Foreword to the Transmission Planning Report 2015

I am pleased to introduce this tenth Transpower Transmission Planning Report (formerly the Annual Transmission Planning Report or APR).

Transpower is the owner, operator and planner of the National Grid – the high voltage electrical transmission system that stretches across both North and South Islands, connecting generation sources to local substations that serve consumers across New Zealand, be they residential, industrial or commercial. The National Grid also facilitates the competitive wholesale electricity market.

The purpose of the Transmission Planning Report (TPR) is to ensure our transmission planning process is open and transparent to all. The TPR also includes both new build and replacements and how they fit into the work we do to deliver the long-term service expected from the grid.

Service has been a focal point for the company over the last year. With more expected from Transpower by our regulator over the next five years, we need to have more definition around what services we provide and how we will be measured against them. For some of our connected customers, this may mean commitments to improved levels of service, for others it may be a reminder that the legacy level of service they presently receive may need refinement in light of our regulatory obligations. We expect to start having those conversations with all our customers over the following year.

The TPR remains an important document to identify future transmission issues and potential solutions to solve them. Together with our more transparent service framework, we expect the Transmission Planning Report to help populate the discussions on future investment by both parties leading to improved decision making and better risk management. For the past ten years we have published this Transmission Planning Report annually. To streamline our business we will be reducing the frequency and ensuring publications align with our 5-year regulatory planning cycle. We expect to publish our next TPR in 2017.

The events at Penrose in October 2014 have underlined the importance of ensuring not only the integrity of our new build and augmentations, but also the integrity of our existing sites and facilities. We are commencing a review with all our customers on our shared facilities to identify issues and solutions to those. While site assessments are a standard part of our and our connected customers’ operations, we believe joint reviews will help better identify and manage risk for all parties. As these develop into concrete actions for Transpower they may well be the subject of mention in future TPRs.

Alison Andrew
Chief Executive
July 2015
Executive Summary

Background

The 2015 Transmission Planning Report (TPR) provides information about:
- the capabilities of the existing National Grid
- demand and generation forecasts for up to 15 years
- the National Grid’s ability to meet future demand and generation needs
- the role of the transmission grid in facilitating generation
- National Grid investment that may be required to meet future needs for up to 15 years and beyond, by way of:
  - grid backbone transmission plans for the main North and South Island transmission corridors, and for the HVDC link, and
  - 13 regional plans.

This TPR represents information available up to 31 May 2015.

Purpose of the TPR

The role of the TPR is to signal proposed and possible transmission investments within a 15 year horizon. It provides our customers and market participants information on the development issues impacting on the National Grid and Transpower’s network development plans to help coordinate with their own plans and strategies.

Overview

The TPR provides our view on future grid development needs and options. To enable stakeholders to evaluate the needs and options, the base data and analytical methods are presented for scrutiny. The TPR takes a national and a regional approach to identify the development needs on the grid backbone and also the requirements for each individual region.

Energy and peak demand forecasts

For this publication of the Transmission Planning Report we have continued to use an “ensemble” approach: where several forecasting models are used to derive our forecasts. We reviewed our methodology in 2013 in response to recent trends and made some further minor adjustments in 2014 to ensure that our modelling adequately captures the range of uncertainty in future electricity demand growth.

Our prudent peak forecasts represent a 10% probability of exceedance forecast for the first 7 years of the forecast period (until 2021), or a 90% chance of being under the forecast (P90). In other words, until 2021 one would expect actual peak demand to exceed the forecast in one year out of ten. Post-2021 we assume an expected (or mean) rate of growth.

The following figure compares the updated 2015 TPR forecast with the TPR forecasts made in each of the previous four years. The forecasts are seen to have moved lower again this year as historical demand growth has flattened.

The updated forecast starts at a similar level to last year’s forecast but projects lower growth averaging 1.1% per annum to 2030.
Executive Summary

Generation forecasts

This year generation scenarios included in the TPR are based on the Ministry of Business, Innovation and Employment’s (MBIE’s) draft Electricity Demand and Generation Scenarios¹ (EDGS) and work done by the New Zealand Smart Grid Forum² on disruptive technologies. MBIE released the draft EDGS for consultation in April 2015. The EDGS will replace the 2010 Statement of Opportunities previously used as a basis for Transpower’s scenario analysis when they are finalised.

Due to the limited lead time since the release of the draft EDGS, for this year’s TPR we have not explicitly considered MBIE’s draft EDGS scenarios 5-8. They are similar to MBIE’s mixed renewables scenario except they have different demand assumptions, such as about the future levels of demand from Tiwai and future demand growth rates.

There are five market development scenarios

- Scenario 1: Mixed Renewable (a ‘balanced’ renewables scenario
- Scenario 2: High geothermal access (allowance of more geothermal generation constructed)
- Scenario 3: Low-cost fossil fuels (assumption of major gas discovery and low carbon charges)
- Scenario 4: Global low carbon (early increase in carbon charges, lower costs for wind and greater uptake of solar and electric vehicles)
- Scenario 5: Disruptive Technologies (strong uptake in electric vehicles, and residential photo-voltaics).

State of the grid

A reliable “fit for purpose” National Grid that meets present consumer needs, and responds to changing demands, is an essential component of a modern society. A robust and capable grid also creates a platform to allow strong competition between generators and retailers, to put downward pressure on prices to the benefit of consumers. The National Grid also continues to provide New Zealanders with access to renewable sources of generation (hydro, wind, geothermal).

Based on present knowledge, we can demonstrate that the projects identified in this report will enable the grid to meet forecast demand and solve the grid related issues predicted to occur up to 15 years into the future.3

Completed projects for 2014

Summary Table 1 lists the projects completed since the 2014 Transmission Planning Report.

<table>
<thead>
<tr>
<th>Project name</th>
<th>Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Additional bus coupler circuit breaker at Islington</td>
<td>2014</td>
</tr>
<tr>
<td>Replace Stratford supply transformer with two 40 MVA units</td>
<td>2014</td>
</tr>
<tr>
<td>Replace Redclyffe supply transformers with two 120 MVA units</td>
<td>2014</td>
</tr>
<tr>
<td>Replace the existing three Timaru 110/11 kV supply transformers with three 47 MVA units</td>
<td>2014</td>
</tr>
<tr>
<td>Replacement 220 kV Wairakei–Whakamaru–C line</td>
<td>2014</td>
</tr>
<tr>
<td>Resolve Balclutha protection and branch component limit</td>
<td>2014</td>
</tr>
<tr>
<td>Paraparaumu 220 kV connection</td>
<td>2015</td>
</tr>
<tr>
<td>Replace Hamilton 220/33 kV supply transformer</td>
<td>2015</td>
</tr>
<tr>
<td>Replace Huirangi supply transformer with two 60 MVA units</td>
<td>2015</td>
</tr>
<tr>
<td>Replace National Park supply transformer</td>
<td>2015</td>
</tr>
<tr>
<td>Replace Ohakune supply transformer</td>
<td>2015</td>
</tr>
<tr>
<td>Replace Tarukenga interconnecting transformer</td>
<td>2014</td>
</tr>
<tr>
<td>Replace Rotorua 110/11 kV supply transformers with two 35 MVA units.</td>
<td>2015</td>
</tr>
</tbody>
</table>

Committed and proposed projects for 2015

Summary Figure 1 and Summary Figure 2 provide a summary of all projects either committed or proposed in this TPR4. Detail around any particular project can be found in the relevant regional or grid backbone chapter.

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3 Transpower is unable to comment on supply side issues (e.g. beyond the grid exit point) other than through the impact of the generation scenarios.
4 Refer to Chapter 1, Section 1.4 for definitions of “committed” and “proposed”. For the purposes of these maps only those capital or customer projects greater than $5 million with a high level of confidence of proceeding during Revenue Control Period 2 (RCP2) are shown.
Executive Summary

Summary Figure 1: Transpower’s committed or proposed projects – North Island

North Island Grid Backbone Projects
- 220 kV Bunnythorpe–Haywards–A and B line conductor replacement.
- Upper North Island Reactive Support 2015+
- Haywards bus section redevelopment
- Bunnythorpe bus section redevelopment
- Mount Roskill bus section redevelopment
- Penrose Interconnecting Transformer upgrade
- Otahuhu Interconnecting Transformer upgrade
- Bunnythorpe Interconnecting Transformer upgrade

Wellington Regional Projects
- Install a third Wilton 110 kV bus section
- Upper Hutt supply transformer protection and metering limit resolution.

Hawkes Bay Regional Projects
- Install Special Protection Scheme at Redclyffe

Waikato Regional Project
- New Putaruru Grid Exit Point

Taranaki Regional Projects
- Release Stratford–Wanganui capacity

Auckland Regional Project
- Otahuhu–Win transmission capacity enhancement
Executive Summary

Summary Figure 2: Transpower’s committed or proposed projects – South Island

South Island Grid Backbone Projects
- Clutha–Upper Waitaki Lines Project.

Otago-Southland Regional Projects
- Lower South Island Reliability Project including:
  - new 220/110 kV interconnection at Gore and 220 kV line connecting Gore to the North Makarewa–Three Mile Hill line
  - Resolve South Dunedin supply transformer metering constraint
  - Halfway Bush 220 kV and 110 kV transformer replacement

South Canterbury projects
- Convert Timaru 110 kV bus to three zones.
- Tekapo A supply transformer branch limit resolution

South Island Grid Backbone Projects
- Clutha–Upper Waitaki Lines Project.
Feedback

We will be using this document as a basis for discussions with our customers and other stakeholders by way of regional forums and other meetings. Feedback received will be used to improve subsequent releases of the Transmission Planning Report. If you are unable to attend a regional forum in your area, but have feedback on how this document might be improved, please address to:

Grid Development
Transpower New Zealand Ltd
PO Box 1021
Wellington
gridinvestmentprojects@transpower.co.nz
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</table>
Chapter 1: Introduction

1 Introduction

1.1 Purpose of the Transmission Planning Report

We produce the TPR to:

• provide an indication of the National Grid’s ability to meet forecast demand and generation development over the next 15 years
• communicate the potential transmission investment required to alleviate anticipated system constraints and issues to customers, industry, regulators and interested parties
• provide transparency in terms of the current transmission network development options, and
• encourage efficient investment decision making via the timely disclosure of grid development options.

This TPR represents our view of how the National Grid might be developed over the next 15 years to provide both reliability of supply and facilitate a competitive electricity market. To achieve this, the TPR:

• presents a grid development plan, which includes possible transmission investments based on preliminary assessments\(^5\) - detailed analysis occurs when preparing a case for investment\(^6\), and
• aims to provide information to enable interested parties to:
  • understand the transmission network’s ability to supply their needs

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\(^5\) This plan does not imply that we have formed a view about a particular transmission investment, or that a transmission (versus a transmission alternative) investment is the most efficient solution.

\(^6\) Investment Approval Process (IAP) is the decision-making framework for preparing investment proposals to meet Transpower’s plans for its grid.

https://www.transpower.co.nz/sites/default/files/plain-page/attachments/investment-approvals-process_0.pdf
• provide input into our transmission network development plans
• identify and evaluate alternative transmission network investments
• identify potentially preferred locations for connecting significant load (e.g. heavy industry)
• identify locations that may benefit from demand-side initiatives, and
• assess generation development opportunities, such as preferred locations and the ability of the transmission network to accommodate the proposed generation.

This document is produced for the purposes specified above. Any associated cost information represents a high level and provisional estimate only and therefore 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.

1.1.1 Document overview

In this TPR:
• Chapter 2 ‘Facilitating New Zealand’s Energy Future’ provides a high-level description of our long term goal and the challenges in meeting it.
• Chapter 3 ‘Existing National Grid provides a description of the National Grid’s existing configuration, including recently completed projects.
• Chapter 4 ‘Demand Assumptions’ provides a high-level description of our demand forecast approach and the various demand forecasts it has developed.
• Chapter 5 ‘Generation Assumptions’ describes the development and selection of our generation scenarios.
• Chapter 6 ‘Grid Backbone’ discusses the grid backbone’s ability to accommodate the forecast demand.
• Chapters 7 - 19 ‘Regional Plans’ describe the specific plan for each region’s transmission network.

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

1.2 The regulatory framework and the TPR’s context

1.2.1 Regulatory framework

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 and generation at grid injection points, and whether the National Grid can be reasonably expected to meet (n-1) security requirements, and
• a Grid Economic Investment Report (GEIR), which identifies economic investments (creates net market benefits) that Transpower considers could be made in respect of the interconnection assets.

The 2015 Transmission Planning Report (TPR) does not include either the GRR and GEIR which are now published and available separately.7

Under the Capital Expenditure Input Methodology (Capex IM) we are required to submit an Integrated Transmission Plan (ITP) as part of our regulatory proposal and update this plan annually (except for the last disclosure year in a regulatory period.) The ITP will provide our 10 year plan to deliver a resilient, cost-effective transmission service. It brings together our development plans with our plans to operate and

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maintain the existing grid. This TPR will be provided as a supporting document to the ITP, as required by Schedule 6 of the Capex IM.

We are publishing our first standalone ITP at the end of September 2015.

1.2.2 The context for our TPR

As owner, operator and planner of the National Grid, we publish the TPR periodically to assist all market participants to understand the extent of potential transmission investments requirements.

System Security Forecast (SSF)

As the System Operator, we also publish the System Security Forecast (SSF). The SSF assesses the National Grid’s capability to meet demand as required under Part 7 of the Code, and generally covers a shorter term and operational focus. The latest SSF is available from our System Operator website.8

Transmission Code

Our Transmission Code codifies a set of technical planning requirements that we apply to ensure the National Grid remains resilient, fit for purpose and is consistent with good industry practice. More information on the Transmission Code can be found on our website.9

1.3 The planning approach

Our long-term strategic view is outlined in Chapter 2 ‘Facilitating New Zealand’s Energy Future’. Planning is framed by the long-term view to ensure the appropriate selection of investment for the maintenance of a reliable and secure electricity supply, under a range of system and environmental conditions.

1.4 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 the context of their state of completion, regulatory status, identification references and costs.

1.4.1 State of completion

We classify transmission network development projects by their state of completion. Table 1-1 lists the completion states by project type and definition.

Table 1-1: State of completion classifications

<table>
<thead>
<tr>
<th>Status</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Completed</td>
<td>Projects that have recently been completed and are commissioned and operating.</td>
</tr>
<tr>
<td>Committed</td>
<td>Projects that are currently underway for which either:</td>
</tr>
<tr>
<td></td>
<td>• the investment has obtained regulatory approval, or</td>
</tr>
<tr>
<td></td>
<td>• Transpower has entered into a new investment contract with a specific</td>
</tr>
<tr>
<td></td>
<td>customer or customers.</td>
</tr>
<tr>
<td>Proposed</td>
<td>Projects that Transpower has proposed, either:</td>
</tr>
<tr>
<td></td>
<td>• to the Commission via a Major Capex Proposal, or</td>
</tr>
<tr>
<td></td>
<td>• as part of our Base Capex funding, or</td>
</tr>
<tr>
<td></td>
<td>• to specific customer or customers for their agreement.</td>
</tr>
<tr>
<td>Preferred</td>
<td>Projects for which Transpower has undertaken detailed analysis and identified a</td>
</tr>
</tbody>
</table>

8 http://www.systemoperator.co.nz/publications#cs-85812
9 https://www.transpower.co.nz/about-us/what-we-do/planning-future/planning-inputs
Chapter 1: Introduction

1.4.2 Investment type

Our transmission network development projects can be classified by the funding source as shown in Table 1-2.

<table>
<thead>
<tr>
<th>Investment type</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Capex</td>
<td>Replacement and Refurbishment projects of any value, or Development projects forecast to cost less than $20 million in Regulatory Control Period 2 (RCP2) These proposed projects are funded under a CC-approved approved Base Capex allowance.</td>
</tr>
<tr>
<td>Major Capex</td>
<td>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 for RCP2. Each proposal must comply with the regulated Investment Test as prescribed in the Transpower Capital Expenditure Input Methodology Determination 10</td>
</tr>
<tr>
<td>Customer-specific</td>
<td>Enhancement projects on assets specific to a customer or group of customers which are agreed and paid for under a new investment contract between Transpower and the customer/group of customers.</td>
</tr>
</tbody>
</table>

1.4.3 Generation proposals

Table 1-3 summarises the generation proposal classifications used throughout the TPR.

<table>
<thead>
<tr>
<th>Status</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Committed</td>
<td>Projects for which:</td>
</tr>
<tr>
<td></td>
<td>• arrangements for securing the required land are in place</td>
</tr>
<tr>
<td></td>
<td>• resource consents have been obtained, and</td>
</tr>
<tr>
<td></td>
<td>• business approval has been obtained.</td>
</tr>
<tr>
<td></td>
<td>The project will be:</td>
</tr>
<tr>
<td></td>
<td>• considered explicitly in Transpower’s assessment of transmission issues and development options, and</td>
</tr>
<tr>
<td></td>
<td>• described in the main body of the text.</td>
</tr>
<tr>
<td>Likely to proceed</td>
<td>Projects for which the following are under way or close to being obtained:</td>
</tr>
<tr>
<td></td>
<td>• procuring land for the project</td>
</tr>
<tr>
<td></td>
<td>• application for resource consent, and</td>
</tr>
<tr>
<td></td>
<td>• business approval.</td>
</tr>
<tr>
<td></td>
<td>The project will be considered as:</td>
</tr>
<tr>
<td></td>
<td>• part of the generation scenarios described in Chapter 5, or</td>
</tr>
<tr>
<td></td>
<td>• a sensitivity assessment, if it does not fit within any of the generation scenarios described in Chapter 5. In this case, the TPR will describe the project in a separate section under the regional plans, including its possible impact on the transmission network and development status.</td>
</tr>
<tr>
<td>Possible</td>
<td>Projects for which the following are in their initial stages or have yet to commence:</td>
</tr>
<tr>
<td></td>
<td>Considered as part of the generation scenarios described in Chapter 5.</td>
</tr>
</tbody>
</table>

### Chapter 1: Introduction

#### Status Definition
- procuring land for the project
- application for resource consent, and
- business approval.

#### Consideration in TPR

1.5 Cost bands

Where investment is required to resolve identified issues, an indicative cost has been developed. The indicative costs represent the expected cost (in 2015 dollars) to fully implement the indicated solution, and include a contingency allowance of 25%, (excluding any property costs that may be required - unless specifically stated). Property costs have not generally been included because of the uncertainties involved, but for some projects the property costs can significantly impact the overall cost.

Table 1-4 lists the indicative cost bands for transmission network development, reflecting the fact that these are broad estimates only.

<table>
<thead>
<tr>
<th>Identifier</th>
<th>Indicative cost band</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>Up to $5 million</td>
</tr>
<tr>
<td>B</td>
<td>$5 - $10 million</td>
</tr>
<tr>
<td>C</td>
<td>$10 - $20 million</td>
</tr>
<tr>
<td>D</td>
<td>$20 - $50 million</td>
</tr>
<tr>
<td>E</td>
<td>$50 - $100 million</td>
</tr>
<tr>
<td>F</td>
<td>$100 - $300 million</td>
</tr>
<tr>
<td>G</td>
<td>$300 million plus</td>
</tr>
</tbody>
</table>
Chapter 2: Facilitating New Zealand’s Energy Future

2 Facilitating New Zealand’s Energy Future

2.1 Introduction

The transmission network enables the economic dispatch of least cost electricity through the electricity market from diverse generation sources and locations to end users to an agreed level of security, reliability, quality and price. It enables a range of ancillary services to support the network, such as frequency keeping, spinning reserve and interruptible load. It also enables new services such as Demand Response, to allow greater participation by end users in the electricity industry.

The services required from the transmission network, and technology to provide these services, evolve over time. Therefore, the future is inherently uncertain. Transmission Tomorrow\(^\text{11}\), developed with input from a wide range of stakeholders, helps us manage the inherently uncertain future. Where relevant to the Transmission Planning Report, Transmission Tomorrow is reflected in Chapter 6 for the grid backbone and Chapters 7-19 for the regional grids.

2.2 How we operate

Transpower has moved from a phase of building several large transmission projects to a phase where we have more, but smaller projects. Our emphasis is also moving to more efficient maintenance of the assets we have. Therefore, it is appropriate to review how we operate as an asset manager and how this integrates with planning the grid.

We have reviewed our Grid Operating Model (GOM) by going back to first principles, developing an effective operating model and comparing that to our current practice. The result is that we are reorganising our grid divisions, along with a consolidation and alignment of our planning documents and processes. This results in a streamlined framework with a clear line of sight from our processes to our company purpose, in accordance with best practice asset management, see Figure 2-1.

\(^{11}\) [https://www.transpower.co.nz/resources/transmission-tomorrow](https://www.transpower.co.nz/resources/transmission-tomorrow)
Chapter 1: Introduction

Figure 2-1: Transpower’s hierarchical framework

Transmission Tomorrow is a document which discusses our vision for grid services out to 2050. It describes our view of the environment Transpower will be operating in out to 2050 and the approaches we will employ to ensure we continue to deliver our strategic themes. This document informs our strategies including asset management strategies, people strategy.

Our strategies are applied annually to produce an Asset Management Plan, which is a component of our Integrated Transmission Plan along with the Transmission Planning Report. Whereas our strategies are long term documents and describe how we should operate, our plans are shorter term (the Integrated Transmission Plan will look out 10 years) and describe what we will do in that term.

This streamlined approach to planning will add clarity to why we are spending what we spend and will make it easier for us to communicate our intentions with stakeholders.

2.3 Long-term performance targets

We have long-term grid performance measures and targets, which have dual roles – providing information to customers, and encouraging us to focus on efficient asset expenditure, where the benefits to customers justify the costs.

The targets split grid exit points (GXPs) into four categories with performance standards for each category. The standards include interruption frequency targets: for example, one interruption per five years on average. However, recognising that a single GXP may have more or less than this in any period, we will also define levels (say, two in two years) which will trigger investigation, reporting and remedial action.

There are also targets for restoration and communicating with customers following interruptions. These targets are important to customers as the impact of an interruption can be reduced by prompt information as to what has happened, what we are doing, and when we think the electricity is likely to come back on.
We are measuring the amount of time each GXP is on N security. This measure gives an indication of the risk of a supply interruption at the GXP. This helps us plan maintenance outages and indicate a need to invest to mitigate the risk of interruptions while GXPs are on N security.

Initially, the targets will be about delivering the service that the customer should expect given the grid assets used to supply them. As our approach matures, we will focus on matching the performance delivered to what is both desired and economic.

2.4 When do we invest?

The underlying principle for investment to provide transmission services in New Zealand is to obtain the highest net benefit, even though the future services required from the transmission network have uncertainties.

Our approach is to manage uncertainty, whether by technology, processes, corridor protection, or developing markets for new products such as demand-side initiatives. These increase the options available for enhancing grid services when necessary.

Demand-side response may be particularly useful for reducing the cost of new investment. Projects may be commissioned ‘early’ to account for the year-to-year variability in peak load growth and the risk of project delays. Demand-side response has the potential to cover this uncertainty, allowing new investment to be deferred. Similarly, demand-side response may also be very useful to manage outages for maintenance, either maintaining security during the outage or avoiding the need for additional investment to allow maintenance outages.

We will invest to reduce losses where economic. This is usually not a stand-alone investment, but either bringing forward an investment for a capacity increase or, for example, installing a lower loss conductor when reconductoring a line.

