 for our enhancement approach.

8.5.4.3 Otahuhu interconnecting transformer capacity

Issue

The Otahuhu 110 kV bus is normally operated split with two separate buses to give better load distribution and manage fault levels. One of the Otahuhu 110 kV buses is supplied by two 220/110 kV transformers (T2 and T4, rated at 100 MVA and 200 MVA, respectively) providing:

- total nominal installed capacity of 300 MVA
- n-1 capacity of 135/145 MVA (summer/winter).

The Otahuhu–T2 and T4 transformers are due for risk-based condition replacement.

What next?

Otahuhu–T2 and T4 supply Wiri and Bombay. Therefore, this issue is considered in the context of other Wiri and Bombay related issues. Refer to sections 8.4.2.2 and 8.4.2.3 for our enhancement approach.

8.5.4.4 Otahuhu–Penrose transmission capacity

Issue

Penrose is supplied by two 220 kV overhead circuits from Otahuhu, and one 220 kV underground cable from Pakuranga. From 2021, an outage of the Pakuranga–Penrose 3 cable circuit during peak load periods is forecast to overload the 220 kV Otahuhu–Penrose circuits.

What next?

The issue affects Vector's sub-transmission network between Penrose, Liverpool Street and Hobson Street, which operates in parallel with the 220 kV transmission network. Refer to section 8.4.2.4 for our enhancement approach.

8.5.4.5 Henderson supply transformer capacity

Issue

Two 220/33 kV transformers supply Henderson's load, providing:

- total nominal installed capacity of 240 MVA
- n-1 capacity of 138/141 MVA[10](summer/winter).

Peak load at Henderson is forecast to exceed the n-1 winter capacity of the transformers by approximately 13 MW in 2019, increasing to approximately 92 MW in 2029.

Our underlying assumptions regarding uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid at peak reduce the forecast n-1 overloading to about 88 MW by 2034 (see Table 8-6).

Table 8-6: Henderson supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Henderson (n-1)	13	21	31	40	48	58	66	73	80	90	92	88

What next?

The issue can be managed operationally in the short term, given Vector's capability to transfer load to other grid exit points via its distribution network. Refer to section 0 for our enhancement approach.

8.5.4.6 Mangere supply transformer capacity

Issue

Two 110/33 kV transformers supply Mangere's load, providing:

- total nominal installed capacity of 240 MVA
- n-1 capacity of 118/118 MVA[11] (summer/winter).

Peak load at Mangere is forecast to exceed the n-1 winter capacity of the transformers by 18 MW in 2019, increasing to approximately 44 MW in 2034 (see Table 8-7).

Table 8-7: Mangere supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Mangere	18	22	24	26	28	31	33	35	37	38	40	44

What next?

The issue can be managed operationally in the short term. Options to address supply transformer issues at Mangere have been identified. Refer to section 8.4.2.7 for our proposed approach.

8.5.4.7 Otahuhu supply transformer capacity

Issue

Two 220/22 kV transformers supply Otahuhu load, providing:

- total nominal installed capacity of 100 MVA
- n-1 capacity of 59/59 MVA[12] (summer/winter).

Peak load at Otahuhu is forecast to exceed the n-1 winter capacity of the supply transformers by 16 MW in 2019, increasing to approximately 22 MW in 2034 (see Table 8-8).

10 The capacity of the transformers is limited by the LV cables and circuit breakers. With these limits resolved, n-1 capacity will be 144/150 MVA (summer/winter).

11 The capacity of the transformers is limited by a protection equipment limit. With this limit resolved, the n-1 capacity will be 138/144 MVA (summer/winter).

12 The capacity of the transformers is limited by LV cable ratings, followed by a transformer bushings limit (64 MVA). With these limits resolved, the n-1 capacity will be 67/71 MVA (summer/winter).

Table 8-8: Otahuhu supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Otahuhu	16	16	17	18	19	19	20	20	21	22	22	22

What next?

This issue is being managed operationally in the short term. Both supply transformers are due for risk-based condition replacements. Refer to section 8.4.2.8 for our enhancement approach.

8.5.4.8 Penrose supply transformer capacity

Issue

Three 220/33 kV transformers supply Penrose's load, providing:

- total nominal installed capacity of 560 MVA
- n-1 capacity limit of 380 MW (summer/winter).

Peak load at Penrose will exceed the n-1 winter capacity of the transformers by approximately 5 MW in 2025, increasing to approximately 14 MW in 2034 (see Table 8-9).

There is also a fourth hot-standby 220/33 kV supply transformer with n-1 capacity of 242/252 MVA. It cannot normally be switched into service because the 33 kV fault level would be too high, but does enable us to rapidly restore capacity following a transformer outage.

Table 8-9: Penrose supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Penrose	0	0	0	0	0	0	5	4	5	7	7	14

What next?

We expect the overload to be manageable operationally by Vector for the forecast period, either through load control or by transferring load to other grid exit points. The hot-standby transformer can be used to rapidly restore capacity following a transformer outage.

Vector has consulted with us extensively on developing an alternate grid exit point to supply some of the Penrose loads. The main driver for this is to increase diversity of its network, as Penrose (33 kV and 22 kV) is currently one of the largest grid exit points in the country with a peak load of over 300 MW.

Discussions are ongoing and no investments are planned at this stage.

8.5.4.9 Takanini supply transformer capacity

Issue

Two 220/33 kV transformers supply Takanini's load, providing:

- total nominal installed capacity of 300 MVA
- n-1 capacity limit of 162/162 MVA[13] (summer/winter).

Peak load at Takanini will exceed the winter n-1 capacity of the transformers by approximately 1 MW in 2022, increasing to approximately 17 MW in 2029.

Our underlying assumptions for uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid at peak reduces the forecast n-1 overloading to about 11 MW by 2034 (see Table 8-10).

13 The capacity of the transformers is limited by a metering accuracy limit. With this limit resolved, the n-1 capacity will be 188/198 MVA (summer/winter).

Table 8-10: Takanini supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Takanini	0	0	0	1	4	7	9	11	13	15	17	11

What next?

Resolving the protection equipment limits will defer the overload issue until the end of the forecast period. Refer to section 8.4.2.9 for our proposed approach.

8.5.4.10 Wiri supply transformer capacity

Issue

Two 110/33 kV transformers supply Wiri's load, providing:

- total nominal installed capacity of 200 MVA
- n-1 capacity limit of 109/115 MVA (summer/winter).

Peak load at Wiri will exceed the winter n-1 capacity of the transformers by approximately 3 MW in 2020, increasing to approximately 22 MW in 2034 (see Table 8-11).

Table 8-11: Wiri supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Wiri	0	3	4	5	8	10	12	14	15	18	20	22

What next?

This issue is being managed operationally in the short-term. Refer to section 8.4.2.10 for our proposed approach.

8.5.5 Auckland bus security

This section presents issues arising from the outage of a single bus section rated at 110 kV and above for the next 15 years.

Bus outages disconnect more than one power system component (for example, circuits, transformers, reactive support or generators). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

8.5.5.1 Transmission bus security

Table 8-12 lists bus outages that cause voltage issues or a total loss of supply. Supply bus outages, typically 11 kV and 33 kV, are not listed.

Table 8-12: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Bombay 110 kV	Bombay 33 kV	-	Bombay–Hamilton 1 overloads Low voltage at Bombay and Wiri	Note 1 Note 1
Henderson 220 kV	-	-	Henderson–T2 or T3 overload	8.5.4.5
Glenbrook 110 kV	Counties Power 33 kV supply	-	-	Note 2
Mangere 110 kV	-	-	Mangere–T1 or T2 overload	8.5.4.6
Mt Roskill 110 kV	All Mt Roskill load	-	-	Note 3
Otahuhu 110 kV	-	-	Bombay–Wiri Tee overloading and low voltages Bombay–Hamilton overloading	8.5.6.2 8.5.6.2
Otahuhu 220 kV	-	-	Otahuhu–T11 or T12 overload	8.5.4.7
Penrose 220 kV	-	-	Penrose–T7 overload Penrose–T9 overload Penrose–T11 overload	8.5.4.8

1. Bombay has two 110 kV bus sections, but the circuits and transformers are not distributed evenly across both bus sections. Tripping Bus A disconnects both supply transformers, causing a loss of supply to the 33 kV load. Tripping Bus A also disconnects two of the three circuits from Arapuni/Hamilton, which can cause the remaining circuit to overload and result in low voltages.
2. The Glenbrook 33 kV bus is split so that one side (the 'dirty' bus) supplies the industrial load at the steel mill and the other side (the 'clean' bus) supplies Counties Power' customers (rural and small towns) in the area.The clean bus is supplied by a single transformer, so an outage of the section of bus to which it is connected will cause an outage to all Counties Power customers in the area.
3. The Mt Roskill 110 kV bus consists of a single bus section. We investigated options to increase the bus security at Mt Roskill but determined that no economic options are available. We will continue to monitor the risk and work with Vector to investigate options that may be economic.

With the exception of the Mt Roskill 110 kV bus, our customers (Counties Power and Vector) have not requested a higher security level. We do not propose increasing bus security and future investment is likely to be customer-driven. If increased bus security is required, the options typically include bus reconfiguration and/or additional bus circuit breakers.

8.5.6 Other regional items of interest

8.5.6.1 Penrose control relay room exit

Issue

The old control relay room, which houses some relay and control equipment at Penrose has seismic deficiencies. The relay room provides a high degree of secondary system diversity for the critical Penrose site.

The 22 kV switchboard is also in this building.

What next?

We plan to exit this building soon by migrating equipment across to a new relay room, which will be built specifically for this project (base capex replacement and refurbishment). We plan to duplicate secondary systems as appropriate for a site of this criticality.

A replacement 22 kV switchboard will be installed by Vector.

8.5.6.2 Transmission capacity to Bombay and Wiri

Issue

An outage of the Otahuhu 110 kV B1 bus section disconnects both 110 kV Otahuhu–Wiri Tee circuits at Otahuhu. In this scenario, all Bombay and Wiri load is supplied via two 110 kV Bombay–Hamilton circuits and one 110 kV Arapuni–Bombay circuit.

Both the Bombay–Hamilton and the Arapuni–Bombay circuits are rated at 51/57/62 MVA (summer/shoulder/winter). The combined Bombay and Wiri load may already overload the

110 kV Hamilton–Bombay circuits for this Otahuhu bus section outage. The Bombay–Wiri 1 circuit may also overload to a lesser extent.

The Otahuhu bus outage may also cause low voltages on the Wiri and Bombay 110 kV buses.

What next?

This issue will be resolved in conjunction with the Bombay–Wiri–Otahuhu transmission constraint issue. See section 8.4.2.3 for our enhancement approach.

8.5.7 New grid exit point at Drury

Issue

KiwiRail is extending the electrification of the Auckland train network south, and requires a new point of supply in the Drury area. At the same time, Counties Power is exploring the option of developing a new grid exit point at Drury to supply new loads and reinforce its existing network supplied from Bombay.

What next?

We are investigtating development of the 220 kV Drury switching station to provide 50 kV and 110 kV grid exit points for KiwiRail and Counties Power, respectively. The designation for Drury has been changed from Switching Station to Grid Exit Point to allow for KiwiRail and Counties Power's future needs.

While no investments are committed for either party yet, we are anticipating investment by KiwiRail in the near term, with a decision by Counties in the medium to longer term.

8.5.8 Auckland generation proposals and opportunities

This section details relevant regional issues for selected generation proposals under investigation by developers and in the public domain, or other generation opportunities. The impact of committed generation projects on the grid backbone is dealt with separately in Chapter 6.

The maximum generation that can be connected depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

8.5.8.1 Maximum regional generation

The Auckland region has some of the highest load densities in New Zealand, coupled with low levels of local generation, so there is no practical limit to the maximum generation that can be connected within the region. However, there will be limits on the maximum generation that can be connected at an individual substation or along an existing line due to the ratings of the existing circuits.

8.5.8.2 Auckland generation issues

There are numerous inter-related issues with supplying the load within the Auckland region, as discussed earlier in this chapter. The impact of new generation will entirely depend on where it connects to the transmission system, and may assist in mitigating an issue, have no impact, or worsen the situation. Additional new transmission investments may be needed in some situations. In addition, new generation in the region will increase fault levels which will be an issue for some parts of the transmission and/or distribution systems and may preclude connection in some locations.

9 Waikato Regional Plan

9.1 Regional overview and transmission

The Waikato region includes the city of Hamilton, together with a number of large towns and smaller rural localities. Significant industry in the region includes dairying and pulp and paper processing.

The existing transmission network for the Waikato region is set out geographically in Figure 9-1 and schematically in Figure 9-2. The region comprises two distinct transmission networks, 110 kV and 220 kV, of which the 220 kV network forms part of the grid backbone.

Figure 9-1: Waikato region transmission network

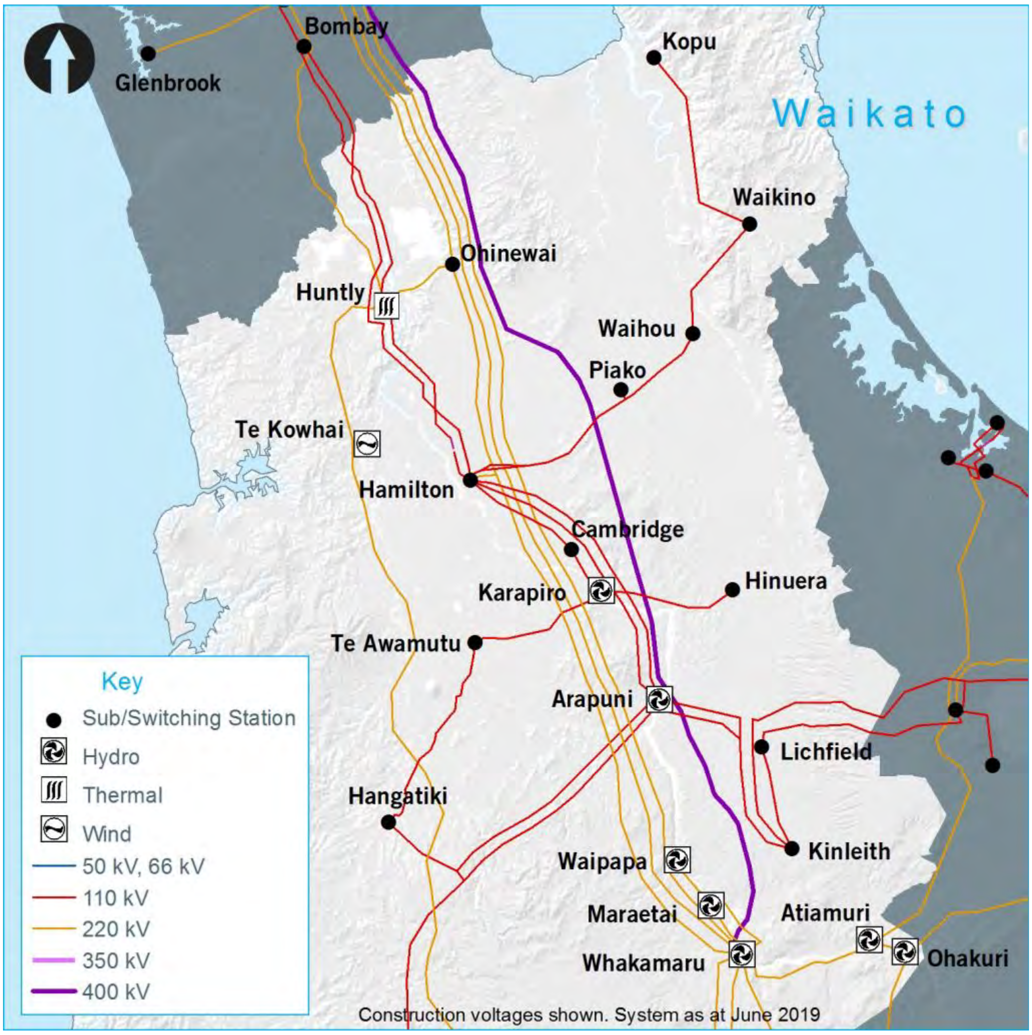
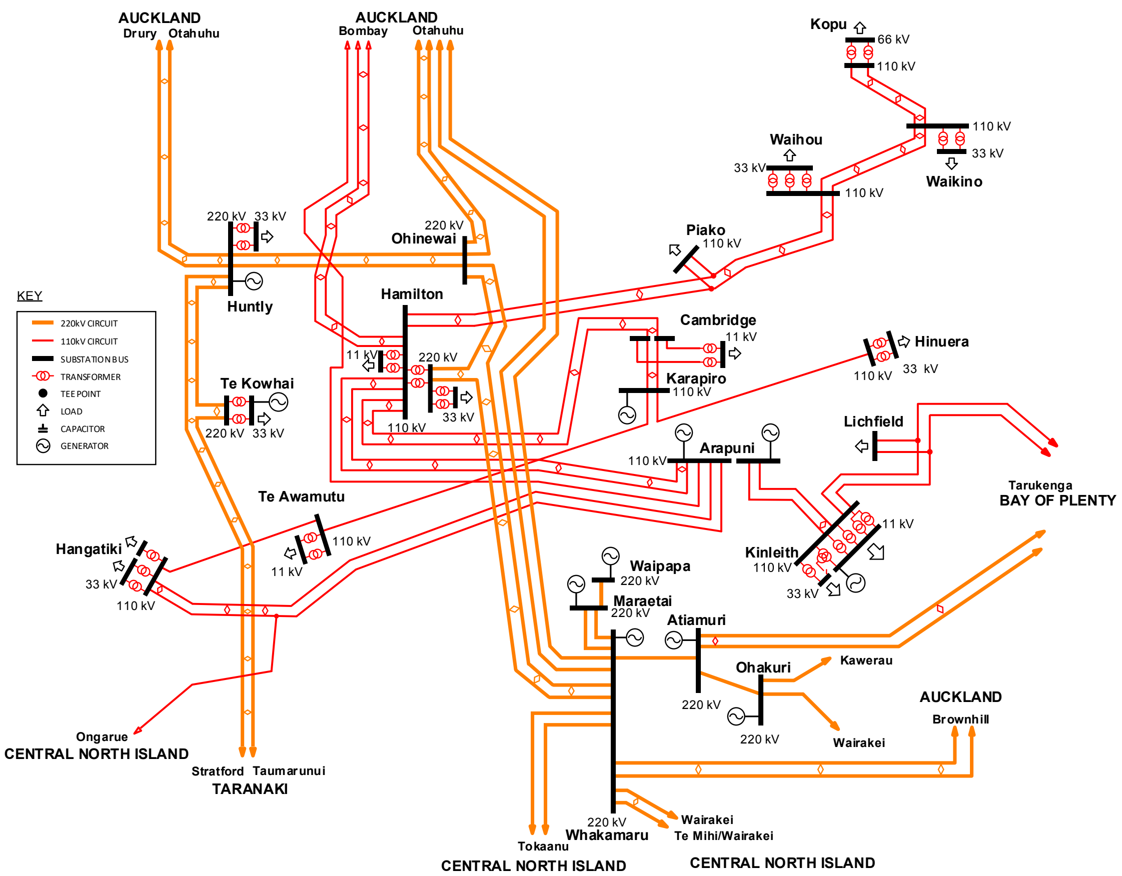


Figure 9-2: Waikato region transmission schematic



9.1.1 Transmission into the region

Transmission in the Waikato region is complex. The 220 kV circuits form part of the grid backbone (Chapter 6) and connect the region to Stratford (Taranaki), Tokaanu and Wairakei (Central North Island), and Drury and Otahuhu (Auckland). The 110 kV circuits connect the region to Tarukenga (Bay of Plenty), Ongarue (Central North Island), and Bombay (Auckland).

The Waikato region includes a significant portion of total North Island generation capacity, and output from the generators generally exceeds local demand. Surplus generation is exported over the 220 kV transmission network. The 220 kV transmission network has sufficient capacity to provide n-1 security to the local load for the forecast period.

9.1.2 Transmission within the region

The 110 kV transmission network within the region supplies and connects the rest of the Waikato region, including most of the regional load and some regional generation.

A significant portion of the regional 110 kV network also runs in parallel with the 220 kV network to transfer power between the Waikato region and the Auckland, Bay of Plenty and Central North Island regions. The region's 110 kV circuits are low capacity relative to the local load, generation and parallel 220 kV network.

9.2 Waikato demand

The Waikato regional peak demand[1] is forecast to grow by an average of 1.7 per cent per annum over the next 15 years, from 522 MW in 2019 to 677 MW in 2034. This exceeds the national average forecast growth rate of 1.2 per cent per annum.

Table 9-1 sets out forecast peak demand (prudent growth[2]) for each grid exit point for the forecast period.

Table 9-1: Forecast annual peak demand (MW) at Waikato grid exit points to 2034

Grid exit point	Power factor	Peak demand (MW)											
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Cambridge[1]	0.99	45	61	65	67	69	81	83	85	86	88	89	95
Hamilton 11 kV	1.00	31	31	31	32	32	33	33	33	34	34	35	35
Hamilton 33 kV[2]	1.00	137	132	136	138	140	141	143	145	146	147	148	139
Hamilton NZR	0.81	5	5	5	5	5	5	5	5	5	6	6	7
Hangatiki[3]	0.90	44	42	47	47	48	48	49	50	50	51	52	58
Hinuera[4]	0.96	48	48	37	36	36	37	38	38	38	38	38	40
Huntly	1.00	27	26	26	27	27	28	28	29	29	30	30	29
Kinleith 11 kV	0.93	83	82	82	82	82	83	83	83	83	83	83	86
Kinleith 33 kV	0.97	20	20	20	21	21	21	22	22	23	23	23	26
Kopu	-0.99	52	51	52	53	54	55	56	57	58	59	60	56
Lichfield	0.95	16	16	16	16	16	16	16	16	16	16	16	17
Piako[4]	0.99	41	40	42	45	46	46	47	47	47	48	48	53
Putaruru[4]	1.00	0	18	18	18	19	19	19	20	20	20	21	23
Te Awamutu[5]	0.98	39	38	42	43	43	44	44	45	45	46	46	45
Te Kowhai[2]	0.99	98	94	98	99	101	101	102	102	101	98	95	90
Waihou	1.00	51	49	51	51	52	52	53	53	53	54	54	56
Waikino	1.00	40	39	40	41	42	42	43	44	44	45	45	42

1. New industrial processing loads are added in 2020 (8.5 MW) and 2024 (9.5 MW).
2. There is frequent load shifting between Hamilton and Te Kowhai.
3. New Dairy Factory loads are added in 2019 (3.2 MW) and 2021 (3.2 MW).
4. 18 MW of load is shifted from Hinuera to Putaruru (supplied from the Arapuni 110 kV north bus) in 2020 and 3 MW of load is shifted from Hinuera to Piako (Waharoa substation) in 2022.
5. Waikeria Prison expansion load step of 4 MW is added in 2021

[1] For discussion on demand forecasting see Chapter 3, section 3.1.

[2] Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

9.3 Waikato generation

Generation capacity in the Waikato region is currently 2,207 MW. Table 9-2 provides the generation forecast by grid injection point for the forecast period. This comprises all known and committed generation stations including those embedded within the relevant local lines company network (Waipa Networks, WEL Networks, The Lines Company or Powerco).[3]

Further generation may be developed during the period but is not sufficiently advanced to be included in our forecasts (refer to section 9.5.7 for more information on potential new generation).

Table 9-2: Forecast annual generation capacity (MW) at Waikato grid injection points to 2034 (existing and committed generation)

Grid injection point (location/name if embedded)	Generation capacity (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Arapuni	197	197	197	197	197	197	197	197	197	197	197	197
Atiamuri	84	84	84	84	84	84	84	84	84	84	84	84
Hangatiki (Mangapehi)	3	3	3	3	3	3	3	3	3	3	3	3
Hangatiki (Wairere Falls)	4	4	4	4	4	4	4	4	4	4	4	4
Hangatiki (Mokauiti)	2	2	2	2	2	2	2	2	2	2	2	2
Hangatiki (Speedies Road)	2	2	2	2	2	2	2	2	2	2	2	2
Huntly[1]	948	948	948	948	948	448	448	448	448	448	448	448
Karapiro[2]	90	90	90	90	90	112	112	112	112	112	112	112
Kinleith	28	28	28	28	28	28	28	28	28	28	28	28
Maraetai	360	360	360	360	360	360	360	360	360	360	360	360
Mokai	112	112	112	112	112	112	112	112	112	112	112	112
Ohakuri	112	112	112	112	112	112	112	112	112	112	112	112
Te Awamutu (Anchor Products)	4	4	4	4	4	4	4	4	4	4	4	4
Te Kowhai (Te Rapa)	44	44	44	44	44	44	44	44	44	44	44	44
Te Kowhai (Te Uku)	64	64	64	64	64	64	64	64	64	64	64	64
Te Kowhai (Horotiu Landfill)	1	1	1	1	1	1	1	1	1	1	1	0
Waikino (Tirohia Landfill)	1	1	1	1	1	1	1	1	1	1	1	1
Waipapa	51	51	51	51	51	51	51	51	51	51	51	51
Whakamaru[3]	100	120	120	120	120	120	120	120	120	120	120	120

1. Two 250 MW coal-fired units are assumed to remain in service at Huntly until the end of 2022, at which time they are decommissioned.
2. Karapiro hydro station refurbishment will increase the installed capacity by 17% once all of the upgrades are completed, which is due in 2024.
3. Whakamaru is currently being upgraded and its capacity will increase by 20 MW once all of the upgrades are completed, which is due in 2020.

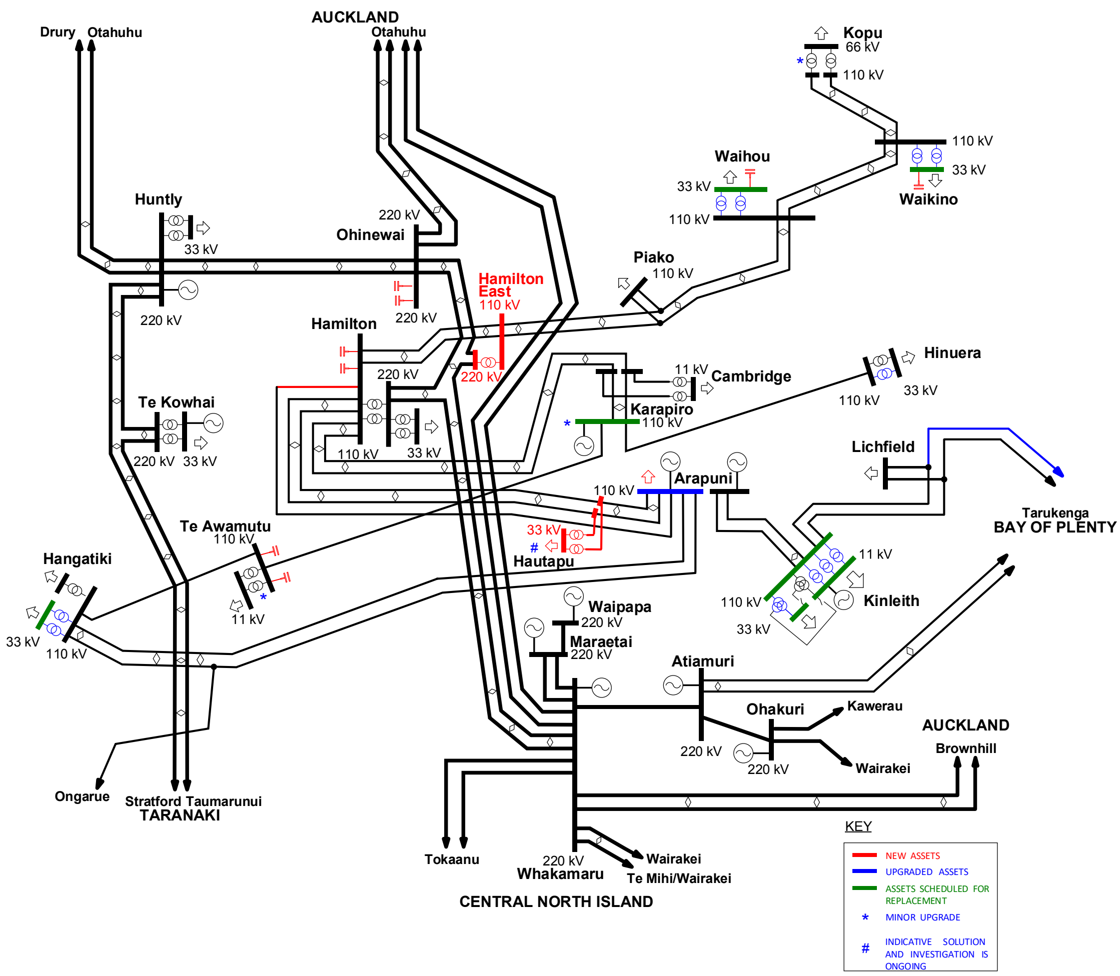
[3] Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest MW.

9.4 Grid enhancement approach

9.4.1 Possible future Waikato transmission configuration

Figure 9-3 shows the possible configuration of Waikato transmission in 2034. New assets, upgraded assets, and assets scheduled for replacement within the forecast period (based on potential enhancement approaches set out in the following sections) are shown.

Figure 9-3: Possible Waikato transmission configuration in 2034



9.4.2 Enhancement approach

Our approach seeks to ensure secure transmission is available into and across the Waikato region into the future. Through the E&D process we have assessed transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified problems and opportunities we take into account uncertainty in future demand, generation and technological developments.

Several possible grid backbone developments through the Waikato region are currently being investigated. These are discussed in Chapter 6, Grid Backbone (North Island section).

The possible enhancements discussed below (except for the Hamilton supply transformer capacity) are either part of or connect to the Waikato 110 kV network. The Waikato 110 kV network in turn connects to the 110 kV networks in other regions. The enhancements in one region may impact multiple issues within and outside the region. See Chapter 6, for an overview of the interrelated 110 kV issues in the North Island.

Transmission issues likely requiring E&D or Customer-funded investments in the Waikato region over the next 10-15 years are:

Section number	Issue
Regional	
9.4.2.1	Arapuni–Hamilton transmission capacity
9.4.2.2	Arapuni–Kinleith–Tarukenga transmission capacity
9.4.2.3	Hamilton–Cambridge–Karapiro transmission capacity
9.4.2.4	Hamilton–Piako transmission capacity
9.4.2.5	Hangatiki transmission capacity
9.4.2.6	Waikato 220/110 kV interconnection capacity
By grid exit point	
9.4.2.7	Cambridge supply transformer capacity
9.4.2.8	Hangatiki supply transformer capacity
9.4.2.9	Hinuera transmission capacity and transmission security
9.4.2.10	Kinleith redevelopment
9.4.2.11	Kopu supply transformer capacity
9.4.2.12	Te Awamutu supply transformer capacity
9.4.2.13	Piako supply capacity
9.4.2.14	Waihou supply transformer capacity and low voltage
9.4.2.15	Waikino supply transformer capacity and low voltage

9.4.2.1 Arapuni–Hamilton 110 kV transmission capacity

The Arapuni bus is normally split with Bombay, Hamilton, and Hangatiki circuits on one side of the split (the “North bus”); the other side of the split connects the Kinleith circuits (the “South bus”). Arapuni generators G1–G4 connect to the North bus and G5–G8 are selectable to the North or South bus.

The Arapuni–Hamilton circuits may overload during periods of high Arapuni generation, requiring pre-contingency constraints on Arapuni generation. Any post-contingent overloads on the circuits are managed by the Arapuni North (Generation) Runback Scheme. In addition, the following range of developments have, or will, reduce constraints on Arapuni generation.

- Growing load at Hangatiki means that more Arapuni generation will be consumed locally (within the Waikato 110 kV network) rather than being exported to Hamilton over the Arapuni–Hamilton circuits.
- Waipa Network’s Hangatiki–Te Awamutu circuit has added a parallel path for exporting Arapuni generation toward Hamilton, reducing the loading on the Arapuni–Hamilton circuits. However, note that this circuit causes issues on the transmission into Hangatiki (see section 9.5.4.9) and exacerbates the Bunnythorpe–Mataroa circuit constraint (see Chapter 11, Central North Island).
- Powerco is investigating the option of reinforcing its Hinuera grid exit point from the Arapuni North bus (refer to section 9.4.2.9). This development would further reduce the need to export Arapuni generation to Hamilton.
- The Arapuni South Runback scheme allows more Arapuni generation to be dispatched on the South bus rather than the North bus, which reduces the probability of constraints on the Arapuni North bus.

This combination of factors means that the likelihood of further investment being needed to relieve transmission constraints on the Arapuni–Hamilton circuits is low. However, this could change should any of the circumstances described above change.

Preliminary analysis suggests that reconductoring the 110 kV Arapuni–Hamilton circuits (and possibly also the Arapuni–Bombay circuits) to remove the overload is unlikely to be economically justifiable, especially as the existing conductors are not expected to require replacement within the forecast period.

The Arapuni bus split was implemented in 2011 as a short-term measure by physically rearranging 110 kV bus conductors to bypass disconnectors. This non-standard bus and equipment configuration reduces security and operational flexibility for both maintenance and fault outages. As a result of changes in load and generation developments since 2011, we now expect the Arapuni bus split to be required for the foreseeable future.

Enhancement approach:

- We will continue to monitor the loading on these circuits and the factors currently relieving the constraints. An investigation to consider options will be initiated if/when the need arises.
- We propose to reconfigure the Arapuni bus split to align with our standard designs to ensure it is suitable as a long-term system configuration.

Base E&D Capex investments

Project Name	Permanently retain Arapuni bus split
Project description:	Restore line disconnectors to three hardwired 110 kV circuits on the North bus
Project's state of completion	Proposed
OAA level completed:	AL 3p
Grid need date:	2019
Indicative cost [$ million]:	1.6
Part of the GEIR?	Yes

9.4.2.2 Arapuni–Kinleith–Tarukenga transmission capacity

The Arapuni bus is normally split with the Kinleith circuits on one side of the split (the "South bus"); the other side of the split connects the Bombay, Hamilton, and Hangatiki circuits (the "North bus"). Arapuni generators G5–G8 are selectable to the North or South bus.

The Arapuni–Kinleith–Tarukenga circuits are normally configured as a spur originating from Tarukenga. The Lichfield substation is connected into the Kinleith–Tarukenga circuits via a double Tee connection.

The spur connects a Fonterra dairy factory at Lichfield (peak demand 17 MW), Oji's pulp and paper plant at Kinleith (peak demand 85 MW), and Powerco's distribution load at Kinleith (peak demand 20 MW). Generation connected to the spur includes Oji's co-generation plant at Kinleith (maximum capacity 39 MW) and Mercury's Arapuni hydro generator (up to four 26 MW units connectable to the Arapuni South bus). Oji's plant can continue to operate at full capacity even if its co-generation is out of service.

The capacity of the spur to supply the connected loads is limited by the n-1 capacity of the Lichfield–Tarukenga circuit sections.[4] The maximum load on the spur occurs in summer, which is when circuit ratings are also at their lowest. As the combined loads on the spur far exceed the n-1 transmission capacity, local generation at Arapuni and Kinleith is critical to maintaining security of supply.

Constraining the minimum and maximum generation connected to the Arapuni South bus may increase other risks. The Kinleith–Lichfield–Tarukenga circuits have variable line ratings applied to minimise the need to constrain on generation at Arapuni during low hydro inflows. The Arapuni South Runback Scheme minimises the need to constrain off Arapuni generation during high hydro inflows.

There is very limited capacity to accommodate additional load growth on the Arapuni–Kinleith–Lichfield–Tarukenga circuits.

Enhancement approach:

- We will investigate options to obtain additional transmission capacity to ensure future demand can be met if/when there is a step-increase in load. Past analysis suggests that reconductoring the circuits will be uneconomic, but a thermal capacity upgrade on the Lichfield–Tarukenga 1 circuit may be justified.

4 During summer, the n-1 capacity of the Lichfield–Tarukenga circuit sections is 51 MVA.

Base E&D Capex investments

Project Name	South Waikato 110 kV Transmission Capacity
Project description:	Minor thermal upgrade of Lichfield–Tarukenga 1 circuit
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	Uncertain, depends on load growth at Kinleith and Lichfield
Indicative cost [$ million]:	0.5
Part of the GEIR?	Yes

9.4.2.3 Hamilton–Cambridge–Karapiro capacity

The "Karapiro Spur" consists of a 110 kV double circuit line from Hamilton to Karapiro with an intermediate substation at Cambridge (Tee connected). From Karapiro there are 110 kV lines to Hinuera and Te Awamutu. At Te Awamutu, Waipa Network's Hangatiki–Te Awamutu single circuit line connects Te Awamutu to Hangatiki at 110 kV.

Hamilton–Cambridge transmission capacity

The combined peak load on the Karapiro spur exceeds the n-1 capacity of the Hamilton–Cambridge circuit sections. However, resource consent restrictions on the Karapiro generating station require a minimum output of 40 MW (assuming generators are available and no water is being spilt). Demand growth at Cambridge is expected to significantly increase the minimum generation requirements at Karapiro and also cause supply transformer constraints at Cambridge. We are working with Waipa to investigate options for reinforcing supply for the Cambridge area (see section 9.4.2.7).

Power flows on other lines impact net load on the Karapiro spur, in turn affecting the constraint. The Hangatiki–Te Awamutu line (which effectively interconnects the Karapiro spur with the rest of the Waikato 110 kV network) has this effect, as will the new Arapuni–Putaruru connection if it proceeds (see section 9.4.2.9).

Enhancement approach:

- While capacity issues can be managed with generation from Karapiro in the short term, we will continue to monitor the constraint on these circuit sections and investigate solutions when necessary.

Cambridge–Karapiro transmission capacity

When load on the Karapiro spur is low and Karapiro generation is high, the Cambridge–Karapiro circuit sections can constrain generation at Karapiro (which would otherwise be exported to Hamilton).

Capacity issues are exacerbated by Waipa Network's Hangatiki–Te Awamutu line and Powerco's potential investment to reinforce its Hinuera grid exit point from the Arapuni North bus (refer to section 9.4.2.9). In addition, Mercury has committed to refurbishing its Karapiro generation station which will increase its capacity by around 17 percent. The increase in capacity will increase the likelihood of constraints on the Cambridge–Karapiro circuit sections.

Enhancement approach:

- We are working with Mercury to investigate options for relieving n-1 constraints on the Cambridge–Karapiro circuit sections. A possible solution is a generation runback scheme to reduce Karapiro generation following a Hamilton–Cambridge–Karapiro circuit outage.

Customer investments

Project Name	Cambridge–Karapiro constraint
Project description:	Karapiro Generation Runback Scheme
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	Uncertain, depends on customer need date
Indicative cost [$ million]:	0.5
Part of the GEIR?	No

9.4.2.4 Hamilton–Piako transmission capacity

The Valley Spur consists of a 110 kV double-circuit line from Hamilton that connects substations at Piako, Waihou, Waikino and Kopu. All four substations have grid exit points supplying Powerco's Waikato distribution network.

The Valley Spur's summer and winter peak loads have become very similar, such that transmission issues previously occurring only in winter now also occur in summer. From 2019 the strong demand on the Valley Spur is expected to cause thermal issues on the Hamilton–Morrinsville Tee section of the Hamilton–Piako–Waihou circuits following an outage on the parallel circuit (the Tee point of the three terminal circuits is called Morrinsville Tee).

Also, a Hamilton–Piako–Waihou circuit outage during a high load period will cause the Waihou and Waikino 110kV supply bus voltages to drop below 0.95 pu with a voltage step exceeding five per cent (see sections 9.4.2.13 and 9.4.2.15).

Enhancement approach:

- In the short-term the issue can be managed operationally.
- We will discuss investment options with Powerco. Installing capacitors at the Waihou and Waikino 33 kV buses would defer the thermal capacity issue by up to two years and would also improve supply voltage quality (see sections 9.4.2.14 and 9.4.2.15).

9.4.2.5 Hangatiki transmission capacity

The Hangatiki grid exit point is supplied by two 110 kV circuits from Arapuni, with one circuit Tee connected to Ongarue (Central North Island region 110 kV). Waipa Network's 110 kV Hangatiki–Te Awamutu circuit also connects Hangatiki to the Karapiro spur.

A significant proportion of the load at the Hangatiki grid exit point is from the Taharoa iron sands operation which has an estimated 10-15 year operating life before the iron sand resources are depleted.

As a whole, the Waikato 110 kV network is already heavily constrained. The Lines Company expects the load at Hangatiki to increase to about 62 MW in stages by 2034. At the same time, The Lines Company plans to improve its overall power factor.

We are investigating constraints that are likely to arise if the Hangatiki load increases to the levels indicated by The Lines Company. The constraints occur not just on the circuits directly connected to Hangatiki but also on circuits several substations from Hangatiki. Load growth at substations connected to the Waikato 110 kV network and adjacent regions also contribute to the constraints.

Part of the issue affecting the 110 kV transmission capacity into Hangatiki is the high reactive power consumption at Hangatiki. This is because the existing transformers are already very highly loaded, and the load power factor is low. Resolving these issues (see section 9.4.2.8) will assist but not resolve the issue of transmission capacity into Hangatiki and the wider 110 kV network.

Our investigations show the usual generation dispatch patterns at Arapuni and Karapiro mean the risks of a thermal constraint binding is low (in the short term). However, there is justification to install capacitors at Te Awamutu to resolve the low voltage and large voltage step issues due to the demand growth at Hangatiki and Te Awamutu.

Enhancement approach:

- We have committed to installing capacitors at the Te Awamutu 110 kV bus, by 2021, to support the 110 kV voltage and supply bus voltage quality in the area. This is in addition to The Lines Company also improving its power factor at Hangatiki.
- We are working with The Lines Company and other customers in the Waikato region to develop a longer-term solution for the wider Waikato 110 kV system constraints. We will also consider the Arapuni North bus security issue when studying investment options (see section 9.5.5.2).

Base E&D Capex investments

Project Name	Hangatiki transmission capacity
Project description:	Install 2x 15 Mvar capacitors at Te Awamutu 110 kV bus
Project's state of completion	Committed
OAA level completed:	AL 3d
Grid need date:	2021
Indicative cost [$ million]:	6.18
Part of the GEIR?	No

9.4.2.6 Waikato 220/110 kV interconnection capacity

The Waikato 220 kV and 110 kV networks are interconnected through two 220/110 kV transformers at Hamilton. During periods of high Waikato 110 kV load and medium/low generation connected to the 110 kV system, these interconnecting transformers can exceed their n-1 ratings, i.e. a trip of one interconnecting transformer can overload the parallel unit (refer to section 9.5.4.3).

The Waikato 110 kV network is also normally connected to the Auckland and Central North Island 110 kV networks. Generation and/or load conditions within these adjacent 110 kV networks can contribute to capacity constraints on the interconnecting transformers at Hamilton.

Enhancement approach:

- We currently manage the interconnecting transformer capacity issue by constraining on generation in the local 110 kV network.
- We will revisit the issue and investigate investment options once transmission developments in the 110 kV networks of the surrounding regions become firm, within the next few years. These are:
  - a long term plan for the 110 kV Hamilton to Bombay transmission lines (see Chapter 8, Auckland region)
  - a long term plan to address transmission issues in the interconnected parts of the Waikato 110 kV network and the configuration of the Arapuni bus.

Options identified to resolve or defer the interconnecting transformer capacity issue include:

- migration of Hamilton 110/11 kV loads to the 220 kV system
- development of one or more new 220 kV grid exit points within the region to supply new and existing loads presently supplied from the 110 kV Waikato network
- installing a third interconnecting transformer in the Hamilton East[5] area. This will also increase transmission security into the Waikato region during maintenance outages (see section 9.5.6.3).

Major Capex investments

Project Name	Waikato 220/110 kV interconnection capacity
Project description:	Build new 220/110 kV interconnection at Hamilton East
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2025
Indicative cost [$ million]:	30
Part of the GEIR?	Yes

5 "Hamilton East" is a location about 5.5 km east of our Hamilton substation where the 220 kV Ohinewai–Whakamaru and the 110 kV Hamilton–Piako–Waihou circuits cross. A 220/110 kV interconnection at Hamilton East would provide increased capacity, security and diversity to Hamilton and the Waikato regional 110 kV loads.

9.4.2.7 Cambridge supply capacity

The Cambridge load is expected to exceed the n-1 capacity of the two 110/11 kV supply transformers from 2019. Both supply transformers are Tee connected to the two 110 kV Hamilton–Cambridge–Karapiro circuits, significantly increasing the probability that a supply transformer will be disconnected.

Enhancement approach:

- We have committed to replace the ageing transformer protection at Cambridge (base capex replacement and refurbishment funded). This will also resolve the transformer branch (protection) limit and will slightly increase the n-1 capacity of the supply transformers from 44.3 MVA to 45/47 MVA (summer/winter), which will relieve the capacity issue but not resolve it.
- In addition, we are installing a transformer overload protection scheme (a special protection scheme) using the new transformer protection relays to provide overload protection on the remaining supply transformer following an outage of the parallel transformer. The scheme will allow the Cambridge grid exit point to supply up to 60 MVA of load with both supply transformers in-service (limited by the rating of the supply transformer LV bushings).
- We are also working with Waipa Networks to investigate longer term options to reinforce supply capacity for the Cambridge area.

Customer investments

Project Name	Cambridge special protection scheme
Project description:	Install Transformer Overload Protection Scheme
Project's state of completion	Committed
OAA level completed:	AL 2d
Grid need date:	2020
Indicative cost [$ million]:	0.25
Part of the GEIR?	No

Project Name	Cambridge supply capacity
Project description:	New 220 kV or 110 kV grid exit point for one or more customers in the Waikato region
Project's state of completion	Possible
OAA level completed:	AL 3p
Grid need date:	2020
Indicative cost [$ million]:	25
Part of the GEIR?	No

9.4.2.8 Hangatiki supply transformer capacity and low voltage

The Lines Company expects the load at Hangatiki to increase to about 62 MW by 2034. The forecast step load increases are driven by developments at the Taharoa iron sands operation and a new dairy factory (developed in 2 stages).

The two existing supply transformers at Hangatiki already operate at their design limits and require major refurbishments. The Lines Company has installed an additional transformer mainly to supply the Taharoa iron sands operation (reducing load on the existing transformers). The additional transformer is not connected to the existing 33 kV bus. The Lines Company does not have immediate plans to contract for replacing the two existing transformers with larger units to provide n-1 security to the existing 33 kV bus.

The Hangatiki 33 kV supply bus voltage may fall below 0.95 pu during high load periods, primarily due to the poor power factor of the Hangatiki load. Other contributing factors are heavy loading on the 110 kV transmission circuits into Hangatiki and the lack of on-load tap changers on the two supply transformers.

Supply bus voltage quality at Hangatiki will be improved by The Lines Company improving its power factor (which also reduces the transformer loading), and/or replacing the two supply transformers with modern units with on-load tap changers.

Enhancement approach:

- The 33 kV supply bus voltage will be improved with our committed investment in capacitors at Te Awamutu (see Section 9.4.2.5).
- We will also work with The Lines Company to investigate longer term investment options to increase supply capacity and/or security to Hangatiki. We will endeavour to optimise our maintenance requirements on the existing Hangatiki supply transformers to suit the future strategy for Hangatiki.

9.4.2.9 Hinuera transmission capacity and transmission security

The Hinuera grid exit point supplies Powerco's eastern Waikato distribution network. Hinuera is connected to the grid via a single 110 kV circuit from Karapiro, providing n security.

Hinuera's peak load exceeds the n-1 capacity of the two supply transformers.

Powerco investigated options to increase security to its eastern Waikato distribution network. Its preferred option is a new 110 kV grid exit point from the Arapuni North bus to its Putaruru substation. The new connection would supply about 35 per cent of the existing Hinuera load during normal operation which would resolve the n-1 capacity issue on the Hinuera supply transformers.

During a Hinuera–Karapiro circuit outage, most of the load at Hinuera would be supplied via the new grid exit point with the remainder transferred to Piako via Powerco's distribution network. Therefore, we do not propose investing in a second 110 kV Hinuera line to provide n-1 security.

Enhancement approach:

- We will continue to discuss the timing of the new 110 kV feeder at Arapuni with Powerco, as well as the longer-term requirements for the Hinuera supply transformers as Hinuera–T1 is due for risk based condition replacement towards the end of the forecast period. Refurbishment of both Hinuera supply transformers towards the start of the forecast period is justified as both transformers will be required in the medium term.

Customer investments

Project Name	Hinuera reinforcement
Project description:	New 110 kV feeder bay on the Arapuni North bus
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2020
Indicative cost [$ million]:	0.5 (costs incurred to Transpower; customer costs are additional)
Part of the GEIR?	No

9.4.2.10 Kinleith redevelopment

The Kinleith grid exit point supplies Powerco. Powerco, in turn, supplies the Oji pulp and paper mill at 11 kV and its own distribution network around Tokoroa at 33 kV. A construction project presently underway will result in the mill's load being supplied by five transformers which do not operate in parallel, so a transformer outage will result in only a partial loss of supply. The distribution load is supplied by a single 110/33/11 kV, 50/40/50 MVA transformer with on-load tap changer and a break-before-make switchover to a backup transformer[6].

A special protection scheme at Kinleith protects the Arapuni–Kinleith circuits from post contingency overloads by tripping Kinleith, which would result in a total loss of supply. This scheme is enabled when there is a system split between Kinleith and Tarukenga. The Arapuni bus split must be closed to allow this system configuration.

Enhancement approach:

- Three 110/11 kV transformers, a 110/33 kV transformer, three 11 kV switchboards, and the 110 kV bus conductor have been or will shortly be replaced based upon their condition. The replacement 110/11 kV transformers are 40 MVA units, and the new 110/33 kV transformer has an 11 kV winding, so supply restrictions are no longer required for planned transformer

6 The backup transformer is the 110/33/11 kV T5 transformer; the 11 kV winding normally supplies the mill load and the 33 kV winding backs up the 33 kV bus. A break-before-make switchover requires disconnecting the first supply transformer before connecting the 33 kV bus to the other supply transformer, resulting in a short loss of supply. The two transformers have a different vector group for the 33 kV winding, which means they cannot be paralleled (connected simultaneously).

outages. The 11 kV loads will still be interrupted for faults on their respective supply transformers. This level of security has been accepted by Oji.

- We upgraded the special protection scheme at Kinleith to allow selective load shedding functionality to be progressively added to minimise lost load when the scheme operates.

We have committed to undertake these works over 2019-20 within the Kinleith Redevelopment Project. The redevelopment funding is predominantly base capex replacement and refurbishment with a small component of customer investment. No further investments are planned for Kinleith.

9.4.2.11 Kopu supply capacity

The Kopu grid exit point is supplied by two 110/66 kV supply transformers. Peak load at Kopu is forecast to exceed the n-1 capacity of the supply transformers in 2024.

Enhancement Approach:

- Resolving the protection limit on the transformers will increase the n-1 capacity to 64/67 MVA (summer/winter). Refurbishment of both supply transformers towards the start of the forecast period is justified as it is not economic to bring forward the transformers' replacement.
- We will discuss longer term investment options with Powerco closer to the need date.

Base E&D Capex investments

Project Name	Kopu supply transformer branch limit
Project description:	Remove protection limit on supply transformers
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2024
Indicative cost [$ million]:	0.12
Part of the GEIR?	No

9.4.2.12 Te Awamutu supply capacity

The Te Awamutu grid exit point is supplied by two 110/11 kV supply transformers. The peak load at Te Awamutu already exceeds the n-1 capacity of the supply transformers.

Enhancement Approach:

- Resolving the protection limit on the supply transformers will increase n-1 capacity to 52/54 MVA (summer/winter), which will provide sufficient n-1 capacity until the end of the forecast period.

Base E&D Capex investments

Project Name	Te Awamutu 110/11 kV supply transformer branch limit
Project description:	Remove protection limit on Te Awamutu supply transformers
Project's state of completion	Committed
OAA level completed:	AL 2
Grid need date:	2019
Indicative cost [$ million]:	0.1
Part of the GEIR?	No

9.4.2.13 Piako supply capacity

The Piako grid exit point is supplied by two 110/33 kV supply transformers. The branch rating of the two 110 kV line sections between Morrinsville Tee and Piako is limited to 46 MVA per line section due to the revenue metering accuracy limit[7]. The peak load at Piako exceeds the n-1 capacity of the 110 kV line sections between Morrinsville Tee and Piako beyond 2025.

[7] The current transformer on the 110 kV side of the 110/33 kV supply transformer at Piako is rated at 240 A due to the revenue metering accuracy limit.

Enhancement Approach:

- Resolving the branch limit on the supply transformers will increase the n-1 capacity of the 110 kV line sections between Morrinsville Tee and Piako to 111/121 MVA (summer/winter), which will provide sufficient n-1 capacity until the end of the forecast period.

Base E&D Capex investments

Project Name	Piako 110/11 kV supply transformer branch limit
Project description:	Remove protection limit on Piako supply transformers
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2025
Indicative cost [$ million]:	0.1
Part of the GEIR?	No

9.4.2.14 Waihou supply transformer capacity and low voltages

Three 110/33 kV transformers supply the Waihou 33 kV load. The peak load at Waihou already exceeds the supply transformers' n-1 capacity.

In addition, the post-contingent static voltages on the Waihou 33 kV bus can drop below 0.95 pu with a voltage step exceeding our planning guidelines of five per cent. The lack of on-load tap changers on the supply transformers makes it impractical to regulate static voltages on the supply bus to within the operational band of 0.95-1.05 pu.

The supply transformers at Waihou are due for risk based condition replacements in 2019-2020 in conjunction with the 33 kV outdoor to indoor conversion.

Enhancement approach:

- We have a project underway to replace the Waihou supply transformers (funded under base capex replacement and refurbishment). The new transformers will have on-load tap changers which will resolve the post-contingent static voltage issue.
- We will work with Powerco to identify the investment requirements to resolve the voltage step issue. A potential investment option is installing capacitors on the Waihou 33 kV bus (customer funded), which would also relieve the Hamilton–Piako transmission issue (see section 9.4.2.4).

Customer investments

Project Name	Waihou voltage quality
Project description:	Install 2x 5 Mvar, 33 kV capacitors
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2020
Indicative cost [$ million]:	1
Part of the GEIR?	No

9.4.2.15 Waikino supply transformer capacity and low voltages

Two 110/33 kV supply transformers supply the Waikino 33 kV load. The peak load at Waikino already exceeds the supply transformers' n-1 capacity.

In addition, post-contingent static voltages on the Waikino 33 kV bus can drop below 0.95 pu with a voltage step exceeding our planning guidelines of five per cent. The lack of on-load tap changers on the supply transformers makes it impractical to regulate static voltages on the supply bus to within the operational band of 0.95-1.05 pu.

The supply transformers at Waikino are due for risk based condition replacements over the next 2-10 years in conjunction with the 33 kV outdoor to indoor conversion (currently funded under base capex replacement and refurbishment).

Enhancement approach:

- We have a project underway to replace one of the Waikino supply transformers due for risk based replacement (funded under base capex replacement and refurbishment). On-load tap changers on the replacement supply transformer will resolve the post-contingent static voltage issue.

- We will work with Powerco to identify the investment requirements to resolve the voltage step issue. A potential investment option is installing capacitors on the Waikino 33 kV bus (customer funded), which would also relieve the Hamilton–Piako transmission issue (see section 9.4.2.4).

Customer investments

Project Name	Waikino voltage quality
Project description:	Install 3x 5 Mvar, 33 kV capacitors
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2020
Indicative cost [$ million]:	1.5
Part of the GEIR?	No

9.5 Asset capability and management

We have assessed transmission capacity and reactive support requirements in the region for the next 15 years. When an issue or opportunity exists, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 9.4.2) have been developed to address issues or opportunities that require action within the forecast period and where investment is justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk based condition replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

9.5.1 Waikato transmission system significant upcoming work

We integrate our capital projects and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Table 9-3 lists the significant upcoming work proposed for the Waikato region over the next 15 years that may significantly impact related system issues or connected parties.

Table 9-3: Proposed significant upcoming work

Description	Tentative year	E&D issues
Hangatiki–T1 and T2 supply transformers refurbishment Hangatiki 33 kV outdoor to indoor conversion	2019-2020 2019-2021	9.5.4.8 9.5.4.8
Hinuera–T1 and T2 supply transformers refurbishment Hinuera–T1 supply transformer risk based condition replacement Hinuera 33 kV outdoor to indoor conversion	2019-2020 2028-2030 2024-2026	9.5.4.10 9.5.4.10 None
Kinleith 11 kV indoor switchboard replacement Kinleith–T1, T2, T3 transformers risk based condition replacement Kinleith 110/33 kV supply transformer replacement Kinleith 110 kV bus refurbishment / replacement	2019-2020 2019-2020 2019-2020 2019-2020	9.5.4.13 9.5.4.13 9.5.4.12 9.5.4.12 and 9.5.4.13
Karapiro 110 kV (Bus) disconnector replacement	2019-2020	9.5.5.1
Kopu–T3 and T4 supply transformers refurbishment	2024-2025	9.5.4.14
Waihou 33 kV outdoor to indoor conversion Waihou–T1, T2, and T3 supply transformers risk based condition replacement	2019-2020 2019-2020	9.5.4.17 9.5.4.17
Waikino 33 kV outdoor to indoor conversion Waikino–T1 supply transformer refurbishment Waikino–T2 supply transformer risk based condition replacement Waikino–T1 supply transformer risk based condition replacement	2019-2020 2021-2022 2018-2020 2026-2028	None 9.5.4.18 9.5.4.18 9.5.4.18

9.5.2 Waikato asset feedback

The Asset Feedback Register does not contain any E&D related entries specific to the Waikato region.

9.5.3 Changes since the 2018 Annual Planning Report

Table 9-4 lists specific new issues and those that are no longer relevant within the forecast period (relative to our previous Transmission Planning Report).

Table 9-4: Changes since the 2018 TPR

Issue	Change
Hangatiki supply transformer capacity and low voltage (see section 9.5.4.8)	Removed. Third 110/33 kV supply transformer commissioned at Hangatiki.
Maraetai bus security	Amended. Maraetai bus section circuit breakers installed.
Piako supply capacity	Added. Increase in load forecast.
Kinleith redevelopment	Project underway. Low 33 kV voltage issue resolved. 11 kV security and capacity improved.

9.5.4 Waikato transmission capability

Table 9-5 summarises identified issues that may affect the Waikato region over the next 15 years. In each case, we have detected a condition that would constrain the network capacity if action were not taken. Each issue is discussed in more detail below.

This transmission capability section reports whether the Grid can reasonably be expected to meet (n-1) security requirements over the next 15 years. This section, in addition to the demand and generation sections, makes up the Grid Reliability Report (GRR).

Table 9-5: Waikato region transmission issues – regional / site by grid exit point

Section number	Issue
Regional	
9.5.4.1	Arapuni–Hamilton 110 kV transmission capacity
9.5.4.2	Arapuni–Kinleith–Tarukenga 110 kV transmission capacity
9.5.4.3	Hamilton interconnecting transformer capacity
9.5.4.4	Hamilton–Piako–Waihou 110 kV transmission capacity
9.5.4.5	Waihou and Waikino low voltage
Site by grid exit point	
9.5.4.6	Cambridge supply transformer capacity
9.5.4.7	Hamilton 220/33 kV supply transformer capacity
9.5.4.8	Hangatiki supply transformer capacity
9.5.4.9	Hangatiki 110 kV transmission capacity
9.5.4.11	Hinuera transmission security
9.5.4.12	Kinleith 110/33 kV supply security and supply transformer capacity
9.5.4.13	Kinleith 110/11 kV supply security
9.5.4.14	Kopu supply transformer capacity
9.5.4.15	Maraetai–Whakamaru transmission capacity
9.5.4.16	Te Awamutu supply transformer capacity
9.5.4.17	Waihou supply transformer capacity
9.5.4.18	Waikino supply transformer capacity

9.5.4.1 Arapuni–Hamilton 110 kV transmission capacity

Issue

The two 110 kV Arapuni–Hamilton circuits are each rated at 51/62 MVA (summer/winter).

The Arapuni 110 kV bus is currently split into two bus sections:[8]

- North bus: Arapuni G1-4 generators, Arapuni–Bombay 1, Arapuni–Hamilton 1 and 2, Arapuni–Hangatiki 1, and the Arapuni–Ongarue 1 circuits
- South bus: Arapuni–Kinleith 1 and 2 circuits.

The Arapuni G5-G8 generators are selectable between the North and South bus sections. At least three of these generators are normally selected to the South bus.

With the Arapuni bus split:

- For the normal selection of generators between the North and South bus sections, there is normally no pre-contingency maximum generation constraint on the North bus. If an Arapuni–Hamilton circuit trips the other Arapuni–Hamilton circuit may overload. This post-contingency overload is automatically removed by the Arapuni North Generation Runback scheme.

The Arapuni bus must be made solid for some maintenance outages. This is becoming increasingly difficult to arrange as closing the bus split causes overloading issues to cascade into the 110 kV networks of adjacent regions (Bay of Plenty and Central North Island). One way to prevent the overloading issues is to constrain on generation in the Waikato 110 kV system and at Huntly. However, there is a high risk that the frequency and extent of constraining on generation will mean that in future it may become impractical to expect generation to be always available when we need it.

Long term retention of the Arapuni bus split will require that 110 kV disconnectors be reinstated on the hardwired circuits on the North bus to facilitate maintenance outages and reduce the restoration time following equipment faults.

8 Cost benefit analysis found this was the most economic normal system configuration.

What next?

We expect to retain the Arapuni bus split and the Arapuni North Generation Runback scheme for the medium to long term.

We expect that the Arapuni–Hamilton circuits would not be upgraded to remove the post-contingency generation constraints but rather would be upgraded only if this addressed other issues in the Waikato 110 kV region. Refer to section 9.4.2.1 for our enhancement approach.

9.5.4.2 Arapuni–Kinleith–Tarukenga 110 kV transmission capacity

Issue

Kinleith and Lichfield are supplied through four 110 kV circuits:

- Arapuni–Kinleith 1 rated at 57/70 MVA (summer/winter)
- Arapuni–Kinleith 2 rated at 63/77 MVA (summer/winter)
- Kinleith–Lichfield–Tarukenga 1 rated at 51/62 MVA (summer/winter)
- Kinleith–Lichfield–Tarukenga 2 rated at 63/77 MVA (summer/winter).

The loading on these circuits may exceed their n-1 capacity under certain operating conditions.

With the Arapuni bus split (normal operating configuration), generation at Kinleith and Arapuni must be managed so that:

- minimum generation at Kinleith and Arapuni is sufficiently high to prevent the Lichfield–Tarukenga circuits exceeding their n-1 capacity
- maximum generation at Arapuni is sufficiently low to prevent the Arapuni–Kinleith circuits exceeding their n-1 capacity.

Variable line ratings are applied on the Kinleith–Lichfield–Tarukenga circuits to ease minimum limits on generation at Arapuni and Kinleith. The Arapuni South Runback scheme eases maximum pre-contingency generation limits on the Arapuni South bus.

What next?

We do not expect it will be justified to increase transmission capacity to remove the existing generation constraints. However, a transmission capacity increase may occur if this is justified as part of the Waikato regional 110 kV grid enhancement strategy. Refer to section 9.4.2.2 for our enhancement approach.

9.5.4.3 Hamilton interconnecting transformer capacity

Issue

Two three-phase interconnecting transformers at Hamilton supply much of the Waikato 110 kV transmission network load, as well as a small proportion of the Auckland 110 kV loads under certain system conditions. These transformers provide:

- total nominal installed capacity of 420 MVA
- n-1 capacity of 243/243 MVA[9] (summer/winter).

During periods of low generation injection from Arapuni and Karapiro into the 110 kV network and high Waikato demand, the load on the Hamilton interconnecting transformers may already exceed their n-1 capacity.

What next?

In the short term, we anticipate continuing to manage this issue operationally by constraining on generation and managing load. Longer term options will be investigated once other, more urgent, 110 kV grid capacity issues in the Waikato and Auckland regions are resolved. Refer to section 9.4.2.6 for our enhancement approach.

9 The transformers' capacity is limited by protection; with this limit resolved, the n-1 capacity will be 248/259 MVA (summer/winter).

9.5.4.4 Hamilton–Piako–Waihou 110 kV transmission capacity

Issue

Two 110 kV Hamilton–Piako–Waihou circuits supply the Thames Valley Spur. Each has a summer/winter capacity of 154/168 MVA. Valley Spur summer and winter peak loads are becoming increasingly similar.

Peak load on the Valley Spur is forecast to exceed the n-1 winter capacity of the circuits by approximately 4 MW in 2019, increasing to approximately 34 MW in 2034 (see Table 9-6). Within the forecast period, the overloading issue will only occur between Hamilton and Piako (Morrinsville Tee).

Low voltage along the Valley Spur exacerbates the transmission loading issue. (Refer to section 9.5.4.5 for more information.)

Table 9-6: Valley Spur circuit overload forecast

	Circuit overload (MW)											
Circuit/grid exit point	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2034**
Valley Spur	4	4	6	12	14	17	20	23	26	29	32	34

What next?

The overload can be managed operationally for the forecast period. The overload may be reduced as a result of resolving other issues. Refer to section 9.4.2.4 and for our enhancement approach.

9.5.4.5 Waihou and Waikino low voltage

Issue

Supply bus voltages at the Waihou and Waikino grid exit points are forecast to fall below 0.95 pu following an outage of a 110 kV Hamilton–Piako–Waihou circuit. The step voltage change will exceed five per cent. Both grid exit points have supply transformers with off-load tap changers.

What next?

We will discuss the issues with Powerco and work together to identify short and long term solutions. Refer to section 9.4.2.4 for our enhancement approach.

9.5.4.6 Cambridge supply transformer capacity

Issue

Two 110/11 kV transformers supply Cambridge's load, providing:

- total nominal installed capacity of 80 MVA
- n-1 capacity of 44/44[10] MVA (summer/winter).

Peak load at Cambridge is forecast to exceed the n-1 winter capacity of the transformers by approximately 3 MW in 2019, increasing to approximately 53 MW in 2034 (see Table 9-7).

In addition, the two Hamilton–Cambridge–Karapiro circuits supplying Cambridge do not have line circuit breakers at Cambridge and a fault on either circuit will disconnect one supply transformer.

Table 9-7: Cambridge supply transformer overload forecast

	Transformer overload (MW)											
Circuit/grid exit point	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2034**
Cambridge	3	20	23	25	27	39	41	43	44	46	47	53

What next?

We expect the issue will be managed operationally for the short-term. We are working with Waipa Networks to investigate longer term options to address the issue. Refer to section 9.4.2.7 for our enhancement approach.

10 The transformers' capacity is limited by protection; with this limit resolved, the n-1 capacity will be 45/47 MVA (summer/winter).

9.5.4.7 Hamilton 220/33 kV supply transformer capacity

Issue

The Hamilton grid exit point has both an 11 kV and a 33 kV supply bus.

Two 220/33 kV transformers supply Hamilton's 33 kV load, providing:

- total nominal installed capacity of 220 MVA
- n-1 capacity of 124/132 MVA (summer/winter).

Peak load at Hamilton 33 kV is forecast to exceed the n-1 winter capacity of the transformers by approximately 11 MW in 2019, increasing to 22 MW by 2029 (see Table 9-8). Forecast n-1 overloading reduces to about 13 MW by 2034 (see Table 9-8) as a result of reductions in forecast demand, caused by underlying assumptions around uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid at peak.

Table 9-8: Hamilton supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Hamilton 33 kV	11	9	10	12	14	15	17	19	20	21	22	13

What next?

Lack of n-1 security at the Hamilton 33 kV grid exit point is managed operationally by WEL Networks, including by load transfer within the distribution network to the Te Kowhai grid exit point. We will investigate options to address the 33 kV n-1 capacity issue when WEL Networks can no longer manage the issue operationally.

We currently have no investments planned to increase the 33 kV supply capacity at Hamilton.

9.5.4.8 Hangatiki supply transformer capacity

Issue

Two 110/33 kV transformers supply Hangatiki's 33 kV grid exit point load, providing:

- total nominal installed capacity of 40 MVA
- n-1 capacity of 22/24 MVA (summer/winter).

The Lines Company recently installed a third 110/33 kV, 30 MVA supply transformer, creating a new 110 kV grid exit point at Hangatiki. The new transformer will not operate in parallel to the existing supply transformers that supply the 33 kV grid exit point. At the time of the TPR analysis, the proportion of loads supplied from each of the Hangatiki 110 kV and 33 kV grid exit points were not clear. We have made the assumption that half of the Hangatiki load will be supplied via the 33 kV grid exit point while the remaining half is transferred to the new 110 kV grid exit point.

Hangatiki winter and summer load peaks have historically been similar. Peak load at Hangatiki 33 kV is forecast to exceed the n-1 winter capacity of the transformers by 4 MW in 2019. increasing to 11 MW by 2034 (see Table 9-9).

Table 9-9: Hangatiki supply transformer overload forecast

Circuit/grid exit point (existing transformers)	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Hangatiki	4	4	4	5	5	5	6	6	7	7	8	11

What next?

We are working with our customers to investigate options. Future upgrades will be customer driven. Refer to sections 9.4.2.8 for our enhancement approach.

9.5.4.9 Hangatiki 110 kV transmission capacity

Issue

Three 110 kV circuits connect Hangatiki to the grid:

- Arapuni–Hangatiki 1 rated at 57/70 MVA (summer/winter)
- Arapuni–Hangatiki–Ongarue 1 which is made up of three thermal branches:
  - Arapuni–Rangitoto Hills Tee rated at 57/70 MVA (summer/winter)
  - Hangatiki–Rangitoto Hills Tee rated at 63/77 MVA (summer/winter)
  - Ongarue–Rangitoto Hills Tee rated at 57/70 MVA (summer/winter)
- Hangatiki–Te Awamutu 1 rated at 106/116 MVA (summer/winter).[11]

With low to moderate levels of generation at Arapuni, a contingency on the Karapiro–Te Awamutu circuit can result in low voltages (<0.95 pu) and large voltage steps (>5 percent) at Te Awamutu.

On the wider 110 kV grid, the following constraints are exacerbated during low Arapuni generation scenarios:

- A contingency on a Hamilton–Cambridge–Karapiro circuit can also cause the Hamilton–Cambridge section of the remaining circuit to overload (see section 9.5.6.1).
- With very high generation in the Taranaki and Wellington regions and low Arapuni generation, the Bunnythorpe–Mataroa circuit may also overload pre-contingency. The pre-contingency overloading can be resolved by either increasing Arapuni generation or constraining generation in the Taranaki or Wellington regions (including HVDC north transfer, see Chapter 11).

What next?

We are currently working with our customers in the Waikato region to identify options for resolving constraints on the wider Waikato 110 kV network, which includes these issues. Refer to section 9.4.2.5 for our enhancement approach.

9.5.4.10 Hinuera supply transformer capacity

Issue

Two 110/33 kV transformers (rated at 30 MVA and 50 MVA) supply Hinuera's load, providing:

- total nominal installed capacity of 80 MVA
- n-1 capacity of 37/40 MVA (summer/winter).