Getting the right investment at the optimum time will continue to be a focus. We will prudently invest in low cost options, such as special protection schemes, to increase the transmission capacity to reduce generation constraints, or demand-side options to reduce load at peak times. This will allow for greater efficiency in the electricity market, applying downward pressure on prices.
Chapter 2: Facilitating New Zealand's Energy Future

3 Existing National Grid

3.1 Introduction

This chapter provides an overview of New Zealand's existing National Grid as at 30 June 2015 with respect to load and generation. New Zealand's National Grid consists of the:

- HVAC transmission network, and
- an inter-island HVDC link.

3.1.1 The AC transmission network

New Zealand's HVAC transmission network supplies most of the major load centres, and consists of a grid backbone of 220 kV transmission lines stretching nearly the full length of each island.

There is also a network of 110 kV lines that run roughly parallel to the 220 kV system. The 110 kV system was the original grid backbone, largely superseded by the introduction of the 220 kV grid from the 1950s onwards. The 110 kV system is now primarily used for transmission to some regions that do not have 220 kV, or for subtransmission to substations within a region.

Figure 3-1 and Figure 3-2 show maps of the transmission network for both the North and South Islands.
Figure 3-1: New Zealand’s North Island transmission network
Figure 3-2: New Zealand’s South Island transmission network
3.1.2 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, where there is an AC/DC converter station. There is a 534 km transmission line between Benmore and Fighting Bay (Marlborough), a 40 km submarine cable between Fighting Bay and Oteranga Bay across the Cook Strait, and a further 37 km transmission line into Haywards substation north of Wellington. At Haywards substation, there is another AC/DC converter station.

HVDC power flow is predominantly from the South Island to the North Island. Power flow is from north to south when it is necessary to conserve South Island hydro resources as part of an efficient generation process, or to supply South Island demand during dry South Island periods.

Table 3-1 lists the existing pole capacities for converting power from AC to DC and from DC to AC for both poles. Total pole capacity equates to the total capacity of the link.

Table 3-1: Converter ratings and pole capacities

<table>
<thead>
<tr>
<th>Pole</th>
<th>Commissioned</th>
<th>Converter type</th>
<th>Transmission capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pole 2</td>
<td>1991</td>
<td>Thyristor valves</td>
<td>700 MW</td>
</tr>
<tr>
<td>Pole 3</td>
<td>2013</td>
<td>Thyristor valves</td>
<td>700 MW</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>1200 MW</td>
</tr>
</tbody>
</table>

3.1.3 Transmission network asset profile

Table 3-2 provides a summary of the transmission network’s assets.

Table 3-2: Transmission network assets

<table>
<thead>
<tr>
<th>Asset description</th>
<th>Detail</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length of HVAC and HVDC transmission line</td>
<td>11,646 route km</td>
</tr>
<tr>
<td>Number of substations (including HVDC)</td>
<td>169</td>
</tr>
<tr>
<td>HVAC transmission line voltages</td>
<td>220, 110, 66, 50 kV</td>
</tr>
<tr>
<td>HVDC transmission line voltage</td>
<td>350 kV</td>
</tr>
<tr>
<td>HVDC link capacity</td>
<td>1200 MW</td>
</tr>
<tr>
<td>Capacitor banks and filters</td>
<td>87</td>
</tr>
<tr>
<td>Transformers (banks)</td>
<td>346</td>
</tr>
<tr>
<td>Synchronous condensers</td>
<td>8</td>
</tr>
<tr>
<td>Static Var Compensators/STATCOMS</td>
<td>8</td>
</tr>
<tr>
<td>Shunt reactor</td>
<td>3</td>
</tr>
<tr>
<td>Series reactor</td>
<td>2</td>
</tr>
</tbody>
</table>

Over the last few years we have been actively pursuing opportunities to rationalise our network assets including transfer of lightly loaded, low voltage and spur line assets to the relevant local lines company. In this TPR year the following transfers have been completed:

- Upper Takaka, Cobb and Motueka substations together with the Motupipi–Upper Takaka–A, Cobb–Upper Takaka–A and B and Stoke–Upper Takaka–A and B lines.
3.1.4 Recently completed transmission upgrade projects

Table 3-3 lists the transmission upgrade projects completed since the last Transmission Planning Report (31 March 2014).

Table 3-3: Projects completed since the 2014 Transmission Planning Report

<table>
<thead>
<tr>
<th>Project name</th>
</tr>
</thead>
<tbody>
<tr>
<td>Additional bus coupler circuit breaker at Islington</td>
</tr>
<tr>
<td>Replace Stratford supply transformer with two 40 MVA units</td>
</tr>
<tr>
<td>Replace Redclyffe supply transformers with two 120 MVA units</td>
</tr>
<tr>
<td>Replace the existing three Timaru 110/11 kV supply transformers with three 47 MVA units</td>
</tr>
<tr>
<td>Replacement 220 kV Wairakei–Whakamaru–C line</td>
</tr>
<tr>
<td>Resolve Balclutha protection and branch component limit</td>
</tr>
<tr>
<td>Paraparaumu 220 kV connection</td>
</tr>
<tr>
<td>Replace Hamilton 220/33 kV supply transformer</td>
</tr>
<tr>
<td>Replace Huirangi supply transformer with two 60 MVA units</td>
</tr>
<tr>
<td>Replace National Park supply transformer</td>
</tr>
<tr>
<td>Replace Ohakune supply transformer</td>
</tr>
<tr>
<td>Replace Tarukenga interconnecting transformer</td>
</tr>
<tr>
<td>Replace Rotorua 110/11 kV supply transformers with two 35 MVA units.</td>
</tr>
<tr>
<td>Resolve South Dunedin supply transformer metering constraint</td>
</tr>
</tbody>
</table>

Table 3-4 lists the committed transmission upgrade projects.

Table 3-4: Committed projects

<table>
<thead>
<tr>
<th>Project name</th>
<th>Expected completion date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lower South Island Reliability projects (including 220/110 kV connection at Gore)</td>
<td>2012-TBC</td>
</tr>
<tr>
<td>Clutha–Upper Waitaki Lines Project</td>
<td>2013-TBC</td>
</tr>
<tr>
<td>Timaru 110 kV bus rationalisation</td>
<td>2017-2018</td>
</tr>
<tr>
<td>A third Wilton 110 kV bus section</td>
<td>2017</td>
</tr>
<tr>
<td>Hawera bus rebuild</td>
<td>2015-2017</td>
</tr>
<tr>
<td>New 110 kV Hangatiki-Te Awamutu circuit (see note 1)</td>
<td>2016</td>
</tr>
<tr>
<td>Install SPS to automatically increase generation and/or reduce load post-contingency at Redclyffe</td>
<td>2015-2016</td>
</tr>
<tr>
<td>Install one additional cable per phase to increase incomer capacity at EDN</td>
<td>2015</td>
</tr>
</tbody>
</table>

1. This line will be built and owned by Waipa Networks

3.2 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. Consequently, the transmission network is essential in complementing generation to bring the power to where it is needed.

A particular feature of the National Grid, and a key benefit for a sustainable New Zealand, is its ability to provide New Zealanders with access to renewable generation. Typically, the remote areas of generation connected by the National Grid...
are renewable (e.g. hydro in the Waitaki Valley, wind in the Tararuas, and hydro and geothermal in the Central North Island).

Figure 3-3 shows a simplified map of load, generation, and the transmission network’s grid backbone. For more information see Chapter 4 for the demand assumptions, Chapter 5 for the generation assumptions and Chapter 6 for the transmission backbone.

Figure 3-3: Load, Generation and the Grid Backbone

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.

Power flow tends to be from south to north during normal rainfall years, delivering power from the hydro generation in the South Island to the North Island through the HVDC link, which also balances demand between the islands. North to south transfers have been occurring for longer periods in recent years. They occur more frequently during dry years where hydro generators in the South Island try to conserve water.
Figure 3-4 shows New Zealand’s electricity energy demand at grid exit points (i.e. this includes distribution network losses but not demand supplied by generation embedded within these networks).

**Figure 3-4: New Zealand Grid energy demand**

Energy demand (GWh) has been relatively flat over the last decade compared to the strong growth seen in earlier decades. In recent years energy demand has been affected by the:

- global recession, reduced industrial demand (e.g. Tiwai Aluminium Smelter and Norske Skog Tasman mill),
- the Christchurch earthquakes
- increased uptake of energy efficiency lighting and appliances
- increases in generation embedded within distribution networks which reduce the demand observed at grid exit points.
4 Demand assumptions

4.1 Introduction

This chapter provides an overview of the grid exit point demand forecasts used in the planning studies for this report.\textsuperscript{12}

Consideration of the National Grid’s future adequacy requires a view of future peak electricity demand, which by definition is uncertain. As part of our forecasting approach we attempt to quantify the range of future uncertainty. Based on this range, we then derive a prudent level of future peak demand growth to use in our planning.

We use a prudent level of peak demand growth to help ensure the timely implementation of new transmission assets or transmission alternatives. Our prudent peak forecasts represent a 10% probability of exceedance forecast for the first 7 years of the forecast period (until 2021), or a 90% chance of being under the forecast (P90). In other words, until 2021 one would expect actual peak demand to exceed the forecast in one year out of ten. Post-2021 we assume an expected (or mean) rate of growth. Our forecast is designed to be an upper estimate of demand to ensure issues are identified with enough time to be resolved and not expose consumers to excessive risks. We consider this an appropriate basis on which to conduct our planning.

We recognise that our customers may use different load forecasting methodologies and have a different interpretation of a prudent forecast in their planning.

For this publication of the Transmission Planning Report we have continued to use an “ensemble” approach: where several forecasting models are used to derive our forecasts. We reviewed our methodology in 2013 in response to recent trends and made some further minor adjustments in 2014 to ensure that our modelling adequately captures the range of uncertainty in future electricity demand growth.

4.2 Energy use versus peak demand

The demand for electrical energy in New Zealand varies from month-to-month, day-to-day, and from hour-to-hour. For example, households demand much more energy between the hours of 7:00 – 9:00 am and 5:00 – 8:00 pm than at other times of the day, due to heavier domestic appliance use. The demand at peak times of the day can be up to twice the lowest demand periods during the day.

Figure 4-1 shows a typical graph (load profile) of daily energy use.

\textsuperscript{12} Transpower publishes the detailed demand forecast as part of the Planning Inputs information pack: https://www.transpower.co.nz/about-us/what-we-do/planning-future/planning-inputs#demand
Because electricity cannot be stored practically in the quantities required, meeting electricity demand means having sufficient capacity in the electricity supply system (generation, transmission and distribution) to meet the highest peak demand.

Peak demand is expressed in instantaneous MW, whereas energy is described as consumption over time, in MWh. Transmission planning requires an analysis of the transmission network’s adequacy in terms of meeting a forecast of peak demand, rather than energy.

4.3 Peak demand forecast methodology

Our approach to demand forecasting uses both top-down modelling of national and regional peak and energy demand, and bottom-up modelling of grid exit point peak demand. The top-down models employ a suite of models that between them incorporate the variability that can be expected in future peak demand. In 2013 we added a short term fit model to allow for the possibility of a continuation of more recent trends. More details are available at https://www.transpower.co.nz/about-us/what-we-do/planning-future/planning-inputs.

At grid exit point level we have employed simpler regression techniques on historical grid exit point demand data to project expected and prudent peaks. We have also sought customer views on grid exit point demand and in many cases modified our forecasts to include specific load information from our customers.  See the relevant regions’ chapters for more information about specific amendments (Chapters 7-19).

Our forecasting structure also allows us to project each grid exit point’s contribution to regional and island peak demand.  These will typically be less than grid exit point peak demand and are calibrated to sum to a similar level as the regional and island peak demands produced by our top-down models.

4.3.1 Customer consultation

We believe customers are best placed to provide information about future demand in their networks. To this end, we made contact with customers in August 2014, seeking views on future levels of demand growth and on future demand steps or load-shifts. We received responses from many of our customers and for others we considered the demand forecasts included in the companies’ Asset Management
Chapter 4: Demand Assumptions

Plans 2014. We have endeavoured, where reasonable and practical, to incorporate these customer views into our forecasts.

We are committed to further consultation with customers with regard to our peak load forecasts and we welcome ongoing dialogue on the nature and timing of changes to grid exit point demand.

4.4 Comparison with previous TPR forecasts

The following figure compares the updated 2015 TPR forecast with the TPR forecasts made in each of the previous four years. The forecasts are seen to have moved lower again this year as historical demand growth has flattened. Note that as we delayed production of our forecast this year we were able to include 2014 peak demand in the historical demand data.

The updated forecast starts at a similar level to last year’s forecast but projects lower growth averaging 1.1% per annum to 2030.

Figure 4-2: Comparison of 2015 TPR prudent peak demand forecast with previous TPR forecasts

The peak demand seen in recent years has been affected by a range of factors: These include:

- the global recession in 2008 and in the year’s following reduced industrial demand (e.g. Tiwai Aluminium Smelter and Norske Skog Tasman mill),
- an increased uptake of energy efficiency lighting and appliances. A number of our customers have noted an ongoing decline in average residential peak demand.
- an increase in generation embedded within distribution networks which reduce the demand observed at grid exit points.
- the Christchurch earthquakes

This period has seen flat peak demand with an exception being 2011 when we saw a new national peak record occur during the unusual polar weather event that affected the whole country in mid-August. The forecasts produced over the last 5 years have moved progressively lower as a response to the ongoing flat growth.
4.5 **Review of forecasting methodology 2013**

Given the sustained period of flat growth in demand, we reviewed our methodology in 2013 to ensure that it adequately models the range of future demand growth.

In our review we considered how we model the appropriate range of uncertainty in the near-term (i.e. 1 to 5 year) forecasts. Our ensemble models were previously all based on long-term trends, but in our review we concluded that it was reasonable to incorporate near term trends into our forecasts.

The addition of the short term model resulted in a lower expected forecast but had little impact on the prudent peak forecast which is driven by the level of variability seen in the historical data.


4.6 **Emerging Technology**

There is a growing awareness in New Zealand of the potential uptake of technology which will impact future grid demand including the uptake of electric vehicles, roof-top solar PV and energy storage by both network companies and distributed energy storage systems.

The demand forecasts presented do not explicitly model the impacts of these technologies however in our generation scenarios we include the impact of PV uptake at varying levels. In particular, in the disruptive technologies scenario we assume the uptake of electric vehicles, residential solar photovoltaics and residential energy storage systems increase rapidly.
5 Generation assumptions

5.1 Introduction

This chapter sets out the planning assumptions used to forecast future electricity generation at each grid injection point.

Transpower undertakes grid planning to ensure that:
- electricity demand is met reliably
- the grid provides for efficient generation investment and as such supports a competitive wholesale energy market
- the generation investment market is efficient for all market participants, and
- the energy market is competitive for all consumers.

Consideration of the National Grid’s future adequacy requires a view of not only future electricity demand – a requirement of both the Transmission Planning Report (TPR) and the Grid Reliability Report (GRR) – but also future electricity generation at each grid injection point.

The uncertainty surrounding future generation requires the consideration of possible generation futures and we have considered five scenarios.

5.2 Generation capacity assumptions

Generation capacity assumptions include:
- **existing grid connected generation** assumed to be available at existing capacity
- **committed new generation** available from publicly notified commissioning dates, at its publicly notified capacity, for the duration of the planning period
- **committed decommissioned generation** from publicly notified decommissioning dates for the remainder of the planning period, and
- **modelled generation (de)commissioning** (un)available as determined to by GEM to be the least cost way to meet the load forecast given our input assumptions

5.2.1 Existing grid connected generation

Table 5-1 lists the operating capacities of existing grid-connected generation. Installed capacities may differ in some cases.

### Table 5-1: Existing grid-connected generation

<table>
<thead>
<tr>
<th>Generation plant</th>
<th>Region</th>
<th>Type</th>
<th>Operating capacity in MW</th>
<th>Grid injection point</th>
</tr>
</thead>
<tbody>
<tr>
<td>Glenbrook¹</td>
<td>Auckland</td>
<td>Cogen</td>
<td>74</td>
<td>Glenbrook</td>
</tr>
<tr>
<td>Otahuhu B</td>
<td>Auckland</td>
<td>Gas - CCGT</td>
<td>380</td>
<td>Otahuhu</td>
</tr>
<tr>
<td>Southdown</td>
<td>Auckland</td>
<td>Cogen</td>
<td>140</td>
<td>Southdown</td>
</tr>
<tr>
<td>Kawerau</td>
<td>Bay of Plenty</td>
<td>Geothermal</td>
<td>105</td>
<td>Kawerau</td>
</tr>
<tr>
<td>Kawerau Norske Skog</td>
<td>Bay of Plenty</td>
<td>Geothermal</td>
<td>25</td>
<td>Kawerau</td>
</tr>
</tbody>
</table>
### Chapter 5: Generation Assumptions

<table>
<thead>
<tr>
<th>Generation plant</th>
<th>Region</th>
<th>Type</th>
<th>Operating capacity in MW</th>
<th>Grid injection point</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kinleith</td>
<td>Bay of Plenty</td>
<td>Cogen</td>
<td>28</td>
<td>Kinleith</td>
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<tr>
<td>Matahina</td>
<td>Bay of Plenty</td>
<td>Hydro</td>
<td>72</td>
<td>Matahina</td>
</tr>
<tr>
<td>Wheaio/Flaxy</td>
<td>Bay of Plenty</td>
<td>Hydro</td>
<td>24</td>
<td>Rotorua</td>
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<td>Aratiatia</td>
<td>Central North Island</td>
<td>Hydro</td>
<td>78</td>
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<td>Hydro</td>
<td>37</td>
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<tr>
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<td>Central North Island</td>
<td>Geothermal</td>
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<td>Poihipi</td>
<td>Central North Island</td>
<td>Geothermal</td>
<td>51</td>
<td>Poihipi</td>
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<td>Rangipo</td>
<td>Central North Island</td>
<td>Hydro</td>
<td>120</td>
<td>Rangipo</td>
</tr>
<tr>
<td>Tararua III2</td>
<td>Central North Island</td>
<td>Wind</td>
<td>93</td>
<td>Bunnythorpe</td>
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<tr>
<td>Te Apiti</td>
<td>Central North Island</td>
<td>Wind</td>
<td>90</td>
<td>Woodville</td>
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<td>Tokaanu</td>
<td>Central North Island</td>
<td>Hydro</td>
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<td>Hydro</td>
<td>36</td>
<td>Tuai</td>
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<td>Hydro</td>
<td>31</td>
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<tr>
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<td>Taranaki</td>
<td>Gas - CCGT</td>
<td>385</td>
<td>Stratford</td>
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<td>Waikato</td>
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<td>Hydro</td>
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### Chapter 5: Generation Assumptions

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<th>Region</th>
<th>Type</th>
<th>Operating capacity in MW</th>
<th>Grid injection point</th>
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<td>Hydro</td>
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<td>Ohau C</td>
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<td>South Canterbury</td>
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<td>840</td>
<td>Manapouri</td>
</tr>
<tr>
<td>Roxburgh</td>
<td>Otago/Southland</td>
<td>Hydro</td>
<td>320</td>
<td>Roxburgh</td>
</tr>
<tr>
<td>Waipori²</td>
<td>Otago/Southland</td>
<td>Hydro</td>
<td>84</td>
<td>Halfway Bush</td>
</tr>
</tbody>
</table>

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 generation.
3. Partly embedded.

#### 5.2.2 Committed new generation

Committed projects are those which are reasonably likely to proceed and where the following are satisfied:
- all necessary resource and construction consents have been obtained
- construction has commenced, or a firm date set
- arrangements for securing the required land are in place
- supply and construction contracts have been executed, and
- financing arrangements are in place.

We are not aware of any new grid-connected generation that meets the criteria above.

#### 5.2.3 Decommissioned generation

Generation forecasts must also account for decommissioned generation. In late 2013, Genesis Energy placed one unit of Huntly (250 MW) into long-term storage, and decommissioned the unit that was currently in long-term storage. This reduced the capacity of the coal-fired steam turbines at Huntly to 500 MW. Technically, units placed into long-term storage could be recertified and brought back into operation within 90 days. However, for modelling purposes we treat storage as equivalent to decommissioning.

Mighty River Power announced in March 2015 that they plan to retire the remaining 140 MW of generation at Southdown in December 2015. We have assumed that Southdown is retired at the end of 2015 in all scenarios.

#### 5.2.4 New generation forecasts

This year generation scenarios included in the TPR are based on the Ministry of Business, Innovation and Employment’s (MBIE’s) draft Electricity Demand and Generation Scenarios¹³ (EDGS) and work done by the New Zealand Smart Grid Forum¹⁴ on disruptive technologies. MBIE released the draft EDGS for consultation in

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April 2015. The EDGS will replace the 2010 Statement of Opportunities previously used as a basis for Transpower’s scenario analysis when they are finalised.

Due to the limited lead time since the release of the draft EDGS, for this year’s TPR we have not explicitly considered MBIE’s draft EDGS scenarios 5-8. They are similar to MBIE’s mixed renewables scenario except they have different demand assumptions, such as about the future levels of demand from Tiwai and future demand growth rates.

**What are generation scenarios?**

Generation scenarios represent possible future generation outcomes, resulting from making specific assumptions about future fuel availability and environmental policy. They enable the assessment of transmission needs. Appendix A gives details on the timing, type, location and size of new generators assumed in each of the generation scenarios.

Transpower’s scenarios are based on the five generation scenarios:

- Scenario 1: Mixed Renewable
- Scenario 2: High geothermal access
- Scenario 3: Low-cost fossil fuels
- Scenario 4: Global low carbon
- Scenario 5: Disruptive Technologies

**Scenario 1 – Mixed Renewables**

Scenario 1 is based on MBIE’s draft mixed renewables scenario. It is a “balanced” renewables scenario, reflecting the current views of relative technology costs and expected fuel costs. Uptake of potentially disruptive technologies – such as energy storage and solar photovoltaics – is relatively muted.

**Scenario 2 – High geothermal access**

Scenario 2 is based on MBIE’s draft high geothermal access scenario. In this scenario we allow more geothermal generation to be constructed sooner. All other assumptions are as in scenario 1.

**Scenario 3 – Low-cost fossil fuels**

Scenario 3 is based on MBIE’s draft low-cost fossil fuels scenario. It assumes there are sizeable discoveries in Taranaki which increase the supply of gas available for electricity generation, resulting in increased baseload gas generation. The carbon cost also remains low throughout the modelling horizon, reducing the incentive to build low-carbon generation.

**Scenario 4 – Global low carbon**

Scenario 4 is based on MBIE’s draft global low carbon scenario. In this scenario carbon prices increase early in the modelling horizon and wind generation costs reduce. Solar photovoltaic installations increase more rapidly and there is a higher uptake of electric vehicles. The amount of geothermal resource available is reduced from the mixed renewables scenario.

**Scenario 5 – Disruptive Technologies**

The disruptive technologies scenario is based on that developed by the New Zealand Smart Grid Forum and assumes that uptake of residential solar photovoltaics and electric vehicle increases more rapidly. From the early 2020s, energy storage becomes standard for residential solar installations, and by 2030 every new light
passenger vehicle purchased is electric. All other assumptions are the same as in the mixed renewables scenario.

**Scenario development approach**

All scenarios were produced using the Generation Expansion Model (GEM), which creates a least-cost schedule of new generation capacity required to meet forecast demand. More information about GEM is available on the GEM project site.\(^\text{15}\)

The scenarios have been produced using the same input assumptions (including capital and maintenance costs, fuel costs and carbon prices) as those used by MBIE and the New Zealand Smart Grid Forum.

GEM data files and code are available on request.

### 5.3 Use of the generation capacity assumptions

#### 5.3.1 Use of generation scenarios in the TPR

Generation development scenarios (see Section 5.2.4) are not explicitly used, other than to note where significant issues may arise if the future generation is in particular regions.

System conditions that we have considered in assessing the grid backbone are broad and encompass significant regional differences in demand, such as could occur if Tiwai was to close. The system conditions also cover the possible impact of the generation scenarios in section 5.2.4. Issues that have already been noted are considered again to determine what effect, if any, the forecast generation will have.

#### 5.3.2 Grid Injection Point injection forecast assumptions

In addition to load forecasts for each Grid Exit Point, the GRR requires Grid Injection Point (GIP) injection forecasts to assess the adequacy of the local grid to receive generation.

GIP injection forecasts are based on the total operating capacity of generators connected to the GIP. The assessment of local grid injection point adequacy is based on ensuring there is adequate transmission capacity to fully dispatch all local generators rather than making assumptions about how much each generator will contribute at the time of maximum injection.

\(^\text{15}\) [http://code.google.com/p/gem/](http://code.google.com/p/gem/)
Chapter 6: Grid Backbone

6 Grid backbone

6.1 Introduction

This chapter describes the adequacy of the grid backbone to transfer energy from generators to the load while maintaining a secure grid, to meet existing and forecast demand and anticipated generation developments.

The grid backbone provides the connection between the regions, which are described in Chapters 7 to 19.

We identify potential grid backbone issues using a range of system conditions to meet the forecast growth in demand (see Chapter 4). Generation development scenarios (see Chapter 5 and Section 5.2.4) are not explicitly used, other than to note where significant issues may arise if future generation is established in particular regions. Grid upgrades to resolve issues must meet the requirements of the Grid Reliability Standards. Many grid upgrades will also require a Major Capex Proposal to be submitted to the Commerce Commission for approval before implementation.

6.2 North Island

6.2.1 North Island existing grid backbone

The North Island grid backbone comprises the:

- 220 kV circuits from Wellington to Auckland located along the central North Island corridor
- 220 kV Wairakei ring circuits (220 kV circuits between Wairakei and Whakamaru) connecting the major hydro and geothermal generation in the central North Island to the transmission network
- 220 kV circuits from Bunnythorpe to Huntly through Stratford connecting Taranaki generation to the transmission network.

An inter-island High Voltage Direct Current (HVDC) link connects the grid backbone in the North and South Islands. Power flows either north or south on the HVDC link. During daylight and periods of normal rainfall in the South Island, power tends to flow north. During non-peak periods (late evenings and early mornings) and years of low South Island rainfall, power tends to flow south.

The existing North Island grid backbone is set out schematically in Figure 6-1 and geographically in Figure 6-2.
Figure 6-1: Simplified North Island grid backbone schematic
Figure 6-2: North Island grid backbone map
6.2.2 Changes since the 2014 Transmission Planning Report

Changes since the 2014 TPR include:

- lower load forecast, with low or almost zero load growth forecast for most regions and a few hot spots with high load growth forecast (which has only a limited impact on the transmission capability and constraints reported in the 2014 TPR)
- an additional system condition for the 2015 TPR to demonstrate the significance of the Waikato region’s southern 110 kV network.

6.2.3 Line conductor replacements

Table 6-1 lists the major grid backbone line conductor replacement projects between 2015 and 2020.

Table 6-1: Grid backbone line conductor replacements 2015 to 2020

<table>
<thead>
<tr>
<th>Line</th>
<th>Affected circuits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bunnythorpe–Haywards A</td>
<td>Bunnythorpe–Paraparaumu–Haywards 1</td>
</tr>
<tr>
<td>Bunnythorpe–Haywards B</td>
<td>Bunnythorpe–Paraparaumu–Haywards 2</td>
</tr>
<tr>
<td>Bunnythorpe–Wilton A (Judgeford section)</td>
<td>Bunnythorpe–Linton–Wilton 1</td>
</tr>
<tr>
<td></td>
<td>Haywards–Wilton 1</td>
</tr>
<tr>
<td>Bunnythorpe–Wilton A (Judgeford–Wilton section)</td>
<td>Bunnythorpe–Tararu C–Haywards 1</td>
</tr>
<tr>
<td></td>
<td>Haywards–Linton 1</td>
</tr>
<tr>
<td>Brunswick–Stratford B</td>
<td>Brunswick–Stratford 3</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Note</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Major Capex Proposal approved by the Commerce Commission</td>
</tr>
<tr>
<td>2. We will potentially submit a Major Capex Proposal to the Commerce Commission</td>
</tr>
</tbody>
</table>

These line conductors are all approaching end-of-life, which provides us with the opportunity to review the circuit capacities and whether they are still required. 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.

The Bunnythorpe–Haywards A and B line conductor

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 will not be complete at the time of publication, the analysis uses the new line conductor.

The Bunnythorpe–Wilton A line conductor

This replacement will be investigated this year and potentially a Major Capex Proposal submitted to the Commerce Commission. The project involves reconductoring the Judgeford–Wilton section in 2015–2020 and the Bunnythorpe–Judgeford section in 2020–2025. The rating of the circuits on this line does not set the n-1 transmission capacity between Wellington and Bunnythorpe, therefore a replacement conductor with a slightly lower rating may be possible. The analysis uses the existing line conductor.

The Brunswick–Stratford B line conductor

This replacement will be investigated this year and potentially a Major Capex Proposal submitted to the Commerce Commission. Options include dismantling the line, upgrading the Brunswick–Stratford–A line and dismantling the B line, and reconductoring the B line. The analysis uses the existing line conductor.
6.2.4 Methodology

System conditions
A small number of realistically challenging system conditions are used to assess the capability of the existing North Island grid backbone (with a few changes in circuit rating for line reconductoring as set out in Section 6.2.3). They provide snapshots to identify transmission constraints that may require minimum or maximum generation limits to avoid overloading the power system following an outage. Transmission upgrades that alleviate the transmission constraints to enable lower minimum and higher maximum generation limits are also identified.

Growth generation
The existing generation is insufficient to supply the forecast load towards the end of the forecast period. Additional growth generation, which can be built anywhere in New Zealand, is also required to supply the forecast load. The system conditions also identify transmission constraints that can occur if growth generation appears predominantly in one area.

Limits in the Electricity Market
Transmission constraints identified by the system conditions do not always cause minimum or maximum generation limits in the 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 as pre-contingent or post-contingent actions, depending on the extent and magnitude of the system impact resulting from the outage.

6.2.5 Overview of results
Key findings for the North Island grid backbone (see Section 6.3) include the following:
- A reduction in thermal generation in the upper North Island may require additional reactive support towards the end of the forecast period. Reduced generation will also worsen, or bring forward, the transmission constraints south of the upper North Island area.
- The south Waikato 110 kV network can cause transmission constraints that require some of the generation in the upper North Island area to be on (assuming the generation is available).
- The Wairakei ring is nearing capacity, even though the high capacity Wairakei–Whakamaru–C line was commissioned in 2014. The Wairakei ring will become a transmission constraint if there is further significant geothermal generation development in the Wairakei area.
- The 110 kV Bunnythorpe–Mataroa circuit may cause a transmission constraint between Bunnythorpe and Whakamaru/Wairakei. There is a low cost solution to alleviate (but not eliminate) the transmission constraint that we intend to implement within the next few years.
- Removing the remaining transmission constraints between Haywards and Whakamaru/Wairakei may require major upgrades that are unlikely to be economic. As a result, we do not intend to conduct any further investigations on upgrades, but will periodically review this situation.
6.3 North Island grid backbone capability and transmission constraints

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

1. low Auckland generation and winter peak load (see Section 6.3.1)
2. low Auckland generation and summer peak load (see Section 6.3.2)
3. HVDC south transfer (winter) (see Section 6.3.3)
4. HVDC south transfer (summer) (see Section 6.3.4)
5. low eastern Bay of Plenty industrial load (see Section 6.3.5)
6. impact of the south Waikato 110 kV regional system (see Section 6.3.6)
7. light load (see Section 6.3.7).

6.3.1 System condition 1: low Auckland generation (winter peak)

This system condition tests the case with extremely low generation in the upper North Island during high load (winter peak). It represents generation development scenarios where more of the existing thermal generation in Auckland is retired (or mothballed)\(^{16}\) and replaced with new generation elsewhere in New Zealand including any additional new generation required to meet load growth. The specific assumptions for this system condition are as follows:

- North Island winter peak load in the year the transmission constraint is identified.
- Generation in the upper North Island is limited to one combined-cycle generating unit and one small open-cycle gas turbine at Huntly.
- Maximum geothermal and hydro generation in the Bay of Plenty, central North Island and Hawke’s Bay.
- Maximum thermal generation in the Taranaki region (including the combined-cycle generating station and the gas peakers).
- Maximum wind generation in the lower and central North Island regions.
- High HVDC north transfer up to 1000 MW.
- Generation and load balance is achieved using growth generation at Wairakei and/or Stratford representing new geothermal and thermal generation in those regions (which by 2030 is more than 800 MW).
- Transmission constraints are addressed by trading off lower North Island and South Island generation with upper North Island generation.

Summary of transmission constraints

Possible transmission constraints include:

- Central North Island constraints
- Huntly–Stratford constraints
- Wairakei ring constraints
- North of Whakamaru constraints.

The 110 kV and 220 kV circuits in the central North Island will overload under this system condition. If most of the 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.

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\(^{16}\) Thermal generation that has been or will soon be retired in the upper North Island area is located at the Huntly (two units, each 250 MW) and Southdown (175 MW) power stations.
Chapter 6: Grid Backbone

SC1: Central North Island constraints

The most common transmission constraint is the loading on the 110 kV Bunnythorpe–Mataroa circuit. The analysis assumes the Bunnythorpe–Mataroa circuit can be loaded to 100% pre-contingency and a special protection scheme will be installed to open the circuit if it overloads. See Central North Island investigations and mitigation measures in Section 6.4.1 for alternative options to address this transmission constraint. The HVDC north transfer is limited to about 950–1000 MW to prevent the circuit from overloading pre-contingency.

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 17. Limits on maximum generation south of Tokaanu will reduce loading with the most effective place to reduce generation being Tokaanu. This is nearly twice as effective as reducing HVDC transfer and two and a half times as effective as reducing Taranaki generation.

SC1: Huntly–Stratford constraints

If the majority of the growth generation appears in the Taranaki area, the Huntly–Stratford circuits may overload from about 2020 for a parallel circuit outage. The Bunnythorpe–Mataroa and Tokaanu–Whakamaru circuits will overload before a Huntly–Stratford circuit. The Huntly–Stratford circuit overload will only occur if the central North Island transmission is upgraded. The transmission constraints caused by the overloads 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 constraints

If the majority of new generation appears near Wairakei, then:

- the Wairakei–Ohakuri–Atiamuri circuits will overload from 2019–2021 following a circuit contingency
- the Wairakei–Ohakuri–Atiamuri circuits will overload pre-contingency from 2029
- the recently commissioned high capacity Wairakei–Whakamaru circuit will overload from 2027 following a Wairakei 220 kV bus section outage
- from about 2029, the majority of existing thermal generation north of Whakamaru 18 is required to prevent the Atiamuri–Ohakuri circuit from overloading for a parallel circuit outage.

The transmission constraints caused by the overloads can be most effectively managed operationally by reducing generation in the Wairakei area. This is four times as effective as reducing HVDC transfer.

SC1: North of Whakamaru constraints

If the majority of new generation appears in, or injects into, the Wairakei ring area, then the 220 kV Otahuhu–Whakamaru–1 and 2 circuits may overload from 2029. These overloads can be managed operationally for the forecast period and beyond by increasing generation in the upper North Island 19.

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17 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 may operate for a Tokaanu–Whakamaru circuit or 220 kV Whakamaru bus outage.

18 With the exception of one Huntly coal fired unit, all existing Huntly and Otahuhu generation is required to avoid exceeding the Atiamuri–Ohakuri circuit’s thermal capacity.

19 This solution assumes that there is at least one generating unit in addition to the assumed 440 MW at Huntly still available to relieve the overload.
Detailed dynamic voltage stability studies have identified the need for additional static capacitors during winter peak load periods in the upper North Island region within the forecast period. These capacitors are required to maintain dynamic reactive power margins in the region.

The 110 kV circuits between Tarukenga and Hamilton will cause transmission constraints into Auckland before the 220 kV transmission constraints appear. See Section 6.3.6 for information about the 110 kV circuit overloads.

**Possible solutions**

These transmission constraints can be managed operationally through generation dispatch in the upper North Island. Alternatively, transmission upgrades to alleviate or remove the transmission constraints are as follows:

- Central North Island 110 kV options (see Central North Island investigations and mitigation measures in Section 6.4.1 for more information).
- Waikato 110 kV options (see Section 6.3.6 for more information).
- Upgrade Tokaanu–Whakamaru transmission capacity (by applying variable line ratings, reconductoring the existing lines, or constructing a new line).
- Increase capacity between Stratford and Huntly (by applying variable line ratings, rebuilding the existing line, or constructing a new line between Stratford and Whakamaru).
- Increase Wairakei ring transmission capacity (by reconductoring the existing Wairakei–Ohakuri–Atiamuri–Whakamaru single circuit line or a new double circuit line).
- Series reactors on the Otahuhu–Whakamaru circuits.
- Series capacitors on the Brownhill Road–Whakamaru circuits (see Transmission into Auckland in Section 6.4.1 for more information).
- Reduce the impact of Whakamaru 220 kV bus outages by rearranging existing bus configurations and/or adding an additional bus section.
- Special protection scheme(s) for fast, automatic redispatch of generation and/or the HVDC.

**6.3.2 System condition 2: low Auckland generation (summer peak)**

This system condition tests the case with low generation in the upper North Island area during a summer afternoon (summer peak). Similarly to system condition 1, but with summer circuit ratings, it retires (or mothballs) more of the existing thermal generation in upper North Island20, replacing it with new generation elsewhere in New Zealand (including any additional new generation required to meet load growth). The specific assumptions for this system condition are as follows:

- North Island summer peak load in the year the transmission constraint is identified.
- Generation in the upper North Island 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.
- Low Taranaki generation, with no generation on the Stratford 220 kV bus.
- Maximum wind generation in the lower and central North Island areas.
- High HVDC north transfer up to 1000 MW.
- Generation and load balance is achieved by trading off hydro generation in the North and South Island. North Island hydro generation is operating at about 66% of installed capacity by 2016 and 95% by 2030.

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20 Thermal generation that has been or will soon be retired in the upper North Island area are at the Huntly (two units, each 250 MW) and Southdown (175 MW) power stations.
Summary of transmission constraints

Possible transmission constraints include:
- central North Island constraints
- Waikato 110 kV constraints
- upper North Island voltage stability
- Wairakei ring constraints.

In general, the 220 kV network is capable of supplying the summer peak load without thermal constraints. Voltage stability limits are expected in the North Island area in the next ten to fifteen years.

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

The Waikato 110 kV network may limit transfer into the upper North Island (see Section 6.3.6 for more information).

SC2: Central North Island constraints

The most common transmission constraint that arises is the loading on the 110 kV Bunnythorpe–Mataroa circuit. The analysis assumes the Bunnythorpe–Mataroa circuit can be loaded to 100% pre-contingency and a special protection scheme will be installed to open the circuit if it overloads. See Central North Island investigations and mitigation measures in Section 6.4.1 for alternative options to address this transmission constraint. The maximum HVDC north transfer is limited to about 920-990 MW to prevent the circuit from overloading pre-contingency.

At present, 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. Once the protection scheme has operated, the loading on the Tokaanu–Whakamaru circuit is slightly below its thermal capacity up to around 2018. However, from around 2018 and as generation at Tokaanu increases, an outage of a Tokaanu–Whakamaru circuit will operate the special protection schemes for Bunnythorpe–Mataroa (proposed) and Tokaanu (existing). Once both special protection schemes have operated, the loading on the Tokaanu–Whakamaru circuit is still slightly above its capacity, causing a transmission constraint.

SC2: Waikato 110 kV constraints

From 2017, the transfer into the upper North Island will be limited by loading on the 110 kV Waikato network between Tarukenga and Hamilton. See Section 6.3.6 for more information.

SC2: upper North Island voltage stability

Detailed dynamic voltage stability studies have identified the summer afternoon period as having the highest risk of dynamic voltage collapse. The analysis confirmed that a voltage stability limit will bind in the next 10 to 15 years. We will continue to update this analysis with changing generation and load patterns in the upper North Island area. The worst case outages are the Pakuranga–Whakamaru and Huntly–Takanini–Otahuhu circuits.

SC2: Wairakei ring constraints

The Atiamuri–Ohakuri circuit is close to its thermal limit during an outage of a Whakamaru 220 kV bus zone, particularly if the special protection schemes at Tokaanu and on the Bunnythorpe–Mataroa circuit in the central North Island operate. This circuit will overload with a small increase in geothermal generation in the Wairakei area.
Possible solutions

These transmission constraints can be managed operationally with additional generation installed and/or dispatched in the upper North Island. Alternatively, they may be alleviated or removed by the following transmission upgrades:

- Central North Island 110 kV options (see Central North Island investigations and mitigation measures in Section 6.4.1 for more information).
- Voltage stability issues may be deferred with series compensation on the Brownhill–Whakamaru circuits and/or addressed with additional dynamic reactive support in the upper North Island area (see Transmission into Auckland in Section 6.4.1 for more information). In addition, dynamic reactive support reserves can be increased with additional static reactive support in the next five to ten years.

6.3.3 System condition 3: HVDC south transfer (winter)

This system condition tests the case with extremely low generation in the South Island, requiring high HVDC south transfer close to the time of winter peak load, and represents a dry year with low wind generation. The specific assumptions for this system condition are as follows:

- Eighty per cent of North Island winter peak load in the year the transmission constraint is identified.
- Generation in the upper North Island is 1300 MW including all normally available coal fired generation at Huntly and the Otahuhu combined cycle generating unit.
- Maximum geothermal and hydro generation in the Bay of Plenty, central North Island and Hawkes Bay.
- Maximum thermal generation in the Taranaki region, including the Taranaki combined cycle unit.
- No wind generation in the lower and central North Island regions.
- High HVDC south transfer up to voltage stability limits.
- Generation and load balance is achieved using growth generation at Huntly, Wairakei or Stratford.
- 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
- Wellington load capacity limits
- Central North Island 220 kV constraints
- Lower North Island 220 kV constraints
- Brunswick–Stratford constraints.

The 110 kV and 220 kV circuits will overload during the forecast period in the central and lower North Island 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, which is designed to reduce HVDC south transfer during outages to maintain voltage stability margins.

**SC3: 110 kV regional constraints**

The most serious issues occur in the 110 kV regional network. There are three main issues.

**Bunnythorpe–Woodville overload**

The Bunnythorpe–Woodville circuit will overload for any HVDC south transfer for an outage of the other Bunnythorpe–Woodville circuit. The existing special protection scheme at Woodville\(^{21}\) will address this transmission constraint. However, if the HVDC south transfer exceeds 350 MW, the Bunnythorpe–Woodville circuits will overload for a Haywards 220 kV bus outage. This limit is similar to the HVDC runback limit for the outage. The existing special protection scheme at Woodville will not operate to address the overload on the Bunnythorpe–Woodville circuits as neither of them is out of service. The transmission constraint can be managed operationally if there is generation at Te Apiti and/or by temporarily reconfiguring the grid to split the 110 kV system.

**Stratford–Hawera–Waverley overload**

By 2020, the Hawera–Stratford circuit may overload:

- for a Brunswick–Stratford or Bunnythorpe–Brunswick outage for HVDC south transfer of about 380–430 MW
- pre-contingency for HVDC south transfer of about 590 MW. This overload is due to the 110 kV bus rating at Hawera.

We are committed to upgrading the rating of the Hawera 110 kV bus (see Section 12.8.2 for more information). The upgraded Hawera 110 kV bus will resolve this transmission constraint. In the interim, the issue can be managed operationally through a temporary grid reconfiguration at Hawera (by putting the Hawera reactor into service and arming the bus splitting special protection scheme).

**Regional low voltage**

Low voltages may occur in the central North Island during a Bunnythorpe 220 kV bus outage for 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.

This issue can be managed operationally post-contingency by increasing the amount of generation and voltage support provided by generation on the 110 kV network. The longer-term solution is to install on-load tap changers on the Bunnythorpe interconnecting transformers when they are replaced.

**SC3: Wellington load capacity limits**

The maximum pre-contingency HVDC south transfer is about:

- 700 MW in 2016 with Wellington load of about 460 MW (assuming no generation injection into the Wellington 110 kV network)

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\(^{21}\) The special protection scheme at Woodville detects an outage of a Bunnythorpe–Woodville circuit and, if the other circuit is overloaded, 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.
670 MW by 2020 with Wellington load of about 510 MW
630 MW by 2030 with Wellington load of about 560 MW.

**SC3: Central North Island 220 kV constraints**

From 2015, the:
- Rangipo–Tangiwi circuit may overload during an outage of a Bunnythorpe or Tokaanu 220 kV bus, or a Bunnythorpe–Tokaanu circuit for HVDC south transfer of about 390–450 MW
- Bunnythorpe–Tangiwi circuit may overload during an outage of a Tokaanu 220 kV bus or Bunnythorpe–Tokaanu circuit for HVDC south transfer of about 450–500 MW
- Bunnythorpe–Tokaanu circuits may overload during an outage of a Bunnythorpe 220 kV bus, the other Bunnythorpe–Tokaanu circuit, or the Bunnythorpe–Tangiwi circuit for an HVDC south transfer of about 470–560 MW
- Rangipo–Tangiwi circuit may overload pre-contingency for HVDC south transfer of more than about 600 MW.

By 2020, the:
- Rangipo–Tangiwi circuit may overload during an outage of a Bunnythorpe or Tokaanu 220 kV bus, or a Bunnythorpe–Tokaanu circuit, for HVDC south transfer of about 370–420 MW
- Bunnythorpe–Tangiwi circuit may overload during an outage of a Tokaanu 220 kV bus or Bunnythorpe–Tokaanu circuit for HVDC south transfer of about 430–480 MW
- Bunnythorpe–Tokaanu circuits may overload during an outage of the other Bunnythorpe–Tokaanu circuit for an HVDC south transfer of more than 480 MW
- Rangipo–Tangiwi circuit may overload pre-contingency for HVDC south transfer of more than about 580 MW.