Peak load at Hinuera is forecast to exceed the n-1 winter capacity of the transformers by approximately 13 MW in 2019 (see Table 9-10). The overload drops off from 2020 onwards (as some load is shifted away from Hinuera) to around 5 MW in 2034 (see section 9.4.2.9).

Table 9-10: Hinuera supply transformer overload forecast

	Transformer overload (MW)											
Circuit/grid exit point	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2034**
Hinuera	13	14	2	1	1	2	3	3	3	3	3	5

What next?

In the short term, load may be transferred within the Powerco network from Hinuera to Waihou and/or Piako to resolve this issue. Powerco is also investigating options to resolve the capacity issue until the end of the forecast period. Refer to section 9.4.2.9 for our enhancement approach.

11 This single circuit line is owned by Waipa Networks but operated by Transpower.

9.5.4.11 Hinuera transmission security

Issue

A single 110 kV circuit from Karapiro supplies Hinuera's load, providing

- capacity of 63/77 MVA (summer/winter)
- n security (given there is only one supplying circuit).

Peak load in the Hinuera area is forecast to be 48 MW in 2019, decreasing to 40 MW in 2034, due to the load shift to Putaruru.

What next?

Powerco is currently investigating the option of building a 110 kV feeder from the Arapuni North bus to its Putaruru substation to reinforce Hinuera. Refer to section 9.4.2.9 for our enhancement approach.

9.5.4.12 Kinleith 110/33 kV supply security and supply transformer capacity

Issue

Two 110/33 kV transformers (rated at 20 MVA and 40 MVA) supply Kinleith's 33 kV load, providing:

- total nominal installed capacity of 60 MVA
- switched n-1 capacity of 24/25 MVA (summer/winter).

The supply transformers cannot be connected to the 33 kV bus at the same time, due to different vector groups. The load is normally supplied by the 40 MVA transformer and there is a brief loss of supply when transferring load between the two transformers.

The peak 33 kV load at Kinleith is forecast to exceed the installed capacity of the 20 MVA transformer by approximately 1 MW in 2019, increasing to approximately 7 MW in 2034 (see Table 9-11).

Table 9-11: Kinleith 33 kV supply transformer overload forecast

	Transformer overload (MW)											
Circuit/grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Kinleith 33 kV	1	1	1	2	2	2	3	3	4	4	4	7

What next?

The 20 MVA supply is a "backup" supply and there are no plans to upgrade it. Refer to section 9.4.2.10 for our enhancement approach.

9.5.4.13 Kinleith 110/11 kV supply security

Issue

Four 110/11 kV supply transformers supply the Oji pulp and paper mill. Each transformer normally supplies a separate 11 kV bus section to limit the fault level to the mill. Therefore, the 11 kV loads do not have no-break transformer security for fault outages, but they have no-break security for planned outages.

What next?

We have a project underway to replace most of the equipment at Kinleith. Refer to section 9.4.2.10 for our enhancement approach.

9.5.4.14 Kopu supply transformer capacity

Issue

Two 110/66 kV transformers supply Kopu's load, providing:

- total nominal installed capacity of 120 MVA
- n-1 capacity of 60/60[12] MVA (summer/winter).

Peak load at Kopu is forecast to exceed the n-1 capacity of the transformers by approximately 1 MW in 2024, increasing to approximately 6 MW in 2029 (see Table 9-12). The n-1 overload is forecast to reduce to about 2 MW by 2034 as a result of our underlying assumptions regarding uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid at peak.

Table 9-12: Kopu supply transformer overload forecast

	Transformer overload (MW)											
Circuit/grid exit point	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2034**
Kopu	0	0	0	0	0	1	2	3	4	5	6	2

What next?

Resolving the protection limit will further increase the n-1 capacity. Refer to section 9.4.2.11 for our proposed enhancement approach.

9.5.4.15 Maraetai–Whakamaru transmission capacity

Issue

The 220 kV Maraetai–Whakamaru 1 and 2 circuits are each rated at 202/246 MVA (summer/winter). These circuits carry the combined 411 MW maximum output from the Waipapa and Maraetai generation stations to Whakamaru.

An outage of one of the Maraetai–Whakamaru circuits restricts generation to approximately 50 per cent of full capacity in summer and 60 per cent of full capacity in winter. Following a contingency, a special protection scheme reduces generation to the available capacity of the remaining circuit.

What next?

The existing arrangement has worked satisfactorily and Mercury has not requested an increase in the transmission capacity.

We have no investments planned to increase the Maraetai–Whakamaru transmission capacity.

9.5.4.16 Te Awamutu supply transformer capacity

Issue

Two 110/11 kV transformers supply Te Awamutu's load, providing:

- total nominal installed capacity of 80 MVA
- n-1 capacity of 41/41 MVA[13] (summer/winter).

Peak load at Te Awamutu is forecast to exceed the n-1 capacity of the transformers by approximately 1 MW in 2019, increasing to approximately 8 MW in 2029 (see Table 9-13). The forecast n-1 overload reduces to about 7MW by 2034 due to underlying assumptions regarding uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid at peak.

12 The transformers' n-1 capacity is limited by protection limits; with these limits resolved, the n-1 capacity will be 64/67 MVA (summer/winter).

13 The transformers' n-1 capacity is limited by protection equipment; with this limit resolved, the n-1 capacity will be 52/54 MVA (summer/winter).

Table 9-13: Te Awamutu supply transformer overload forecast

	Transformer overload (MW)											
Circuit/grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Te Awamutu	1	1	4	5	5	6	6	7	7	8	8	7

What next?

Presently the capacity issue can be managed by operational measures. Refer to section 9.4.2.12 for our enhancement approach.

9.5.4.17 Waihou supply transformer capacity

Issue

Three 110/33 kV transformers supply Waihou's load, providing:

- total nominal installed capacity of 60 MVA
- n-1 capacity of 48/51 MVA (summer/winter).

The issues at Waihou involve the following:

- Peak load[14] at Waihou is forecast to exceed the n-1 summer capacity of the transformers by approximately 5 MW in 2019, increasing to approximately 10 MW in 2034 (see Table 9-14).
- An outage of a supply transformer will cause the supply bus voltage to fall below 0.95 pu.[15]

Table 9-14: Waihou supply transformer overload forecast

	Transformer overload (MW)											
Circuit/grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Waihou	5	4	5	5	6	6	7	7	7	8	8	10

What next?

Following a supply transformer contingency (for example, a unit failure) full capacity can be restored by:

- shifting load to other grid exit points, including Powerco transferring some load to the Piako grid exit point
- swapping a transformer unit with an on-site spare unit.

As the supply transformers are due for risk based condition replacements, we have discussed their replacement with Powerco. Refer to section 9.4.2.13 for our enhancement approach.

9.5.4.18 Waikino supply transformer capacity

Issue

Two 110/33 kV transformers supply Waikino's load, providing:

- total nominal installed capacity of 60 MVA
- n-1 capacity of 37/39 MVA (summer/winter).

The issues at Waikino involve the following:

- Peak load at Waikino is forecast to exceed the n-1 winter capacity of the transformers by approximately 3 MW in 2019, increasing to approximately 8 MW in 2029 (see Table 9-15). Forecast n-1 overload falls to about 5 MW by 2034 as a result of underlying assumptions regarding uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid at peak.
- An outage of a supply transformer will cause the supply bus voltage to fall below 0.95 pu.[16]

14 The peak load at Waihou occurs in the shoulder period when summer ratings are applied to transformers.

15 This is due to the Waihou supply transformers not having on-load tap changers.

16 This is due to the Waihou supply transformers not having on-load tap changers.

Table 9-15: Waikino supply transformer overload forecast

	Transformer overload (MW)										
Circuit/grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Waikino	3	3	3	4	5	5	6	7	7	8	8	5

What next?

Operational measures can be used to manage this issue in the short-term. As the supply transformers are also due for risk based condition replacement we have discussed their replacement with Powerco. Refer to section 9.4.2.15 for our enhancement approach.

9.5.5 Waikato bus security

This section presents issues arising from the outage of a single bus section rated at 66 kV and above for the next 15 years.

Bus outages disconnect more than one power system component (for example, other circuits, transformers, reactive support or generators). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

Table 9-16: Waikato region transmission issues – bus security

Section number	Issue
9.5.5.1	Transmission bus security
9.5.5.2	Arapuni North bus security
9.5.5.3	Kinleith 110 kV bus security

9.5.5.1 Transmission bus security

Table 9-17 lists bus outages that cause voltage issues or a total loss of supply. Generators are included only if a bus outage disconnects the whole generation station or causes a widespread system impact. Supply bus outages, typically 11 kV and 33 kV, are not listed.

Table 9-17: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Arapuni North 110 kV	-	Arapuni North	- Karapiro–Te Awamutu 1 overloading. Excessive voltage steps and low voltages at some Waikato and Central North Island 110 kV buses.	- 9.5.5.2 9.5.5.2
Arapuni South 110 kV	-	Arapuni South	Kinleith–Tarukenga 1 overloading.	Note 1
Atiamuri 220 kV	-	Atiamuri	-	-
Hamilton 110 kV	-	-	Hamilton–Piako–Waihou overloading. Hamilton 220/110 kV transformer capacity. Low voltages on most supply buses in the Waikato region.	9.5.4.4 9.5.4.3 -
Hamilton 220 kV	Hamilton 55 kV	-	- Hamilton 220/110 kV transformer capacity. Hamilton 220/33 kV supply transformer capacity. Hamilton low voltage.	Note 2 9.5.4.3 9.5.4.7 Note 3
Hangatiki 110 kV	Hangatiki	-	-	Note 4
Hinuera 110 kV	Hinuera	-	-	9.5.4.11

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Karapiro 110 kV	Hinuera Cambridge	- - Karapiro	- - - Hangatiki–Rangitoto Hills 1 overloading	Note 5 Note 5 - Note 6
Kinleith 110 kV	Kinleith to Oji Fibre Solutions. Kinleith to Powerco	Kinleith	-	9.5.5.3
Ohakuri 220 kV	-	Ohakuri	-	-
Maraetai 220 kV	-	Waipapa	-	Note 7
Whakamaru 220 kV	-	Mokai	- Maraetai–Whakamaru overloading. Tokaanu–Whakamaru, Bunnythorpe–Mataroa, or Atiamuri–Ohakuri circuits may overload.	Note 8 Note 9 Note 10
Waihou 110 kV	Kopu Waihou Waikino	-	-	Note 11 Note 11 Note 11
Waikino 110 kV	Kopu Waikino	-	-	Note 12 Note 12

1. An Arapuni South bus outage will disconnect all the Arapuni South bus generation, which causes the Kinleith–Lichfield–Tarukenga 1 circuit to overload during high load and low Kinleith generation scenarios.
2. Both Hamilton 220/55 kV transformers are connected to the same 220 kV bus zone.
3. A bus section outage that disconnects the Hamilton–Ohinewai circuit will cause low voltages (see section 9.5.6.2).
4. There is no bus protection at Hangatiki so a bus fault removes all circuits from service causing a loss of supply.
5. There is no bus zone protection at Karapiro. Therefore, a bus fault at Karapiro disconnects the Karapiro spur at the Hamilton 110 kV bus. This causes a loss of connection to Karapiro generation and a loss of supply to Cambridge, and Hinuera. (See section 9.5.4.11 for improving transmission security to Hinuera.)
6. As part of our risk based need to replace the 110 kV bus disconnectors at Karapiro, we will also install a single zone bus protection scheme at Karapiro. The new bus protection scheme will allow Karapiro 110 kV bus faults to be cleared locally which means supply to Cambridge will be maintained.
7. There is a single circuit between Waipapa and Maraetai. A bus outage at Maraetai disconnects the circuit to Waipapa, disconnecting the Waipapa generation station.
8. Mokai generation station and Mighty River Power’s G4 generator at Whakamaru are connected to the grid through a common circuit breaker. A bus section outage at Whakamaru can therefore disconnect the Mokai generation station (as well as Whakamaru G4).
9. A bus section outage will disconnect a Maraetai–Whakamaru circuit, which will cause the other circuit to overload during high generation at Maraetai and Waipapa (see section 9.5.4.15).
10. Depending on generation scenarios, Whakamaru bus section outages may also cause overloads on the Bunnythorpe–Mataroa, Tokaanu–Whakamaru, or Atiamuri–Ohakuri circuits (see Chapter 6).
11. There is a single 110 kV bus zone protection at Waihou. Therefore, a bus fault will trip all connected circuits and transformers, causing a loss of supply at Waihou, Waikino and Kopu.
12. A 110 kV bus fault at Waikino will cause both Waihou–Waikino circuits to trip. This will cause a total loss of supply to Waikino and Kopu.

Options to increase bus security typically include bus reconfiguration and/or additional bus circuit breakers.

The other customers (KiwiRail, The Lines Company, Powerco, Waipa Networks and WEL Networks) have not requested a higher security level. No further action will be taken unless requested by a customer.

9.5.5.2 Arapuni North bus security

Issue

The Arapuni 110 kV bus consists of two bus sections and it is normally split into the Arapuni North and Arapuni South buses.

A contingency on the North bus disconnects:

- 110 kV Arapuni–Hamilton 1 and 2 circuits
- 110 kV Arapuni–Hangatiki 1 circuit
- 110 kV Arapuni–Hangatiki–Ongarue 1 circuit
- 110 kV Arapuni–Bombay 1 circuit
- Mercury generators connected to the Arapuni North bus.

This contingency results in the Hangatiki load being supplied from Ongarue and Te Awamutu (via Waipa Network's Hangatiki–Te Awamutu 1 circuit).

During peak load periods, voltage steps of greater than five percent can be expected on some supply buses supplied by the Waikato and Central North Island 110 kV network. The post contingency static voltages at the Hangatiki and Ongarue supply buses may drop below 0.95 pu.

What next?

We will consider this issue when investigating the long-term solution for addressing the Hangatiki 110 kV transmission capacity. Refer to section 9.4.2.5 for our enhancement approach.

9.5.5.3 Kinleith 110 kV bus security

Issue

There are two 110 kV bus sections at Kinleith.

An outage of one Kinleith 110 kV bus section disconnects the:

- 110 kV Arapuni–Kinleith 1 and 2 circuits
- 110/33/11 kV Kinleith–T9 supply transformer
- 110/11 kV Kinleith–T7, T8 and T3 supply transformers (T3 will soon be decommissioned).

This bus outage results in a loss of supply to Powerco and the Oji pulp and paper mill. Also, if the Arapuni bus split is open, there will be a loss of connection for the Mercury generation connected to the Arapuni South bus. Depending on the generation at Kinleith, this outage may also result in low voltage on the remaining Kinleith 110 kV supply buses.

An outage of the remaining Kinleith 110 kV bus section disconnects the:

- 110 kV Kinleith–Lichfield–1 an d 2 circuits
- 110/11 kV Kinleith–T6 supply transformer (project to install this transformer is underway)
- 110/11 kV Kinleith–T2 supply transformer (soon to be decommissioned)
- 110/33/11 kV Kinleith–T5 supply transformer.

This bus outage will result in a loss of supply and generation connection at Kinleith. Also, if the Arapuni bus split is open, the Mercury generation connected to the Arapuni South bus and the remaining Kinleith load will be left operating as an island, which is unlikely to be sustainable. A loss of supply for Powerco and Oji and loss of connection for Mercury will be required before normal operation can resume.

What next?

We have discussed options with Powerco and Oji to determine whether it is economic to resolve the issue. Their preferred option is to retain the two bus section design at Kinleith.

9.5.6 Other regional items of interest

9.5.6.1 Hamilton–Cambridge–Karapiro capacity

Issue

The 110 kV Hamilton–Cambridge–Karapiro (Karapiro spur) and Hangatiki–Te Awamutu circuits connect the Cambridge, Te Awamutu, and Hinuera loads and generation at Karapiro.

The Hamilton–Cambridge sections of the Karapiro spur, each with a capacity of 57/70 MVA (summer/winter), constrain transmission capacity into the area.[17] The combined peak load at Cambridge, Hinuera, and Te Awamutu exceeds the n-1 transmission capacity into the area. This is managed using constrained on generation from Karapiro, especially in summer. The minimum generation required for the forecast period for this purpose is approximately 45-75 MW (upper range at the end of the forecast period).[18] However, commissioning of the Hangatiki–Te Awamutu circuit has also increased the need for the Karapiro generators to be constrained on to provide voltage support, as reactive power is normally exported to Hangatiki on the new circuit.

The Cambridge–Karapiro sections of the Karapiro spur, each with a capacity of 57/70 MVA (summer/winter), constrain Karapiro generation during low load conditions. This can be managed by constraining Karapiro generation. The constraint does not occur frequently enough to justify investments.

What next?

Generation from Karapiro will be used to manage the loading on the Hamilton–Cambridge circuits in the short to medium term. We also need to investigate longer term solutions to resolve the Cambridge supply transformer constraint (refer to section 9.5.4.6) where a credible option is to develop a new grid exit point to take some load off Cambridge. This option would help reduce minimum generation requirements at Karapiro. We will continue to monitor loading on the Karapiro spur to determine when an issue may arise (refer to section 9.4.2.3).

9.5.6.2 Hamilton low voltage

Issue

Towards the end of the forecast period, when there are periods of high load and low Waikato 110 kV generation, the Hamilton 220 kV bus will have low voltage (below 0.90 pu) for an outage of the 220 kV Hamilton–Ohinewai circuit.

What next?

The Waikato and Upper North Island (WUNI) project is investigating options to provide voltage support in the Waikato and Upper North Island area. The project will also likely resolve the low voltage issue at Hamilton. Refer to Chapter 6, Grid Backbone, North Island section.

9.5.6.3 Hamilton transmission security during maintenance

Issue

The 220 kV Hamilton–Whakamaru and Hamilton–Ohinewai circuits, and the two 220/110 kV interconnecting transformers at Hamilton supply most of the load in the Waikato region.

An outage of a 220 kV circuit to Hamilton or a Hamilton 220/110 kV transformer will place many grid exit points in the region on n security.[19] Such an outage will require the Waikato 110 kV network be split in multiple locations so that a contingency on the remaining 220 kV circuit or interconnecting transformer does not affect neighbouring regions (by voltage collapse spreading to neighbouring regions). Although this is an acceptable operating measure, it does increase the difficulty of managing the system during outages.

What next?

No investments are planned to directly resolve this issue. However, it will be considered as part of the investigation to increase 220/110 kV interconnection capacity at Hamilton (see section 9.4.2.6).

17 An outage of a Hamilton–Cambridge–Karapiro circuit will cause the Hamilton–Cambridge section of the remaining circuit to overload.

18 Karapiro has an installed capacity of 90 MW and typically generates 40 MW during low load periods and 80-90 MW during peaks

19 The Waikato 110 kV system is split so it does not form a parallel connection with the 220 kV system.

9.5.7 Waikato generation proposals and opportunities

This section describes regional issues that may affect generation proposals under investigation by developers and in the public domain, or other generation opportunities. The impact of committed generation projects on the grid backbone is dealt with separately in Chapter 6.

The maximum generation that can be connected depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

9.5.7.1 Hangatiki generation

There are prospects to connect up to about 40 MW of generation at Hangatiki. Any generation will worsen the overloading issue on the 110 kV Arapuni–Hamilton circuits (refer to section 9.5.4.1) and on the 110 kV Cambridge–Karapiro circuit sections (section 9.5.6.1) but would relieve transmission constraints into Hangatiki (section 9.5.4.9).

We will investigate the system issues in detail if/when generation developments proceed. It is likely some investments will be required to resolve transmission constraints on the Waikato 110 kV system.

10. Bay of Plenty Regional Plan

10.1 Regional overview and transmission system

The Bay of Plenty region has a mix of growing provincial cities (Mount Maunganui, Tauranga, and Rotorua) together with smaller towns and rural localities (such as Waiotahi) and heavy industry (Kawerau).

The existing transmission network for the Bay of Plenty region is shown geographically in Figure 10-1 and schematically in

Figure 10-2.

Figure 10-1: Bay of Plenty region transmission

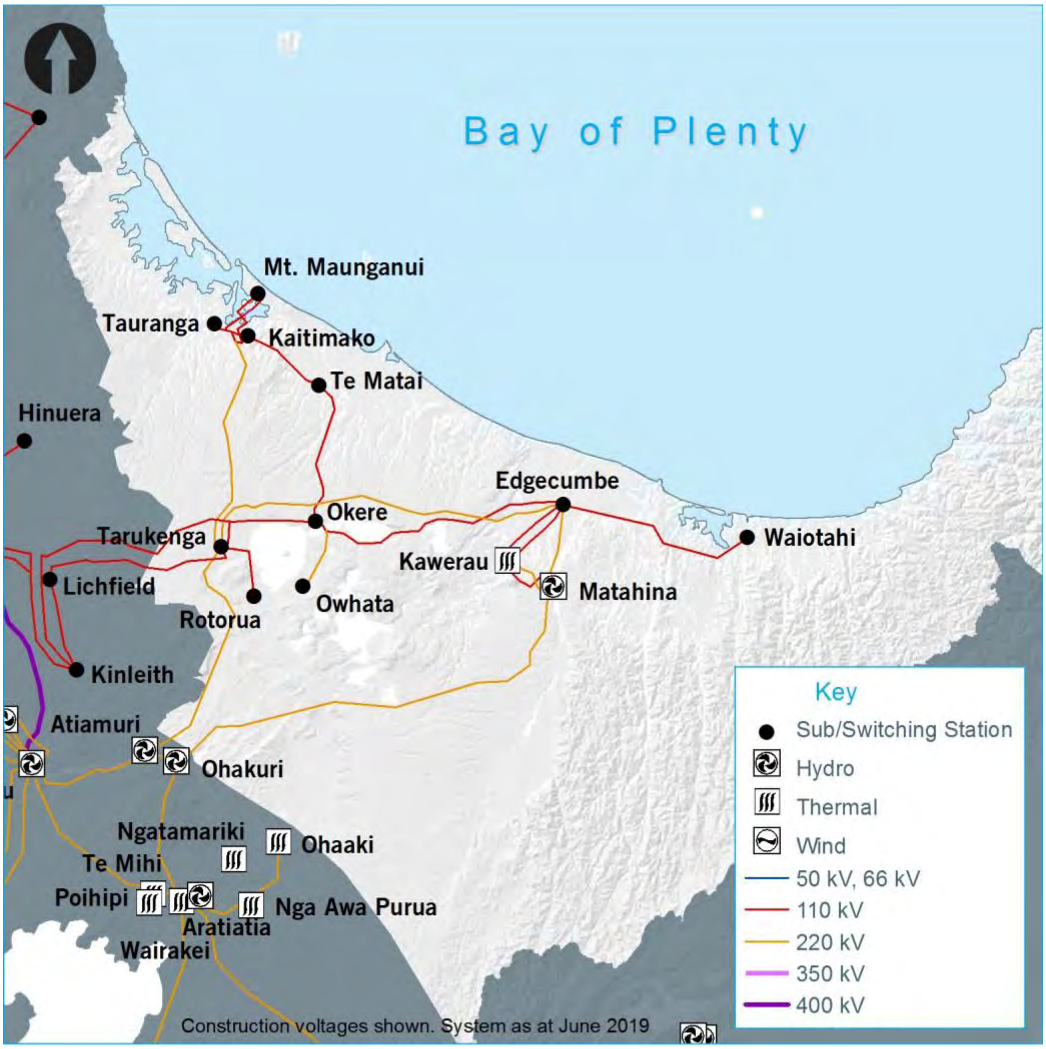
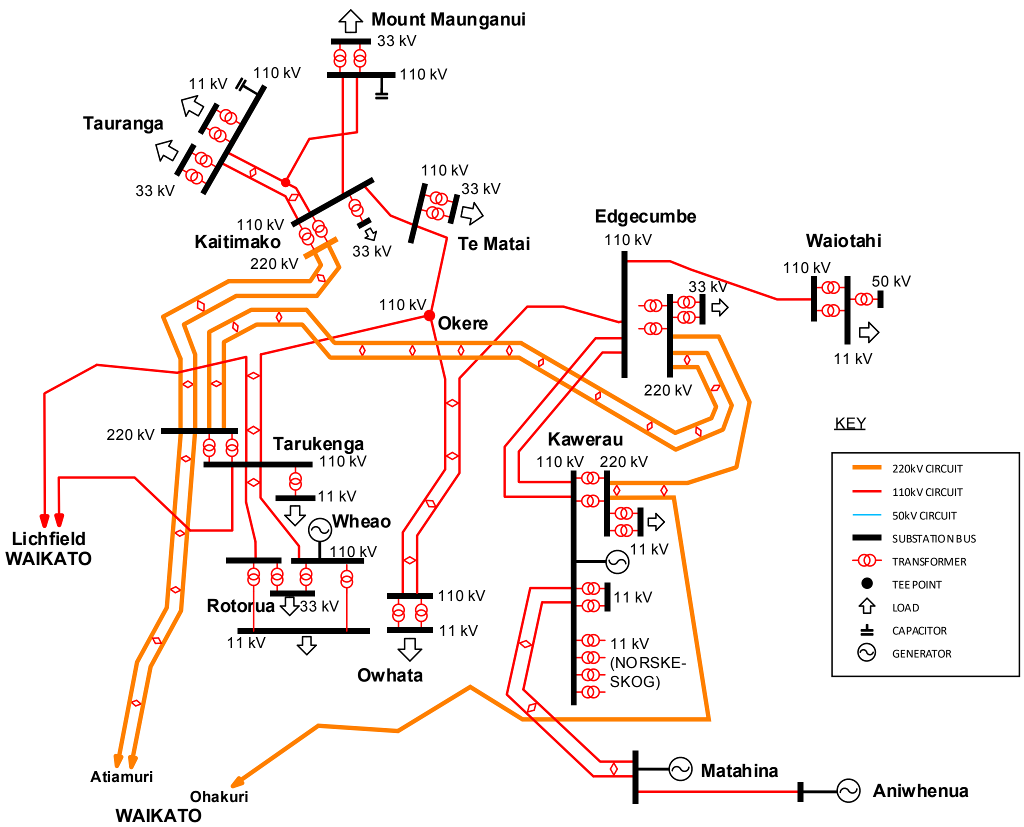


Figure 10-2: Bay of Plenty region transmission schematic



10.1.1 Transmission into the region

As generation capacity in the Bay of Plenty region is lower than its maximum demand, the deficit is imported through the National Grid during peak load conditions, and any surplus is exported during light load conditions.

The 220 kV Atiamuri–Whakamaru and Ohakuri–Wairakei circuits connect the region to the rest of the National Grid. The Bay of Plenty load is predominantly supplied through these circuits, and the region will be on n security whenever one of these circuits is out of service. These two circuits form part of the grid backbone (refer to Chapter 6 for further discussion).

There is also a low capacity 110 kV Tarukenga–Kinleith–Arapuni connection that connects the Bay of Plenty to the Waikato 110 kV regional network. In normal operation this connection is split at Arapuni to prevent overloading.[1]

10.1.2 Transmission within the region

The transmission network in the Bay of Plenty region comprises high capacity 220 kV and low capacity 110 kV circuits, with interconnecting transformers located at Tarukenga, Kaitimako, Edgecumbe, and Kawerau.

Reactive support is provided by 25 Mvar capacitors at Tauranga and Mount Maunganui as these two areas have a relatively high load with very little local generation.

The Kawerau 110 kV bus is unique in that it has a significant amount of generation and interruptible load connected to it, which can respond to North Island under frequency events.

1 See Chapter 9 for more information about the Arapuni bus split.

Under frequency events may cause generation constraints for some outages of the 220/110 kV interconnecting transformers.

Most of the Bay of Plenty generation is at the eastern end of the region (around Kawerau) but the bulk of the load is near the western end (near Rotorua and Tauranga) so power flow within the region is generally from east to west.

10.2 Bay of Plenty demand

The Bay of Plenty regional peak demand[2] is forecast to grow by an average of 1.4 per cent per annum over the next 15 years, from 412 MW in 2019 to 507 MW in 2034. This exceeds the national average growth rate of 1.2 per cent per annum .

Table 10-1 sets out forecast peak demand (prudent growth[3]) at each grid exit point over the forecast period.

Table 10-1: Forecast annual peak demand (MW) at Bay of Plenty grid exit points to 2034

Grid exit point	Power factor	Peak demand (MW)											
		2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2034**
Edgecumbe	0.97	68	69	71	73	75	77	79	81	82	84	85	88
Kaitimako[1]	1.00	31	32	34	35	36	38	39	40	41	48	48	48
Kawerau – Horizon	0.92	21	22	22	23	23	24	25	25	25	26	27	30
Kawerau–T6 -T9	0.98	53	53	53	53	53	53	53	53	53	52	52	50
Kawerau–T11 and T14	1.00	78	77	77	77	77	77	77	77	77	77	77	80
Mt Maunganui 33 kV[2]	0.99	60	63	65	67	69	71	73	74	76	77	77	74
Owhata[3]	1.00	15	17	18	19	20	20	20	20	20	20	20	19
Rotorua 11 kV	1.00	29	30	31	31	32	33	33	34	34	34	34	32
Rotorua 33 kV[3]	0.98	51	51	50	50	49	49	50	50	50	49	49	49
Tarukenga 11 kV	1.00	9	9	10	10	10	10	10	10	10	10	10	9
Tauranga 11 kV[1]	1.00	28	30	31	32	33	34	35	35	36	30	30	30
Tauranga 33 kV	0.99	67	69	72	75	77	80	82	83	84	85	85	81
Te Matai[2]	0.98	53	54	55	56	57	58	59	60	60	61	61	63
Waiotahi	0.99	13	13	13	14	14	15	15	15	16	17	17	21

1. 8 MW moves from Tauranga11 kV to Kaitimako in 2028.
2. 14 MW moves from Mount Maunganui to Te Matai in 2019.
3. 2 MW moves from Rotorua 33 kV to Owhata in 2020.

10.3 Bay of Plenty generation

The Bay of Plenty region's generation capacity is currently approximately 417 MW. This is less than regional peak demand so any deficit imported is through the National Grid. At low load the region may import or export power depending on the level of generation dispatched.

Kaimai is a run-of-river hydro scheme that injects at the Tauranga 33 kV bus. Output from the scheme varies between 14 MW and 42 MW – typically, 14 MW is the minimum generation available from the scheme at peak load, though this relies on sufficient water being available.

2 For discussion on demand forecasting see Chapter 3, section 3.1.

3 Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

Table 10-2 lists the generation forecast for each grid injection point for the forecast period. This includes all known and committed generation stations including those embedded within the relevant local lines company's network (Horizon Networks, Unison, or Powerco).[4]

Further generation may be developed during the period but is not sufficiently advanced to be included in our forecasts. (Refer to section 10.5.7 for more information on potential new generation.)

Table 10-2: Forecast annual generation capacity (MW) at Bay of Plenty grid injection points to 2034 (existing and committed generation)

Grid injection point (location/name if embedded)	Generation capacity (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Aniwhenua	25	25	25	25	25	25	25	25	25	25	25	25
Edgecumbe (Bay Milk)	10	10	10	10	10	10	10	10	10	10	10	10
Kawerau (BOPE)	6	6	6	6	6	6	6	6	6	6	6	6
Kawerau (Oji)	27	27	27	27	27	27	27	27	27	27	27	27
Kawerau (KAG)	105	105	105	105	105	105	105	105	105	105	105	105
Kawerau (KA24)	9	9	9	9	9	9	9	9	9	9	9	9
Kawerau (Ngāti Tūwharetoa[1])	25	25	25	25	25	25	25	25	25	25	25	25
Kawerau (TPP)	37	37	37	37	37	37	37	37	37	37	37	37
Kawerau (Te Ahi O Maui)	25	25	25	25	25	25	25	25	25	25	25	25
Matahina	72	72	72	72	72	72	72	72	72	72	72	72
Mount Maunganui (Balance Agri)	7	7	7	7	7	7	7	7	7	7	7	7
Rotorua (Fletcher Forests)	3	3	3	3	3	3	3	3	3	3	3	3
Rotorua (Wheao Flaxy Scheme)	24	24	24	24	24	24	24	24	24	24	24	24
Tauranga (Kaimai)	42	42	42	42	42	42	42	42	42	42	42	42

1. The electricity market designation for the Ngāti Tūwharetoa generator is Onepu.

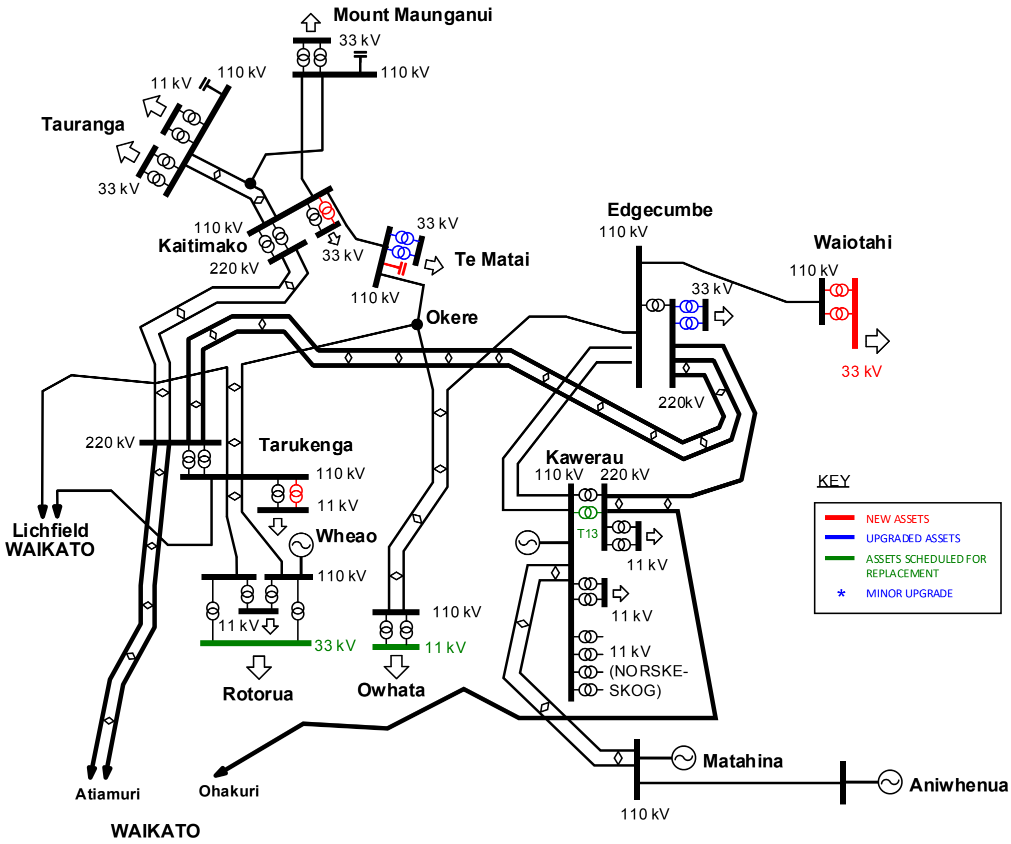
10.4 Grid enhancement approach

10.4.1 Possible future Bay of Plenty transmission configuration

Figure 10-3 shows the possible configuration of Bay of Plenty transmission in 2034. New assets, upgraded assets, and assets scheduled for replacement within the forecast period (based on potential enhancement approaches set out in the following sections) are shown.

4 Only generating stations with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

Figure 10-3: Possible Bay of Plenty region transmission configuration in 2034



10.4.2 Enhancement approach

Our approach seeks to ensure secure transmission into and within the Bay of Plenty region into the future. Through the E&D process we assess transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified issues and opportunities we take into account uncertainty in future demand, generation and technological developments.

Transmission issues likely requiring E&D or Customer-funded investments in the Bay of Plenty over the next 10-15 years are:

Section number	Issue
Regional	
10.4.2.1	Kawerau area generation constraints
Site by grid exit point	
10.4.2.2	Edgecumbe supply transformer capacity
10.4.2.3	Mount Maunganui and Te Matai supply capacity and security
10.4.2.4	Tauranga and Kaitimako supply capacity and security
10.4.2.5	Rotorua supply capacity
10.4.2.6	Waiotahi supply capacity

10.4.2.1 Kawerau area generation constraints

There is potential for significant additional geothermal generation to be developed in the eastern Bay of Plenty area, around Kawerau. If this does eventuate, a staged transmission capacity upgrade will be required (see section 10.5.7.1 for more information on generation opportunities in the region).

Existing generation on the Kawerau 110 kV bus may be constrained at times due to the low capacity 110 kV Edgecumbe–Kawerau and Edgecumbe–Owhata circuits and the low capacity Kawerau–T13 interconnecting transformer. The circuit capacity constraints are managed by special protection schemes while the interconnecting transformer capacity issue is currently not managed, as connected parties are satisfied that the probability of overloading and tripping of the transformer is sufficiently low (with existing levels of load and generation).

What, if any, transmission investments are required in future will depend on the scale of additional generation. Connecting more than approximately 20-30 MW of additional generation directly or indirectly to the Kawerau 110 kV bus will cause constraints on the 110 kV network and the 220/110 kV interconnecting transformers. As constraints are highly dependent upon system conditions around Kawerau, they can vary considerably.

Connecting more than approximately 35 MW of additional generation at Kawerau (to the 110 kV or 220 kV buses), will also cause infrequent constraints on the 220 kV Edgecumbe–Kawerau and Kawerau–Ohakuri circuits. The Atiamuri–Ohakuri circuit in the core grid may also cause constraints on generation export from the Kawerau area and Wairakei (see Chapter 6).

Enhancement approach:

- If new generation proposals are confirmed in the Kawerau area, we will investigate investment options to address generation export constraints. Depending on the scale of additional generation, options for a staged upgrade of generation export capacity include:
  - 220/110 kV transformer capacity:
    - replace Kawerau–T13 with a new 250 MVA, 10% transformer identical to Kawerau–T12
  - 110 kV transmission capacity:
    - split the 110 kV system between Edgecumbe and Kawerau
    - install a replacement 220/110 kV transformer at Edgecumbe and decommission the existing transformers
  - 220 kV transmission capacity:
    - implementing special protection scheme(s) to automatically reduce generation if an overload occurs
    - increasing the thermal rating of the circuits
    - building a second 220 kV Edgecumbe–Kawerau circuit.

Base E&D Capex investments

Project name:	Kawerau interconnection capacity
Project description:	Replace Kawerau–T13 with a 250 MVA, 10% transformer
Project's state of completion:	Possible
OAA level completed:	AL 3p
Grid need date:	Uncertain (generation development dependant)
Indicative cost ($ million):	7
Part of the GEIR?:	Yes

Project name:	Kawerau 220 kV constraints
Project description:	Install Kawerau 220 kV generation runback scheme(s)
Project's state of completion:	Possible
OAA level completed:	None
Grid need date:	Uncertain (generation development dependant)
Indicative cost ($ million):	1
Part of the GEIR?:	Yes

Project name:	Edgecumbe interconnecting transformer/s
Project description:	Replace Edgecumbe 220/110 kV transformer/s and open Edgecumbe–Kawerau 110 kV circuits
Project's state of completion:	Possible
OAA level completed:	None
Grid need date:	Uncertain (generation development dependant)
Indicative cost ($ million):	5 (one transformer)
Part of the GEIR?:	Yes

Project name:	Kawerau 110 kV bus
Project description:	Install 110 kV ring bus at Kawerau
Project's state of completion:	Possible
OAA level completed:	None
Grid need date:	Uncertain (generation development dependant)
Indicative cost ($ million):	0.7
Part of the GEIR?:	No

10.4.2.2 Edgecumbe supply transformer capacity

The Edgecumbe supply transformers currently exceed their n-1 rating. One of the 220/33 kV supply transformers, T8, is due for risk-based condition replacement in 2021. The T8 supply transformer has a slightly lower rating than the parallel T7 transformer, and replacing T8 with a larger unit will only provide a slight increase in n-1 capacity at Edgecumbe (around 3-4 MW), which does not provide n-1 capacity for the forecast period.

Enhancement approach:

- Following consultation with Horizon Networks, it was agreed that T8 will be replaced by a 80 MVA transformer (base capex replacement and refurbishment) by mid 2021. Horizon has decided not to replace T7 with a larger unit at the same time to provide n-1 security (customer-funded replacement). We will continue to monitor the situation with Horizon.

Customer investments

Project name	Edgecumbe supply capacity
Project description:	Replace Edgecumbe–T7 220/33 kV supply transformer with a larger unit
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	TBA
Indicative cost ($ million):	6
Part of the GEIR?:	No

10.4.2.3 Mount Maunganui and Te Matai supply capacity and security

We forecast significant growth in demand for the Tauranga area, underpinned by both infill and greenfield residential and commercial developments. Due to this growth in demand, constraints are expected at two of Powerco's four grid exit points within the 5–10 years.

Powerco transferred load from Mount Maunganui to the Te Matai grid exit point in early 2019 to prevent overloading of the circuits to Mount Maunganui within the forecast period.

However, the increased load at Te Matai causes:

- the Te Matai supply transformers' n-1 capacity to be exceeded initially, with the continuous capacity of Te Matai–T1 (the smaller of the two supply transformers) exceeded at a later time
- large voltage steps at Te Matai for a Kaitimako–Te Matai circuit outage and low post contingency voltages towards the end of the forecast period.
-

Enhancement approach:

- Te Matai–T1 limits the n-1 capacity of the supply transformers. We are working with Powerco to investigate options; a possible solution is to replace both supply transformers with higher rated units in 2021. (The relatively new T2 transformer would be reused at Powerco's future Putaruru substation.)
- In parallel, we are investigating options to improve voltage quality at the Te Matai supply bus. A possible option is to install a capacitor at Te Matai to provide voltage support.
- We will work with Powerco to identify a long-term development strategy to maintain a secure supply to the loads at Te Matai, including investigating interim options such as variable line rating (VLR). This work will also include the Kaitimako and Tauranga issues, see 10.4.2.4.

Customer investments

Project name:	Te Matai supply capacity
Project description:	Replace Te Matai supply transformers
Project's state of completion:	Possible
OAA level completed:	AL 2p
Indicative timing:	2021-2022
Indicative cost ($ million):	6 (two transformers)
Part of the GEIR?	No

Base E&D Capex investments

Project name:	Te Matai voltage quality
Project description:	Install capacitor at Te Matai
Project's state of completion:	Possible
OAA level completed:	None
Indicative timing:	2025-2026
Indicative cost ($ million):	1.8
Part of the GEIR?	No

10.4.2.4 Tauranga and Kaitimako supply capacity and security

We would expect to see n-1 110 kV transmission constraints at Tauranga within the forecast period. However, Powerco plans to transfer load from the Tauranga 11 kV grid exit point to the Kaitimako 33 kV grid exit point from 2019, which will resolve the issue for the forecast period. However, the Kaitimako 33 kV grid exit point is supplied by a single supply transformer, providing n security.

We also forecast that the two 220/110 kV interconnecting transformers at Kaitimako will exceed their n-1 ratings from 2031 during periods of high load and low generation.

The severity of the 110 kV transmission issues is very sensitive to the level of generation embedded within the Tauranga 33 kV grid exit point, especially at peak times. Tauranga will become more dependent on this generation to maintain n-1 security as the forecast period progresses if no investments are made in the transmission system.

Enhancement approach:

- We expect to be able to manage the interconnecting transformer capacity issue operationally in the forecast period. The Kaitimako substation was designed to host a third 220/110 kV interconnecting transformer if needed.
- We will investigate interim solutions such as variable line rating to manage the capacity of the circuits into Tauranga.
- At this stage, PowerCo has not requested a second 110/33 kV supply transformer at Kaitimako to improve the supply security, as backfeed capability from Tauranga is sufficient in most cases.
- We are working with PowerCo to identify a long-term development strategy to maintain a secure supply to the Tauranga and Kaitimako loads in conjunction with issues at Mount Maunganui and Te Matai, see 10.4.2.3.

10.4.2.5 Rotorua supply capacity

The Rotorua 33 kV and 11 kV grid exit points are supplied by two 110 kV Rotorua–Tarukenga circuits that have a lower n-1 capacity than the supply transformers. The peak loading on the circuits is expected to slightly exceed their n-1 capacity so an outage on one circuit during a peak load period will cause the parallel circuit to overload at high loads from 2019.

Unison's distribution network has a high level of interconnectivity between the grid exit points at 11 kV. This interconnectivity, together with investments in automation, allows Unison to quickly transfer loads between the grid exit points after a fault has occurred.

Enhancement approach:

We are discussing solutions with Unison, including:

- shifting more load from Rotorua 11 kV to the Owhata grid exit point, where the supply transformers were recently replaced by larger units.
- applying variable line rating on the Rotorua–Tarukenga circuits
- applying Demand Response to alleviate the overload.

10.4.2.6 Waiotahi supply capacity

The Waiotahi grid exit point supplies the Opotiki and Te Kaha towns and their surrounding areas.

Peak demand at the Waiotahi grid exit point is expected to exceed the n-1 capacity of its supply transformers from 2020.

Horizon Networks has indicated that its 11 kV distribution network into Opotiki (from Waiotahi) is voltage-constrained and it is investigating upgrade options to reinforce supply to Opotiki.

Enhancement approach:

We are discussing investment options with Horizon Networks, including:

- Replacing the existing 110/11 kV supply transformers at Waiotahi with 110/33-11 kV transformers to facilitate staged development. Future investment will be customer driven.

10.5 Asset capability and management

We have assessed the transmission capacity and reactive support requirements in the region for the next 15 years. When an issue or opportunity exists, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 10.4) have been developed to address issues or opportunities that require action within the forecast period and where investment is justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk-based asset replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

10.5.1 Bay of Plenty significant upcoming work

We integrate our capital project and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Table 10-3 lists the significant upcoming works[5] proposed within the Bay of Plenty region for the next 15 years that may significantly impact related system issues or connected parties.

Table 10-3: Proposed significant upcoming work

Description	Tentative year	E&D issue
Edgecumbe supply transformer risk based condition replacement	2019-2021	10.5.4.3
Kawerau 110 kV switchgear replacements	2018-2021	10.5.2.2
Owhata 11 kV switchgear replacement	2020-2022	-
Te Matai–T1 transformer risk based condition replacement Te Matai capacitor bank installation	2021-2022 2025-2026	10.5.4.9 10.5.4.9
Rotorua 33 kV switchboard replacement	2029-2031	-

10.5.2 Bay of Plenty asset feedback

The Asset Feedback Register includes the following entries related to E&D that are specific to the Bay of Plenty region:

- Edgecumbe–T4/T5 decommissioning investigation
- Kawerau 110 kV bus rationalisation

10.5.2.1 Edgecumbe–T4/T5 decommissioning investigation

Issue

Edgecumbe–T4 and T5 220/110 kV transformers are normally on hot standby (open at the 110 kV end). We need to review this arrangement to determine whether these units are still required and the economic benefit of retaining or decommissioning them.

What next?

This issue is addressed in "Other Items of Interest", section 10.5.6.1.

10.5.2.2 Kawerau 110 kV bus rationalisation

Issue

There is little physical space in and around the Kawerau 110 kV bus, so access for works can be constrained. It can also be difficult to obtain outages for maintenance because multiple parties are connected to the same bus section and their maintenance cycles often differ.

What next?

The issue was investigated as part of the Kawerau 110 kV switchgear replacement and 110/11 kV transformer replacement investigations. The maintenance access issue is partially addressed within these projects. However, significant new generation will be needed to justify major 110 kV bus investment such as a ring bus. It is uneconomic to address the issue of multiple parties connected to the same bus section as this requires a major reconfiguration of the bus.

5 This may include replacement of the asset due to its condition assessment.

10.5.3 Changes since the 2018 Transmission Planning Report

Table 10-4 lists the specific new issues and those that are no longer relevant within the forecast period (relative to our previous Transmission Planning Report).

Table 10-4: Changes since the 2018 TPR

Issues	Change
Kawerau–T13 age and condition Kawerau supply transformer–T1/T2 capacity and bus security	Removed. Transformer replaced. Removed. Transformers replaced by higher rated units on different bus sections.
Mount Maunganui supply transformer and transmission capacity	Removed. Powerco transferred load to Te Matai.
Rotorua area supply capacity	Partially removed. Owhata transformers replaced with higher rated units.

10.5.4 Bay of Plenty transmission capability

Table 10-5 summarises identified issues that may affect for the Bay of Plenty region during the next 15 years. In each case, we identified a condition that constrains network capacity if action is not taken. Each issue is discussed in more detail below.

This transmission capability section reports whether the Grid can reasonably be expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, forms part of the Grid Reliability Report (GRR).

Table 10-5: Bay of Plenty region transmission issues – regional / site by grid exit point

Section number	Issue
Regional	
10.5.4.1	Kawerau 110 kV bus constraint
10.5.4.2	Tauranga and Mount Maunganui transmission security
Site by grid exit point	
10.5.4.3	Edgecumbe supply transformer capacity
10.5.4.4	Kaitimako supply transformer security
10.5.4.5	Kaitimako 220/110 kV interconnection capacity
10.5.4.6	Kawerau–Matahina 110 kV transmission security and capacity
10.5.4.7	Rotorua–Tarukenga 110 kV transmission capacity and security
10.5.4.8	Tarukenga supply security
10.5.4.9	Te Matai supply transformer capacity and low voltage
10.5.4.10	Waiotahi supply transformer capacity

10.5.4.1 Kawerau 110 kV bus constraints

Issue

Generation at Aniwhenua, Matahina, Kawerau Geothermal (KAG), embedded generation within Horizon's distribution network, and embedded generation within the Norske Skog mill all connect to the Kawerau 110 kV bus. The Kawerau 110 kV bus is connected to the rest of the system via the:

- Kawerau–T12, 220/110 kV transformer (250 MVA, 10 per cent impedance)
- Kawerau–T13, 220/110 kV transformer (100 MVA, 20 per cent impedance)
- low capacity 110 kV circuits (Kawerau–Edgecumbe 1 and 2, each rated at 48/59 MVA summer/winter, in series with Edgecumbe–Owhata rated at 57/69 MVA summer/winter).

To avoid pre-contingency generation constraints for circuit outages, two special protection schemes open the circuit if it overloads:

- Edgecumbe–Owhata 2 overload protection scheme

- Edgecumbe–Kawerau 1 and 2 overload protection scheme.

There are constraints on generation export from the Kawerau 110 kV bus when there is high generation and low demand at Kawerau:

- An outage of the Kawerau–T12 transformer may cause the Edgecumbe–Owhata 2 overload protection scheme to operate. This will overload the Kawerau–T13 transformer and may cause it to trip, resulting in a loss of supply to load (at Kawerau and Waiotahi) and a loss of connection for the generation.

What next?

We discussed the risks of a Kawerau–T12 contingency causing a loss of supply to the Kawerau 110 kV bus with interested stakeholders. Their feedback supports taking no action at present to mitigate the risk. This approach is supported by our economic analysis, even after commissioning the 25 MW Te Ahi O Maui geothermal generator. This is because the probability of a Kawerau–T12 outage is low and with the usual levels of generation and load the Edgecumbe–Owhata 2 special protection scheme will not operate. Therefore Kawerau–T13 will not usually overload and trip.[6]

See section 10.4.2.1 for our approach.

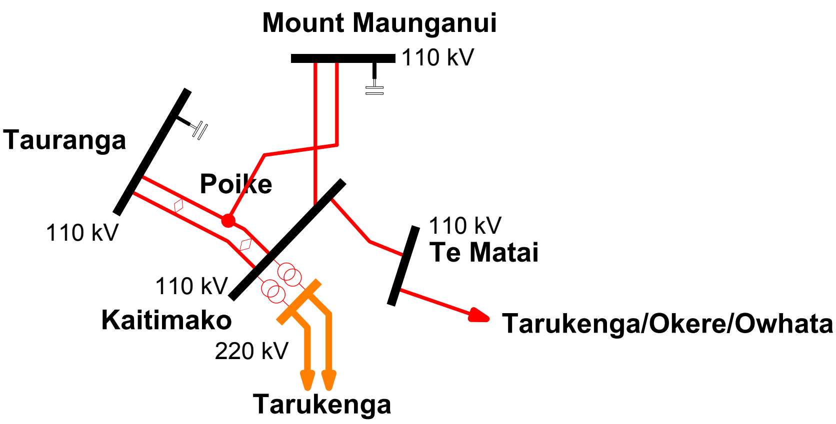
10.5.4.2 Tauranga and Mount Maunganui transmission security

Issue

Tauranga and Mount Maunganui are supplied from Kaitimako through the following 110 kV circuits (see Figure 10-4):

- Kaitimako–Tauranga 1, rated at 96/105 MVA (summer/winter)
- Kaitimako–Mount Maunganui 1, rated at 63/77 MVA (summer/winter)
- a shared Kaitimako–Tauranga–Mount Maunganui 2 circuit with the following ratings:
  - Kaitimako–Poike section 96/105 MVA (summer/winter)
  - Poike–Tauranga section 96/105 MVA (summer/winter)
  - Poike–Mount Maunganui 63/77 MVA (summer/winter).

Figure 10-4: Kaitimako grid configuration



An outage of the Kaitimako–Tauranga 1 circuit or the Kaitimako–Mt Maunganui 1 circuit may trigger a special protection scheme to reconfigure the grid and put Tauranga and Mount Maunganui on n security to prevent overloading[7] of the Kaitimako–Poike circuit section.

An outage of either circuit to Tauranga will overload the other circuit at peak time and with extremely low Kaimai generation from 2019, affecting 33 kV and 11 kV grid exit points at Tauranga.

6 See section 10.5.5.4810.5.5.4 for information about the effect of a Kawerau–T12 outage due to a bus tripping.

7 This assumes Kaimai (embedded at Tauranga) is generating 14 MW.

What next?

In the short to medium term, Powerco plans to shift load away from Tauranga to resolve capacity issues on the 110 kV transmission network.

See sections 10.4.2.3 (Mount Maunganui) and 10.4.2.4 (Tauranga) for our proposed approach.

10.5.4.3 Edgecumbe supply transformer capacity

Issue

Two 220/33 kV transformers supply Edgecumbe's load, providing:

- total nominal installed capacity of 100 MVA
- n-1 capacity of 62/67 MVA (summer/winter).

Peak load at Edgecumbe is forecast to exceed the n-1 winter capacity of the transformers by approximately 11 MW in 2019, increasing to approximately 28 MW in 2034 even after replacement of the T8 supply transformer (see Table 10-6).

Table 10-6: Edgecumbe supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Edgecumbe	11	13	15	17	19	21	23	24	26	28	29	32
Edgecumbe (after T8 replacement)	7	9	11	13	15	17	19	20	22	23	25	28

What next?

One of the 220/33 kV supply transformers (T8) is due for risk-based condition replacement in 2022. See section 10.4.2.2 for our proposed approach.

10.5.4.4 Kaitimako supply transformer security

Issue

A single 110/33 kV, 75 MVA transformer supplies load at Kaitimako resulting in n security. Some of the 11 kV Tauranga load is to be shifted to Kaitimako in future, with peak demand forecast to grow to 47 MW by 2034.

What next?

The lack of n-1 security is currently managed operationally using load backfeeding capability from Tauranga at 33 kV. See section 10.4.2.4 for our proposed longer-term approach.

10.5.4.5 Kaitimako 220/110 kV interconnection capacity

Issue

Two interconnecting transformers at Kaitimako supply much of the Tauranga region at 110 kV. These transformers provide:

- total nominal installed capacity of 300 MVA
- n-1 capacity of 223/225 MVA (summer/winter).

During periods of high load and low generation in the area, the load on the transformers is forecast to exceed their n-1 capacity from around winter 2028.

What next?

We expect the issue will be managed operationally in the Tauranga area in the forecast period. We will continue to monitor developments in the region and develop a long-term plan with Powerco closer to the need date. See section 10.4.2.4 for our enhancement approach for the Tauranga area.

10.5.4.6 Kawerau–Matahina 110 kV transmission security and capacity

Issue

The 110 kV Kawerau–Matahina line comprises two circuits each rated at 88/98 MVA (summer/winter).

The loss of one Kawerau–Matahina circuit may overload the remaining circuit if there is high generation output at Matahina and Aniwhenua.

What next?

The overload can be managed operationally by constraining generation at Matahina and Aniwhenua. Alternatively, the Aniwhenua generation can be reconfigured to inject into Horizon's 33 kV network instead, reducing the transmission requirements on the 110 kV Kawerau–Matahina circuits.

After consulting with customers, we applied variable line rating to the circuits to reduce, but not eliminate, the generation constraint. No further investments are planned to increase the transmission capacity.

10.5.4.7 Rotorua–Tarukenga 110 kV transmission capacity and security

Issue

The 110 kV Rotorua–Tarukenga line comprises two circuits, each rated at 63/77 MVA (summer/winter). The Rotorua 110 kV bus is split so that:

- the local generation at Wheao, one 110/33 kV transformer, and one 110/11 kV transformer are all connected to the Rotorua–Tarukenga 2 circuit
- one 110/33 kV transformer and one 110/11 kV transformer are supplied from the 110 kV Rotorua–Tarukenga 1 circuit.

An outage of the 110 kV Rotorua–Tarukenga 2 circuit:

- results in the loss of Wheao generation
- overloads the remaining 110 kV Rotorua–Tarukenga 1 circuit (as it supplies all of Rotorua's load).

Peak load at Rotorua is forecast to exceed the n-1 capacity of the circuits by approximately 2 MW in 2019, increasing to approximately 4 MW in 2034 (see Table 10-7).

Table 10-7: Rotorua–Tarukenga circuit overload forecast

	Circuit overload (MW)											
Circuit	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Rotorua–Tarukenga	2	3	2	2	2	2	3	2	3	4	5	4

What next?

We are discussing future supply options with Unison (the local lines company) and Trustpower (owner of the embedded generation connected at Rotorua), including both operational and investment options. See section 10.4.2.5 for our proposed approach.

10.5.4.8 Tarukenga supply security

Issue

A single 110/11 kV, 20 MVA supply transformer supplies the Tarukenga grid exit point resulting in n security. The peak load at Tarukenga is forecast to grow to 9 MW by 2034, which is well within the capacity of the supply transformer.

What next?

The customer (Unison) is able to manage the lack of n-1 security issue operationally by transferring load to alternative grid exit points. See section 10.4.2.5 for our proposed approach.

10.5.4.9 Te Matai supply transformer capacity and low voltage

Issue

Two 110/33 kV transformers (rated at 30 MVA and 40 MVA) supply Te Matai's load, providing:

- total nominal installed capacity of 70 MVA
- n-1 capacity of 36/39 MVA (summer/winter).

The peak load at Te Matai is forecast to exceed the n-1 winter capacity of the transformers by approximately 16 MW in 2019, increasing to approximately 26 MW in 2034 (see Table 10-8). Also, the pre-contingency ratings (with both transformers in service) is forecast to be exceeded by approximately 1 MW in 2022, increasing to approximately 8 MW in 2034.

Table 10-8: Te Matai supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Te Matai – pre-contingency	0	0	0	1	2	3	4	5	5	6	6	8
Te Matai – post-contingency	16	17	18	19	20	21	22	23	23	24	24	26

A voltage step greater than five per cent occurs at Te Matai from about 2028 for the Kaitimako–Te Matai contingency.

Only one of the existing supply transformers has an on-load tap changer. Using the on-load tap changer to manage the 33 kV bus voltage will cause circulating reactive power flows, further increasing the loading on the transformers.

What next?

We are working with Powerco to identify investment options to increase the supply capacity and address voltage issues at Te Matai. See section 10.4.2.3 for our proposed approach.

10.5.4.10 Waiotahi supply transformer capacity and transmission security

Issue

Waiotahi is supplied through a single 110 kV Edgecumbe–Waiotahi circuit providing n security.

Two 110/11 kV transformers supply Waiotahi's load, providing:

- total nominal installed capacity of 20 MVA
- n-1 capacity of 11/12 MVA (summer/winter).

The transformers also supply a 50 kV feeder via an 11/50 kV step-up transformer. The combined 11 kV and 50 kV peak load is forecast to exceed the n-1 winter capacity of the transformers by approximately 1 MW in 2020, increasing to 8 MW in 2034 (see Table 10-9).

Table 10-9: Waiotahi supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Waiotahi (11 kV and 50 kV)	0	1	1	2	2	2	3	3	4	4	5	8

What next?

The lack of n-1 security can be managed operationally by Horizon Networks. We have no investments planned to increase security to Waiotahi.

The Waiotahi supply transformers are due for risk-based condition replacement in 2021 and Horizon Networks has forecast voltage constraints on its 11 kV distribution network to Opotiki, where the bulk of its load is. We are working with Horizon Networks to identify investment options to increase supply capacity at Waiotahi and into Opotiki. See section 10.4.2.6 for our proposed approach.

10.5.5 Bay of Plenty bus security

Table 10-10 presents issues arising from the outage of a single bus section rated at 66 kV and above for the next 15 years. These are discussed in more detail in the subsequent sections.

Bus outages disconnect more than one power system component (for example, other circuits, transformers, reactive support or generators). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

Table 10-10: Bay of Plenty region transmission issues – bus security

Section number	Issue
0	Transmission bus security
10.5.5.2	Western Bay of Plenty 220 kV transmission capacity
10.5.5.3	Kaitimako 110 kV bus security
10.5.5.4	Kawerau 220 kV bus security
10.5.5.5	Okere–Te Matai 110 kV transmission capacity

10.5.5.1 Transmission bus security

Table 10-11 lists bus outages that cause voltage issues or a total loss of supply. Generators are included only if a bus outage disconnects the whole generation station or causes a widespread system impact. Supply bus outages, typically 11 kV and 33 kV, are not listed.

Table 10-11: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Edgecumbe 110 kV	Waiotahi	-	-	10.5.4.10
Edgecumbe 220 kV	Edgecumbe	-	-	Note 1
Kaitimako 110 kV	Kaitimako	-	- 220/110 kV transformer overloading	10.5.5.3 10.5.5.3
Kaitimako 220 kV	-	-	Okere–Te Matai overloading	10.5.5.5
Kawerau 110 kV	Kawerau (partial)	- KAG	- -	Note 2 Note 2
Kawerau 220 kV	Kawerau Waiotahi	- -	- - T13 220/110 kV transformer overloading	10.5.5.4 10.5.5.4 10.5.5.4
Mount Maunganui 110 kV	Mount Maunganui	-	-	Note 1
Owhata 110 kV	Owhata	-	-	Note 1
Tarukenga 110 kV	Tarukenga	- Wheao	- -	10.5.4.8 Note 3
Tarukenga 220 kV	-	-	Atiamuri–Tarukenga overloading	10.5.5.2
Tauranga 110 kV	Tauranga 11 kV Tauranga 33 kV	- -	- -	Note 1 Note 1
Rotorua 110 kV	-	Wheao	- Rotorua–Tarukenga overloading	Note 3 10.4.2.5
Te Matai 110 kV	Te Matai	-	-	Note 1
Waiotahi 110 kV	Waiotahi	-	-	10.5.4.10

1. There are no bus section circuit breakers at Edgecumbe, Mount Maunganui, Owhata, Tauranga and Te Matai, so a bus fault causes loss of supply.
2. Kawerau geothermal generation is only connected to one side of the Kawerau 110 kV bus, so a loss of the concerned bus section causes a loss of generation. A loss of a 110 kV bus section will also cause a partial loss of supply to the Norske Skogg load.
3. Wheao generation is only connected to one side of the Rotorua 110 kV bus, so a loss of the bus causes a loss of generation.

Our customers (Horizon Networks, Norske Skog, Powerco, Pioneer Energy, Trustpower, and Unison) have not requested a higher security level. Unless otherwise noted, we do not propose to increase bus security and future investment is likely to be customer driven.

If increased bus security is required, the options typically include bus reconfiguration and/or additional bus circuit breakers.

10.5.5.2 Western Bay of Plenty 220 kV transmission capacity

Issue

The outage of Tarukenga 220 kV bus section B disconnects:

- a 220/110 kV Tarukenga interconnecting transformer
- a 220 kV Atiamuri–Tarukenga circuit
- a 220 kV Kaitimako–Tarukenga circuit
- both 220 kV Edgecumbe–Tarukenga circuits.

This may in turn overload the 110 kV Edgecumbe–Owhata circuit, which has a special protection scheme to automatically open the circuit to remove the overload. From about 2025 this may result in overloading of the remaining 220 kV Atiamuri–Tarukenga circuit and low voltages during periods of high load, possibly leading to a regional loss of supply.

What next?

In the medium term this issue can be managed operationally. We will continue to monitor the risk associated with the loss of this Tarukenga bus section and review the economic analysis when the need arises. An option to resolve this issue is to connect one of the Edgecumbe–Tarukenga circuits to the other 220 kV bus section at Tarukenga.

We currently have no investment planned to address this bus security issue.

10.5.5.3 Kaitimako 110 kV bus security

Issue

There are three 110 kV bus sections at Kaitimako. An outage of one of the 110 kV bus sections disconnects the:

- 220/110 kV Kaitimako–T4 interconnecting transformer
- 110 kV Kaitimako–Mount Maunganui circuit
- 110 kV Kaitimako–Te Matai circuit.

This bus outage can cause overloads on the Kaitimako–T2 interconnecting transformer during periods of high load and low generation at Kaimai. This outage is the most critical for the 220/110 kV supply capacity, as it disconnects not only one 220/110 kV transformer at Kaitimako, but also the 110 kV circuit Kaitimako–Te Matai circuit, that normally provides support from Tarukenga 110 kV when a 220/110 kV transformer is unavailable in Kaitimako. An outage of another 110 kV bus disconnects the:

- 220/110 kV Kaitimako–T2 interconnecting transformer
- 110 kV Kaitimako–Tauranga 1 circuit
- 110/33 kV Kaitimako–T1 supply transformer.

This bus outage results in a loss of supply at Kaitimako because there is only one supply transformer (see section 10.5.4.4). This load can usually be backfed from Tauranga, but the simultaneous loss of the Kaitimako–Tauranga 1 circuit will result in Tauranga being supplied only from the Kaitimako–Mount Maunganui–Tauranga 2 circuit, which may restrict the amount of load that can be transferred to Tauranga.

Any 110 kV bus section outage beyond 2024 will cause constraints at peak load on the remaining circuit to Tauranga if Kaimai generation is lower than 14 MW.

What next?

Capacity constraints into Kaitimako and Tauranga can be managed operationally. Our proposed longer-term approach for this area is discussed in section 10.4.2.4.

We have no investments planned to increase security of the Kaitimako 110 kV bus.

10.5.5.4 Kawerau 220 kV bus security

Issue

The outage of the Kawerau 220 kV bus section A disconnects:

- the Kawerau–T12, 250 MVA, 220/110 kV transformer
- the 220 kV Edgecumbe–Kawerau 3 circuit
- one of the two 220/11 kV transformers supplying Norske Skog.

This may overload the Edgecumbe–Owhata 2 circuit, which has a special protection scheme to automatically open the circuit to remove the overload. This in turn may overload and trip the Kawerau–T13, 220/110 kV transformer, disconnecting the Kawerau 110 kV bus and in turn causing a loss of supply to the Kawerau and Waiotahi grid exit points and a loss of connection to generation (see section 10.5.4.1).

What next?

We have no investments planned to address the Kawerau 220 kV bus security issue. See section 10.4.2.1 for our proposed approach.

10.5.5.5 Okere–Te Matai 110 kV transmission capacity

Issue

The outage of a Kaitimako 220 kV bus section disconnects a:

- 220/110 kV Kaitimako interconnecting transformer
- 220 kV Kaitimako–Tarukenga circuit.

This bus outage causes an increase in the power flow from Okere to Te Matai and on to Kaitimako. The Okere–Te Matai circuit may overload from around 2024 during periods of high western Bay of Plenty load and low western Bay of Plenty generation.

What next?

This issue can be resolved operationally by opening the Kaitimako–Te Matai circuit if the Kaitimako bus outage occurs. This, however, may overload the remaining Kaitimako 220/110 kV interconnecting transformer. We will continue to monitor this risk and investigate investment options as the need arises.

No investments are currently planned to address this issue.

10.5.6 Other regional items of interest

10.5.6.1 Edgecumbe 220/110 kV interconnecting transformers

Issue

The two 220/110 kV interconnecting transformers at Edgecumbe (T4 and T5) are normally operated on hot standby (opened on the 110 kV side). Both transformers were manufactured in the early 1950's.

What next?

The transformers meet most criteria for risk-based replacement, except they are not normally on load. The transformers are switched in for maintenance outages that require the 110 kV Edgecumbe–Kawerau 1 and 2 circuits to be out of service (e.g. Kawerau–T12 outages). When switched in, the transformers maintain the existing level of security to Owhata and Waiotahi, manage voltage issues at Te Matai, and manage loading on the 110 kV Okere–Tarukenga circuit section.

One of the transformers (T4) will be decommissioned as part of the project to replace the T8 supply transformer (see section 10.4.2.2). We will retain the other transformer (T5) in its existing configuration until its condition deteriorates to a point where it creates an unacceptable risk or requires major investment. We will then decommission the transformer.

We will assess options before decommissioning the transformer. For the existing levels of generation at Kawerau, we expect it will be uneconomic to replace the transformers and outages will need to be carefully managed. However, the transformer will be replaced if significant additional generation is connected to the Kawerau 110 kV bus (see section 10.4.2.1).

10.5.7 Bay of Plenty proposals and opportunities

This section details relevant regional issues for selected generation proposals under investigation by developers and in the public domain, or other generation opportunities. The impact of committed generation projects on the grid backbone is dealt with separately in Chapter 6.

The maximum generation that can be connected depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

10.5.7.1 Generation connection at Kawerau

There are a number of future generation connection proposals in the Kawerau area, as the area has significant geothermal resources. If more than approximately 20-30 MW of additional generation (in addition to the 25 MW from Te Ahi O Maui connected in 2018) connects directly or indirectly to the Kawerau 110 kV bus, constraints may arise. The constraints are highly dependent upon system conditions around Kawerau so can vary considerably. Connecting more than approximately 35 MW of generation at Kawerau (to the 110 kV or 220 kV buses), will also overload the 220 kV Edgecumbe–Kawerau, or Kawerau–Ohakuri circuits if the other circuit is out of service.

Existing and future generation connected at Kawerau could be affected by a potential transmission constraint on the Wairakei–Ohakuri–Atiamuri–Whakamaru circuit. See Chapter 6 for details on the Wairakei Ring transmission capacity.

See section 10.4.2.1 for our approach to facilitate generation connection at Kawerau.

10.5.7.2 Generation connection to the 220 kV Edgecumbe–Tarukenga circuits

The area around the Edgecumbe–Tarukenga 1 and 2 circuits has a number of potential geothermal developments. Up to approximately 250 MW of generation could connect to these circuits before system upgrades are required, depending on developments at Kawerau. This capability decreases for outages of some 220 kV circuits in the Bay of Plenty region.

10.5.7.3 Generation connection to the Okere–Te Matai circuit

Some generation prospects exist close to the 110 kV circuits bounded by Tarukenga, Te Matai and Kawerau. These circuits can become highly loaded for some circuit outages when there is high demand. Under these conditions, the generation may need to be reduced or switched off.

11 Central North Island Regional Plan

11.1 Regional overview and transmission system

The Central North Island region is home to a variety of loads including the city of Palmerston North and its environs (supplied from Bunnythorpe and Linton), numerous medium to small loads, and a large industrial load at Tangiwai. A number of generating stations are also located in the region.