By 2030, the:
- Rangipo–Tangiwi circuit may overload during an outage of a Bunnythorpe or Tokaanu 220 kV bus or a Bunnythorpe–Tokaanu circuit for HVDC south transfer of about 190–290 MW
- Bunnythorpe–Tangiwi circuit may overload during an outage of a Tokaanu 220 kV bus or a Bunnythorpe–Tokaanu circuit for HVDC south transfer of about 250–350 MW
- Bunnythorpe–Tokaanu circuits may overload during an outage of a Bunnythorpe 220 kV bus, the other Bunnythorpe–Tokaanu circuit, or the Bunnythorpe–Tangiwi circuit for an HVDC south transfer of about 260–420 MW
- Rangipo–Tangiwi circuit may overload pre-contingency for HVDC south transfer of more than about 450 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 traded off with 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 220 kV constraints**

From 2015:
- the Bunnythorpe–Paraparaumu circuit 2 may overload during an outage of a Bunnythorpe 220 kV bus for HVDC south transfer of about 210 MW
• the Bunnythorpe–Paraparaumu circuits may overload during an outage of a Haywards 220 kV bus, or a section of the Bunnythorpe–Linton–Haywards circuit, for HVDC south transfer of about 470 MW
• the Haywards–Paraparaumu circuits may overload for a Haywards–Linton circuit outage for an HVDC south transfer of more than 500 MW
• a Bunnythorpe–Paraparaumu circuit may also overload for an outage of the other Bunnythorpe–Paraparaumu–Haywards circuit for an HVDC south transfer of about 550 MW.

We are committed to reconductoring the Bunnythorpe–Paraparaumu–Haywards circuits in 2020. This reconductoring will increase the capacity of those circuits.

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

**SC3: Brunswick–Stratford constraints**

If the majority of growth generation appears in the Taranaki area, then the following HVDC south transfer limits will occur.

From 2015, the Brunswick–Stratford circuits may overload for an outage of one of the other Brunswick–Stratford circuits for HVDC south transfer of about 520–550 MW.

By 2020, the Brunswick–Stratford circuits may overload for an outage of one of the:
• other Brunswick–Stratford circuits for HVDC south transfer of about 350–380 MW
• central North Island 220 kV circuits for HVDC south transfer of about 510–540 MW
• 110 kV Taranaki circuits between Stratford and Wanganui for HVDC south transfer of about 540–570 MW.

By 2030, the Brunswick–Stratford circuits may overload:
• for an outage of one of the other Brunswick–Stratford circuits for HVDC south transfer of about 70–110 MW
• for an outage of one of the central North Island 220 kV bus sections for HVDC south transfer of about 240–300 MW
• for an outage of any 110 kV circuit between Wanganui and Stratford for HVDC south transfer of about 280–290 MW
• for an outage of one of the 220 kV circuits between Huntly and Stratford for HVDC south transfer of about 280–290 MW
• pre-contingency for HVDC south transfer of about 360 MW, which is largely due to more than 500 MW of generation at Stratford to balance with load.

These HVDC south transfer limits increase if new generation is installed at Wairakei rather than Huntly or Stratford.

**Possible solutions**

These transmission constraints can be addressed with additional generation installed and/or dispatched in the lower North Island or South Island. Alternatively, they may be alleviated or removed by the following transmission upgrades:
• When new transformers with on-load tap changers replace the Bunnythorpe interconnecting transformers, low voltage issues in the central North Island will occur only at Brunswick for this level of HVDC south transfer.
• Central North Island 110 kV options (see Central North Island investigations and mitigation measures in Section 6.4.1 for more information).
• Taranaki 110 kV options (see Chapter 12 for more information).
• Upgrade Rangipo–Tangiwi–Bunnythorpe and Bunnythorpe–Tokaanu transmission capacity (apply variable line ratings, reconductor the existing lines, or construct a new line).
• Increase voltage stability limits by installing static and/or dynamic reactive support at Bunnythorpe and/or Haywards.
• Increase capacity between Stratford and Brunswick (by applying variable line ratings or reconductoring the existing lines).
• Reduce the adverse impact of Bunnythorpe and Haywards 220 kV bus outages by rearranging existing bus configurations and/or adding an additional bus section.

6.3.4 System condition 4: HVDC south transfer (summer)

This system condition tests the case with extremely low generation in the South Island requiring high HVDC south transfer close to the time of summer peak load. Similarly to system condition 3 (only with summer circuit ratings) it represents a dry year with low wind. The specific assumptions for this system condition are as follows:
• Eighty per cent of North Island summer peak load in the year the transmission constraint is identified.
• No thermal generation in Auckland.
• Maximum geothermal and hydro generation in the Bay of Plenty, central North Island and Hawkes Bay.
• Low Taranaki generation, with no generation on the Stratford 220 kV bus.
• No wind generation in the lower and central North Island regions.
• High HVDC south transfer up to voltage stability limits.
• Generation and load balance is achieved using Huntly.

Summary of transmission constraints

Possible transmission constraints include:
• 110 kV regional network
• 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 a parallel circuit outage. This transmission constraint is addressed by the existing special protection scheme at Woodville\(^\text{22}\). The Bunnythorpe–Woodville circuits may also cause a transmission constraint for HVDC south transfer exceeding 390 MW (in 2015) for a 220 kV bus outage. This transmission constraint is not addressed by the existing 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.

\(^{22}\) The special protection scheme at Woodville detects an outage of a Bunnythorpe–Woodville circuit and if the other circuit is overloaded, then 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.
SC4: 220 kV thermal overloads

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

- Rangipo–Tangiwai
- Bunnythorpe–Tangiwai
- Bunnythorpe–Tokaanu
- Rangipo–Tangiwai (pre-contingency)
- Bunnythorpe–Paraparaumu

Possible solutions

These transmission constraints can be addressed with additional generation installed and/or dispatched in the lower North Island or South Island. Alternatively, they may be alleviated or removed by the following transmission upgrades:

- Bunnythorpe–Woodville upgrade options (see Chapter 11, Section 11.8.3 for more information).
- Upgrade Rangipo–Tangiwai–Bunnythorpe and Bunnythorpe–Tokaanu transmission capacity (by applying variable line ratings reconductoring the existing lines, or constructing a new line).
- Improve the impact of Bunnythorpe and Haywards 220 kV bus outages by rearranging existing bus configurations and/or adding an additional bus section.

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

This system condition tests the effect of high generation export from Kawerau on the grid backbone. It represents a summer peak period where there is low generation in upper North Island, high generation in the eastern Bay of Plenty, and no industrial load at Kawerau. The specific assumptions for this system condition are as follows:

- North Island summer peak load, with all directly connected industrial load on the Kawerau 110 kV and 220 kV buses turned off.
- Kawerau–T13 is replaced with a new transformer bank identical to the existing Kawerau–T12.
- Generation in the upper North Island is limited to one combined cycle generating unit at Huntly.
- Maximum geothermal generation in the Bay of Plenty, central North Island and Hawkes Bay.
- Hydro generation at 80% of installed capacity, with the exception of Matahina and Aniwihenua, which are operating at 100%.
- Low Taranaki generation, with no generation on the Stratford 220 kV bus.
- Maximum wind generation in the lower and central North Island regions.
- Generation and load balance is achieved using HVDC north transfer (HVDC north transfer is 430 MW in 2015, 700 MW in 2020, and restricted to 950 MW in 2030 to prevent overloading the 110 kV Bunnythorpe–Mataroa circuit pre-contingency, and using a Huntly 250 MW coal fired unit to supply the deficit).

Summary of transmission constraints

Possible transmission constraints include:

23 The HVDC south transfer limit increases following Bunnythorpe–Paraparaumu–Haywards reconductoring.
24 An alternative to this development is to enable the existing Kawerau–13 overload protection scheme, which reduces Kawerau 110 kV generation if Kawerau–T13 overloads and Kawerau–T12 is out. However, this system condition is intended to highlight constraints on the grid backbone, which the special protection scheme does not illustrate.
• 110 kV regional network
• 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, after the operation of which the Atiamuri–Ohakuri circuit may exceed its summer rating.

**SC5: 110 kV regional network**

A number of contingencies will result in 110 kV circuit thermal overloads (see Chapter 10, Section 10.8.1, for more information). A number of special protection schemes will operate to remove overloaded 110 kV circuits, however, the special protection scheme on the Edgecumbe–Owhata circuit\(^{25}\) 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, particularly if the special protection scheme on the Edgecumbe–Owhata circuit operates
• Edgecumbe–Kawerau–3 circuit, which may also overload for an Atiamuri–Ohakuri circuit outage
• Atiamuri–Tarukenga circuit, which may overload for a Tarukenga 220 kV bus outage.

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 250 MW in 2015, 180 MW in 2020, and 150 MW in 2030
• an Edgecumbe 220 kV bus outage followed by operation of the Edgecumbe–Owhata special protection scheme for Kawerau generation of more than 290 MW in 2015, 210 MW in 2020 and 180 MW in 2029
• a Kawerau 220 kV bus outage followed by operation of the Edgecumbe–Owhata special protection scheme for Kawerau generation of more than 250 MW in 2015, 180 MW in 2020, and 150 MW in 2030
• a Tarukenga 220 kV bus outage followed by operation of the Edgecumbe–Owhata special protection scheme for Kawerau generation of more than 325 MW in 2015, 275 MW in 2020, and 250 MW in 2030.

**SC5: other transmission constraints**

The following transmission constraints are not caused by high generation export and no industrial load at Kawerau, but still cause transmission constraints with the specific assumptions used for system condition 5. The transmission 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 (although it is assumed this will be managed with a special protection scheme that opens Bunnythorpe–Mataroa if it overloads)

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\(^{25}\) 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.
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• the transfer into the upper North Island from 2017 onwards will be limited by loading on the Waikato 110 kV network between Tarukenga and Hamilton (see Section 6.3.6 for more information)
• a Tokaanu–Whakamaru circuits may overload for an outage of the other Tokaanu–Whakamaru circuit (although it is assumed this will be managed with the existing special protection scheme at Tokaanu26).

Possible solutions

These transmission constraints can be managed operationally by limiting generation on the Kawerau 110 kV bus during low industrial load periods. Alternatively, they may be alleviated or removed by the following transmission upgrades:
• Increase Wairakei ring capacity (see Section 6.3.1, System condition 1: low Auckland generation (winter peak), for more information).
• Install a special protection scheme to open Atiamuri–Ohakuri if it overloads. The scheme will require further investigation before implementation as it may be the second or third scheme to operate in the area.

6.3.6 System condition 6: South Waikato 110 kV transmission capacity

This system condition tests the case if the Arapuni bus split is permanently closed in 201727 and the impact of transmission constraints on the grid backbone caused by the 110 kV network between Tarukenga and Hamilton. The specific assumptions for this system condition are as follows:
• North Island summer peak load.
• Maximum geothermal and hydro generation in the Bay of Plenty, central North Island and Hawkes Bay.
• Maximum hydro generation at Karapiro28.
• Maximum thermal generation in the Taranaki region, including the Taranaki combined-cycle unit.
• Wind generation at 20% of installed capacity.
• Generation and load balance is achieved by trading of upper North Island and Waikato generation with South Island generation via the HVDC link.

Summary of transmission constraints

The transmission constraints, which can significantly impact generation, differ for:
• Kinleith generation unavailable
• Kinleith generation available
• Hangatiki–Te Awamutu circuit in/out of service.

The first transmission constraint for transfer into the upper North Island is the loading on the 110 kV circuits between Tarukenga and Hamilton, which will arise if the Arapuni bus split is closed to accommodate a new grid exit point at Putaruru.

The generation north of Tarukenga will need to be carefully managed to ensure the loading on the Lichfield–Tarukenga–1 circuit does not limit power flow into the upper

26 Assuming the special protection scheme at Tokaanu is in service reduces the reliance on generation in the upper North Island and Waikato areas. However, because of high minimum generation requirements at Arapuni, to balance water flow between power stations a high level of generation at Karapiro is also assumed.
27 See Chapter 9, Section 9.10.1, for the issue in the Waikato region which may require the Arapuni bus split to be closed.
28 This assumption reduces reliance on upper North Island generation, however, because of high minimum generation requirements at Arapuni, to balance water flow between power stations a high level of generation at Karapiro is assumed.
North Island. The minimum and maximum generation limits will become increasingly restrictive with load growth.

The transmission constraints, and hence generation limits, differ if the embedded generation at Kinleith is unavailable or available.

If the Arapuni bus split remains open, then this system condition causes no significant transmission constraints in addition to those already identified system conditions 1–5. However, it will cause significant issues in the Waikato region.\textsuperscript{29}

**SC6: Kinleith generation unavailable**

With no generation at Kinleith, the transmission constraint is the loading on the Lichfield–Tarukenga circuit for an outage of the other 110 kV Kinleith–Lichfield–Tarukenga circuit.

This transmission constraint can be managed by increasing generation at Arapuni, Huntly and Otahuhu. However, from summer 2028 there is insufficient existing generation north of Kinleith to prevent this overload from occurring.

**SC6: Kinleith generation available**

With Kinleith generating 19 MW, the limiting outage becomes the 220 kV Hamilton–Whakamaru circuit. This outage requires the generation north of Hamilton to be carefully managed to ensure that the Arapuni runback\textsuperscript{30} does not reduce generation at Arapuni to a point where the Lichfield–Tarukenga–1 circuit overloads.

In summer:
- 2017, minimum generation of 480 MW is required north of Hamilton, and Arapuni generation must operate above about 155 MW
- 2020, minimum generation of 530 MW is required north of Hamilton, and Arapuni generation must operate above about 170 MW
- 2025, minimum generation of 685 MW is required north of Hamilton, and Arapuni generation must operate above about 175 MW
- 2030, minimum generation of 800 MW is required north of Hamilton, and Arapuni generation must operate above about 180 MW (which is close to its installed capacity).

**SC6: Hangatiki–Te Awamutu circuit in/out of service**

If the Hangatiki–Te Awamutu circuit is open, then in summer with 19 MW of generation at Kinleith, in:
- 2017, minimum generation of 590 MW is required north of Hamilton, and Arapuni generation must operate above about 140 MW
- 2020, minimum of generation 630 MW is required north of Hamilton, and Arapuni generation must operate above about 150 MW
- 2025, minimum generation of 775 MW is required north of Hamilton, and Arapuni generation must operate above about 160 MW
- 2030, minimum generation of 895 MW is required north of Hamilton, and Arapuni generation must operate above about 165 MW.

\textsuperscript{29} See Chapter 9, Section 9.10.1, for issues that may arise if the Arapuni bus split remains open.

\textsuperscript{30} The Arapuni runback detects an overload on one of the Arapuni–Hamilton circuits and reduces generation at Arapuni so that the circuit loading is reduced to 95% of seasonal rating.
Possible solutions

These transmission constraints can be managed operationally with generation north of Tarukenga, but will become more restrictive as load grows. Alternatively, they will be alleviated or removed by the following transmission upgrades:

- Bus the Arapuni–Bombay circuit at Hamilton to raise the Arapuni runback limit.
- Split the system between Kinleith and Tarukenga, and either upgrade the existing special protection scheme on the Arapuni–Kinleith circuits\(^{31}\) or reconductor the Arapuni–Kinleith circuits.

Transmission upgrades that reduce the impact of Hamilton–Whakamaru outages on the Waikato 110 kV network include:

- series compensation on the Brownhill Road–Whakamaru circuits (see Transmission into Auckland in Section 6.4.1 for more information)
- the Otahuhu–Wiri upgrade (see Section 8.8.3 for more information), options for which include splitting the system at Bombay, which may positively impact the limits around Arapuni.

Conversely, the possible special protection scheme on the 110 kV Bunnythorpe–Mataora circuit may have a negative impact on the Waikato 110 kV power flows (particularly if the scheme were to operate for a Hamilton–Whakamaru outage)\(^{32}\). The scheme’s design will account for these possible interactions.

6.3.7 System condition 7: light load

This system condition tests the effect of low load on the grid backbone. It represents a summer night light load period and is designed to highlight overvoltage issues. The specific assumptions for this system condition are as follows:

- North Island trough summer night load.
- Generation in the upper North Island is limited to one combined cycle generating unit at Huntly.
- Maximum geothermal in the Bay of Plenty, central North Island and Hawkes Bay.
- Low hydro generation, many generation stations have only one unit in service with the exceptions of Arapuni, Karapiro, Rangipo and Tokaanu.
- No Taranaki generation.
- No wind generation in the lower and central North Island regions.
- HVDC north transfer of 140 MW representing a limitation dictated by the reduced number of harmonic filters in service.
- Generation and load balance is achieved by altering Huntly generation.

Summary of transmission constraints

Possible transmission constraints include:

- Te Kowhai and Taumarunui high voltage
- Auckland area high voltages
- Wellington area high voltages
- Wairakei bus outages.

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

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\(^{31}\) The Arapuni–Kinleith special protection scheme detects an overload on one of the Arapuni–Kinleith circuits and opens it. This scheme is presently used during maintenance outages where the 110 kV network is split between Kinleith and Tarukenga. The existing scheme results in a complete loss of supply at Kinleith.

\(^{32}\) The dispatch pattern used under this system condition will not result in operation of the Bunnythorpe–Mataora special protection scheme for a Hamilton–Whakamaru outage.
voltage profile can be maintained at around 1.0 pu at most generating stations. However, this requires generation to absorb a high level of reactive power pre-contingency, limiting the available response to a post-contingency event. It can also be difficult to change the system voltage to 1.0 pu during low load periods and change the voltage again to a higher voltage during normal and high load periods on a daily basis.

**SC7: 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. The extent of the overvoltage also depends on the response from the two generating stations embedded at Te Kowhai (Te Rapa and Te Uku).

**SC7: Auckland area high voltages**

Keeping the Auckland area voltages within acceptable limits with all circuits in service requires high levels of reactive power absorption from available units at Huntly. If this reactive power absorption is not available, circuits (such as Pakuranga–Whakamaru) may need to be removed from service to maintain voltages.

**SC7: Wellington area high voltages**

Keeping the Wellington area voltages within acceptable limits with all circuits in service requires high levels of reactive power absorption from the Haywards synchronous condensers. HVDC transfer may also be limited for harmonic performance if the number of filters must be reduced.

**SC7: Wairakei bus outages**

A number of generating stations are connected to the same bus sections at Wairakei. These stations are predominantly geothermal, so are likely to be available at light load periods. If a Wairakei 220 kV bus outage occurs, the Edgecumbe 33 kV voltage may exceed 1.05 pu. There are no on-load tap changers on the 220/33 kV supply transformers at Edgecumbe.

**Possible solutions**

At present, the high voltages are managed via operational measures (including removing circuits from service). If high voltages cannot be managed operationally then one transmission solution is to install shunt reactors. However, previous analysis showed capital expenditure to be uneconomic unless high voltages occur quite often. The frequency of high voltages will reduce over time as system demand at times of light load increases.

### 6.4 Future North Island grid backbone

#### 6.4.1 Grid backbone to 2030

This section provides information about the transmission constraints we will investigate or mitigate over the next few years. Constraints that are not considered include those that only occur:

- for a particular generation development scenario (for example, most new generation only occurs in the Taranaki region)
- towards the end of the forecast period.

Transmission constraints being investigated or mitigated over the next few years include:

- central North Island investigation and mitigation measures
transmission through the Wairakei ring
south Waikato 110 kV investigation
transmission into Auckland.

Figure 6-3 provides an indication of a possible North Island transmission backbone development in the medium term (the next 15 years).
Figure 6-3: Indicative North Island grid backbone schematic to 2030

- NEW ASSETS
- UPGRADED ASSETS

KEY:
- * double circuit transmission line constructed for 400 kV operation but initially operated at 220 kV.
- ** possible new connection point for 110 kV Valley Spur circuits
Central North Island investigation and mitigation measures

The capacity of the central North Island circuits and the transmission constraints they impose are common to many generation dispatch and development scenarios (such as the system conditions described in Section 6.3) and we will investigate options to upgrade this part of the system. It is anticipated, however, that although new or replacement transmission lines will not be justified, lower cost upgrade options may be justified.

The thermal rating of the 110 kV circuits between Bunnythorpe and Arapuni are usually the first transmission constraint to limit power flow north on the North Island grid backbone. We are investigating options to manage these circuits to increase the transmission capacity, which include:

- a special protection scheme to split the 110 kV network if the Bunnythorpe–Mataroa circuit overloads and/or a series reactor
- reconductoring the line with a higher capacity and lower loss conductor (although experience indicates it is unlikely to be economic to upgrade 110 kV circuits until the conductor needs to be replaced based on condition assessment).

Any upgrade will need to account for the effect on the 110 kV network in the Waikato region (see Chapter 9, Section 9.10.1, for more information).

The thermal rating of the 220 kV circuits between Bunnythorpe and Whakamaru, and between Bunnythorpe and Wairakei, may constrain power flow north (after the 110 kV constraint is removed) and south. We will investigate medium-term options to increase the north and/or south flow transmission capacity, which include:

- using variable line ratings
- circuit thermal upgrades
- special protection schemes (which are expected to have limited application in the grid backbone)
- reconductoring with higher capacity and lower loss conductors, as the additional benefit from the reduction in losses may justify the cost of reconductoring.

Low voltage in the central and lower North Island may limit transmission capacity before some of the 220 kV transmission constraints. Low voltage is presently managed using HVDC controls (power limits and runbacks; see Section 6.8.2 for more information) and limits on generation. Part of the reason for the low voltage is that transformers at substations like Bunnythorpe, Brunswick and Waipawa do not have on-load tap changers. In the medium term, the low voltage constraints will be alleviated (but not completely removed) when the existing transformers are replaced, due to age or condition, as the replacement transformers will have on-load tap changers.

Transmission through the Wairakei ring

The capacity of the Wairakei–Ohakuri–Atiamuri–Whakamaru circuits may cause a transmission constraint for very high generation scenarios. This transmission constraint will worsen if there is a reduction in industrial load in the Bay of Plenty area, or if there is additional generation in the Wairakei or Bay of Plenty areas (both of which have the potential for a significant increase in geothermal generation).

We will monitor load and generation developments and will investigate options to increase transmission capacity when new generation development is committed. The

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33 The Bunnythorpe–Tangiwai and Tangiwai–Rangipo circuits can be thermally upgraded. The other 220 kV circuits have already been thermally upgraded to the maximum extent technically possible.

34 Special protection schemes have only a limited application in meshed networks, such as this part of the grid backbone, because it is difficult to ensure they will always operate to maintain system security for all combinations of power flow.
limiting circuits have already been thermally upgraded and use variable line ratings, so there is no scope to increase the transmission capacity using these techniques.

**South Waikato 110 kV investigation**

We are investigating options to address the grid backbone transmission constraints and regional transmission issues caused by the south Waikato 110 kV network.

One possible option is an Arapuni 110 kV bus upgrade to allow the existing split to remain long term, upgrade and extend the existing special protection schemes between Arapuni and Tarukenga, and possibly reconductor some of the 110 kV lines between Arapuni and Tarukenga.

**Transmission into Auckland**

Transmission constraints between Whakamaru and Auckland may be addressed with series capacitors on the Brownhill Road–Whakamaru circuits. This will also reduce the system losses. We will carry out an economic analysis to determine if the reduction in system losses justifies bringing forward the installation of series capacitors before the need date for transmission constraints.

Series capacitors to address transmission constraints between Whakamaru and Auckland will also require 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.

Voltage stability in the upper North Island is an ongoing issue. We will provide additional reactive support to maintain upper North Island voltage stability as regional load continues to grow. Series capacitors on the Brownhill Road–Whakamaru circuits will reduce the need for additional voltage support.

6.4.2 Grid backbone beyond 2030

Figure 6-4 provides an indication of the possible North Island transmission backbone development in the longer term (beyond 2030).

**Increased operating voltages from Whakamaru to Brownhill Road**

The operating voltage on the new overhead transmission line from Whakamaru to Brownhill Road may increase 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.

**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 additional advantage of increasing security to the Bay of Plenty region during maintenance outages.