The existing transmission network is shown geographically in Figure 11-1 and schematically in Figure 11-2.

Figure 11-1: Central North Island region transmission

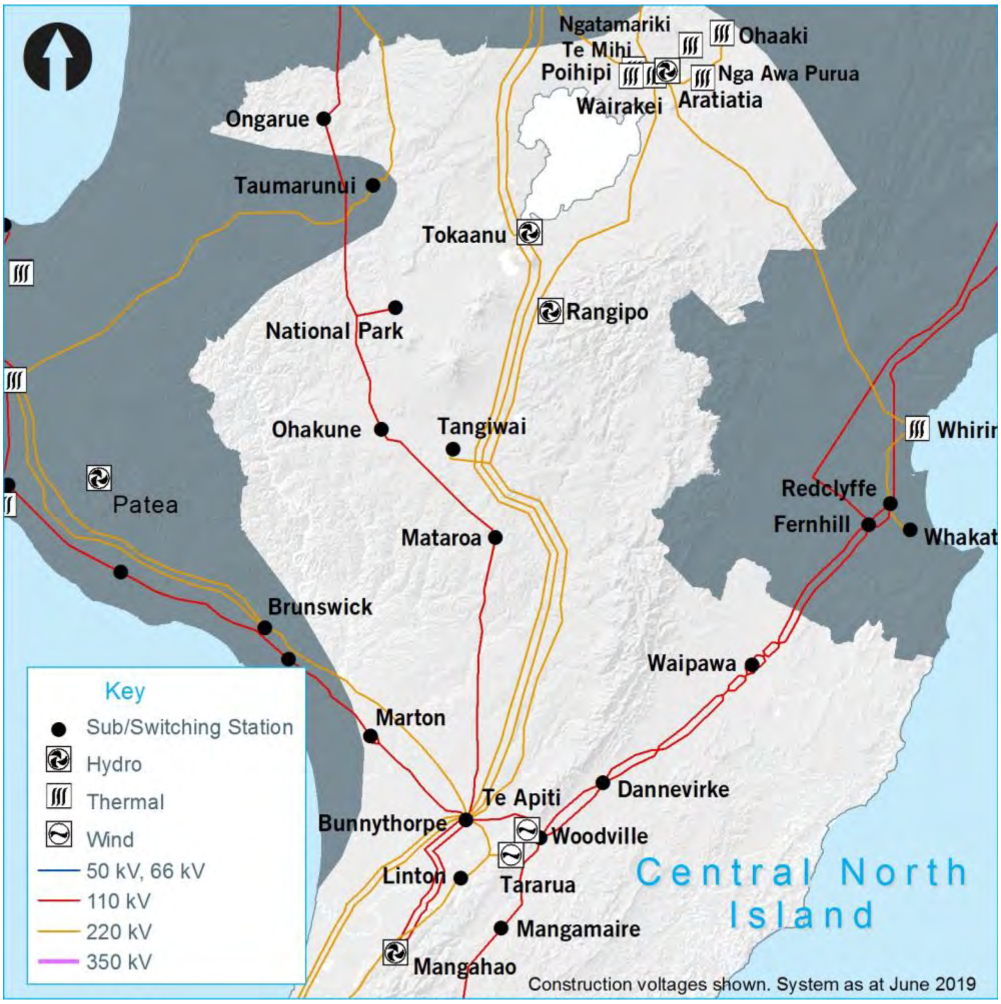
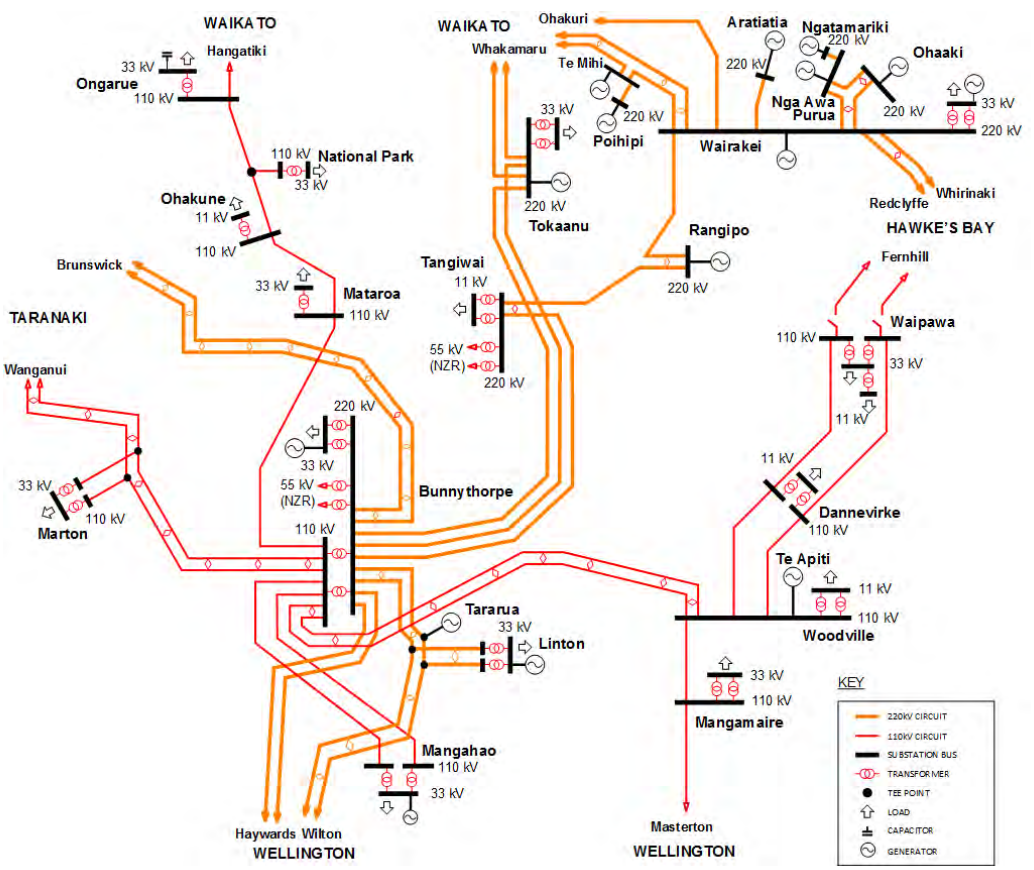


Figure 11-2: Central North Island region transmission schematic



11.1.1 Transmission into the region

The Central North Island region comprises 220 kV and 110 kV transmission circuits with interconnecting transformers located at Bunnythorpe. The direction of power flow through the region, north or south, is determined by generation, direction of HVDC flow and loads outside the region.

All the 220 kV circuits form part of the grid backbone. The 110 kV transmission network is mainly supplied through the 220/110 kV interconnecting transformers at Bunnythorpe, as well as through low capacity connections to other regions.

The Central North Island region is a main corridor for 220 kV transmission circuits through the North Island. The 220 kV transmission system connects the Wellington region to the south, the Taranaki region to the west, and the Waikato region to the north.

Most of the Central North Island's generation capacity is connected to the 220 kV circuits and output significantly exceeds the local demand. The National Grid enables surplus generation to be exported to other demand centres.

11.1.2 Transmission within the region

The 110 kV transmission system within the Central North Island region mainly consists of low-capacity circuits. The transmission system may become constrained under certain operating conditions, and operational measures are required to ensure the 110 kV circuits operate within their thermal capacity. These are:

- normally splitting the 110 kV system at Waipawa, for the Fernhill–Waipawa circuits
- managing generation output to avoid overloading of the 110 kV:
  - Bunnythorpe–Woodville circuits
  - circuits between Bunnythorpe and Arapuni (Waikato region)
  - circuits between Bunnythorpe and Stratford (Taranaki region).

Special protection schemes at Mataroa, Tokaanu and Woodville are also used to automatically reconfigure the grid or reduce generation to ensure the circuits operate within their thermal capacity.

11.2 Central North Island demand

The Central North Island regional peak demand[1] is forecast to grow by an average of 1.1 per cent per annum over the next 15 years, from 283 MW in 2019 to 332 MW in 2034. This is lower than the national average growth rate of 1.2 per cent per annum.

Table 11-1 sets out forecast peak demand (prudent growth[2]) at each grid exit point over the forecast period.

Table 11-1: Forecast annual peak demand (MW) at Central North Island grid exit points to 2034

Grid exit point	Power factor	Peak demand (MW)											
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Bunnythorpe 33 kV[1,2]	0.99	102	103	104	92	94	95	97	98	100	101	101	96
Bunnythorpe – NZR	1.00	5	5	5	5	5	5	5	5	5	5	5	5
Dannevirke	0.98	14	13	14	14	14	14	14	14	14	14	14	15
Linton[1]	0.99	70	70	71	85	86	87	88	89	89	90	90	88
Mangahao	0.96	38	38	38	39	39	39	38	38	36	35	33	30
Mangamaire	0.97	16	16	16	16	16	16	16	16	16	16	16	16
Marton[2]	0.98	17	17	17	17	17	17	17	18	18	18	18	18
Mataroa	0.99	7	7	7	7	7	7	8	8	8	8	8	9
National Park	0.97	7	7	7	7	7	7	7	7	7	7	7	8
Ohakune	0.98	9	9	9	9	9	10	10	10	10	11	11	13
Ongarue	1.00	12	12	12	12	12	12	12	12	12	13	13	15
Tangiwai 11 kV	1.00	42	42	43	43	43	44	44	44	45	45	45	46
Tangiwai –NZR	1.00	7	7	7	7	7	7	7	7	7	7	7	8
Tokaanu	0.99	12	12	12	12	12	12	12	12	13	13	13	15
Waipawa	0.97	20	21	21	21	21	21	21	22	22	22	22	23
Wairakei	0.98	53	53	54	55	55	56	56	57	58	58	59	54
Woodville	0.99[3]	3	3	3	3	3	3	3	3	3	3	3	4

1. Powerco has advised a load shift from Bunnythorpe to Linton of 22 MW in 2022.
2. Powerco is investigating shifting 10-16 MW from Bunnythorpe to Marton. This is not included in the load forecast.
3. This is a leading power factor.

[1] For discussion on demand forecasting see Chapter 3, section 3.1.

[2] Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

11.3 Central North Island generation

Generation capacity in the Central North Island region is currently 1,489 MW. Table 11-2 lists the generation capacity forecast for each grid injection point for the forecast period. This includes all known and committed generation stations, including those embedded in local lines company's networks.[3] This generation constitutes a significant portion of total North Island generation and exceeds local demand. Surplus generation is exported over the National Grid.

Further generation may be developed during the period but is not sufficiently advanced to be included in our forecasts. (Refer to section 11.5.6 for more information on potential new generation).

Table 11-2: Forecast annual generation capacity (MW) at Central North Island grid injection points to 2034 (existing and committed generation)

Grid injection point (location/name if embedded)	Generation capacity (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Aratiatia	84	84	84	84	84	84	84	84	84	84	84	84
Bunnythorpe (Tararua Wind Stage 2)	36	36	36	36	36	36	36	36	36	36	36	36
Linton (Tararua Wind Stage 1)	32	32	32	32	32	32	32	32	32	32	32	32
Linton (Totara Road)	1	1	1	1	1	1	1	1	1	1	1	1
Linton (Turitea Wind)	0	119	119	119	119	119	119	119	119	119	119	119
Mangahao	30	30	30	30	30	30	30	30	30	30	30	30
Nga Awa Purua	140	140	140	140	140	140	140	140	140	140	140	140
Nga Awa Purua (Ngatamariki)	82	82	82	82	82	82	82	82	82	82	82	82
Ohaaki	56	56	56	56	56	56	56	56	56	56	56	56
Ongarue (Mokauiti, Kuratau and Wairere Falls)	13	13	13	13	13	13	13	13	13	13	13	13
Poihipi	51	51	51	51	51	51	51	51	51	51	51	51
Rangipo	120	120	120	120	120	120	120	120	120	120	120	120
Tararua Wind Central (Tararua Wind Stage 3)	93	93	93	93	93	93	93	93	93	93	93	93
Tararua Wind Central (Te Rere Hau)	49	49	49	49	49	49	49	49	49	49	49	49
Te Mihi	175	175	175	175	175	175	175	175	175	175	175	175
Tokaanu	240	240	240	240	240	240	240	240	240	240	240	240
Wairakei	132	132	132	132	132	132	132	132	132	132	132	132
Wairakei (Hinemaiaia)	7	7	7	7	7	7	7	7	7	7	7	7
Wairakei (Rotokawa)	35	35	35	35	35	35	35	35	35	35	35	35
Wairakei (Te Huka)	23	23	23	23	23	23	23	23	23	23	23	23
Woodville (Te Apiti)	90	90	90	90	90	90	90	90	90	90	90	90

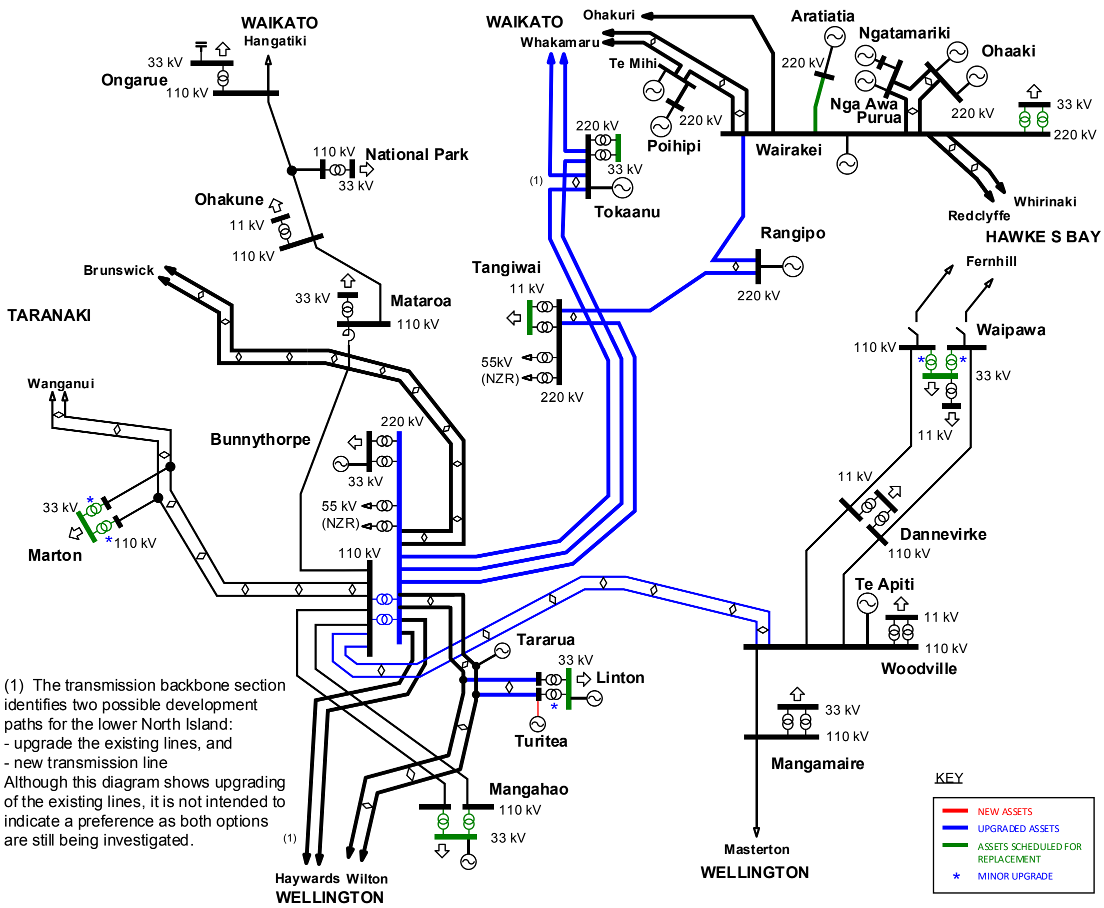
3 Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

11.4 Grid enhancement approach

11.4.1 Possible future Central North Island transmission configuration

Figure 11-3 shows the possible configuration of Central North Island transmission in 2034. New assets, upgraded assets, and assets scheduled for replacement within the forecast period (based on potential enhancement approaches set out in the following sections) are shown.

Figure 11-3: Possible Central North Island transmission configuration in 2034



11.4.2 Enhancement approach

Our approach seeks to ensure secure transmission into and within the Central North Island region into the future. Through the E&D process we assess transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified issues and opportunities we take into account uncertainty in future demand, generation and technological developments.

Grid backbone issues through the Central North Island region are discussed in Chapter 6, Grid Backbone (North Island section).

Short and long term transmission issues likely requiring E&D or customer-funded investments in the Central North Island region over the next 10-15 years are:

Section number	Issue
811.4.2.1	Palmerston North area supply capacity
811.4.2.2	Bunnythorpe–Mataroa 110 kV transmission capacity
811.4.2.3	Mangahao supply capacity
811.4.2.4	Marton low voltage
811.4.2.5	Waipawa supply transformer capacity and security

11.4.2.1 Palmerston North area supply capacity

In the Palmerston North area, Powerco's distribution network is supplied from the Bunnythorpe and Linton 33 kV grid exit points. There is also wind generation (Tararua wind farm) embedded at both Bunnythorpe and Linton.

With low wind generation at Bunnythorpe, load may exceed the n-1 capacity of the transformers. This can be managed operationally in the short term by Powerco transferring load within its distribution network to the Linton grid exit point, which has spare capacity.

Powerco is planning to permanently shift some load from Bunnythorpe to Linton in 2020, which will remove the n-1 capacity issue at Bunnythorpe but at the same time will introduce an n-1 capacity issue at Linton. The n-1 constraint at Bunnythorpe will reappear towards the end of the forecast period due to load growth.

In addition, Powerco is considering transferring up to 16 MW of load from Bunnythorpe to Marton in the next five to ten years. This load transfer will have a substantial impact on the capacity at Marton and the transmission capacity between Bunnythorpe and Stratford. (This potential load transfer is not accounted for in our load forecast.)

Enhancement approach:

- The Linton transformers' n-1 capacity is limited by Linton–T3's metering equipment. Recalibrating the metering will resolve the n-1 capacity issue for the forecast period, including once load has been transferred from Bunnythorpe.
- The Bunnythorpe transformers' n-1 capacity limit will be managed operationally, with the ability to transfer load to Linton.
- We will discuss the possible load transfer from Bunnythorpe to Marton with Powerco. If this load transfer occurs it will require increasing the Marton transformers' n-1 capacity as well as possible investment to increase the 110 kV circuit capacity between Bunnythorpe and Stratford. Any investment in the 110 kV circuit capacity will also need to consider possible developments at Wanganui, Waverley and Hawera. See the Taranaki chapter (Chapter 12) for more information on issues in those areas.

Base E&D Capex investments

Project Name	Linton supply transformer capacity
Project description:	Recalibrate metering on Linton–T3 to remove branch limit
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2019
Indicative cost [$ million]:	0.1
Part of the GEIR?	No

11.4.2.2 Bunnythorpe–Mataroa 110 kV transmission capacity

The Bunnythorpe–Mataroa circuit can overload for certain generation dispatch patterns combined with an outage of some of the 220 kV circuits.

Enhancement approach:

- Currently we manage the issue operationally using one or more of the following measures:
  - limiting HVDC north flow
  - constraining-on generation at Arapuni
  - opening the Arapuni–Ongarue circuit (this is usually only used during planned outages on lower North Island 220 kV circuits as it leaves Ongarue, National Park, Ohakune, and Mataroa on n security).

- A series reactor and a special protection scheme at Mataroa were installed on the 110 kV Bunnythorpe–Mataroa circuit at Mataroa in 2018. The series reactor and special protection scheme will reduce power flow on the circuit and reconfigure the grid post-contingency to relieve the circuit constraint.
- However, if substantial amounts of generation are developed in the lower North Island or in very low Waikato River generation scenarios, the Bunnythorpe–Mataroa circuit may still overload pre-contingency with the series reactor in service. We will continue to monitor the risk of this constraint in the future as it may be relieved as we resolve existing issues on the Waikato and Auckland 110 kV networks such as the Otahuhu–Wiri constraint (refer to Chapter 8).

11.4.2.3 Mangahao supply capacity

Load at Mangahao is expected to already exceed the n-1 capacity of the supply transformers when Mangahao generation is unavailable. However, Mangahao generation is usually available during peak load periods so the probability of the constraint binding is very low.

Both Mangahao supply transformers are due for risk-based condition replacement towards the end of the forecast period.

Enhancement approach:

- We will discuss the need to increase the supply transformer capacity with Electra, closer to the time when the transformers need to be replaced.

11.4.2.4 Marton low voltage and supply capacity

The Marton supply bus voltage can drop below 0.95 pu following a contingency on a Bunnythorpe–Marton–Wanganui circuit. The Marton supply transformers do not have on-load tap changers, so they cannot regulate the supply voltages to within acceptable limits.

Enhancement approach:

- This issue has been substantially addressed with the new Bunnythorpe 220/110 kV transformers.
- The Marton–T2 transformer is due for risk-based condition replacement towards the end of the forecast period (base capex replacement and refurbishment). The replacement transformer will have on-load tap changers, providing voltage regulating capability, which will address the issue.
- If Powerco transfers 16 MW of load from Bunnythorpe to Marton the replacement of the Marton supply transformers may be advanced to manage both the n-1 loading on the transformers and low voltage issues.

11.4.2.5 Waipawa supply transformer capacity and security

Waipawa has loads at 33 kV and 11 kV. The Waipawa 33 kV load is expected to exceed the n-1 capacity of the supply transformers towards the end of the forecast period.

As the branch constraints at Waipawa are due to metering and protection ratings, upgrading the 110/33 kV transformers' metering and protection limits will resolve the issue for the forecast period.

The Waipawa supply bus voltage can drop below 0.95 pu following a contingency on a Woodville–Dannevirke–Waipawa circuit.

Enhancement approach:

- Closer to the need date, we will investigate upgrading the transformers' metering and protection.
- Closer to the need date we will investigate options of a capacitor bank or replacement transformers with on-load tap changers.

Base E&D Capex investments

Project Name	Waipawa supply capacity
Project description:	Resolve metering limits on Waipawa–T1 and T2
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2032
Indicative cost [$ million]:	0.1
Part of the GEIR?	No

11.5 Asset capability and management

We have assessed the transmission capacity and reactive support requirements in the region for the next 15 years. When an issue or opportunity exists, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 11.4.2) have been developed to address issues or opportunities that require action within the forecast period and where investment is justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk-based asset replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

11.5.1 Central North Island transmission system significant upcoming work

We integrate our capital project and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Table 11-3 lists the significant upcoming work proposed for the Central North Island region over the next 15 years that may significantly impact related system issues or connected parties.

Table 11-3: Proposed significant upcoming work

Description	Tentative year	E&D issues
Aratiatia–Wairakei reconductoring	2022-2025	None
Linton 33 kV outdoor to indoor conversion	2020-2021	11.5.4.4
Mangahao 33 kV outdoor to indoor conversion Mangahao supply transformers risk based condition replacement	2019-2020 2031-2033	11.5.4.5
Mangamaire special protection scheme replacement Ongarue 33 kV capacitor risk based condition replacement	2020-2022 2029-2032	11.5.4.2 11.5.4.7 11.5.4.10
Tokaanu 33 kV outdoor to indoor conversion	2024-2026	11.5.4.11
Waipawa 33 kV outdoor to indoor conversion Waipawa supply transformers risk based condition replacement	2021-2023 2032-2035	11.5.4.12 11.5.4.13
Wairakei supply transformers risk based condition replacement	2019-2021	None
Woodville special protection scheme replacement	2022-2024	11.5.4.2

11.5.2 Central North Island asset feedback

The Asset Feedback Register includes no entries that are E&D related, specific to the Central North Island region.

11.5.3 Changes since the 2018 Transmission Planning Report

Table 11-4 lists the specific new issues and those that are no longer relevant (relative to our previous Transmission Planning Report).

Table 11-4: Changes since the 2018 TPR

Issues	Change
Bunnythorpe–Mataroa series reactor and special protection scheme	Removed from issues list. Installed a series reactor and Special Protection Scheme at Mataroa.

11.5.4 Central North Island transmission capability

Table 11-5 summarises identified issues that may affect the Central North Island region during the next 15 years. In each case we have detected a condition that would constrain the network capacity if action were not taken. Each issue is discussed in more detail below.

This transmission capability section reports whether the Grid can reasonably be expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, forms part of the Grid Reliability Report (GRR).

Table 11-5: Central North Island region transmission issues – regional/ site by grid exit point

Section number	Issue
Regional	
11.5.4.1	Bunnythorpe–Mataroa 110 kV transmission capacity
11.5.4.2	Bunnythorpe–Woodville 110 kV transmission capacity
Site by grid exit point	
11.5.4.3	Bunnythorpe supply transformer capacity
11.5.4.4	Linton supply transformer capacity
11.5.4.5	Mangahao supply transformer capacity
11.5.4.7	Mataroa supply transformer security and low voltage
11.5.4.8	National Park transmission and supply transformer security
11.5.4.9	Ohakune supply transformer security
11.5.4.10	Ongarue supply transformer security
11.5.4.11	Tokaanu supply transformer security
11.5.4.12	Waipawa low voltage
11.5.4.13	Waipawa supply transformer capacity and security

11.5.4.1 Bunnythorpe–Mataroa 110 kV transmission capacity

Issue

The Bunnythorpe–Mataroa single circuit is rated at 57/70 MVA (summer/winter). This circuit can overload for some generation dispatch patterns (such as high HVDC north power flow, high wind generation in the lower North Island, or low Arapuni generation) and an outage of a 220 kV Hamilton–Whakamaru, Tokaanu–Whakamaru, Huntly–Stratford, Stratford–Taumarunui, Bunnythorpe–Tokaanu, or Rangipo–Wairakei circuit.

What next?

We currently manage this issue operationally with generation dispatch. A series reactor and special protection scheme at Mataroa was installed to help manage this issue. Refer to section 11.4.2.2 for our proposed approach.

11.5.4.2 Bunnythorpe–Woodville 110 kV transmission capacity

Issue

The Bunnythorpe–Woodville circuits are rated at 57/70 MVA (summer/winter). The loading on these circuits depends on the HVDC transfer direction and level, Te Apiti generation and the loads in Wellington, Wairarapa, Dannevirke, and Waipawa. The circuits may overload for an outage of:

- one circuit, overloading the remaining circuit during high HVDC south flow
- two or more 220 kV circuits between Bunnythorpe and Haywards, overloading the Bunnythorpe–Woodville circuits.

What next?

A special protection scheme at Woodville manages overloads on the Bunnythorpe–Woodville 110 kV circuit following an outage on the parallel circuit by:

- detecting an outage of a Bunnythorpe–Woodville 110 kV circuit causing overloading of the remaining Bunnythorpe–Woodville circuit
- opening the Mangamaire–Woodville circuit at Woodville to prevent through-transmission, and
- constraining off Te Apiti generation if the overload on Bunnythorpe–Woodville remains.

For a 220 kV circuit outage between Bunnythorpe and Haywards, we manage the overloading operationally by:

- restricting HVDC south flow, or
- opening the 110 kV Mangamaire–Masterton circuit at Mangamaire (CB172), leaving Mangamaire on n security. The Mangamaire auto-changeover scheme will be enabled to automatically restore supply to Mangamaire from Masterton following a Mangamaire–Woodville outage.

Our investigation shows that the risk of the Bunnythorpe–Woodville circuits overloading is very low. The existing special protection schemes and operational measures discussed above remain the most cost effective method for resolving the constraint as it arises.

We will continue to monitor the development of generation in the area as connection of significant amounts of generation on the 110 kV system will create the need to invest. This is discussed in section 11.5.6.4.

11.5.4.3 Bunnythorpe supply transformer capacity

Issue

Two 220/33 kV transformers supply the load at Bunnythorpe, providing:

- total nominal installed capacity of 166 MVA
- n-1 capacity of 101/101 MVA[4] (summer/winter).

Peak load at Bunnythorpe is forecast to exceed the n-1 winter capacity of the transformers by approximately:

- 7 MW in 2019
- 8 MW in 2020, following some load transfer to Linton
- 9 MW in 2021 (see Table 11-6).

Tararua wind generation (Stage 2) is connected to the Bunnythorpe 33 kV bus, and the forecast assumes that the wind farm is not generating during peak load periods.

The overload will cease during 2022-24 with the load transfer to Linton. We expect it will reappear in subsequent years, then decline to about 1 MW by 2034 (see Table 11-6), in line with our load forecast for the grid exit point.

Our load forecast for the Bunnythorpe grid exit point shows a decline later in the period due to assumptions we have made around uptake of new technologies. These include batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid at peak. . The underlying demand forecast assumptions are set out in Chapter 3 of this TPR.

[4] The transformers' capacity is limited by a 33 kV cable on T9. With this limit resolved, the n-1 capacity will be 101/106 MVA (summer/winter)

Table 11-6: Bunnythorpe supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)										
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Bunnythorpe	7	8	9	0	0	0	2	3	4	5	6	1

What next?

Powerco can transfer load to Linton within the distribution system following a contingency. For our longer term approach, refer to section 11.4.2.1.

11.5.4.4 Linton supply transformer capacity

Issue

Two 220/33 kV transformers (rated at 82 MVA and 117 MVA) supply Linton's load, providing:

- total nominal installed capacity of 199 MVA
- n-1 capacity of 82/82 MVA[5] (summer/winter).

Peak load at Linton is forecast to exceed the n-1 summer capacity of the transformers by approximately 7 MW in 2022 (seeTable 11-7), increasing to a maximum approximately 12 MW in 2030. Tararua wind generation (Stage 1) is connected to the Linton 33 kV bus, and the forecast conservatively assumes that the wind farm is not generating during peak load periods.

As described above for Bunnythorpe, our underlying load forecast assumptions about new technology uptake result in an expectation of declining load at Linton later in the period. This will result in a reduction in the forecast n-1 overloading to about 10 MW by 2034 (see Table 11-7).

Table 11-7: Linton supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)										
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Linton	0	0	0	7	7	8	9	10	11	11	11	10

What next?

The n-1 capacity can be increased significantly by recalibrating the revenue metering on Linton–T3. Refer to section 11.4.2.1 for our proposed approach.

11.5.4.5 Mangahao supply transformer capacity

Issue

Two 110/33 kV transformers supply Mangahao's load, providing:

- total nominal installed capacity of 60 MVA
- n-1 capacity of 37/39 MVA (summer/winter).

Peak load at Mangahao is forecast to exceed the n-1 winter capacity of the transformers by approximately 4 MW in 2019, increasing to approximately 5 MW in 2025 (see Table 11-8). The Mangahao generation station is connected to the 33 kV bus, and the forecast conservatively assumes that Mangahao is not generating during peak load periods.

Assumptions included in our demand forecast model around uptake of new technologies (such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid at peak) result in falling demand at Mangahao towards the end of the forecast period, causing the forecast n-1 overloading to reduce to zero by 2028 (see Table 11-8).

5 The transformers' capacity is limited by a metering limit on T3. With this limit resolved, the n-1 capacity will be 113/119 MVA (summer/winter).

Table 11-8: Mangahao supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)										
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Mangahao	4	4	4	4	5	5	5	4	2	0	0	0

What next?

The supply transformer overload is managed operationally as Mangahao generation is usually available during peak load periods. Refer to section 11.4.2.3 for our proposed approach.

11.5.4.6 Marton low voltage

Issue

The supply bus voltage at Marton may fall below 0.95 pu following an outage of a Bunnythorpe–Marton–Wanganui circuit.

The Marton supply transformers do not have on-load tap changers.

Two 110/33 kV transformers (rated at 20 MVA and 30 MVA) supply Marton's load providing:

- total nominal installed capacity of 50 MVA
- n-1 capacity of 24/24 MVA[6] (summer/winter).

Powerco is considering transferring up to 16 MW of load from Bunnythorpe to Marton from around 2023-2025. With this load transfer the peak load at Marton is forecast to exceed the n-1 winter capacity of the transformers by 11 MW. The low voltage issue will be exacerbated by this load shift.

In addition, with the possible load transfer the circuits between Marton and Bunnythorpe may overload for a 110 kV Bunnythorpe–Marton–Wanganui outage during periods of high HVDC north flow and low Taranaki generation.

What next?

The low voltage issue can be managed operationally in the short term by managing Taranaki generation and HVDC transfer during peak load periods. For our longer term proposed approach, refer to section 11.4.2.4.

11.5.4.7 Mataroa supply transformer security and low voltage

Issue

The load at Mataroa is supplied by a single 110/33 kV, 30 MVA supply transformer comprising three single-phase units, resulting in n security.

The supply bus voltage at Mataroa is forecast to fall below 0.95 pu following an outage of a Bunnythorpe–Mataroa 1 circuit.

A spare on-site unit may be able to provide backup following a unit failure, with replacement taking 8-14 hours. However, this is an uncontracted spare and may not be available when needed.

What next?

Powerco considers the lack of n-1 security can be managed operationally during the forecast period. The low voltage issue can be managed operationally by constraining on generation at Arapuni. We have not planned any investments to increase security at Mataroa.

11.5.4.8 National Park transmission and supply transformer security

Issue

The load at National Park is supplied through a single 110 kV transmission circuit and a single 110/33 kV, 15 MVA supply transformer, resulting in n security.

The substation allows connection of our mobile substation for transformer maintenance outages, subject to its availability and location.

7 The capacity of the transformers is limited by the LV protection limit followed by a transformer bushing (27 MVA) limit. With these limits resolved, the n-1 capacity will be 29/30 MVA (summer/winter).

What next?

Some load can be backfed through The Lines Company's distribution system. The Lines Company considers the lack of n-1 security is operationally managable for the forecast period. We have not planned any investments to increase security at National Park.

11.5.4.9 Ohakune supply transformer security

Issue

The load at Ohakune is supplied by a single 110/11 kV, 20 MVA supply transformer, resulting in n security.

The substation allows connection of our mobile substation for transformer maintenance outages, subject to its availability and location.

What next?

The issue can be managed operationally. Some of The Lines Company's load can be backfed from Tangiwai. The local lines companies, The Lines Company and Powerco, have not requested a higher security level at Ohakune. We have not planned any investments to increase security at Ohakune.

11.5.4.10 Ongarue supply transformer security and low voltage

Issue

The load at Ongarue is supplied by a single 110/33 kV, 20 MVA supply transformer comprising three single-phase units, resulting in n security.

The loss of the Karapiro–Te Awamutu 110 kV circuit causes low voltages at Ongarue, especially at times of high load and low Arapuni generation.

What next?

The lack of n-1 security can be managed by backfeeding the load through The Lines Company's distribution system.

The post-contingent low voltage issue is likely to be resolved as we invest to increase transmission capacity into Hangatiki (see Chapter 9 for investments at Hangatiki).

We have no investments planned to increase supply security at Ongarue.

11.5.4.11 Tokaanu supply transformer security

Issue

The load at Tokaanu is supplied by a single 220/33 kV, 20 MVA supply transformer, with a second transformer that can be manually switched into service when required. This means that Tokaanu does not have no-break transformer security. Tripping the on-load transformer will result in a loss of supply until the other transformer is manually switched into service.

What next?

The Lines Company has not requested a higher level of security at Tokaanu. We have no investments planned to increase supply security at Tokaanu.

11.5.4.12 Waipawa low voltage

Issue

Waipawa is normally supplied at 110 kV from Bunnythorpe via Dannevirke. The supply bus voltages at Waipawa are forecast to fall below 0.95 pu following an outage of a Waipawa–Dannevirke–Woodville circuit. In addition, this outage causes a step voltage change greater than five per cent.

The Waipawa supply transformers have off-load tap changers, so these transformers cannot be used to manage the post-contingent voltage.

What next?

The Bunnythorpe interconnecting transformers which have on-load tap changers can assist with, but not eliminate, the low voltage issue.

The Waipawa 110 kV disconnectors are motorised and can be controlled remotely via SCADA. Therefore, if low voltage occurs, the load can be quickly transferred from the Central North Island to the Hawke's Bay region.

As the low voltage issue is expected to occur from 2020, we anticipate managing it operationally, either with a Wider Voltage Agreement or by shifting the system split to supply Waipawa from Fernhill. If the constraint becomes significantly more onerous in future, it may be economically justifiable to install a capacitor bank on the 33 kV busbar or bring forward the replacement of the 110/33 kV transformers. Replacement transformers will have on-load tap changers.

We have no additional investments planned to address this issue.

11.5.4.13 Waipawa supply transformer capacity and security

Issue

Waipawa has loads at 33 kV and 11 kV. Two 110/33 kV transformers (rated at 20 MVA and 30 MVA) supply Waipawa's load, providing:

- total nominal installed capacity of 50 MVA
- n-1 capacity of 26/26 MVA[7] (summer/winter).

Peak load at Waipawa is forecast to exceed the n-1 summer capacity of the transformers towards the end of the forecast period, by 1 MW (see Table 11-9).

A single 33/11 kV, 10 MVA transformer supplies Waipawa's 11 kV load, resulting in n security.

Table 11-9: Waipawa supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Waipawa	0	0	0	0	0	0	0	0	0	0	0	1

What next?

Resolving the 110/33 kV transformers' metering and protection limits will resolve the 33 kV issue for the forecast period. Refer to section 11.4.2.5 for our proposed approach.

Centralines will manage the lack of n-1 security for Waipawa's 11 kV load operationally. We have no investment planned to increase security to the Waipawa 11 kV load.

11.5.5 Central North Island bus security

This section presents issues arising from the outage of a single bus section rated at 66 kV and above for the next 15 years.

Bus outages disconnect more than one power system component (for example, other circuits, transformers, reactive support or generators). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

11.5.5.1 Transmission bus security

Table 11-10 lists bus outages that cause voltage issues or a total loss of supply. Generators are included only if a bus outage disconnects the whole generation station or causes a widespread system impact. Supply bus outages, typically 11 kV and 33 kV, are not listed.

Note that the customers at these grid exit points (Mighty River Power, Contact Energy, Genesis Energy, Meridian Energy, Scanpower, Powerco, The Lines Company, and Centralines) have not requested a higher security level.

[7] The capacity of the transformers is limited by the LV protection limit followed by a transformer bushing (27 MVA) limit. With these limits resolved, the n-1 capacity will be 29/30 MVA (summer/winter).

Table 11-10: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Arapuni 110 kV	-	Arapuni	-	Note 1
Aratiatia 220 kV	-	Aratiatia		Note 2
Bunnythorpe 110 kV	-	-	Bunnythorpe–Woodville overloading Regional low voltage	Note 3 Note 4
Bunnythorpe 220 kV	-	-	Bunnythorpe–Woodville overloading Regional low voltage	Note 5 Note 4
Mangamaire 110 kV	Mangamaire	-	-	Note 2
Mataroa 110 kV	Mataroa	-	-	Note 2
Nga Awa Purua 220 kV	-	Nga Awa Purua Ngatamariki	-	Note 6 Note 6
Ohakune 110 kV	Ohakune National Park	-	-	Note 7 Note 7
Ongarue 110 kV	Ongarue	-	-	Note 2
Rangipo 220 kV	-	Rangipo	-	Note 2
Tokaanu 220 kV	Tokaanu	-	-	11.5.4.11
Wanganui 110 kV (Taranaki region)	Marton Wanganui	-		Note 8 Note 2
Woodville 110 kV	Dannevirke Waipawa Woodville	Te Apiti	-	Note 9 Note 9 Note 2 Note 2
Wairakei 220 kV	-	Aratiatia Wairakei	-	Note 10 Note 11

1. Arapuni has a split 110 kV busbar with generation split between the North Bus and the South Bus. A North bus fault will lose Arapuni G1, G2, G3, G4 & G8. A South bus fault will lose Arapuni G5, G6 & G7.
2. There are single bus sections at Aratiatia, Mangamaire, Mataroa, Ongarue, Wanganui, Woodville and Rangipo, so a bus fault will cause loss of connection and loss of supply.
3. An outage of a Bunnythorpe 110 kV bus section will also disconnect a Bunnythorpe–Woodville circuit, which may overload the remaining circuit. A special protection scheme at Woodville will operate to remove the overload (see section 11.5.4.2).
4. An outage of a Bunnythorpe 110 kV bus section will also disconnect several circuits which may cause low voltage at Marton (see section 11.5.4.6), Mataroa (see section 11.5.4.7) and Waipawa (see section 11.5.4.12).
5. An outage of a Bunnythorpe 220 kV bus section disconnects circuits to Haywards. This may cause both Bunnythorpe–Woodville circuits to overload, which is not prevented by the special protection scheme at Woodville (see sections 0 and 11.5.4.2).
6. Nga Awa Purua has a single bus, with a single connection to Ngatamariki. A bus outage at Nga Awa Purua will disconnect all generation at Nga Awa Purua and Ngatamariki.
7. National Park is supplied from the Ohakune–National Park–Ongarue circuit. Because there is no bus zone protection at Ohakune, a fault on the Ohakune 110 kV bus will disconnect the circuit, causing loss of supply at National Park and Ohakune.
8. Marton is supplied from the Bunnythorpe–Marton–Wanganui circuits. Because there is no bus zone protection at Wanganui (in the Taranaki region), a fault on the Wanganui 110 kV bus will disconnect both circuits, causing loss of supply at Marton, and Wanganui (see Chapter 12).
9. Dannevirke and Waipawa are normally supplied via the Waipawa–Dannevirke–Woodville circuits as a spur from Woodville. An outage of the Woodville 110 kV bus disconnects both circuits, causing loss of supply.
10. Aratiatia is connected to Wairakei through a single circuit. A Wairakei bus outage that disconnects this circuit disconnects the Aratiatia generation station.
11. All generators at Wairakei connect to the same bus zone, so an outage of this bus zone disconnects all generators.

11.5.5.2 Bunnythorpe 220 kV bus security

Issue

The Bunnythorpe 220 kV bus is divided into three bus sections. One of the sections connects the following:

- 220 kV Bunnythorpe–Brunswick 1 circuit
- 220 kV Bunnythorpe–Paraparaumu–Haywards 1 circuit
- 220 kV Bunnythorpe–Linton–Wilton 1 circuit
- 220 kV Bunnythorpe–Tokaanu 2 circuit
- 220/110 kV Bunnythorpe–T3 interconnecting transformer
- 220/33 kV Bunnythorpe–T10 supply transformer.

A contingency on this bus section can lead to low supply bus voltages in the Central North Island.

What next?

We have investigated rearranging the bus connections at Bunnythorpe or installing a fourth 220 kV bus section to reduce the impact of a bus section contingency. The investigation found the risk of a contingency on the bus section is not significant enough to justify any of the investment options. We will continue to monitor this issue and review the analysis as warranted.

11.5.6 Central North Island generation proposals and opportunities

This section details relevant regional issues for selected generation proposals under investigation by developers and in the public domain, or other generation opportunities. The impact of committed generation projects on the grid backbone is dealt with separately in Chapter 6.

The maximum generation that can be connected depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

11.5.6.1 Additional geothermal generation

A number of geothermal generating stations in the region are already connected into or near the Wairakei Ring. While some further generation can be accommodated by current arrangements, significant future generation connection in the area may require transmission investment as the Wairakei Ring is nearing capacity. (See Chapter 6, Grid Backbone for more information).

11.5.6.2 Additional generation connection to the 220 kV circuits between Wairakei and Hawke's Bay

A possible geothermal power station, Tauhara, may connect into a 220 kV circuit from Wairakei to the Hawke's Bay region. A possible wind farm (Maungaharuru) may also connect to this circuit (see Chapter 13 for generation opportunities in the Hawke's Bay region). Capacity is sufficient to allow both generation connections.

There is potential for further geothermal generation development in the Tauhara area, as well as further wind and hydro generation development in the Hawke's Bay region. If this potential additional geothermal generation eventuated, Tauhara would need to be connected to both 220 kV circuits from Wairakei to the Hawke's Bay region, and a thermal upgrade of the circuits between Wairakei and Tauhara would be needed.

11.5.6.3 Additional wind generation connection to the 220 kV circuits between Bunnythorpe and Wellington

There are several investigations and proposals for wind generation station connections to the 220 kV double-circuit line between Bunnythorpe, Linton, and Wellington, which could occur at Linton or at new connection points along the line.

This is a high-capacity line and the effect of some additional generation on transmission capacity between Bunnythorpe and Wellington will be a small net percentage increase or decrease in transfer capacity, depending on the direction of power flow. A total of up to approximately 830 MW of generation injected into each of the 220 kV Bunnythorpe–Tararua Wind Central–Linton and Bunnythorpe–Linton circuits will not cause system issues directly, although the increase in generation south of Bunnythorpe may cause issues north of Bunnythorpe.

Mercury Energy is building a wind farm at Turitea. It will have a capacity of 119 MW (33 turbines), and will be commissioned in 2020. A 220 kV line will be required to connect Turitea to Linton.

The total amount of generation proposed to be connected between Bunnythorpe, Linton and Wellington is likely to result in transmission constraints. It is unlikely we can justify upgrading the transmission system to accommodate all the generation.

11.5.6.4 Additional generation connected to the 110 kV buses

There are several possible wind generation sites close to the 110 kV transmission circuits that run from Mangamaire to Woodville, Dannevirke, and Waipawa. The capacity on the existing 110 kV Masterton–Mangamaire–Woodville and Bunnythorpe–Woodville circuits would allow the connection of approximately 80 MW of additional generation, depending on where the generation is connected. Higher levels of generation may result in occasional generation constraints or incremental and/or major system upgrades (including new lines).

11.5.6.5 Puketoi ranges

There are several prospective wind generation sites in the Puketoi ranges with a combined capacity of many hundreds of megawatts. The closest transmission network is our 110 kV transmission network (see previous section), which is some distance away. If multiple wind generation stations were to be developed in this area, a possible solution would be to construct a single new transmission line from the wind generation stations to the National Grid at Bunnythorpe.

Generation from the Puketoi ranges could also connect along the 220 kV double-circuit line from Bunnythorpe to Wellington. However, care would be required to ensure the total generation from the Puketoi ranges plus other generation injecting along the 220 kV lines between Bunnythorpe and Wellington does not become too high (see section 11.5.6.3). It is also possible some of the 110 kV lines may be rationalised as part of this work.

Mercury Energy has consent for a wind farm in the Puketoi range, comprising 53 turbines. If built, it is proposed to connect it to the National Grid via the Turitea wind farm (section 11.5.6.3).

12 Taranaki Regional Plan

12.1 Regional overview and transmission system

The Taranaki transmission system supplies the city of New Plymouth (from the New Plymouth, Carrington Street, and Huirangi grid exit points) and other smaller towns in the Taranaki region including Stratford, Hawera, Waverley, and Wanganui.

A major oil and gas industry in the region includes both upstream and downstream facilities. These receive electricity supply from our Opunake, Kapuni, Hawera (Kupe), Huirangi, and Motonui grid exit points.

Due to the region's rich oil and gas resources, a significant portion of the country's remaining thermal generation is in Taranaki.

As with many of the regions, Taranaki has a strong dairy industry that relies on the transmission system. One of the world's largest dairy factories, Whareroa, is connected at Hawera; most of its electricity load is offset by onsite gas fired co-generation.

The existing transmission network for the Taranaki region is set out geographically in Figure 12-1 and schematically in Figure 12-2

Figure 12-1: Taranaki region transmission network

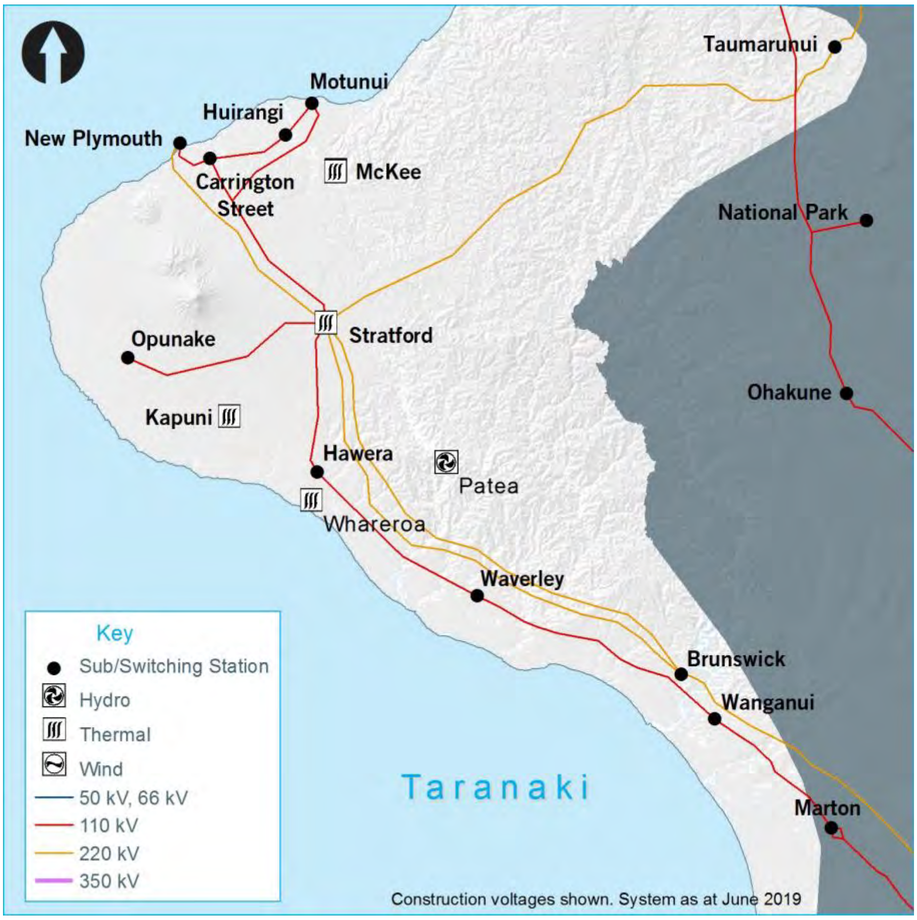
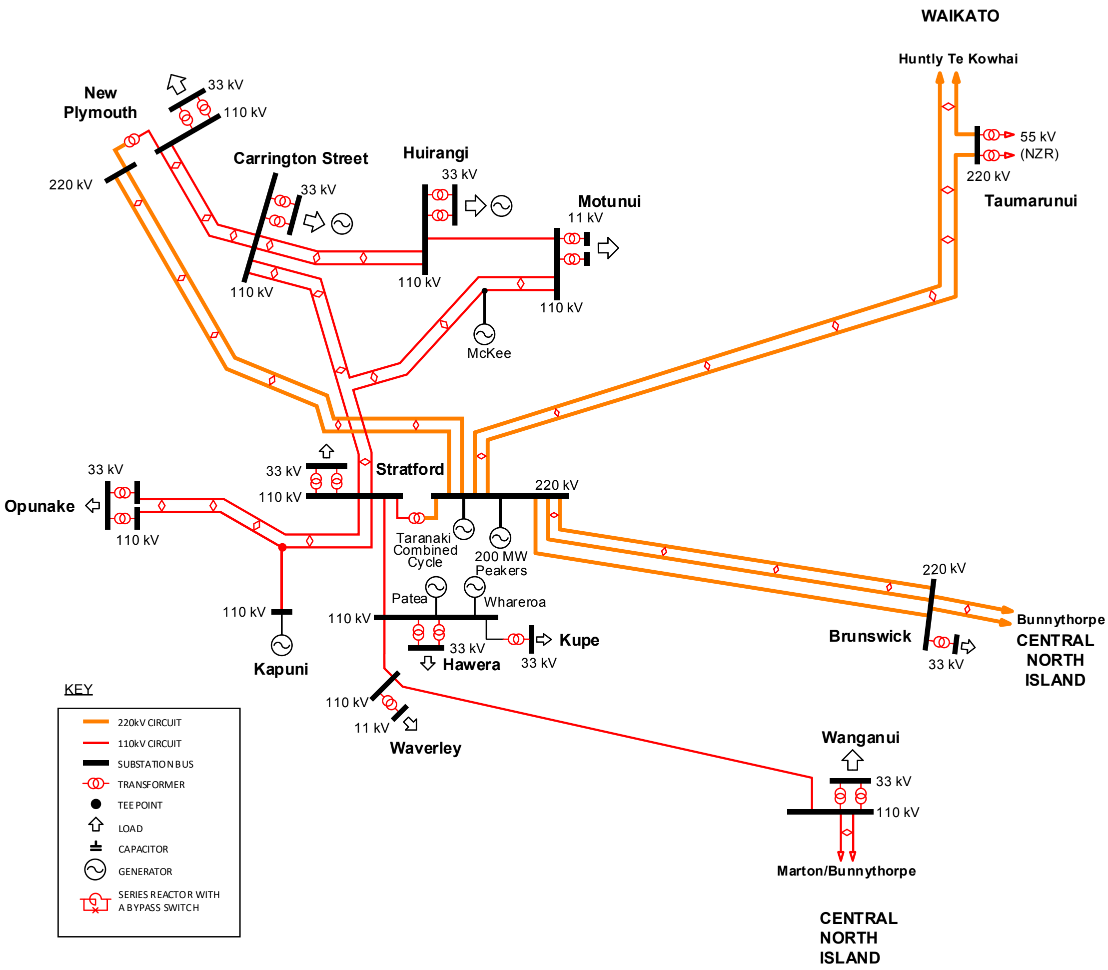


Figure 12-2: Taranaki region transmission schematic



12.1.1 Transmission into the region

The Taranaki region connects to the National Grid through 220 kV circuits that run north to Huntly and south-east to Bunnythorpe. Under normal operation, local generation exceeds regional demand and power is exported to other parts of the National Grid.

The interconnecting transformer at Stratford operates in parallel with the one at New Plymouth to supply Taranaki's regional 110 kV load. The Stratford transformer also assists with through-transmission on the 110 kV transmission network between Bunnythorpe and Stratford.

Between Stratford and Bunnythorpe there is a 110 kV line in parallel with the 220 kV line.

12.1.2 Transmission within the region

Most of the 220 kV Taranaki transmission network forms part of the grid backbone.

The 110 kV transmission network within the region has both capacity and voltage issues under certain operating conditions. Some parts of the 110 kV transmission network are almost fully utilised by existing generation. Any new generation will need to be connected at points where there is spare capacity, or transmission upgrades may be required.

12.2 Taranaki demand

The Taranaki regional peak demand[1] is forecast to grow by an average of 0.5 per cent per annum over the next 15 years, from 228 MW in 2019 to 246 MW in 2034. This is lower than the national average growth rate of 1.2 per cent per annum.

Table 12-1 sets out forecast peak demand (prudent growth[2]) for each grid exit point over the forecast period.

Table 12-1: Forecast annual peak demand (MW) at Taranaki grid exit points to 2034

Grid exit point	Power factor	Peak demand (MW)											
		2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2034**
Brunswick	0.97	40	39	40	40	40	41	41	41	41	41	41	39
Carrington Street[1]	0.97	50	73	74	75	77	78	79	80	81	82	83	82
Huirangi	0.94	40	43	43	44	45	46	47	47	47	46	46	43
Hawera	0.97	30	30	30	30	30	30	31	31	31	31	30	28
Hawera (Kupe)	0.97	10	10	10	10	10	10	10	10	10	10	10	11
Kaponga (Kapuni)	1	4	4	4	4	4	4	4	4	4	4	4	4
Motunui	0.96	9	9	9	9	9	9	9	9	9	9	9	10
New Plymouth[1]	0.97	23	0	0	0	0	0	0	0	0	0	0	0
Opunake	0.91	12	12	12	12	12	12	12	12	12	12	12	11
Stratford 33 kV	0.96	28	29	29	29	29	29	29	29	29	28	28	27
Taumarunui	0.85	6	6	6	6	6	6	6	6	6	6	6	6
Wanganui	0.97	42	42	43	43	44	44	44	44	44	45	45	43
Waverley	0.92	5	5	5	5	5	5	5	5	5	5	5	6

1. The load forecast assumes that the Moturoa grid exit point is transferred to Carrington Street in 2019-20 as part of the New Plymouth rationalisation.

12.3 Taranaki generation

The Taranaki region's generation capacity is currently 964 MW. This excludes any embedded solar (PV) generation, which was approximately 2 MW at the time of publication.[3] Depending on generation dispatch, the region may import or export power to the National Grid.

Table 12-2 lists the generation forecast at each grid injection point for the period to 2034. This includes all known and committed generation stations including those embedded within the Powerco's local lines company network.[4] Further generation may be developed during the period but is not sufficiently advanced to be included in our forecasts. (See section 12.5.7 for more information on potential new generation.)

1 For discussion on demand forecasting see Chapter 3, section 3.1.

2 Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

3 Electricity Market Information (EMI) installed distributed generation trends, https://www.emi.ea.govt.nz/Retail/Reports/GUEHMT?DateFrom=20130901&DateTo=20190731&RegionType=REG_COUNCIL&FuelType=solar&seriesFilter=07&_rsdr=ALL&Show=Capacity&_si=v|3

4 Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

Table 12-2: Forecast annual generation capacity (MW) at Taranaki grid injection points to 2034

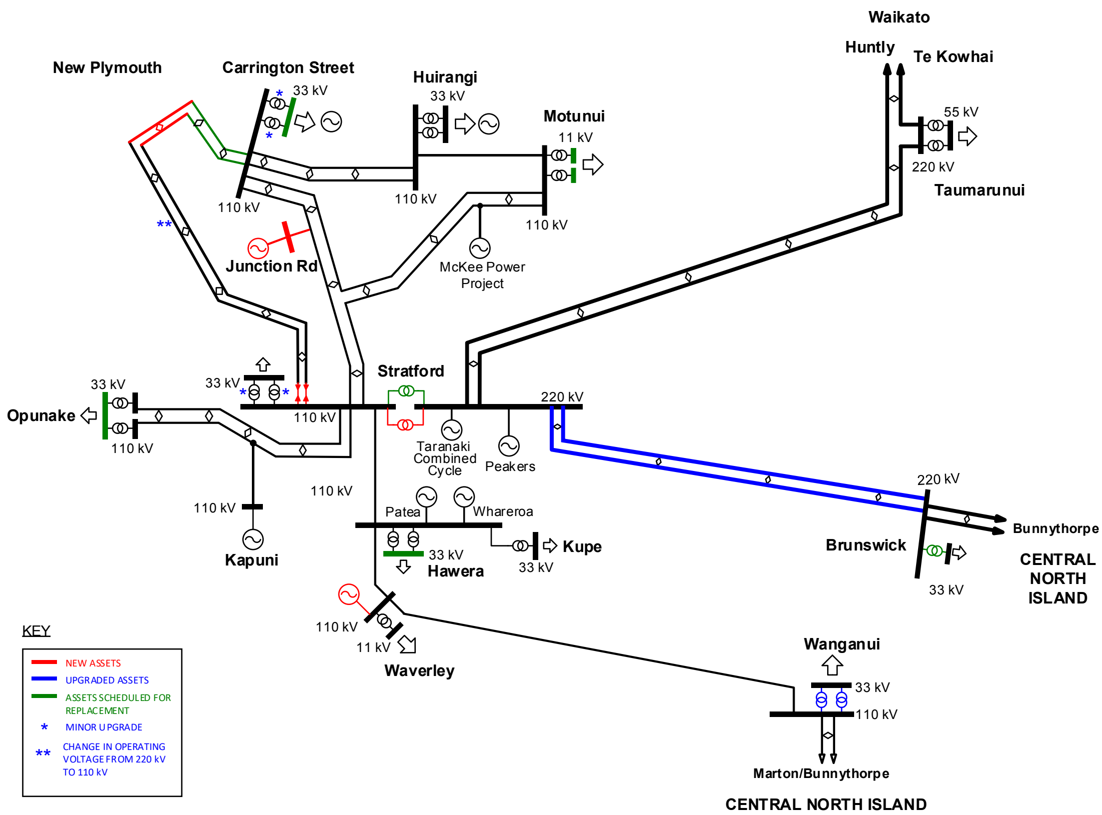
Grid injection point (location/name if embedded)	Generation capacity (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Carrington St (Mangorei)	5	5	5	5	5	5	5	5	5	5	5	5
Hawera – Kiwi Dairy (Whareroa)	70	70	70	70	70	70	70	70	70	70	70	70
Hawera – Patea	31	31	31	31	31	31	31	31	31	31	31	31
Huirangi (Mangahewa)	9	9	9	9	9	9	9	9	9	9	9	9
Huirangi (Motukawa)	5	5	5	5	5	5	5	5	5	5	5	5
Junction Road	0	100	100	100	100	100	100	100	100	100	100	100
Kapuni	25	25	25	25	25	25	25	25	25	25	25	25
McKee	100	100	100	100	100	100	100	100	100	100	100	100
Taranaki Combined Cycle	385	385	385	385	385	385	385	385	385	385	385	385
Stratford Peaker	200	200	200	200	200	200	200	200	200	200	200	200
Stratford (Stratford Austral Pacific)	1	1	1	1	1	1	1	1	1	1	1	1
Waverley (Waipipi)	0	0	133	133	133	133	133	133	133	133	133	133

12.4 Grid enhancement approach

12.4.1 Possible future Taranaki transmission configuration

shows the possible configuration of Taranaki transmission in 2034. New assets, upgraded assets, and assets scheduled for replacement within the forecast period (based on potential enhancement approaches set out in the following sections) are shown.

Figure 12-3: Possible Taranaki transmission configuration in 2034



12.4.2 Enhancement approach

Our approach seeks to ensure secure transmission into and within the Taranaki region into the future. Through the E&D process we assess transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified issues and opportunities we take into account uncertainty in future demand, generation and technological developments.

We do not expect any significant new transmission to be required in the Taranaki region in the next 15 years. Transmission investment needs will continue to be driven by new generation connections which may require thermal upgrades or reconductoring of nearby circuits to provide additional capacity for export.

High levels of new generation may require additional transmission circuits. These investment requirements are discussed further in Chapter 6.

Transmission issues likely requiring E&D or Customer-funded investments in Taranaki over the next 10-15 years are:

Section number	Issue
Regional	
12.4.2.1	North Taranaki supply security
Site by grid exit point	
12.4.2.2	Brunswick and Wanganui supply security
12.4.2.3	Hawera voltage quality

12.4.2.1 North Taranaki supply security

The northern Taranaki region consists of the New Plymouth, Carrington Street, and Huirangi grid exit points, which supply the general load in north Taranaki, and the Motonui grid exit point that only supplies Methanex. The region is supplied by a 110 kV transmission system, which connects to the 220 kV core grid via interconnecting transformers at New Plymouth and Stratford.

New Plymouth substation decommissioning

The New Plymouth substation's land and buildings are owned by Ports of Taranaki and our occupancy rights are regulated by the Electricity Act 2003. We have worked with the Port to rationalise our presence at New Plymouth and we will decommission the substation. The services currently provided by the New Plymouth substation will be relocated to other sites. We have undertaken investigations and determined our approach.

Enhancement approach:

- Decommission the New Plymouth 220/110 kV interconnecting transformer and install a new 220/110 kV, 200 MVA transformer at Stratford. This new transformer will operate in parallel with Stratford's existing 100 MVA transformer.
- Reconfigure the 110 kV Carrington Street–New Plymouth A line and the 220 kV New Plymouth–Stratford A line to bypass the New Plymouth site. The two lines will be connected and operated at 110 kV.
- Powerco will transfer Moturoa load, presently supplied from the New Plymouth grid exit point, to Carrington Street through two new 33 kV cable feeders. This project is funded and delivered by Powerco.
- Convert the Carrington Street 33 kV switchyard into an indoor switchboard. This will create spare bays that will enable connection of additional feeders.

North Taranaki 220/110 kV interconnecting transformer capacity

An outage of the New Plymouth interconnecting transformer (prior to exiting the New Plymouth site) or the new 220/110 kV, 200 MVA transformer at Stratford (once we have exited New Plymouth,see above) may cause the existing Stratford interconnecting transformer to exceed its n-1 capacity. There is a significant amount of generation connected in the 110 kV system, and this constraint only occurs during low generation-peak load scenarios.

Enhancement approach:

- The existing Stratford interconnecting transformer is currently undergoing repairs and bushing replacement. This will extend its service life by 10-15 years, following which we are likely to replace it. We will investigate the appropriate rating of the replacement transformer to provide interconnection security to the region closer to the need date.

Base E&D Capex investments

Project Name	Stratford second interconnecting transformer
Project description:	Install a new 220/110 kV, 200 MVA transformer at Stratford (replaces the New Plymouth interconnecting transformer)
Project's state of completion	Delivery
OAA level completed:	4d
Indicative commissioning:	2019
Indicative cost [$ million]:	17
Part of the GEIR?	Yes

Project Name	Carrington Street outdoor to indoor conversion
Project description:	Carrington Street outdoor-indoor conversion
Project's state of completion	Delivery
OAA level completed:	3d
Indicative commissioning:	2020
Indicative cost [$ million]:	7
Part of the GEIR?	No

Project Name	New Plymouth substation decommissioning
Project description:	New Plymouth substation decommissioning and disestablishment
Project's state of completion	Proposed
OAA level completed:	4d
Indicative commissioning:	2020
Indicative cost [$ million]:	2.5
Part of the GEIR?	No

12.4.2.2 Brunswick and Wanganui supply security

Brunswick supply security

The Brunswick load is supplied by a single 220/33 kV, 50 MVA transformer. This transformer is expected to be due for risk-based condition replacement around 2024-2026.

Enhancement approach:

- Currently, a transformer unit failure can be managed by transferring load to the Wanganui grid exit point via Powerco's network. However, some load curtailment may be necessary during peak periods as Powerco's distribution network may not have the capacity to shift the entire load to Wanganui. As there is a non-contracted spare transformer on-site, replacement may be possible within 8-14 hours (provided the spare unit is available).
- We are working with Powerco to determine the requirements for the replacement transformer and whether there is a need to install a second supply transformer at Brunswick to provide n-1 security.

Wanganui supply security

There are two 110/33 kV supply transformers at Wanganui (T1 and T2). Peak load at Wanganui already exceeds the n-1 capacity of the supply transformers.

The Wanganui–T1 transformer is due for major refurbishment in 2019/20 and T2 is due for risk-based condition replacement in 2023.

Enhancement approach:

- At present, Powerco has elected to not maintain n-1 security at the Wanganui grid exit point. Following a contingency, it can shift some load to the Brunswick grid exit point via its distribution network, which it is planning to upgrade. Load shifting capacity is currently limited by both the Powerco network and the Brunswick supply transformer.
- In the near-future, we will discuss with Powerco the requirements for the replacement of Wanganui–T2 and the possibility of replacing T1 at the same time (to address the lack of n-1 capacity).

Base E&D Capex investments

Project Name	Wanganui supply capacity
Project description:	Replace Wanganui–T2 with a higher capacity transformer
Project's state of completion	Possible
OAA level completed:	None
Indicative commissioning:	2023
Indicative cost [$ million]:	5
Part of the GEIR?	No

12.4.2.3 Hawera voltage quality

An outage of the 110 kV Hawera–Stratford circuit can result in low voltages and voltage drops greater than five per cent when there is no local generation available at Hawera. Installation of the second 220/110 kV transformer at Stratford (see section 12.4.2.1) will not improve this issue.

The Patea and Whareroa generators both inject into the Hawera 110 kV bus and assist with voltage support. However, the Whareroa generation (co-generation) is coupled to the industrial process at Fonterra's factory at Hawera and may not always be available to provide voltage support.

Enhancement approach:

- As this risk will arise only in infrequent circumstances (high load coinciding with low generation), we will continue to monitor the voltage issues and investigate options to resolve or manage them if the need arises. Options we have identified include installing capacitors at Hawera to support the voltage post-contingency, or managing the Stratford 110 kV voltage pre-contingency to reduce the voltage step if Hawera becomes separated from Stratford.

12.5 Asset capability and management

We have assessed the transmission capacity and reactive support requirements in the region for the next 15 years. When an issue or opportunity exists, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (see to section 0) have been developed to address issues or opportunities that require action within the forecast period and where investment is economically justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk-based asset replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

12.5.1 Taranaki transmission system significant upcoming work

We integrate our capital project and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Table 12-3 lists the significant upcoming work proposed for the Taranaki region for the next 15 years that may significantly impact related system issues or connected parties.

Table 12-3: Proposed significant upcoming work for the Taranaki transmission system

Description	Tentative year	E&D issues
Brunswick–Stratford A/B line reconductoring	2021-2026	Section 6.4
Brunswick supply transformer risk-based condition replacement	2024-2026	12.5.4.2
Carrington Street–New Plymouth A line reconductoring	2021-2022	None
Hawera 33 kV outdoor to indoor conversion	2020-2021	None
Opunake 33 kV outdoor to indoor conversion	2020-2022	None
Refurbish Stratford–T10 on site	2018-2019	None
Wanganui supply transformers risk-based condition replacement	2021-2023	12.5.4.7
Motunui 11 kV switchboard replacement	2018-2020	None

12.5.2 Taranaki asset feedback

There are no entries in the Asset Feedback Register related to E&D specific to this region.

12.5.3 Changes since the 2018 Transmission Planning Report

Table 12-4 lists the specific new issues and those that are no longer relevant within the forecast period (relative to our previous Transmission Planning Report).

Table 12-4: Changes since the 2018 TPR

Issues	Change
Brunswick supply transformer capacity	Removed. Lower load forecast.
Carrington Street supply transformer capacity	Removed. New 33 kV indoor switchboard.
Hawera supply transformer capacity	Removed. Lower load forecast.

12.5.4 Taranaki transmission capability

Table 12-5 summarises identified issues that may affect the Taranaki region over the next 15 years. In each case, we have detected a condition that would constrain the network if action were not taken. Each issue is discussed in more detail below.

This transmission capability section reports whether the Grid can reasonably be expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, forms part of the Grid Reliability Report (GRR).

Table 12-5: Taranaki region transmission issues – regional and site by grid exit point

Section number	Issue
Regional	
12.5.4.1	North Taranaki transmission capacity
Site by grid exit point	
12.5.4.2	Brunswick supply security
12.5.4.3	Hawera voltage quality
12.5.4.4	Hawera (Kupe) supply security
12.5.4.5	Kapuni supply security
12.5.4.6	McKee supply security
12.5.4.7	Wanganui supply transformer capacity
12.5.4.8	Waverley supply securityWanganui supply transformer capacity

12.5.4.1 North Taranaki transmission capacity

Issue

The 220/110 kV, 100 MVA interconnecting transformer at Stratford operates in parallel with the 220/110 kV, 195 MVA interconnecting transformer at New Plymouth to supply Taranaki's regional 110 kV load.

The Stratford and New Plymouth transformers provide:

- total nominal installed capacity of 295 MVA
- n-1 capacity of 135/143 MVA (summer/winter).

An outage of the New Plymouth interconnecting transformer may cause the Stratford interconnecting transformer to exceed its n-1 capacity (depending on Taranaki 110 kV generation).

What next?

The project to exit New Plymouth and install a second 220/110 kV transformer at Stratford will not change the n-1 capacity. See to section 12.4.2.1 for our enhancement approach.

12.5.4.2 Brunswick supply security

Issue

A single 220/33 kV, 50 MVA transformer bank supplies load at Brunswick resulting in n security.