**Transmission capacity north of Bunnythorpe**

Transmission capacity north of Bunnythorpe may be increased through either the central North Island to Whakamaru and/or through the Taranaki region 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 south of Taupo.
Reinforcing Hamilton and the Waikato region

Reinforcing the transmission capacity into Hamilton may be justified in future to provide security to the Waikato region during maintenance outages. One option is a new 220/110 kV connection to the east of Hamilton, supplied off the 220 kV Ohinewai–Whakamaru circuit and connected to the 110 kV Hamilton–Piako–Waihou circuits to backfeed Hamilton and the rest of the Waikato region.
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

**** New grid exit point(s) south of Otahuhu, possibly:
- north of Drury, and/or
- at Brownhill Road by extending the 220 kV bus.
6.5 South Island

6.5.1 South Island existing grid backbone

The South Island grid backbone comprises 220 kV circuits with:

- three circuits from Islington to Kikiwa
- four circuits from Twizel and Livingstone in the Clutha Upper Waitaki Valley area to Islington
- nine circuits within the Waitaki Valley between Twizel and Livingstone, which connect six large hydro generation stations and the HVDC link
- three circuits from Roxburgh to Twizel and Livingstone in the Clutha Upper Waitaki Valley area
- four circuits from Roxburgh to Invercargill/North Makarewa (two via Three Mile Hill) and nine circuits within the Lower Southland area.

Power flows either north or south on the inter-island HVDC link. During daylight, power tends to flow north to meet peak demand. During light load periods, power can flow south to conserve the level of South Island hydro storage, especially during periods of low hydro inflow.

The existing South Island grid backbone is set out schematically in Figure 6-5 and geographically in Figure 6-6.
Figure 6-5: South Island grid backbone schematic
6.5.2 Changes since the 2014 Transmission Planning Report

Changes since the 2014 TPR include:

- the load forecast, with low or almost zero load growth forecast for most regions and a few hot spots with high load growth forecast (which has only a limited impact on the transmission capability and constraints reported in the 2014 TPR)

- installation of the Roxburgh Export Overload Protection (REOLP) scheme (which monitors the current and direction of power flow on the Naseby–Roxburgh circuit) to increase the transmission capacity for power flow from Roxburgh to the Waitaki Valley.\(^{35, 36}\)

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\(^{35}\) If an overload occurs with power flowing north, then Stage 1 of the scheme splits the Roxburgh 220 kV bus to reduce power flow on the Naseby–Roxburgh circuit and force more power through the
Projects that are not complete at the time of publication but used in the analysis are:

- the Aviemore–Waitaki–Livingstone line (duplexing) capacity upgrade, which is due to be commissioned in Q2 2016
- installation of a 220/110 kV interconnection at Gore and implementation of a system split at the Gore 110 kV bus, which is programmed for commissioning in 2017.\(^{37}\)

### 6.5.3 Line conductor replacements

There are no line conductor replacements in the South Island based on age and condition.

As part of the Clutha Upper Waitaki Lines Project (CUWLP) to increase transmission capacity (see Clutha Upper Waitaki Lines Project in Section 6.7.1 for more information), the:

- Aviemore–Waitaki circuit was recently duplexed
- Livingstone–Waitaki circuit is due to be duplexed in 2016.

The TPR’s analysis uses both these upgrades.

### 6.5.4 Methodology

#### System conditions

A small number of realistically challenging system conditions are used to assess the capability of the existing South Island grid backbone (with a few changes in circuit rating for line reconductoring as set out in Section 6.5.3). They provide snapshots to identify transmission constraints that may require minimum or maximum generation limits to avoid overloading the power system following an outage. Transmission upgrades that alleviate the transmission constraints to enable lower minimum and higher maximum generation limits are also identified.

#### Growth generation

The existing generation is insufficient to supply the forecast load towards the end of the forecast period. Additional growth generation, which can be built anywhere in New Zealand, is also required to supply the forecast load. The system conditions also identify transmission constraints that can occur if growth generation appears predominantly in one area.

#### Limits in the Electricity Market

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

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36 The Gore 220/110 kV connection includes two 220/110 kV transformers at Gore, teed off the 220 kV North Makarewa–Three Mile Hill 1 and 2 circuits. It also includes normally splitting the Gore 110 kV bus to prevent overloading of the regional 110 kV system. One side of the split will have the Balclutha–Gore and Gore–Roxburgh circuits, and the other side of the split will have the two 220/110 kV transformers, the two Gore supply transformers, and the 110 kV Brydone–Gore circuit. The build date for the Gore 220/110 kV interconnection is an estimate that depends on when Transpower acquires the property rights for a short length of 220 kV transmission line.

37 The Gore 220/110 kV interconnection is an estimate that depends on when Transpower acquires the property rights for a short length of 220 kV transmission line.
• 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 as pre-contingent or post-contingent actions, depending on the extent and magnitude of the system impact resulting from the outage.

6.5.5 Overview of results

Key findings for the South Island grid backbone (see Section 6.6) include the following:

• The transmission capacity to the upper South Island is limited by a voltage stability constraint. When the need arises, our preferred option is to sectionalise the 220 kV circuits from the Waitaki Valley to Islington by bussing them at new switching stations at Orari and Rangitata.

• The Gore 220/110 kV connection is required to increase the transmission capacity of the core grid into and out of the lower South Island (south of Roxburgh). It is also necessary to allow REOLP Stage 2 to be used to increase generation export north from Roxburgh to the Waitaki Valley.

• An assessment of completing the CUWLP line upgrades, between Roxburgh and the Waitaki Valley, indicates this will be economic only if there is a significant decrease in load or an increase in generation in the lower South Island.

• We are studying options for managing high voltages during light load periods in the upper South Island after the decommissioning of Islington SVC-3 (which is reaching the end of its economic life). Preliminary options include identifying additional operational measures for the System Operator or installing a new shunt reactor in the region to provide additional reactive power absorption capabilities.

6.6 South Island grid backbone capability and constraints

The system conditions that provide a snapshot of the capability of the South Island grid backbone to transfer energy from generators to the load while maintaining a secure grid are as follows:

1. Low upper South Island generation (see Section 6.6.1).
2. High lower South Island generation (see Section 6.6.2).
3. Low lower South Island generation (see Section 6.6.3).
4. Light load (see Section 6.6.4).

6.6.1 System condition 1: low upper South Island generation

This system condition tests a case with extremely low generation in the upper South Island area during high load. Although the upper South Island has relatively little generation compared with the load, generation still has a noticeable effect on transmission constraints. The specific assumptions for this system condition are as follows:

• South Island peak load.

• Low generation in the upper South Island.

• High Waitaki generation and high lower South Island generation.

• Generation and load balance is achieved using the HVDC (representing new geothermal or thermal generation in the North Island resulting in reduced north transfer during peak loads).

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

There is insufficient transmission capacity to supply the upper South Island loads for the forecast period under this system condition. The transmission capacity into the upper South Island is constrained by voltage stability from 2022 and by transmission thermal capacity from 2027.

Possible transmission constraints include:
- Voltage stability constraints
- Transmission thermal limits
- Impact of new generation and outages.

SC1: voltage stability constraints

The voltage stability within the upper South Island area is influenced by the:
- reactive power losses due to the transmission system
- reactive power demand due to load composition (in particular the proportion and type of motor load)
- generation.

Reactive support for the upper South Island is provided by:
- two SVCs\(^{38}\) 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.

The outages that may cause a voltage stability constraint at peak load periods are the:
- Ashburton bus section C\(^{39}\) from winter 2022
- Islington bus section A\(^{40}\) or Ashburton bus section A\(^{41}\) from winter 2023
- Islington bus section B\(^{42}\) from winter 2024.

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 2027.

SC1: impact of new generation and outages

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

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\(^{38}\) We plan to decommission Islington–SVC3 in the next five years due to the end-of-life of its control system.

\(^{39}\) An Ashburton bus section C outage disconnects the Ashburton–Timaru–Twizel and Ashburton–Bromley circuits.

\(^{40}\) An Islington bus section A outage disconnects the Islington–Tekapo–B circuit and Islington–T7 (220/66 kV) transformer.

\(^{41}\) An Ashburton bus section A outage disconnects the Ashburton–Timaru–Twizel–1 circuit and the Ashburton–Bromley circuit.

\(^{42}\) An Islington bus section B outage disconnects the Islington–Livingstone circuit and Islington–T6 (220/66 kV) transformer.
An outage of a circuit or other transmission element for maintenance will increase the reactive power losses of the transmission system. This requires maintenance to be scheduled:

- at a low load period
- with demand-side load reduction
- with high minimum levels of generation
- following investment in additional reactive support.

**Possible solutions**

After investigating the next tranche of investments to relieve the upper South Island voltage stability constraint, the preferred option is sectionalising the 220 kV circuits from the Waitaki Valley to Islington by bussing them at new switching stations at Orari and Rangitata. This option also resolves transmission thermal capacity limits for the forecast period. This project may be required at the earliest by 2022 and we are progressing preliminary work to reduce lead times.

In the longer term, options to improve voltage stability include installing approximately 300 Mvar of additional reactive support by 2030.

Some longer-term options to address the n-1 transmission thermal capacity include either:

- reconductoring existing transmission lines for higher capacity
- 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).

These resolving projects may need to be brought forward a few years to ensure there is sufficient opportunity to take equipment out of service for maintenance and construction.

We will monitor the loading on the upper South Island circuits to determine when a transmission upgrade investigation is required.

### 6.6.2 System condition 2: high lower South Island generation

This system condition tests the case where there is either significant new generation developed or a significant reduction in load in the lower South Island (south of Roxburgh). It tests the ability of the grid to transmit surplus power from south of Roxburgh to the large load centres in Christchurch and/or the North Island (HVDC). The specific assumptions for this system condition are as follows:

- The forecast 2017 South Island summer peak load for summer transmission constraints and the forecast 2018 South Island winter peak load for winter transmission constraints.
- High generation on the Clutha hydro system and moderate generation on the Waitaki, Ohau, and Tekapo hydro systems.
- High HVDC north transfer up to 1200 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 transmission constraint
- Clyde–Cromwell–Twizel transmission constraint.
The transmission constraints are highly sensitive to the generation assumptions, especially at Clyde and Roxburgh\textsuperscript{43}. Generation constraints in the lower South Island do not occur frequently with present load and generation levels, but will become frequent if a significant:

- reduction in load occurs
- amount of growth generation is developed in the region to supply the rest of New Zealand’s future demand.

**SC2: Livingstone–Naseby–Roxburgh transmission constraint**

In most normal operating scenarios, the capacity of the Livingstone–Naseby–Roxburgh circuit causes the transmission constraint that requires a maximum generation export limit from the lower South Island.

The Livingstone–Naseby–Roxburgh circuit operates in parallel with the higher capacity Clyde–Cromwell–Twizel 1 and 2 circuits, and will overload for a Clyde–Cromwell–Twizel outage if the north transfer from the lower South Island exceeds approximately 640 MW in summer and 800 MW in winter\textsuperscript{44} (with both stages of REOLP operated).

**SC2: Clyde–Cromwell–Twizel transmission constraint**

The Clyde–Cromwell–Twizel circuits are usually the next transmission constraint that limits 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 the generation export from the lower South Island exceeds approximately 660 MW in summer and 830 MW in winter (with both stages of REOLP operated).

This transmission constraint is very close to the Livingstone–Naseby–Roxburgh transmission constraint.

**Possible solutions**

These transmission constraints are presently managed operationally by limiting the maximum generation in the Southland area. Alternatively, they may be alleviated or removed by completing the second tranche of CUWLP. The timing for the second tranche of CUWLP will be reviewed by the end of 2015. We are also investigating alternative options to some of the upgrades proposed in the second tranche of the CUWLP (see Clutha Upper Waitaki Lines Project in Section 6.7.1 for more information).

6.6.3 **System Condition 3: low generation South of Clyde (summer)**

This system condition tests an extremely low generation in the lower South Island (south of Clyde) to represent low hydro inflows in the South Island. The balance of power flows into the lower South Island from generation in the Waitaki or the North Island (represented by HVDC south flow). The specific assumptions for this system condition are as follows:

- South Island 2017 summer forecast peak load.

\textsuperscript{43} The generation at Roxburgh has the biggest effect on export limits from the lower South Island as the REOLP 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.

\textsuperscript{44} These limits are the pre-contingency power flows measured across the Naseby–Roxburgh circuit and Cromwell–Clyde sections so it includes generation from Clyde and Roxburgh.
• Low generation at Clyde and Roxburgh.
• High HVDC south flow.\textsuperscript{45}
• 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 with:
• high Waitaki Valley generation
• high HVDC south flow.

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 lower South Island.

**SC3: high Waitaki Valley generation**

With high Waitaki Valley generation and HVDC with low south transfer or north transfer, the:
• Livingstone–Naseby–Roxburgh circuit will overload for a Clyde–Cromwell–Twizel outage if the lower South Island import\textsuperscript{46} exceeds approximately 465 MW
• Cromwell–Twizel section of the remaining Clyde–Cromwell–Twizel circuit will overload for an outage on the other Clyde–Cromwell–Twizel circuit if the lower South Island import exceeds 675 MW.

**SC3: high HVDC south flow**

With moderate Waitaki Valley generation and high levels of HVDC south transfer:
• an Aviemore–Benmore circuit will overload for an outage of the other Aviemore–Benmore circuit if the lower South Island import exceeds approximately 265 MW
• the Livingstone–Naseby circuit will overload for a Clyde–Cromwell–Twizel outage if the lower South Island import exceeds 450 MW.

**Possible solutions**

This transmission constraint can be managed operationally using minimum levels of generation in the lower South Island.

Alternatively, the transmission constraint may be alleviated or removed by a transmission upgrade, starting with implementing the second tranche of CUWLP, which significantly increases the south transmission thermal capacity (see Clutha Upper Waitaki Lines Project in Section 6.7.1 for more information). On completion of CUWLP, the transmission constraint into the lower South Island is set by:
• voltage stability in the region\textsuperscript{47}
• the capacity of the Invercargill–Roxburgh circuits, to about 710 MW, assuming there is enough voltage support close to or at Manapouri.

If the voltage stability constraint in the lower South Island needs to be alleviated or removed, options include:

\textsuperscript{45} The HVDC link has a south flow rated capacity of 850 MW but has only been tested to 750 MW (at the sending end), therefore this value was assumed as the maximum for this analysis.
\textsuperscript{46} This limit is the pre-contingency power flow measured across the Livingstone–Naseby circuit and Cromwell–Twizel sections.
\textsuperscript{47} 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, which also reduces the amount of voltage support available in the Southland region.
• operating Manapouri generating units in tail water depressed mode to provide voltage support
• upgrading the North Makarewa capacitors
• installing additional shunt capacitors at North Makarewa or other Southland substations.

If the transmission constraint caused by the capacity of the Invercargill–Roxburgh circuits needs to be alleviated or removed, options include installing a:
• special protection scheme to automatically increase Southland generation following a circuit outage
• series capacitor on a North Makarewa–Three Mile Hill circuit.

If a significant amount of the balance of power into the lower South Island came from the HVDC and the Waitaki Valley rather than from Clyde/Roxburgh, the Benmore–Twizel circuit also needs to be upgraded.

6.6.4 System Condition 4: light load

This system condition tests the effect of low load on the grid backbone. It represents a summer night light load period and is designed to highlight possible overvoltage issues. The specific assumptions for this system condition are as follows:
• South Island trough summer night load.
• Very low HVDC north transfer.

Summary of transmission constraint

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 changeable throughout the day with very low loads overnight, especially in summer. This is compounded by long transmission lines and the lack of generation in the region. The long transmission lines produce significant amounts of reactive power during light load periods (increasing the voltage) and the lack of generation reduces the ability to absorb reactive power (to reduce the voltage).

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 static var compensators (SVC) 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, which reduces loading on the SVCs at Islington but has very little effect further north.

Decommissioning Islington–SVC3 will remove 50 Mvar of reactive power absorption capability from the grid. As SVC3 is frequently used to absorb reactive power, decommissioning it will worsen high voltage levels in the region north of the Waitaki Valley during light load periods.

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48 The two existing 50 Mvar capacitors at North Makarewa are designed to be easily upgraded to 75 Mvar.
49 The Islington–SVC3 is forecast to reach its end of useful life around 2016 and it was determined that it is uneconomical to replace.
Possible solutions

When there is insufficient capacity to absorb reactive power within the dynamic voltage control plants, we usually remove the Islington–Kikiwa–1 circuit from service, which has the effect of removing about 30 Mvar from the system.

We are studying options for managing high voltages during light load periods after the decommissioning of Islington–SVC3. Possible solutions include:

- removing a 220 kV circuit between the Waitaki Valley and Islington from service
- converting Islington–SVC3 to a switched shunt reactor
- installing shunt reactors at Islington or north of Islington.

Future preferred solutions will need to be economically justified.

6.7 Future South Island grid backbone

6.7.1 Grid backbone to 2030

This section provides information about the transmission constraints we will investigate or mitigate over the next few years. Constraints that are not considered include those that only occur:

- for a particular generation development scenario (for example, most new generation only occurs in the Canterbury region)
- towards the end of the forecast period.

Transmission constraints being investigated or mitigated over the next few years include:

- Upper South Island voltage stability, and
- Clutha/Upper Waitaki Lines Project (CUWLP).

Figure 6-7 provides an indication of possible South Island transmission backbone development in the medium term (the next 15 years).
Although this diagram shows new static reactive support installed at Islington, and new switching stations and GXP, this is indicative only as options are still being investigated.
Upper South Island voltage stability

Further investments in the upper South Island to maintain voltage stability and meet load growth will be required. Currently, our preferred option is sectionalising the 220 kV circuits from the Waitaki Valley to Islington by bussing them at new switching stations at Orari and Rangitata. Towards the end of the forecast period, we will also install about 300 Mvar of reactive support to improve voltage stability in the upper South Island.

Upper South Island voltage stability is an ongoing issue. We will continue to study the additional reactive support requirements to maintain upper South Island voltage stability as regional load continues to grow.

Clutha/Upper Waitaki Lines Project (CUWLP)

The CUWLP is an approved suite of projects to increase transmission capacity between the Clutha and Upper Waitaki areas.

The first tranche of CUWLP is:
- duplexing the Clyde–Roxburgh 1 and 2 circuits (completed)
- duplexing the Aviemore–Waitaki circuit (completed)
- duplexing the Livingstone–Waitaki circuit (expected to be completed in Q2 of 2016).

The second tranche of CUWLP, which is yet to commence, is:
- thermally upgrading the Cromwell–Twizel sections of the Clyde–Twizel 1 and 2 circuits
- duplexing the Roxburgh–Naseby–Livingstone circuits
- duplexing the Aviemore–Benmore 1 and 2 circuits.

The existing levels of generation and load in the lower South Island do not justify implementing the second tranche of CUWLP. Its primary justification is to increase transmission capacity for power flow from the lower South Island to the Waitaki Valley, if there is a significant load reduction or increase in generation in the lower South Island. However, the second tranche of the CUWLP also substantially increases the transmission capacity for power flow from the Waitaki Valley to the lower South Island, for periods when there is low generation in the lower South Island. We will review the need for the second tranche by the end of 2015 to optimise the timing of the upgrades.

Figure 6-8 shows the circuits after both tranches of CUWLP are completed.

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50 The increase in transmission thermal capacity is progressive, with increased transmission capacity available at the completion of each upgrade. The north transmission thermal capacity increases to approximately 1100 MW in summer and 1200 MW in winter once the second tranche of CUWLP is complete.
Figure 6-8: 220 kV circuits between Roxburgh and Twizel after CUWLP upgrade

We are also investigating alternative options to some of the upgrades proposed in the second tranche of CUWLP, which include:

- installing a special protection scheme on the Aviemore–Benmore circuits as an alternative to duplexing them
- installing a series reactor on the Naseby–Roxburgh circuit in conjunction with thermally upgrading the Cromwell–Twizel sections of the Clyde-Twizel 1 and 2 circuits as an alternative to duplexing the Roxburgh–Naseby–Livingstone circuit.

These alternatives may defer the second tranche of CUWLP or provide more economical solutions, depending on future system conditions and needs.

6.7.2 Grid backbone beyond 2030

Figure 6-9 provides an indication of the possible South Island transmission backbone development in the longer-term (beyond 2030).

Transmission capacity upgrades into Christchurch are required towards the end of the forecast period, which can be achieved with 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 when transmission reinforcement is needed.

The Inangahua–Kikiwa B line was designed and built as a 220 kV double-circuit line. However, only one circuit has been strung and is presently operated at 110 kV. If required, transmission capacity into the West Coast can be upgraded by operating the existing circuit at 220 kV and stringing a second 220 kV circuit. This may also allow us to decommission the older Inangahua–Kikiwa A line and connect Murchison to the upgraded 220 kV circuit.
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.
6.8 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 large hydro generation capacity, which can be important for the North Island in peak winter periods
- South Island with access to the North Island's gas and coal generation, which is important for the South Island during dry periods.

In terms of the North and South Islands, the HVDC link reduces the need for extra generation investment in each island, facilitates price competition, and plays an important part in managing renewable energy sources between the two.

6.8.1 HVDC link configuration

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

- a +/- 350 kV thyristor bipole converter (Pole 2 and Pole 3), with a converter station at Benmore in the South Island and Haywards in the North Island, with protection and control systems at Benmore and Haywards
- a 350 kV bipolar transmission line, 535 km long from Benmore to Fighting Bay on the shore of Cook Strait in the South Island and 37 km long from Haywards to Oteranga Bay on the shore of Cook Strait in the North Island
- three 350 kV underwater 40 km 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 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
6.8.2 HVDC link capability

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. There are two 500 MW HVDC cables connected to Pole 3, so the nominal end-to-end capacity is 700 MW.

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

The HVDC has a capacity of up to 1,000 MW in balanced 500/500 MW bipole operation and up to 1,200 MW51 in unbalanced 500/700 MW bipole operation.

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, should one pole fail, the remaining pole can increase its power transfer to provide partial or full self-cover depending on pre-fault power flow of the remaining pole.

To assist with the reserve cover, both Pole 2 and Pole 3 have short-term ratings higher than their nominal ratings. This reduces the overall reserve requirements. The duration of the short-term ratings depends on the pre-contingency loading (temperature) of equipment and the post-contingency loading, and may be available for several seconds to several minutes.

The Pole 2 short-term capacity with a single DC cable is 2400A for 5 seconds and is then limited by the maximum temperature of the single cable connected to the pole. The HVDC controls calculate the maximum current that the cable can sustain for 30 minutes without exceeding the cable’s design temperature limit, based on its design parameters and its pre-fault loading, and will reduce Pole 2 power transfer to 500 MW when the 30-minute overload period has expired or if the design temperature is reached.

The Pole 3 short-term capacity is limited by either the rating of the converter (1000 MW for 30 minutes), or the rating of the other AC or DC equipment (for example, the overhead transmission line, smoothing reactor or converter transformer). The HVDC controls:

- measure the temperatures in the Pole 3 converter equipment and calculate the line’s temperature based on its design parameters
- will reduce the Pole 3 power transfer to the maximum continuous power capability after 30 minutes of operation above this value.

Pole 3’s maximum continuous power capability is in the range of 700–840 MW, depending on the ambient temperature and the cooling systems that are available.

No self-cover is possible in monopolar operation (with only one pole in service) or for a bipole trip.