What next?

Our customer, Powerco, has not requested a higher level of security. The issue can be managed operationally by shifting load within Powerco's distribution network. However, there are other linked issues in the region. See to section 12.4.2.2 for our enhancement approach.

12.5.4.3 Hawera voltage quality

Issue

An outage of the 110 kV Hawera–Stratford circuit can result in low voltages and voltage drops greater than five per cent when there is no local generation available at Hawera. When this occurs, Hawera is supplied from a 143 km spur line from Bunnythorpe. As the load on this spur grows, the voltage quality issues may spread to Waverley.

Patea (31 MW) and Whareroa[5] (70 MW) inject into the Hawera 110 kV bus, but are not always available to provide voltage support.

[5] The dairy factory load at Whareroa usually consumes a large portion of the power generated by the generation station at Whareroa.

What next?

Currently, no investments are planned to address this issue. See to section 12.4.2.3 for our enhancement approach.

12.5.4.4 Hawera (Kupe) supply security

Issue

A single 110/33 kV, 30 MVA supply transformer supplies the Origin Energy Resources' Kupe load, resulting in n security. At present the load can be transferred to the other supply transformers at Hawera by closing the 33 kV bus coupler.

What next?

Our customer has not requested a higher level of security so no investments are planned.

12.5.4.5 Kapuni supply security

Issue

Kapuni generation is connected to the grid through a single Tee connection on the 110 kV Opunake–Stratford 2 circuit resulting in n security.

In addition, bus section contingencies at either Stratford or Opunake would result in loss of supply to Kapuni (see section 12.5.5.1).

What next?

Our customer, Nova Energy, has not requested a higher level of security so no investments are planned to increase supply security.

12.5.4.6 McKee supply security

Issue

McKee is connected to the grid through a single Tee connection on the 110 kV Motunui–Stratford 1 circuit, resulting in n security.

What next?

Our customer, Todd Energy, has not requested a higher level of security so no investments are planned to increase supply security.

12.5.4.7 Wanganui supply transformer capacity

Issue

Two 110/33 kV transformers (rated 20 MVA and 30 MVA) supply Wanganui's load, providing:

- total nominal installed capacity of 50 MVA
- n-1 capacity of 24/24 MVA[6] (summer/winter).

The peak load already exceeds the winter n-1 capacity of the transformers and the overload is forecast to increase to approximately 20 MW in 2034 (see Table 12-6).

In addition, peak load at Wanganui is forecast to exceed the continuous capacity of both transformers by the end of the forecast period.

6 The transformers' capacity is limited by the transformer LV bushing; with this limit resolved, the n-1 capacity will be 27/28 MVA (summer/winter).

Table 12-6: Wanganui supply transformer overload forecast

	Transformer overload (MW)											
Circuit/grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Wanganui n-1	19	20	20	21	21	21	21	22	22	22	22	20

What next?

In the short-term, Powerco is able to manage the transformer overload issue operationally. See to section 12.4.2.2 for our enhancement approach.

12.5.4.8 Waverley supply security

Issue

A single 110/11 kV, 10 MVA transformer supplies load at Waverley resulting in n security.

What next?

Powerco can manage the issue during maintenance outages for the forecast period. There is a national spare transformer located off-site that would enable replacement within 2-4 weeks following a unit failure.

Powerco has not requested higher security at this grid exit point, so no investments are planned to increase supply security.

12.5.5 Taranaki bus security

This section discusses bus security issues identified for the Taranaki region during the next 15 years. Only issues arising from the outage of a single bus section rated at 66 kV and above are included.

Bus outages disconnect more than one power system component (for example: circuits, transformers, reactive support or generators). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

12.5.5.1 Transmission bus security

Table 12-7 lists bus outages that cause voltage issues or a total loss of supply. Generators are included only if a bus outage disconnects the whole generation station or causes a widespread system impact. Supply bus outages, typically 11 kV and 33 kV, are not listed.

Table 12-7: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Hawera 110 A Hawera 110 B	Hawera (Kupe)	- Patea	- -	Note 1 Note 1
New Plymouth 110 kV	New Plymouth	-	-	Note 2
Opunake 110 kV	-	Kapuni	-	12.5.5.2
Stratford 110 kV	-	Kapuni	-	12.5.5.2
Wanganui 110 kV	Marton Wanganui	- -	- -	Note 3 Note 3
Waverley 110 kV	Waverley	-	-	Note 4

1. Kupe and Patea only have a single connection to the Hawera 110 kV bus. The Kupe load can be transferred to the Powerco 33 kV bus during an outage of Hawera–T3.
2. This is a grid backbone bus, but only the local load is affected. This load will be transferred to Carrington Street when we exit the New Plymouth site.
3. There is no bus protection at Wanganui, so bus faults are cleared by the connected circuits' remote end protection at Bunnythorpe and Waverley. This causes a loss of supply to Wanganui and Marton (which is Tee-connected to the Bunnythorpe–Marton–Wanganui circuits in the Central North Island region).
4. There is no bus protection at Waverley, so bus faults are cleared by the connected circuits' remote end potection at Hawera and Wanganui, causing a loss of supply at Waverley.

Our customers in the Taranaki region (Nova Energy, Origin Energy and Powerco) have not requested a higher bus security level. If increased bus security is required, the options typically include bus reconfiguration and/or additional bus circuit breakers.

12.5.5.2 Kapuni and Opunaki security

Issue

The Kapuni generation is Tee-connected to the 110 kV Opunake–Stratford 2 circuit. An outage of the Stratford bus section that connects this circuit will also intertrip Kapuni, disconnecting the Kapuni generation.

There is no bus zone protection at the Opunake 110 kV bus (split bus with no incoming 110 kV line circuit breakers). A fault on the Opunake bus section, connecting the Opunake–Stratford 2 circuit, will be cleared by the line protection at Stratford, disconnecting the Kapuni generators.

What next?

Our customer, Nova Energy, has not requested a higher level of security, so no investments are planned to resolve this issue (see also section 12.5.4.5).

12.5.6 Other regional items of interest

12.5.6.1 Brunswick-Stratford transmission capacity

The three 220 kV Brunswick–Stratford circuits are part of the grid backbone connecting Taranaki to the rest of the National Grid. The loading on these three circuits is approximately equal, which maximises their transfer capacity. The capacity of the Brunswick–Stratford circuits may constrain the amount of generation that can be exported from the Taranaki region depending on HVDC power flow and direction.

In addition, the conductor on the Brunswick–Stratford B line is due for replacement within 10 years (see section 12.5.1). Refer to Chapter 6, Grid backbone, for more information on the Brunswick–Stratford constraint.

12.5.7 Taranaki generation proposals and opportunities

This section describes relevant regional issues that may affect generation proposals under investigation by developers and in the public domain, or other generation opportunities. The impact of committed generation projects on the grid backbone is dealt with separately in Chapter 6.

The maximum generation that can be connected in a particular location depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

12.5.7.1 Maximum regional generation

For generation connections at the Stratford 220 kV bus, the maximum generation that can be injected will depend on the direction of HVDC power flow, constraints on the Brunswick–Stratford circuits, and the grid backbone circuits in the central North Island.

During high HVDC north power flow, no additional generation (in addition to the existing 385 MW Taranaki Combined Cycle, 200 MW Stratford peaking stations, 100 MW McKee generators and the future 100 MW Junction Rd generation) can be injected at the Stratford 220 kV bus under n-1 conditions (. This is limited by the capacity of the Huntly–Stratford 1 circuit (refer to Chapter 6, Grid backbone, for more information on the Huntly–Stratford constraint).

If the branch constraint (a protection limit) on the Huntly–Stratford 1 circuit is removed, approximately 80 MW can be injected. The Central North Island Tokaanu–Whakamaru 1 and 2 circuits are then the constraint.

For maximum HVDC south power flow there is no capacity for additional injection due to the limited capacity of the Brunswick–Stratford circuits. Generation stability issues may also need to be addressed to enable injection with significant HVDC southward flow.

12.5.7.2 Wind generation at Waverley

There is a committed 130 MW wind generation development that will connect at Waverley. To minimise generation constraints in the region, a special protection scheme will automatically reduce generation at the wind farm following an outage of a Marton–Wanganui circuit.

Further significant wind generation development will need to be connected at 220 kV. The loading on the three 220 kV Brunswick–Stratford circuits is approximately equal, which maximises their transfer capacity. In order to maintain approximately equal loading to maintain the existing transfer capacity, a large wind generation station would need to be connected to all three circuits. Alternately,the capacity of one or more of the circuits will need to be increased. The project to reconductor the Brunswick–Stratford A and B lines may rationalise the assets to two circuits, in which case a large wind generation station would need to connect to the two circuits.

12.5.7.3 New Plymouth–Stratford A line

We will exit the New Plymouth site in 2020 and convert the New Plymouth–Stratford A line from 220 kV to 110 kV operation. This will bypass the New Plymouth site and connect directly to the 110 kV Carrington Street–New Plymouth line. The maximum generation that can be injected onto this new 110 kV Carrington Street–Stratford line is at least 300 MW. However, there are other constraints in the region, such as the 220/110 kV interconnection capacity at Stratford and the Huntly–Stratford 1 circuit, that would need to be considered. If higher capacity were needed to accommodate new generation injection, it may be necessary to convert the New Plymouth–Stratford A line back to 220 kV operation.

12.5.7.4 Additional generation at other locations

Depending on the size of any new generation, connection to the 220 kV and some 110 kV lines in the northern Taranaki area may be possible without a major line capacity upgrade.

Any generation injecting into the northern Taranaki region would play a significant role in regulating 110 kV bus voltages in the region.

The Opunake–Stratford circuit has sufficient capacity for approximately 75 MW of new generation on a secure double circuit.

The Carrington Street–Stratford circuit will have no spare capacity for additional generation following connection of the Junction Road power station.

13 Hawke's Bay Regional Plan

13.1 Regional overview and transmission system

Hawke's Bay load includes a mix of significant provincial cities (Napier, Hastings and Gisborne), heavy industry (Panpac Mill), and smaller towns (Havelock North and Wairoa).

The existing transmission network for the Hawke's Bay region is set out geographically in Figure 13-1 and schematically in Figure 13-2.

Figure 13-1: Hawke's Bay region transmission network

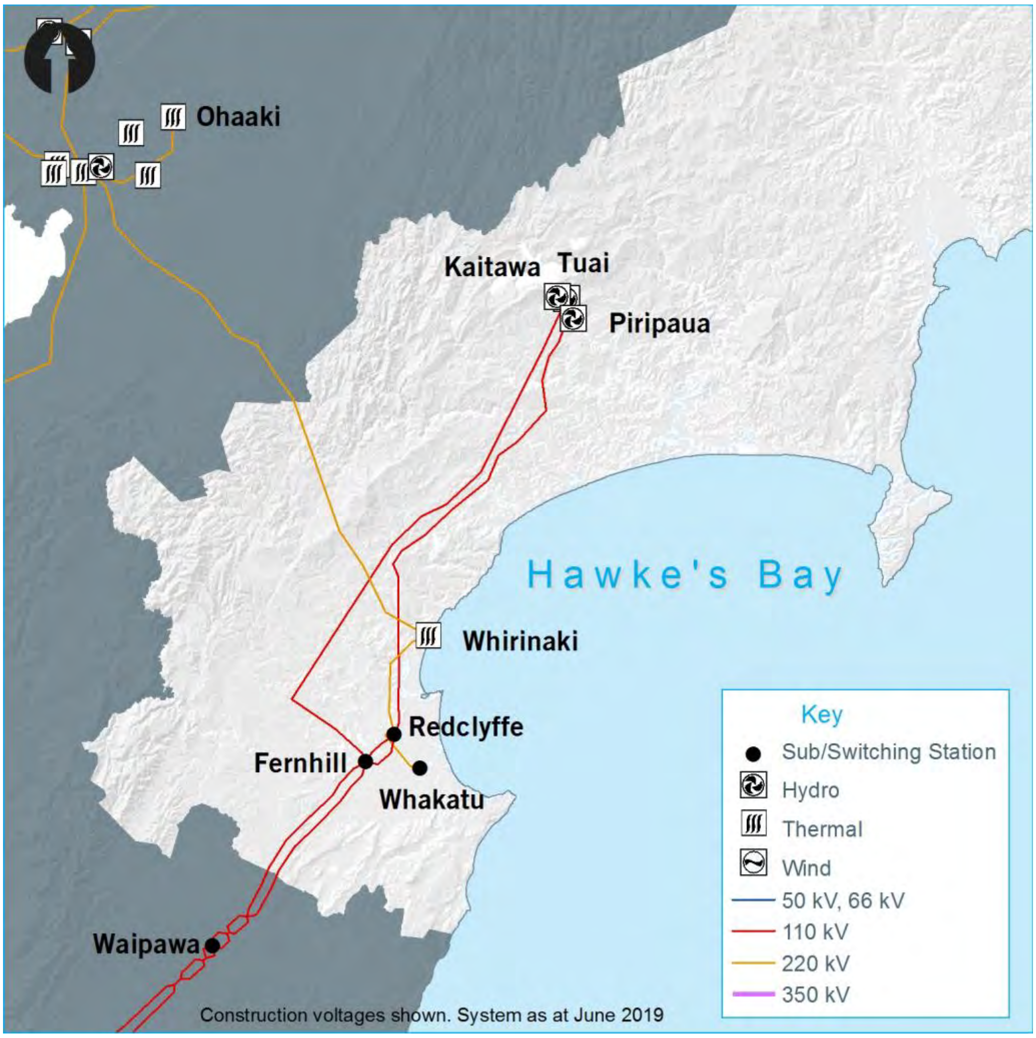
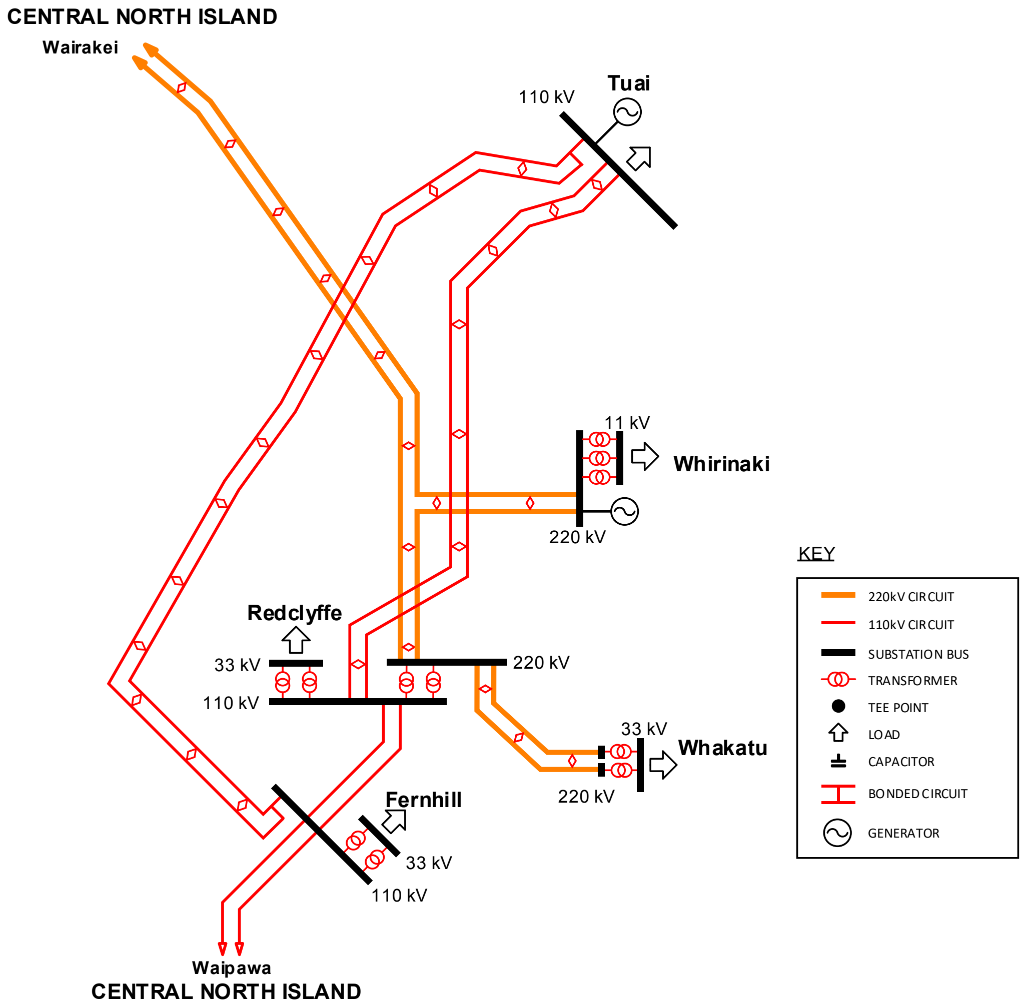


Figure 13-2: Hawke's Bay region transmission schematic



13.1.1 Transmission into the region

Transmission into the Hawke's Bay region is via two 220 kV circuits from Wairakei that directly supply the Whirinaki and Whakatu loads, and two 220/110 kV interconnecting transformers at Redclyffe.

Two 110 kV circuits also connect the Hawke's Bay 110 kV system at Fernhill from Waipawa in the south. These are normally open at Waipawa.

13.1.2 Transmission within the region

Within the Hawke's Bay region, the transmission network comprises 220 kV and 110 kV transmission circuits. The majority of the region's load is supplied via the 220/110 kV transformers at Redclyffe. Transmission within the region is predominantly at 110 kV.

13.2 Hawke's Bay demand

The Hawkes Bay regional peak demand[1] is forecast to grow by an average of 0.5 per cent per annum over the next 15 years, from 337 MW in 2019 to 365 MW in 2034. This is lower than the national average growth rate of 1.2 per cent per annum.

1 For discussion on demand forecasting see Chapter 3, section 3.1.

Table 13-1 sets out forecast peak demand (prudent growth[2]) for each grid exit point over the forecast period.

Table 13-1: Forecast annual peak demand (MW) at Hawke's Bay grid exit points to 2034

Grid exit point	Power factor	Peak demand (MW)											
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Fernhill	0.98	63	64	65	66	67	68	68	69	70	70	71	73
Redclyffe	0.99	75	76	76	77	77	77	77	78	78	78	78	71
Tuai	0.99	64	65	66	67	68	69	70	71	72	73	72	68
Whakatu	0.98	95	97	99	101	103	104	105	107	108	108	109	107
Whirinaki	0.99	80	79	79	79	79	79	79	80	80	80	80	83

13.3 Hawke's Bay generation

Generation capacity in the Hawke's Bay is currently 332 MW. The Tuai, Kaitawa, and Piripaua hydro generation stations (collectively the 138 MW Waikaremoana Hydro Scheme) connect to the Tuai 110 kV bus. There is a 155 MW diesel-fuelled generator at Whirinaki that runs infrequently. Other generating stations are embedded in local distribution networks (Unison or Eastland Networks).[3] These include hydro and mobile diesel generating units.

Table 13-2 lists forecast generation capacities at each grid injection point over the period to 2034. Further generation may be developed during the period but is not sufficiently advanced to be included in our forecasts. (Refer to section 13.5.7 for more information on potential new generation).

Table 13-2: Forecast annual generation capacity (MW) at Hawke's Bay grid injection points to 2034

Grid injection point (location/name if embedded)	Generation capacity (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Kaitawa[1]	36	36	36	36	36	36	36	36	36	36	36	36
Piripaua[1]	42	42	42	42	42	42	42	42	42	42	42	42
Redclyffe (Ravensdown)	8	8	8	8	8	8	8	8	8	8	8	8
Redclyffe (Esk River)	4	4	4	4	4	4	4	4	4	4	4	4
Tuai[1]	60	60	60	60	60	60	60	60	60	60	60	60
Tuai (Gisborne)	7	7	7	7	7	7	7	7	7	7	7	7
Tuai (Matawai)	2	2	2	2	2	2	2	2	2	2	2	2
Tuai (Waihi)	5	5	5	5	5	5	5	5	5	5	5	5
Whirinaki	155	155	155	155	155	155	155	155	155	155	155	155
Whirinaki (Pan Pac)	13	13	13	13	13	13	13	13	13	13	13	13

1. Kaitawa, Piripaua and Tuai are collectively known as the Waikaremoana scheme.

13.4 Grid enhancement approach

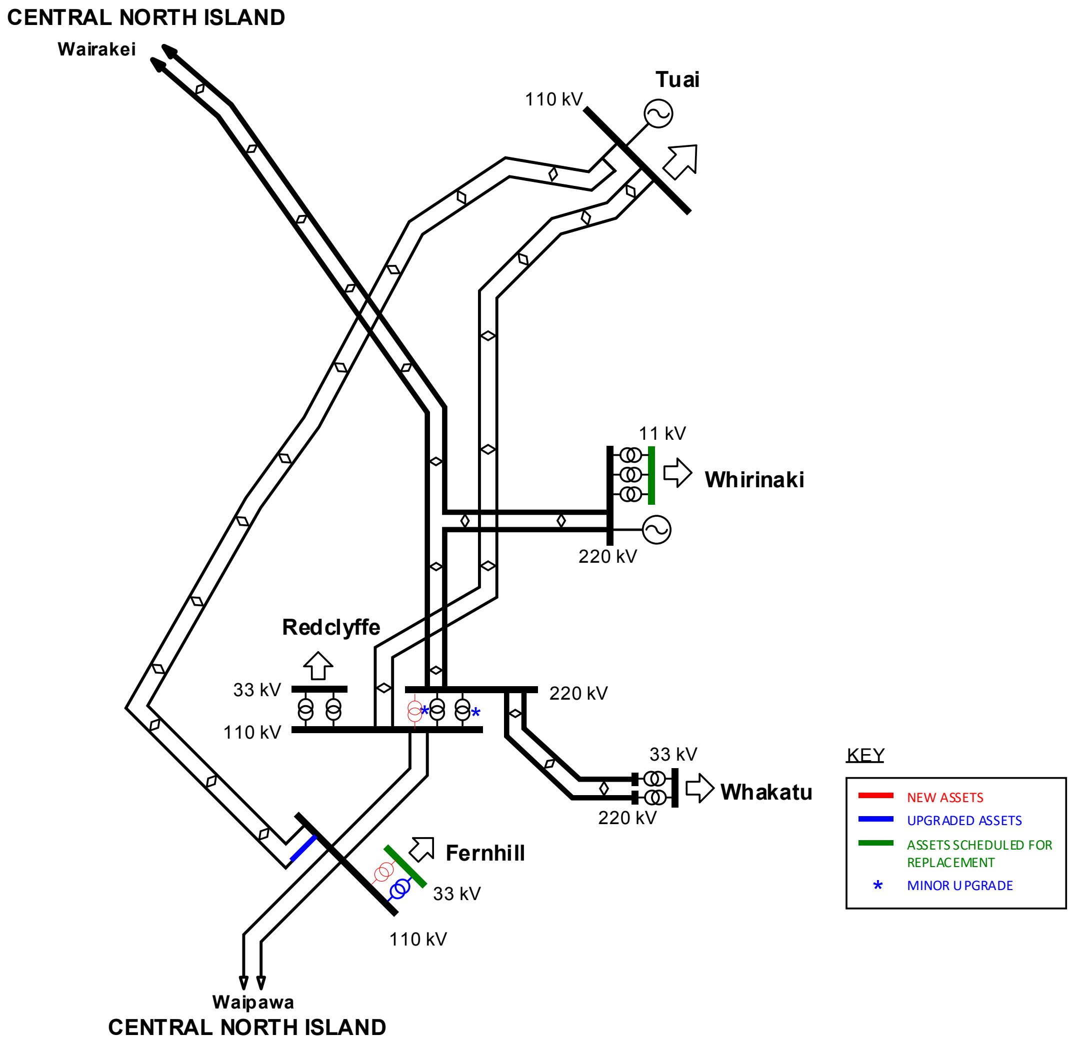
13.4.1 Possible future Hawke's Bay transmission configuration

Figure 13-3 shows the possible configuration of Hawke's Bay transmission in 2034. New assets, upgraded assets, and assets scheduled for replacement within the forecast period (based on potential enhancement approaches set out in the following sections) are shown.

2 Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

3 Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

Figure 13-3: Possible Hawke's Bay transmission configuration in 2034



13.4.2 Enhancement approach

Our approach seeks to ensure secure transmission into and within the Hawke's Bay region into the future. Through the E&D process we assess transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified issues and opportunities we take into account uncertainty in future demand, generation and technological developments.

Transmission issues likely requiring E&D or Customer-funded investments in Hawkes Bay over the next 10-15 years are:

Section number	Issue
Regional	
13.4.2.1	Hawke's Bay 220 kV transmission security
13.4.2.2	Hawke's Bay voltage quality
13.4.2.3	Redclyffe 220/110 kV interconnection capacity
Site by grid exit point	
13.4.2.4	Fernhill supply capacity
13.4.2.5	Whakatu supply capacity

13.4.2.1 Hawke's Bay 220 kV transmission security

The 220 kV Wairakei–Whirinaki A line into Hawke's Bay is susceptible to double circuit outages during heavy snow storms or lightning. A double circuit outage causes a loss of supply to the Hawke's Bay.

We have:

- Installed interphase spacers on one of the two circuits so it is less prone to tripping during heavy snow storms, to maintain a reliable supply on a single circuit to Hawke's Bay.
- Upgraded the line protection to eliminate incorrect double-circuit tripping for some rare fault sequences during lightning.
- Automated some stages of our operating procedures to speed up restoration following a loss of supply in the Hawke's Bay.

We are not proposing further investment for Hawke's Bay 220 kV transmission security at this stage.

13.4.2.2 Hawke's Bay voltage quality

The loss of a 220 kV circuit at high load when there is minimal Waikaremoana generation results in low voltages at the Fernhill supply bus. As regional load grows, tthis issue is expected to progressively arise at other Hawke's Bay high voltage buses.

Enhancement approach:

- The short term operational solution is to constrain on generating units at Waikaremoana to provide voltage support during high load periods.
- In the medium term, the replacement Fernhill supply transformer (see section 13.4.2.4) will resolve the post-contingency low voltage issue on the Fernhill supply bus.
- In the longer term, we will continue to monitor the voltage quality on other Hawke's Bay buses and investigate options as issues arise. Any investment to increase the Redclyffe 220/110 kV interconnection capacity (see section 13.4.2.3) will likely also improve voltage quality to the Hawke's Bay region.

13.4.2.3 Redclyffe 220/110 kV interconnection capacity

Two 220/110 kV interconnecting transformers at Redclyffe supply the majority of the Hawke's Bay load (i.e. all but the load at Whirinaki and Whakatu, which is supplied from the 220 kV transmission system).

During periods of high load and minimal Waikaremoana generation, or low load and high Waikaremoana generation, the interconnecting transformers can exceed their n-1 capacity, i.e. an unplanned outage of an interconnecting transformer can overload the parallel unit.

Enhancement approach:

- In the short term our approach is to operationally manage any overloading pre-contingency by transferring load (within Unison's network) from the 110 kV transmission network to the 220 kV network and by constraining-on generation at Waikaremoana. As Hawke's Bay's load continues to grow, the expectation is that more generation will need to be constrained-on more frequently.
- A special protection scheme automatically trips Redclyffe 33 kV feeder load post-contingency to reduce the risk of a transformer overload and trip.
- At present, options to increase the interconnecting transformer capacity at Redclyffe are uneconomic. However, potential long term investments include installing a third interconnecting transformer or replacing the existing transformers with higher rated units. We will continue to monitor the economics of these long term investments and undertake a detailed investigation, when it becomes economically justifiable.

Base E&D capex investments

Project Name	Redclyffe interconnecting capacity - build
Project description:	Increase of interconnecting capacity
Project's state of completion	Uncertain
OAA level completed:	None
Grid need date:	2024
Indicative cost [$ million]:	11
Part of the GEIR?	No

13.4.2.4 Fernhill supply capacity

Peak load at Fernhill already exceeds the n-1 winter capacity of the supply transformers.

Enhancement approach:

- In the short term a transformer outage is managed operationally by shifting load within the Unison network.
- The lower capacity Fernhill supply transformer is due for risk-based replacement. The replacement transformer will be higher capacity and have on-load tap changers, which will also resolve the low voltage issue on the Fernhill supply bus (see section 13.4.2.2).

Base E&D capex investments

Project Name	Fernhill–T1 110 kV supply transformer replacement
Project description:	Replacement of supply transformerr 110/33 kV – 80 MVA
Project's state of completion	Delivery
OAA level completed:	AL 2d
Grid need date:	2019
Indicative cost [$ million]:	4.8
Part of the GEIR?	No

13.4.2.5 Whakatu supply capacity

The Whakatu load is supplied by two 220/33 kV supply transformers.

The 33 kV load is forecast to exceed the n-1 winter capacity of the supply transformers by 2031 under our base demand forecast. However, when assumptions regarding uptake of new technologies are taken into consideration, forecast n-1 overloading reduces to about 1 MW (see section 13.5.4.6). Note that Whakatu load may potentially increase if Unison shifts 110 kV load to manage post contingent overloading for the Redclyffe interconnecting transformer.

Enhancement approach:

- We will discuss long term options with Unison closer to the need date. These include upgrading the Whakatu supply transformers or installing a third supply transformer at Whakatu.

Customer investments

Project Name	Whakatu third supply bank transformer
Project description:	Install additional supply bank transformer
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2031
Indicative cost [$ million]:	11
Part of the GEIR?	No

13.5 Asset capability and management

We have assessed the transmission capacity and reactive support requirements in the region for the next 15 years. When an issue or opportunity exists, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 13.4.2) have been developed to address issues or opportunities that require action within the forecast period and where investment is justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk-based asset replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

13.5.1 Hawke's Bay transmission system significant upcoming work

We integrate our capital project and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished.

Table 13-3 lists the significant upcoming work proposed for the Hawke's Bay region for the next 15 years that may significantly impact related system issues or connected parties.

Table 13-3: Proposed significant upcoming work on the Hawke's Bay transmission system

Description	Tentative year	E&D issues
Fernhill 33 kV outdoor to indoor conversion Fernhill 110/33 kV T1 supply transformer risk based replacement	2018-2019 2021-2023	None 13.5.4.5
Whirinaki 11 kV Bus B and C switchboard replacement	2023-2025	None

13.5.2 Hawke's Bay asset feedback

The Asset Feedback Register does not include any entries specific to the Hawke's Bay region.

13.5.3 Changes since the 2018 Transmission Planning Report

Table 13-4 lists the specific new issues and those that are no longer relevant within the forecast period (relative to our previous Transmission Planning Report).

Table 13-4: Changes since the 2018 TPR

Issues	Change
Redclyffe 220/110 kV Interconnecting Transformer special protection scheme	Removed. Project commissioned in 2019.
Tuai bus security	Removed. Customer relinquished supply.
Whirinaki supply capacity	Added. Due to operational configuration.

13.5.4 Hawke's Bay transmission capability

Table 13-5 summarises identified issues that may affect the Hawke's Bay region over the next 15 years. For more information about a particular issue, refer to the listed section number.

Table 13-5: Hawke's Bay region transmission issues – regional and grid exit point

Section number	Issue
Regional	
13.5.4.1	Hawke's Bay voltage quality
13.5.4.2	Fernhill–Redclyffe 110 kV transmission capacity
13.5.4.3	Redclyffe–Tuai 110 kV transmission capacity
13.5.4.4	Redclyffe interconnecting transformer capacity
Site by grid exit point	
13.5.4.5	Fernhill supply transformer capacity
13.5.4.6	Whakatu supply transformer capacity
13.5.4.7	Whirinaki supply transformer

13.5.4.1 Hawke's Bay voltage quality

Issue

The Hawke's Bay transmission network is primarily supplied from the 220 kV Redclyffe bus, which is in turn supplied from the grid backbone by two 220 kV circuits from Wairakei. The 138 MW Waikaremoana hydro scheme connects to the 110 kV network, which also supplies the region's load.

The loss of a 220 kV circuit at high load and minimal Waikaremoana generation may result in low voltages at the supply buses throughout the entire region. This issue progressively arises at other high voltage buses as load increases.

Currently we manage the low voltage risk operationally by constraining-on generating units at Waikaremoana so that generation reactive support is available. As Hawke's Bay load increases, a 220 kV circuit outage will require more Waikaremoana generating units to be in service for reactive support.

What next?

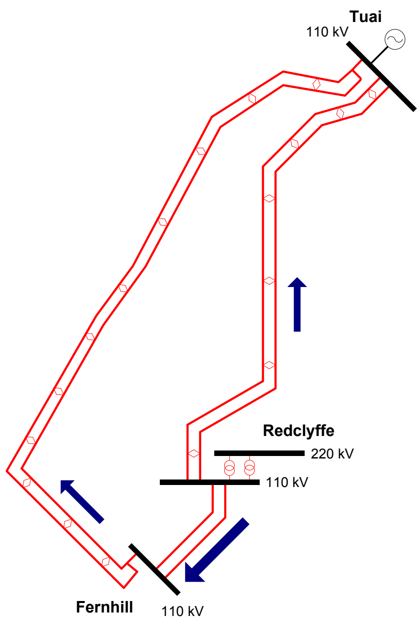
Voltage can be managed during high load periods by constraining on Waikaremoana generation to provide voltage support. In the event there is low Waikaremoana generation, load shifting by Unison could be considered. Refer to section 13.4.2.2 for our enhancement approach.

13.5.4.2 Fernhill–Redclyffe 110 kV transmission capacity

Issue

There are two 110 kV Fernhill–Redclyffe circuits, each rated at 51/62 MVA (summer/winter). During periods of high load and low Waikaremoana generation, power flows from Redclyffe to Tuai on the 110 kV circuits, as shown on Figure 13-4. In this situation, an outage of one Fernhill–Redclyffe circuit can overload the other circuit.

Figure 13-4: Power flow from Redclyffe to Tuai during high load and low generation at Tuai



What next?

We currently manage the circuit constraint operationally by constraining on Waikaremoana hydro generation to avoid exceeding the n-1 capacity of the circuits. The minimum generation level required is expected to be approximately 47 MW for the 2019 winter peak, increasing to approximately 75 MW by 2034. This is well within the capacity of the connected generation; however, during dry periods the minimum peak generation has been below 47 MW.

We will continue to monitor our ability to manage the constraint operationally and investigate options as the need arises. A potential option studied previously involves unbonding[4] the 110 kV

[4] Presently the Fernhill–Tuai circuit consists of a bonded double circuit line. Unbonding the circuit would involve removing the double circuit bondings and enabling single circuit switching.

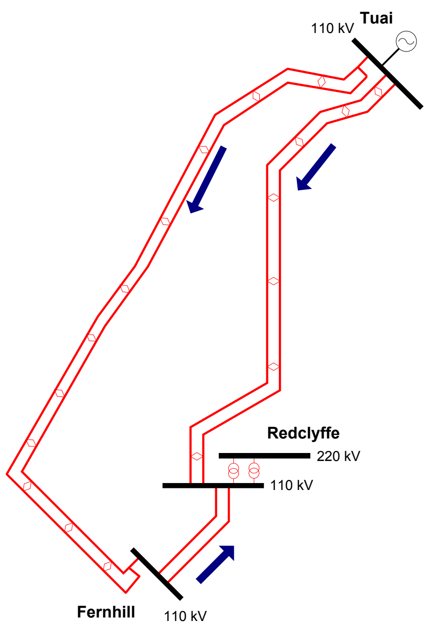
Fernhill–Tuai circuits. This increases the impedance of the Redclyffe–Fernhill–Tuai path and reduces the power flow through the Fernhill–Redclyffe circuits. This option does not eliminate the need to constrain on Waikaremoana generation but does reduce the generation requirements. We will revisit the economic feasibility of this option should generation constraints become unmanageable.

13.5.4.3 Redclyffe–Tuai 110 kV transmission capacity

Issue

There are two 110 kV Redclyffe–Tuai circuits, each rated at 57/70 MVA (summer/winter). During periods of low load and high generation injection at Tuai, power flows from Tuai to Redclyffe on the 110 kV system as shown by the blue load arrows in Figure 13-5. In this situation, an outage of the Fernhill–Tuai circuit can overload both Redclyffe–Tuai circuits.

Figure 13-5: Power flow from Tuai to Redclyffe during low load and high Tuai generation



What next?

Presently, we can manage the constraint operationally by constraining generation from the Waikaremoana hydro stations.

We will continue to monitor the constraints on the Redclyffe–Tuai circuits and investigate options as the need arises.

13.5.4.4 Redclyffe interconnecting transformer capacity

Issue

Two 220/110 kV interconnecting transformers at Redclyffe supply the majority of the Hawke's Bay load (except for the load at Whirinaki and Whakatu, which are supplied from the 220 kV transmission system). The transformers provide:

- nominal installed capacity of 170 MVA
- n-1 capacity of 98/104 MVA (summer/winter).

An outage of either interconnecting transformer will overload the remaining transformer during periods of either:

- high load and minimal Waikaremoana generation, or
- low load and high Waikaremoana generation.

We forecast that peak 110 kV load will exceed the n-1 winter capacity of the transformers by approximately 31 MW in 2019, increasing to approximately 37 MW in 2034, as shown in Table 13-7. This forecast assumes minimum Waikaremoana generation of 25 MW. However, in 2019, we did experience a short period where Waikaremoana generation was below 25 MW, resulting in constraints on the transformer. During the forecast period from 2019 to 2022, a special protection scheme is in place which trips the Redclyffe 33 kV load to prevent overloading the Redclyffe interconnecting transformers.

Table 13-6: Redclyffe interconnecting transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Redclyffe	31	32	34	36	37	38	39	39	41	42	42	37
Redclyffe (SPS)	0	0	0	1	2	3	4	10	11	13	14	2

What next?

We manage the overload operationally by transferring load (within Unison's network) from the 110 kV to the 220 kV transmission network, and by constraining on generation at Waikaremoana. Our underlying assumptions for uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid at peak reduces the forecast n-1 overloading to about 2 MW by 2034 (see table Table 13-6: Redclyffe interconnecting transformer overload forecast. See section 13.4.2.1 for our enhancement approach.

13.5.4.5 Fernhill supply transformer capacity

Issue

Two 110/33 kV transformers (rated at 30 MVA and 50 MVA) supply Fernhill's load, providing:

- nominal installed capacity of 80 MVA
- n-1 capacity of 35/35 MVA[5] (summer/winter).

Table 13-7 shows that peak load at Fernhill already exceeds the n-1 winter capacity of the transformers by approximately 29 MW in 2019. We forecast that the overload will be approximately 10 MW in 2034 due to a transformer replacement.

Table 13-7: Fernhill supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Fernhill	29	30	31	33	4	5	5	6	7	7	8	10

What next?

The short-term operational solution involves load shifting within Unison's network following a transformer outage.

In the mid-term, the smaller 30 MVA supply transformer is planned for replacement, with a new transformer with capacity of 80 MVA. The remaining transformer, T2, has a branch constraint that we may consider rectifying to remove overloads till 2027. See section 13.4.2.4 for our proposed enhancement approach.

13.5.4.6 Whakatu supply transformer capacity

Issue

Two 220/33 kV transformers supply Whakatu's load, providing:

- nominal installed capacity of 200 MVA
- n-1 capacity of 116/121 MVA (summer/winter).

The peak load at Whakatu is forecast to exceed the transformers' n-1 capacity by approximately 1 MW from 2031 to 2033 only. The forecast overloading occurs for only a few years and then disappears. This is due to the underlying demand forecast assumptions for uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid at peak, which reduce forecast load after 2034.

5 The transformers' capacity is limited by the rating of the LV busbar, followed by bushings limits (36 MVA) and LV meter accuracy limit (41 MVA); with these limits resolved, the n-1 capacity will be 42/45 MVA (summer/winter).

What next?

We will continue to monitor this risk and investigate investment options as the need arises.

13.5.4.7 Whirinaki supply transformer

Issue

Three 220/11 kV transformers supply Pan Pac Forest's load, providing:

- nominal installed capacity of 180 MVA
- n-1 capacity of 125/125 MVA (summer/winter).

The three 220/11 kV supply transformers at Whirinaki are a dedicated supply to the Pan Pac Mill. The 11 kV bus is split, with most of the load supplied at n security through a single supply transformer, T1, and the remaining load suppied at n-1 security through parallel transformers T2 and T3. The 11 kV bus is operated split to manage the fault level within the customer's 11 kV network. Hence the issue is security rather than a capacity constraint.

What next?

Any change in the security level would be customer-driven. Closing the 11 kV bus split will provide n-1 security.

13.5.5 Hawke's Bay bus security

This section discusses bus security issues identified for the Hawke's Bay region during the next 15 years. Only issues arising from the outage of a single bus section rated at 66 kV and above are included.

Bus outages disconnect more than one power system component (for example, circuits, transformers, reactive support or generators). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

13.5.5.1 Transmission bus security

Table 13-8 lists bus outages that cause voltage issues or a total loss of supply. Generators are included only if a bus outage disconnects the whole generation station or causes a widespread system impact. We do not include supply bus outages, typically 11 kV and 33 kV.

Note the customers at these grid exit points (Genesis, Contact, Unison, Eastland Network and Pan Pac) have not requested a higher security level. Unless otherwise noted, we do not propose to increase bus security. During low generation at Waikaremoana generation, bus fault create more system security concerns.

Table 13-8: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Fernhill 110 kV	Fernhill	-	-	Note 1
Redclyffe 110 kV	-	-	Redclyffe 220/110 kV transformer overloading	13.5.4.4
Redclyffe 220 kV	-	-	Redclyffe 220/110 kV transformer overloading	13.5.4.4
Whirinaki 220 kV	Whirinaki	Whirinaki		Note 2

1. Fernhill has a single bus zone, so a bus fault will cause a loss of supply.
2. Whirinaki has a single bus zone, so a bus fault disconnects all generation and supply transformers (causing a total loss of supply). An increase in bus security is not expected to be economically justified.

13.5.6 Other regional items of interest

13.5.6.1 Hawke's Bay supply security for double 220 kV circuit outages

Issue

Transmission into the Hawke's Bay region is via two 220 kV circuits from Wairakei to Whirinaki and Redclyffe. Both circuits are strung on a single 220 kV line known as the Wairakei–Whirinaki A line. The line traverses some very harsh terrain and sections of the line are exposed to the elements making the line susceptible to double circuit outages caused by:

- conductor clashing from snow unloading
- lightning, compounded by high tower footing resistance and lack of earth wire on the line.

An outage of both 220 kV circuits causes loss of supply to the Hawke's Bay region.

What next?

We invested to minimise the two major causes of double 220 kV circuit outages into Hawke's Bay and reduce restoration time following a double-circuit outage. See 13.4.2.1 for our enhancement approach.

13.5.7 Hawke's Bay generation proposals and opportunities

This section details relevant regional issues that may affect generation proposals under investigation by developers and in the public domain, or other generation opportunities. The impact of committed generation projects on the grid backbone is discussed in Chapter 6.

The maximum generation that can be connected in a particular location depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

13.5.7.1 Maximum regional generation

All generation in excess of load is exported from the Hawke's Bay region via the 220 kV double-circuit line from Redclyffe to Wairakei. Each circuit is rated at 478/583 MVA (summer/winter, subject to replacing some substation equipment), and there is scope for thermally upgrading the circuits to approximately 690/760 MVA (summer/winter). Additional reactive power sources such as capacitors may be required to achieve this as these circuits are relatively long (137 km), and absorb reactive power when highly-loaded.

Generation connected to grid exit points on the 110 kV network in the Hawke's Bay region is exported via the Redclyffe interconnecting transformers. Each interconnecting transformer has a 24-hour post-contingency rating of 98/104 MVA (summer/winter). Estimates of maximum generation assume a light load in the North Island and high generation in the region (Waikaremoana generation of 121 MW).

For generation connected at the Redclyffe 220 kV bus, up to 470 MW could be injected with n-1 security, or approximately 580 MW if the 220 kV circuit constraints were removed. The constraint is due to an overload of the 220 kV Redclyffe–Whirinaki circuit when the 220 kV Redclyffe–Wairakei circuit is out of service.

For generation connected at the Redclyffe 110 kV bus, up to approximately 70 MW could be injected with n-1 security. The constraint is due to an overload of the Redclyffe interconnecting transformer when the other interconnecting transformer is out of service.

13.5.7.2 Maungaharuru wind and Tauhara geothermal generation stations

The site of the proposed Maungaharuru wind generation station is approximately 27 km from Whirinaki, and the station may have a capacity of up to approximately 140 MW. The 220 kV Wairakei–Redclyffe double-circuit line traverses the site, and is the main supply line to the Hawke's Bay area from Wairakei.

The proposed Tauhara geothermal generation station in the Central North Island region would also connect to one of the 220 kV Wairakei–Redclyffe circuits.

There are no issues with connecting wind and geothermal generation, as proposed, into the 220 kV Wairakei–Redclyffe circuits (see Chapter 11, Central North Island region).

13.5.7.3 Additional generation connected to the 110 kV network

A number of potential wind and hydro generation prospects have been identified that may connect into one or more of the 110 kV circuits in the region.

The impact of new generation on circuit loading depends on where the connection is and how it is configured. For some connection locations and configurations, altering the hydro generation injected at Tuai would resolve the circuit overload issue, although this will impact the energy market. To increase transmission capacity, the circuits will need to be reconductored and/or the Fernhill–Tuai circuit unbonded.

Capacity of the Redclyffe 220/110 kV interconnecting transformers may also need to be increased to avoid overloading when there is high generation and low load, as power flows from the 110 kV transmission network into the 220 kV transmission network.

14 Wellington Regional Plan

14.1 Regional overview and transmission system

The Wellington region is the major load centre of the southern North Island, comprising both residential loads and a large Central Business District (CBD). The region includes the large load centre of Wellington City, together with provincial towns and smaller rural localities.

The existing transmission network for the Wellington region is set out geographically in Figure 14-1 and schematically in Figure 14-2.

Figure 14-1: Wellington region transmission network

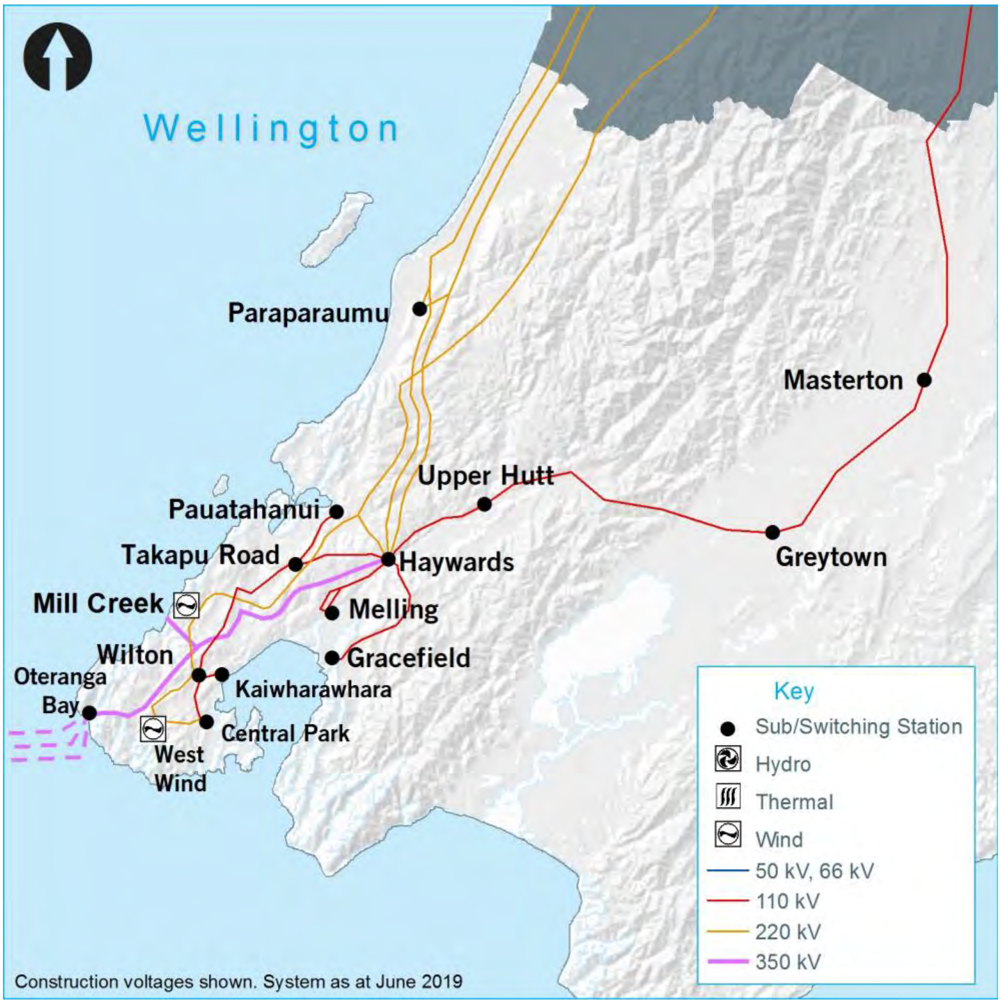
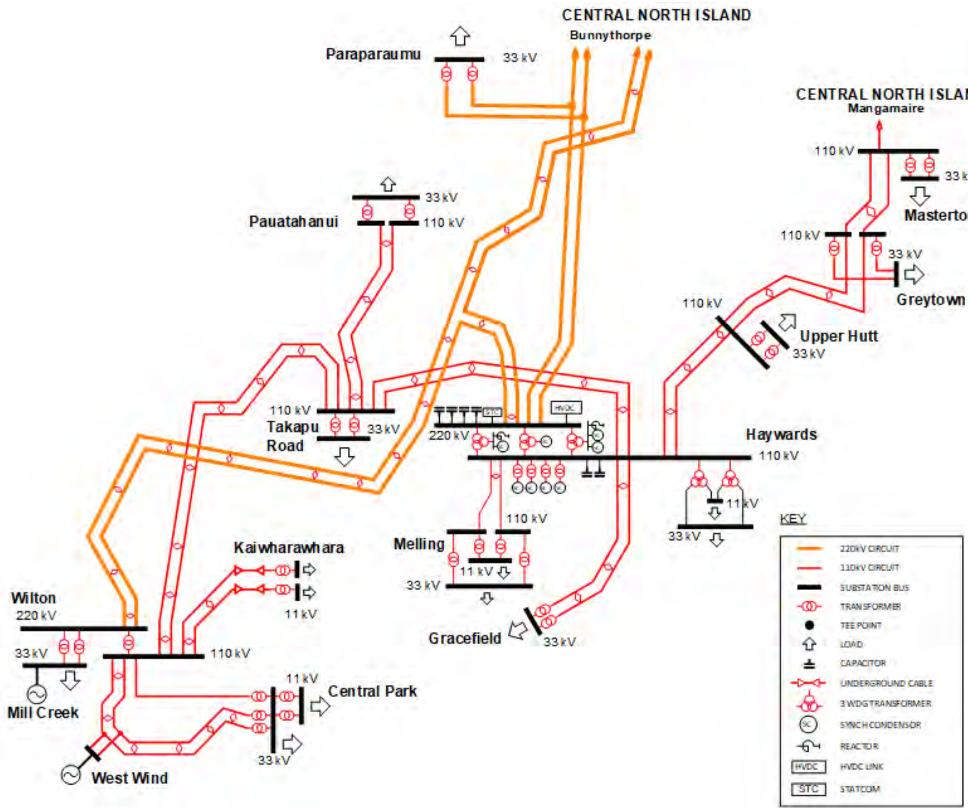


Figure 14-2: Wellington region transmission schematic



14.1.1 Transmission into the region

The Wellington region is connected to the rest of the National Grid through 220 kV circuits from Bunnythorpe and the HVDC inter-island link. It is a main corridor for through-transmission between the North and South Islands. The loading of these circuits is primarily driven by HVDC power flow and Central North Island generation.

The HVDC link's North Island terminal is at Haywards. The HVDC link can transfer up to 850 MW to the South Island (depending on the load and generation in the Wellington region), and up to 1,200 MW from the South Island (see Chapter 6).

As generation capacity in the region is much lower than local load, power is normally imported via the HVDC link (from the South Island) or from the Central North Island.

14.1.2 Transmission within the region

The region has some of the higher load densities in the North Island.

Transmission within the Wellington region comprises:

- 220 kV circuits entering the region from Bunnythorpe
- 110 kV circuits entering the region from Mangamaire
- interconnecting transformers located at Haywards and Wilton.

Reactive support in the region is mainly provided from the Haywards substation, with some contribution from the West Wind and Mill Creek wind generation stations.

14.2 Wellington demand

The Wellington regional peak demand[1] is forecast to grow by an average of 0.8 per cent per annum over the next 15 years, from 723 MW in 2019 to 810 MW in 2034. This is lower than the national average forecast growth rate of 1.2 per cent per annum.

Table 14-1 lists the peak demand forecast (prudent growth[2]) at each grid exit point for the forecast period.

Table 14-1: Forecast annual peak demand (MW) for Wellington grid exit points to 2034

Grid exit point	Power factor	Peak demand (MW)											
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Central Park 11 kV	0.98	26	26	26	27	27	27	28	28	28	28	29	32
Central Park 33 kV	0.97	166	166	168	170	172	173	176	177	178	179	180	173
Gracefield	0.98	66	67	68	69	71	71	73	73	74	75	76	78
Greytown	0.98	15	15	16	16	17	17	17	18	18	18	18	19
Haywards 11 kV	1.00	19	19	19	19	20	20	20	20	20	21	22	22
Haywards 33 kV	0.99	19	19	19	20	20	21	21	22	22	23	23	23
Kaiwharawhara	0.99	35	35	36	36	37	37	38	38	38	39	39	41
Masterton	0.98	50	51	52	53	54	56	57	58	59	59	60	58
Melling 11 kV	0.99	27	27	27	28	27	27	27	27	28	28	28	28
Melling 33 kV	1.00	38	38	38	38	39	39	40	40	40	40	39	36
Paraparaumu	1.00	70	71	73	74	77	78	81	82	84	85	85	79
Pauatahanui	0.99	21	21	21	22	22	22	23	23	23	23	23	23
Takapu Rd	0.99	107	109	112	113	116	118	120	122	123	125	126	123
Upper Hutt	1.00	33	33	34	34	35	36	36	37	37	38	38	37
Wilton	1.00	57	57	58	58	59	60	60	61	61	62	62	60

1 Historical regional peak demand is defined as the time-coincident sum of all GXP demands within the region. For planning purposes half-hourly historical demand is used.

2 Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

14.3 Wellington generation

The Wellington region's generation capacity is currently 226 MW, which is significantly lower than the local load. Most of the generation capacity is from wind generation stations, the largest being West Wind at 143 MW.

Table 14-2 lists the generation forecast for each grid injection point for the forecast period. This includes all known and committed generation stations, including those embedded within the local lines companies' networks (Wellington Electricity, Powerco, and Electra).[3]

Further generation may be developed during the period but is not sufficiently advanced to be included in our forecasts. (Refer to section 14.5.6.4 for more information on potential new generation).

Table 14-2: Forecast annual generation capacity (MW) for Wellington grid injection points to 2034 (existing and committed generation)

Grid injection point (location/name if embedded)	Generation capacity (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Central Park (Southern Landfill)	1	1	1	1	1	1	1	1	1	1	1	1
Central Park (Wellington Hospital[1])	10	10	10	10	10	10	10	10	10	10	10	10
Greytown (Hau Nui)	8	8	8	8	8	8	8	8	8	8	8	8
Haywards (Silverstream)	3	3	3	3	3	3	3	3	3	3	3	3
Masterton (Kourarau A and B)	1	1	1	1	1	1	1	1	1	1	1	1
West Wind	143	143	143	143	143	143	143	143	143	143	143	143
Wilton (Mill Creek)	60	60	60	60	60	60	60	60	60	60	60	60
Haywards 220 kV (HVDC North transfer[2, 3])	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200

1. The Wellington Hospital generation is standby only.
2. The HVDC link is included because it injects power into the region like a generator. Note that unlike generating stations, the HVDC link consumes reactive power, so voltage support equipment associated with the HVDC is required to provide reactive power support.
3. A fourth cable may be installed in future as an additional stage in the HVDC development, increasing the HVDC link capacity to 1,400 MW.

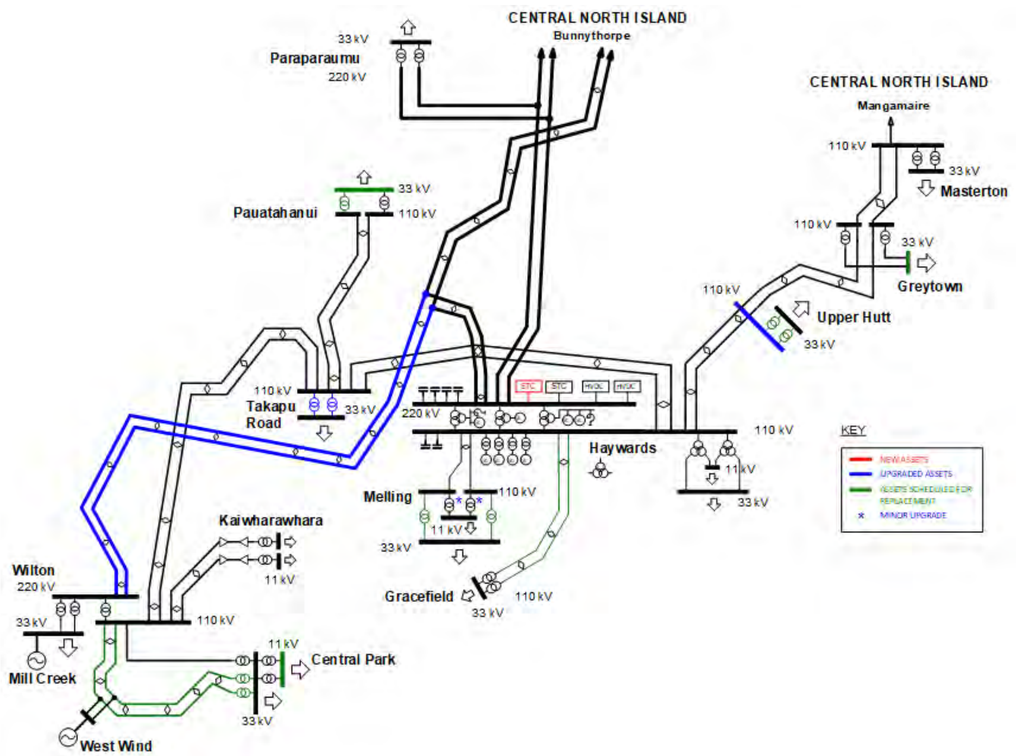
[3] Only generators with capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

14.4 Grid enhancement approach

14.4.1 Possible future Wellington transmission configuration

Figure 14-3 shows the possible configuration of Wellington transmission in 2034. New assets, upgraded assets, and assets scheduled for replacement within the forecast period (based upon potential enhancement approaches set out in the following sections) are shown.

Figure 14-3: Possible Wellington region transmission configuration in 2034



14.4.2 Enhancement approach

Our approach seeks to ensure secure transmission into and within the Wellington region into the future. Through the E&D process we assess transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified issues and opportunities we take into account uncertainty in future demand, generation, and technological developments.

Transmission issues likely requiring E&D or Customer-funded investments in Wellington over the next 10-15 years are:

Section number	Issue
Regional	
14.4.2.1	Greytown–Upper Hutt 110 kV transmission capacity
Site by grid exit point	
14.4.2.2	Central Park supply transformer capacity
14.4.2.3	Melling supply transformer capacity and low voltage
14.4.2.4	Pauatahanui and Takapu Road supply transformer capacity

14.4.2.1 Greytown–Upper Hutt 110 kV transmission capacity

A 110 kV double-circuit operates in parallel with the four 220 kV circuits between Bunnythorpe and Haywards via the Wairarapa.

During very high HVDC northward transfer, an outage on either of the Masterton–Greytown–Upper Hutt circuits may cause the loading on the Greytown–Upper Hutt section of the remaining circuit to exceed its summer capacity.

Enhancement approach:

- In the short-to-medium term, this constraint can be resolved by using a temporary grid reconfiguration to open the Mangamaire–Masterton circuit at Mangamaire and enabling the Mangamaire Auto-Changeover Scheme.
- We will continue to monitor the risk of placing the Mangamaire load on n security and consider possible transmission investments, if these can be economically justified.

14.4.2.2 Central Park supply transformer capacity

The Central Park load is supplied by three 110 kV circuits terminating on three 110/33 kV supply transformers (no 110 kV bus). The load is supplied at two voltage levels: 33 kV and 11 kV (via 33/11 kV supply transformers).

The combined load is forecast to exceed n-1 capacity of the 110/33 kV supply transformers from 2025.

Enhancement approach:

- Two of the three 110/33 kV supply transformers are due for risk-based condition replacement within the next 15 years, with the first replacement expected as early as 2024 (base capex replacement and refurbishment). We will discuss the need to increase the capacity of the replacement transformers with Wellington Electricity, as increasing transformer capacity will resolve the n-1 capacity issue for the forecast period. There is some capability within Wellington Electricity's network to transfer load to Wilton which may defer the n-1 capacity issue.
- Resiliency upgrades to mitigate high impact low probability events are possible at Central Park, as discussed in Section 14.5.6.1.

14.4.2.3 Melling supply transformer capacity and low voltage

The Melling load is supplied by two 110/33 kV supply transformers and two 110/11 kV supply transformers.

The 11 kV load already exceeds the n-1 capacity of the supply transformers, and post-contingency 33 kV bus voltage can fall below 0.95 pu (depending on the Haywards 110 kV voltage).

Both Melling 110/33 kV supply transformers will reach their expected risk-based condition replacement criteria within the next 10 years.

Enhancement approach:

- The n-1 capacity issue on the 110/11 kV transformers can be managed operationally at present. We plan to resolve the protection limits on these transformers when we replace the transformer protection in 2020 (base capex replacement and refurbishment). This will increase the n-1 capacity to 32/34 MVA (summer/winter), providing sufficient capacity for the forecast period.
- The low voltage issue on the 33 kV supply bus can be managed operationally at present. The two 110/33 kV supply transformers are due for major refurbishment in 2019 and then risk-based condition replacement in 2027. The replacement of these transformers (base capex replacement and refurbishment) will resolve the voltage issue as the replacement transformers will have on-load tap changers, allowing the 33 kV voltage to be regulated.

14.4.2.4 Pauatahanui and Takapu Road supply transformer capacity

The north-western section of Wellington Electricity's network is supplied from the Pauatahanui and Takapu Road grid exit points. The Takapu Road grid exit point is forecast to exceed the n-1 winter capacity of its transformers from 2021. The Pauatahanui grid exit point will approach the n-1 winter capacity of its transformers from 2028.

Wellington Electricity is able to transfer loads between these two grid exit points via its distribution network. Therefore, it is pragmatic to have a combined enhancement approach to maintaining adequate supply capacity for this area.

Enhancement approach:

- The n-1 capacity issue at Takapu Road may be able to be managed by transferring load to Pauatahanui. We will discuss the load transfer capability with Wellington Electricity.
- During peak load periods, the Pauatahanui or Takapu Road supply transformers will exceed their n-1 capacity with load transferred from the other grid exit point.
- We will discuss longer term options with Wellington Electricity. These include operationally managing the loading on the Pauatahanui or Takapu Road supply transformers following load transfers, upgrading the Pauatahanui or Takapu Road supply transformers, or installing a third supply transformer at Takapu Road.

14.5 Asset capability and management

We have assessed the transmission capacity and reactive support requirements in the region for the next 15 years. When an issue or opportunity exists, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 14.4.2) have been developed to address issues or opportunities that require action within the forecast period and where investment is justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk-based asset replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

14.5.1 Wellington region significant upcoming work

We integrate our capital project and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Table 14-3 lists the significant upcoming work proposed for the Wellington region during the next 15 years that may significantly impact related system issues or connected parties.

Table 14-3: Proposed significant upcoming work

Description	Tentative year	E&D issue
Bunnythorpe–Linton–Wilton 1 and Haywards–Wilton 1 circuit reconductoring (Judgeford to Wilton section) and reconfiguration of Haywards–Linton–Wilton 1 and 2 circuits.	2019-2024	None
Central Park–T3 transformer risk-based condition replacement Central Park–T4 transformer risk-based condition replacement Central Park 11 kV switchboard replacement	2022-2024 2032-2034 2020-2022	14.5.4.2 14.5.4.2 None
Central Park–Wilton 2 and 3 circuit reconductoring (zebra section)	2019	None
Gracefield 33 kV switchboard replacement	2021-2023	None
Gracefield–Haywards reconductoring	2029-2030	None
Greytown 33 kV outdoor to indoor conversion	2022-2023	None
Melling–T3 and T4 transformers risk-based condition replacement	2027-2029	14.5.4.5
Pauatahanui 33 kV outdoor to indoor conversion Pauatahanui–T1 transformer risk-based condition replacement	2024-2026 2030-2032	None None
Upper Hutt supply transformers risk-based condition replacement	2026-2027	None

14.5.2 Wellington asset feedback

The Asset Feedback Register does not include any E&D items specific to the Wellington region.

14.5.3 Changes since the 2018 Transmission Planning Report

Table 14-4 lists the specific new issues and those that are no longer relevant within the forecast period (relative to our previous Transmission Planning Report).

Table 14-4: Changes since the 2018 TPR

Issue	Change
Haywards 110 kV bus security	Removed. Haywards 110 kV bus has been split to ensure multiple interconnecting transformers are not interrupted for a bus fault.
Greytown supply capacity	Added. Increased load forecast.
Paraparaumu supply capacity	Removed. Metering limit resolved.
Pauatahanui supply capacity	Removed. Reduced load forecast.
Haywards supply transformer capacity	Removed. New supply transformers and reconfiguration has occurred.

14.5.4 Wellington transmission capability

This transmission capability section reports whether the Grid can be reasonably expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, forms part of the Grid Reliability Report (GRR).

Table 14-5 summarises transmission capability issues that were identified for the Wellington region during the next 15 years. In each case we have detected a condition that would constrain the network capacity if action were not taken. Each issue is discussed in more detail below.

Table 14-5: Wellington region transmission issues – regional/ site by grid exit point

Section number	Issue
Regional	
14.5.4.1	Greytown–Upper Hutt 110 kV transmission capacity
Site by grid exit point	
14.5.4.2	Central Park supply transformer capacity
14.5.4.3	Greytown Supply Transformer capacity
14.5.4.4	Kaiwharawhara supply capacity and security
14.5.4.5	Melling supply capacity
14.5.4.6	Takapu Road supply capacity

14.5.4.1 Greytown–Upper Hutt 110 kV transmission capacity

Issue

The transmission network between Upper Hutt and Masterton consists of:

- two 110 kV Greytown–Upper Hutt circuits rated at 63/77 MVA (summer/winter)
- two 110 kV Greytown–Masterton circuits rated at 88/98 MVA (summer/winter).

There are no line circuit breakers at Greytown so an outage on a Greytown–Upper Hutt circuit will also remove the corresponding Greytown–Masterton circuit and vice versa.

With high HVDC north transfer and high wind generation in the Wellington region, an outage on either of the Masterton–Greytown–Upper Hutt circuits may cause the loading on the Greytown–Upper Hutt section of the remaining circuit to exceed its summer capacity.

What next?

The issue can be managed operationally. This may require splitting the 110 kV network at Mangamaire, placing Mangamaire on n security. Refer to section 14.4.2.1 for our enhancement approach.

14.5.4.2 Central Park supply transformer capacity

Issue

At Central Park, Wellington Electricity is supplied at two voltage levels.

Three 110/33 kV transformers (one rated 120 MVA and two rated at 100 MVA), each connected directly onto a 110 kV circuit, supply Central Park's 33 kV and 11 kV loads to provide:

- total nominal installed capacity of 320 MVA
- n-1 capacity of 217/223 MVA (summer/winter).

Peak load at Central Park for the combined 33 kV and 11 kV load is forecast to exceed the n-1 winter capacity of the transformers by approximately 2 MW in 2025, increasing to approximately 8 MW in 2029 then reducing to approximately 5 MW in 2034 (see Table 14-6). The reduction in forecast n-1 overloading is due to our underlying assumptions regarding uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid during peak. See Chapter 3 for details.

Table 14-6: Central Park supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Central Park 33 kV and 11 kV	0	0	0	0	0	0	2	4	5	6	8	5

What next?

We expect to apply operational measures to manage this issue. Refer to section 14.4.2.2 for our enhancement approach.

14.5.4.3 Greytown Supply Transformer capacity

Issue

The Greytown load is supplied by two 110/33 kV supply transformers which provide:

- total nominal installed capacity of 40 MVA
- n-1 capacity of 20/20 MVA (summer/winter).

Peak load at Greytown is forecast to exceed the n-1 shoulder capacity of the transformers by approximately 1 MW in 2032 and continue to do so for the remainder of the forecast period (see Table 14-7).

Table 14-7: Greytown supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Greytown	0	0	0	0	0	0	0	0	0	0	0	1

What next?

We will discuss with Powerco how to address the forecast supply transformer constraint closer to the need date. We are not currently planning further investments to increase supply transformer capacity at Greytown.

14.5.4.4 Kaiwharawhara supply capacity and security

Issue

The Kaiwharawhara load is supplied by:

- two 110 kV circuits from Wilton, each rated at 57/66 MVA[4] (summer/winter)
- two 110/11 kV supply transformers, providing:
  - total nominal installed capacity of 60 MVA
  - n-1 capacity of 38/38 MVA[5] (summer/winter).

The Kaiwharawhara substation is configured with no 110 kV bus (each transformer is connected to only one 110 kV circuit) and the 11 kV bus is operated split (due to excessive fault levels on the distribution network). Tripping either one of the transformer feeders will result in a loss of supply to half the load.

If this load was transferred to the remaining transformer feeder, the total Kaiwharawhara peak load would be expected to exceed the n-1 winter and summer capacities of the transformers by approximately 1 MW from 2022 increasing to approximately 6 MW in 2034 (see Table 14-8).

Table 14-8: Kaiwharawhara supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Kaiwharawhara	0	0	0	1	1	2	2	3	3	3	4	6

What next?

Wellington Electricity considers that this issue can be managed operationally within its distribution network, for example by transferring excess load to other grid exit points. We are not planning further investments to increase supply capacity at Kaiwharawhara.

14.5.4.5 Melling supply capacity

Issue

The Melling load is supplied by:

- two 110 kV circuits from Haywards, each rated at 95/101 MVA[6] (summer/winter)
- two 110/33 kV transformers supplying Melling's 33 kV load, providing:
  - total nominal installed capacity of 100 MVA
  - n-1 capacity of 64/65 MVA[7] (summer/winter)
- two 110/11 kV transformers supplying Melling's 11 kV load, providing:
  - total nominal installed capacity of 50 MVA
  - n-1 capacity of 28/28 MVA[8] (summer/winter).

The 11 kV peak load is forecast to exceed the n-1 winter capacity of the transformers by 1 MW in 2019, increasing to approximately 2 MW in 2034 (see Table 14-9).