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51 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 6.3 and 6.6 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.
Transient overvoltage

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

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.

HVDC runbacks

The HVDC controls will automatically reduce HVDC transfer (i.e. runbacks) 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 sharing of reserves and 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 to represent the AC transmission system, interfaced to a complete spare HVDC control hardware suite.

6.8.3 Future HVDC developments

HVDC controls

The control systems have a shorter lifetime because of obsolescence (around 15–20 years) than the main HVDC converter equipment, requiring at least one full replacement in the converter equipment's lifetime. The HVDC controls and protections 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.

HVDC link expansion to 1,400 MW

Figure 6-11 shows a simplified diagram for a possible further expansion of the HVDC link to 1,400 MW north capacity, which involves installing:
- one additional submarine cable
- additional filters at both Benmore and Haywards
- additional dynamic reactive support at Haywards.

When planning for the additional cable, the condition and risks associated with the existing cables will also be reviewed and the need for a spare (fifth) cable will be assessed.

We will monitor the use of the HVDC link to determine if and when an investigation for an upgrade may be required. The earliest anticipated date is 2017. This will be a Major Capex Proposal.
We anticipate that a capacity increase to 1400 MW will be sufficient to enable diversity of generation in the North and South Islands for the foreseeable future.

**HVDC line rating**

The HVDC line’s capacity can be increased to allow the unconstrained use of the converters’ short-term overload rating for all operating conditions.

We will monitor the use of the HVDC link to determine if and when an investigation for an upgrade of the HVDC line may be required. This is a possible Major Capex Proposal and we anticipate seeking approval for this project at a date to be advised.

**Figure 6-11: Possible future HVDC link**
Chapter 7: Northland Region

7 Northland Regional Plan

7.1 Regional overview

This chapter details the Northland regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

Figure 7-1: Northland region
Chapter 7: Northland Region

The Northland region load includes a major industrial load at Bream Bay, and loads at smaller regional centres to the north.

We have assessed the Northland region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be sufficiently flexible to respond to a range of future service and technology possibilities, taking into consideration:

- the existing transmission network
- forecast demand
- forecast generation
- equipment replacement based on condition assessment, and
- possible technological development.

7.2 Northland transmission system

This section highlights the state of the Northland regional transmission network. The existing transmission network is set out geographically in Figure 7-1 and schematically in Figure 7-2.

Figure 7-2: Northland transmission schematic
7.2.1 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, which is effectively in parallel with the 220 kV circuits.

The Northland region’s generation capacity is well short of that needed to meet local demand, and so it must import most of its power through Auckland.

7.2.2 Transmission within the region

Transmission within the Northland region consists of two sub-regions.

The first sub-region is the high capacity 220 kV double-circuit line from Huapai to Marsden and Bream Bay. Two static synchronous compensators (STATCOMs) have been installed at Marsden, connected on the tertiaries of the interconnecting transformers, for voltage support.

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. The 110 kV double circuit line from Maungatapere to Kensington was divested to Northpower in early 2015. At present, voltage support for the sub-region is provided by capacitors at Kaitaia and, within the distribution network, at Kaikohe.

There are two 220/110 kV interconnecting transformers at Marsden.

7.2.3 Longer-term development path

No new transmission lines are expected to be required from Auckland to Northland to provide additional transmission capacity. At most, the single conductor (i.e. simplex) portion of the 220 kV circuit from Huapai to Bream Bay and Marsden may need to be reconductored to duplex if 300-500 MW of generation appears in the region, depending on where the generation is connected. Also, a system split along the two 110 kV Henderson–Maungatapere circuits may also be needed if generation is connected along the line or the load growth is significantly higher than forecast at Wellsford or Maungaturoto.

A new transmission line will be required from the Auckland region to Northland if an increase in security is required at some time in the future, particularly if security needs to be maintained during maintenance outages and can be justified economically.

No additional voltage support is forecast to be required within the planning period. When additional voltage support is required at Maungatapere or Kaikohe, the most effective solution is likely to be installing capacitors within the distribution system to provide unity or leading power factor.

7.3 Northland demand

The after diversity maximum demand (ADMD) for the Northland region is forecast to grow on average by 1.1% annually over the next 15 years, from 260 MW in 2015 to 310 MW by 2030. This is the same rate as the national average demand growth.

Figure 7-3 shows the historical and forecast demand for the Northland region. The TPR 2015 forecast is derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data, and is used to calculate the real power capacity for power transformers and transmission lines. See Chapter 4 for more information about demand forecasting.
Figure 7-3: Northland region after diversity maximum demand forecast

Table 7-1 lists forecast peak demand (prudent growth) for each grid exit point for the forecast period.

Table 7-1: Forecast annual peak demand (MW) at Northland grid exit points to 2030

<table>
<thead>
<tr>
<th>Grid exit point</th>
<th>Power factor</th>
<th>Peak demand (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bream Bay¹</td>
<td>0.97</td>
<td>55</td>
<td>56</td>
<td>57</td>
</tr>
<tr>
<td>Kaikohe</td>
<td>0.96³</td>
<td>79</td>
<td>79</td>
<td>80</td>
</tr>
<tr>
<td>Maungatapere²</td>
<td>0.97</td>
<td>108</td>
<td>110</td>
<td>112</td>
</tr>
<tr>
<td>Maungaturoto</td>
<td>1.00</td>
<td>19</td>
<td>19</td>
<td>20</td>
</tr>
<tr>
<td>Wellsford</td>
<td>1.00</td>
<td>35</td>
<td>35</td>
<td>36</td>
</tr>
</tbody>
</table>

1. Northpower advised that a 5 MW load increase expected 2015.
2. Maungatapere includes Kensington and Dargarville.
3. This is a leading power factor.

7.4 Northland generation

The Northland region’s generation capacity is approximately 41 MW, well short of the local demand and 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).²

Table 7-2: Forecast annual generation capacity (MW) at Northland grid injection points to 2030 (including existing and committed generation)

<table>
<thead>
<tr>
<th>Grid injection point (location if embedded)</th>
<th>Generation capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td></td>
<td>35</td>
</tr>
</tbody>
</table>

² Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.
Chapter 7: Northland Region

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maungaturoto 33 kV outdoor to indoor conversion</td>
<td>2023-2025</td>
</tr>
<tr>
<td>Wellsford supply transformers expected end-of-life</td>
<td>2018–2020</td>
</tr>
</tbody>
</table>

This may include replacement of the asset due to its condition assessment.
7.7 Changes since the 2014 Transmission Planning Report

Table 7-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year's report.

Table 7-4: Changes since 2014

<table>
<thead>
<tr>
<th>Issues</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marsden interconnecting transformer capacity</td>
<td>Removed, reduced load forecast</td>
</tr>
<tr>
<td>Kensington supply transformer capacity</td>
<td>Removed, assets transferred</td>
</tr>
</tbody>
</table>

7.8 Northland transmission capability

Table 7-5 summarises issues involving the Northland region for the next 15 years. For more information about a particular issue, refer to the listed section number.

Table 7-5: Northland region transmission issues

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional</td>
<td></td>
</tr>
</tbody>
</table>
7.8.1 Upper North Island voltage instability for grid backbone contingencies

**Project status/type:** This issue is for information only

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

**Solution**
We propose to install additional capacitors in the Auckland region to maintain voltage stability margins in the Auckland and Northland regions.

See Chapter 6, Sections 6.3.1 and 6.3.2 for more information.

7.8.2 Kaikohe–Maungatapere 110 kV transmission capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Upgrade transmission capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, customer-specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>To be advised</td>
</tr>
</tbody>
</table>

**Issue**
Two 110 kV Kaikohe–Maungatapere circuits supply Kaikohe providing:
- a total nominal installed capacity of 141/155 MVA (summer/winter), and
- n-1 capacity of 63/77 MVA (summer/winter).

The peak load of Kaikohe may already exceed the transmission n-1 capacity for an outage of a Kaikohe–Maungatapere circuit at Maungatapere when Ngawha is not generating.

**Solution**
The Ngawha generation station is embedded behind the Kaikohe supply bus. If Ngawha is generating near its 25 MW maximum, the issue can be delayed beyond the end of the forecast period. Other short-term options include:
- raising the 110 kV voltage at Kaikohe above minimum requirements by installing reactive support within the distribution network, particularly at Kaitaia, to give a leading power factor
- Top Energy limiting the net peak load to the circuit’s capacity, or
- installing an automatic post-contingency load shedding scheme.

A possible longer-term option is to thermally upgrade the Kaikohe–Maungatapere circuits. Future investment will be customer driven.
7.8.3 Maungaturoto supply transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Protection and metering upgrade, 33 kV outdoor to indoor conversion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2018</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>A</td>
</tr>
</tbody>
</table>

**Issue**

Two 110/33 kV transformers supply Maungaturoto's load, providing:
- a total nominal installed capacity of 50 MVA, and
- n-1 capacity of 20/20 MVA\(^{54}\) (summer/winter).

The peak load at Maungaturoto is forecast to exceed the transformers’ n-1 winter capacity by 1 MW in 2018, increasing to approximately 5 MW in 2030 (see Table 7-6).

**Table 7-6: Maungaturoto supply transformer overload forecast**

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Maungaturoto</td>
<td>1.0</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

Northpower has the ability to control at least 1 MW of load at Maungaturoto that could be used to defer the transformer overload until 2022.

Resolving the protection and metering limits will increase the supply transformer capacity. This will solve the supply transformer capacity issue for the forecast period and beyond.

Additionally, we will convert the Maungaturoto 33 kV outdoor switchyard to an indoor switchboard within the next 10 years. Resolving the protection and metering limits may be undertaken in conjunction with converting the 33 kV outdoor switchyard to an indoor switchboard. We will discuss options for the conversion with Northpower closer to the need date.

7.8.4 Wellsford supply transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Protection and metering upgrade, transformer replacement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>A</td>
</tr>
</tbody>
</table>

**Issue**

Two 110/33 kV transformers supply Wellsford's load, providing:
- a total nominal installed capacity of 60 MVA, and
- n-1 capacity of 32/32 MVA\(^{55}\) (summer/winter).

The peak load at Wellsford already exceeds the transformers’ n-1 winter capacity, and the overload is forecast to increase to approximately 12 MW in 2030 (see Table

---

\(^{54}\) The transformers' capacity is limited by protection and metering limits; with these limits resolved, the n-1 capacity will be 31/33 MVA (summer/winter).

\(^{55}\) The transformers' capacity is limited by protection equipment and metering limits; with these limits resolved, the n-1 capacity will be 37/39 MVA (summer/winter).
Both existing transformers are made up of three single-phase units, with no spare unit on site.

Table 7-7: Wellsford supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Wellsford</td>
<td>1.0</td>
<td>4  4  5  5  6  6</td>
</tr>
</tbody>
</table>

Solution

Vector is investigating upgrade options within their distribution network that will allow the supply transformers’ protection limit to be resolved and enable use of the transformers’ full capacity. This will increase the n-1 capacity to 37/39 MVA (summer/winter), deferring the issue for three years.

Both 110/33 kV transformers at Wellsford have an expected end-of-life within the next five years. We will discuss with Vector the rating and timing for the replacement transformers.

7.9 Northland bus security

This section presents issues arising from the outage of a single bus section rated at 50 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).

7.9.1 Transmission bus security

All 220 kV and 110 kV buses in the Northland region have bus section circuit breakers and bus zone protection. Therefore, a bus fault will trip only half a bus (and connected circuits and transformers). Supply will be maintained through the circuits and transformers connected to the other half bus that did not trip.

7.10 Other regional items of interest

7.10.1 North of Huapai transmission security

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Bus upgrade</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>A</td>
</tr>
</tbody>
</table>

Issue

The Huapai switching station comprises three circuit breakers:
- one on each of the 220 kV circuits connecting Marsden and Bream Bay, and
- a shared circuit breaker for the two incoming 220 kV circuits from Albany and Henderson.

If the shared circuit breaker fails to trip following a fault, both the incoming circuits will trip, leaving the entire load north of Huapai supplied by the low capacity 110 kV Henderson–Maungatapere circuits. This will result in significant load shedding.
The consequence of a failure of the shared circuit breaker is very similar to bus coupler circuit breakers at most other substations (for example Marsden), where a failure will also trip all connected circuits.

Solution

We will monitor this issue and upgrade Huapai when economic to do so.

7.11 Northland 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

7.11.1 Maximum regional generation

The following maximum generation estimates assume a light North Island load profile and that existing generation is high (Ngawha generating 25 MW).

For generation connected at the Maungatapere 110 kV bus, the maximum generation that can be injected under n-1 is approximately 300 MW. Generation is 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 can be injected under n-1 is approximately 560 MW. This constraint is due to the Henderson–Huapai–1 circuit overloading when Albany–Huapai–1 is out of service. This may increase to 750 MW if a substation equipment constraint on this circuit is removed.

7.11.2 Generation injection at Maungatapere

Generation of approximately 300 MW can be connected directly or indirectly to the Maungatapere 110 kV bus. This includes generation at Kaikohe, and for some system configurations, generation connected to the 110 kV Henderson–Maungatapere line (see also Section 7.11.3). Higher levels of generation may be possible by replacing some equipment at substations, upgrading the Marsden interconnection capacity, and thermally upgrading the Henderson–Maungatapere line.

7.11.3 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 approximately 200 MW can be connected, provided a system split is put in place with half the generation transmitted towards Maungatapere and half towards Henderson. In addition, if one circuit is out of service, the generation must be automatically reduced to match the capacity of the remaining circuit.

The two circuits can be thermally upgraded to allow approximately 300 MW of generation, or have replacement conductors to allow even greater generation. Generation transmitted towards Maungatapere forms part of the generation injection limit into Maungatapere (see Section 7.11.2 for more information).
7.11.4 Generation connected to the 220 kV Huapai–Marsden line

There is a 220 kV double-circuit line from Huapai (north of Auckland) to Marsden and Bream Bay (in Northland), which is the main connection to the Northland region. One circuit is predominantly a simplex conductor and the other is a duplex conductor, with ratings of 333/370 MVA and 666/740 MVA\(^{56}\), respectively.

Generation can 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 the generation connects into, with the simplex Bream Bay–Huapai conductor being the limiting component. New generation elsewhere in the Northland region will reduce this limit.

7.11.5 Generation connected to the 220 kV bus at Marsden

For generation connected at the Marsden 220 kV bus, the maximum generation that can be injected under n-1 is approximately 600 MW. The constraint is due to the Bream Bay–Huapai–1 circuit overloading for an outage of the Albany–Huapai–Marsden line.

7.11.6 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 is approximately 275 MW. The constraint is due to one Marsden interconnecting transformer overloading for an outage of the parallel transformer.

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\(^{56}\) The actual circuit rating is presently limited to 457 MVA due to some substation equipment, which is relatively easy and inexpensive to replace in the context of generation connection. Therefore, the limit is ignored in the context of this discussion.
8 Auckland Regional Plan

8.1 Regional overview

This chapter details the Auckland regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

Figure 8-1: Auckland region

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2015 Transmission Planning Report © Transpower New Zealand Limited 2015. All rights reserved.
The Auckland region has some of the highest load densities in New Zealand, coupled with relatively low levels of local generation.

We have assessed the Auckland region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be sufficiently flexible to respond to a range of future service and technology possibilities, taking into consideration:

- the existing transmission network
- forecast demand
- forecast generation
- equipment replacement based on condition assessment, and
- possible technological development.

### 8.2 Auckland transmission system

This section highlights the state of the Auckland regional transmission network. The existing transmission network is set out geographically in Figure 8-1 and schematically in Figure 8-2.
8.2.1 Transmission into the region

As approximately 80% of the Auckland and Northland regions’ peak electricity demand is supplied by generation located south of Bombay, transmission is necessary to keep the energy flowing into Auckland and through to north Auckland and the Northland region.

There are eight high capacity 220 kV circuits from Whakamaru (the generation-rich centre of the North Island) into Auckland, providing:
• adequate transmission capacity within the forecasting period to meet increased load demand and enable new generation to displace the higher cost fossil-fuelled and base load generation in and near Auckland, and
• security by establishing diverse transmission routes that provide two transmission infeeds into the Auckland region, at Otahuhu and Pakuranga.

Transmission into Auckland also requires voltage support to ensure stability, which is provided by static capacitors at Henderson, Hepburn Road, Albany, Otahuhu, Penrose, and Bombay substations. The dynamic reactive support at Albany, Penrose and Marsden helps to relieve voltage stability issues for outages of circuits supplying Auckland or outages of a major generation unit within or near the Auckland region.

8.2.2 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 connecting the two infeeds at Otahuhu and Pakuranga providing increased security and capacity in the region, and
• the other from Otahuhu and Penrose through the Henderson and Albany substations in the North Isthmus providing security to the North Isthmus and the Northland region by establishing diverse transmission routes from various substations.

In addition, the 220 kV cable circuit from Penrose to Albany connects to Vector’s Hobson Street and Wairau Road substations, to provide security and capacity. The 220 kV cable also enables Vector to redistribute load from existing grid exit points, particularly the Albany 110 kV (Wairau Road) and Auckland CBD loads.

The normal operating configuration of the 220 kV cable is for the series reactor at Penrose to be bypassed. This allows greater power flow through the cable, resulting in power infed at the Hobson Street substation. The series reactor is put in service for outages of the 220 kV circuits supplying Northland to balance power flows between the cable and overhead lines.

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 and Penrose. The transformers may be connected through the 110 kV Otahuhu–Penrose circuit57, which operates in parallel with the 220 kV Otahuhu–Penrose double circuit line. The 110 kV network also connects to the Waikato region via a Bombay–Wiri–Otahuhu double-circuit line, with power flow generally south out of Otahuhu.
• The other half has 220/110 kV interconnecting transformers at Otahuhu, Henderson and Albany. The transformers are all connected through the 110 kV network which supplies Mangere and Mount Roskill in a double-circuit ring, extending from Mount Roskill through a double-circuit 110 kV connection to Henderson and Albany. The 110 kV lines operate in parallel with the 220 kV Otahuhu–Henderson–Albany double-circuit lines. Power flow is generally into Mount Roskill on all circuits, from both Otahuhu and the North Isthmus.

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57 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.
Chapter 8: Auckland Region

110 kV distribution network

Vector’s 110 kV distribution network is in parallel with the 220 kV transmission network between Penrose and Hobson Street. There is risk of overloading one of Vector’s Penrose–Liverpool Street cables for an outage of the parallel cable. To prevent this, the Otahuhu—Penrose 110 kV circuit is normally switched out (operating on hot standby).

Vector can also supply the CBD from the Mount Roskill substation via Vector’s Liverpool Street substation. However, this is normally split and is used to enable maintenance outages.

Vector supplies the Auckland CBD load from their Liverpool Street, Hobson and Quay Street substations.

8.2.3 Longer-term development path

We have identified a longer-term development path to address issues involving transmission into, within and through the Auckland region, which will be re-examined when the need arises. The timing of the transmission investments depends on the net load of the Auckland and Northland regions. New generation in the region or demand-side response may defer transmission investment. Similarly, regional generation retirement or increased demand will bring forward the need for transmission investment.

Possible future upgrades include, but are not limited to the following:

- Installing series compensation on the 220 kV Pakuranga–Whakamaru circuits to improve load sharing with the other 220 kV circuits. Ultimately, the Brownhill–Whakamaru section of the Pakuranga–Whakamaru circuits will be upgraded to operate at 400 kV, by installing 400/220 kV transformers at Brownhill and Whakamaru.
- Increasing the transfer capacity into Auckland by building a switching station at Brownhill and cable circuits from Brownhill to Otahuhu.
- Increasing the capacity of the 110 kV circuits between Arapuni and Otahuhu via thermal upgrades or re-conductoring with higher-capacity conductors.
- Transmission reinforcement within the Auckland region via additional 220 kV cable circuits between Pakuranga, Penrose, and Mount Roskill, with a 220/110 kV connection at Mount Roskill.
- Transmission reinforcement to the North Isthmus via a second cable between Penrose and Albany.
- Additional static and dynamic reactive power plant approximately every 8-10 years to ensure power system voltage stability and the maintenance of sufficient reserves to cover the worst transmission contingency. The series compensation on the 220 kV Pakuranga–Whakamaru circuits may be brought forward because of its positive contribution to voltage stability and reduction in transmission losses.

Beyond the next 30 years, new transmission capacity may be required into Auckland, which can be provided by a new 400 kV line, an HVDC link or refurbishment of the existing lines.

The development of the Auckland Unitary plan 58 (particularly in the South Auckland area) will influence future options for increasing transmission capacity into Auckland.

58 Auckland City’s development plan that contains rules for development including what can be built and where it can be built (see [http://unitaryplan.aucklandcouncil.govt.nz/](http://unitaryplan.aucklandcouncil.govt.nz/)).
8.3 Auckland demand

The after diversity maximum demand (ADMD) for the Auckland region is forecast to grow on average by 1.2% annually over the next 15 years, from 2,110 MW in 2015 to 2,520 MW by 2030. This is higher than the national average demand growth of 1.1% annually.

Figure 8-3 shows the historical and forecast demand for the Auckland region. The 2015 TPR forecast is derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data. See Chapter 4 for more information about demand forecasting.

Table 8-1 lists forecast peak demand (prudent growth) for each grid exit point for the forecast period.

### Table 8-1: Forecast annual peak demand (MW) at Auckland grid exit points to 2030

<table>
<thead>
<tr>
<th>Grid exit point</th>
<th>Power factor</th>
<th>Peak demand (MW)</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
<td>2022 2024 2026 2028 2030</td>
</tr>
<tr>
<td>Albany 33 kV</td>
<td>0.99</td>
<td>133 134 136 138 139 141</td>
<td>144 148 152 155 159</td>
</tr>
<tr>
<td>Albany 110 kV</td>
<td>0.98</td>
<td>174 175 177 178 180 181</td>
<td>184 187 190 194 197</td>
</tr>
<tr>
<td>Wairau Road</td>
<td></td>
<td>0.98</td>
<td>174 175 177 178 180 181</td>
</tr>
<tr>
<td>Bombay 33 kV</td>
<td>0.99</td>
<td>13 13 13 14 14 14</td>
<td>143 157 171 185 195</td>
</tr>
<tr>
<td>Bombay 110 kV</td>
<td>0.99</td>
<td>82 89 95 102 109 130</td>
<td>143 157 171 185 195</td>
</tr>
<tr>
<td>(clean bus)</td>
<td></td>
<td>0.99</td>
<td>0 0 0 0 0</td>
</tr>
<tr>
<td>Glenbrook 33 kV</td>
<td>1.00</td>
<td>80 81 82 82 83 84</td>
<td>85 87 88 89 91</td>
</tr>
<tr>
<td>(clean bus)</td>
<td></td>
<td>1.00</td>
<td>0.99 114 116 116 116 116 116</td>
</tr>
<tr>
<td>Henderson</td>
<td>1.00</td>
<td>134 138 141 144 148 151</td>
<td>158 166 173 180 186</td>
</tr>
<tr>
<td>Hepburn Rd</td>
<td>0.99</td>
<td>158 159 160 161 162 163</td>
<td>165 167 169 171 173</td>
</tr>
<tr>
<td>Hobson Street</td>
<td>0.99</td>
<td>111 113 115 118 120 122</td>
<td>127 132 137 142 146</td>
</tr>
<tr>
<td>Mangere 33 kV</td>
<td>0.99</td>
<td>107 109 111 114 116 118</td>
<td>123 127 132 137 141</td>
</tr>
</tbody>
</table>
8.4 Auckland generation

The Auckland region’s generation capacity is approximately 707 MW\(^59\). This generation is less than the region’s peak demand and the deficit is 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 within the relevant local lines company’s network (Vector or Counties Power), and generation retirements.\(^60\)

No new generation is known to be committed in the Auckland region for the forecast period.