Table 14-9: Melling supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Melling 11 kV	1	0	1	1	0	0	1	1	1	1	2	2

4 The Kaiwharawhara–Wilton circuits are limited by the cable rating; with this limit resolved, the n-1 capacity will be 57/70 MVA (summer/winter).

5 The transformers' capacity is limited by the 11 kV circuit breaker owned by the local distribution company; with this limit resolved, the n-1 capacity will be 40/41 MVA (summer/winter).

6 The Haywards–Melling circuits are limited by the cable rating; with this limit resolved, the n-1 capacity will be 95/105 MVA (summer/winter).

7 The transformers' winter capacity is limited by the LV current transformers; with this limit resolved, the n-1 capacity will be 64/67 MVA (summer/winter).

8 The transformers' capacity is limited by protection equipment; with these limits resolved, the n-1 capacity will be 32/34 MVA (summer/winter).

What next?

We expect to use operational measures to manage these issues in the short term. Refer to section 14.4.2.3 for our enhancement approach.

14.5.4.6 Takapu Road supply capacity

Issue

Two 110/33 kV transformers supply Takapu Road's load, providing:

- total nominal installed capacity of 180 MVA
- n-1 capacity of 111/116 MVA (summer/winter).

Peak load at Takapu Road is forecast to exceed the n-1 winter capacity of the transformers by approximately 1 MW in 2021, increasing to approximately 16 MW in 2029 then reducing to approximately 13 MW in 2034 (see Table 14-10). The reduction is due to our underlying assumptions regarding uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid during peak.

Table 14-10: Takapu Road supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Takapu Road	0	0	2	3	6	7	10	12	13	15	16	13

What next?

We expect that this issue can be managed operationally in the short term. Refer to section 14.4.2.4 for our enhancement approach to maintaining adequate capacity for Wellington Electricity's north-western network.

14.5.5 Wellington bus security

This section presents issues arising from the outage of a single bus section rated at 66 kV and above for the next 15 years. Each issue listed in Table 14-11 is discussed in more detail below.

Bus outages disconnect more than one power system component (for example, other circuits, transformers, reactive support or generators). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

Table 14-11: Wellington region transmission issues – bus security

Section number	Issue
14.5.5.1	Transmission bus security
14.5.5.2	Wellington interconnecting transformer overloading
14.5.5.3	Wairarapa low voltage

14.5.5.1 Transmission bus security

Table 14-12 lists bus outages that cause voltage issues or a total loss of supply. Generators are included only if a bus outage disconnects the whole generation station or causes a widespread system impact. Supply bus outages, typically 11 kV and 33 kV, are not listed.

Note the customers at these grid exit points (Wellington Electricity, Powerco, Electra, and Meridian) have not requested a higher security level. Unless otherwise noted, we do not propose increasing bus security and future investment is likely to be customer-driven.

If increased bus security is required, the options typically include bus reconfiguration and/or additional bus circuit breakers.

Table 14-12: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Haywards 110 kV	-	-	Wellington interconnecting transformer overloading and low voltage	14.5.5.2
Haywards 220 kV	-	-	Wellington interconnecting transformer overloading and low voltage	14.5.5.2
Masterton 110 kV	Masterton	-	-	Note 1
Upper Hutt 110 kV	Upper Hutt	-	Wairarapa low voltage	Note 1 14.5.5.3
Wilton 110 kV	Kaiwharawhara	West Wind	-	Note 2 Note 3

1. The substation has no bus section circuit breaker; a bus fault will trip the whole bus and cause a total loss of supply.
2. An outage of a Wilton bus section may disconnect one of the two Kaiwharawhara circuits. Because Kaiwharawhara has no 110 kV bus, this will cause a partial interruption to the load at Kaiwharawhara (see section 14.5.4.4).
3. An outage of a Wilton bus section may disconnect Central Park–West Wind–Wilton 1 or 2. Because West Wind has no 110 kV bus, this also disconnects half of the wind farm.

14.5.5.2 Wellington interconnecting transformer overloading and low voltage

Issue

The Wellington 110 kV transmission network is predominantly supplied by 220/110 kV interconnecting transformers, with three transformers at Haywards and one at Wilton. The loading of these interconnecting transformers depends on the Wellington regional load, wind generation in the region, and the HVDC transfer level and direction (north or south power flow).

An outage of a Haywards 220 kV or 110 kV bus section can cause the remaining interconnecting transformers to exceed their n-1 winter capacity from 2023.

An outage of a Haywards 110 kV bus section can cause supply bus voltages at Melling and Upper Hutt to fall below 0.95 pu from 2028 depending on the HVDC transfer level and direction (north or south power flow) as well as the amount of local wind generation.

The worst contingency affecting the Wellington 110 kV area supply bus voltages and interconnecting transformer loading is an outage of the 110 kV middle bus section at Haywards, disconnecting several components:

- one of the three 220/110 kV transformers
- one of the two new 110/33/11 kV supply transformers
- four 110 kV circuits
- two of the four condensers and a shunt filter.

This contingency could also separate the two outer bus sections, causing an imbalance in interconnecting transformer loading.

What next?

We expect that this issue can be managed operationally in the short term.

14.5.5.3 Wairarapa low voltage

Issue

Depending on the availability of wind generation at Te Apiti, an outage of the Upper Hutt 110 kV bus:

- would be expected to cause transmission bus voltages at Greytown and Masterton to fall below 0.90 pu, from winter 2021
- may cause a voltage step of more than 10 per cent at the supply buses at Greytown and Masterton.

What next?

Our high-level investigation indicates no economic investment options are available to address this issue, so no investment is planned.

14.5.6 Other regional items of interest

14.5.6.1 Central Park resiliency

Issue

Central Park (via Wellington Electricity's distribution network) supplies a large portion of Wellington's CBD as well as the eastern and southern suburbs within which the hospital and airport are located. Wellington Electricity takes supply at 33 kV and 11 kV, and the combined peak load is currently about 175 MW, forecast to increase to about 205 MW by 2034.

Central Park is a relatively compact substation and is exposed to a range of potential single points of failure within the substation. In addition, all three Central Park–Wilton circuits are strung on three triple circuit towers entering the substation.

A high impact low probability (HILP) incident at Central Park substation, such as a triple circuit tower failure or cable fire, would result in a loss of supply to a large load, potentially for an extended period. Wellington Electricity has limited capacity to shift CBD load to other grid exit points at Wilton and Kaiwharawhara and there is presently no alternative to supply the remaining load.

What next?

We are working closely with Wellington Electricity to determine the most economic options to reduce the exposure to and mitigate the impact of HILP incidents at Central Park.

- We are working on initiatives to mitigate some of the risks that arise due to the compact nature of the Central Park site.
- We have contingency plans in place for returning supply to the site quickly following a tower failure.
- Investigations have shown that duplicating the 33 kV switchgear and associated protection is economic. Wellington Electricity plans to consult with [its customers?] regarding the additional resiliency and associated costs for relocating the T3 replacement. Increasing the capacity of Wellington Electricity's network can reduce the impact of a HILP incident at Central Park by enabling load to be transferred to other grid exit points. We are collaborating with Wellington Electricity to help identify options and progress investigations.

14.5.6.2 Central Park–Wilton B reconductoring

This is an approved project to replace the conductor on the duplex section of the Central Park–Wilton B line based on condition. This work is to be completed before the end of 2019. The old duplex conductor will be replaced with simplex conductor, which will result in a small reduction in capacity.

During the reconductoring work:

- Central Park will retain n-1 security[9] during the works with the exception of two, one-day outages needed for construction reasons. During these times Central Park will be supplied from a single circuit and supply transformer
- West Wind generation will be connected with n security and capacity during the works with the exception of two, one-day outages needed for construction reasons. During these times West Wind will be disconnected.

14.5.6.3 Bunnythorpe–Wilton A reconductoring and reconfiguration

We are proposing to replace the duplex conductor on the Judgeford–Wilton section of the Bunnythorpe–Wilton A line based on condition; this work will be completed in the next five years. The conductor will be replaced with simplex conductor, and the circuits between Haywards, Wilton and Linton reconfigured as two Tee circuits: Haywards–Linton–Wilton 1 and 2.

The main economic driver for reconfiguring as two Tee circuits is loss reduction. Other benefits include a small improvement in the voltage stability limit, greater thermal transmission capacity into the Wellington region (presently limited by other grid constraints), and improved security to Linton (Central North Island region).

During most of the reconductoring work, n-1 security to the grid exit points in the region will be retained. We expect that Wilton will be on n security for a few days for construction reasons. A special protection scheme may be required to trip some feeders following a contingency during a high load period.

14.5.6.4 Wellington generation proposals and opportunities

This section details relevant regional issues for selected generation proposals under investigation by developers and in the public domain, or other generation opportunities.

The maximum generation that can be connected depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

See Chapter 11 for a discussion about connecting wind generation in the lower North Island.

14.5.6.5 Generation connection options - general

Most of the transmission network in the region is used to supply load rather than connect generation. In general, there are no issues with connecting up to several hundred megawatts of generation to these circuits. Higher generation levels would reverse the power flow direction and approach the circuits' ratings. As a result, depending on where generation is located, some comparatively minor upgrades may be required, such as increasing 220/110 kV interconnection capacity. However, note that the capacity of the grid backbone between regions may constrain the generation level that can be connected (see also Chapter 6).

14.5.6.6 Generation connection to the 110 kV network in the Wairarapa area

There is a 110 kV double-circuit line from Haywards to Upper Hutt, Greytown, and Masterton, and a single-circuit line from Masterton to Mangamaire and Woodville (in the Central North Island region).

The amount of generation that can be installed on this line depends on the generation location along the 110 kV line, and any line upgrades that may be undertaken. Approximately 180 MW of generation could connect at Masterton under normal operating conditions. Other generation locations and upgrade options may result in maximum generation levels ranging from zero to approximately 180 MW.

9 The Central Park Transformer Overload Protection Scheme will be enabled where necessary. The scheme reduces load at Central Park if one of the supply transformers overloads due to a parallel circuit outage.

15 Nelson-Marlborough Regional Plan

15.1 Regional overview and transmission system

The Nelson-Marlborough region includes a mix of significant and growing provincial cities and towns (Nelson, Blenheim and Richmond) together with smaller rural localities (Picton, and the Golden Bay area).

Local generation at Cobb, embedded behind the Stoke 66 kV grid exit point, provides important voltage and load support to the region.

The existing transmission network for the Nelson-Marlborough region is set out geographically in Figure 15-1 and schematically in Figure 15-2.

Figure 15-1: Nelson-Marlborough region transmission network

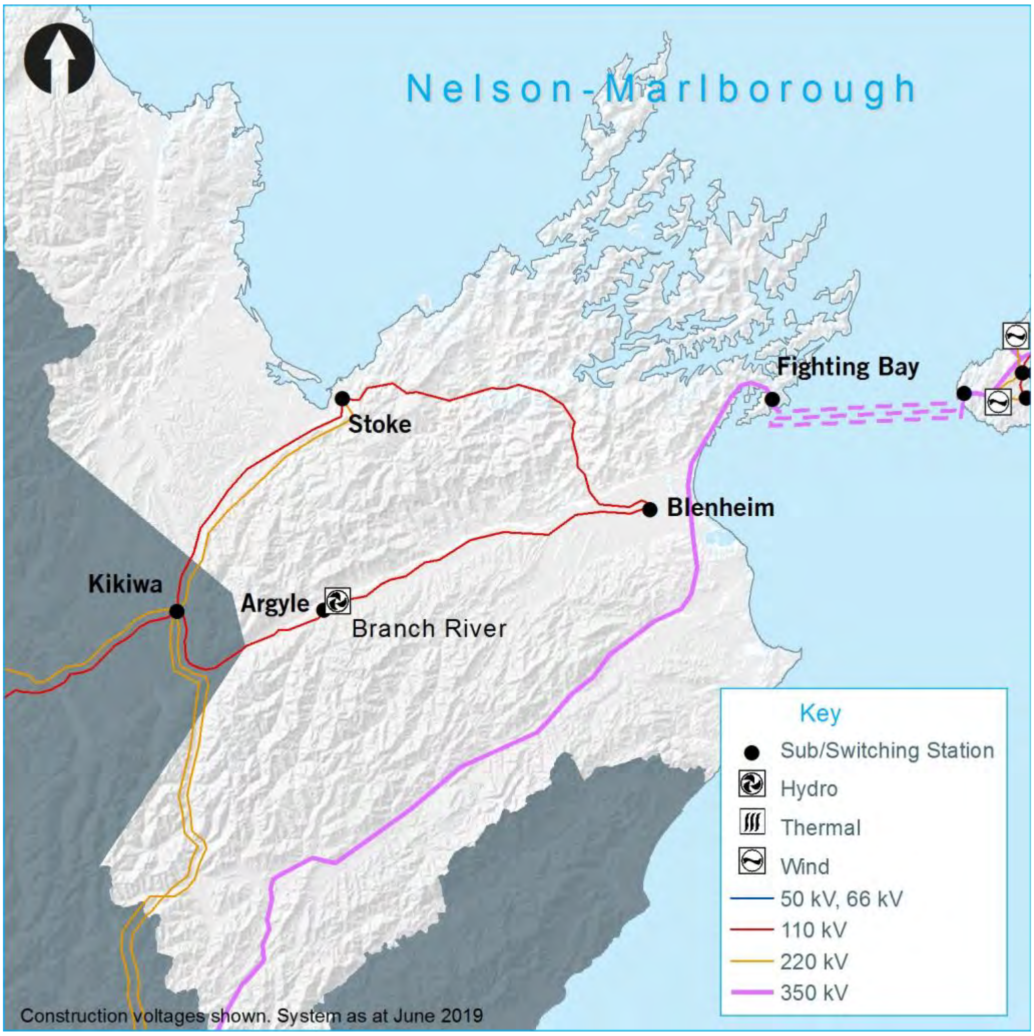
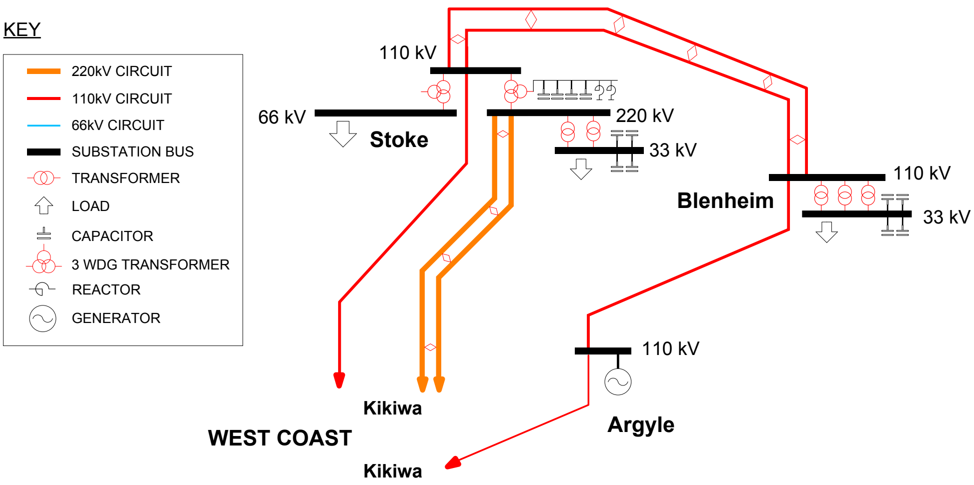


Figure 15-2: Nelson-Marlborough region transmission schematic



15.1.1 Transmission into the region

The Nelson-Marlborough region, together with the West Coast region, is connected to the National Grid via 220 kV circuits at Kikiwa.

The load of the two regions far exceeds generation so most of the load is supplied via 220 kV circuits from the Waitaki Valley, which also supply significant load in the South Canterbury and Canterbury regions. This shared capacity from the Waitaki Valley is important for supply security to all four regions.

15.1.2 Transmission within the region

Within the Nelson-Marlborough region, transmission comprises 220 kV circuits from Kikiwa (in the West Coast region) to Stoke and parallel 110 kV circuits forming a 'triangle' between Kikiwa, Stoke, and Blenheim. Interconnection between the 220 kV and 110 kV within the region is provided by a single interconnecting transformer at Stoke. There is a second interconnecting transformer at Kikiwa[1] which, together with the Stoke unit, provides n-1 security to the 110 kV transmission network.

The reactive power support in this region is provided by:

- 61.5 Mvar of capacitors and 10 Mvar of shunt reactors at Stoke
- 20.4 Mvar of capacitors at Blenheim.

15.2 Nelson-Marlborough demand

The Nelson-Marlborough regional peak demand[2] is forecast to grow by an average 1.0 per cent per annum over the next 15 years, from 204 MW in 2019 to 238 MW by 2034. This is lower than the national average growth rate of 1.2 per cent per annum.

Table 15-1 lists the peak demand forecast (prudent growth[3]) for each grid exit point for the forecast period.

1 Stoke has only one 220/110 kV, 150 MVA interconnecting transformer. This transformer essentially operates in parallel with Kikiwa–T2 (150 MVA).

2 For discussion on demand forecasting see Chapter 3, section 3.1.

3 Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

Table 15-1: Forecast annual peak demand (MW) at Nelson-Marlborough grid exit points to 2034

Grid exit point	Power factor	Peak demand (MW)											
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Blenheim	0.98	76	78	79	81	82	84	85	87	88	89	90	90
Stoke 33 kV	0.99	131	134	136	138	141	143	146	148	150	152	153	146
Stoke 66 kV[1]	0.98	30	31	31	32	33	33	34	34	35	35	35	34

1. Stoke 66 kV load is a net value. It assumes a seasonal estimated generation from Cobb (distribution network connected).

15.3 Nelson-Marlborough generation

The Nelson-Marlborough region's current generation capacity is 50 MW, which is lower than local demand, requiring power to be imported through the National Grid. Table 15-2 lists the generation forecast at each grid injection point for the period to 2034. This includes all known and committed generation stations, including those embedded within the relevant local lines company's network (Network Tasman or Marlborough Lines).[4]

Further generation may be developed during the period but is not sufficiently advanced to be included in our forecasts. (Refer to section 15.5.6 for more information on potential new generation.)

Table 15-2: Forecast annual generation capacity (MW) at Nelson-Marlborough grid injection points to 2034 (existing and committed generation)

Grid injection point (location/name if embedded)	Generation capacity (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Argyle – Branch River Scheme	11	11	11	11	11	11	11	11	11	11	11	11
Blenheim (Lulworth Wind)	1	1	1	1	1	1	1	1	1	1	1	1
Blenheim (Waihopai)	3	3	3	3	3	3	3	3	3	3	3	3
Motupipi (Onekaka)	1	1	1	1	1	1	1	1	1	1	1	1
Stoke (Cobb)	34	34	34	34	34	34	34	34	34	34	34	34

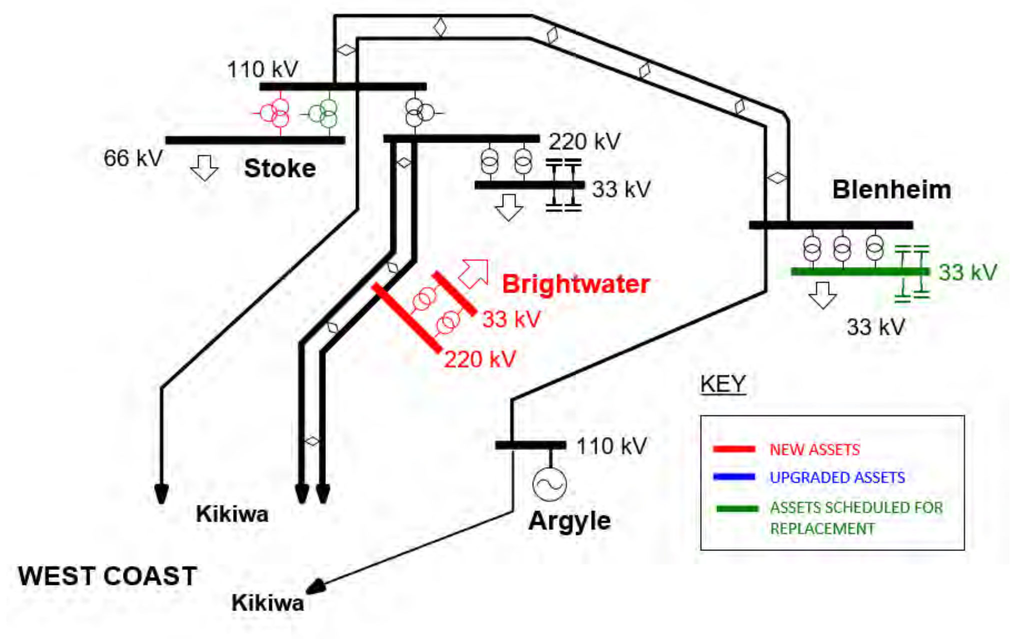
4 Only generators with capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

15.4 Grid enhancement approach

15.4.1 Possible future Nelson-Marlborough transmission configuration

Figure 15-3 shows the possible configuration of Nelson-Marlborough transmission in 2034. New assets, upgraded assets, and assets scheduled for replacement within the forecast period (based on potential enhancement approaches set out in the following sections) are shown.

Figure 15-3: Possible Nelson-Marlborough transmission configuration in 2034



15.4.2 Enhancement approach

Our approach seeks to ensure we secure transmission into and within the Nelson-Marlborough region into the future. Through the E&D process we assess transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified issues and opportunities we take into account uncertainty in future demand, generation and technological developments.

As the Nelson-Marlborough region relies on generation from several hundred kilometres away, there will be an ongoing need for investment in reactive support equipment (such as the STATCOM at Kikiwa and additional capacitors) to support regional voltage. Any future investment in reactive support equipment in the region (such as replacement of the Blenheim and Stoke capacitor banks), would consider location and sizing in terms of voltage issues faced by the wider Upper South Island. Our approach to maintaining voltage stability in the region is discussed in Chapter 6, Grid Backbone (South Island section).

Transmission issues likely requiring E&D or customer funded investments in Nelson-Marlborough over the next 10-15 years are:

Section number	Issue
Regional	
15.4.2.1	Nelson-Marlborough 220/110 kV interconnection security
Site by grid exit point	
15.4.2.2	Nelson supply capacity and security
15.4.2.3	Stoke 66 kV capacity and security

15.4.2.1 Nelson-Marlborough 220/110 kV interconnection security and high voltage steps

The Nelson-Marlborough 110 kV region is supplied by two interconnecting transformers, one at Stoke and one at Kikiwa. The Stoke 220/110 kV interconnection operates in parallel with the interconnecting transformer at Kikiwa in the West Coast region. An outage of the Stoke 220/110 kV interconnecting transformers may overload assets or create low voltage in the Nelson-Marlborough region. These issues depend on load and generation in the Nelson-Marlborough and West Coast regions.

Kikiwa–Stoke 110 kV transmission capacity

An outage of the Stoke 220/110 kV interconnecting transformer results in the Nelson-Marlborough region being supplied from the Kikiwa interconnecting transformer via two 110 kV circuits (Kikiwa–Stoke 3 and Kikiwa–Argyle–Blenheim–Stoke 1). The Kikiwa–Stoke 3 circuit may overload as a result, when the regional load is very high with low local generation.

In the short term, this issue can be managed operationally by controlling levels of load and generation in the region. The Stoke–T7 Outage Intertrip Scheme manages this issue during planned outages of the interconnecting transformer.

Enhancement approach:

- Our investigation has found that the value of unserved energy is very low for this constraint. As a result, we have been unable to identify any economic options to resolve it.
- We will continue to monitor the constraint and revisit the economic analysis when necessary.

High voltage steps at Blenheim 33 kV

An outage of the Stoke 220/110 kV interconnecting transformer can lead voltage drops larger than 5% at Blenheim 33 kV and Stoke 66 kV immediately after the contingency in a high load, low local generation scenario.

Enhancement approach:

- The frequency of a Stoke 220/110 kV interconnecting outage is not high enough to justify investment to reduce the voltage step.

15.4.2.2 Nelson supply capacity and security

The city of Nelson and its surrounding area is supplied from the Stoke 33 kV grid exit point. Peak load is forecast to exceed the n-1 winter capacity of the two supply transformers from 2024. This is 6 years later than we estimated in last year's TPR, due to a combination of reduced load growth expectations and a recalculation of the transformer protection limit that resulted in a 3 MVA increase in the supply transformers' branch ratings.

Enhancement approach:

- In the medium-term, Network Tasman can manage its load to resolve the overloading issue. Resolving the protection limit that constrains the capacity of the transformers would increase the supply capacity by 2 MVA. However, at this point the rating of the 33 kV switchgear would become a constraint. Given the low capacity gain, this improvement was found to be uneconomic, and will not be considered further.
- Network Tasman is considering developing a new 220/33 kV grid exit point at Brightwater, connected to one of the 220 kV Kikiwa–Stoke circuits. This investment will be customer funded. Network Tasman has selected land for the grid exit point and will decide on timing for it. Some load will be shifted from the Stoke grid exit point to Brightwater to ensure the load at Stoke remains within the n-1 capacity of the Stoke supply transformers. A new grid exit point would also provide diversity for Nelson's electricity supply.

Customer investments

Project Name	Stoke 33 kV supply capacity
Project description:	Develop new 220/33 kV grid exit point (Brightwater GXP)
Project's state of completion	Possible
OAA level completed:	None
Grid need date	2024, customer initiated
Indicative cost [$ million]:	25
Part of the GEIR?	No

15.4.2.3 Stoke 66 kV capacity and security

A single 110/66 kV transformer at Stoke serves the Golden Bay area. The winter peak load exceeds the special rating[5] of the transformer.

This issue is managed operationally by constraining on Cobb generation which is embedded in the 66 kV distribution network. During transformer and bus maintenance the Golden Bay area's distribution network is operated islanded and supplied from Cobb.

Network Tasman has requested that the existing transformer be upgraded and a second 110/66 kV, 40 MVA transformer be installed. The existing transformer (T3) is due for risk based condition replacement and will be replaced by end of 2019.

Enhancement approach:

- We have a project underway to replace the existing 110/66 kV supply transformer (funded under base capex replacement and refurbishment) and to install a second transformer at the same time (Customer-funded). This development, in conjunction with generation from Cobb, will provide a secure supply to the Golden Bay area for the forecast period and beyond.

Customer investments

Project Name	Stoke–T4 Transformer
Project description:	Install a second 110/66 kV supply transformer (T4) at Stoke
Project's state of completion	Delivery
OAA level completed:	AL 2d
Grid need date	2019
Indicative cost [$ million]:	3.4
Part of the GEIR?	No

5 The special rating refers to a rating above our normal practice, which is applied due to the particular network configuration at this location.

15.5 Asset capability and management

We have assessed the transmission capacity and reactive support requirements in the region for the next 15 years. When an issue or opportunity exists, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 15.4) have been developed to address issues or opportunities that require action within the forecast period and where investment is justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk-based asset replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

15.5.1 Nelson-Marlborough significant upcoming work

We integrate our capital project and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Table 15-3 lists the significant upcoming work[6] proposed for the Nelson-Marlborough region for the next 15 years that may significantly impact related system issues or connected parties.

Table 15-3: Proposed significant upcoming work

Description	Tentative year	E&D issue
Blenheim 33 kV capacitor bank replacement Blenheim 33 kV switchboard partial replacement	2022-2024 2030-2032	15.4.2.1 None
Stoke 11 kV capacitor banks and shunt reactors removal Stoke 110/66 kV–T3 transformer risk based condition replacement	2019-2020 2018-2019	None 15.5.4.3

15.5.2 Nelson-Marlborough asset feedback

The Asset Feedback Register does not include any E&D items specific to the Nelson-Marlborough region.

15.5.3 Changes since the 2018 Transmission Planning Report

Table 15-4 lists the specific issues that are either new or no longer relevant within the forecast period (relative to our previous Transmission Planning Report).

Table 15-4: Changes Since the 2018 TPR

Issues	Change
Stoke 220/110 kV interconnecting transformer capacity	Removed. Reduced load forecast.

6 Condition-based replacement of the asset is included in this list.

15.5.4 Nelson-Marlborough transmission capability

Table 15-5 summarises issues involving the Nelson-Marlborough region for the next 15 years. For more information about a particular issue, refer to the listed section number.

Table 15-5: Nelson-Marlborough region transmission issues – by region/grid exit point

Section number	Issue
Regional issue	
15.5.4.1	Kikiwa–Stoke 110 kV transmission capacity and low voltages in Blenheim
Site by grid exit point	
15.5.4.2	Stoke 220/33 kV supply transformer capacity
15.5.4.3	Stoke 110/66 kV supply transformer capacity and supply security

15.5.4.1 Kikiwa–Stoke 110 kV transmission capacity and low voltages in Blenheim

Issue

There are two 110 kV circuits connecting the Nelson-Marlborough and West Coast regions:

- Kikiwa–Stoke 3 circuit rated at 56/68 MVA (summer/winter)
- Kikiwa–Argyle–Blenheim 1 circuit rated at 56/68 MVA (summer/winter).

An outage of the Stoke 220/110 kV interconnecting transformer results in the Nelson-Marlborough region being supplied from the interconnection at Kikiwa via the two 110 kV circuits. The Kikiwa–Stoke 3 circuit may overload and low voltages may occur at Blenheim when Nelson-Marlborough region load is high, coupled with low local generation.

What next?

We manage these issues operationally via generation rescheduling and load management in the region. The low voltage issue in Blenheim can be addressed via a tap change on the off-load tap changer of the supply transformers T1 and T2. Refer to section 15.4.2.1 for our enhancement approach.

15.5.4.2 Stoke 220/33 kV supply transformer capacity

Issue

Two 220/33 kV transformers supply Stoke's 33 kV load, providing:

- total nominal installed capacity of 240 MVA
- n-1 capacity of 141/141 MVA[7] (summer/winter).

Peak load at Stoke is forecast to exceed the n-1 winter capacity of the transformers by approximately 2 MW in 2024, increasing to approximately 12 MW in 2029 before decreasing to 5 MW in 2034. This decrease is caused by a reduction in demand later in the period, due to our underlying demand forecast assumptions for uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid at peak (see Table 15-6).

Table 15-6: Stoke 220/33 kV supply transformer overload forecast

	Transformer overload (MW)											
Circuit/grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Stoke 33 kV	0	0	0	0	0	2	5	7	9	11	12	5

[7] The transformers' capacity is limited by protection equipment of 141 MVA; if this limit is resolved, the n-1 capacity will be 143/143 MVA (summer/winter), constrained by the rating of the 33 kV switchgear.

What next?

These issues will be managed operationally at first. Refer to section 15.4.2.2 for our enhancement approach.

15.5.4.3 Stoke 110/66 kV supply transformer capacity and supply security

Issue

The Stoke 66 kV bus is supplied by a single 110/66 kV transformer with a nominal installed capacity of 20 MVA, resulting in n security. The continuous operational rating of the transformer has been increased to 28/30 MVA (summer/winter).

The generation at Cobb affects the transformer overload. Assuming no contribution from Cobb, the summer peak load at Stoke 66 kV is forecast to exceed the increased continuous rating of the transformer by approximately 10 MW in 2019, increasing to approximately 14 MW in of 2034 (see Table 15-7).

Table 15-7: Stoke 110/66 kV transformer overload forecast (without reinforcement project)

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Stoke 66 kV	10	10	11	12	13	13	14	14	15	15	15	14

What next?

This issue is currently managed by constraining on Cobb generation, which is connected within the 66 kV distribution network. A project is underway to replace the single transformer with two new transformers which will resolve this issue for the forecast period and beyond. Refer to section 15.4.2.3 for our enhancement approach.

15.5.5 Nelson-Marlborough bus security

This section summarises bus security issues identified for the Nelson-Marlborough region during the next 15 years, arising from the outage of a single bus section rated at 50 kV and above.

Bus outages disconnect more than one power system component (for example, other circuits, transformers, reactive support or generators). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

15.5.5.1 Transmission bus security

Table 15-8 lists the bus outages that cause voltage issues or a total loss of supply. Generators are included only if a bus outage disconnects the whole generation station or causes a widespread system impact. Supply bus outages, typically 11 kV and 33 kV, are not listed.

Our customers (Network Tasman and Marlborough Lines) have not requested a higher security level. Unless otherwise noted, we do not propose to increase bus security.

Table 15-8: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Argyle 110 kV	-	Argyle	-	-
Blenheim 110 kV	Blenheim 	 Argyle	-	 Note 1
Stoke 66 kV	Stoke 66 kV 	 Cobb	-	 Note 2
Stoke 110 kV	Blenheim Stoke 66 kV 	 Cobb	-	15.5.5.2 Note 2 Note 2
Stoke 220 kV	-	-	Possible overload of Kikiwa–Stoke 3	Note 3

1. There is no bus protection at Blenheim, so bus faults remove all connected circuits from service. This includes the Blenheim–Argyle–Kikiwa circuit, causing a loss of connection at Argyle.
2. An outage of the Stoke 110 kV or 66 kV bus will disconnect the Stoke 66 kV bus, including Cobb generation which is connected within the 66 kV distribution network. This may or may not cause a loss of supply, depending on the balance of load and generation in the area.
3. An outage of the Stoke 220 kV bus-section A1 will disconnect the 220/110 kV interconnecting transformer, potentially causing overloading of the 110 kV Kikiwa–Stoke circuit, depending on levels of generation and load in the region (see 15.5.4.1).

15.5.5.2 Blenheim supply security and voltage quality

Issue

There is a single 110 kV bus section at Blenheim, resulting in n security. There are three 110 kV circuits (two from Stoke and one from Argyle) supplying Blenheim's load. A fault on the:

- Blenheim 110 kV bus will result in a total loss of supply to Blenheim load.
- Stoke 110 kV bus will disconnect both Blenhein–Stoke circuits. This may overload the Blenhein–Argyle–Kikiwa circuit which will also cause a low voltage issue at Blenheim. The Blenheim–Kikiwa 110 kV Overload Protection Scheme is normally enabled and if the loading exceeds the rating of the Blenheim–Argyle–Kikiwa 1 circuit, it will trip up to three feeders to reduce Blenheim load. This will normally address the issues, but if the loading still exceeds the circuit rating the scheme will trip the circuit, causing a total loss of supply at Blenheim.

What next?

We will continue to manage these issues operationally. Our customer has not requested a higher level of security, therefore we have no investments planned to address this issue.

15.5.6 Nelson-Marlborough generation proposals and opportunities

This section describes regional issues that may affect generation proposals under investigation by developers and in the public domain, or other generation opportunities. We discuss the impact of committed generation projects on the grid backbone separately in Chapter 6.

The maximum generation that can be connected depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

15.5.6.1 Maximum regional generation

To estimate the maximum amount of new generation that can be connected in the Nelson-Marlborough region, we assume a light South Island load profile and high generation in the Nelson-Marlborough region (Cobb generating 27 MW).

For generation connected at the Stoke 220 kV bus, the maximum that can be injected under n-1 is approximately 380 MW. The constraint is caused by the 220 kV Kikiwa–Stoke circuit overloading when the other circuit is out of service.

Generation up to approximately 130 MW can be connected at the Blenheim 110 kV bus, or to the two 110 kV Blenheim–Stoke circuits. Higher levels of generation (approximately 160 MW under an n-1 condition) would require a thermal upgrade of the 110 kV Kikiwa–Stoke 3 circuit and a protection upgrade on the Blenheim–Stoke 1 circuit. Further increases would require a thermal upgrade of the 110 kV Blenheim–Argyle–Kikiwa circuit.

15.5.6.2 Generation on the Blenheim–Argyle–Kikiwa circuit

Blenheim–Argyle–Kikiwa is a single 110 kV circuit rated at 56/68 MVA. The maximum generation that can be connected to this circuit depends on where it is connected. With all circuits in service, approximately 50 MW can be connected, in addition to existing generation injected at Argyle. Generation beyond this amount will need to be embedded within the Marlborough Lines network. Generation restrictions may also be needed for some outages. Alternatively, increasing the rating of the circuit is also technically feasible.

15.5.6.3 Generation connection at Stoke 66 kV

The existing Cobb hydro generation station is embedded in the Network Tasman 66 kV transmission network. The maximum new generation that can be connected at the 66 kV bus depends on the 66 kV load profile, existing Cobb generation and the capacity of the Stoke 110/66 kV transformer.

Approximately 50 MW of additional generation can be connected.

16 West Coast Regional Plan

16.1 Regional overview and transmission system

The West Coast region includes a mix of significant provincial towns (Dobson, Greymouth, and Hokitika) and smaller, lower-growth rural localities.

The major industries in the region are minerals, dairying, and tourism. Over the years, the decline of the coal mining industry, closure of the cement plant at Cape Foulwind and an increase in embedded generation has resulted in a reduction in forecast demand. This has impacted transmission needs within the region.

The existing transmission network for the West Coast region is set out geographically in Figure 16-1 and schematically in Figure 16-2.

Figure 16-1: West Coast region transmission network

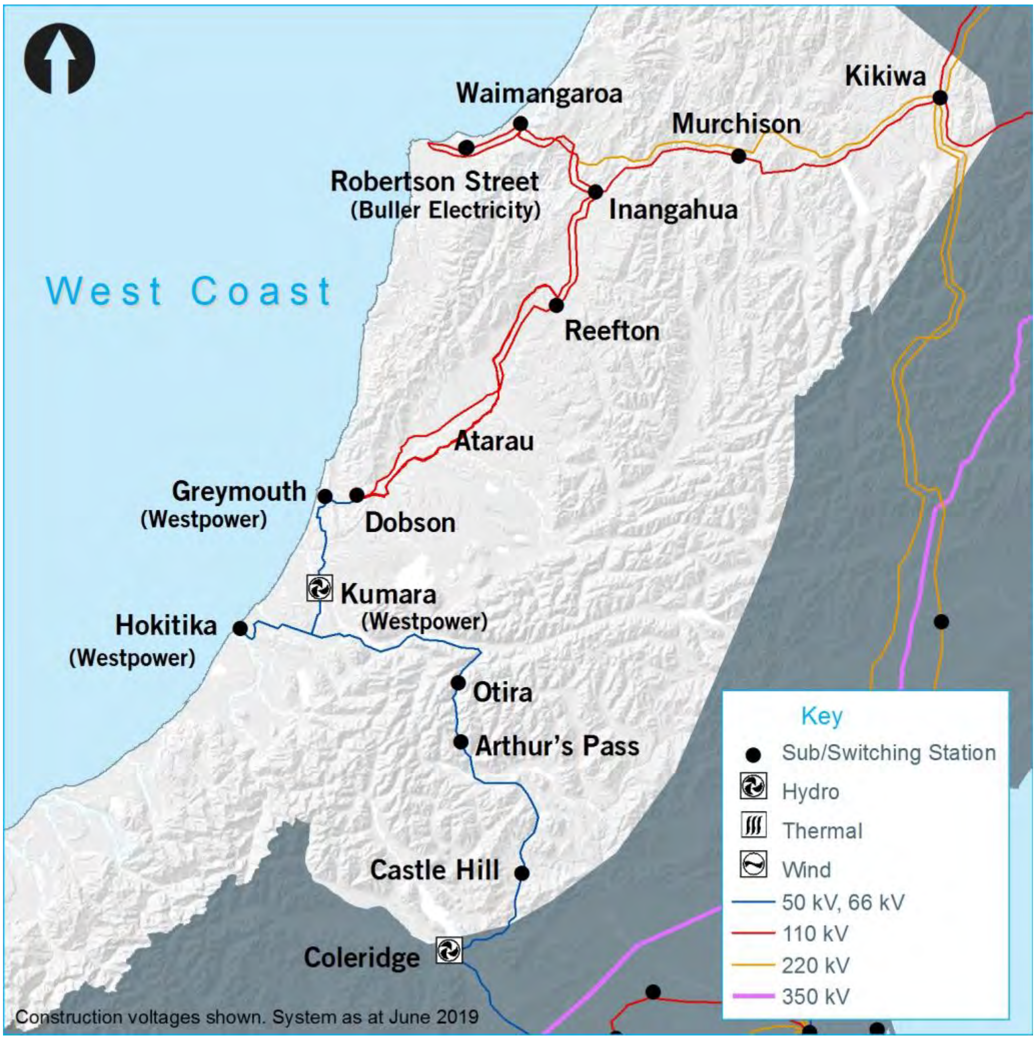
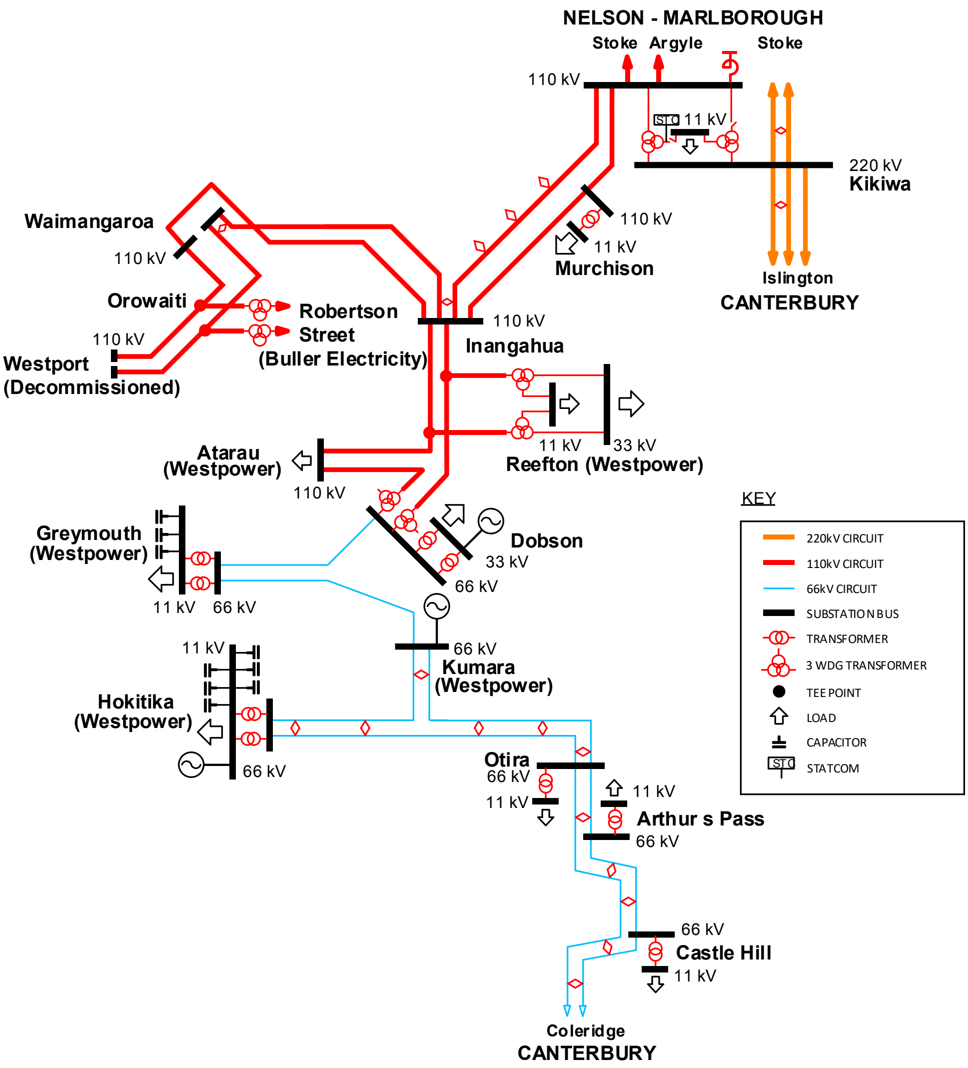


Figure 16-2: West Coast transmission schematic



16.1.1 Transmission into the region

The West Coast region is connected to the National Grid via two 220/110 kV interconnecting transformers at Kikiwa (one on standby) and two 66 kV circuits from Coleridge. The 220/110 kV interconnection at Kikiwa effectively operates in parallel with the transformer at Stoke (in the Nelson-Marlborough region).

The amount of generation in the West Coast and Nelson-Marlborough regions combined is much less than their combined demand. Significant imports are required, most of which is supplied from remote generation in the Waitaki Valley, with significant load off-take in the South Canterbury and Canterbury regions.

16.1.2 Transmission within the region

Within the West Coast region, the transmission network comprises 110 kV and 66 kV transmission circuits, with two 110/66 kV interconnecting transformers at Dobson.

Most of the West Coast load is supplied from the northern infeed, with power flowing through the region on the 110 kV circuits from Kikiwa to Dobson via Inangahua, and the 110 kV spur from Inangahua to Robertson Street and Westport (which no longer supplies any load). Some loads are fed from the south via low capacity 66 kV circuits from Coleridge, which also provide significant voltage support to the region. Reactive support for the region (and grid backbone) is provided by a STATCOM at Kikiwa and capacitor banks at Greymouth and Hokitika.

Most of the assets at Robertson Street, Reefton, Atarau, Greymouth, Kumara and Hokitika are owned by the local lines companies (Westpower and Buller Network).

16.2 West Coast demand

The West Coast regional peak demand[1] is forecast to grow by an average of 2.5 per cent per annum over the next 15 years, from 49 MW in 2019 to 71 MW in 2034. This exceeds the national average growth rate of 1.2 per cent per annum

Table 16-1 sets out forecast peak demand (prudent growth[2]) for each grid exit point for the forecast period.

Table 16-1: Forecast annual peak demand (MW) at West Coast grid exit points to 2034

Grid exit point	Power factor	Peak demand (MW)											
		2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2034**
Arthur's Pass	0.99	0.4	0.4	0.4	0.4	1	1	1.1	1.1	1.1	1.1	1.1	1.6
Atarau[1]	0.98	1.5	0	0	0	0	0	0	0	0	0	0	0
Castle Hill[2]	1	1	1	1	1	1	4	4	5	5	5	5	5
Dobson	0.99	10	11	11	11	11	12	12	12	12	12	12	11
Greymouth	0.99	15	16	17	17	17	18	18	19	19	19	20	22
Hokitika	0.85	18	19	20	21	22	22	23	23	24	24	24	24
Kikiwa	0.98	4	4	4	4	4	4	5	5	5	5	5	5
Kumara	0.99	5	5	5	5	5	5	5	5	5	5	5	5
Murchison	0.98	3	3	3	3	3	3	3	3	3	3	3	3
Robertson Street[3]	1	12	13	13	14	14	14	14	15	15	15	16	17
Otira	0.77	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.9	1.2
Reefton	1	5	6	6	6	6	6	6	6	6	6	7	7

1. Atarau grid exit point demand forecast incorporates plans for a Pike River Mine re-entry and subsequent final closure.
2. Customer has advised of a 4.4 MW step load growth in 2024 – Porters Ski Area development.
3. Robertson Street (owned by Westpower) is connected to the grid at Orowaiti.

16.3 West Coast generation

The West Coast region's generation capacity is currently 30 MW. Table 16-2 lists the generation forecast for each grid injection point in the West Coast region for the forecast period. This includes all known and committed generation stations including those embedded in local lines company networks (Westpower, Buller Networks, Network Tasman, or Orion).[3]

Additional generation may be developed during the forecast period but is not sufficiently advanced to be included in our forecasts. (Refer to section 16.5.7 for more information on potential new generation.)

[1] For discussion on demand forecasting see Chapter 3, section 3.1.

[2] Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

[3] Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

Table 16-2: Forecast annual generation capacity (MW) at West Coast grid injection points to 2034 (existing and committed generation)

Grid injection point (location/ name if embedded)	Generation capacity (MW)											
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2034**
Dobson (Arnold)	3	3	3	3	3	3	3	3	3	3	3	3
Hokitika (Amethyst)	6	6	6	6	6	6	6	6	6	6	6	6
Hokitika (McKays Creek)	1	1	1	1	1	1	1	1	1	1	1	1
Hokitika (Wahapo-Okarito Forks)	3	3	3	3	3	3	3	3	3	3	3	3
Kumara (Hokitika Diesel)	3	3	3	3	3	3	3	3	3	3	3	3
Kumara (Kumara and Dillmans)[1]	10	10	10	10	10	10	10	10	10	10	10	10
Robertson Street (Kawatiri Hydro)	4	4	4	4	4	4	4	4	4	4	4	4

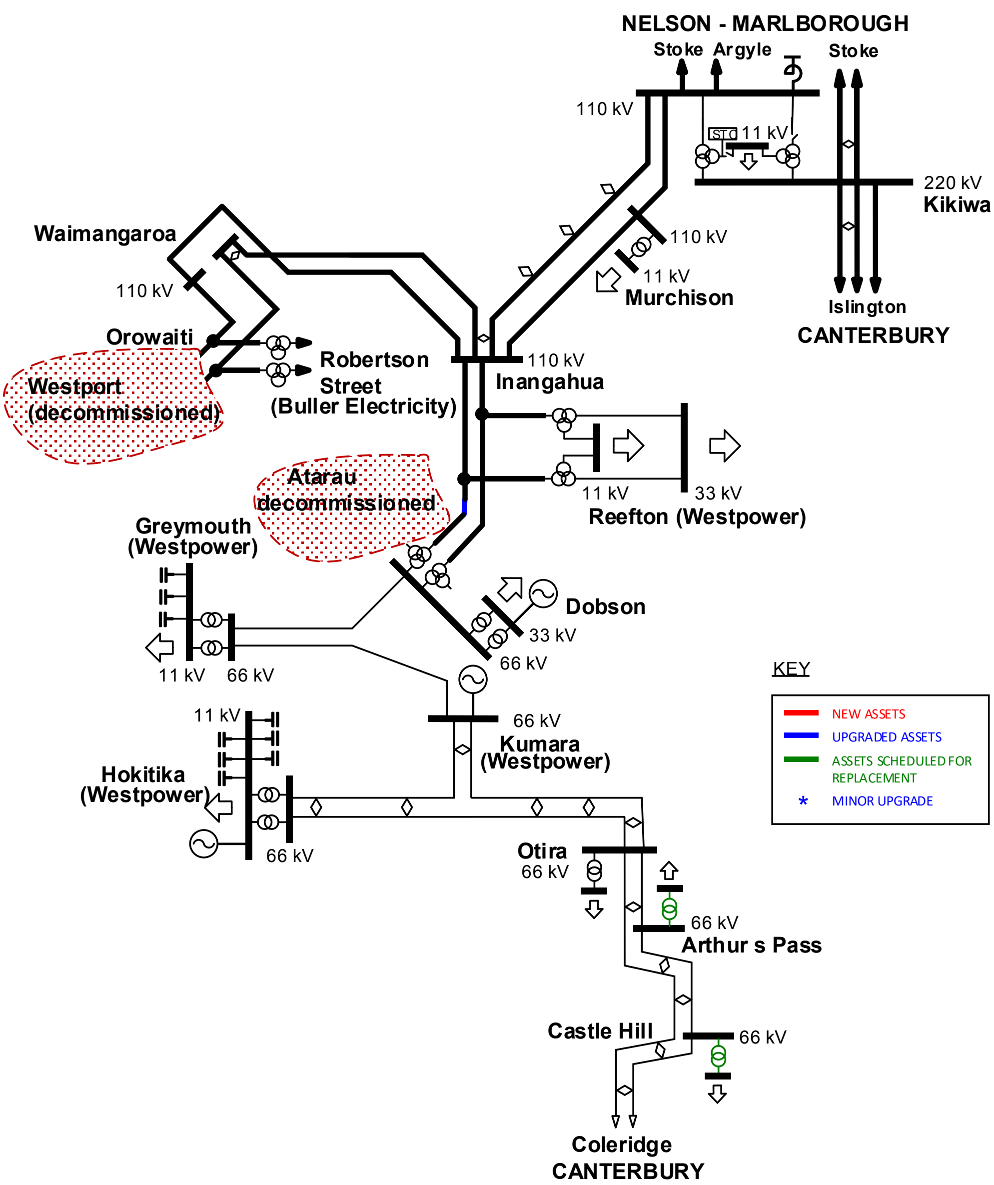
1. Kumara does not have significant water storage but is expected to supply an average of 4 MW during summer peaks.

16.4 Grid enhancement approach

16.4.1 Possible future West Coast transmission configuration

Figure 16-3 shows the possible configuration of West Coast transmission in 2034. New assets, upgraded assets and assets scheduled for replacement within the forecast period (based on potential enhancement approaches set out in the following sections) are shown.

Figure 16-3: Possible West Coast transmission configuration in 2034



16.4.2 Enhancement approach

Our approach seeks to ensure secure transmission into and within the West Coast region into the future. Through the E&D process we have assessed transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified issues and opportunities we take into account uncertainty in future demand, generation and technological developments.

Transmission issues likely requiring E&D or Customer-funded investments in the West Coast region over the next 10-15 years include:

Section number	Issue
16.4.2.1	Arthurs Pass and Castle Hill supply security and capacity
16.4.2.2	Orowaiti–Westport 110 kV transmission lines
16.4.2.3	West Coast high voltage

16.4.2.1 Arthurs Pass and Castle Hill supply security and capacity

Arthurs Pass and Castle Hill are each supplied by a single transformer, resulting in n security. The Castle Hill load is expected to exceed the capacity of its supply transformer from 2024.

There is a non-contracted spare transformer on site, allowing possible replacement within 8-14 hours following a unit failure (if the spare unit is available).

Enhancement approach:

- The Arthurs Pass and Castle Hill supply transformers are aged, but it is not economic to install replacement transformers. We have strategic spare transformers[4] to cover for failure of the Arthur's Pass, Castle Hill, Otira and Coleridge supply transformers. The customers have not requested a higher level of security for these sites.
- Future investment to supply the forecast step load increase at Castle Hill will be customer-driven.

16.4.2.2 Orowaiti–Westport 110 kV transmission lines

The Westport substation and associated 110 kV transmission lines (Orowaiti Tee[5]–Westport sections of the Inangahua–Westport A and Waimangaroa–Westport B lines) primarily supplied Holcim's Cape Foulwind cement plant in Westport. Holcim ceased operations at this site in 2016 and Buller Electricity has subsequently disconnected its supply at Westport. As a result, our transmission assets into Westport are not currently serving any customers.

Enhancement approach:

- The lines between Orowaiti and Westport will be dismantled in 2020.

Base E&D Capex investments

Project Name	Westport Future Needs (Stage 2)
Project description:	Remove transmission lines between Orowaiti and Westport
Project's state of completion	Proposed
OAA level completed:	AL 2d
Grid need date:	2020
Indicative cost [$ million]:	3
Part of the GEIR?	No

16.4.2.3 West Coast high voltage

Under light load conditions and high generation from the local embedded and grid connected generators, high voltages can occur on the West Coast 110 kV transmission system.

Currently the issue is managed operationally by switching some of the transmission circuits in the region out of service.

Enhancement approach:

- Investments (including reactor at Kikiwa) to resolve the upper South Island high voltage issues (refer to Chapter 6, Grid Backbone, South Island section) will also relieve the high voltage issue in the West Coast.

4 We own a large strategic spare transformer and have access to a smaller, easier-to-transport strategic spare transformer.

5 Orowaiti is the point where the 110 kV connection to Robertson Street (owned by Westpower) connects to the grid.

16.5 Asset capability and management

We have assessed the transmission capacity and reactive support requirements in the region for the next 15 years. When an issue or opportunity exists, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 16.4.2) have been developed to address issues or opportunities that require action within the forecast period and where investment is justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk-based asset replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

16.5.1 West Coast transmission system significant upcoming work

We integrate our capital project and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Table 16-3 lists the significant upcoming work[6] proposed for the West Coast region for the next 15 years that may significantly impact related system issues or connected parties.

Table 16-3: Proposed significant upcoming work on the West Coast transmission system

Description	Tentative year	E&D issue
66/22/11 kV Strategic spare for Arthur's Pass / Castle Hill / Otira / Coleridge	2019-2021	16.4.2.1
Kikiwa Reactor – Upper South Island high voltage management	2020	16.4.2.3
Orowaiti–Westport lines decommissioning	2020	16.4.2.2

16.5.2 West Coast transmission system asset feedback

The Asset Feedback Register does not include any E&D related items specific to the West Coast region.

16.5.3 Changes since the 2018 Transmission Planning Report

Table 16-4 lists the specific new issues and those that are no longer relevant within the forecast period (relative to our previous Transmission Planning Report).

Table 16-4: Changes since the 2018 TPR

Issues	Change
Hokitika transmission capacity	Removed. Reduced load forecast
Kikiwa Reactor	Added

16.5.4 West Coast transmission capability

This transmission capability section reports whether the Grid can reasonably be expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, forms part of the Grid Reliability Report (GRR).

6 Condition-based replacement of the asset is included in this list.

Table 16-5 summarises identified issues that may affect the West Coast region during the next 15 years. In each case we have detected a condition that would constrain the network capacity if action were not taken. Each issue is discussed in more detail below.

This transmission capability section reports whether the Grid can reasonably be expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, forms part of the Grid Reliability Report (GRR).

Table 16-5: West Coast region transmission issues – regional / site by grid exit point

Section number	**Issue**
Regional	
16.5.4.1	Kikiwa–Stoke circuit capacity
Site by grid exit point	
16.5.4.2	Arthur's Pass transmission and supply security
16.5.4.3	Castle Hill transmission and supply security
16.5.4.4	Kikiwa supply capacity and security
16.5.4.4	Murchison transmission and supply security
16.5.4.5	Otira supply security

16.5.4.1 Kikiwa–Stoke circuit capacity

Issue

There are two 220/110 kV interconnecting transformers (T1 and T2) at Kikiwa:

- Kikiwa–T1 is rated at 50 MVA and normally supplies local 11 kV load only
- Kikiwa–T2 is rated at 150 MVA and normally provides the 220/110 kV interconnection between the West Coast region and the rest of the National Grid. It also operates in parallel with the 220/110 kV, 150 MVA Stoke–T7 interconnecting transformer in the Nelson-Marlborough region due to the 110 kV network connections between them.

The loss of the Stoke interconnecting transformer would result in the Kikiwa interconnecting transformer supplying both the West Coast and Nelson-Marlborough loads. This may result in overload of the 110 kV Kikiwa–Stoke 3 circuit at the end of the forecast period in situations when there is:

- high load in the West Coast and Nelson-Marlborough regions, and
- low generation in the West Coast and Nelson-Marlborough regions.

What next?

We expect this issue to be manageable over the forecast period by temporarily reconfiguring the grid. No investments are planned to address this issue but we will continue to monitor the extent of the generation constraints and will initiate an investigation to look at investment options when the need arises.

16.5.4.2 Arthur's Pass transmission and supply security

Issue

The two circuits supplying Arthur's Pass only have line circuit breakers and protection at Coleridge and Otira. A fault on any section of the Coleridge–Castle Hill–Arthur's Pass–Otira circuits will result in a loss of supply to the Arthur's Pass load.

A single 66/11 kV, 3 MVA transformer (constrained to 1.1 MVA[7]) supplies load at Arthur's Pass, resulting in n security.

The peak load at Arthur's Pass is forecast to exceed the winter capacity of the transformer by 0.1 MW in 2030, increasing to 0.4 MW in 2034 (see Table 16-6).

[7] The capacity of the transformer capacity is limited to 1.1 MVA (summer/winter) due to a metering accuracy limit; with this limit resolved, the capacity will be 3 MVA (summer/winter).

Table 16-6: Arthur's Pass supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Arthur's Pass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4

What next?

We will remove the transformer (metering accuracy limit) constraint before the need capacity date. Our customer has not requested a higher level of security. See section 16.4.2.1 for our enhancement approach.

16.5.4.3 Castle Hill transmission and supply security

Issue

The two circuits supplying Castle Hill only have line circuit breakers and protection at Coleridge and Otira. A fault on any section of the Coleridge–Castle Hill–Arthur's Pass–Otira circuits will result in a loss of supply to the Castle Hill load.

A single 66/11 kV, 3.75 MVA[8] transformer supplies load at Castle Hill, resulting in n security.

Peak load at Castle Hill is forecast to exceed the winter capacity of the transformer by approximately 3.2 MW in 2024, increasing to approximately 4.1 MW in 2034 (see Table 16-7). This is driven by an expected step change in Castle Hill load in 2024.

Table 16-7: Castle Hill supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Castle Hill	0.0	0.0	0.0	0.0	0.0	3.2	3.5	3.7	4.0	4.0	4.0	4.1

What next?

In the short term we will remove metering limits to increase the transformer capacity. See section 16.4.2.1 for our enhancement approach.

16.5.4.4 Kikiwa supply capacity and security

Issue

The Kikiwa load is normally supplied from the 11 kV tertiary winding of the Kikiwa–T1 interconnecting transformer, normally energised from the 220 kV side only and with the 110 kV side open. There is a backup supply from the T2 interconnecting transformer. Transferring the load between T1 and T2 requires a short interruption of the load.

An outage of the 11 kV switchgear, fault limiting reactor or voltage regulator results in a total loss of supply, as these assets have n security.

The 20 MVA voltage regulator is limited to 3.4 MVA.[9] The peak load is forecast to exceed the capacity of the voltage regulator by 0.4 MW in 2019, increasing to approximately 1.6 MW in 2034 (see Table 16-8).

Table 16-8: Kikiwa supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Kikiwa	0.4	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.5	1.6

8 The capacity of the transformer is limited to 1.1 MVA due to a metering accuracy limits; once this is resolved the next limit of 3.5 MVA is caused by protection on Castle Hill CB 152

9 The capacity of the transformer is limited to 3.4 MVA due to protection; once this is resolved limits will be imposed by metering and cables.

What next?

The forecast overload is can be delt with operationally.

Our customer (Network Tasman) has not requested a higher level of security for the Kikiwa 11 kV load, so no investments are planned.

16.5.4.5 Murchison transmission and supply security

Issue

The load at Murchison is supplied by:

- two circuits, which do not have line protection at Murchison
- a single 110/11 kV, 10 MVA supply transformer.

A fault on either circuit or the supply transformer will result in a loss of supply to Murchison as it is on n security. Peak load is not forecast to exceed the transformer rating within the forecast period.

What next?

Our customer has not requested a higher level of security, so no investments are planned.

16.5.4.6 Otira supply security

Issue

Otira is supplied by a single 66/11 kV, 2.5 MVA transformer, resulting in n security. Peak load is not forecast to exceed the transformer rating within the forecast period.

What next?

Our customer (Westpower) has not requested a higher level of security. Therefore, we have not planned any investments to increase supply security at Otira.

16.5.5 West Coast bus security

This section discusses bus security issues identified for the West Coast region during the next 15 years, arising from the outage of a single bus section rated at 66 kV and above.

Bus outages disconnect more than one power system component (for example, other circuits, transformers, reactive support or generating units). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

16.5.5.1 Transmission bus security

Table 16-8 lists bus outages that cause voltage issues or a total loss of supply. Generation is included only if a bus outage disconnects the whole generation station or causes a widespread system impact. Supply bus outages, typically 11 kV and 33 kV, are not listed.

Note that the customers (Buller Networks, Westpower, Network Tasman, and Orion) have not requested a higher security level, and unless otherwise noted we do not propose to increase bus security.

Table 16-8: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Arthur's Pass 66 kV	Arthur's Pass Castle Hill	-	-	Note 1 Note 1
Castle Hill 66 kV	Arthur's Pass Castle Hill	-	-	Note 1 Note 1
Coleridge 66 kV	Arthur's Pass Castle Hill Coleridge	-	Dobson–Greymouth circuit overload	Note 2 Note 2 Note 2 Note 3
Dobson 66 kV	Dobson	-	-	Note 4
Kikiwa 110 kV	West Coast load	-	-	16.5.5.2
Kikiwa 220 kV	Kikiwa West Coast load	-	-	16.5.4.4 16.5.5.2
Inangahua 110 kV	Robertson Street(4) West Coast load	-	-	16.5.5.2 16.5.5.2
Murchison 110 kV	Murchison	-	-	16.5.4.5
Otira 66 kV	Arthur's Pass Castle Hill Otira	-	Dobson–Greymouth circuit overload	Note 2 Note 2 Note 2 -

1. There is no 66 kV circuit protection at Arthur's Pass or Castle Hill. Therefore, a bus fault at either grid exit point will trip the Coleridge–Castle Hill–Arthur's Pass–Otira circuit, causing a loss of supply at both Arthur's Pass and Castle Hill.
2. There is no bus protection at Coleridge or Otira, so bus faults remove all load at the substations. A bus fault would also remove the connected circuits from service, including the Coleridge–Castle Hill–Arthur's Pass–Otira circuit, causing a loss of supply at Castle Hill and Arthur's Pass.
3. A Coleridge 66 kV bus outage may also cause low voltage at Hororata (Canterbury region), which will cause the Hororata Automatic Under Voltage Load Shedding (AUVLS) to operate.
4. There is a single solid bus (with no bus protection) at Dobson, so bus faults will cause a loss of supply.
5. Robertson Street substation is owned by Buller Electricity; its point of connection to the grid is at Orowaiti, a point along the 110 kV Waimangaroa–Westport A and Inangahua–Westport B lines.

16.5.5.2 West Coast low voltage and transmission capacity

Issue

The West Coast 110 kV load is mainly supplied from the National Grid via two 110 kV Inangahua–Kikiwa circuits, with lower capacity 66 kV backup circuits from Coleridge. There are single 110 kV bus sections at Kikiwa and Inangahua, so a bus outage will disconnect both circuits. This will cause:

- low voltage issues at all 110 kV and 66 kV[10] buses
- transmission circuit capacity issues in the West Coast region.

The effect of the low voltages and circuit overloading is difficult to predict, as this will be heavily influenced by the local generation and load composition at the time of the outage. The low voltages may cause enough motor load to trip that the transmission system stays intact and continues to supply the remaining load. Otherwise, one or more circuits will trip, causing a total loss of supply to some or all of the grid exit points in the region.

In addition, towards the end of the forecast period, an outage of the Kikiwa 220 kV bus section (which disconnects the Kikiwa–T2 interconnecting transformer) will cause the transmission bus voltages in the region to fall below 0.90 pu.

10 There are wider voltage agreements (WVA) in place in Arthur's Pass, Coleridge, Castle Hill, Dobson, Greymouth, Hokitika, Kumara and Otira that allow the 66kV voltage to be between 0.9-1.1pu.

What next?

The customers (Westpower, Buller Networks, Network Tasman, and Orion) have not requested a higher security level. Therefore, we have not planned any investments to increase bus security at Kikiwa and Inangahua.

16.5.6 Other regional items of interest

16.5.6.1 Westport substation

Issue

In mid-2016 Holcim closed its Cape Foulwind cement operation which was supplied from the Westport substation. Buller Electricity served us a disconnection notice and has subsequently disconnected from the substation.

What next?

We are in the process of rationalising our unused assets at Westport. See section 16.4.2.2 for our approach.

16.5.6.2 West Coast high voltage

High voltage will occur on the 110 kV transmission system under light load conditions where there is also high generation from the local embedded and grid connected generators.

In addition, an outage of the Kikiwa–T2 interconnecting transformer[11] will also disconnect the Kikiwa STATCOM (which is connected to the transformer's tertiary winding) from the network resulting in reduced amount of available reactive power support. This will cause transmission bus voltages in the region to rise above 1.1 pu.

This issue can be managed operationally at present by switching out selected circuits. Increased levels of embedded generation (as a result of new generation investment) or a further reduction in load, will cause this issue to become more significant, potentially requiring more intensive operational control of the generating units' voltage set-points.

Investments to resolve the upper South Island high voltage issue, including the Kikiwa reactor (refer to Chapter 6, Grid Backbone, South Island section) will also relieve the high voltage issue on the West Coast.

16.5.7 West Coast generation proposals and opportunities

This section describes relevant regional issues that may affect generation proposals under investigation by developers and in the public domain, or other generation opportunities. We discuss the impact of committed generation projects on the grid backbone separately in Chapter 6.

We have received a number of requests regarding connection of generation to the transmission system in the West Coast region. Some of the larger proposals would require significant transmission upgrades to facilitate the export of generation from the region to the rest of the National Grid.

The maximum generation that can be connected depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

16.5.7.1 Maximum regional generation

Our estimates of the maximum generation that can be accommodated in the region assume light load conditions for the South Island and that existing generation in the West Coast region is operating at high levels (Kumara generating 10 MW, Amethyst generating 6 MW, and Kawatiri generating 4 MW).

For generation connected at the Kikiwa 220 kV bus, the maximum generation that can be injected under n-1 is approximately 760 MW. The constraint is the Islington–Kikiwa 2 or 3 circuit when either of the two circuits is out of service.

11 Kikiwa–T2 contingency.

For a West Coast load of 35 MW, the estimated maximum generation injection[12] at the two key buses is as follows:

- At the Kikiwa 110 kV bus, under normal operating conditions, a maximum of 260 MW, to avoid overloading the Kikiwa–T2 interconnecting transformer. The generation injection value decreases to approximately 135 MW for an outage of Kikiwa–T2 to avoid overloading the 110 kV Kikiwa–Stoke circuits.
- At the Inangahua 110 kV bus, under normal operating conditions, a maximum of approximately 165 MW, to avoid overloading the 110 kV Inangahua–Murchison–Kikiwa 1 circuit. The generation injection value decreases to approximately 105 MW for an outage of the 110 kV Inangahua–Kikiwa2 circuit to avoid overloading the Inangahua–Murchison–Kikiwa 1 circuit.

Generation connected to the West Coast 66 kV transmission network may be constrained by several low capacity 66 kV circuits.

16.5.7.2 Generation connected to the Inangahua to Westport spur

Two circuits form the Inangahua to Westport spur, with substations at Waimangaroa, Robertson Street and Westport (see Section 16.5.6.1). The Inangahua–Waimangaroa 1 circuit is rated at 101/111 MVA[13] (summer/winter) and the Inangahua–Waimangaroa 2 circuit is rated at 56/68 MVA (summer/winter).

Depending on the amount of generation connected to the spur, it may be necessary to:

- close the split at the Waimangaroa 110 kV bus
- install a special protection scheme to allow unconstrained pre-contingency generation injection
- increase the circuit capacity between Waimangaroa, Inangahua, and Kikiwa.

Generation connected to the spur would also form part of the maximum level of generation that can be connected within the region (refer section 16.5.7.1).

12 The generation injection at a bus applies if the generation is connected directly at the bus, or indirectly at other locations within the region. For example, generation at Dobson or along the Waimangaroa spur connects indirectly to the Inangahua bus and Kikiwa bus. Generation connected to the 110 kV system in the Nelson-Marlborough region (Chapter 15) also injects indirectly to the Kikiwa 110 kV bus.

13 The circuit is presently limited to 76/76 MVA by substation equipment.

17 Canterbury Regional Plan

17.1 Regional overview and transmission system

The Canterbury region is the South Island's major load centre. It includes the city of Christchurch together with smaller rural localities.

The existing transmission network for the Canterbury region is set out geographically in Figure 17-1 and schematically in Figure 17-2.

Figure 17-1: Canterbury region transmission network

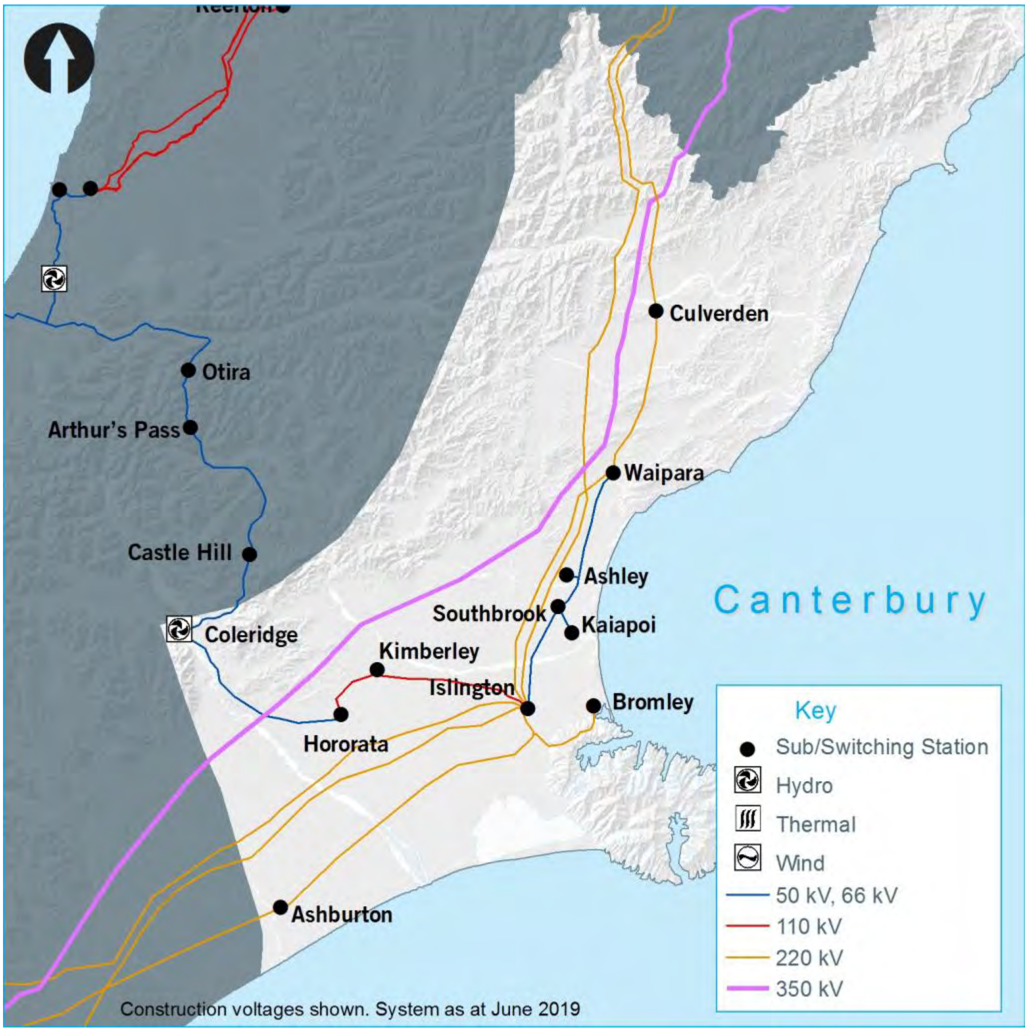
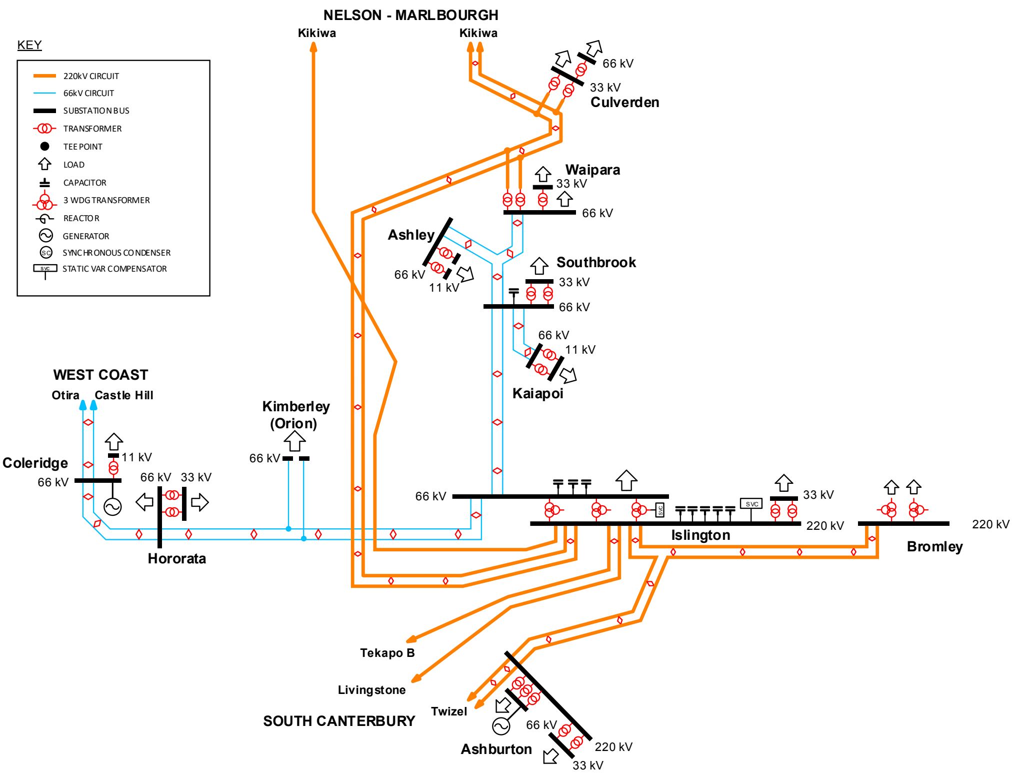


Figure 17-2: Canterbury region transmission schematic



17.1.1 Transmission into the region

The Canterbury region has some of the South Island's highest load densities, but relatively low levels of local generation. As a result, most of Canterbury's electricity demand is supplied by generation located in the South Canterbury region, via four 220 kV transmission circuits – three from Twizel and one from Livingstone. This transmission is essential for power flow into Canterbury and onwards to the Nelson-Marlborough and West Coast regions of the South Island.

17.1.2 Transmission within the region

Within the Canterbury region, the transmission network comprises 220 kV and 66 kV transmission circuits, with five 220/66 kV interconnecting transformers – three at Islington and two at Waipara.

Reactive support for the region (and grid backbone) is provided by:

- static var compensators at Islington
- capacitor banks at Islington, Bromley and Southbrook.

17.2 Canterbury demand

The Canterbury regional peak demand[1] is forecast to grow by an average of 0.8 per cent per annum over the next 15 years, from 792 MW in 2019 to 897 MW in 2034. This is lower than the national average growth rate of 1.2 per cent per annum.

Table 17-1 sets out forecast peak demand (prudent growth[2]) at each grid exit point over the forecast period.

1 For discussion on demand forecasting see Chapter 3, section 3.1.

2 Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

Table 17-1: Forecast annual peak demand (MW) at Canterbury grid exit points to 2034

Grid exit point	Power factor	Peak demand (MW) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Ashburton 66 kV1	0.95	222	223	226	228	231	234	239	240	242	245	247	258
Ashley (Main Power)	0.88	9	9	10	9	9	9	9	9	10	10	10	10
Ashley (Daikon)	0.92	11	11	11	11	11	11	11	11	11	11	11	11
Bromley 66 kV2	0.97	152	153	154	154	160	185	184	196	198	201	203	198
Coleridge	0.99	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5
Culverden 33 kV	0.95	21	21	22	22	22	22	23	23	23	23	23	24
Culverden 66 kV	0.93	7	7	7	8	8	8	8	8	8	8	8	10
Hororata 33 kV	0.96	25	26	26	26	27	27	28	28	29	29	29	34
Hororata 66 kV	0.96	20	20	20	20	21	21	21	21	21	21	21	22
Islington 33 kV	0.98	78	78	78	78	81	80	81	80	80	80	80	75
Islington 66 kV2	1	462	465	474	478	486	461	474	462	469	471	477	478
Kaiapoi	1	34	35	36	30	32	32	34	34	35	36	36	36
Kimberley	0.97	20	20	20	20	20	20	21	21	21	21	21	24
Southbrook 33 kV3	0.97	31	31	32	0	0	0	0	0	0	0	0	0
Southbrook 66 kV3	0.97	37	37	38	62	66	67	69	70	71	73	74	79
Waipara 33 kV4	0.96	10	10	10	9	9	9	9	9	9	10	10	13
Waipara 66 kV	0.94	10	10	10	11	11	11	11	11	12	12	12	13

1. Ashburton 33 kV was decommissioned with load being transferred to Ashburton 66 kV since the last TPR.
2. Orion has advised they plan to shift 25 MW of load from Islington to Bromley in 2024.
3. Southbrook 33 kV will be decommissioned in 2022 with load being transferred to the Southbrook 66 kV bus.
4. Forecast load at Waipara decreases until 2028 at which point it begins increasing again. This is due to our underlying assumptions for uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid during peak load periods.

17.3 Canterbury generation

The Canterbury region's generation capacity is currently 73 MW. Table 17-2 lists the generation forecast for each grid injection point for the forecast period. This includes all known and committed generation stations including those embedded in local lines company's networks (Electricity Ashburton, Orion or MainPower).[3] Further generation may be developed during the period but is not sufficiently advanced to be included in our forecasts. (Refer to section 17.5.7 for more information on potential new generation).

Table 17-2: Forecast annual generation capacity (MW) at Canterbury grid injection points to 2034 (existing and committed generation)

Grid injection point (location/name if embedded)	Generation capacity (MW) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Ashburton (Highbank)	25	25	25	25	25	25	25	25	25	25	25	25
Ashburton (Montalto)	2	2	2	2	2	2	2	2	2	2	2	2
Bromley (City Waste)	3	3	3	3	3	3	3	3	3	3	3	3
Bromley (QE2 diesel)1	4	0	0	0	0	0	0	0	0	0	0	0
Coleridge	39	39	39	39	39	39	39	39	39	39	39	39
Islington (QE2 diesel)1	0	4	4	4	4	4	4	4	4	4	4	4

1. The customer has advised that QE2 diesel generation will be shifted to the Islington 66 kV GXP.

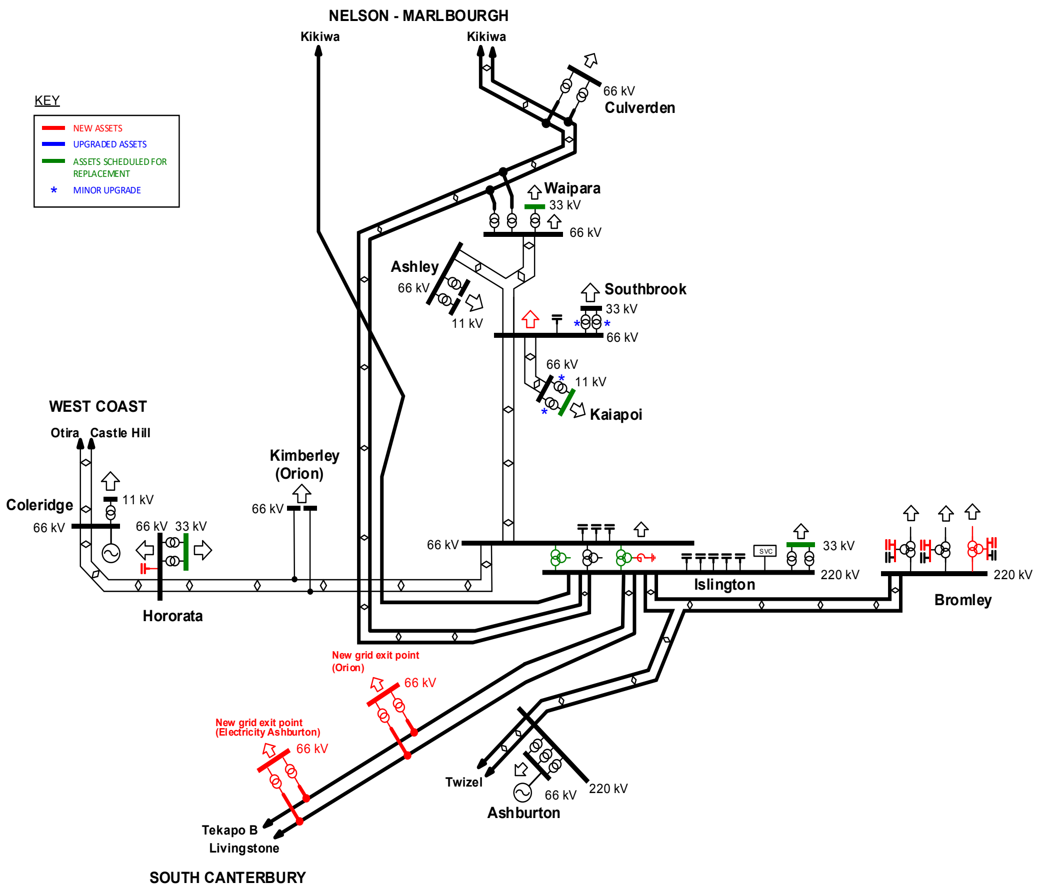
3 Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

17.4 Grid enhancement approach

17.4.1 Possible future Canterbury transmission configuration

Figure 17-3 shows the possible configuration of Canterbury transmission in 2034. New assets, upgraded assets, and assets scheduled for replacement within the forecast period (based on potential enhancement approaches set out in the following sections) are shown.

Figure 17-3: Possible Canterbury transmission configuration in 2034



17.4.2 Enhancement approach

Our approach seeks to ensure secure transmission into and within the Canterbury region into the future. Through the E&D process we assess transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified issues and opportunities we take into account uncertainty in future demand, generation and technological developments.

There are future opportunities to increase the capacity of the 220 kV grid backbone into the Canterbury region. The issues and our enhancement approach for the 220 kV grid backbone is discussed in Chapter 6.

Transmission issues likely requiring E&D or Customer-funded investments in Canterbury over the next 10-15 years are:

Section number	Issue
Regional	
17.4.2.1	Christchurch supply capacity
Site by grid exit point	
17.4.2.2	Ashburton supply capacity
17.4.2.3	Hororata and Kimberley low voltage and transmission capacity
17.4.2.4	Kaiapoi supply capacity

17.4.2.1 Christchurch supply capacity

Christchurch load is supplied primarily via the Bromley and Islington grid exit points. The customer, Orion, can transfer load between the two sites and therefore the sites should be considered together when considering security of supply.

Two 220/66/11 kV transformers currently supply Bromley's 66 kV load.

Three 220/66 kV interconnecting transformers at Islington currently supply a significant proportion of Canterbury's load (including Islington 66 kV, Southbrook, Kaiapoi, Kimberley and Hororata). Orion is planning to transfer some load from Islington to Bromley in 2024.

Depending on Orion's network configuration, either Bromley or Islington might have n-1 security pre-contingency, with the other sitting on n security under high load conditions.

For example, if Islington is at n-1 security pre-contingency with Bromley at n security, then a contingency at Bromley will cause a brief loss of supply. In this event, Orion will shift load to Islington taking it to n security post-contingency. There will then be sufficient released capacity to restore Bromley at n security. The inverse arrangement is also possible with Bromley at n-1 pre-contingency and Islington at n.

The load at Islington is forecast to exceed the n-1 capacity of the Islington interconnecting transformers in 2030.

Enhancement approach:

- We anticipate the transformer n-1 overloading issue will initially be resolved by shifting load between Bromley and Islington via Orion's network.
- Closer to the need date, we will carry out an investigation to look at the need to increase the 220/66 kV supply transformer capacity at Bromley. A possible investment option is to install a third 220/66 kV supply transformer at Bromley.
- Orion is also planning a new 220/66 kV grid exit point in the Norwood area south of Christchurch, which has the potential to relieve these transformer constraints. The new grid exit point may connect to the 220 kV Islington–Livingstone circuit or to one of the Ashburton–Islington/Ashburton–Bromley circuits. We will work with Orion to determine the investment approach if/when Orion decides to proceed with this work.

Customer investments

Project Name	Bromley 220/66 kV supply transformer capacity
Project description:	Install a third 220/66 kV supply transformer at Bromley
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	To be determined in discussion with customer
Indicative cost [$ million]:	7.7
Part of the GEIR?	No

Project Name	New GXP Norwood area
Project description:	New 220/66kV south of Christchurch
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	To be determined in discussion with customer
Indicative cost [$ million]:	Scope dependant
Part of the GEIR?	No

17.4.2.2 Ashburton supply capacity

Three 220/66 kV transformers supply Ashburton's 66 kV load. Electricity Ashburton Networks (EA Networks) has indicated it may develop a second, separate 66 kV grid exit point (Rakaia) on a different site to the west of Ashburton to diversify its risk and lower 66 kV sub-transmission losses when the load exceeds 180 MW or 190 MVA. Some of the Ashburton load would be transferred to the new Rakaia grid exit point.

The connection configuration for the potential new grid exit point is uncertain as yet. It is likely to be supplied from one or both of the 220 kV Islington–Livingstone and Islington–Tekapo B circuits.

Enhancement approach:

- The proposed development of a new Customer-funded Rakaia grid exit point would increase security of supply to Ashburton. Investment timing would be determined by EA Networks, but is expected to be at least ten years away.

Customer investments

Project Name	New grid exit point for EA networks
Project description:	Develop a new Rakaia 220/66 kV grid exit point for EA networks
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2023
Indicative cost [$ million]:	25
Part of the GEIR?	No

17.4.2.3 Hororata and Kimberley low voltage and transmission capacity

Hororata and Kimberley substations are supplied from:

- Islington by two 66 kV Hororata–Kimberley–Islington circuits, each rated at 59/62 MVA (summer/winter)
- Coleridge and the West Coast by two 66 kV Coleridge–Hororata circuits, each rated at 30/37 MVA (summer/winter).

A wider voltage agreement at Hororata and Kimberley 66 kV buses allows a post contingent operating voltage band of between 0.9 and 1.05 pu.

With low Coleridge generation (three of the five units in service), and high load at Hororata and Kimberley, a Hororata–Kimberley–Islington circuit outage may cause voltages on the Hororata and Kimberley 66 kV buses to drop below 0.9 pu.

In addition, the combined load may exceed the n-1 thermal capacity of the Hororata–Kimberley–Islington circuits.

Towards the end of the forecast period, low generation at Coleridge may result in pre-contingent undervoltage (<0.95 pu) at Hororata and Kimberley.

Enhancement approach:

- There is an automatic under voltage load shedding scheme at Hororata to manage the voltage quality (post contingency) at Hororata and Kimberley in the short-term. As the load limit for voltage is lower than the load limit for thermal issues on the Hororata–Kimberley–Islington circuits, the scheme's post contingency action will also resolve potential thermal capacity constraints.
- In the medium term, possibly within the next 5-7 years, the low voltage and thermal issues may be resolved by installing capacitors at Hororata. The timing of investments will be determined in discussion with the customer (Orion), taking into consideration possible increases in dairy and irrigation loads in the area.

Base E&D capex investments

Project Name	Hororata and Kimberley voltage quality
Project description:	Install 3x 9 Mvar capacitors at Hororata (assumed based on switching voltage step limitations)
Project's state of completion	Possible
OAA level completed:	AL 2p
Grid need date:	To be determined in discussion with customer
Indicative cost [$ million]:	4
Part of the GEIR?	No

17.4.2.4 Kaiapoi supply capacity

Two 66/11 kV transformers supply the 11 kV load at Kaiapoi. Peak load at Kaiapoi is forecast to exceed the n-1 capacity of the supply transformers from 2023.

Enhancement approach:

- Planned Kaiapoi 11 kV switchgear replacement (base capex replacement and refurbishment) will resolve the transformers' branch component limits (circuit breaker and LV cable, protection equipment), which will solve the overloading issue beyond the forecast period.

17.5 Asset capability and management

We have assessed transmission capacity and reactive support requirements in the region over the next 15 years. When an issue or opportunity is likely to arise, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 0) have been developed to address issues or opportunities that require action within the forecast period and where investment is justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk based replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

17.5.1 Canterbury transmission system significant upcoming work

We integrate our capital projects and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Table 17-3 lists the significant upcoming work[4] proposed for the Canterbury region during the next 15 years that may significantly impact related system issues or connected parties.

Table 17-3: Proposed significant upcoming work for the Canterbury transmission system

Description	Tentative year	E&D issue
Kaiapoi switchgear replacement	2019-2020	17.5.4.8

17.5.2 Canterbury asset feedback

The Asset Feedback Register includes the following entries related to E&D that are specific to the Canterbury region:

- Islington–T8 Hot Standby
- To review the need for Islington 66 kV capacitor bank C15
- To review the need for Islington SVC3.

The last two entries relate to assets installed in the Canterbury region. However, as their impacts are largely on the South Island grid backbone, our progress with these entries is discussed in Chapter 6 (Grid Backbone).

17.5.2.1 Islington–T8 Hot Standby

Issue

If one of the three Islington 220/66 kV interconnecting transformers is out of service, the other two may not be able to carry peak load in the event of the loss of Bromley 66 kV substation.

What's next?

We are currently undertaking an investigation to determine the most cost effective solution to address this issue.

17.5.3 Changes since the 2018 Transmission Planning Report

Table 17-4 lists the specific new issues and those that are no longer relevant within the forecast period (relative to our previous Transmission Planning Report).

Table 17-4: Changes since the 2018 TPR

Issues	Change
Ashburton transmission bus security	Removed. Ashburton 220/33 kV supply decommissioned
Islington 66 kV bus outage	Added
Waipara 66 kV bus outage	Added

17.5.4 Canterbury transmission capability

This transmission capability section reports whether the Grid can reasonably be expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, forms part of the Grid Reliability Report (GRR).

Table 17-5 summarises identified issues that may affect the Canterbury region during the next 15 years. In each case we have detected a condition that would constrain the network capacity if action were not taken. Each issue is discussed in more detail below.

[4] Condition-based replacement of the asset is included in this list.

This transmission capability section reports whether the Grid can reasonably be expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, forms part of the Grid Reliability Report (GRR).

Table 17-5: Canterbury region transmission issues – site by grid exit point

Section number	Issue
Regional	
17.5.4.1	Islington interconnecting transformer capacity
Site by grid exit point	
17.5.4.2	Ashburton supply transformer capacity
17.5.4.3	Coleridge supply transformer security
17.5.4.4	Culverden supply transformer security
17.5.4.5	Culverden supply transformer capacity
17.5.4.6	Hororata and Kimberley low voltage and transmission capacity
17.5.4.7	Hororata supply transformer capacity
17.5.4.8	Kaiapoi supply transformer capacity
17.5.4.9	Waipara supply transformer security

17.5.4.1 Islington interconnecting transformer capacity

Issue

Three 220/66 kV interconnecting transformers at Islington supply a significant proportion of Canterbury's load (including Islington 66 kV, Southbrook, Kaiapoi, Kimberley and Hororata). The transformers provide:

- nominal installed capacity of 650 MVA
- n-1 capacity of 504/532 MVA (summer/winter).

An outage of interconnecting transformer T6 during peak load will cause the remaining transformers to exceed their n-1 winter capacity by approximately 2 MW in 2030 increasing to approximately 6 MW in 2033 (not shown in Table 17-6).

The forecast n-1 overloading reduces to about 4 MW by 2034 (see Table 17-6) as a result of declining peak load. This is due to our underlying demand forecast assumptions for uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid during peak load periods.

Table 17-6: Islington interconnecting transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Islington	0	0	0	0	0	0	0	0	0	0	0	4

What next?

We anticipate this issue will initially be managed by load shifting between Bromley and Islington within Orion's network. Refer to section 17.4.2.1 for our enhancement approach to address capacity issues in Christchurch.

17.5.4.2 Ashburton supply transformer capacity

Issue

Three 220/66 kV transformers supply load at Ashburton, providing:

- total nominal installed capacity of 340 MVA
- n-1 capacity of 229/238 MVA (summer/winter).

Peak load at Ashburton is forecast to exceed the n-1 summer capacity of the supply transformers by approximately 3 MW in 2023, increasing to approximately 30 MW in 2034 (see Table 17-7).

Table 17-7: Ashburton supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Ashburton 220/66 kV	0	0	0	0	3	6	10	11	14	16	18	30

What next?

The issue can be managed operationally in the medium-term. Longer-term, the proposed development of a new Rakaia grid exit point would increase security of supply to Ashburton. Investment timing would be determined by EA Networks. Refer to section 17.4.2.2.

17.5.4.3 Coleridge supply transformer security

Issue

A single 66/11 kV, 2.5 MVA three phase supply transformer supplies the load at Coleridge, resulting in n security.

What next?

There is an off-site spare transformer available. Transportation to site and installation is likely to take several days during which time supply will be unavailable. Orion has not requested a higher level of security, so no investment is planned to address this.

17.5.4.4 Culverden supply transformer security

Issue

A single 33/66 kV, 20 MVA three phase supply transformer supplies the 66 kV load at Culverden, resulting in n security.

What next?

The issue of having only n security can be managed operationally. MainPower has not requested a higher level of security, therefore no investment is planned to address this.

17.5.4.5 Culverden supply transformer capacity

Issue

Two 220/33 kV transformers supply load at Culverden, providing:

- total nominal installed capacity of 40 MVA
- n-1 capacity of 30/32 MVA (summer/winter).

Peak load at Culverden is forecast to exceed the n-1 summer capacity of the supply transformers by approximately 0.5 MW in 2023, increasing to approximately 5 MW in 2034 (see Table 17-8).

Table 17-8: Ashburton supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Culverden 220/33 kV	0	0	0	0	0.5	1	1	2	2	2	3	5

What next?

The supply transformer capacity issue can be managed operationally. Future investment will be customer driven.

17.5.4.6 Hororata and Kimberley low voltage and transmission capacity

Issue

Hororata and Kimberley substations are supplied from Islington and Coleridge/West Coast by:

- two 66 kV Hororata–Kimberley–Islington circuits, each rated at 59/62 MVA (summer/winter)
- two 66 kV Coleridge–Hororata circuits, each rated at 30/37 MVA (summer/winter).

A wider voltage agreement at the Hororata and Kimberley 66 kV buses allows a post contingent operating voltage band of between 0.9 and 1.05 pu.

With low Coleridge generation (three of the five units in service), and high load at Hororata and Kimberley, a Hororata–Kimberley–Islington circuit outage may cause voltages on the Hororata and Kimberley 66 kV buses to drop below 0.9 pu.

In addition:

- the combined load may exceed the n-1 thermal capacity of the Hororata–Kimberley–Islington circuits. However, the low voltage issue precedes this thermal issue
- the Hororata 66 kV bus voltage may drop below 0.95 pu pre-contingency from around 2033 under low generation, this is not allowed under the wider voltage agreement which only covers the post contingent voltage band.
- an Hororata–Kimberley– Islington circuit outage may cause voltage instability from around 2026.

What next?

Refer to section 17.4.2.1 for our enhancement approach.

17.5.4.7 Hororata supply transformer capacity

Issue

Two 66/33 kV transformers supply Hororata 33 kV load, providing:

- total nominal capacity of 34 MVA
- n-1 capacity of 23/23 MVA[5] (summer/winter).

Peak load on the Hororata 33 kV bus is forecast to exceed the n-1 summer capacity of the transformers by approximately 6 MW in 2019, increasing to approximately 15 MW in 2034 as shown in Table 17-9.

Table 17-9: Hororata supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Hororata 33 kV	6	6	7	7	8	8	9	9	10	10	10	15

What next?

The supply transformer capacity issue can be managed operationally. Future investment will be customer driven.

17.5.4.8 Kaiapoi supply transformer capacity

Issue

Two 66/11 kV transformers supply load at Kaiapoi, providing:

- total nominal installed capacity of 80 MVA
- n-1 capacity of 38/38[6] MVA (summer/winter).

Peak load at Kaiapoi is forecast to exceed the n-1 winter capacity of the supply transformers by approximately 0.5 MW in 2027, increasing to approximately 2 MW in 2034 (see Table 17-10).

[5] The transformers' capacity is limited by bus section rating. With this limit resolved, the n-1 capacity will be 23/24 MVA (summer/winter).

[6] The transformers' capacity is limited by a circuit breaker and LV cable, followed by the protection equipment limit (41 MVA). With these limits resolved, the n-1 capacity will be 49/51 MVA (summer/winter).

Table 17-10: Kaiapoi supply transformer overload forecast

Circuit/grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Kaiapoi 11 kV	0	0	0	0	0.5	1	1	1	1	1	1	2

What next?

Resolving all transformers' branch component limits (circuit breaker and LV cable, protection equipment) will solve the overloading issue beyond the forecast period. Refer to section 17.4.2.4 for our enhancement approach.

17.5.4.9 Waipara supply transformer security

Issue

A single 66/33 kV, 16 MVA transformer supplies load at Waipara resulting in n security.

What next?

MainPower is able to transfer load from the 33 kV to 66 kV network, and has indicated its plans to continue with the present level of security. No investment is planned to increase security.

17.5.5 Canterbury bus security

This section presents issues arising from the outage of a single bus section rated at 66 kV and above.

Bus outages disconnect more than one power system component (for example, other circuits, transformers, reactive support or generators). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

17.5.5.1 Transmission bus security

Table 17-11 lists bus outages that cause voltage issues or total loss of supply. Generation is included only if a bus outage disconnects the whole generation station or results in a widespread system impact. Supply bus outages, typically 11 kV and 33 kV, are not listed.

Note that the customers at these grid exit points (Orion, Electricity Ashburton, MainPower, and Trustpower) have not requested a higher level of security.

Table 17-11: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Ashburton 220 kV	-	-	Upper South Island voltage stability	Chapter 6
Ashley 66 kV	Ashley	-	-	Note 1
Coleridge 66 kV	Coleridge	Coleridge	-	Note 1
Hororata 66 kV	Hororata	-	-	Note 2
Islington 220 kV	-	-	Upper South Island voltage stability	Chapter 6
Islington 66 kV	-	-	North Canterbury 66 kV line capacity	17.5.5.3
Kaiapoi 66 kV	Kaiapoi	-	-	Note 1
Waipara 66 kV	Waipara	-	North Canterbury 66 kV line capacity	17.5.5.2 Note 1

1. Ashley, Coleridge, Kaiapoi and Waipara have no 66 kV bus zone protection, hence bus faults will be cleared by the connected circuits' far end line protection, causing a loss of supply.
2. Hororata has a single bus section with bus zone protection, so a bus fault will cause a loss of supply.

17.5.5.2 Waipara bus security

Issue

The North Canterbury 66 kV network is supplied via 220/66 kV interconnectors at Waipara and Islington. An outage of the Waipara 66 kV bus will disconnect Waipara's connection to the region so that all load must be supplied from Islington. At peak load this will overload the Islington–Southbrook circuits supplying the region, from 2031 onwards.

What next?

In the short term, this issue can be managed operationally. Options will be discussed with the customer closer to the need date.

17.5.5.3 Islington 66 kV bus security

Issue

The North Canterbury 66 kV network is supplied via 220/66 kV interconnectors at Waipara and Islington. An outage of one of the Islington 66 kV bus sections will disconnect one of the Islington–Southbrook circuits and one of the shunt capacitors on the Islington 66 kV bus. At peak load this will overload the remaining Islington–Southbrook circuit as well as the Ashley–Waipara circuit and the Southbrook–Waipara circuit, from 2032.

What next?

In the short term, this issue can be managed operationally. Options will be discussed with the customer closer to the need date.

17.5.6 Other regional items of interest

17.5.6.1 Christchurch supply security during maintenance

Issue

The three 220/66 kV interconnecting transformers at Islington supply most of the load in the Christchurch region.

An outage of one of the 220/66 kV transformers will place many grid exit points in the region on n security. Such an outage may require load shifting to Bromley during periods of high load and minimal generation at Coleridge. Depending on the time taken to restore n-1 security on the system, we would consider putting the system spare 220/66 kV, 250 MVA transformer into service.

What next?

No investments are planned to directly resolve this issue. However, it will be considered as part of the Christchurch supply capacity investigation (refer to section 17.5.4.1).

17.5.7 Canterbury generation proposals and opportunities

This section describes relevant regional issues that may affect generation proposals under investigation by developers and in the public domain, or other generation opportunities. We discuss the impact of committed generation projects on the grid backbone separately in Chapter 6.

The maximum generation that can be connected in a particular location depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

17.5.7.1 Maximum regional generation

High load density areas coupled with relatively low levels of local generation in Canterbury mean there is no practical limit to the amount of generation that can be connected within the region. However, there will be limits to the generation that can be connected at a particular substation or along an existing line due to the rating of existing circuits.

17.5.7.2 Mount Cass wind generation station

There is a proposal by MainPower to install an approximately 60 MW wind generation station at Mount Cass. This station could be connected to the Waipara 66 kV bus without any restrictions when all transmission assets are in service. Generation greater than 60 MW will require automatic controls to limit it following some outages to prevent circuits overloading.

17.5.7.3 Inland Canterbury wind sites

Wind maps show that inland Canterbury has good wind resources for generation, but most of the area is distant from significant transmission.

There are two 66 kV Hororata–Islington circuits rated at 60/63 MVA, and two Coleridge–Hororata circuits rated at 30/37 MVA[7] (summer/winter). It is possible to connect over 85 MW of generation directly to the Hororata 66 kV bus, or up to approximately the rating of a single circuit if the generation is connected onto a circuit.

Hundreds of megawatts of generation can be connected to the 220 kV Islington–Kikiwa circuits north of Christchurch. The limit depends on the connection point location and the number of circuits it is connected to.

There is some spare capacity south of Christchurch to connect generation into the 220 kV Islington–Livingstone circuit, the primary purpose of which is to supply loads in and north of Christchurch. However, connecting more than 400 MW[8] of generation to this circuit will overload it, reducing the amount of load that can be supplied.

7 The rating could be increased to 50/55 MVA by reconductoring a section of the Coleridge–Hororata circuits, if required.

8 More generation could be connected if the Rangitata to Islington section of the Islington–Livingston circuit was thermally upgraded.

18 South Canterbury Regional Plan

18.1 Regional overview and transmission system

The South Canterbury region includes a mix of significant provincial towns (Timaru and Oamaru) and smaller rural localities.

The region has one of the highest demand growth rates nationally, supported by the growing dairy industry (irrigation loads and dairy factories). The region also hosts the bulk of the Island's hydro generation and the southern end of the HVDC inter-island link.

The existing transmission network for the South Canterbury region is set out geographically in Figure 18-1 and schematically in Figure 18-2

Figure 18-1: South Canterbury region transmission

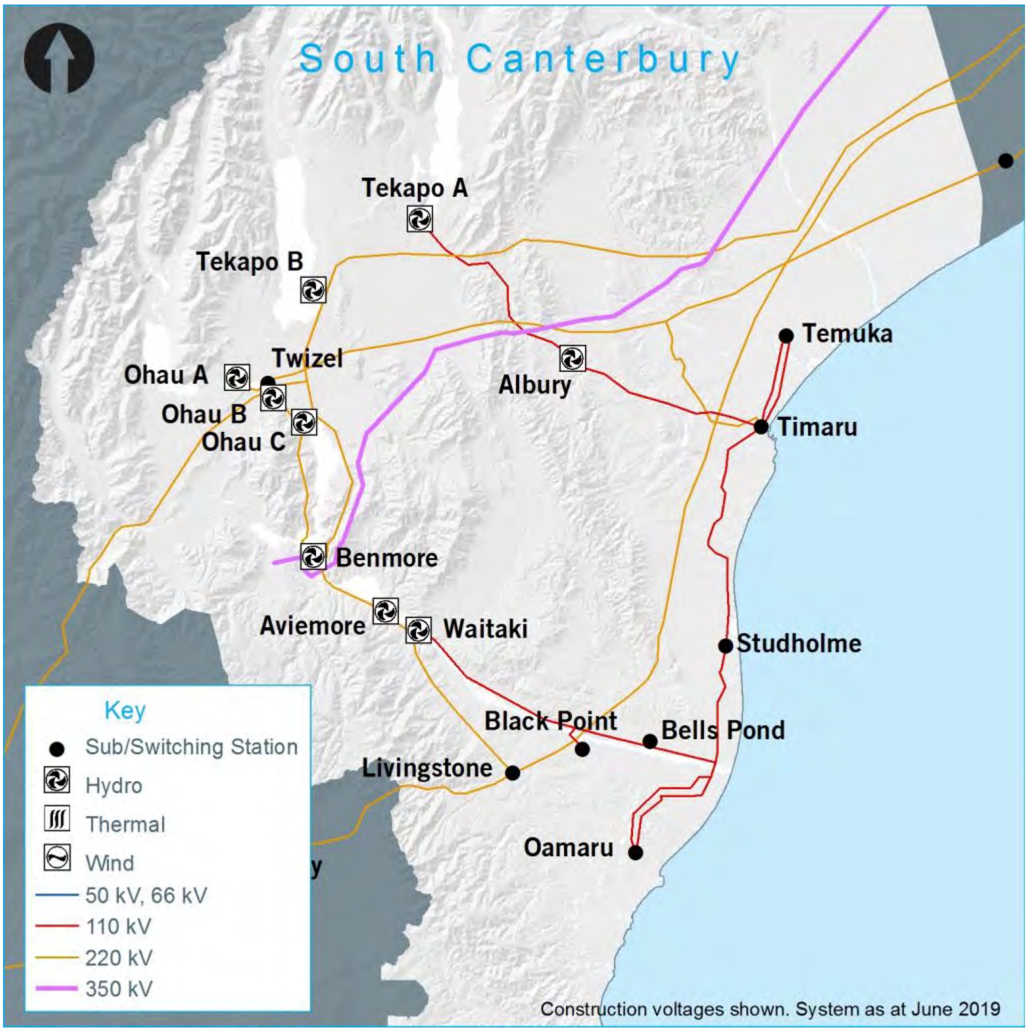
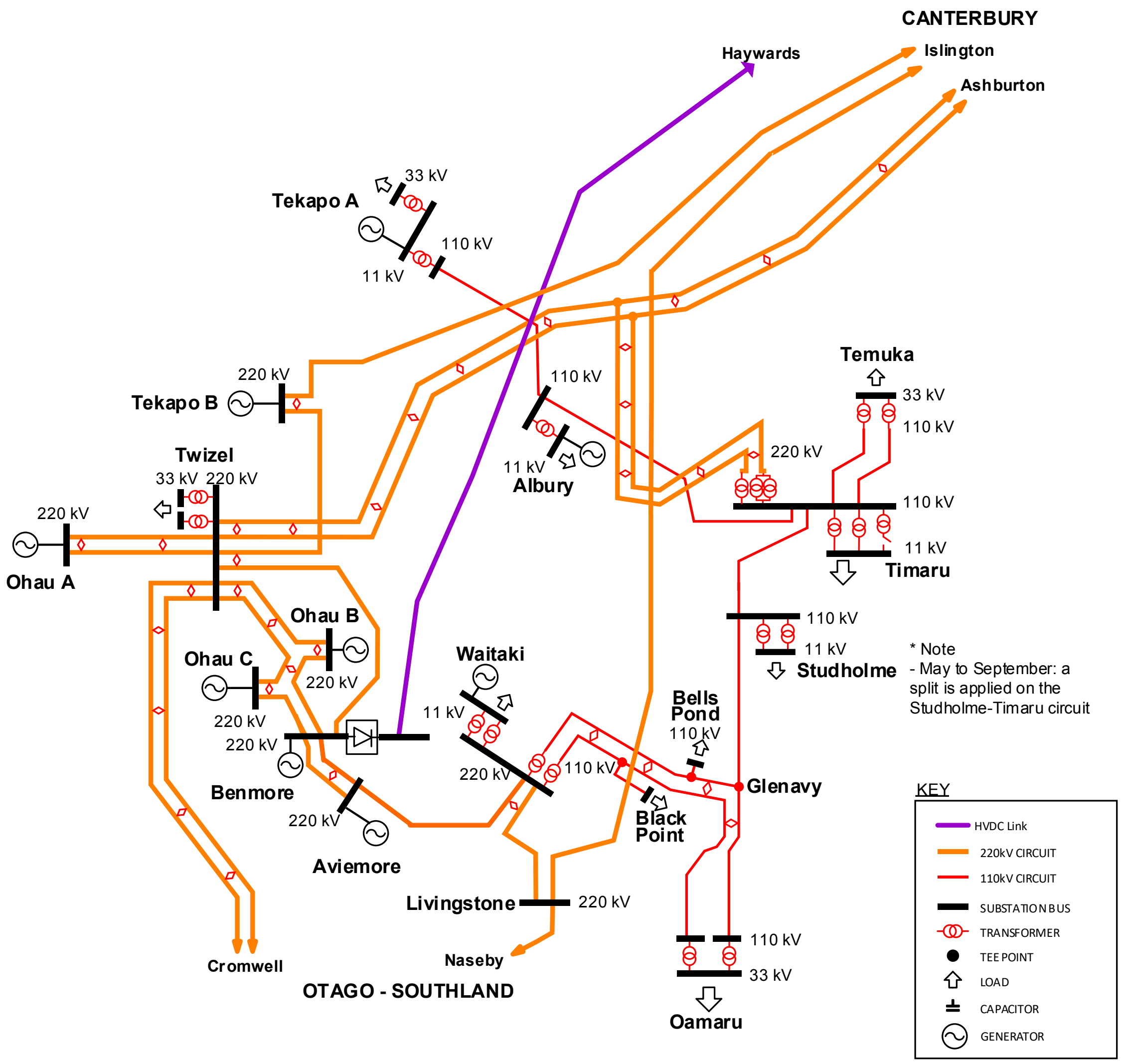


Figure 18-2: South Canterbury region transmission schematic



18.1.1 Transmission into the region

Several major 220 kV lines serve the South Canterbury region, connecting it to Christchurch and the upper South Island to the north, as well as the Otago-Southland region to the south.

This region contributes a major portion of the generation in the South Island, feeding the 220 kV transmission network from the Tekapo, Ohau, and Waitaki Valley generation stations. Transmission capacity requirements are driven by generation capacity (as generation in the region far exceeds local demand) and the need to transfer power the length of the South Island and into the North Island. In dry periods with low generation south of Clyde, there may also be a need to transfer power southwards to the Otago-Southland region (see Chapter 6 for transmission issues on the 220 kV grid backbone).

18.1.2 Transmission within the region

The South Canterbury regional transmission network comprises 220 kV and 110 kV transmission circuits, with interconnecting transformers at Timaru and Waitaki. Almost all loads in the South Canterbury region are supplied via the 110 kV transmission network, which runs up the east coast from Oamaru to Temuka.

The 110 kV transmission network is split at Studholme from May to September.[1] The split creates two radial feeds incorporating the:

1 The split reduces system losses by avoiding through transmission on the 110 kV network between Waitaki and Timaru, forcing northward power to flow over the more efficient 220 kV network.

- Timaru 220/110 kV interconnecting transformers supplying Timaru, Albury, Tekapo A and Temuka
- Waitaki 220/110 kV interconnecting transformers supplying Bells Pond, Black Point, Oamaru and Studholme.

Much of the 110 kV transmission network is nearing capacity. This is mainly due to growth associated with the dairy industry, including dairy processing expansion and irrigation. Supplying existing and committed new load via the 110 kV network is currently achievable, but will become increasingly difficult to manage if potential load in the area is developed.

Multiple special protection schemes are utilised on the 110 kV transmission system to protect assets from overloading post-contingency. These include both automatic grid reconfiguration and load shedding schemes.

18.2 South Canterbury demand

The South Canterbury regional peak demand[2] is forecast to grow by an average of 2.2 per cent per annum over the next 15 years, from 217 MW in 2019 to 303 MW in 2034. This exceeds the national average of 1.2 per cent per annum. The highest recent peak load for the region, approximately 200 MW, occurred in December 2017.

Table 18-1 sets out forecast peak demand (prudent growth[3]) for each grid exit point for the forecast period. Refer to Chapter 3 for further information on demand forecasting.

Table 18-1: Forecast annual peak demand (MW) at South Canterbury grid exit points to 2034

Grid exit point	Power factor	Peak demand (MW)											
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Albury	0.97	6	6	6	6	7	7	7	7	8	8	8	9
Bells Pond[1]	0.96	15	16	22	23	25	26	28	29	31	32	32	35
Black Point	0.92	16	16	16	16	16	16	16	16	16	16	16	17
Oamaru[3]	0.98	42	43	44	41	42	43	45	44	45	45	46	49
Studholme	0.96	17	18	18	19	20	20	21	22	22	23	23	25
Tekapo A[2]	1.00	6	8	10	12	13	14	14	15	15	15	16	17
Temuka[1]	0.96	64	69	71	73	75	76	78	79	80	81	83	88
Timaru	0.99	78	79	78	80	82	83	85	89	92	91	92	97
Twizel	0.99	6	6	6	6	7	7	7	8	8	8	8	8
Waitaki[3]	0.95	13	14	14	16	17	17	18	19	20	20	20	22

1. Demand forecasts for these grid exit points include committed step changes in demand identified in discussion with customers. Loads include irrigation schemes and associated dairy industry developments.
2. Includes several committed commercial developments around Tekapo (from customer information).
3. 2022 change includes load transfer from Oamaru to Waitaki grid exit point.

2 For discussion on demand forecasting see Chapter 3, section 3.1.

3 Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

18.3 South Canterbury generation

The South Canterbury region's generation capacity is currently 1,747 MW. This represents a major portion of total South Island generation and significantly exceeds local demand. Surplus generation is exported via the National Grid to other demand centres in the South Island, and via the HVDC link to the North Island. Up to 30 MW of generation is injected directly into the 110 kV transmission network from Tekapo A.

Table 18-2 lists the generation forecast for each grid injection point in the South Canterbury region for the forecast period. This includes all known and committed generation stations including those embedded within local lines company networks (Network Waitaki and Alpine Energy).[4]

Further generation may be developed during the period but is not sufficiently advanced to be included in our forecasts (refer to section 18.5.6 for more information on potential new generation).

Table 18-2: Forecast annual generation capacity (MW) at South Canterbury grid injection points to 2034 (existing and committed generation)

Grid injection point (location/name if embedded)	Generation capacity (MW)										
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2034
Albury (Opuha)	7	7	7	7	7	7	7	7	7	7	7
Aviemore	220	220	220	220	220	220	220	220	220	220	220
Benmore	540	540	540	540	540	540	540	540	540	540	540
Ohau A	264	264	264	264	264	264	264	264	264	264	264
Ohau B	212	212	212	212	212	212	212	212	212	212	212
Ohau C	212	212	212	212	212	212	212	212	212	212	212
Tekapo A	30	30	30	30	30	30	30	30	30	30	30
Tekapo B	160	160	160	160	160	160	160	160	160	160	160
Waitaki	105	105	105	105	105	105	105	105	105	105	105

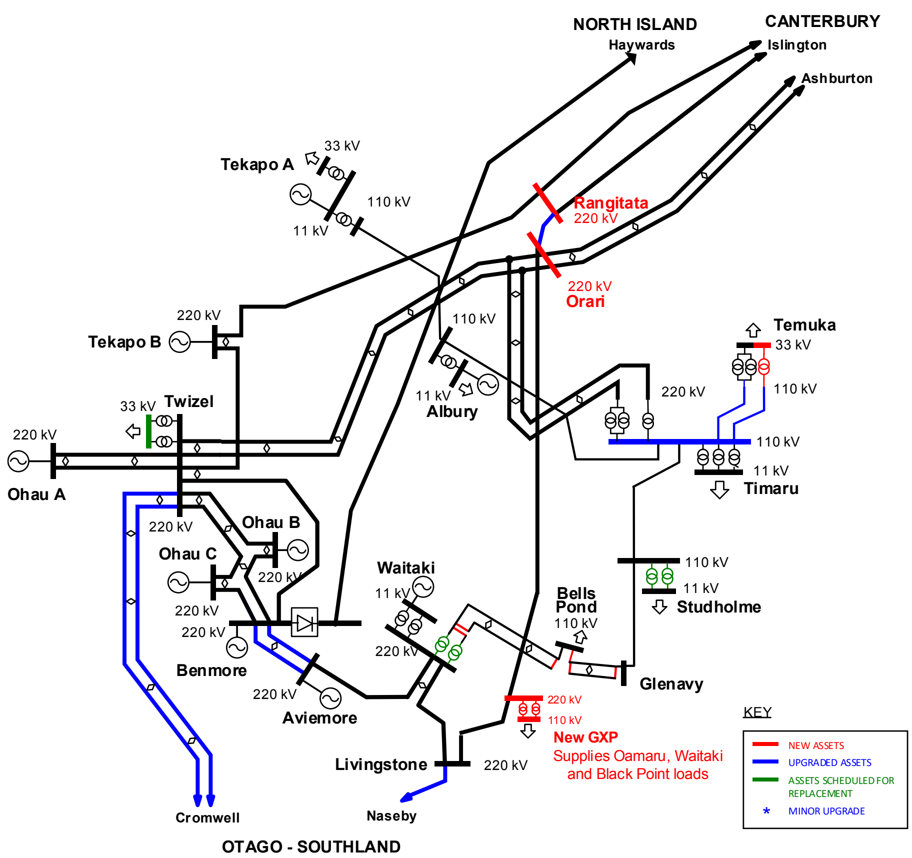
4 Only generators with capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest MW.

18.4 Grid enhancement approach

18.4.1 Possible South Canterbury transmission configuration

Figure 18-3 shows the possible configuration of South Canterbury transmission in 2034. New assets, upgraded assets, and assets scheduled for replacement within the forecast period (based on potential enhancement approaches set out in the following sections) are shown. Changes to the grid backbone shown below are discussed in Chapter 6 Grid Backbone.

Figure 18-3: Possible South Canterbury transmission configuration in 2034



18.4.2 Enhancement approach

Our approach seeks to ensure secure transmission into and within the South Canterbury region into the future. Through the E&D process we assess transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified issues and opportunities we take into account uncertainty in future demand, generation and technological developments.

Transmission issues likely requiring E&D or customer-funded investment in the South Canterbury region over the next 10-15 years include:

Section number	Issue
18.4.2.1	Lower Waitaki Valley transmission capacity and supply security
18.4.2.2	Timaru interconnecting transformer voltage stability
18.4.2.3	Timaru 110 kV bus security
18.4.2.4	Black Point single supply security
18.4.2.5	Bells Pond supply capacity
18.4.2.6	Studholme supply transformer capacity
18.4.2.7	Temuka supply transformer and transmission capacity
18.4.2.8	Twizel supply security

18.4.2.1 Lower Waitaki Valley transmission capacity and supply security

The loads at the Oamaru, Black Point, Bells Pond, and Studholme grid exit points all peak in summer, which coincides with lower circuit ratings. Due to the high load growth forecast for the area, post-contingency voltage quality and thermal overloading issues are anticipated.

We have implemented several developments that allow increased load to be supplied in this area, including:

- a Wider Voltage Agreement with Network Waitaki, which extends the lower voltage range at the Oamaru 110 kV bus to 0.875 pu
- a demand response scheme in the area, to manage pre-contingency loading on the Bells Pond–Waitaki circuit
- preparation to enable a permanent system split between Glenavy and Studholme,[5] which will reduce loading on the Bells Pond–Waitaki circuit if demand response is not available or is inadequate to reduce circuit loading to within the required limits
- the Oamaru–Waitaki circuit overload protection scheme, which manages the n-1 constraints on both the 110 kV Black Point–Waitaki and Bells Pond–Waitaki circuits
- variable line ratings on both 110 kV Glenavy–Oamaru circuits, which maximise thermal capacity by changing circuit ratings every two hours based on historical temperature records for the area
- additional 220/110 kV transformer capacity at Timaru (see section 18.4.2.2). This also reduces power flow north on the 110 kV circuits between Waitaki and Timaru.

These developments provide additional capacity at Oamaru, Black Point and Bells Pond. The additional capacity at Black Point and Bells Pond has lower security, as it is exposed to an outage of both the 110 kV Oamaru–Black Point–Waitaki and Oamaru–Studholme–Bells Pond–Waitaki circuits.

From summer 2019, the Oamaru load may exceed the n-1 thermal capacity of the two 110 kV Glenavy–Oamaru circuits. The forecast overload is approximately 42-56 MW depending on the time of day[6], the Oamaru load power factor, other loads in the region and (to a lesser extent) the Waitaki voltage set point.

The Oamaru load has a voltage limit of 50-60 MW depending on the load power factor. The limit is due to low voltage and voltage stability on the Oamaru 110 kV bus, and may be higher than the thermal limit at Oamaru. The preferred solution to the voltage constraint will depend on the solution to the thermal constraint.

From summer 2020, there is potential for the Bells Pond–Waitaki circuit section to overload pre-contingency (with all assets in service).[7]

If the Bells Pond–Waitaki circuit loading cannot be kept below 95% of the circuit rating, a system split will be required between Glenavy and Studholme.

Enhancement approach:

[5] A permanent system split between Glenavy and Studholme leaves Studholme supplied only from Timaru, putting the dairy factory at Studholme on n security.

[6] Due to the variable line ratings that have been applied, the Glenavy–Oamaru circuit ratings change every two hours.

[7] This assumes that capacity at Oamaru is at least 50 MW and Tekapo A generation is out of service.

- For Oamaru constraints, we are discussing options with Network Waitaki. In the short term these include a special protection scheme at Oamaru to allow additional load on the existing network, or shifting additional load to the Waitaki grid exit point.
- We will investigate options to reduce system restoration times at Studholme following an outage of the Studholme–Timaru circuit. This will improve reliability at Studholme if and when the Glenavy–Studholme permanent system split is implemented, and may be part of a larger capacity upgrade at Studholme (see section 18.4.2.6).
- For the medium to long-term, we have worked with Alpine Energy and Network Waitaki to identify investment options including building a new 220 kV grid exit point between Livingstone and the Waitaki River. This would supply loads that are presently supplied from Black Point, Oamaru and Waitaki grid exit points, removing the Oamaru and Black Point loads from the existing Oamaru–Waitaki circuits. At present this development is being considered by Network Waitaki and Alpine Energy, and we will reassess our development path for the area as decisions are made.

Base E&D Capex investments

Project name:	Improve restoration time at Studholme
Project description:	Install remote switching at Studholme to reduce restoration time if Studholme is supplied only from Timaru
Project's state of completion:	Possible
OAA level completed:	None
Grid need date:	2022
Indicative Cost ($ million):	0.5
Part of the GEIR?	No

Customer Investments

Project name:	Increase Oamaru load limit
Project description:	Oamaru post-contingency load management scheme
Project's state of completion:	Possible
OAA level completed:	None
Grid need date:	Customer initiated
Indicative cost ($ million):	0.3
Part of the GEIR?	No

Project name:	Increase supply capacity in the lower Waitaki Valley
Project description:	New grid exit point
Project's state of completion:	Possible
OAA level completed:	AL 4p
Grid need date:	Customer initiated
Indicative cost ($ million):	25 – 35
Part of the GEIR?	No

18.4.2.2 Timaru interconnecting transformer voltage stability

Two 220/110 kV interconnecting transformers at Timaru supply the Timaru area loads (Timaru, Temuka, Albury, Tekapo A and potentially Studholme).

We recently increased interconnecting transformer capacity at Timaru, by paralleling the two existing interconnecting transformers onto one circuit and installing a new transformer on the other circuit. This increased the voltage stability limit to approximately 164/174 MW (without/with Tekapo A generation).

The Timaru area load is forecast to exceed the voltage stability limit of 164 MW by 2022.

The post-contingency steady-state voltages on transmission buses in the area may begin to fall below 0.9 pu when the area load exceeds around 157 MW, forecast for 2020.

The resolutions to other constraints in the region[8] will affect the timing of the Timaru voltage constraints, particularly if solutions involve shifting the load from Studholme and/or Temuka to new grid exit points.

Enhancement approach:

- We will investigate voltage support options including the installation of shunt capacitors on the Timaru 110 kV bus to increase the voltage stability limit in the Timaru area.
- A Wider Voltage Agreement may delay investment by up to two years.

Base E&D Capex investments

Project name:	Timaru voltage support
Project description:	Install shunt capacitors
Project state of completion:	Possible
OAA level completed:	None
Grid need date:	2022
Indicative Cost ($ million):	3
Part of the GEIR?	No

18.4.2.3 Timaru 110 kV bus security

Increasing the Timaru interconnecting transformer capacity (see section 18.4.2.2) has reduced (but not eliminated) issues arising from a Timaru 110 kV bus tripping. A fault on a Timaru 110 kV bus section will cause several issues to arise, the most onerous being a fault on bus section C. This will:

- disconnect Tekapo A and Albury
- overload the remaining Temuka supply transformer and Temuka–Timaru circuit if the Temuka load is high, triggering the Temuka special protection scheme to reduce load at Temuka
- potentially trigger a voltage collapse driven by low voltages at Temuka.

Enhancement approach:

- We will consider reconfiguring the Timaru 110 kV bus to connect the Albury circuit (which also connects Tekapo A) to bus section B,[9] and/or
- We will consider installing capacitors to/which will ….
- We are considering a transformer upgrade at Temuka (see section 18.4.2.7) will also reduce the risk of voltage collapse.
- We do not plan to investigate options to increase security to Albury and Tekapo A for a Timaru bus section outage as the customers connected to the single circuit line, Alpine Energy and Genesis Energy, have not requested a higher level of security.

Base E&D Capex investments

Project name:	Timaru bus security
Project description:	Timaru 110 kV bus reconfiguration
Project state of completion:	Possible
OAA level completed:	None
Grid need date:	2019
Indicative Cost ($ million):	2
Part of the GEIR?	No

8 These include the Studholme supply transformer constraint (see section 818.4.2.5) and the Temuka supply transformer and transmission constraint (see section 818.4.2.7).

9 This keeps at least one Timaru interconnecting transformer and the Tekapo A generation in service for a worst-case bus section outage.

18.4.2.4 Black Point single supply security

The Black Point load cannot be supplied during an outage of the 110 kV Oamaru–Black Point–Waitaki circuit or its associated Waitaki 220/110 kV interconnecting transformer (T24).

This creates challenges in planning outages for the circuit and its associated interconnecting transformer.

Enhancement approach:

We will investigate the option of closing the Oamaru 110 kV bus split during outages of the Waitaki interconnecting transformer to supply some of the Black Point load via Oamaru. Black Point will still be disconnected for Oamaru–Black Point–Waitaki circuit outages.

Base E&D Capex investments

Project name:	Black Point security of supply
Project description:	Supply Black Point via Oamaru 110 kV bus
Project's state of completion:	Possible
OAA level completed:	None
Grid need date:	2019
Indicative Cost ($ million):	0.5
Part of the GEIR?	No

18.4.2.5 Bells Pond supply capacity

Bells Pond is connected to the Oamaru–Studholme–Waitaki 2 circuit via a short single-circuit Tee line. There is a metering accuracy limit on this circuit, limiting the Bells Pond load to 32 MW. The load is forecast to exceed this limit in 2026.

Enhancement approach:

We will investigate removing this constraint as required. Other constraints in the lower Waitaki 110 kV transmission system (see section 18.4.2.1) will need to be resolved before this constraint binds.

Base E&D Capex investments

Project name:	Bells Pond Tee constraint removal
Project description:	Remove the metering accuracy limit on Bells Pond Tee
Project's state of completion:	Possible
OAA level completed:	None
Grid need date:	Customer initiated
Indicative cost ($ million):	TBA
Part of the GEIR?	No

18.4.2.6 Studholme supply transformer capacity

The peak load at Studholme already exceeds the n-1 capacity of the two 110/11 kV supply transformers and is forecast to exceed the continuous capacity at peak periods from next summer.[10] Transformers cannot supply load beyond their continuous capacity pre-contingency, so operational measures will be required if no further investment is made.

The existing transformers meet the requirements for replacement based on condition.

Enhancement approach:

- Alpine Energy has requested that we investigate options to increase transformer capacity at Studholme.We will work with Alpine Energy to determine the preferred development option for Studholme. We will manage the existing transformers until there is certainty on the future capacity requirements for new transformers.

[10] Based on Transpower's prudent demand forecast. Alpine Energy expects the Studholme load to reach the transformer limit in 2021 or later

Base R&R Capex investments

Project name:	Studholme supply transformer replacement
Project description:	Replace Studholme supply transformers with two larger units
Project's state of completion:	Possible
OAA level completed:	None
Grid need date:	Customer initiated
Indicative cost ($ million):	7
Part of the GEIR?	No

18.4.2.7 Temuka supply transformer and transmission capacity

The peak load at Temuka already exceeds the n-1 capacity of the two 110/33 kV supply transformers and the two 110 kV Temuka–Timaru circuits. The capacity of the transformers is lower than that of the circuits.

There is a special protection scheme at Temuka that allows the load to exceed the n-1 capacity of the supply transformers. This means that load in excess of approximately 54 MW (the summer limit) will be on single security, and will be reduced automatically if there is a transformer or circuit outage. This scheme is expected to be effective until the Temuka load exceeds about 85 MW (forecast in 2023).

Enhancement approach:

We are investigating an upgrade at the request of Alpine Energy, which includes:

- increasing the supply transformer capacity at Temuka by paralleling the existing transformers and installing one new 120 MVA supply transformer, and,
- installing a new 33 kV switchboard.

In future an upgrade of the Temuka–Timaru circuits may also be justified. This may require easements.

Customer investments

Project name:	Temuka supply capacity constraints
Project description:	Upgrade Temuka supply transformer capacity
Project state of completion:	Possible
OAA level completed:	None
Grid need date:	Customer initiated
Indicative cost ($ million):	13
Part of the GEIR?	No

Project name:	Temuka–Timaru transmission constraint
Project description:	Upgrade Temuka–Timaru transmission capacity
Project state of completion:	Possible
OAA level completed:	None
Grid need date:	Customer initiated
Indicative cost ($ million):	15
Part of the GEIR?	No

18.4.2.8 Twizel supply security

Two 220/33 kV transformers supply the Twizel load, but the loads supplied from the Twizel 33 kV grid exit point have single transformer security because the supply bus is split. Hydro generation control structures in the area (Ohau A, B and C, Tekapo B, Ruataniwha and Pukaki) take their local service supply from this bus, and it is split to reduce the risk of losing connection to all sites simultaneously for a bus contingency.

The bus split can be closed to avoid loss of supply during transformer maintenance, and within a short time following an unplanned transformer outage.

Alpine Energy takes 33 kV supply from one side of the split, and Network Waitaki takes supply from the other side of the split.

Enhancement approach:

A project to replace the existing outdoor 33 kV switchyard with an indoor switchboard is planned for 2019-2021. This will include a 33 kV bus section breaker.

Base R&R Capex investments

Project name:	Twizel indoor-outdoor project
Project description:	Replace outdoor 33 kV switchyard with indoor switchboard
Project state of completion:	Committed
OAA level completed:	None
Grid need date:	2019
Indicative cost ($ million):	5.5
Part of the GEIR?	No

18.5 Asset capability and management

We have assessed the transmission capacity and reactive support requirements in the region for the next 15 years. When an issue or opportunity exists, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 18.4.2) were developed to address issues or opportunities that require action within the forecast period and where investment is justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk-based asset replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

18.5.1 South Canterbury significant upcoming work

We integrate our capital project and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Table 18-3 lists the significant upcoming work proposed for the South Canterbury region for the next 15 years that may significantly impact related system issues or connected parties.

Table 18-3: Proposed significant upcoming work for the South Canterbury transmission system

Description	Tentative year	E&D issue
Studholme special protection scheme replacement	2027-2029	18.5.4.9
Tekapo A 11 kV switchboard replacement Tekapo A–T1 supply transformer risk based condition replacement	2021-2023 2032-2034	None 18.5.4.11
Twizel 33 kV outdoor to indoor conversion	2019-2021	18.5.4.14
Waitaki interconnecting transformers risk based condition replacement	2031-2033	18.5.4.3

18.5.2 South Canterbury asset feedback

The Asset Feedback Register includes the following E&D related entry specific to the South Canterbury region:

- When Waitaki–T24 is out of service, Black Point loses supply. No grid exit point ties exist for Network Waitaki's Black Point load.

18.5.2.1 Black Point connection security during Waitaki 220/110 kV transformer outages

Issue

The Black Point load cannot be supplied during Waitaki interconnecting transformer T24 outages. This causes challenges for outage planning of T24.

What next

We are reviewing options to supply at least a portion of the Black Point load during T24 outages. Refer to section 18.4.2.4 for our proposed approach.

18.5.3 Changes since the 2018 Transmission Planning Report

Table 18-4 lists the specific new issues and those that are no longer relevant within the forecast period (relative to our previous Transmission Planning Report).

Table 18-4: Changes since the 2018 TPR

Issues	Change
Bells Pond supply capacity	Increased load forecast at Bells Pond
Tekapo A supply capacity	Increased load forecast at Tekapo

18.5.4 South Canterbury transmission capability

Table 18-5 summarises identified issues that may affect the South Canterbury region over the next 15 years. In each case, we have detected a condition that would constrain the network if action were not taken. Each issue is discussed in more detail below.

This transmission capability section reports whether the Grid can reasonably be expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, forms part of the Grid Reliability Report (GRR).

Table 18-5: South Canterbury region transmission issues- regional/site by grid exit point

Section number	Issue
Regional	
18.5.4.1	Oamaru–Waitaki voltage quality and transmission capacity
18.5.4.2	Timaru interconnecting transformer capacity
18.5.4.3	Waitaki 220/110 kV interconnecting transformer capacity
Site by grid exit point	
18.5.4.4	Albury supply security
18.5.4.5	Albury and Tekapo A transmission security
18.5.4.6	Bells Pond single supply security and capacity
18.5.4.7	Black Point single supply security
18.5.4.8	Oamaru supply transformer capacity
18.5.4.9	Studholme single supply security
18.5.4.10	Studholme supply transformer capacity and security
18.5.4.11	Tekapo A supply security and capacity
18.5.4.12	Temuka transmission security and supply transformer capacity
18.5.4.14	Twizel supply security

18.5.4.1 Oamaru–Waitaki voltage quality and transmission capacity

The Oamaru, Black Point, Bells Pond, and Studholme grid exit points are collectively referred to as the lower Waitaki Valley area. These loads are supplied via two 110 kV circuits from Waitaki:

- Oamaru–Black Point–Waitaki 1 circuit (supplies Black Point via a Tee connection)
- Oamaru–Studholme–Bells Pond–Waitaki 2 circuit (supplies the Bells Pond and Studholme loads from Tee connections).

There is also a 110 kV circuit into Studholme from Timaru but this circuit is normally opened in the dairy off-season (May to September) when demand is lower. This open configuration significantly reduces transmission losses and outweighs the benefits of providing n-1 capacity to Studholme during winter. In the event of an unplanned outage of the Oamaru–Studholme–Bells Pond–Waitaki 2 circuit, the Studholme auto-changeover scheme[11] switches on the Studholme–Timaru circuit so that the Studholme load is supplied from Timaru.

When demand from the dairy factory connected to Studholme is high (over the summer months) the 110 kV Studholme–Timaru circuit is closed to provide n-1 security to Studholme. The increased load at Studholme and the higher value of the load (the dairy factory) means the benefit of providing higher security to Studholme is higher than the cost of increased transmission losses.

With the 110 kV Studholme–Timaru circuit closed, power normally flows from Waitaki, via Studholme, to Timaru. While Timaru provides some voltage support to the lower Waitaki Valley area via that circuit, the loads in the lower Waitaki Valley are supplied by the two 110 kV circuits from Waitaki.

The load growth forecast for the lower Waitaki Valley area is considerably higher than the national average, mainly due to irrigation and dairy industry-related loads. The Oamaru, Black Point, Bells Pond, and Studholme grid exit points all peak in summer, when circuit ratings are lower.

Bells Pond–Waitaki and Black Point–Waitaki transmission constraints

Two thermal overloading issues have been identified on the two 110 kV circuits from Waitaki to Bells Pond and Black Point during summer periods:

11 The Studholme auto-changeover scheme is an automatic control scheme enabled when the system is split on the Studholme–Timaru 1 circuit. Following an outage of the Oamaru–Studholme–Bells Pond–Waitaki 2 circuit it reconfigures the grid to have Studholme connected to Timaru. During the changeover, there will be approximately 25 seconds of loss of supply to Studholme.

- Currently, the Bells Pond–Waitaki circuit may overload following an outage of the Oamaru–Black Point–Waitaki 1 circuit or one of the 220 kV circuits between Islington and the Waitaki Valley.
- Currently, the Black Point–Waitaki circuit section may overload following an outage of the Oamaru–Studholme–Bells Pond–Waitaki 2 circuit.
- From summer 2021, pre-contingency loading on the the Bells Pond–Waitaki circuit section may exceed 95% of its capacity[12] during peak load periods.

What next?

We installed the Oamaru–Waitaki circuit overload protection scheme to manage overloading on the two 110 kV circuits from Waitaki. This allows the circuits to be loaded above their n-1 limit.

We also have a demand response programme for the lower Waitaki Valley to allow customers to reduce their demand, for a payment, when we send them a request.

If the demand response programme is insufficient to manage pre-contingency loading on the Bells Pond–Waitaki circuit section, further action will be required. We will then split the system between Glenavy and Studholme, supplying Studholme from Timaru to reduce loading on the 110 kV Bells Pond–Waitaki and Black Point–Waitaki circuits.

We are working with Alpine Energy to identify a higher-security solution to this issue. Refer to section 18.4.2.1 for our enhancement approach.

Oamaru supply capacity

The maximum load that can be supplied at Oamaru is limited by the thermal capacity of the Glenavy–Oamaru section of the 110 kV Oamaru–Waitaki circuits. The Oamaru load is forecast to exceed the n-1 capacity of these circuits from 2019 (see also section 18.5.4.8).

What next?

Network Waitaki plans to further develop its distribution system between the Waitaki grid exit point and Oamaru to enable the transfer of load away from the Oamaru grid exit point.

Our previous investigations have indicated a major upgrade of transmission to increase capacity to Oamaru does not pass the investment test. Hence, we do not have any committed investments to increase supply capacity to Oamaru.

However, the situation is fluid and we will continue to work with Network Waitaki on options to enable additional load at Oamaru. Refer to section 18.4.2.1 for our enhancement approach.

Voltage quality and stability

An unplanned outage of a 110 kV circuit from Waitaki, an Oamaru supply transformer, or a Waitaki interconnecting transformer will cause:

- voltage at the Oamaru 110 kV bus to fall below 0.875 pu[13] by around 2024[14]
- a large voltage step at Oamaru during peak load periods.[15]

In the medium term, voltage stability issues will also emerge. The limits are highly dependent on the location of load growth and the load power factor.

We expect voltage stability issues may occur sometime after 2024 (with the timing depending on the Oamaru load power factor). The issues will correspond to Oamaru loads between 50 MW and 60 MW. This is beyond the present thermal limit, and depends on the Black Point and Bells Pond loads.

What next?

The voltage issues occur after the thermal limit on the two 110 kV circuits from Waitaki. Investment to improve the thermal and voltage limits at Oamaru will be customer driven. We will continue to work with Network Waitaki to understand their development needs and interdependencies with the wider regional grid issues. We do not currently have any investments planned specifically to address voltage issues.

18.5.4.2 Timaru interconnecting transformer capacity

12 95% loading of the Bells Pond–Waitaki circuit is considered a maximum allowable for the Oamaru–Waitaki overload protection sceheme to work reliably.