Table 8-2: Forecast annual generation capacity (MW) at Auckland grid injection points to 2030 (including existing and committed generation)

<table>
<thead>
<tr>
<th>Grid injection point (location if embedded)</th>
<th>Generation capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Next 5 years 6-15 years out</td>
</tr>
<tr>
<td>Mangere 110 kV</td>
<td>0.88 50 50 50 50 50 50 50 50 50 50 50</td>
</tr>
<tr>
<td>Meremere</td>
<td>0.99 6 6 6 6 6 6 6 6 6 6</td>
</tr>
<tr>
<td>Mt Roskill 22 kV(^1)</td>
<td>0.98 137 138 140 129 131 132 135 138 141 144 147</td>
</tr>
<tr>
<td>Mt Roskill 110 kV - Kingsland feeder(^2)</td>
<td>1.00 73 74 75 76 77 78 80 82 84 86 88</td>
</tr>
<tr>
<td>Mt Roskill 110 kV - Liverpool Street feeder(^3)</td>
<td>1.00 0 0 0 0 0 0 0 0 0 0 0</td>
</tr>
<tr>
<td>Otahuhu</td>
<td>1.00 66 67 68 65 67 68 71 73 76 78 81</td>
</tr>
<tr>
<td>Pakuranga</td>
<td>0.99 154 155 156 160 161 162 163 164 166 167 168</td>
</tr>
<tr>
<td>Penrose 22 kV</td>
<td>0.98 55 56 56 57 58 58 59 60 62 63 64</td>
</tr>
<tr>
<td>Penrose 33 kV</td>
<td>0.99 295 305 310 315 320 325 335 345 355 366 376</td>
</tr>
<tr>
<td>Penrose 110 kV - Liverpool Street(^3)</td>
<td>0.99 111 113 115 118 120 122 127 132 137 142 146</td>
</tr>
<tr>
<td>Silverdale</td>
<td>1.00 89 91 92 94 96 98 102 106 110 113 117</td>
</tr>
<tr>
<td>Takana</td>
<td>1.00 120 121 122 124 125 126 129 131 134 136 139</td>
</tr>
<tr>
<td>Wiri</td>
<td>0.90 86 87 87 88 89 90 92 94 96 97 99</td>
</tr>
</tbody>
</table>

1. Counties Power advised that the 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. Meremere is supplied from the Bombay 33 kV bus. The Meremere load is not included in the Bombay 33 kV load forecast. An 8 MW Tunnel Boring machine will operate behind Mount Roskill until 2018.
5. This includes the Kingsland feeders only.
6. Only used during maintenance and usually unloaded. When loaded the Mt Roskill load is dependent on the load being supplied at Liverpool Street and the CBD network configuration at the time.

\(^59\) Generation capacity will reduce to about 530 MW in 2016 after Southdown decommissioning.

\(^60\) Only generators with capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.
## 8.5 Auckland significant maintenance work

Our capital projects and maintenance works are integrated to enable system issues to be resolved if possible when assets are replaced or refurbished. Table 8-3 lists the significant maintenance-related work proposed for the Auckland region for the next 15 years that may significantly impact related system issues or connected parties.

### Table 8-3: Proposed significant maintenance work

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albany 33 kV outdoor to indoor conversion, and</td>
<td>2015-2017</td>
</tr>
<tr>
<td>Albany 220/110 kV interconnecting transformer expected end-of-life</td>
<td>2023-2025</td>
</tr>
<tr>
<td>Bombay supply transformers expected end-of-life</td>
<td>2021-2023</td>
</tr>
<tr>
<td>Henderson 33 kV outdoor to indoor conversion, and</td>
<td>2014-2016</td>
</tr>
<tr>
<td>Henderson 220/110 kV interconnecting transformers expected end-of-life</td>
<td>2023-2025</td>
</tr>
<tr>
<td>Hepburn Road 33 kV outdoor to indoor conversion</td>
<td>2014-2017</td>
</tr>
<tr>
<td>Mangere 33 kV outdoor to indoor conversion</td>
<td>2018-2019</td>
</tr>
<tr>
<td>Mount Roskill 22 kV outdoor to indoor conversion, and</td>
<td>2015-2017</td>
</tr>
<tr>
<td>Mount Roskill supply transformer T3 expected end-of-life</td>
<td>2019-2020</td>
</tr>
<tr>
<td>Otahuhu–T2 220/110 kV interconnecting transformer expected end-of-life, and</td>
<td>2021-2022</td>
</tr>
<tr>
<td>Otahuhu supply transformers’ expected end-of-life</td>
<td>2019-2022</td>
</tr>
<tr>
<td>Penrose 33 kV outdoor to indoor conversion</td>
<td>2014-2015</td>
</tr>
<tr>
<td>Penrose–T10 220/110 kV interconnecting transformer expected end-of-life</td>
<td>2017-2019</td>
</tr>
<tr>
<td>Penrose 22 kV circuit breaker replacements, and</td>
<td>2022-2024</td>
</tr>
<tr>
<td>Penrose 33 kV circuit breaker replacements</td>
<td>2024-2025</td>
</tr>
<tr>
<td>Takanini 33 kV outdoor to indoor conversion</td>
<td>2017-2019</td>
</tr>
<tr>
<td>Wiri 33 kV outdoor to indoor conversion, and</td>
<td>2017-2019</td>
</tr>
<tr>
<td>Wiri supply transformer expected end-of-life</td>
<td>2021-2023</td>
</tr>
</tbody>
</table>

---

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. Mighty River Power announced the closure of Southdown from the end of 2015.

---

61 This may include replacement of the asset due to its condition assessment.
8.6 Future Auckland transmission configuration

Figure 8-4 shows the possible configuration of Auckland transmission in 2030, with new assets, upgraded assets, and assets undergoing significant maintenance within the forecast period. While we include sections of Vector’s network for clarity, we are making no statement about their future development plans.

Figure 8-4: Possible Auckland transmission configuration in 2030
8.7 Changes since the 2014 Transmission Planning Report

Table 8-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year’s report.

Table 8-4: Changes since 2014

<table>
<thead>
<tr>
<th>Issues</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Henderson Interconnecting transformers</td>
<td>Removed. Albany T4 original unit has been recommissioned resulting in more power flow through Albany.</td>
</tr>
<tr>
<td>Wiri supply transformer capacity</td>
<td>Removed. Load forecast reduced.</td>
</tr>
<tr>
<td>Otahuhu–Penrose 110 kV transmission capacity</td>
<td>Removed. Normal operating configuration bypasses the Penrose reactor resulting in lower power flow on the Otahuhu–Penrose 110 kV circuit. The load forecast in the Auckland CBD has also decreased.</td>
</tr>
<tr>
<td>Otahuhu–Mount Roskill transmission capacity</td>
<td>Removed. Lower load forecast at Mount Roskill.</td>
</tr>
<tr>
<td>Hepburn Road 110 kV bus security</td>
<td>Removed. Lower load forecast results in lower circuit loadings.</td>
</tr>
</tbody>
</table>

8.8 Auckland transmission capability

Table 8-5 summarises issues involving the Auckland region for the next 15 years. For more information about a particular issue, refer to the listed section number.

Table 8-5: Auckland region transmission issues

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional</td>
<td></td>
</tr>
<tr>
<td>8.8.1</td>
<td>Auckland region voltage quality</td>
</tr>
<tr>
<td>8.8.2</td>
<td>Bombay transmission capacity</td>
</tr>
<tr>
<td>8.8.3</td>
<td>Bombay–Wiri–Otahuhu 110 kV transmission capacity</td>
</tr>
<tr>
<td>8.8.4</td>
<td>Otahuhu interconnecting transformer capacity</td>
</tr>
<tr>
<td>Site by grid exit point</td>
<td></td>
</tr>
<tr>
<td>8.8.5</td>
<td>Henderson supply transformer capacity</td>
</tr>
<tr>
<td>8.8.6</td>
<td>Mangere supply transformer capacity</td>
</tr>
<tr>
<td>8.8.7</td>
<td>Mount Roskill supply transformer capacity</td>
</tr>
<tr>
<td>8.8.8</td>
<td>Otahuhu supply transformer capacity</td>
</tr>
<tr>
<td>8.8.9</td>
<td>Penrose 33 kV supply transformer capacity</td>
</tr>
<tr>
<td>8.8.10</td>
<td>Silverdale supply transformer capacity</td>
</tr>
<tr>
<td>8.8.11</td>
<td>Takanini supply transformer capacity</td>
</tr>
<tr>
<td>Bus security</td>
<td></td>
</tr>
<tr>
<td>8.9.1</td>
<td>Transmission bus security</td>
</tr>
</tbody>
</table>

8.8.1 Auckland region voltage quality

| Project status/type: | This issue is for information only |

Issue

As demand grows in the Auckland and Northland regions, regional voltages may deteriorate to a point where the outage of a 220 kV circuit may cause voltage collapse.
Generation located in the Auckland and Northland regions is insufficient to meet reactive power demand. Reactive power from non-generation sources such as shunt capacitors, series capacitors, static synchronous compensators (STATCOM) and static var compensators (SVC) is required to ensure the maintenance of acceptable voltage levels and quality.

**Solution**

Auckland voltage stability is an ongoing issue requiring regular review as the Auckland and Northland regional loads grow, which will take into account the closure of the Southdown generation station.

See Chapter 6, Section 6.3.2 and 6.3.7 for more information.

### 8.8.2 Bombay transmission capacity

**Project status/type:** This issue is for information only

**Issue**

Bombay has an increased load forecast due to proposed housing and commercial developments in the area. The amount of load that can be supplied at Bombay is constrained by the capacity of the circuits supplying Bombay and the generation dispatch patterns both in the Auckland and Waikato regions.

High generation in Auckland and low generation in Waikato is the most constraining scenario with an Otahuhu–Wiri Tee circuit overloading for outage of the parallel Otahuhu–Wiri Tee circuit.

**Solution**

This issue is related to issues involving transmission into Bombay and other issues in the wider Auckland region:

- Bombay–Wiri–Otahuhu 110 kV transmission capacity (Section 8.8.3), and
- Auckland 220/110 kV transformer capacity and security (Section 8.10.1).

The Bombay transmission capacity issue may be partially or wholly resolved by the solutions to these other issues but additional work, such as a new grid exit point may be required.

### 8.8.3 Bombay–Wiri–Otahuhu 110 kV transmission capacity

**Project description:** Upgrade transmission capacity

**Project status/type:** Possible, Base Capex

**Indicative timing:** To be advised

**Indicative cost band:** C

**Issue**

The Wiri load is supplied via double hard tee connection to the two 110 kV Bombay–Wiri–Otahuhu circuits, with the:

- Bombay–Wiri section of each circuit rated at 62/76 MVA (summer/winter)
- Otahuhu–Wiri section of each circuit rated at 92/101 MVA (summer/winter), and
- Wiri–Wiri Tee section of each circuit rated at 92/101 MVA (summer/winter)

There are three issues affecting the Bombay–Wiri–Otahuhu transmission capacity.

- An outage of one of the 110 kV Bombay–Wiri–Otahuhu circuits is forecast to overload the Otahuhu–Wiri section of the remaining circuit during peak load periods from 2015. This will occur during periods of high Auckland generation and low Waikato generation.
• 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 from 2015. The overload occurs due to unequal load sharing of the Wiri supply transformers as the transformers have different characteristics and the Wiri 110 kV bus is split.

• The peak load at Wiri is forecast to exceed the n-1 summer capacity of the Wiri–Wiri Tee section from 2025.

**Solution**

In the short term, Vector can limit Wiri load with future load growth transferred to other grid exit points. Possible longer-term options are:

• a new 110 kV cable from Otahuhu to a new 110/33 kV supply transformer at Wiri

• a new 110/33 kV transformer at Otahuhu and a new 33 kV cable to Wiri

• a new 220/110 kV connection at the Bombay substation on the Huntly–Otahuhu circuit (to reinforce the supply to Wiri), or

• reconductoring the 110 kV Otahuhu–Wiri and the Wiri–Wiri tee sections with a higher capacity conductor.62

Variable line rating is a possible option for managing capacity of the Wiri–Wiri tee section.

Upgrading the Wiri 110 kV to a full bus resolves the capacity issue for Bombay–Wiri section until near the end of the forecast period, when additional reactive support at Bombay is required to address the overload on the Bombay–Wiri section until after the forecast period.

Additionally, the Bombay–Wiri–Otahuhu transmission capacity issue will be investigated as part of a Bombay regional plan. This integrated work plan has begun.

**8.8.4 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:

• a total nominal installed capacity of 300 MVA, and

• n-1 capacity of 135/145 MVA (summer/winter).

Toward the end of the forecast period, the T2 transformer will exceed its post-contingency capacity at peak load times for an outage of the T4 transformer.

**Solution**

The Otahuhu T2 transformer has an expected end-of-life within the next ten years. The Penrose T10, 220/110 kV transformer has an expected end-of-life within the next five years and several other 220/110 kV transformers in the Auckland region have an expected end-of-life within the forecast period. See Section 8.10.1 for more information about managing these transformers.

---

62 Although the Wiri Tee section is only approximately 90 metres long, it crosses over a motorway, which is can complicate an otherwise relatively minor project.
8.8.5 Henderson supply transformer capacity

Project description: Increase supply transformer capacity
Project status/type: Possible, customer-specific
Indicative timing: To be advised
Indicative cost band: B

Issue

Two 220/33 kV transformers supply Henderson’s load, providing:
- a total nominal installed capacity of 240 MVA, and
- n-1 capacity of 135/135 MVA (summer/winter).

The peak load at Henderson is forecast to exceed the transformers’ n-1 winter capacity by approximately 3 MW in 2015, increasing to approximately 55 MW in 2030 (see Table 8-6).

Table 8-6: Henderson supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Henderson</td>
<td>1.00</td>
<td>3</td>
</tr>
</tbody>
</table>

Solution

There is a project underway to convert the Henderson 33 kV outdoor switchgear to an indoor switchboard. This will raise the n-1 limit but will not resolve the issue.

In addition, Vector has the ability to shift load between Henderson and Hepburn Road, providing an operational solution when the issue arises. A longer-term option is to install a third supply transformer. This will be considered in the new indoor switchboard design.

8.8.6 Mangere supply transformer capacity

Project description: Resolve protection limits
Project status/type: Possible, Base Capex
Indicative timing: 2017
Indicative cost band: A

Issue

Two 110/33 kV transformers supply Mangere’s load, providing:
- a total nominal installed capacity of 240 MVA, and
- n-1 capacity of 118/118 MVA (summer/winter).

The peak load at Mangere is forecast to exceed the transformers’ n-1 winter capacity by 2 MW in 2017, increasing to approximately 32 MW in 2030 (see Table 8-7).

Table 8-7: Mangere supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid</th>
<th>Power</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
</table>

---

63 The transformers’ capacity is limited by a bus section, circuit breaker and disconnector; with these limits resolved, the n-1 capacity will be 144/150 MVA (summer/winter).

64 The transformers’ capacity is limited by a protection equipment limit; with this limit resolved, the n-1 capacity will be 138/144 MVA (summer/winter).
8.8.7 Mount Roskill supply transformer capacity

Project status/type: This issue is for information only

Solution

We are investigating the option of increasing the protection limits on these transformers.

In addition, we also plan to convert the Mangere 33 kV outdoor switchgear to an indoor switchboard within the next five years.

Future development options to increase transformer capacity for this grid exit point will be customer driven.

8.8.8 Otahuhu supply transformer capacity

Project description: Replace supply transformer, capacity increase.

Project status/type: Possible, customer-specific

Indicative timing: To be advised

The transformers’ capacity is limited by a circuit breaker limit on the 50 MVA transformer and relay limits on the 70 MVA transformers; with auxiliary equipment limits resolved, the n-1 capacity will be 145/152 MVA (summer/winter).
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**Indicative cost band:** B

**Issue**

Two 220/22 kV transformers supply Otahuhu’s load, providing:
- a total nominal installed capacity of 100 MVA, and
- n-1 capacity of 59/59 MVA\(^66\) (summer/winter).

The peak load at Otahuhu is forecast to exceed the n-1 winter capacity by 8 MW in 2015, increasing to approximately 23 MW in 2030 (see Table 8-9).

### Table 8-9: Otahuhu supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Otahuhu</td>
<td>1.00</td>
<td>8</td>
</tr>
</tbody>
</table>

**Solution**

Upgrading the LV cable and removing the bushing constraints on the supply transformers will not resolve the issue.

We will discuss other options with Vector, which include:
- limiting peak load to the firm transformer capacity, with future load growth transferred to other grid exit points
- adding a third supply transformer, or
- replacing the two existing supply transformers with higher-rated units.

Both supply transformers have an expected end-of-life within the forecast period. We will discuss the ratings and timing for the replacement transformers with Vector. Further development options to increase the transformer capacity for this grid exit point will be customer driven.

8.8.9 **Penrose 33 kV supply transformer capacity**

**Project status/type:** This issue is for information only

**Issue**

Three 220/33 kV transformers (two rated at 200 MVA and one at 160 MVA) supply Penrose’s load, providing:
- a total nominal installed capacity of 560 MVA, and
- n-1 capacity of 429/450 MVA (summer/winter).

The peak load at Penrose is forecast to exceed the transformers’ n-1 winter capacity by approximately 7 MW in 2022, increasing to approximately 51 MW in 2030 (see Table 8-10).

### Table 8-10: Penrose supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Penrose</td>
<td>0.99</td>
<td>0</td>
</tr>
</tbody>
</table>

\(^{66}\) The transformers’ capacity 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).
Solution

We are discussing future development options for this connection point with Vector. It is expected that the peak load will be limited to the firm transformer capacity. Vector has announced plans to build a new zone substation at Newmarket that will increase loading on the Penrose 33 kV bus and are investigating diversification of the load at Penrose through a new grid exit point at Southdown.

A 220/33 kV system spare supply transformer is located at Penrose. This allows us to manage outages of the existing three supply transformers for the next 15 years. This does not affect the firm capacity because only three of the four transformers are permanently connected.

Additionally, there is a project underway to convert the Penrose 33 kV outdoor switchyard to an indoor switchboard.

8.8.10 Silverdale supply transformer capacity

**Project description:** Resolve supply transformer metering constraints

**Project status/type:** Possible, Base Capex

**Indicative timing:** 2026

**Indicative cost band:** A

**Issue**

Two 110/33 kV transformers supply Silverdale’s load, providing:

- a total nominal installed capacity of 220 MVA, and
- n-1 capacity of 109/109 MVA\(^{67}\) (summer/winter).

The peak load at Silverdale is forecast to exceed the transformers’ n-1 winter capacity by approximately 3 MW in 2026, increasing to approximately 10 MW in 2030 (see Table 8-11).

**Table 8-11: Silverdale supply transformer overload forecast**

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Silverdale</td>
<td>1.00</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

Recalibrating the metering parameters resolves the issue for the forecast period and beyond.

8.8.11 Takanini supply transformer capacity

**Project description:** Upgrade transformer branch limiting components

**Project status/type:** Possible, Base Capex

**Indicative timing:** 2017-2019

**Indicative cost band:** Upgrade transformer branch limiting components: A

**Issue**

Two 220/33 kV transformers supply Takanini’s load, providing:

- a total nominal installed capacity of 300 MVA, and
- n-1 capacity limit of 126/126 MVA\(^{68}\) (summer/winter).

---

\(^{67}\) The transformers’ capacity is limited by a metering limit, followed by a cable limit (120 MVA); with these limits resolved, the n-1 capacity will be 126/132 MVA (summer/winter).
The peak load at Takanini is forecast to exceed the transformers’ n-1 winter capacity by 1 MW in 2017, increasing to approximately 18 MW in 2030 (see Table 8-12).

Table 8-12: Takanini supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Next 5 years</td>
<td>6-15 years out</td>
</tr>
<tr>
<td>Takanini</td>
<td>1.00</td>
<td>0 0 1 3 4 5</td>
</tr>
<tr>
<td></td>
<td></td>
<td>8 10 13 15 18</td>
</tr>
</tbody>
</table>

Solution

Vector has advised that they expect to keep peak load within the transformers’ n-1 capacity for several years.

The Takanini 33 kV outdoor switchyard will be converted into an indoor switchboard within the next five years. Upgrading the protection in conjunction with the 33 kV conversion provides sufficient capacity beyond the forecast period.69

The equipment configuration is also unusual for the high level of load forecast for Takanini. Typically, two transformers are used to supply a maximum of 120 MW to 150 MW of load70, after which a third transformer will be installed. It is expected that a third supply transformer will be required within the forecast period. This also requires converting the two transformers’ double tee connection to the 220 kV circuits to a full bus with bus section circuit breakers.

Further development options to increase the transformer capacity for this grid exit point will be customer driven.

8.9 Auckland bus security

This section presents issues arising from the outage of a single bus section rated at 50 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).

8.9.1 Transmission bus security

Table 8-13 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 8-13: Transmission bus outages

<table>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bombay 110 kV</td>
<td>Bombay 33 kV</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td></td>
<td>Meremere</td>
<td>-</td>
<td>-</td>
<td>See note 2</td>
</tr>
<tr>
<td>Mount Roskill 110 kV</td>
<td>Mount Roskill 110 kV</td>
<td>-</td>
<td>-</td>
<td>See note 3</td>
</tr>
<tr>
<td></td>
<td>Mount Roskill 22 kV</td>
<td>-</td>
<td>-</td>
<td>See note 3</td>
</tr>
</tbody>
</table>

68 The transformers’ capacity is limited by protection equipment limit, followed by the circuit breaker (137 MVA) and 33 kV bus (137 MVA) limits; with these limits resolved, the n-1 capacity will be 188/198 MVA (summer/winter).
69 The 33 kV equipment will have an unusually high capacity rating
70 The Takanini load is forecast to reach 120 MW in 2015 and 150 MW after 2030.
Chapter 8: Auckland Region

8.8.3

1. Bombay has two 110 kV bus sections. However, both Bombay supply transformers are connected to the same 110 kV bus section.

2. Meremere is supplied from the Bombay 33 kV, so issues affecting Bombay also affects Meremere.

3. We will investigate the option of a 110 kV bus coupler to alleviate the risk of total loss of supply in the event of a bus fault.

The customers (Counties Power, Vector, or Mighty River Power) have not requested a higher security level (except for the Mount Roskill 110 kV bus). 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.

8.10 Other regional items of interest

8.10.1 Auckland 220/110 kV transformer capacity and security

<table>
<thead>
<tr>
<th>Project description</th>
<th>Replace 220/110 kV transformers.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band</td>
<td>B for each new replacement transformer</td>
</tr>
</tbody>
</table>

Ten 220/110 kV transformers supply the 110 kV network in the Auckland region. Two of these transformers, Otahuhu T2 and Penrose T10, are nearing their expected end-of-life within the next ten years. The Albany T4 transformer, Henderson T1 and T5 transformers, and Otahuhu T4 transformer will also reach their expected end-of-life within the forecast period.