13 There is a wider voltage agreement for the Oamaru 110 kV bus: -12.5% / +10% (96.3 kV / 121 kV).

14 Depending on the Oamaru power factor and assuming the Black Point or Bells Pond loads are shed due to high circuit loading.

15 There are no steady state voltage issues at Oamaru 33 kV, due to the range of the supply transformer on-load tap changers.

Issue

Two 220/110 kV interconnecting transformers supply the loads at Timaru, Temuka, Albury, Tekapo A, and Studholme[16] (collectively referred to as the Timaru area) providing:

- total nominal installed capacity of 490 MVA
- n-1 thermal capacity of 244/256 MVA[17] (summer/winter).
- static voltage stability limits of approximately 167 MW (without Tekapo A generation)
- dynamic voltage stability limits of approximately 164/174 MW (without/with Tekapo A generation)
- low voltage limits on 110 kV buses of approximately 157 MW (without Tekapo A generation).

The Timaru area load is not expected to exceed the upgraded n-1 thermal capacity of the interconnecting transformers within the forecast period.

The Timaru area load is forecast to exceed the Timaru area voltage stability limits from 2022 (without Tekapo A generation).

What next?

We will investigate options to address the voltage stability limit. Refer to section 18.4.2.2 for our enhancement approach.

16 When the Studholme–Timaru split is closed and the Glenavy–Studholme circuit is open.

17 The capacity of the transformers is limited by the rating of the 220 kV Opihi–Timaru line section. If this constraint is removed the n-1 capacity will be 246/256 MVA.

18.5.4.3 Waitaki 220/110 kV interconnecting transformer capacity

Issue

Two 220/110 kV interconnecting transformers (T23 and T24) at Waitaki supply the lower Waitaki Valley loads, providing:

- total nominal installed capacity of 130 MVA
- n-1 capacity of 80/85 MVA (summer/winter).

The combined Oamaru and Bells Pond load is forecast to first exceed the post-contingency capacity of T23 in 2021 and T24 in 2031. However, these transformers have a higher capacity than the circuits they supply, so they are not the first constraint. A special protection scheme is installed that will manage load within the capacity of the transformers post-continegency (see Section 18.4.2.1).

The tap changers on T23 and T24 cannot be operated due to their condition. The lack of operable tap changers marginally worsens voltage issues on the lower Waitaki Valley 110 kV transmission system (see section 18.4.2.1).

What next?

The transformers are expected to require risk-based condition replacement within the next 10-15 years. We have not planned any investments to increase the capacity of the Waitaki transformers. We will investigate investment options as the need arises.

18.5.4.4 Albury supply security

Issue

A single 110/11 kV, 20 MVA transformer[18] supplies the load at Albury resulting in n security.

Albury has embedded generation at Opuha, which results in Albury injecting power into the National Grid during periods of low demand and/or high generation.

What next?

The n security issue can be managed operationally for the forecast period. The embedded Opuha generation can supply some of the local load during planned outages at Albury. Alpine Energy can also transfer some load to adjacent grid exit points. Our mobile substation can be used at Albury to cover a transformer planned outage. Therefore, we have no planned investments to increase the security of supply to Albury.

18.5.4.5 Albury and Tekapo A transmission security

Issue

A single 110 kV Tekapo A–Albury–Timaru circuit connects Tekapo A, Albury, and Opuha to the National Grid. If the circuit trips, Albury and Tekapo A will lose supply, and the Tekapo A and Opuha (embedded at Albury) generation will disconnect from the grid.

What next?

Albury and Tekapo A loads may be restored by operating Opuha and Tekapo A generation islanded (not connected to the grid). Alpine Energy considers the issue to be manageable operationally for the forecast period. Therefore, we have not planned any investment to increase transmission security to these sites.

18 Capacity presently limited to 11.1 MVA by a protection setting

18.5.4.6 Bells Pond single supply security and capacity

Issue

Bells Pond is connected via a single 110 kV Tee connection to the Oamaru–Studholme–Bells Pond–Waitaki circuit providing 34/34[19] MVA (summer/winter) capacity. An outage of the circuit or its associated Waitaki 220/110 kV interconnecting transformer (T23) results in a loss of supply to Bells Pond.

The peak load at Bells Pond is forecast to exceed the n-1 summer capacity of the circuit in 2026, increasing to approximately 8 MW in 2034 (see Table 18-6).

Table 18-6: Bells Pond tee circuit overload forecast

	forecast overload (MW)											
Grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Bells Pond	0	0	0	0	0	0	0	1	3	4	5	8

Presently, Alpine Energy can supply some Bells Pond load from the Studholme grid exit point via its distribution network. The Bells Pond grid exit point can also be supplied from Timaru (after some switching) if Waitaki T23 is out of service and the Oamaru–Studholme–Bells Pond–Waitaki circuit is in service.

What next?

We are discussing investment options with Alpine Energy to resolve capacity issues on the Bells Pond–Waitaki and parallel Black Point–Waitaki circuits (refer to section 18.4.2.1). If capacity becomes available on these circuits, this will enable options to address the Bells Pond security issue.

The branch limit on the Bells Pond Tee line section will be removed as required. See section 18.4.2.5 for our proposed approach.

18.5.4.7 Black Point single supply security

Issue

Black Point is connected via a single 110 kV Tee connection to the Oamaru–Black Point–Waitaki circuit. An outage of the circuit or its associated Waitaki 220/110 kV interconnecting transformer (T24) results in a loss of supply to Black Point.

Network Waitaki cannot supply the Black Point load from an alternative grid exit point. Therefore, there are constraints on maintenance outages during the irrigation season, which extends from September to May. The outage constraints are difficult to manage as some maintenance cannot be done during winter, leaving a narrow window for outages.

What next?

We are investigating possible solutions to reduce the impact of Waitaki 220/110 kV interconnecting transformer outages. Refer to sections 18.4.2.4 and 18.4.2.1 for our proposed approaches.

18.5.4.8 Oamaru supply transformer capacity

Issue

Two 110/33 kV transformers supply Oamaru's load, providing:

- total nominal installed capacity of 120 MVA

19 The circuit's capacity is limited by a CT rating at Bells Pond. With this limit resolved, the capacity will be 66/80 MVA (summer/winter).

- n-1 capacity of 65/65 MVA (summer/winter).[20]

The peak load at Oamaru is forecast to exceed the n-1 summer capacity of the transformers in 2025, increasing to approximately 6 MW in 2034 (see table Table 18-7).

Table 18-7: Oamaru supply transformer and circuit overload forecast

	forecast overload (MW)											
Grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Oamaru supply transformers	0	0	0	0	0	0	1	0	1	1	2	6
Glenavy–Oamaru circuits	4	6	7	4	5	6	8	7	8	8	9	13

The capacity of the supply transformers is reduced by low voltages at Oamaru when there is a 110 kV circuit outage. However, the capacity of the 110 kV circuits (see Table 18-7 and section 18.5.4.1) is the limiting factor for Oamaru load.

What next?

If the low voltage issues are resolved and the transformer branch constraints removed, the transformer capacity will be sufficient for the forecast period.

18.5.4.9 Studholme single supply security

Issue

The Studholme–Timaru circuit is opened at Studholme during the dairy off-season (May to September), and Studholme is supplied by the Oamaru–Studholme–Bells Pond–Waitaki circuit. Splitting the 110 kV network prevents power flow on the 110 kV circuits from Waitaki to Timaru, reducing the transmission losses by having power flow through the more efficient 220 kV network. This reduction in transmission losses outweighs the benefit of having n-1 security at Studholme during the dairy off-season.

If the Oamaru–Studholme–Bells Pond–Waitaki circuit faults, a special protection scheme automatically transfers Studholme load to the Studholme–Timaru circuit. There is approximately a 25 second loss of supply at Studholme before the switch-over occurs.

This brief loss of supply can cause economic loss for the dairy factory at Studholme, so the split is closed for the peak dairy season (October to April).

However, one of our options to resolve pre-contingency overloading of the Bells Pond–Waitaki circuit during the peak dairy season is to open the Glenavy–Studholme circuit at Studholme. This option will result in Studholme having single supply security from Timaru and will only be applied if a pre-contingency overload is expected and demand response is unavailable or insufficient to resolve the issue. The Glenavy–Studholme split may extend to the entire summer season within the next 5 years.

What next?

We have reviewed the economics of closing the Studholme–Timaru 110 kV system split over the dairy off-season. We found retaining the split remains the most economic option, so we are proposing no change to the configuration over the dairy off-season.

For the dairy peak season, we will investigate options to reduce system restoration times at Studholme should the Timaru–Studholme circuit trip while the Glenavy–Studholme system split is in place. See section 18.4.2.1 for our enhancement approach.

18.5.4.10 Studholme supply transformer capacity and security

Issue

Two 110/11 kV transformers supply Studholme's load, providing:

- total nominal installed capacity of 20 MVA
- n-1 capacity of 11/12 MVA (summer/winter).

20 The capacity of the transformers is limited by the LV protection limit followed by the LV circuit breaker rating (71 MVA) limit. With these limits resolved, the n-1 capacity will be 72/76 MVA (summer/winter).

The peak load at Studholme is forecast to exceed the summer n-1 capacity of the transformers by 9 MW in 2019, increasing to approximately 20 MW in 2034 (see Table 18-10). From summer 2019 the peak load at Studholme may exceed the continuous capacity of both transformers.

Table 18-8: Studholme supply transformer overload forecast

	Transformer overload (MW)											
Circuit/grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Studholme n-1	9	11	11	12	13	14	15	15	16	17	17	20
Studholme continuous	2	3	3	4	5	6	7	8	9	9	10	12

In addition, the two 110/11 kV supply transformers at Studholme have no dedicated 110 kV circuit breakers. This means both supply transformers will trip for a transformer fault, causing a loss of supply. Supply can be restored after the faulted transformer is disconnected.

What next?

The load cannot be allowed to exceed the continuous capacity of both transformers, so in the short-term it may be necessary to use operational measures such as load shifting or load shedding to manage the transformer loading.

In the medium to long-term, Alpine Energy has requested that we investigate options to increase capacity at Studholme

A resolution of the issues at Studholme is also connected to the possible development options in the lower Waitaki Valley. Refer to section 18.4.2.1 for our enhancement approach for the lower Waitaki Valley transmission issues.

We will continue to work with Alpine Energy to find a preferred solution for the Studholme transformer constraint. Refer to section 18.4.2.6 for our enhancement approach.

18.5.4.11 Tekapo A supply security and capacity

Issue

A single 110/11 kV, 35 MVA transformer (T6) in series with a single 33/11 kV, 10 MVA transformer (T1) supplies load at Tekapo, resulting in n security.

The peak load at Tekapo A is forecast to exceed the continuous rating of T1 in 2023, increasing to 5 MW by 2034 (see Table 18-11).

Table 18-9: Tekapo A supply transformer overload forecast

	Transformer overload (MW)											
Circuit/grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Tekapo A	0	0	0	0	1	2	2	2	3	3	3	5

What next?

Our mobile substation can be used at Tekapo A during planned outages. Alpine Energy considers the lack of n-1 security can be managed operationally for the forecast period.

Tekapo–T1 is due for risk-based condition replacement towards the end of the study period. We will discuss options with Alpine Energy to resolve the forecast capacity constraint.

We presently have no planned investments to upgrade the security or capacity at Tekapo A.

18.5.4.12 Temuka transmission security and supply transformer capacity

Issue

At Temuka, two 110/33 kV transformers supply the 33 kV load, providing:

- total nominal installed capacity of 108 MVA
- n-1 capacity of 63/63 MVA (summer/winter).[21]

The peak load at Temuka is forecast to exceed the n-1 summer capacity of the transformers by approximately 20 MW in 2019, increasing to approximately 48 MW in 2034 (see Table 18-10).

In addition, two 110 kV Temuka–Timaru circuits, rated at 71/79 MVA and 73/80 MVA (summer/winter), supply the Temuka 33 kV load. An outage of either circuit can already overload the other circuit during summer peak demand periods (see Table 18-10).

There is no 110 kV bus at Temuka, so each circuit and the corresponding supply transformer effectively form a single branch. Therefore, a circuit outage also causes an outage of the associated 110/33 kV supply transformer. The n-1 limit of the transformers is lower than that of the circuits.

The overload is driven by load growth at Temuka and expansion at the Clandeboye dairy factory (which represents more than half of the Temuka peak load).

There is a special protection scheme (SPS) at Temuka, which allows the load to exceed the n-1 capacity of the transformers. If one circuit-transformer branch trips during a high load period, the SPS will reduce the Temuka load until it is within the rating of the remaining transformer.

The SPS is effective until Temuka load increases to 85 MW, at which point there is a risk that an outage of one transformer will cause the remaining transformer to trip on overload before the SPS acts.

The peak load at Temuka is forecast to first exceed the SPS limit in 2023, increasing to 17 MW by 2034 (see Table 18-10).

Table 18-10: Temuka supply transformer overload forecast

	Transformer overload (MW)											
Circuit/grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Temuka supply transformers	20	26	29	31	33	35	37	38	40	41	42	48
Timaru–Temuka circuits	6	10	13	14	16	17	18	19	20	22	23	27
Temuka SPS limit	0	0	0	0	2	3	5	7	8	9	11	17

What next?

We are discussing short and long-term options with Alpine Energy. Refer to section 18.4.2.7 for our proposed approach.

21 The 63 MVA summer rating is a 30-minute emergency rating. For an outage of one transformer, the loading on the other transformer must be reduced to 61/63 MVA (summer/winter) within 30 minutes.

18.5.4.13 Timaru supply transformer limit

Issue

Three 110/11 kV transformers supply the Timaru load, providing:

- total nominal installed capacity of 143 MVA
- n-1 capacity of 94 MVA

The three Timaru supply transformers are operated with one unit on hot-standby, to ensure that 11 kV fault levels remain within the rating of Alpine Energy's distribution equipment. If one in-service transformer trips out, the third transformer will automatically switch into service, resulting in no loss of supply at Timaru.

The peak load at Timaru is forecast to first exceed the n-1 capacity of the supply transformers in 2025, increasing to approximately 9 MW in 2034 (see Table 18-11: Timaru supply transformer overload forecast).

Table 18-11: Timaru supply transformer overload forecast

	Transformer overload (MW)											
Circuit/grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Timaru	0	0	0	0	0	0	2	3	4	4	6	9

What next?

We will discuss options with Alpine Energy. We presently have no planned investments to upgrade the capacity at Timaru.

18.5.4.14 Twizel supply security

Issue

Two 220/33 kV transformers supply the Twizel load, providing:

- total nominal installed capacity of 40 MVA
- switched n-1 capacity of 26/27 MVA (summer/winter).

The loads supplied from the Twizel 33 kV grid exit point have single transformer security because the supply bus is split. Hydro generation control structures in the area (Ohau A, B and C, Tekapo B, Ruataniwha and Pukaki) take their local service supply from this bus, and it is split to reduce the risk of losing connection to all sites simultaneously for a bus contingency.

The bus split can be closed to avoid loss of supply during transformer maintenance, and within a short time following an unplanned transformer outage.

Alpine Energy takes 33 kV supply from one side of the split, and Network Waitaki takes supply from the other side of the split.

What next?

Alpine Energy, Network Waitaki, Meridian Energy, and Genesis Energy consider the present level of security can be managed operationally.

Conversion of the 33 kV switchyard to an indoor switchboard is planned for within the next five years. It is planned to include a 33 kV bus section breaker as part of this work, which will allow the bus to be run solid while maintaining a high level of security.

18.5.5 South Canterbury bus security

This section includes issues arising from the outage of a single bus section rated at 110 kV and above for the next 15 years.

Bus outages disconnect more than one power system component (for example, other circuits, transformers, reactive support or generating units). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

18.5.5.1 Transmission bus security

Table 18-12 lists bus outages that cause voltage issues or a total loss of supply. Generation is included only if a bus outage disconnects the whole generation station or causes a widespread system impact. Supply bus outages, typically 11 kV and 33 kV, are not listed.

Table 18-12: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Albury 110 kV	Albury Tekapo A	 Tekapo A	-	Note 1 Note 1
Aviemore 220 kV		Aviemore	-	
Oamaru 110 kV 1	Black Point	-		Note 2
Oamaru 110 kV 2	Bells Pond Studholme	-	-	Note 2 Note 2,3
Ohau A 220 kV		Ohau A	-	
Studholme 110 kV	Studholme	-	-	
Tekapo B 220 kV		Tekapo B	-	
Timaru 110 kV A	Temuka	-	Temuka–Timaru transmission capacity	28118.5.4.12
Timaru 110 kV C	Albury Tekapo A Temuka	 Tekapo A	Temuka–Timaru transmission capacity	28118.5.4.12
Waitaki 220 kV A	Bells Pond Studholme	-	-	Note 4 Note 4
Waitaki 220 kV B	Black Point	-	-	Note 4

1. An Albury 110 kV bus outage will disconnect the Albury load and embedded generator (Opuha) and the single circuit to Tekapo A, also disconnecting the generation and load at Tekapo A.
2. This is a minor issue where, without a line circuit breaker, the bus becomes an extension of a long circuit, and adds a small level of additional risk of that circuit tripping.
3. There is a loss of supply at Studholme only if the Studholme–Timaru circuit is open (normally in winter only).
4. This is a minor issue. The loads that are on n security due to a circuit outage are also at risk from a low probability outage of a Waitaki 220/110 kV transformer or 220 kV bus section because there is no 110 kV bus at Waitaki.

The customers in this region (Alpine Energy, Network Waitaki, Genesis Energy and Meridian Energy) have not requested a higher bus security level. Unless otherwise noted, we do not propose increasing bus security and future investment is likely to be customer driven.

If increased bus security is required, the options typically include bus reconfiguration and/or additional bus circuit breakers.

18.5.5.2 Timaru 110 kV bus security

Issue

The Timaru 110 kV bus is configured with three sections:

- Section A: 220/110 kV transformer T5, Temuka circuit 1 and 110/11 kV transformer T4
- Section B: Studholme circuit 1 and 110/11 kV transformer T3
- Section C: 220/110 kV transformer T8, 110/11 kV transformer T6, Temuka circuit 2 and Albury circuit 1 (that connects to Tekapo A).

A fault on bus section C has the worst impact as it disconnects infeed from one of the interconnecting transformers and from Tekapo A, reducing available voltage support. This fault will cause:

- a total loss of supply at Tekapo A and the disconnection of the Tekapo A generation
- the disconnection of Albury and (possibly) loss of supply to Albury and the disconnection of Opuha generation if islanding is unsuccessful
- depending on the loading at the time, (possibly) a voltage collapse in the Timaru area, with a risk of low voltage or voltage collapse spreading to the Ashburton area and upper South Island.

A fault on bus section C or bus section A may (depending on loading at the time):

- overload the remaining Temuka supply transformer and its associated Temuka–Timaru circuit (refer section 18.5.4.12), triggering automatic load shedding at Temuka to remove the transformer overload.

What next?

The possible project to upgrade the Temuka supply transformers will reduce (but not eliminate) the risk to Temuka load. Refer to section 18.4.2.3 for our enhancement approach to the Timaru area capacity and security issues.

18.5.6 South Canterbury generation proposals and opportunities

This section details relevant regional issues for generation proposals under investigation by developers and in the public domain, or other generation opportunities. The impact of committed generation projects on the grid backbone is dealt with separately in Chapter 6.

The maximum generation that can be connected depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

18.5.7 Wind generation

There are no issues with connecting wind or other generation at 220 kV at existing substations within the Waitaki Valley.

The maximum generation that can be connected varies with the point of connection and the circuit. Connections close to the Waitaki Valley enable the most generation (approximately equal to the circuit rating). The best case location and circuit will allow 400–700 MW of generation. The worst case location and circuit will not support the dispatch of any further generation.

Generation connected to one of the four circuits to Christchurch would need to avoid causing significant imbalance in circuit loading as this would reduce the maximum load that can be supplied across all four circuits.

There is limited opportunity to connect new generation to the Tekapo A–Albury–Timaru circuit without the risk of dispatch constraints. This is because the existing generation at Tekapo A and Opuha (embedded at Albury) generates up to 33 MW and the circuit capacity is 51 MVA (summer).

The other 110 kV circuits in the South Canterbury region can support generation connections up to or slightly higher than the circuit rating.

19 Otago-Southland Regional Plan

19.1 Regional overview and transmission

The Otago-Southland region includes a mix of provincial cities (Dunedin and Invercargill) together with the smaller but still significant tourist/rural service centres of Queenstown, Wanaka and Cromwell. New Zealand's largest electricity consumer, the New Zealand Aluminium Smelter at Tiwai Point is also located in this region.

The existing transmission network for the Otago-Southland region is shown geographically in Figure 19-1 and schematically in Figure 19-2.

Figure 19-1: Otago-Southland region transmission network

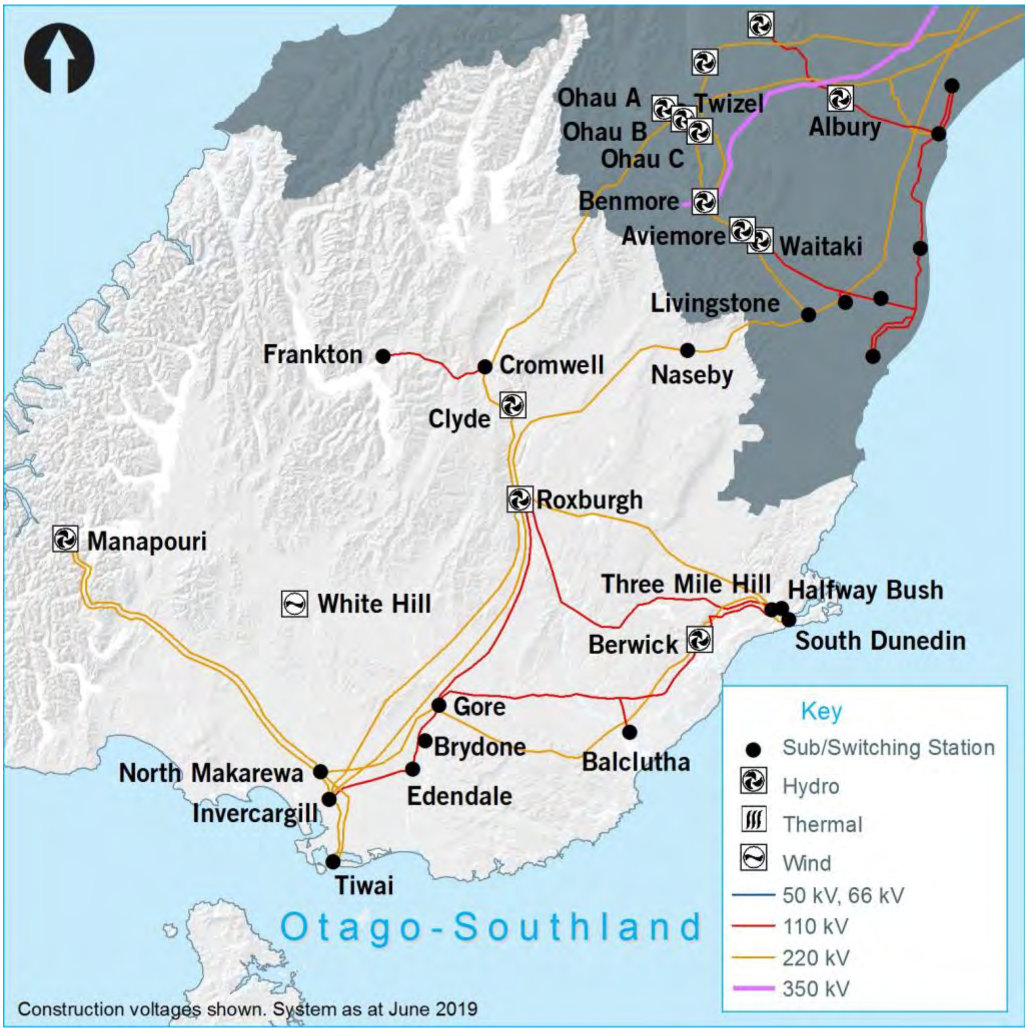
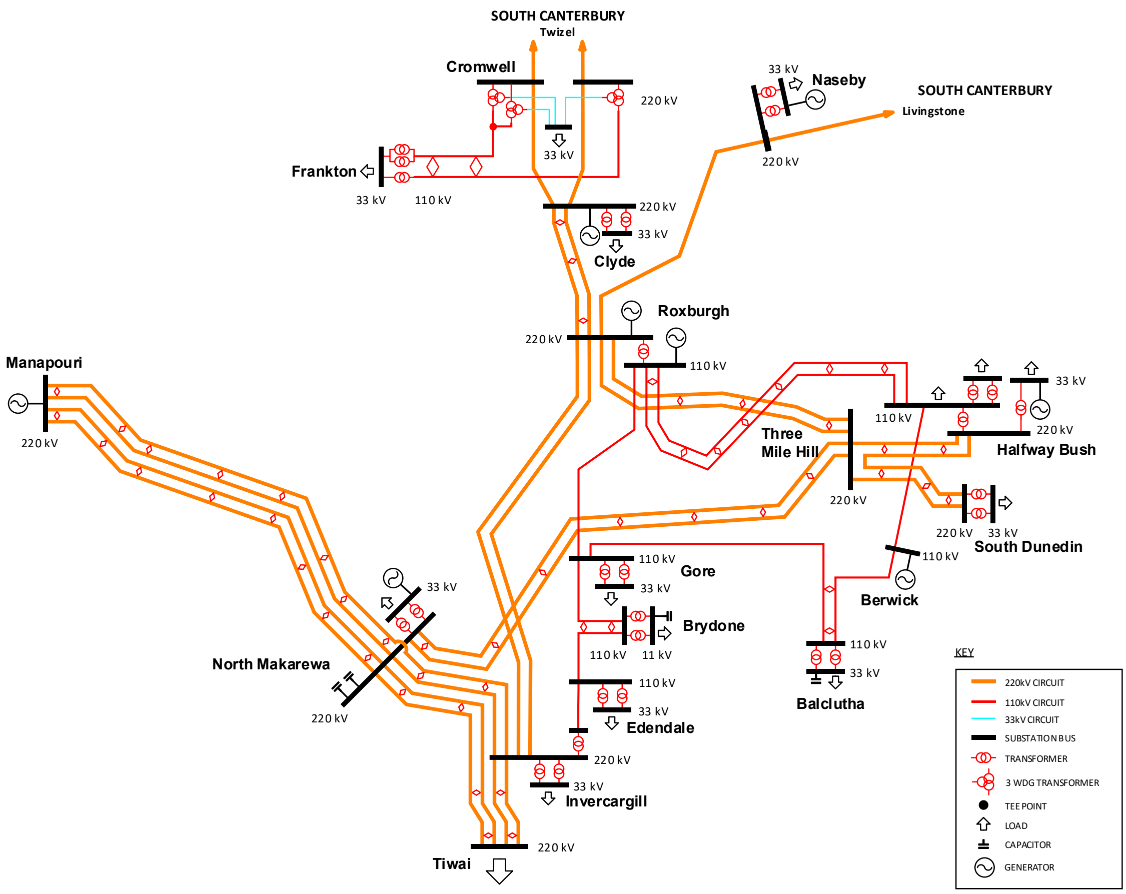


Figure 19-2: Otago-Southland region transmission schematic



19.1.1 Transmission into the region

Three 220 kV circuits connect the Otago-Southland region to the rest of the National Grid. The region has substantial hydro generation, much of which is consumed locally. Transmission capacity into the region is largely driven by the local hydrology: during wet periods, significant amounts of power are exported to the Waitaki Valley, while during dry periods power may need to be imported.

19.1.2 Transmission within the region

Transmission within the Otago-Southland region comprises 220 kV and 110 kV transmission circuits with interconnecting transformers located at Cromwell, Gore, Halfway Bush, Roxburgh, and Invercargill.

Capacitors are installed at North Makarewa to improve system voltage and voltage stability performance. There are also capacitors on the supply buses at Brydone and Balclutha for power factor correction and system voltage support.

The region can be divided into four load centres:

- The Southland 220 kV area, comprising the Tiwai, Invercargill, and North Makarewa substations, is predominantly supplied from Manapouri, or via the 220 kV Invercargill–Roxburgh circuits at times of low Manapouri generation.
- The Dunedin area, comprising South Dunedin and Halfway Bush, is predominantly supplied via Three Mile Hill.
- The Southland 110 kV network is supplied via the five interconnecting transformers at Halfway Bush, Roxburgh, and Invercargill and Gore.
- Central Otago load is supplied from Cromwell and Frankton via the Cromwell interconnecting transformers.

The 110 kV transmission network predominantly comprises low-capacity circuits supplying the smaller centres within the region. Both capacity and voltage issues can arise during outages, especially during the summer and shoulder seasons (dairying loads). In addition, many of the transformers connected to the 110 kV transmission network are older, single-phase units.

19.2 Otago-Southland demand

The Otago-Southland regional peak demand[1] is forecast to grow by an average 0.8 per cent per annum over the next 15 years, from 1,114 MW in 2019 to 1,257 MW by 2034. This is lower than the national average growth rate of 1.3 per cent per annum.

Table 19-1 sets out forecast peak demand (prudent growth[2]) for each grid exit point over the forecast period.

Table 19-1: Forecast annual peak demand (MW) at Otago-Southland grid exit points to 2034

Grid exit point	Power factor	Peak demand (MW)											
		2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2034**
Balclutha	0.97	34	34	36	37	42	53	54	54	54	54	54	56
Brydone	0.78	11	11	11	11	11	11	11	11	11	11	11	12
Clyde	0.92	11	11	12	12	12	12	13	13	13	14	14	14
Cromwell	0.99	37	38	39	40	41	43	44	45	46	47	47	49
Edendale	0.95	34	34	35	34	36	36	36	36	36	38	38	41
Frankton	1.00	67	70	71	73	75	77	79	81	83	85	85	85
Gore	0.97	34	34	33	35	34	35	35	35	35	36	36	36
Halfway Bush 110 kV[1]	0.99	6	6	6	6	6	6	6	6	6	6	6	5
Halfway Bush 33 kV1[1]	1.00	84	84	85	85	85	85	84	83	80	77	74	66
Halfway Bush 33 kV-2[2]	1.00	50	50	51	51	51	51	51	51	51	50	50	40
Invercargill	0.99	94	97	98	100	102	104	106	108	110	111	112	106
Naseby	0.97	32	32	33	33	34	35	35	36	36	36	37	40
North Makarewa	0.97	60	62	64	65	67	68	70	71	72	73	74	73
South Dunedin	0.99	88	89	91	92	93	94	95	96	96	96	97	101
Tiwai	0.97	622	619	619	619	619	619	619	619	619	619	619	619

1. The load at Halfway Bush 110 kV is an interim arrangement to supply Palmerston and surrounding areas. The customer will transfer this load to 33 kV once works related to replacement of supply transformers and the outdoor to indoor conversion at Halfway Bush are commissioned in 2019. The date for the load transfer is likely to be in 2020-2021 but is unconfirmed, so the load forecast shows continued supply at 110 kV indefinitely.
2. We are replacing the 33 kV outdoor switchgear with an indoor switchboard, and will be making the HWB 33 kV buses solid. The transfer of all feeders off the existing bus is expected in 2020-2021.

[1] For discussion on demand forecasting see Chapter 3, section 3.1.

[2] Our prudent peak forecast has been constructed using a 10 per cent probability of exceedance forecast of underlying demand for the first seven years of the forecast period. For the rest of the forecast period we assume an expected (or mean) rate of underlying growth. Refer to Chapter 3 for further information on demand forecasting.

19.3 Otago-Southland generation

The Otago-Southland region's generation capacity is currently 1,859 MW.[3] Generation within the region contributes a major portion of total South Island generation. It usually exceeds regional demand, with the surplus exported via the National Grid.

Table 19-2 lists the generation forecast for each grid injection point for the forecast period. This includes all known and committed generation stations, including those embedded within the local lines company networks (PowerNet, OtagoNet, or Aurora Energy).[4]

Further generation may be developed during the period but is not sufficiently advanced to be included in our forecasts. (Refer to section 19.5.7 for more information on potential new generation).

Table 19-2: Forecast annual generation capacity (MW) at Otago-Southland grid injection points to 2034 (existing and committed generation)

	Generation capacity (MW)											
Grid injection point (location/name if embedded)	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2034**
Clyde	432	432	432	432	432	432	432	432	432	432	432	432
Manapouri	850	850	850	850	850	850	850	850	850	850	850	850
Roxburgh	320	320	320	320	320	320	320	320	320	320	320	320
Berwick/Halfway Bush (Waipori and Mahinerangi)	84 36	84 36	84 36	84 36	84 36	84 36	84 36	84 36	84 36	84 36	84 36	84 36
Balclutha (Mt. Stuart)	8	8	8	8	8	8	8	8	8	8	8	8
Clyde (Lower Fraser)	3	3	3	3	3	3	3	3	3	3	3	3
Clyde (Upper Fraser)	0	8	8	8	8	8	8	8	8	8	8	8
Clyde (Horseshoe Bend hydro and wind)	4 2	4 2	4 2	4 2	4 2	4 2	4 2	4 2	4 2	4 2	4 2	4 2
Clyde (Talla Burn)	2	2	2	2	2	2	2	2	2	2	2	2
Clyde (Teviot and Kowhai)	11 2	11 2	11 2	11 2	11 2	11 2	11 2	11 2	11 2	11 2	11 2	11 2
Cromwell (Roaring Meg)	4	4	4	4	4	4	4	4	4	4	4	4
Frankton (Wye Creek)	1	1	1	1	1	1	1	1	1	1	1	1
Gore (Blue Mountain Lumber)	1	1	1	1	1	1	1	1	1	1	1	1
Halfway Bush (Deep Stream)	5	5	5	5	5	5	5	5	5	5	5	5
Invercargill (Flat Hill)	7	7	7	7	7	7	7	7	7	7	7	7
Naseby (Falls Dam)	1	1	1	1	1	1	1	1	1	1	1	1
Naseby (Paerau)	10	10	10	10	10	10	10	10	10	10	10	10
Naseby (Patearoa)	2	2	2	2	2	2	2	2	2	2	2	2
North Makarewa (Monowai)	7	7	7	7	7	7	7	7	7	7	7	7
North Makarewa (White Hill)	58	58	58	58	58	58	58	58	58	58	58	58

3 This excludes the potential Clyde and Roxburgh generation station capacity increases for which resource consents have been sought.

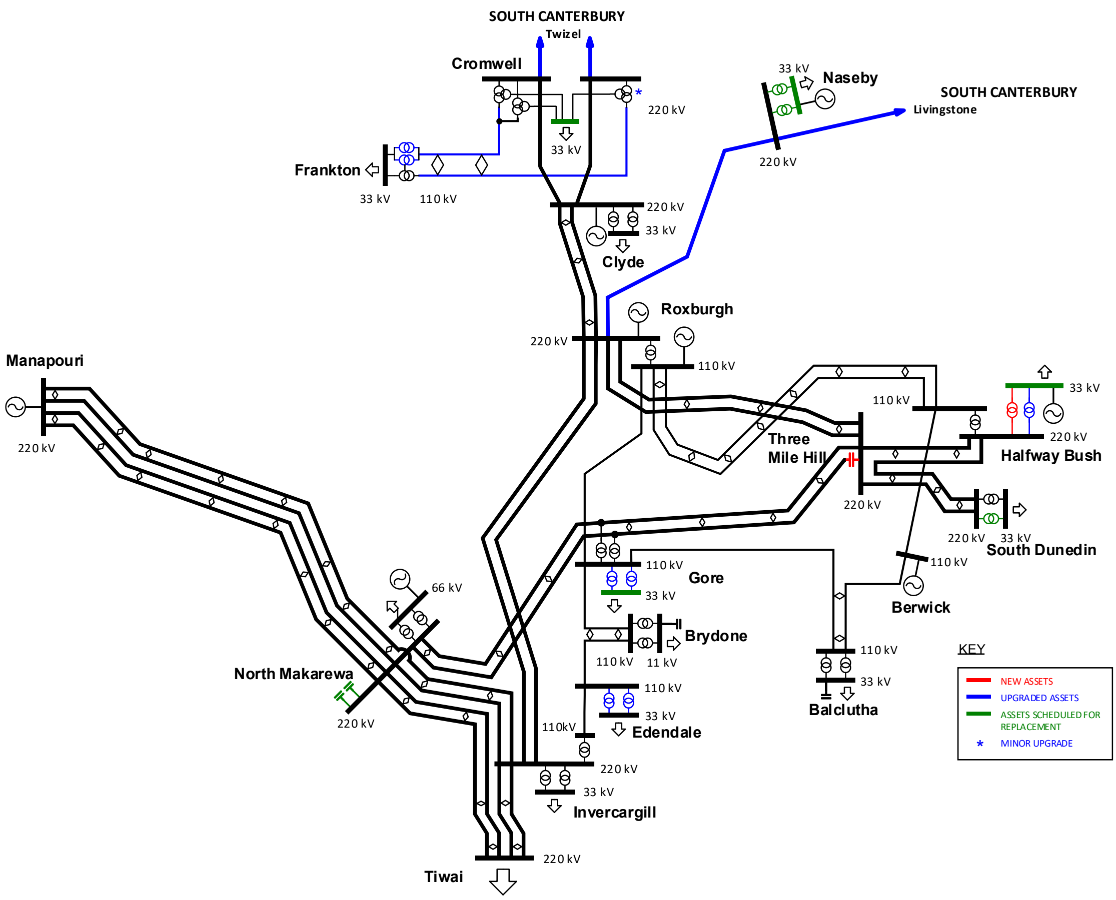
4 Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

19.4 Grid enhancement approach

19.4.1 Possible future Otago-Southland transmission configuration

Figure 19-3 shows the possible configuration of Otago-Southland transmission in 2034. New assets, upgraded assets, and assets scheduled for replacement within the forecast period (based on potential enhancement approaches set out in the following sections) are shown.

Figure 19-3: Possible Otago-Southland transmission configuration in 2034



19.4.2 Enhancement approach

We aim to ensure secure transmission into and within the Otago-Southland region into the future. Through the E&D process we assess transmission capacity and reactive support requirements in the region over the next 15 years (while remaining cognisant of longer-term development opportunities). In developing Grid Enhancement Approaches to address identified issues and opportunities we take into account uncertainty in future demand, generation and technological developments.

The issues and opportunities with 220 kV circuits connecting the region to the Waitaki Valley are discussed in the South Island section of Chapter 6, Grid Backbone.

The Otago-Southland transmission issues likely requiring E&D or Customer-funded investments over the next 10-15 years include:

Section number	Issue
Regional	
19.4.2.1	Southland 110 kV transmission capacity and low voltage
Site by grid exit point	
19.4.2.2	Balclutha supply capacity
19.4.2.3	Cromwell supply capacity
19.4.2.4	Edendale supply capacity
19.4.2.5	Frankton transmission and supply capacity
19.4.2.6	Gore supply capacity
19.4.2.7	Halfway Bush 33 kV supply capacity
19.4.2.8	Naseby supply capacity
19.4.2.9	North Makarewa supply capacity

19.4.2.1 Southland 110 kV transmission capacity and low voltage

The configuration of the Southland 110 kV network can result in low voltages and the 110 kV network overloading for outages on some of the region's circuits and/or interconnecting transformers.

- Balclutha experiences low voltages for outages of Balclutha–Berwick–Halfway Bush or Balclutha–Gore circuits.
- Brydone and Edendale may experience low voltages for outages of any 110 kV circuit between Gore and Invercargill.
- Brydone–Gore and Edendale–Invercargill circuits may overload for an outage of the other circuit towards the end of the forecast period.
- Gore–Roxburgh may overload for an outage of a 220 kV Invercargill–Roxburgh circuit when Manapouri generation is low.
- Gore–Roxburgh may overload for an outage of a 220 kV North Makarewa–Gore–Three Mile Hill circuit.

Enhancement approach:

The issues may be resolved by:

- increasing the tap position on the Invercargill, Gore and/or Halfway Bush interconnecting transformers to resolve low voltage issues.
- increasing the tap position of the Edendale supply transformers (off-load tap changers) over the dairy peak load periods to resolve low voltage issues.
- using operational measures such as oad control or an special protection scheme to reduce load post-contingency, or line reconductoring.
- splitting the normally solid Gore 110 kV bus in future to address overloading of the 110 kV network. This approach will exacerbate low voltage issues at Balclutha.[5]
- using operational measures to manage the small Gore–Roxburgh overload.

19.4.2.2 Balclutha supply capacity

The forecast load growth at Balclutha is driven by industrial load growth in Milburn and Balclutha.

The peak load at the Balclutha 33 kV grid exit point is forecast to exceed the n-1 summer capacity of the supply transformers by 2022. The capacity is limited by the thermal capacity of the transformers.

[5] The Gore 110 kV bus split has Balclutha–Gore and Gore–Roxburgh on one side of the split and the remaining circuits on the other side. For a Balclutha–Berwick–Halfway Bush outage, Gore is supplied supplied from Roxburgh which causes a large voltage drop along this long circuit.

The next constraint is overloading of the Balclutha–Berwick–Halfway Bush circuit for the outage of the Balclutha–Gore circuit, and vice-versa.

Enhancement approach:

We are discussing future options (and timing) with PowerNet and other stakeholders. Options include a special protection scheme to automatically shed load post contingency, replacing supply transformers or a new grid exit point from the North Makarewa–Three Mile Hill 220 kV line.

Customer investments

Project Name	Balclutha supply capacity
Project description:	New grid exit point
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2022
Indicative cost [$ million]:	Scope dependant
Part of the GEIR?	No

19.4.2.3 Cromwell supply capacity

Two transformers[6] at Cromwell provide supply at 33 kV to the areas of Cromwell, Queensberry, Wanaka and their surrounding areas, and connect the Roaring Meg embedded generator. In recent years we have seen steady load growth during the summer, mainly due to irrigation loads. This has caused summer to become the peak load season though it is expected to change to winter peaking in 2024. The peak load from the Cromwell 33 kV grid exit point is forecast to exceed the n-1 summer capacity of the supply transformers from 2019. The capacity of the supply transformers is currently limited by protection and switchgear ratings.

Enhancement approach:

- Initially, the issue can be managed using operational measures (shifting or limiting load within the transformers' capability).
- We plan to replace the existing 33 kV outdoor switchyard at Cromwell in 2020-2022 (base capex replacement and refurbishment) and are discussing options with the customer. As part of this work we expect the switchgear and protection components that limit the supply transformers' capacity will be resolved. With these limits resolved, the n-1 capacity at Cromwell will increase to 65/68 MVA (summer/winter), which will be sufficient for the forecast period.

Base Capex R&R investments

Project Name:	Cromwell supply capacity
Project description:	Replace existing outdoor switchyard
Project's state of completion:	Proposed
OAA level completed:	None
Grid need date:	2020-22
Indicative cost ($ million):	Scope dependant
Part of the GEIR?:	No

6 The two transformers are 220/110/33 kV; the 110 kV windings connect to the line supplying Frankton and the 33 kV windings supply the 33 kV bus at Cromwell. One transformer is a bank of two transformers connected in parallel and operated as a single unit.

19.4.2.4 Edendale supply capacity

The Edendale 33 kV grid exit point serves Fonterra's Edendale dairy plant and the local rural load. The summer peak load at Edendale is expected to exceed the n-1 capacity of the supply transformers from 2019.

The supply transformers are due for risk-based condition replacement towards the end of the forecast period.

Enhancement approach:

- Initially, the issue can be managed using operational measures (shifting or limiting load within the transformers' capability).
- We are discussing future options (and timing) with PowerNet and other stakeholders. Options include upgrading the transformers' capacity by adding additional cooling equipment, replacing the existing transformers with higher rated units, or developing a new grid exit point. The planned refurbishment of the Edendale supply transformers (base capex replacement and refurbishment) are high priority as they pose a high risk of failure. However, if our customer requests an upgrade of the transformers within the next few years the refurbishment will not be required.

Customer investments

Project Name	Edendale supply capacity
Project description:	Replace Edendale supply transformers with higher capacity units
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2019
Indicative cost [$ million]:	9.9
Part of the GEIR?	No

19.4.2.5 Frankton transmission and supply capacity

The supply at Frankton serves the resort town of Queenstown and surrounding areas. Frankton's demand is driven by ski-field operations and tourism activity around the area. Load is forecast to continue increasing, influenced by new proposed residential/holiday subdivision developments.

Peak load at Frankton is forecast to exceed the n-1 winter thermal capacity of the 110 kV Cromwell–Frankton circuits from 2019 and the n-1 winter capacity of the transformers from 2022.

Enhancement approach:

We are discussing options with Aurora and OtagoNet. Possible options include one or a combination of the following:

- resolving the transformer protection limits and Cromwell and Frankton
- thermally upgrading and/or implementing variable line rating on the Cromwell–Frankton circuits
- using a special protection scheme to automatically reduce load post-contingency
- seeking non-transmission alternatives such as distributed generation and/or demand response
- replacing the existing bank of transformers with a higher-rated unit.

In the short term, we will use operational measures, and we are in the process of upgrading the transformer protection. In the medium term we will likely thermally upgrade the circuits.

Customer investments

Project Name	Frankton supply capacity (short term)
Project description:	Remove metering, protection and current transformer limits
Project's state of completion	In progress
OAA level completed:	None
Grid need date:	2019
Indicative cost [$ million]:	0.05
Part of the GEIR?	No

Customer investments

Project Name	Frankton supply capacity (medium term)
Project description:	Thermal upgrade of lines
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2022
Indicative cost [$ million]:	Scope dependant
Part of the GEIR?	No

Customer investments

Project Name	Frankton supply capacity (long term)
Project description:	Transformer upgrade
Project's state of completion	Possible
OAA level completed:	None
Grid need date:	2024
Indicative cost [$ million]:	Scope dependant
Part of the GEIR?	No

19.4.2.6 Gore supply capacity

The supply at Gore 33 kV serves rural farms, Tapanui and Gore townships, the village of Waikaka, and a meat processing plant.

Based on our demand forecasts, the peak load season at Gore will change from summer to winter in 2021, then to shoulder in 2024. The peak load at Gore is forecast to exceed the n-1 summer capacity of the transformers in 2019.

Enhancement approach:

- Initially, the issue can be managed using operational measures (shifting or limiting load within the transformers' capability).

We will discuss future supply options with PowerNet, including:

- load projections and developments in the area
- managing the load to within the capability of the existing transformers
- replacing the existing transformers with two higher-rated units when they are due for risk based condition replacement (due early 2030s)

Base Capex R&R investment

Project Name	Gore supply transformer upgrade
Project description:	Upgrade supply transformers T2 and T3
Project's state of completion	Proposed
OAA level completed:	None
Grid need date:	2019
Indicative cost [$ million]:	9.5
Part of the GEIR?	No

19.4.2.7 Halfway Bush 33 kV supply capacity

The supply at Halfway Bush 33 kV serves a large portion of the city of Dunedin and the town of Palmerston. Additionally, it connects a portion of the Waipori generation.

Peak load at Halfway Bush currently exceeds the n-1 winter capacity of the transformers when embedded generation at Waipori is low.

Enhancement approach:

Presently, we manage the loading of the supply transformers operationally, by:

- transferring load between the Halfway Bush 110 kV and 220 kV buses with the 33 kV bus split[7]
- increasing output from Waipori generation which injects into the Halfway Bush 33 kV bus, and/or
- transferring up to 5 MW to the South Dunedin grid exit point via the distribution network.

We have a committed investment program with our customers at Halfway Bush (Aurora and OtagoNet). The work has is being undertaken in a coordinated manner; all all of the works are due to be commissioned in 2019:

- Aurora is transferring around 15 MW of load to the South Dunedin grid exit point.
- We are replacing the 33 kV outdoor switchgear with an indoor switchboard.
- We are replacing the two 110/33 kV, 50 MVA supply transformers with a single 220/33 kV, 120 MVA supply transformer. This will provide a small increase in n-1 transformer capacity as well as allowing the 33 kV bus to be operated solid, improving security.
- OtagoNet will convert its remaining 110 kV feeder to 33 kV and connect onto the Halfway Bush 33 kV bus to provide a second 33 kV feeder.

Following this co-ordinated investment programme, we expect the n-1 capacity of the 220/33 kV supply transformers will still be exceeded when there is low Waipori embedded generation. However, based on historic availability, we (and our customers) expect that embedded generation from Waipori will be sufficient to provide n-1 security to the load for the forecast period.

In the longer term, replacing the lower rated (100 MVA) 220/33 kV supply transformer with a 120 MVA unit will further increase the n-1 capacity for the Halfway Bush 33 kV. Our customers have not yet requested a capacity increase (beyond the committed investments discussed above) so we have not planned for this investment.

7 Two 110/33 kV transformers supply one 33 kV bus while a single 220/33 kV transformer supplies the other 33 kV bus. A loss of one 110/33 kV supply transformer may overload the parallel unit.

Base Capex R&R investments

Project Name:	Halfway Bush–T1 and T2 replacement and outdoor to indoor conversion
Project description:	Replace 110/33 kV transformers and carry out 33 kV outdoor to indoor conversion
Project's state of completion:	Delivery
OAA level completed:	AL 3d
Grid need date:	2019
Indicative cost ($ million):	$10.8
Part of the GEIR?:	No

19.4.2.8 Naseby supply capacity

The Naseby 33 kV grid exit point supplies Oceana Gold's mine and rural areas around Naseby. The peak load at Naseby is forecast to exceed the n-1 capacity of the transformers from 2032.

Enhancement approach:

- The 220/33 kV supply transformers will be replaced in 2019-2020 due to risk-based condition. In discussion with PowerNet we will install 220/66-33 kV 40 MVA transformers.
- We will remove the 33 kV outdoor bus and connect the two 66 kV feeders directly to the transformer through outdoor disconnecting circuit breakers.

Base Capex R&R investments

Project Name:	Naseby supply transformer replacement
Project description:	Replace and upgrade 220/33 kV transformers
Project's state of completion:	Proposed
OAA level completed:	AL 2p
Grid need date:	2032
Indicative cost ($ million):	7.5
Part of the GEIR?:	No

19.4.2.9 North Makarewa supply capacity

The supply at North Makarewa 33 kV serves rural farms, small towns, villages, small industrial plants and a coal mine.

Based on our demand forecasts, the peak load season is expected to change from summer to shoulder peaking in 2024. The peak load at North Makarewa is forecast to exceed the n-1 shoulder capacity of the transformers in 2029.

Enhancement approach:

The transformer capacity is limited by cables, circuit breakers, current transformers, disconnectors and protection. Cable, circuit breaker and protection replacements are scheduled for 2024 (base capex replacement and refurbishment). The transformer capacity will then be limited by the disconnectors at 71 MVA (currently 67 MVA summer/winter).

Base Capex R&R investments

Project Name:	North Makarewa supply capacity
Project description:	Remove cable, circuit breaker, current transformer limits
Project's state of completion:	Proposed
OAA level completed:	AL 2p
Grid need date:	2029
Indicative cost ($ million):	1.8
Part of the GEIR?:	No

19.5 Asset capability and management

We have assessed the transmission capacity and reactive support requirements in the region for the next 15 years. When an issue or opportunity exists, we have examined initial options and actions that may be taken to address it. Grid Enhancement Approaches (refer to section 19.4.2) have been developed to address issues or opportunities that require action within the forecast period and where investment is justified.

This section discusses the main inputs to the E&D process. These are:

- transmission capability (taking into account forecast demand and generation and possible technological changes)
- customer requests
- generation proposals and opportunities
- risk-based asset replacements
- significant upcoming work planned over the period
- asset feedback (information on assets or issues submitted through the asset feedback process).

19.5.1 Otago-Southland transmission system significant upcoming work

We integrate our capital project and maintenance works to enable system issues to be resolved, if possible, when assets are replaced or refurbished. Table 19-3 lists the significant upcoming works[8] proposed for the Otago-Southland region for the next 15 years that may significantly impact related system issues or connected parties.

Table 19-3: Proposed significant upcoming work for the Otago-Southland transmission system

Description	Tentative year	E&D issue
Clyde 33 kV switchboard replacement	2025-2027	None
Cromwell 33 kV outdoor switchgear replacement	2020-2022	19.4.2.3
Edendale 110/33 kV supply transformers risk-based condition replacement	2029-2032	19.4.2.4
Cromwell–Frankton 110 kV thermal upgrade Frankton 33 kV supply transformers protection limits upgrade	2021-2022 2021-2022	19.4.2.5 19.4.2.5
Gore 110/33 kV supply transformers risk-based condition replacement Gore 33 kV outdoor to indoor conversion	2031-2034 2017-2019	19.4.2.6 19.4.2.6
Halfway Bush 110/33 kV supply transformers risk based condition replacement Halfway Bush 33 kV outdoor to indoor conversion Halfway Bush 220/33 kV supply transformer risk-based condition replacement	2016-2019 2016-2019 2033-2035	19.4.2.7 19.4.2.7 19.4.2.7
Naseby 220/33 kV supply transformers risk-based condition replacement Naseby 33 kV rationalisation to 66 kV outdoor circuit breakers	2019-2020 2019-2020	19.4.2.8 19.4.2.8
North Makarewa supply transformer protection replacement North Makarewa circuit breaker replacement, remove current transformer limits North Makarewa incomer cable replacement	2023-2025 2024-2026 2024-2026	19.4.2.9 19.4.2.9 19.4.2.9

19.5.2 Otago-Southland transmission system asset feedback

The Asset Feedback Register does not include any entries related to E&D specific to the Otago-Southland region.

19.5.3 Changes since the 2018 Transmission Planning Report

Table 19-4 lists the specific issues that are either new or no longer relevant within the forecast period (relative to our previous Transmission Planning Report).

Table 19-4: Changes Since the 2018 TPR

Issues	Change
Southland transmission capacity and low voltage	Modified. Commissioning two 220/110 kV transformers at Gore has resolved the issue for now, but the issue reappears towards the end of the forecast period.
Balclutha supply transformer capacity	Added. Increased load forecast.
South Dunedin supply transformer capacity	Removed. Decreased load forecast.

19.5.4 Otago-Southland transmission capability

This transmission capability section reports whether the Grid can reasonably be expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, forms part of the Grid Reliability Report (GRR).

Table 19-5 summarises identified issues that may affect the Otago-Southland region during the next 15 years. In each case we have detected a condition that would constrain network capacity if action were not taken. Each issue is discussed in more detail below.

This transmission capability section reports whether the Grid can reasonably be expected to meet (n-1) security requirements over the next 15 years. This section, together with the demand and generation sections, forms part of the Grid Reliability Report (GRR).

8 Risk-based replacement of the asset is included in this list.

Table 19-5: Otago-Southland region transmission issues – regional/ by grid exit point

Section number	Issue
Regional	
19.5.4.1	Southland transmission capacity and low voltage
Site by grid exit point	
19.5.4.2	Balclutha supply transformer capacity
19.5.4.3	Cromwell supply transformer capacity
19.5.4.4	Edendale supply transformer capacity
19.5.4.5	Frankton transmission and supply security
19.5.4.6	Gore supply transformer capacity
19.5.4.7	Halfway Bush supply transformer capacity
19.5.4.8	Naseby supply transformer capacity
19.5.4.9	North Makarewa supply transformer capacity
19.5.4.10	Waipori transmission security
Bus security	
19.5.5.1	Transmission bus security
19.5.5.2	Halfway Bush bus security

19.5.4.1 Southland transmission capacity and low voltage

Issue

The 220 kV Southland transmission network links the substations at Roxburgh, Halfway Bush, Gore and Invercargill. 220/110 kV interconnecting transformers at these four substastions supply the Southland 110 kV network.

The 110 kV network features a geographical triangle between Roxburgh, Halfway Bush and Gore, with a single 110 kV circuit from Gore to Brydone, Edendale, and Invercargill.

Some of the Southland 110 kV circuits and/or interconnecting transformers may overload for an outage of:

- some of the Southland 110 kV circuits and interconnecting transformers. Brydone–Gore and Edendale–-Invercargill circuits may overload for an outage of the other circuit towards the end of the forecast period.
- one of the 220 kV Invercargill–Roxburgh circuits
- one of the 220 kV Roxburgh–Three Mile Hill circuits.

The Gore-Roxburgh circuit may overload for an outage of a 220 kV North Makarewa–Gore–Three Mile Hill circuit.

A 220 kV Invercargill–Roxburgh circuit may also overload for an outage of the parallel circuit when Manapouri generation is low.

A 110 kV Gore-Roxburgh circuit may overload for an outage of a 220 kV Invercargill–Roxburgh circuit when Manapouri generation is low.The severity of these overloads depends on Roxburgh, Manapouri, and Waipori generation at the time of the outage.

In addition, an outage of some of the Southland transmission circuits or interconnecting transformers may result in low voltages at Gore, Brydone, and Edendale.

What next?

Presently we manage the thermal and voltage issues operationally.

19.5.4.2 Balclutha supply transformer capacity

Issue

Balclutha load is supplied by:

- two 110 kV circuits, one from Gore, one from Berwick, with a
  - total nominal installed capacity of 101/124 MVA
  - n-1 capacity of 51/62 MVA (summer/winter).
- two 110/33 kV transformers (rated at 30 MVA each) supply Balclutha's 33 kV loads, providing:
  - total nominal installed capacity of 60 MVA
  - n-1 capacity of 37/39 MVA (summer/winter).

Peak load at Balclutha is forecast to exceed the n-1 summer transformer capacity by 2 MW in 2022, increasing to approximately 21 MW in 2034. For the contingency of Balclutha–Gore 1, Balclutha–Berwick–Halfway Bush overloads by 8 MW by 2024, increasing to 9 MW for subsequent years, then decreases back to 8 MW in 2034 (Table 19-6).

Table 19-6: Balclutha supply transformer overload forecast (33 kV supply)

Grid exit point	Overload (MW)										
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Balclutha	0	0	0	2	7	18	19	19	19	19	19	21
Balclutha-Berwick circuit	0	0	0	0	0	8	9	9	9	9	9	8

What next?

A discussion for future options is underway with PowerNet. In the interim, the issue can be managed using operational measures. Refer to section 19.4.2.2 for our enhancement approach.

19.5.4.3 Cromwell supply transformer capacity

Issue

Two 220/110/33 kV transformers (rated at 73 MVA[9] and 50 MVA) supply Cromwell's 33 kV loads, providing:

- total nominal installed capacity of 123 MVA
- n-1 capacity of 41/41 MVA[10] (summer/winter).

Under our demand forecasts, the peak season changes from summer to winter in 2024. Peak load at Cromwell 33 kV is forecast to exceed the n-1 summer capacity of the transformers by approximately 3 MW in 2019, increasing to approximately 8 MW in 2034 (Table 19-7).

Table 19-7: Cromwell supply transformer overload forecast (33 kV supply)

Grid exit point	Transformer overload (MW)										
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Cromwell	3	4	3	3	2	2	3	5	6	7	7	8

9 This is a bank of two transformers connected in parallel and operated as a single unit, with the 33 kV transformer windings providing a combined nominal installed capacity of 73 MVA.

10 The transformers' capacity is limited by a protection limit of 41 MVA, followed by circuit breaker, current transformer, and disconnector limits of 46 MVA, and a bus section limit of 50 MVA. With these limits resolved, the n-1 capacity will be 65/68 MVA (summer/winter).

What next?

An outdoor to indoor switchyard conversion is proposed for this site, which will resolve the issues causing the constraint. In the interim, the issue can be managed using operational measures. Refer to section 19.4.2.3 for our enhancement approach.

19.5.4.4 Edendale supply transformer capacity

Issue

Two 110/33 kV transformers supply Edendale's load, providing:

- total nominal installed capacity of 60 MVA
- n-1 capacity of 34/36 MVA (summer/winter).

Peak load at Edendale is forecast to exceed the n-1 summer capacity of the supply transformers by approximately 8 MW in 2019, increasing to approximately 18 MW in 2034 (Table 19-8).

Table 19-8: Edendale supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Edendale	8	9	12	12	13	13	13	14	14	15	15	18

What next?

Operational measures can be used to manage this issue. We are also discussing future supply options with PowerNet. Refer to section 19.4.2.4 for our enhancement approach.

19.5.4.5 Frankton transmission and supply security

Issue

The Frankton load is supplied by:

- two 110 kV circuits from Cromwell, with a
  - total nominal installed capacity of 127/152 MVA (summer/winter)
  - n-1 capacity of 63/76 MVA[11] (summer/winter)
- two 110/33 kV supply transformers rated at 66 MVA[12] and 85 MVA, providing:
  - total nominal installed capacity of 151 MVA
  - n-1 capacity of 80/80 MVA[13] (summer/winter).

There is no 110 kV bus at Frankton, so a fault on either a circuit or Frankton supply transformer will cause both the circuit and supply transformer to be taken out of service.

Peak load at Frankton is forecast to exceed the n-1 winter thermal capacity of the circuits from approximately 2019, and the n-1 winter capacity of the transformers by approximately 2 MW in 2022. These forecast overloads would increase to approximately 26 MW and 14 MW, respectively, in 2034 (Table 19-9).

11 The circuits' capacity is limited by protection; with these limits resolved, the n-1 capacity will be 63/77 MVA (summer/winter).

12 This is a bank made up of two transformers connected in parallel and operated as a single unit, providing a total nominal installed capacity of 66 MVA.

13 The transformer's capacity is limited by a protection limit (80 MVA) on T4 and the thermal limit of the parallel bank of transformers (T2A and T2B).

Table 19-9: Frankton supply transformer and Cromwell–Frankton circuit overload forecast

Grid exit point	Overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Frankton supply transformer	0	0	0	2	4	6	8	10	12	13	14	14
Cromwell–Frankton circuits	9	11	13	15	17	19	21	23	25	26	27	26

What is next?

Operational measures can be used to manage the issue. We will also discuss future supply options with Aurora and OtagoNet. Refer to section 19.4.2.5 for our enhancement approach.

19.5.4.6 Gore supply transformer capacity

Issue

Two 110/33 kV transformers supply Gore's 33 kV load, providing:

- total nominal installed capacity of 60 MVA
- n-1 capacity of 37/39 MVA (summer/winter)

Peak load at Gore is forecast to exceed the transformers' n-1 summer capacity by approximately 0.8 MW in 2019, increasing to 2.1 MW in 2034 (Table 19-10).

Table 19-10: Gore supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Gore	0.8	0.8	0.4	0.1	0.3	0.7	1.1	1.4	1.6	1.9	2.1	2.1

What's next?

The two Gore supply transformers are due for risk-based condition replacement in the early 2030's. Until then, operational measures can be used to manage the issue. See section 5.623.-1.0 for our enhancement approach.

19.5.4.7 Halfway Bush supply transformer capacity

Issue

Halfway Bush's 33 kV load is supplied by:

- two 110/33 kV transformers, each with nominal capacity of 50 MVA, and n-1 capacity of 54/57 MVA (summer/winter)
- one 220/33 kV transformer, with a nominal capacity of 100 MVA.

We operate the 33 kV bus split with:

- both 110/33 kV transformers supplying one bus section
- the 220/33 kV transformer supplying the other bus section, resulting in no continuous n-1 supply security.

The 33 kV bus split can be closed during an outage of any one of the three transformers supplying the 33 kV load. This provides an n-1 capacity of 107/114 MVA (summer/winter) for an outage of the 220/33 kV transformer.

A project will be commissioned later in 2019 to replace the two 110/33 kV transformers with a single 220/33 kV transformer which will be operated with the 33 kV bus closed to provide n-1 security, resulting in:

- two 220/33 kV supply transformers rated at 100 MVA and 120 MVA, giving an n-1 capacity of 124/131 MVA (summer/winter).

Following this co-ordinated investment program, we expect the n-1 capacity of the 220/33 kV supply transformers will still be exceeded when there is low Waipori embedded generation. However, based on historic availability, we (and our customers) expect that embedded generation from Waipori will be sufficient to provide n-1 security to the load for the forecast period.

After the transformer replacement, peak load at Halfway Bush is forecast to exceed the n-1 winter capacity of the two 220/33 kV supply transformers by approximately 0.6 MW in 2026 increasing to approximately 1.1 MW in 2029. The forecast n-1 overoading then reduces to 0 MW in 2034[14] due to underlying demand forecast assumptions relating to uptake of new technologies such as batteries installed as part of residential photovoltaic installations, utility-scale batteries and electric vehicles providing power to the grid at peak (see Table 19-11).

Table 19-11 Halfway Bush supply transformer overload forecast

Grid exit point	Transformer overload (MW)										
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
Halfway Bush 1 and 2	0	0	0	0	0	0	0	0.6	0.9	1.3	1.1	0

What next?

We (and our customers) expect the Waipori generation embedded at the Halfway Bush 33 kV will be available and sufficient to provide security to the load for the forecast period. Refer to section 19.4.2.7 for our enhancement approach.

19.5.4.8 Naseby supply transformer capacity

Issue

Two 220/33 kV transformers supply Naseby's load, providing:

- total nominal installed capacity of 70 MVA
- n-1 capacity of 35/35 MVA (summer/winter).

Under our demand forecasts, the peak season at Naseby changes from shoulder to summer in 2023. Peak load at Naseby[15] is forecast to exceed the transformers' n-1 summer/shoulder capacity by approximately 0.8 MW in 2032, increasing to approximately 2.1 MW in 2034 (see Table 19-12).

Table 19-12: Naseby supply transformer overload forecast

Grid exit point	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
	Transformer overload (MW)											
Naseby	0	0	0	0	0	0	0	0	0	0	0	2.1

What next?

The Naseby supply transformers are due for ris- based condition replacement in 2018-2020. See section 19.4.2.8 for our enhancement approach.

14 This forecast assumes that Waipori and Mahinerangi generation stations inject 16 MW of power into the Halfway Bush 33 kV bus.

15 The forecast peak load at Naseby assumes that the embedded generation in the area (Paearu and Falls Down) injects 6 MW into the Naseby 33 kV and load will be curtailed if generation is not available.

19.5.4.9 North Makarewa supply transformer capacity

Issue

Two 220/33 kV transformers supply North Makarewa's load, providing:

- total nominal installed capacity of 120 MVA
- n-1 capacity of 67/67 MVA[16] (summer/winter).

Peak load at North Makarewa is forecast to exceed the transformers' n-1 summer capacity by approximately 0.6 MW in 2028 increasing to 2.1 MW in 2034 (see Table 19-13).

Table 19-13: North Makerewa supply transformer overload forecast

Grid exit point	Transformer overload (MW)											
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034
North Makarewa	0	0	0	0	0	0	0	0	0	0.6	1.1	2.1

What next?

Removing the transformer branch component limits will resolve the issue within the forecast period. See section 19.4.2.9 for our enhancement approach.

19.5.4.10 Waipori transmission security

Issue

A portion of the Waipori generation injects into the Berwick 110 kV bus. The 110 kV Balclutha–Berwick and Berwick–Halfway Bush circuits have no line protection at the Berwick ends, so both circuits will trip following a fault on either circuit. The portion of Waipori generation connected at 110 kV will disconnect from the National Grid, resulting in n connection security.

What next?

If n-1 connection security is required, line protection together with the associated 110 kV current transformers and a voltage transformer at Berwick would need to be installed. However, we have not planned for this investment as Trustpower has not requested a higher security level for its Berwick-connected generation.

19.5.5 Otago-Southland bus security

This section presents issues arising from the outage of a single bus section rated at 66 kV and above for the next 15 years.

Bus outages disconnect more than one power system component (for example, other circuits, transformers, reactive support or generating units). Therefore, bus outages may cause greater issues than a single circuit or transformer outage (although the risk of a bus fault is low, being less common than a circuit or transformer outage).

16 The transformers' capacity is limited by cables, circuit breakers, current transformers and disconnectors. With these limits resolved, the rating will be 76/79 MVA (summer/winter).

19.5.5.1 Transmission bus security

Table 19-14 lists bus outages that cause voltage issues or a total loss of supply. Generation is included only if a bus outage disconnects the whole generation station or causes a widespread system impact. Supply bus outages, typically 11 kV and 33 kV, are not listed.

Table 19-14: Transmission bus outages

Transmission bus outage	Loss of supply	Generation disconnection	Transmission issue	Further information
Balclutha 110 kV	Balclutha	-	-	Note 1
Brydone 110 kV	Brydone	-	-	Note 1
Edendale 110 kV	Edendale	-	-	Note 1
Gore 110 kV	Gore	-	-	Note 1
Halfway Bush 110 kV	Halfway Bush 33 kV and 110 kV	-	-	19.5.5.2
Halfway Bush 220 kV	Halfway Bush 33 kV	-	-	19.5.5.2

1. There are no bus section circuit breakers at Balclutha, Brydone, Edendale, and Gore so bus faults cause loss of supply.

Our customers in the Otago-Southland region (Aurora Energy, PowerNet, OtagoNet, Solid Energy, and Dongwha Patinna) have not requested a higher security level. Unless otherwise noted, we do not propose to increase bus security.

19.5.5.2 Halfway Bush bus security

Issue

The Halfway Bush 33 kV bus is normally split.

- One side of the 33 kV bus is supplied through a single 220/33 kV supply transformer. An outage of the associated 220 kV bus will disconnect the single supply transformer and cause a loss of supply.
- The other side of the 33 kV bus is supplied through two 110/33 kV supply transformers. An outage of the 110 kV bus will disconnect both supply transformers and cause a loss of supply.

What next?

The issue is managed operationally at present. Refer to section 19.4.2.7 for our upgrade approach.

19.5.6 Other regional items of interest

19.5.6.1 Cromwell and Frankton security during maintenance

Issue

Cromwell and Frankton are connected to the National Grid via double Tee connections onto the 220 kV Clyde–Twizel circuits. Two 220/110/33 kV transformers connect onto the 220 kV Tee connections without a bus on the 220 kV or 110 kV sides.

An outage on a Clyde–Twizel circuit or a 220/110/33 kV transformer places all of the Cromwell and Frankton loads on n security.

What next?

Aurora and OtagoNet (local lines companies) have expressed interest in increasing security of supply to Cromwell and Frankton during an outage of a Clyde–Twizel circuit or a Cromwell transformer, as these outages place both grid exit points on n security. A preliminary investigation indicates that the solution will require a connection/bus at the 220 kV Tee point. We will investigate this option further when our customers request a higher level of security during Clyde–Twizel circuit outages. We currently have no investments planned to address this issue.

19.5.7 Otago-Southland generation proposals and opportunities

This section details relevant regional issues for generation proposals under investigation by developers and in the public domain, or other generation opportunities. The impact of committed generation projects on the grid backbone is dealt with separately in Chapter 6.

The maximum generation that can be connected depends on several factors and is usually expressed as a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

19.5.7.1 Maximum regional generation

Otago-Southland is a generation-rich region. Surplus generation export is currently constrained during light load conditions to avoid overloading of the 220 kV Livingstone–Roxburgh–Naseby circuit under both normal operating conditions and during contingency events. This issue and our approach is discussed in Chapter 6.

19.5.7.2 Mahinerangi wind generation station

Expansion of the Mahinerangi wind generation station beyond stage 1 can be accommodated on the two 110 kV Halfway Bush–Roxburgh circuits.

Only minor upgrades within the Otago-Southland region would be required to enable the connection of over 200 MW of Mahinerangi generation. Potential upgrades include a thermal upgrade of part of the two 110 kV Roxburgh–Halfway Bush circuits, and increasing the Halfway Bush or Roxburgh 220/110 kV transformer capacity. The level of investment required on the transmission system depends on how the wind generation station development is staged, load growth in the area, and the market dispatch patterns of the wind and hydro generation at Waipori and Roxburgh.

19.5.7.3 Edendale–Gore wind generation stations

There are a number of wind generation prospects in the area to the south-east of the line between Edendale and Gore.

One option is to connect wind generation to the relatively low capacity 110 kV single-circuit line that runs between the Invercargill and Halfway Bush substations, which connects through the Edendale, Brydone, and Gore substations. This 110 kV line cannot be thermally upgraded. Approximately 100-120 MW of wind generation can be connected at a substation (or less if at a new connection point along the line), but output would need to be constrained for outages of circuits within the region.

Another option is to connect the wind generation stations to the 220 kV double-circuit North Makarewa–Three Mile Hill line. Approximately 350 MW of generation can be connected, but parts of the line will need to be thermally upgraded.

Appendix A: Enhancement and Development Planning Process

The System Planning function ensures that we have a system view of the problems and opportunities across the grid. This system view is important for all grid problems and opportunities, including across asset portfolios, but is particularly relevant to those that enhance or reduce the capability of the grid.

The Enhancement and Development Planning (E&D) process is the primary mechanism for addressing these problems and opportunities.

This Appendix describes at a high level how the E&D process operates, utilising existing Transpower processes, including our Decision Framework.

A.1 E&D process overview

The E&D process consists of four inter-related processes:

- Annual Transmission Planning
- Customer Technical Requests (CTR) including High Level Responses (HLRs)
- Asset Feedback
- Asset Planning Decision Framework (Decision Framework).

The first three processes provide information on the capability of the grid to provide the system capacity, reliability and security required to meet future customer and grid needs. Where the capability of the grid is insufficient, or changes in load or generation require a reassessment of system requirements, a problem or opportunity is passed to the Decision Framework for further investigation. This becomes an E&D System Need (System Need).

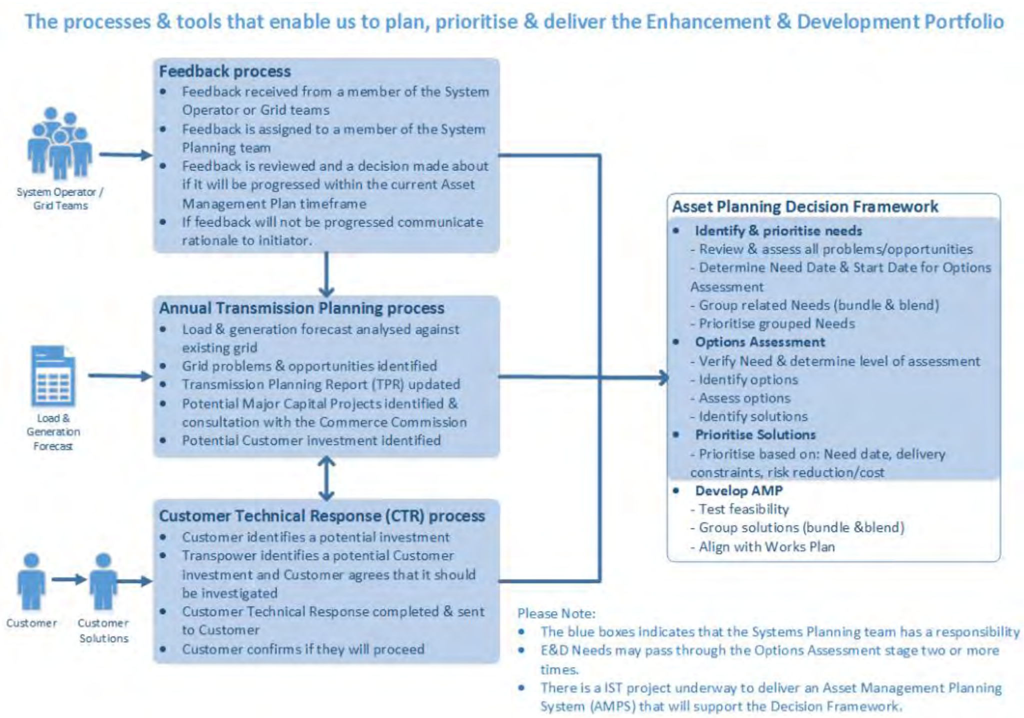
The Decision Framework provides a mechanism for grouping System and Asset Needs (needs identified in the asset portfolios) to prioritise and collectively consider them.

The Decision Framework incorporates the Options Assessment Approach (OAA), which specifies how Needs are investigated, the level of analysis being commensurate with the complexity of the issue, likely level of expenditure and timing of the Need. The outcome of the delivery-level OAA is selection of a preferred solution.

The Grid Enhancement Approach (GEA) as detailed in this TPR comprises both current System Planning knowledge relating to System Needs, and the progress of System Needs through the Decision Framework. The GEA discusses investment drivers, investment uncertainties, collective Needs, options for resolution and indicative investment costs. The accuracy of information in the GEA is commensurate with level of certainty of investment, timing of the System Need and level of OAA investigation completed.

Figure A-1 presents a high-level overview of the inter-related processes and information flows that comprise the E&D process.

Figure A-1 Overview of the Enhancement and Development Process



A.2 E&D process inputs: grid and asset capability

The inputs to the E&D process come from three processes that inform us about the existing capability of the grid both now and in the future (the three boxes on the left hand side of Figure A-1). Each process is described in more detail in the section below, with a specific focus on problems and opportunities within the E&D portfolio.

A.2.1 Annual Transmission Planning Process

The Annual Transmission Planning Process assesses the existing grid for potential capacity and service level problems and opportunities over a 15 year planning period, in accordance with the Grid Reliability Standards[1] and our Transmission System Planning Criteria.

This process uses load forecasts, generation forecasts and the current power system configuration (modelled in DIgSILENT Powerfactory) to identify the problems and opportunities relating to grid capability over the forecast period. Other environmental information that can impact the need for changes in grid capability is considered, such as customer development plans and step increases or decreases in load or generation connections.

There are several outputs from the Annual Transmission Planning Process:

- Regulatory reporting through the Grid Reliability Report (GRR), Grid Economic Investment Report (GEIR) and publication of 10 year forecast fault levels.
- The publication of current and forecast grid capability through the TPR.
- Identification of problems and opportunities that may result in Major Capital Projects (MCPs). This information is shared with the Commerce Commission.
- Where problems or opportunities impact connection assets that are paid for by customers, we share the information with those customers.
- Information relating to the problem or opportunity is passed to the Decision Framework. The System Need is confirmed, collected with other relevant System and Asset Needs and

1 https://www.ea.govt.nz/code-and-compliance/the-code/part-12-transport/

prioritised for investigation. The Asset Management Planning System (AMPS) will record and track the progress of all System Needs through the Decision Framework.

The Annual Transmission Planning Process is repeated on an annual basis with updated inputs and provides the main input to the Decision Framework for E&D System Needs.

A.2.2 Customer Investment Process

Customer-initiated investments are identified through three broad areas:

- Customer's requesting connection or changes to existing connections (changes to their connection assets, grid configuration, protection settings or metering). Customers raise problems and opportunities with us through Customer Technical Requests (CTRs). These projects progress to the Decision Framework when there is a high level of certainty they will proceed.
- The Annual Transmission Planning Process may identify problems or opportunities associated with connection assets. If the customer elects to invest, it initiates this process using a CTR. If the customer chooses not to progress an investment we must ensure the customer understands the risks associated with this course of action.
- When System Needs involving interconnection assets are being investigated through the OAA, options for resolving the problem or opportunity may include customer-funded, or partially customer-funded investment options. If a preferred solution is a customer funded investment, and the customer agrees to invest, a contract is signed by the customer and the investment is prioritised for delivery in the Decision Framework

Information on customer-initiated investments is passed to the Decision Framework through the CTR process, and to the Annual Transmission Planning Process as inputs to assessments of grid capability.

A.2.3 Asset Feedback Process

The E&D Planning Process utilises our Asset Feedback Process to capture and record information from around the business relating to the performance and operation of the system and existing grid assets. This information is appropriately tagged to identify its source and who should act on it.

The Asset Feedback Process provides a central location for information to be recorded, stored and shared, ensuring visibility of the issues raised across the business. The issues entered are reviewed regularly, with those requiring further investigation being passed to the Decision Framework for consideration. The initiator of the entry in the Asset Feedback register is informed of the action taken.

A.3 E&D process: Decision Framework

The Decision Framework allows us to make effective, consistent, repeatable asset planning decisions that balance risk, service levels and investment. It is used to justify and prioritise all grid expenditure within our Asset Management Plan (AMP) including both capex and opex expenditure across the following:

- Asset replacements and refurbishments
- Grid enhancement and development
- Customer projects
- Maintenance activities
- Investigations required to deliver the Asset Management Plan.

The Decision Framework has four decision steps:

- Identify and prioritise Needs
- Apply OAA to each Need
- Prioritise Solutions
- Develop Asset Management Plan.

E&D problems and opportunities are inputs to the Decision Framework, transitioning to a System Need once the Need is confirmed.

Assessing E&D System Needs through the Decision Framework allows for related Needs to be grouped together. This ensures that expenditure on asset replacement, refurbishment and maintenance costs are appropriately considered alongside grid capability requirements and expenditure. It also allows System Needs to be considered together where resolution of one issue may impact decisions made for another.

A.3.1 Options Assessment Approach

The Decision Framework incorporates the Options Assessment Approach (OAA) which specifies how problems and opportunities are investigated, the level of analysis being commensurate with the complexity of the issue, level of expenditure and timing of the Need. The outcome of the OAA is selection of a preferred solution.

The OAA has four sequential stages as shown in Figure A-2:

- Verify Need and Determine Assessment Level
- Identify Options
- Assess Options
- Identify Solution.

Figure A-2: Steps in Options Assessment Approach

The OAA involves undertaking analysis commensurate with the certainty of the System Need and the complexity of the issue. As a result, E&D System Needs may progress through the OAA process more than once, with higher level investigations informing the timing and prioritisation of future delivery level investigations, as well as increasing our knowledge of the System Need, its associated risk, and credible options and costs to resolve. Higher level OAA planning assessments also inform our capex forecasting and regulatory reset proposals.

If the outcome of a high level OAA planning assessment is to undertake a delivery level OAA at a future point in time, this information will be recorded in the Asset Management Planning System and work picked up again at the appropriate point in time.

Detailed delivery level OAA investigations result in a preferred solution being identified. All preferred solutions are prioritised according to the principles of the Decision Framework. The preferred solution will also be used to inform our capex forecasting and regulatory processes. It will also become an input to the assessment of future grid capability in the Annual Transmission Planning Process.

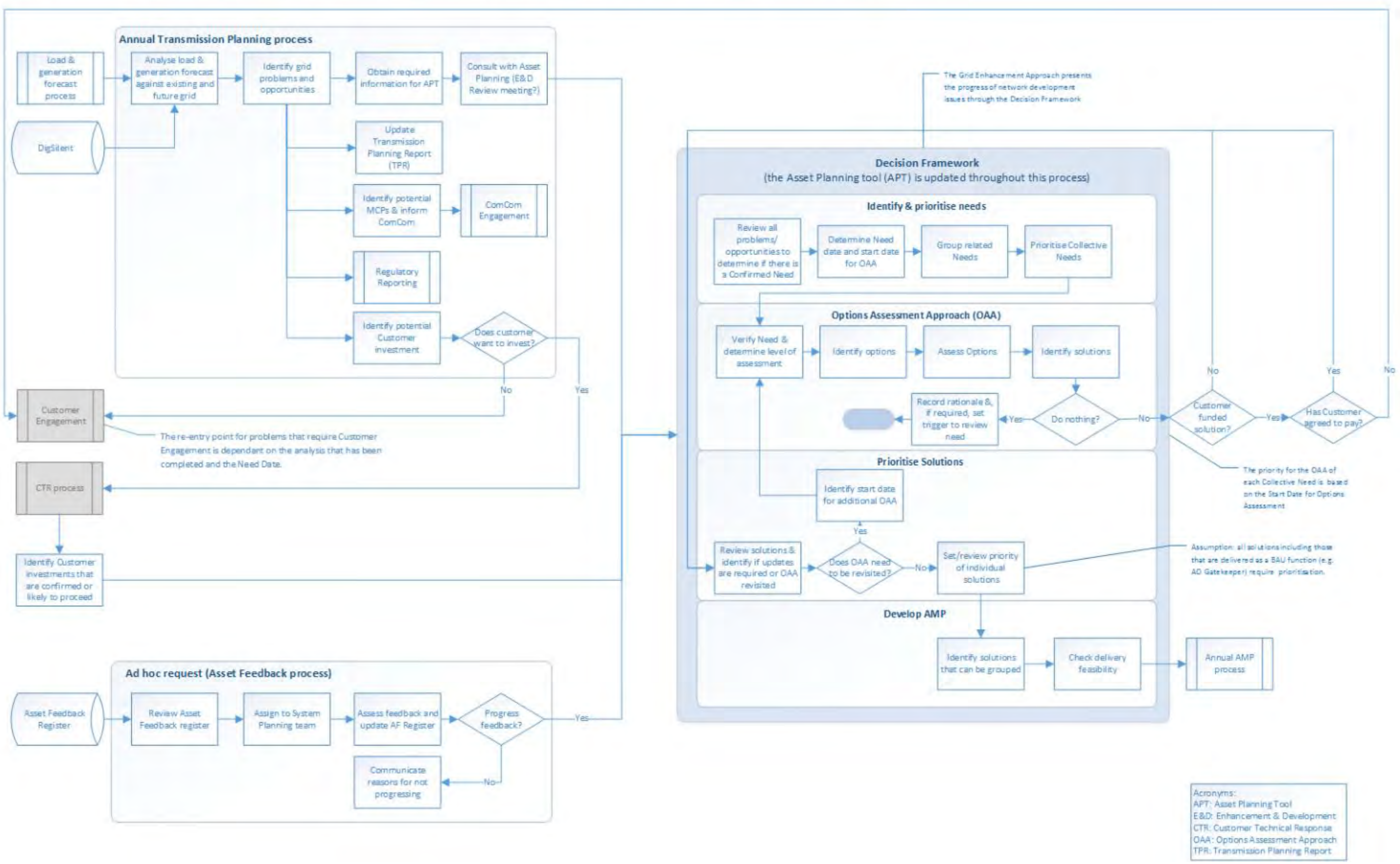
A.3.2 Grid Enhancement Approach

The Grid Enhancement Approach (GEA) is presented in this TPR to illustrate the progress of System Needs through the Decision Framework at a point in time. The GEA also discusses how investment drivers, uncertainties and interactions between System Needs impact our decision making and options analysis.

The GEA provides insight into decision making on E&D System Needs and proposals to address them. The accuracy of information in the GEA around options, costs and timing is commensurate with the OAA assessment level that has been completed. More detailed information with a higher degree of analysis will be available for System Needs that are more certain, or occur in the immediate and short term.

A.4 A3 Process diagram

The processes & tools that enable us to plan, prioritise & deliver the E&D Portfolio (detailed view)



Appendix B: Forecast Fault Levels

This Appendix presents an update to the 10 year forecast fault levels report. The Connection Code contained in Schedule 8 of the Benchmark Agreement requires Transpower to publish, annually, a 10-year forecast of the expected fault levels at each customer point of service.[1]

Transpower last published the Ten Year Forecast of Fault Levels in September 2018.

B.1 Forecast fault levels calculation assumptions

Calculated fault levels are very dependent on the assumptions used in, and method of, the calculation.

Minimum fault level calculations depend on generation and grid asset dispatch assumptions, and are generally used for ensuring the coordination of protection relays between asset owners. Protection coordination has very important consequences for power system security and safety of people and assets. Accordingly, we will only publish the maximum fault levels. We encourage connected parties to talk with us directly on matters concerning protection coordination.

Table B-3 and Table B-4 list the maximum three-phase fault current and maximum single-phase to ground fault current, respectively, for all of Transpower's transmission buses. Both tables list the 10 year forecast fault current for the existing grid configuration. The listed value is the initial RMS symmetrical short-circuit current (I_k'') as defined by IEC 60909 2001.

The 10 year forecast of maximum fault levels is based on information currently known to Transpower. The values in the tables should be regarded as indicative only. We have modelled committed future transmission upgrades and generation projects using the best information we have at this time. We know that towards the end of the 10 year period, there may be additional transmission upgrades and additional generation required to meet New Zealand's power and energy requirements. We cannot know exactly the nature or location of these future transmission upgrades and new generation. The maximum fault level at a transmission bus[2] may also change where the number of supply transformers increase or are replaced as part of a Service Change to meet load growth or provide supply security.

Therefore the maximum short-circuit currents listed should not be relied upon for specifying short-circuit requirements for new substation equipment. **The forecast fault levels provide an early warning of when plant capability may be exceeded.**

Accordingly, while Transpower endeavours to forecast fault levels accurately, the levels may change for a number of reasons and Transpower does not accept liability for other parties reliance on the fault values contained in the forecast. We encourage asset owners to consult with us for detailed information on maximum fault levels at specific sites relating to new equipment connection.

The Connection Code (5.1(h)) puts an obligation on Transpower and the customer to ensure that equipment connected to the grid does not cause the maximum short-circuit power and current limits in Appendix B Table B2 of the Connection Code to be exceeded on or nearby to the grid. Table B-1 shows the short-circuit power and current limits contained in Table B-2 of Appendix B of the Connection Code. Note that the fault levels at some buses are already near or exceed these values.

1 Connection Code clause 4.2(g): to publish annually a 10 year forecast of the expected minimum and maximum fault level at each customer point of service.

2 This report includes the maximum fault level for all Transpower's transmission buses, which encompass customer points of service.

Table B-1: Maximum short-circuit power and current limits

Nominal voltage (kV)	Maximum short-circuit power and current limits (MVA)	(kA)
220	12,000	31.5
110	6,000	31.5
66	1,800	16
50	1,350	16
33	1,400	25
22	950	25
11	475	25

We have calculated maximum fault levels in Table B-3 and Table B-4 using the 2001 IEC 60909 method. The values are the initial RMS symmetrical short-circuit levels.

The fault levels have been calculated on the following basis:

- All generating units and all transmission assets are assumed to be in service.
- A full representation of the existing transmission grid, directly connected generation and embedded generation above 1 MW known to us is assumed. The existing wind farms are assumed to provide only full load current into a fault.
- Motor loads are not modelled.
- The breaker time is 0.1 seconds and the fault clearing time is 1 second.
- The fault impedance is zero ohms.
- Future committed changes to the power system including transmission upgrades and new generation detailed in the 2019 Transmission Planning Report. We represented new transmission lines in the model with electrical parameters estimated from the best matches with existing lines of the same conductor type. We have represented committed generation in our power system model with their electrical parameters scaled from the latest example of their type that is known to us. We based the timing of these connections on open discussion with the asset owner, and information from the generator's website. The actual commissioning date may vary.

Table B-2 sets out our assumption of fault current contributions from future generation.

Table B-2: Fault current contributions from future generation

Category	Technology / application	Fault current contribution (per unit of capacity)
Thermal	Coal, diesel, combined cycle gas turbine, open cycle gas turbine, gas-fired peaker, cogeneration	2.87
Thermal	Geothermal	3.60
Hydro	Peak hydro, stored hydro, run of river	3.67
Wind	Wind	0.0
Solar	Photovoltaic	0.0
Load	Interruptible load, demand side response	0.0

B.2 Ten year forecast of maximum three-phase fault levels

Table B-3: Ten year forecast of maximum three-phase fault levels (kA)

Grid exit point	Transmission bus	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
NORTHLAND												
Bream Bay	33 kV	10.3	10.3	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Bream Bay	220 kV	5.1	5.1	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Marsden	110 kV	7.1	7.1	7.1	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Marsden	220 kV	5.1	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Maungatapere	110 kV	6.1	6.1	6.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Maungaturoto	33 kV	5.7	5.7	5.7	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Maungaturoto	110 kV (T1)	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Maungaturoto	110 kV (T2)	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Wellsford	33 kV	7.2	7.2	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Wellsford	110 kV (T1)	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Wellsford	110 kV (T2)	3.9	3.9	3.9	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
AUCKLAND												
Albany	33 kV	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4
Albany	110 kV	15.9	15.9	16.1	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Albany	220 kV	12.4	12.4	12.5	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
Bombay	33 kV	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Bombay	110 kV	10.2	10.3	10.7	10.7	10.7	10.7	10.8	10.8	10.8	10.8	10.8
Drury	220 kV	12.6	12.6	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
Glenbrook	33 kV (T4/T5)	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Glenbrook	33 kV (T6)	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8
Glenbrook	220 kV	10.0	10.0	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Henderson	33 kV	18.5	18.5	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
Henderson	110 kV	19.7	19.7	20.6	20.7	20.7	20.7	20.8	20.8	20.8	20.8	20.8
Henderson	220 kV	12.6	12.6	12.7	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Hepburn Road	33 kV	20.9	20.9	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Hepburn Road	110 kV	18.1	18.1	19.5	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Hobson Street	110 kV	16.0	16.6	17.9	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Hobson Street	220 kV	13.9	13.9	14.0	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Huapai	220 kV	11.3	11.3	11.4	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
Mangere	33 kV	14.6	15.2	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Mangere	110 kV	16.0	18.7	20.4	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Mount Roskill	22 kV	24.5	24.8	25.3	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4
Mount Roskill	110 kV	17.1	17.7	19.3	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Otahuhu	22 kV	26.0	26.0	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1
Otahuhu	110 kV (T2/T4)	18.8	20.4	22.5	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6
Otahuhu	110 kV (T3/T5)	16.9	20.4	22.5	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6
Otahuhu	220 kV	16.5	16.5	16.5	16.6	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Pakuranga	33 kV	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8

Pakuranga	220 kV	15.8	15.8	15.9	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Penrose	22 kV	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
Penrose	33 kV	25.7	25.7	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8
Penrose	110 kV	17.1	18.1	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8
Penrose	220 kV	14.9	14.9	15.0	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Silverdale	33 kV	17.9	17.9	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Silverdale	220 kV (T1)	8.4	8.4	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Silverdale	220 kV (T2)	8.4	8.4	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Southdown	220 kV	14.0	14.0	14.0	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Takanini	33 kV	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
Takanini	220 kV (T5)	13.6	13.6	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
Takanini	220 kV (T8)	13.4	13.4	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Wairau Road	33 kV	17.1	17.1	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2
Wairau Road	220 kV	12.8	12.8	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Wiri	33 kV	18.3	18.7	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1
Wiri	110 kV (T1)	13.7	14.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4	15.4
Wiri	110 kV (T2)	13.6	14.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
WAIKATO												
Arapuni	110 kV (North Bus)	12.6	12.6	12.6	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
Arapuni	110 kV (South Bus)	12.6	12.6	12.6	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
Atiamuri	220 kV	17.6	17.5	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6
Cambridge	11 kV	22.7	22.7	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8	22.8
Cambridge	110 kV (T3)	8.3	8.3	8.3	8.3	8.3	8.3	8.4	8.4	8.4	8.4	8.4
Cambridge	110 kV (T4)	8.3	8.3	8.3	8.3	8.3	8.3	8.4	8.4	8.4	8.4	8.4
Hamilton	11 kV	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Hamilton	33 kV	20.9	20.9	20.9	20.9	20.9	20.9	21.0	21.0	21.0	21.0	21.0
Hamilton	110 kV	15.0	15.0	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Hamilton	220 kV	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6
Hangatiki	33 kV	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Hangatiki	34 kV TLC	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Hangatiki	110 kV	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Hinuera	33 kV	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Hinuera	110 kV	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Huntly	33 kV	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6
Huntly	11 kV	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Huntly	220 kV	21.0	21.0	21.1	21.1	21.1	21.1	21.1	21.1	21.1	21.1	21.1
Karapiro	110 kV	8.7	8.7	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Kinleith	11 kV (T8)	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Kinleith	11 kV (T7)	14.0	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Kinleith	11 kV (T6)	14.7	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Kinleith	11 kV (T5)	35.5	35.5	35.5	35.5	35.5	35.5	35.5	35.5	35.5	35.5	35.5
Kinleith	33 kV	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Kinleith	110 kV	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Kopu	66 kV	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7

Kopu	110 kV (T3)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Kopu	110 kV (T4)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Lichfield	110 kV (T1)	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Lichfield	110 kV (T2)	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Maraetai	220 kV	21.8	21.8	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9
Ohakuri	220 kV	17.0	17.0	17.0	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
Ohinewai	220 kV	19.3	19.3	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4	19.4
Piako	110 kV	5.8	5.8	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Te Awamutu	11 kV	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Te Awamutu	110 kV	5.5	5.5	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Te Kowhai	33 kV	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Te Kowhai	220 kV	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Waihou	33 kV	11.3	11.3	10.7	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Waihou	110 kV	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Waikino	33 kV	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Waikino	110 kV	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Waipapa	220 kV	13.4	13.4	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Whakamaru	220 kV	28.0	28.0	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2	28.2
BAY OF PLENTY												
Aniwhenua	110 kV	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Edgecumbe	33 kV	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Edgecumbe	110 kV	8.8	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Edgecumbe	220 kV	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Kaitimako	33 kV	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Kaitimako	110 kV	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Kaitimako	220 kV	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Kawerau	11 kV (T1/T2)	19.9	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7
Kawerau	11 kV (T6)	35.2	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
Kawerau	11 kV (T7)	35.2	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
Kawerau	11 kV (T8)	35.2	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
Kawerau	11 kV (T9)	35.2	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
Kawerau	11 kV (T11/T14)	35.2	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1	35.1
Kawerau	110 kV	12.7	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3	12.3
Kawerau	220 kV	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Matahina	110 kV	10.7	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Mt Maunganui	33 kV	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Mt Maunganui	110 kV	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Okere	110 kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Owhata	11 kV	16.1	16.1	16.1	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Owhata	110 kV	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Rotorua	11 kV	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Rotorua	33 kV	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Rotorua	110 kV (Tarukenga 1)	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Rotorua	110 kV (Tarukenga 2)	6.7	6.7	6.7	6.7	6.7	6.7	6.8	6.8	6.8	6.8	6.8

Tarukenga	11 kV	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Tarukenga	110 kV	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
Tarukenga	220 kV	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Tauranga	11 kV	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2
Tauranga	33 kV	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
Tauranga	110 kV	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Te Matai	33 kV	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Te Matai	110 kV	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Waiotahi	11 kV	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Waiotahi	110 kV	2.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
CENTRAL NORTH ISLAND												
Aratiatia	220 kV	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4
Bunnythorpe	33 kV	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8
Bunnythorpe	110 kV	12.4	12.4	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Bunnythorpe	220 kV	12.4	12.4	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dannevirke	11 kV	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Dannevirke	110 kV (T1)	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Dannevirke	110 kV (T2)	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Linton	33 kV	15.9	15.9	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
Linton	220 kV (T2)	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Linton	220 kV (T3)	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Mangahao	33 kV	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Mangahao	110 kV (T3)	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Mangahao	110 kV (T4)	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Mangamaire	33 kV	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Mangamaire	110 kV	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Marton	33 kV	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Marton	110 kV (T1)	5.2	5.2	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Marton	110 kV (T2)	5.2	5.2	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Mataroa	33 kV	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Mataroa	110 kV	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
National Park	33 kV	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
National Park	110 kV	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Nga Awa Purua	220 kV	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Ngatamariki	220 kV	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Ohaaki	220 kV	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Ohakune	11 kV	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Ohakune	110 kV	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Ongarue	33 kV	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Ongarue	110 kV	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Poihipi	220 kV	21.3	21.3	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Rangipo	220 kV	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
Tangiwai	11 kV	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8	19.8
Tangiwai	220 kV	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Tararua Central	220 kV	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7

Te Mihi	220 kV	23.7	23.7	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
Tokaanu	33 kV	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Tokaanu	220 kV	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1
Waipawa	11 kV	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Waipawa	33 kV	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Waipawa	110 kV (T1)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Waipawa	110 kV (T2)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Wairakei	33 kV	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Wairakei	220 kV	26.6	26.5	26.6	26.6	26.6	26.6	26.6	26.6	26.6	26.6	26.6
Woodville	11 kV	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Woodville	110 kV	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
TARANAKI												
Brunswick	33 kV	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Brunswick	220 kV	10.2	10.2	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Carrington St	33 kV	13.2	11.9	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Carrington St	110 kV	11.3	8.7	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Hawera	33 kV (T1/T2)	8.1	8.2	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Hawera	33 kV (T3)	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Hawera	110 kV	7.6	7.9	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Huirangi	33 kV	12.8	11.7	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Huirangi	110 kV	8.9	7.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Junction Road Tee	110 kV	0.0	8.5	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Kapuni Tee	110 kV	5.9	6.3	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
McKee Tee	110 kV	6.8	6.3	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Motunui	11 kV (T3)	16.0	15.5	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9
Motunui	11 kV (T4)	16.0	15.5	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9
Motunui	110 kV	8.6	7.4	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
New Plymouth	33 kV	10.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Plymouth	110 kV	12.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Plymouth	220 kV	8.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Opunake	33 kV	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Opunake	110 kV (T4)	3.5	3.6	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Opunake	110 kV (T5)	3.3	3.4	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Stratford	33 kV	11.3	11.7	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Stratford	110 kV	12.7	14.9	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4
Stratford	220 kV	12.7	12.8	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
Taumarunui	220 kV	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Wanganui	33 kV	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Wanganui	110 kV	5.1	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Waverley	11 kV	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Waverley	110 kV	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
HAWKE'S BAY												
Fernhill	33 kV	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Fernhill	110 kV	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5

Redclyffe	33 kV	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2
Redclyffe	110 kV	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Redclyffe	220 kV	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Tuai	110 kV	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Whakatu	33 kV	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
Whakatu	220 kV (T3)	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Whakatu	220 kV (T4)	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Whirinaki	11 kV (T1)	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3
Whirinaki	11 kV (T2)	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2
Whirinaki	11 kV (T3)	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7	23.7
Whirinaki	220 kV	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
WELLINGTON												
Central Park	11 kV (T11)	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Central Park	11 kV (T12)	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Central Park	33 kV	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3
Central Park	110 kV (T3)	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Central Park	110 kV (T4)	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Central Park	110 kV (T5)	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Gracefield	33 kV	13.3	13.3	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Gracefield	110 kV (T5)	9.2	9.2	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
Gracefield	110 kV (T6)	9.2	9.2	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
Greytown	33 kV	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Greytown	110 kV (T2)	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Greytown	110 kV (T3)	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Haywards	11 kV	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Haywards	33 kV	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Haywards	110 kV	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Haywards	220 kV	10.8	10.8	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Kaiwharawhara	11 kV (T1)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Kaiwharawhara	11 kV (T3)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Kaiwharawhara	110 kV (T1)	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Kaiwharawhara	110 kV (T3)	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Masterton	33 kV	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Masterton	110 kV	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Melling	11 kV	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Melling	33 kV	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Melling	110 kV (T1/T3)	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Melling	110 kV (T2/T4)	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Paraparaumu	33 kV	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4
Paraparaumu	220 kV (T1)	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Paraparaumu	220 kV (T2)	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Pauatahanui	33 kV	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Pauatahanui	110 kV (T1)	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5

Pauatahanui	110 kV (T2)	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Takapu Road	33 kV	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
Takapu Road	110 kV	15.1	15.1	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2
Upper Hutt	33 kV	9.5	9.5	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Upper Hutt	110 kV	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
West Wind	110 kV (Circuit–2)	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
West Wind	110 kV (Circuit–3)	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Wilton	33 kV	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
Wilton	110 kV	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Wilton	220 kV	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
NELSON-MARLBOROUGH												
Argyle	110 kV	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Blenheim	33 kV	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Blenheim	110 kV	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Stoke	33 kV	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
Stoke	66 kV	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Stoke	110 kV	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Stoke	220 kV	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
WEST COAST												
Arthurs Pass	11 kV	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Arthurs Pass	66 kV	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Atarau	110 kV	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Castle Hill	11 kV	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Castle Hill	66 kV	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Dobson	33 kV	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Dobson	66 kV	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Dobson	T11 (110 kV)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Dobson	T12 (110 kV)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Greymouth	66 kV	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Hokitika	66 kV	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Inangahua	110 kV	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Kikiwa	11 kV	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Kikiwa	110 kV	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Kikiwa	220 kV	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Kumara	66 kV	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Murchison	11 kV	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Murchison	110 kV	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Orowaiti	110 kV (Circuit–1)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Orowaiti	110 kV (Circuit–2)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Otira	11 kV	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Otira	66 kV	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Reefton	110 kV (Circuit–1)	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Reefton	110 kV	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8

	(Circuit–2)											
Waimangaroa	110 kV (Circuit–1)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Waimangaroa	110 kV (Circuit–2)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Westport	11 kV	6.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Westport	110 kV (T1)	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Westport	110 kV (T2)	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CANTERBURY												
Ashburton	33 kV	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Ashburton	66 kV	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1
Ashburton	220 kV	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Ashley	11 kV (T5)	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Ashley	11 kV (T3)	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Ashley	66 kV	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Bromley	66 kV	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Bromley	220 kV	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Coleridge	11 kV	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Coleridge	66 kV	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Culverden	33 kV	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Culverden	66 kV	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Culverden	220 kV (T22)	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Culverden	220 kV (T23)	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Hororata	33 kV	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Hororata	66 kV	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Islington	33 kV	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Islington	66 kV	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Islington	220 kV	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
Kaiapoi	11 kV	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Kaiapoi	66 kV	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Kimberley	66 kV (T1)	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Kimberley	66 kV (T2)	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Southbrook	33 kV	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Southbrook	66 kV	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Waipara	33 kV	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Waipara	66 kV	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Waipara	220 kV (T12)	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Waipara	220 kV (T13)	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
SOUTH CANTERBURY												
Albury	11 kV	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Albury	110 kV	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Aviemore	220 kV	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
Bells Pond	110 kV	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Benmore	220 kV	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Black Point	110 kV	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3

Livingstone	220 kV	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Oamaru	33 kV	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Oamaru	110 kV (T1)	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Oamaru	110 kV (T2)	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Ohau A	220 kV	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Ohau B	220 kV	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Ohau C	220 kV	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Studholme	11 kV	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Studholme	110 kV	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Tekapo A	11 kV	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8
Tekapo A	33 kV	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Tekapo A	110 kV	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Tekapo B	220 kV	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2
Temuka	33 kV	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Temuka	110 kV (T1)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Temuka	110 kV (T2)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Timaru	11 kV	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
Timaru	110 kV	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Timaru	220 kV (T5)	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Timaru	220 kV (T8)	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Twizel	33 kV (T18)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Twizel	33 kV (T19)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Twizel	220 kV	21.8	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9	21.9
Waitaki	11 kV	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5
Waitaki	11 kV	36.4	36.4	36.4	36.4	36.4	36.4	36.4	36.4	36.4	36.4	36.4
Waitaki	33 kV (T28)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Waitaki	220 kV	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3
OTAGO-SOUTHLAND												
Balclutha	33 kV	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Balclutha	110 kV	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Berwick	110 kV	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Brydone	11 kV	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2
Brydone	110 kV	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Clyde	33 kV	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Clyde	220 kV	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7
Cromwell	33 kV	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Cromwell	110 kV (T5A/B)	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Cromwell	110 kV (T8)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Cromwell	220 kV (T5A/B)	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Cromwell	220 kV (T8)	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Edendale	33 kV	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Edendale	110 kV	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
Frankton	33 kV	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Frankton	110 kV (T2)	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8

Frankton	110 kV (T4)	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Gore	33 kV	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Gore	110 kV	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Gore	220 kV (T11)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gore	220 kV (T12)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Halfway Bush	33 kV (T3)	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Halfway Bush	33 kV (T5)	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Halfway Bush	110 kV	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
Halfway Bush	220 kV	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Invercargill	33 kV	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6
Invercargill	110 kV	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Invercargill	220 kV	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Manapouri	220 kV	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
North Makarewa	33 kV	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
North Makarewa	220 kV	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Naseby	33 kV	7.5	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
Naseby	220 kV	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Roxburgh	110 kV	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7
Roxburgh	220 kV	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
South Dunedin	33 kV	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3
South Dunedin	220 kV	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Three Mile Hill	220 kV	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Tiwai	220 kV	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9

B.3 Ten year forecast of maximum single-phase to ground fault levels

Table B-4: Ten year forecast of maximum single-phase to ground fault levels (kA)

Grid exit point	Transmission bus	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
NORTHLAND												
Bream Bay	33 kV	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Bream Bay	220 kV	5.6	5.6	5.6	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Marsden	110 kV	8.7	8.7	9.0	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Marsden	220 kV	5.8	5.8	5.8	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Maungatapere	110 kV	5.0	5.0	5.7	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Maungaturoto	33 kV	6.4	6.4	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Maungaturoto	110 kV (T1)	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Maungaturoto	110 kV (T2)	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Wellsford	33 kV	8.3	8.3	8.3	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Wellsford	110 kV (T1)	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Wellsford	110 kV (T2)	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

AUCKLAND												
Albany	33 kV	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Albany	110 kV	18.7	18.7	18.8	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
Albany	220 kV	16.1	16.1	16.1	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3
Bombay	33 kV	9.7	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Bombay	110 kV	5.9	6.0	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Drury	220 kV	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Glenbrook	33 kV (T4/T5)	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Glenbrook	33 kV (T6)	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Glenbrook	220 kV	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Henderson	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Henderson	110 kV	23.8	23.8	24.6	24.9	24.9	24.9	24.9	24.9	24.9	24.9	24.9
Henderson	220 kV	14.6	14.6	14.7	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9
Hepburn Road	33 kV	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Hepburn Road	110 kV	17.6	17.7	18.5	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
Hobson Street	110 kV	19.3	19.0	20.2	20.4	20.4	20.4	20.4	20.3	20.3	20.3	20.3
Hobson Street	220 kV	18.1	18.0	18.0	18.3	18.3	18.3	18.3	18.2	18.2	18.2	18.2
Huapai	220 kV	12.6	12.6	12.6	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Mangere	33 kV	16.0	16.5	16.7	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8
Mangere	110 kV	15.5	17.9	18.9	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1
Mount Roskill	22 kV	27.1	27.3	27.7	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8
Mount Roskill	110 kV	15.2	16.0	16.8	16.9	16.9	16.9	17.0	16.9	16.9	16.9	16.9
Otahuhu	22 kV	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5
Otahuhu	110 kV (T2/T4)	19.7	23.6	25.5	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7
Otahuhu	110 kV (T3/T5)	19.2	23.6	25.5	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7
Otahuhu	220 kV	20.8	20.7	20.1	20.3	20.3	20.3	20.4	20.3	20.3	20.3	20.3
Pakuranga	33 kV	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Pakuranga	220 kV	20.6	20.5	20.3	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Penrose	22 kV	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Penrose	33 kV	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Penrose	110 kV	20.8	20.8	22.3	22.4	22.4	22.4	22.4	22.3	22.3	22.3	22.3
Penrose	220 kV	19.5	19.4	19.3	19.6	19.6	19.6	19.6	19.5	19.5	19.5	19.5
Silverdale	33 kV	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Silverdale	220 kV (T1)	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Silverdale	220 kV (T2)	9.0	9.0	9.0	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Southdown	220 kV	15.4	15.4	15.1	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Takanini	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Takanini	220 kV (T5)	14.7	14.7	14.6	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Takanini	220 kV (T8)	14.7	14.7	14.6	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Wairau Road	33 kV	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Wairau Road	220 kV	16.8	16.7	16.7	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9
Wiri	33 kV	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Wiri	110 kV (T1)	11.4	12.5	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Wiri	110 kV (T2)	11.4	12.4	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9

WAIKATO												
Arapuni	110 kV (North Bus)	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
Arapuni	110 kV (South Bus)	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
Atiamuri	220 kV	16.8	16.7	16.7	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8
Cambridge	11 kV	24.7	24.7	24.7	24.7	24.7	24.7	24.8	24.8	24.8	24.8	24.8
Cambridge	110 kV (T3)	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Cambridge	110 kV (T4)	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Hamilton	11 kV	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8
Hamilton	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Hamilton	110 kV	13.8	13.8	13.5	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Hamilton	220 kV	11.4	11.4	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Hangatiki	33 kV	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Hangatiki	110 kV	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Hinuera	33 kV	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Hinuera	110 kV	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Huntly	11 kV	17.0	17.0	17.0	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
Huntly	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Huntly	220 kV	24.4	24.4	24.4	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Karapiro	110 kV	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
Kinleith	11 kV (T1A)	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Kinleith	11 kV (T2)	14.8	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Kinleith	11 kV (T3A and T3B)	15.6	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Kinleith	11 kV (T5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kinleith	33 kV	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Kinleith	110 kV	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Kopu	66 kV	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Kopu	110 kV (T3)	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Kopu	110 kV (T4)	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Lichfield	110 kV (T1)	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Lichfield	110 kV (T2)	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Maraetai	220 kV	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7
Ohakuri	220 kV	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8
Ohinewai	220 kV	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8	16.8
Piako	110 kV	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Te Awamutu	11 kV	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3	23.3
Te Awamutu	110 kV	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Te Kowhai	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Te Kowhai	220 kV	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Waihou	33 kV	14.3	14.3	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Waihou	110 kV	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Waikino	33 kV	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Waikino	110 kV	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Waipapa	220 kV	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Whakamaru	220 kV	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2

BAY OF PLENTY												
Aniwhenua	110 kV	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Edgecumbe	33 kV	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Edgecumbe	110 kV	7.9	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Edgecumbe	220 kV	8.0	8.0	7.9	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Kaitimako	33 kV	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Kaitimako	110 kV	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7
Kaitimako	220 kV	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Kawerau	11 kV (T1/T2)	21.0	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.4
Kawerau	11 kV (T6)	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Kawerau	11 kV (T7)	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Kawerau	11 kV (T8)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Kawerau	11 kV (T9)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Kawerau	11 kV (T11/T14)	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Kawerau	110 kV	15.6	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Kawerau	220 kV	8.8	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Matahina	110 kV	10.8	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6
Mt Maunganui	33 kV	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Mt Maunganui	110 kV	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Okere	110 kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Owhata	11 kV	19.9	19.8	19.3	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Owhata	110 kV	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Rotorua	11 kV	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Rotorua	33 kV	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Rotorua	110 kV (Tarukenga 1)	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Rotorua	110 kV (Tarukenga 2)	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Tarukenga	11 kV	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Tarukenga	110 kV	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
Tarukenga	220 kV	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Tauranga	11 kV	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Tauranga	33 kV	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Tauranga	110 kV	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Te Matai	33 kV	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Te Matai	110 kV	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Waiotahi	11 kV	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Waiotahi	110 kV	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
CENTRAL NORTH ISLAND												
Aratiatia	220 kV	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Bunnythorpe	33 kV	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Bunnythorpe	110 kV	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3
Bunnythorpe	220 kV	12.3	12.3	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
Dannevirke	11 kV	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2
Dannevirke	110 kV (T1)	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Dannevirke	110 kV (T2)	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Linton	33 kV	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Linton	220 kV (T2)	7.4	7.4	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Linton	220 kV (T3)	7.4	7.4	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Mangahao	33 kV	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Mangahao	110 kV (T3)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Mangahao	110 kV (T4)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Mangamaire	33 kV	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Mangamaire	110 kV	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Marton	33 kV	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Marton	110 kV (T1)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Marton	110 kV (T2)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Mataroa	33 kV	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Mataroa	110 kV	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
National Park	33 kV	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
National Park	110 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Nga Awa Purua	220 kV	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
Ngatamariki	220 kV	12.8	12.8	12.8	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
Ohaaki	220 kV	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1
Ohakune	11 kV	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
Ohakune	110 kV	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Ongarue	33 kV	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Ongarue	110 kV	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Poihipi	220 kV	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Rangipo	220 kV	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
Tangiwai	11 kV	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2
Tangiwai	220 kV	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Tararua Central	220 kV	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Te Mihi	220 kV	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
Tokaanu	33 kV	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Tokaanu	220 kV	11.9	11.9	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Waipawa	11 kV	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Waipawa	33 kV	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Waipawa	110 kV (T1)	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Waipawa	110 kV (T2)	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Wairakei	33 kV	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6	22.6
Wairakei	220 kV	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8	27.8
Woodville	11 kV	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Woodville	110 kV	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9

TARANAKI												
Brunswick	33 kV	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
Brunswick	220 kV	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
Carrington St	33 kV	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Carrington St	110 kV	11.0	8.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Hawera	33 kV (T1/T2)	9.1	9.1	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2

Hawera	33 kV (T3)	9.1	9.1	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Hawera	110 kV	8.1	8.3	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Huirangi	33 kV	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Huirangi	110 kV	8.1	6.6	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Junction Road Tee	110 kV	0.0	9.6	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Kapuni Tee	110 kV	4.1	4.2	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
McKee Tee	110 kV	8.0	7.5	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Motunui	11 kV (T3)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Motunui	11 kV (T4)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Motunui	110 kV	9.0	7.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
New Plymouth	33 kV	11.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Plymouth	110 kV	13.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Plymouth	220 kV	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Opunake	33 kV	4.8	4.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Opunake	110 kV (T4)	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Opunake	110 kV (T5)	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Stratford	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Stratford	110 kV	15.0	17.3	18.9	18.9	18.9	18.9	18.9	18.9	18.9	18.9	18.9
Stratford	220 kV	14.0	14.2	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Taumarunui	220 kV	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Wanganui	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Wanganui	110 kV	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Waverley	11 kV	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Waverley	110 kV	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
HAWKE'S BAY												
Fernhill	33 kV	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Fernhill	110 kV	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Redclyffe	33 kV	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Redclyffe	110 kV	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Redclyffe	220 kV	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Tuai	110 kV	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
Whakatu	33 kV	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Whakatu	220 kV (T3)	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Whakatu	220 kV (T4)	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Whirinaki	11 kV (T1)	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Whirinaki	11 kV (T2)	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Whirinaki	11 kV (T3)	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Whirinaki	220 kV	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
WELLINGTON												
Central Park	11 kV (T11)	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Central Park	11 kV (T12)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Central Park	33 kV	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6
Central Park	110 kV (T3)	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4

Central Park	110 kV (T4)	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Central Park	110 kV (T5)	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
Gracefield	33 kV	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
Gracefield	110 kV (T5)	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Gracefield	110 kV (T6)	6	6	6	6	6	6	6	6	6	6	6
Greytown	33 kV	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Greytown	110 kV (T2)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Greytown	110 kV (T3)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Haywards	11 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Haywards	33 kV	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Haywards	110 kV	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6
Haywards	220 kV	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
Kaiwharawhara	11 kV (T1)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Kaiwharawhara	11 kV (T3)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Kaiwharawhara	110 kV (T1)	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Kaiwharawhara	110 kV (T3)	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Masterton	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Masterton	110 kV	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Melling	11 kV	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Melling	33 kV	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Melling	110 kV (T1/T3)	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Melling	110 kV (T2/T4)	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Paraparaumu	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Paraparaumu	220 kV (T1)	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Paraparaumu	220 kV (T2)	7	7	7	7	7	7	7	7	7	7	7
Pauatahanui	33 kV	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Pauatahanui	110 kV (T1)	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
Pauatahanui	110 kV (T2)	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
Takapu Road	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Takapu Road	110 kV	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Upper Hutt	33 kV	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Upper Hutt	110 kV	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
West Wind	110 kV (Circuit–2)	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
West Wind	110 kV (Circuit–3)	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Wilton	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Wilton	110 kV	13.5	13.5	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Wilton	220 kV	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
NELSON-MARLBOROUGH												
Argyle	110 kV	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Blenheim	33 kV	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Blenheim	110 kV	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Stoke	33 kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stoke	66 kV	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3

Stoke	110 kV	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Stoke	220 kV	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
WEST COAST												
Arthurs Pass	11 kV	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Arthurs Pass	66 kV	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Atarau	110 kV	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Castle Hill	11 kV	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Castle Hill	66 kV	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Dobson	33 kV	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Dobson	66 kV	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Dobson	T11 (110 kV)	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Dobson	T12 (110 kV)	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Greymouth	66 kV	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Hokitika	66 kV	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Inangahua	110 kV	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Kikiwa	11 kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kikiwa	110 kV	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Kikiwa	220 kV	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Kumara	66 kV	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Murchison	11 kV	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Murchison	110 kV	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Orowaiti	110 kV (Circuit–1)	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Orowaiti	110 kV (Circuit–2)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Otira	11 kV	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Otira	66 kV	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Reefton	110 kV (Circuit–1)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Reefton	110 kV (Circuit–2)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Waimangaroa	110 kV (Circuit–1)	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Waimangaroa	110 kV (Circuit–2)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Westport	11 kV	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Westport	110 kV (T1)	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Westport	110 kV (T2)	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CANTERBURY												
Ashburton	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Ashburton	66 kV	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Ashburton	220 kV	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Ashley	11 kV (T5)	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Ashley	11 kV (T3)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Ashley	66 kV	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Bromley	66 kV	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
Bromley	220 kV	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Coleridge	11 kV	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7

Coleridge	66 kV	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Culverden	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Culverden	66 kV	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Culverden	220 kV (T22)	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Culverden	220 kV (T23)	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Hororata	33 kV	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Hororata	66 kV	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Islington	33 kV	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Islington	66 kV	21.1	21.1	21.1	21.1	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Islington	220 kV	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Kaiapoi	11 kV	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Kaiapoi	66 kV	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
Kimberley	66 kV (T1)	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Kimberley	66 kV (T2)	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Southbrook	33 kV	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Southbrook	66 kV	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Waipara	33 kV	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Waipara	66 kV	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Waipara	220 kV (T12)	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Waipara	220 kV (T13)	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
SOUTH CANTERBURY												
Albury	11 kV	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Albury	110 kV	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Aviemore	220 kV	18.0	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Bells Pond	110 kV	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Benmore	220 kV	24.6	24.7	24.7	24.7	24.7	24.7	24.7	24.7	24.7	24.7	24.7
Black Point	110 kV	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Livingstone	220 kV	6.7	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Oamaru	33 kV	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Oamaru	110 kV (T1)	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Oamaru	110 kV (T2)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Ohau A	220 kV	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
Ohau B	220 kV	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Ohau C	220 kV	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
Studholme	11 kV	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Studholme	110 kV	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Tekapo A	11 kV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tekapo A	33 kV	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Tekapo A	110 kV	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Tekapo B	220 kV	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Temuka	33 kV	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Temuka	110 kV (T1)	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Temuka	110 kV (T2)	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Timaru	11 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1

Timaru	110 kV	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Timaru	220 kV (T5)	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Timaru	220 kV (T8)	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Twizel	33 kV (T18)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Twizel	33 kV (T19)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Twizel	220 kV	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2	23.2
Waitaki	11 kV (T28)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Waitaki	33 kV	14.8	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9
Waitaki	220 kV	14.8	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9
OTAGO-SOUTHLAND												
Balclutha	33 kV	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Balclutha	110 kV	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Berwick	110 kV	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Brydone	11 kV	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Brydone	110 kV	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Clyde	33 kV	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Clyde	220 kV	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
Cromwell	33 kV	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Cromwell	110 kV (T5A/B)	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Cromwell	110 kV (T8)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Cromwell	220 kV (T5A/B)	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
Cromwell	220 kV (T8)	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Edendale	33 kV	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Edendale	110 kV	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Frankton	33 kV	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Frankton	110 kV (T2)	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Frankton	110 kV (T4)	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Gore	33 kV	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
Gore	110 kV	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Gore	220 kV (T11)	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Gore	220 kV (T12)	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Halfway Bush	33 kV (T3)	16.8	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Halfway Bush	33 kV (T5)	16.8	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Halfway Bush	110 kV	7.1	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Halfway Bush	220 kV	6.5	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Invercargill	33 kV	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Invercargill	110 kV	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Invercargill	220 kV	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Manapouri	220 kV	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
North Makarewa	33 kV	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
North Makarewa	220 kV	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Naseby	33 kV	8.3	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Naseby	220 kV	4.2	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Roxburgh	110 kV	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Roxburgh	220 kV	15.8	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9	15.9
South Dunedin	33 kV	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
South Dunedin	220 kV	6.1	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
Three Mile Hill	220 kV	6.8	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9
Tiwai	220 kV	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6

Appendix C: Glossary

Term	Description
after diversity maximum demand	The peak consumption of energy (averaged over a half-hour period and expressed in Watts) that incorporates the non-simultaneous nature of each point of supply's load peak time.
automatic under frequency load shedding	The automatic disconnection of customers for severe or prolonged under frequency. Implemented on relays installed within the distribution network or at Transpower's substations, customers are currently tripped in two, nominally, 20% groups.
availability	The number of hours per year the network or part thereof is in service. Unavailability is the opposite of availability (for example, the hours per year the network or part thereof is not providing service).
bay (of a station)	That part of a substation or power station where a given circuit's switchgear is located. According to the type of circuit, a substation or power station may include: feeder bays, transformer bays, bus coupler bays, etc.
breaker-and-a-half station	A double-bus substation where, for two circuits, three circuit-breakers are connected in series between the two buses, the circuits being connected on each side of the central circuit-breaker.
bus	The common primary conductor of power from a power source to two or more separate circuits.
bus coupler circuit-breaker	A circuit-breaker located between two busbars that can both be accessed by the same external circuit. The bus coupler circuit-breaker permits the busbars to be connected together or separated under load or fault conditions.
bus section	Part of a bus that can be isolated from another part of the same bus.
cable	One or more insulated conductors forming a transmission circuit above or below ground.
capacitor bank	A number of capacitors connected together in series and/or parallel to form the requisite capacitance and voltage rating for reactive compensation and harmonic filters on the HVAC and HVDC power systems.
charging current (line)	The current taken by a transmission circuit to energise its conductors due to the capacitive effect of the circuit.
circuit (transmission) (cct)	A set of conductors (normally three) plus associated hardware and insulation on a transmission line, which together form a single electrical connection between two or more stations and which, when faulted, is removed automatically from the system (by circuit-breakers) as a single entity.
circuit-breaker	A switching device, capable of making, carrying and breaking currents under normal circuit conditions and also making, carrying for a specified time and breaking currents under specified abnormal conditions, such as those of short circuit.
cogeneration	The use of high-pressure steam from a turbo-generator set for an industrial process. The production of electricity is usually secondary to the requirements of the industrial process.
commissioned	The operational state of equipment that has undergone the commissioning process and is brought under the operational control of a service centre/controller.
committed projects	Refers to actual proposed projects that satisfy a number of criteria indicating that they are extremely likely to proceed in the near future. For example: • land has been acquired for construction of the project • planning consents, construction approvals and licences have been obtained • construction has begun, or a firm commencement date has been set • contracts for supply and construction have been finalised, and • financing arrangements are largely complete.
constraint	A local limitation in the transmission capacity of the grid required to maintain grid security or power quality.

contingency	The uncertainty of an event occurring, and the planning to cover for this. For example, a single contingency could be: a. in relation to transmission, the unplanned tripping of a single item of equipment, or b. in relation to a fall in frequency, the loss of the largest single block of generation in service, or the loss of one HVDC pole.
contingent event	Those events for which, in the reasonable opinion of the system operator, resources can be economically provided to maintain the security of the grid and power quality without the shedding of demand.
continuous rating	The maximum rating to which equipment can be operated continuously.
decommissioned	The status of equipment which is permanently disconnected from the power system, made permanently inoperable, and free of any operational identification.
demand	A measure of the rate of consumption of electrical energy.
demand-side management	Initiatives or mechanisms used to control electricity demand. Examples include ripple controls on water heating or contracted shedding of load (demand).
disconnector	A switch that, when in the open position, provides an isolating distance in accordance with specified requirements.
dispatch	The process of : a. pre-dispatch scheduling to allocate active and reactive power generation, including additional ancillary services and reserve, to match expected demand, within the limitations of the grid and equipment b. rescheduling to meet forecast demand, and c. issuing instructions based on the schedule and the real-time conditions to manage resources to meet the actual demand.
distribution (of electricity)	The transfer of electricity between the transmission network and end users through a local network.
distribution line	An electric line that is part of a local network.
double circuit line	A transmission line carrying two circuits.
duplicate protection	A protection scheme for a plant item such that any fault on the plant item can be cleared by two independent sets of relays, either of which is able to operate correctly even if the other fails completely.
electricity distributor	An asset owner whose assets are predominantly for the distribution of electricity to customers.
Electricity Industry Act 2010	The Act setting out the present framework including the Electricity Industry Participation Code.
Electricity Industry Participation Code	The requirements on the electricity industry made pursuant to the Electricity Industry Act 2010.
embedded generators	Smaller power plants connected to a regional electricity line business's distribution network (as opposed to the high voltage transmission network).
end user	An entity connected to the power system for the primary purpose of consuming electricity.
event	A term identifying undesired or untoward operational happenings, principally: a. accidents (resulting in loss) b. near-misses (which, under slightly different circumstances, could have caused loss) to people, process, equipment, material or the environment c. a disturbance to the power system d. a significant change in the state of the grid e. equipment defects, and f. fire or intruder alarm operation.
feeder	A circuit that provides a direct connection to a customer.
firm capacity	Power capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.
forced outage	The automatic or urgent removal from service of an item of equipment.
frequency (power)	The rate of cyclic change in value of current and voltage, quantified by the international standard term 'Hertz' (Hz).

frequency excursion	A variation of the power system frequency above 50.25 Hz or below 49.75 Hz.
gas turbine (GT)	A heat engine that uses the energy of expanding gases passing through a multi-stage turbine to create rotational power.
generating set	A group of rotating machines transforming mechanical or thermal energy into electricity. Note: for the purposes of the operating codes and the output ratings referred to, the set is taken to include the limitations of the energy source, turbine, generator, cable, set transformer and switchgear. [GOSP glossary - IEC 50 (602-02-01)]
generation	The electrical energy produced by a generator, a generating station or within a power system as a whole. The process of producing electricity.
generator	A person who owns and/or manages one or more generating sets that are physically connected to the grid assets or to a network or to other assets connected to the grid assets.
grid	That part of the New Zealand electricity transmission system, the operation of which is undertaken by the grid operator.
grid asset owner	Transpower New Zealand Limited.
grid assets	At any time, the plant, transmission lines and other facilities, owned or managed by the grid asset owner, and which are used to interconnect all the points of connection for connected parties.
grid exit point (GXP)	A point of connection where electricity may flow out of the grid.
grid injection point	A point of connection where electricity may flow into the grid.
HVAC	High voltage alternating current.
HVDC	High voltage direct current.
in service	The state of equipment that is connected to a source of energy or may be connected to a source of energy by an operating action.
instantaneous load	The maximum instantaneous current drawn. It consists of continuous, non-continuous and momentary currents.
intertrip	A protection signalling system whereby a signal initiated at one station trips a circuit-breaker at another station.
islanded operation	The condition that arises when a section of the power system is disconnected from and operating independently of the remainder of the power system.
life expectancy	The date where replacement/major refurbishment is necessary.
line [overhead]	A series of structures carrying overhead one or more transmission circuits.
load control	Types of load control include: • automatic under frequency load shedding (see MW reserve of a power system) • interruptible load (see MW reserve of a power system), and • manual load shedding (see manual load shedding).
load shedding	The forced disconnection of load, in stages. This is either manual (see load control) or automatic (see MW reserve [of a power system]).
main protection	Protection equipment (or a system) expected to have priority in initiating either a fault clearance or an action to terminate an abnormal condition in the power system.
manual load shedding	The forced disconnection of load by an operator/controller.
maximum continuous rating (MCR)	The value assigned to an equipment parameter by the manufacturer, and at which the equipment may be operated for an unlimited period without damage.
maximum demand	The peak consumption of energy (averaged over a half-hour period and expressed in watts) recorded during a given time, for example, a day, week, or year.

MegaVoltAmpere (MVA)	1000 kVA. The flow of active power is measured in megaWatts (MW). When compounded with the flow of reactive power, which is measured in Mvar, the resultant is measured in MegaVoltAmperes (MVA).
n-1, "n"	Refers to the planning standard that Transpower generally plans the grid to. The n-1 security level provides supply security to the connected loads under a single credible contingency with all the assets that can reasonably be expected in service. The single credible contingencies that are defined in the Rules are: • a single transmission circuit interruption • the failure or removal from operational service of a single generating unit • an HVDC link single pole interruption • the failure or removal from service of a single bus section • a single interconnecting transformer interruption, and • the failure or removal from service of a single shunt connected reactive component. An ''n" security standard means that any outage will trip load. It is often found in smaller supply areas, where just one transmission circuit or supply transformer provides supply.
nominal rating	The design rating of the equipment or transmission circuit. For equipment, this is often referred to as the 'nameplate rating'.
nominal system frequency	50 Hertz.
non-continuous load	A load that is energised for a portion of the duty cycle greater than one minute. It may be for a set period, and removal may be automatic or by operator action or it may continue to the end of the duty cycle.
normal system conditions	The state of the power system when it is operating in accordance with statutory requirements as regards quality of supply and within basic design and operational parameters.
on-load tap-changer (OLTC)	Equipment fitted to a power transformer by which the voltage ratio between the windings can be varied while the transformer is on-load.
outage	The state of an item of equipment when it is not available to perform its intended function. An outage may or may not cause an interruption of supply to customers.
overhead line	A transmission line.
overload	A load greater than the maximum continuous rating.
Overload protection scheme	A type of special protection scheme that prevents loading of assets above their stated capacity
peak demand	See maximum demand.
peak load	The maximum peak load (in amps) that can be expected to be carried within a twelve month period on the circuit or by the equipment/component.
planned outage	A deliberate outage scheduled for maintenance purposes.
power factor	The ratio between active power (expressed in watts, W) and true power (expressed in volt-amperes, VA). Can vary between 1 and 0. A load with a low power factor uses more reactive current than a load with a high power factor for the same amount of useful power transferred.
power flow analysis	Simulation of the actual power system using computer models, so as to analyse the effects of changes to inputs (like demand, supply, and asset ratings), and identify constraints or other issues that might affect security of supply to a region.
power system stability	The capability of a power system to regain a steady state, characterised by the synchronous operation of the generators after a disturbance due, for example, to variation of power or impedance.
power transformer	A transformer that primarily changes voltage and current for the efficient conveyance of electricity over the circuits connected to it.
protection	The equipment provided for detecting abnormal conditions in a power system and then initiating fault clearance or actuating signals or indications.

reactive power	Energy that flows in the power system between alternators, capacitors, SVCs, etc., and inductive and capacitive equipment such as transmission lines and low power factor loads. It is the product of the voltage and out-of-phase components of the alternating current and is measured in vars.
relay	A device designed to produce predetermined changes in one or more electrical output circuits, when certain conditions are fulfilled in the electrical input circuits controlling the device.
reliability	The failure rate. For example, the number of failures per year based on experience over a long time period, say 10 years or more.
resource consent	A consent to use land, air or water granted by the local government under the Resource Management Act. The consent usually imposes limits on that use.
return period	The statistical return period of a weather-related event, load or load effect.
risk based condition replacement	Replacement of existing assets based on risk of failure due to asset condition
runback scheme	An automatic limit on generation or HVDC transfer, which typically would be enabled when there is loss of a particular circuit, transformer, signalling or control system.
security	A term used to describe the ability or capacity of a network to provide service after one or more equipment failures. It can be defined by deterministic planning criteria such as (n), (n-1), (n-2) security contingency. A security contingency of (n-m) at a particular location in the network means that 'm' component failures can be tolerated without loss of service.
short circuit rating	The three second fault rating of equipment.
short term rating	The maximum rating to which equipment can be operated for a specified duration.
single-circuit line	A transmission line carrying one circuit.
spur circuit	A circuit connected to the transmission system at only one point.
stability limit	The critical value of a given system state variable that cannot be exceeded without endangering power system stability. For a power system without a fault, this concept is related to the steady state stability of the system.
steady state stability	A power system stability in which disturbances have only small rates of change and small relative magnitudes.
substation	A building, structure or enclosure incorporating equipment used principally for the control of the transmission or distribution of electricity.
switchgear	A collective term for switches of all types and their associated equipment, including circuit-breakers, disconnectors, and earthing switches.
switchgear group	A circuit-breaker and related disconnectors. The relationship is determined by switchgear numbering.
switching station	A station existing solely for the purpose of transmission rather than supply.
synchronous condenser	A synchronous machine running without mechanical load and supplying or absorbing reactive power to regulate local voltage.
system frequency	At any instant the value of the frequency of the power in the North Island or South Island. See also Hertz, nominal system frequency, and frequency.
system normal	The power system is operating in the normal state when: • generation meets the demand at 50Hz (±0.2 Hz) • voltage requirements are met • grid equipment is operated within design ratings, and • reserve margins and the power system configuration provide an adequate level of operational security.
system operator	The person responsible from time to time for the operation of the grid system. The system operator is Transpower New Zealand Limited.
tee (or T) point	The point at which a branch transmission circuit is solidly and permanently connected to a main circuit, usually without switchgear. See also tee-off.

tee-off	A branch transmission circuit joining a main circuit and that is protected as part of the main circuit.
thermal constraints/limits/ capacities	Refers to the temperature ratings of the assets (lines, generators, transformers) connected to the power system, beyond which the assets cannot securely be operated.
thermal upgrade	The increase in temperature ratings of assets to provide more capacity.
transformer	A static electric device consisting of a winding or two or more coupled windings which transfer power by electromagnetic induction between circuits of the same frequency, usually with changed values of voltage and current.
transient (in)stability	Refers to the response of the power system when it experiences a large disturbance like a line fault or outage of a generator.
transmission	The conveying of bulk electricity from power stations to points of supply (compared with distribution).
transmission circuit	An electrical circuit the primary purpose of which is the transmission of electricity from one geographical location to another.
transmission line	A series of structures carrying one or more transmission circuits overhead.
transmission system	That part of the power system primarily intended for the conveyance of bulk electricity.
voltage	The nominal potential difference between conductors or the nominal potential difference between a conductor and earth, whichever is applicable.
voltage collapse	A sudden and large decrease in the voltage of the electrical system.
voltage (in)stability	Refers to the power system's ability to maintain a satisfactory voltage at all buses for any disturbance, such as a variation in load or an outage of plant.

Appendix D: Grid Exit and Injection Points

Key	
GXP	Grid Exit Point
GIP	Grid Injection Point
SWI	Switching Station

Table D-1: North Island Grid Exit and Injection Points

North Island

North Isthmus		Auckland		Waikato		Bay of Plenty		Central North Island		Taranaki		Hawkes Bay		Wellington	
Bream Bay	GXP	Albany	GXP	Arapuni	GIP	Aniwhenua	GIP	Bunnythorpe	GXP	Brunswick	GXP	Fernhill	GXP	Central Park	GXP
Kaikohe	GXP	Bombay	GXP	Atiamuri	GIP	Edgecumbe	GXP	Aratiatia	GIP	Carrington Street	GXP	Redclyffe	GXP	Gracefied	GXP
Maungatapere	GXP	Brownhill Road	SWI	Cambridge	GXP	Kaitimako	GXP	Dannevirke	GXP	Hawera	GXP/GIP	Tuai	GXP/GIP	Greytown	GXP
Maungaturoto	GXP	Drury	SWI	Hamilton	GXP	Kawerau	GXP	Linton	GXP	Huirangi	GXP	Whakatu	GXP	Haywards	GXP
Wellsford	GXP	Glenbrook	GXP/GIP	Hangatiki	GXP	Matahina	GIP	Mangahao	GIP	Kaponga	GXP	Whirinaki	GXP/GIP	Kaiwharawhara	GXP
		Henderson	GXP	Hinuera	GXP	Mt Maunganui	GXP	Mangamaire	GXP	Kapuni	GIP			Masterton	GXP
		Hepburn Road	GXP	Huntly	GXP/GIP	Owhata	GXP	Marton	GXP	McKee	GIP			Melling	GXP
		Hobson Street	GXP	Karapiro	GIP	Rotorua	GXP	Mataroa	GXP	Motunui	GXP			Paraparaumu	GXP
		Huapai	SWI	Kinleith	GXP/GIP	Tarukenga	GXP	National Park	GXP	New Plymouth	GIP			Pauatahanui	GXP
		Mangere	GXP	Kopu	GXP	Tauranga	GXP	Nga Awa Purua	GIP	Opunake	GXP			Takapu Rd	GXP
		Mount Roskill	GXP	Lichfield	GXP	Te Matai	GXP	Ohaaki	GIP	Stratford	GXP/GIP			Upper Hutt	GXP
		Otahuhu	GXP	Maraetai	GIP	Waiotahi	GXP	Ohakune	GXP	Taumarunui	GXP			West Wind	GIP

		Pakuranga	GXP	Mokai	GIP			Ongarue	GXP	Wanganui	GXP			Wilton	GXP
		Penrose	GXP	Ohakuri	GIP			Poihipi	GIP	Waverley	GXP				
		Silverdale	GXP	Ohinewai	SWI			Rangipo	GIP						
		Southdown	GXP	Piako	GXP			Tangiwai	GXP						
		Takanini	GXP	Te Awamutu	GXP			Tararua	GIP						
		Wairau Road	GXP	Te Kowhai	GXP			Te Mihi	GIP						
		Wiri	GXP	Waihou	GXP			Tokaanu	GXP/GIP						
				Waikino	GXP			Waipawa	GXP						
				Waipapa	GIP			Wairakei	GXP/GIP						
				Whakamaru	GIP			Woodville	GXP/GIP						

Table D-2: South Island Grid Exit and Injection Points

South Island									
Nelson/Marlborough		**West Coast**		**Canterbury**		**South Canterbury**		**Otago/Southland**	
Argyle	GIP	Arthurs Pass	GXP	Ashburton	GXP	Albury	GXP	Balclutha	GXP
Blenheim	GXP	Atarau	GXP	Ashley	GXP	Aviemore	GIP	Berwick	GIP
Cobb	GIP	Castle Hill	GXP	Bromley	GXP	Benmore	GIP	Brydone	GXP
Stoke	GXP	Dobson	GXP	Coleridge	GIP	Black Point	GXP	Clyde	GXP/GIP
		Greymouth	GXP	Culverden	GXP	Bells Pond	GXP	Cromwell	GXP
		Hokitika	GXP	Hororata	GXP	Livingstone	SWI	Edendale	GXP
		Inangahua	SWI	Islington	GXP	Oamaru	GXP	Frankton	GXP
		Kikiwa	GXP	Kaiapoi	GXP	Ohau A	GIP	Gore	GXP
		Kumara	GIP	Kimberley	GXP	Ohau B	GIP	Halfway Bush	GXP
		Murchison	GXP	Southbrook	GXP	Ohau C	GIP	Invercargill	GXP

Orowaiti (Robertson Rd)	GXP	Waipara	GXP	Studholme	GXP	Manapouri	GIP
Otira	GXP			Tekapo A	GXP/GIP	Naseby	GXP
Reefton	GXP			Tekapo B	GIP	North Makarewa	GXP
Waimangaroa	SWI			Temuka	GXP	Roxburgh	GIP
				Timaru	GXP	South Dunedin	GXP
				Twizel	GXP	Three Mile Hill	SWI
				Waitaki	GXP/GIP	Tiwai	GXP