In addition, toward the end of the forecast period, the Otahuhu T2 transformer will exceed its post-contingency rating at peak load times for an outage of the Otahuhu T4 transformer (see Section 8.8.4).

A number of significant upgrade projects in the Auckland region that directly or indirectly affect the 220/110 kV transformers were completed in the last few years. The projects with the most significant effects on the Auckland 110 kV network include:

- converting the Pakuranga grid exit point from 110/33 kV to 220/33 kV, removing load from the 110 kV network
- the 220 kV cable circuits from Pakuranga to Penrose and onto Albany (via Hobson Street and Wairau Road)
- the new Hobson Street 220/110 kV grid exit point, with a connection through Vector’s 110 kV network to the Penrose 110 kV bus, and
- the new Wairau Road 220/33 kV grid exit point, removing some load from the 110 kV network.

The 110 kV network in the Auckland region is also normally operated with a number of system splits to give better load distribution and manage fault levels.

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%), and
- Hobson Street T12 (250 MVA, 15%).

---

71 The ten 220/110 kV transformers in the Auckland region are:
The next phase for the evolution of the power system within the Auckland region is an investigation to determine options for a long term development path to manage the 220/110 kV end-of-life transformers. Options include combinations of the following:

- Decommissioning transformer(s) and not replacing them immediately.
- Grid reconfigurations.
- A 220/110 kV interconnection at Bombay (see Section 8.8.2).
- Better utilisation of the existing 220/110 kV, 250 MVA system spare transformer.
- Extending the lives of the existing transformers.
- Replacement transformers, with timing and location dependent on load growth and the security standard.

The long-term development path should allow the most efficient use of transmission and distribution assets across all the substations in the Auckland region.

8.11 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

8.11.1 Maximum regional generation

The Auckland region has some of the highest load densities in New Zealand, coupled with relatively low levels of local generation, and 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 a substation or along an existing line due to the rating of the existing circuits.

8.11.2 Auckland generation issues

There are numerous inter-related issues with supplying the load within the Auckland region, as discussed earlier in this chapter. In addition, the increase in fault level due to generators will be an issue for some parts of the transmission and/or distribution systems.

The complexity of the region means that the impact of new generation will entirely depend on where it connects. Therefore, new generation within the Auckland region may assist in addressing an issue, make it worse, have no effect, or may require specific additional transmission investment to enable connection. Fault-level issues may also preclude new generation connection in some locations.
Chapter 9: Waikato Region

9 Waikato Regional Plan

9.1 Regional overview

This chapter details the Waikato regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

Figure 9-1: Waikato region
Chapter 9: Waikato Region

The Waikato region comprises two distinct transmission networks, 110 kV and 220 kV, of which the 220 kV network forms part of the grid backbone. The 220 kV circuits enter the region from Stratford, Tokaanu, and Wairakei. The 110 kV circuits enter the region from Tarukenga to Kinleith, and from Ongarue to Hangatiki. The northern boundary is crossed by the:

- 220 kV circuits from Huntly, Ohinewai, and Whakamaru, and
- 110 kV circuits from Hamilton and Arapuni.

We have assessed the Waikato region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be sufficiently flexible to respond to a range of future service and technology possibilities, taking into consideration:

- the existing transmission network
- forecast demand
- forecast generation
- equipment replacement based on condition assessment, and
- possible technological development.

9.2 Waikato transmission system

This section highlights the state of the Waikato regional transmission network. The existing transmission network is set out geographically in Figure 9-1 and schematically in Figure 9-2.

Figure 9-2: Waikato transmission schematic
9.2.1 Transmission into the region

This region's generation contributes a significant portion of total North Island generation and exceeds local demand. Surplus generation is exported over the 220 kV transmission network to the rest of the country. The 220 kV transmission network has enough capacity to provide n-1 security to the local load indefinitely.

9.2.2 Transmission within the region

The 110 kV transmission network within the region predominantly supplies and connects the rest of the Waikato region, including most of the regional load and some regional generation.

Transmission system issues

The 110 kV transmission network predominantly comprises low capacity circuits. Even with all circuits in service, there are still security issues at grid exit points and generation restrictions, particularly at Arapuni and Kinleith, and also within the Auckland region.

Maintenance security issues

The 220/110 kV interconnection at Hamilton supplies most of the load in the Waikato region. The outage of a 220 kV circuit to Hamilton or a 220/110 kV interconnecting transformer at Hamilton will place many grid exit points in the region on n security. We will consider options to increase the security of this interconnection to provide full or partial n-1 security.

9.2.3 Longer-term development path

We will continue to resolve the short and long-term issues in the region, including the:

- Waikato 110 kV transmission network (the 110 kV circuits that operate in parallel with the grid backbone between Tarukenga and Bombay)
- 110 kV Thames Valley spur (connecting Piako, Waihou, Waikino, and Kopu), and
- Hamilton interconnecting transformer capacity and maintenance security.

Additionally, in order to meet high load growth in the Tauranga area, one option is a transmission connection between Waihou and a new grid exit point north of Tauranga.

The following projects represent possible grid backbone developments through the Waikato region:

- installing series capacitors on the 220 kV Brownhill–Whakamaru circuits (likely within the forecast period).
- converting the 220 kV Brownhill–Whakamaru circuits to 400 kV operation by installing 400/220 kV interconnecting transformers at Brownhill and Whakamaru (likely beyond the forecast period).

9.3 Waikato demand

The after diversity maximum demand (ADMD) for the Waikato region is forecast to grow on average by 1.2% annually over the next 15 years, from 620 MW in 2015 to 740 MW by 2030. This is higher than the national average demand growth of 1.1% annually.
Chapter 9: Waikato Region

Figure 9-3 shows a comparison of the 2014 and 2015 TPR forecast 15-year maximum demand (after diversity\textsuperscript{72}) for the Waikato region. The forecasts are derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data. See Chapter 4 for more information about demand forecasting.

Figure 9-3: Waikato region after diversity maximum demand forecast

Table 9-1 lists forecasts peak demand (prudent growth) for each grid exit point for the forecast period.

Table 9-1: Forecast annual peak demand (MW) at Waikato grid exit points to 2030

<table>
<thead>
<tr>
<th>Grid exit point</th>
<th>Power factor</th>
<th>Next 5 years</th>
<th>Peak demand (MW)</th>
<th>6-15 years out</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cambridge</td>
<td>0.98</td>
<td>43</td>
<td>44</td>
<td>44</td>
<td>45</td>
</tr>
<tr>
<td>Hamilton 11 kV</td>
<td>1.00</td>
<td>39</td>
<td>39</td>
<td>40</td>
<td>40</td>
</tr>
<tr>
<td>Hamilton 33 kV\textsuperscript{1}</td>
<td>0.99</td>
<td>141</td>
<td>143</td>
<td>144</td>
<td>146</td>
</tr>
<tr>
<td>Hamilton NZR</td>
<td>0.79</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>Hangatiki</td>
<td>0.91</td>
<td>34</td>
<td>35</td>
<td>36</td>
<td>35</td>
</tr>
<tr>
<td>Hinuera\textsuperscript{2,6}</td>
<td>0.94</td>
<td>49</td>
<td>48</td>
<td>48</td>
<td>31</td>
</tr>
<tr>
<td>Huntly</td>
<td>1.00</td>
<td>27</td>
<td>28</td>
<td>28</td>
<td>28</td>
</tr>
<tr>
<td>Kinleith 11 kV</td>
<td>0.86</td>
<td>83</td>
<td>83</td>
<td>83</td>
<td>83</td>
</tr>
<tr>
<td>Kinleith 33 kV</td>
<td>0.98</td>
<td>20</td>
<td>20</td>
<td>21</td>
<td>21</td>
</tr>
<tr>
<td>Kopu</td>
<td>1.00</td>
<td>50</td>
<td>51</td>
<td>52</td>
<td>53</td>
</tr>
<tr>
<td>Lichfield\textsuperscript{4}</td>
<td>0.95</td>
<td>9</td>
<td>17</td>
<td>17</td>
<td>18</td>
</tr>
<tr>
<td>Piako\textsuperscript{5}</td>
<td>0.96</td>
<td>34</td>
<td>37</td>
<td>38</td>
<td>38</td>
</tr>
<tr>
<td>Putaruru\textsuperscript{2}</td>
<td>1.00</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>18</td>
</tr>
<tr>
<td>Te Awamutu</td>
<td>0.99</td>
<td>39</td>
<td>39</td>
<td>39</td>
<td>39</td>
</tr>
<tr>
<td>Te Kowhai\textsuperscript{1,4}</td>
<td>0.98</td>
<td>94</td>
<td>95</td>
<td>96</td>
<td>97</td>
</tr>
</tbody>
</table>

\textsuperscript{72} The after diversity maximum demand (ADMD) for the region will be less than the sum of the individual grid exit point peak demands, as it takes into account the fact that the peak demand does not occur simultaneously at all the grid exit points in the region.
Chapter 9: Waikato Region

9.4 Waikato generation

The Waikato region’s generation capacity is 2,201 MW. This generation exceeds the local demand and surplus generation is exported over the National Grid to other demand centres.

Table 9-2 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 (Waipa Networks, WEL Networks, The Lines Company or Powerco).73

Table 9-2: Forecast annual generation capacity (MW) at Waikato grid injection points to 2030 (including existing and committed generation)

<table>
<thead>
<tr>
<th>Grid exit point (location if embedded)</th>
<th>Power factor</th>
<th>Next 5 years</th>
<th>Peak demand (MW)</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Waihou</td>
<td>0.99</td>
<td>49</td>
<td>50</td>
<td>51</td>
</tr>
<tr>
<td>Waikino</td>
<td>0.99</td>
<td>38</td>
<td>38</td>
<td>39</td>
</tr>
</tbody>
</table>

1. There is frequent and regular load shifting between Hamilton and Te Kowhai.
2. Some load will be shifted from Hinuera to a proposed new grid exit point at Putaruru in 2018.
3. New load added from 2016 – Lichfield new drier, 8 MW.
4. New load added from 2015 – mining, 3 MW.
5. Load shift from 2016 – some Waharoa load shifted from Hinuera to Piako, 2 MW.

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73 Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.
9.5 Waikato significant maintenance work

Our capital projects and maintenance works are integrated to enable system issues to be resolved if possible when assets are replaced or refurbished. Table 9-3 lists the significant maintenance-related work\(^7^4\) proposed for the Waikato region for the next 15 years that may significantly impact related system issues or connected parties.

Table 9-3: Proposed significant maintenance work

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arapuni–Ongarue–A line reconductoring (Arapuni–Rangitoto section)</td>
<td>2020-2022</td>
</tr>
<tr>
<td>Hamilton–T5 supply transformer expected end-of-life</td>
<td>2022-2024</td>
</tr>
<tr>
<td>Hangatiki–T1 and T2 supply transformers’ expected end-of-life, and</td>
<td>2021-2023</td>
</tr>
<tr>
<td>Hangatiki 33 kV outdoor to indoor conversion</td>
<td>2021-2023</td>
</tr>
<tr>
<td>Hangatiki–T1 and T2 supply transformers’ expected end-of-life</td>
<td>2021-2023</td>
</tr>
<tr>
<td>Kinleith 11 kV indoor switchboard replacement</td>
<td>2015-2018</td>
</tr>
<tr>
<td>Kinleith 33 kV indoor switchboard replacement (possible, not proposed)</td>
<td>2015-2018</td>
</tr>
<tr>
<td>Kinleith 110/11 kV supply transformers (all) expected end-of-life</td>
<td>2016-2018</td>
</tr>
<tr>
<td>Kinleith 110/33 kV supply transformer replacement, and</td>
<td>2016-2018</td>
</tr>
<tr>
<td>Kinleith 110 kV bus refurbishment / replacement</td>
<td>2016-2019</td>
</tr>
<tr>
<td>Waihou 33 kV outdoor to indoor conversion, and</td>
<td>2016-2018</td>
</tr>
<tr>
<td>Waihou supply transformers’ expected end-of-life</td>
<td>2016-2018</td>
</tr>
<tr>
<td>Waihou supply transformers’ expected end-of-life</td>
<td>2016-2018</td>
</tr>
<tr>
<td>Waikino supply transformers’ expected end-of-life, and</td>
<td>2020-2022</td>
</tr>
<tr>
<td>Waikino 33 kV outdoor to indoor conversion</td>
<td>2020-2022</td>
</tr>
</tbody>
</table>

9.6 Future Waikato transmission configuration

Figure 9-4 shows the possible configuration of Waikato transmission in 2030, with new assets, upgraded assets, and assets undergoing significant maintenance within the forecast period.

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\(^{74}\) This may include replacement of the asset due to its condition assessment.
9.7 Changes since the 2014 Transmission Planning Report

Table 9-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year’s report.

Table 9-4: Changes since 2014

<table>
<thead>
<tr>
<th>Issues</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Piako transmission security</td>
<td>Removed. Second Piako connection commissioned.</td>
</tr>
<tr>
<td>Waihou transformer capacity</td>
<td>Added. Higher load forecast at Waihou.</td>
</tr>
<tr>
<td>Te Kowhai substation development</td>
<td>Removed. Lower load forecast in Hamilton.</td>
</tr>
<tr>
<td>Kinleith–Tarukenga transmission capacity</td>
<td>Combined with Arapuni–Kinleith 110 kV transmission capacity.</td>
</tr>
</tbody>
</table>

9.8 Waikato transmission capability

Table 9-5 summarises issues involving the Waikato region for the next 15 years. For more information about a particular issue, refer to the listed section number.

Table 9-5: Waikato region transmission issues

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional</td>
<td></td>
</tr>
<tr>
<td>9.8.1</td>
<td>Arapuni–Hamilton 110 kV transmission capacity</td>
</tr>
<tr>
<td>9.8.2</td>
<td>Arapuni–Kinleith–Tarukenga 110 kV transmission capacity</td>
</tr>
<tr>
<td>9.8.3</td>
<td>Hamilton interconnecting transformer capacity</td>
</tr>
<tr>
<td>9.8.4</td>
<td>Hamilton–Piako–Waihou 110 kV transmission capacity</td>
</tr>
</tbody>
</table>
9.8.1 Arapuni–Hamilton 110 kV transmission capacity

**Project status/type:** This issue is for information only

**Issue**

The two 110 kV Arapuni–Hamilton circuits are each rated at 51/62 MVA (summer/winter).

A cost benefit analysis showed the most economic normal system configuration is to split the Arapuni 110 kV bus. The normal split for the Arapuni 110 kV bus currently comprises two bus sections:

- Arapuni G1-4 generators, Arapuni–Bombay–1, Arapuni–Hamilton–1 and 2, Arapuni–Hangatiki–1, and the Arapuni–Ongarue–1 circuits on the north bus, and
- Arapuni–Kinleith–1 and 2 circuits on the south bus
- The Arapuni G5-8 generators are selectable between the north and south bus sections.

With the Arapuni bus split:

- Arapuni north bus generation may be constrained pre-contingency to manage the loading on an Arapuni–Hamilton circuit for an outage of the other Arapuni–Hamilton circuit, and
- the Arapuni runback scheme is enabled on Arapuni G1-4 to reduce generation if an Arapuni–Hamilton circuit overloads.

When the new Putaruru grid exit point is connected in 2018 (see Section 9.8.10) the Arapuni bus may need to be normally solid (as opposed to split) to manage the loading on the 110 kV circuits between Arapuni and Tarukenga (see Section 9.8.2).

With a solid Arapuni bus:
Arapuni generation may experience greater pre-contingency constraints to manage the loading on a 110 kV Arapuni–Hamilton circuit for an outage of the other Arapuni–Hamilton circuit or the 220 kV Hamilton–Whakamaru circuit.

- the Arapuni runback scheme is enabled on all Arapuni generators to reduce generation if an Arapuni–Hamilton circuit overloads.
- the operation of the Arapuni runback scheme for an outage of the 220 kV Hamilton–Whakamaru circuit may overload the Lichfield–Tarukenga circuit (see Section 9.8.2).
- there are additional minimum and maximum constraints on Arapuni generation to reduce loading to within circuit capacity on the circuits between Arapuni and Tarukenga (see Section 9.8.2), and
- the worst case conditions occur during peak load periods with moderate to low thermal generation north of Whakamaru.

In addition, the Arapuni bus must be made solid for some maintenance outages, which will become increasingly difficult to arrange because of generation and load constraints. Even if the Arapuni bus split is retained, additional 110 kV disconnectors will be required to facilitate maintenance outages and reduce the restoration time following equipment faults.

With the Arapuni bus solid there is a high risk that we will need to constrain Auckland region generation with increasing frequency to the extent that it may become impractical to expect generation to be available at all times when we need it.

**Solution**

With the Arapuni bus split, issues with the Arapuni–Hamilton transmission capacity can be managed operationally. However, this will cause issues with the Arapuni–Kinleith–Tarukenga transmission capacity.

After connection of the new Putaruru grid exit point (see Section 9.8.10), closing the Arapuni bus split and operating the new Hangatiki–Te Awamutu circuit closed (see Section 9.8.16) will partially relieve but not resolve the issue with the Arapuni–Hamilton transmission capacity. Issues with the Arapuni–Kinleith–Tarukenga transmission capacity will remain.

A preliminary assessment of the Investment Test indicates that reconductoring the 110 kV Arapuni–Hamilton circuits (and possibly also the Arapuni–Bombay circuits) to remove the overload is unlikely to be economic. A condition assessment shows that the existing conductor will not require replacement within the forecast period.

The Arapuni–Hamilton transmission capacity issue is driven mainly by the Arapuni–Kinleith–Tarukenga transmission capacity issue and the solutions are described in more detail in Section 9.8.2 (with an overview in Section 9.10.1).

### 9.8.2 Arapuni–Kinleith–Tarukenga 110 kV transmission capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Special Protection Schemes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Variable line ratings</td>
</tr>
<tr>
<td></td>
<td>Reconductor 110 kV circuits</td>
</tr>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex / Major Capex Project</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>Special Protection Schemes – A</td>
</tr>
<tr>
<td></td>
<td>Variable line ratings – A</td>
</tr>
<tr>
<td></td>
<td>Reconductor 110 kV circuits – C</td>
</tr>
</tbody>
</table>

**Issue**

Kinleith and Lichfield are supplied through the following 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), and
• Kinleith–Lichfield–Tarukenga–2 rated at 63/77 MVA (summer/winter)

**Figure 9-5: Arapuni–Kinleith–Tarukenga 110 kV configuration**

The loading on the Arapuni–Kinleith and Kinleith–Lichfield–Tarukenga circuits may exceed their n-1 capacity under certain operating conditions.

The connection of new load at Lichfield from 2016 and Putaruru from 2018 will progressively make the circuit capacity issues worse and more complex to manage operationally.

With the Arapuni bus split:

- generation at Kinleith and Arapuni must be managed so the:
  - minimum generation at Kinleith and Arapuni is high enough to prevent the Lichfield–Tarukenga circuits exceeding their n-1 capacity, and
  - maximum generation at Arapuni is low enough to prevent the Arapuni–Kinleith circuits exceeding their n-1 capacity.
- when the load increase at Lichfield occurs in 2016, there will be minimum generation requirements at Kinleith during high load periods
- when the new Putaruru grid exit point is connected in 2018, the minimum generation requirement at Kinleith and Arapuni becomes difficult to manage and may become unmanageable if the full capacity of either generating station is unavailable.

With the Arapuni bus solid after the connection of the Putaruru grid exit point in 2018, the:

- Lichfield–Tarukenga circuits may overload for an outage of the 220 kV Hamilton–Whakamaru circuit; this issue may be exacerbated by the Arapuni runback operating to reduce loading on the Arapuni–Hamilton circuits (see Section 9.8.1).
- Lichfield–Tarukenga circuit may overload for an outage of the other Kinleith–Lichfield–Tarukenga circuit with low generation at Arapuni and Kinleith.
- Arapuni–Kinleith or Arapuni–Putaruru circuit may overload for an outage of the other circuit with high Arapuni generation.
- worst conditions occur during summer peak load periods with moderate to low thermal generation in the Auckland region.

**Solution**

In the short term, the loading on these circuits will continue to be managed operationally.

While we are investigating possible alternative options, we are also investigating several interim options to manage the Arapuni–Kinleith–Lichfield–Tarukenga transmission capacity issues, which all assume there is a special protection scheme to automatically prompt Powerco to transfer load from Putaruru to Hinuera as the first
action to prevent overloading\textsuperscript{75}. These interim options include some or all of the following:

- Keep the Arapuni bus split and apply variable line ratings on the Kinleith–Tarakenga–Lichfield circuits to ease limits on generation.
- Keep the Arapuni bus split, replace the existing Arapuni–Kinleith special protection scheme with a second Arapuni generation runback scheme to allow more generation on the Arapuni South bus pre-contingency.
- Install a special protection scheme at Tarukenga to manage load at Putaruru, Lichfield, and Kinleith post-contingency.

We will investigate a range of longer-term options to resolve the capacity issues between Arapuni and Tarukenga. The options include making the Arapuni bus solid and reconductoring the:

- 110 kV Arapuni–Kinleith circuits, and normally splitting the 110 kV system between Kinleith and Lichfield, or
- 110 kV Kinleith–Lichfield–Tarukenga circuits, and installing a special protection scheme at Arapuni to manage loading on the Arapuni–Kinleith circuits.

Acquisition of property easements may be required for reconductoring work in some cases.

\textbf{9.8.3 Hamilton interconnecting transformer capacity}

<table>
<thead>
<tr>
<th>Project description</th>
<th>New interconnecting transformer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band</td>
<td>B</td>
</tr>
</tbody>
</table>

\textbf{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:

- a total nominal installed capacity of 420 MVA, and
- n-1 capacity of 243/243 MVA\textsuperscript{76} (summer/winter).

During low 110 kV generation in Waikato (Arapuni and Karapiro generation) and high Waikato demand, the load on the Hamilton interconnecting transformers may exceed their n-1 capacity. This overloading issue worsens with low Upper North Island generation.

\textbf{Solution}

In the short term, we anticipate this issue will be managed operationally with generation rescheduling and load management.

Long-term options to address this issue include a new 220/110 kV transformer:

- in parallel with the existing transformers, or
- at a new substation, connected to the intersection of the 220 kV Otahuhu–Whakamaru C line and the 110 kV Hamilton–Waihou A line.

\textsuperscript{75} When the new Putaruru substation is connected we intend to install a special protection scheme on the Arapuni–Kinleith circuits to reduce loading on these circuit post-contingency by automatically prompting Powerco to transfer load away from Putaruru. If the load is not reduced sufficiently within a specific time frame, the scheme will trip the load at Putaruru.

\textsuperscript{76} The transformers’ capacity is limited by protection equipment; with this limit resolved, the n-1 capacity will be 248/259 MVA (summer/winter).
The second option improves security during maintenance outages of the 220 kV circuits supplying Hamilton, and forms the connection point for a third circuit to Waihou (instead of a Hamilton connection, see Section 9.8.4 for more information).

9.8.4 Hamilton–Piako–Waihou 110 kV transmission capacity

<table>
<thead>
<tr>
<th>Project description</th>
<th>Increase Hamilton–Piako–Waihou transmission capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type</td>
<td>Possible, customer-specific</td>
</tr>
<tr>
<td>Indicative timing</td>
<td>2021</td>
</tr>
<tr>
<td>Indicative cost band</td>
<td>C or D</td>
</tr>
</tbody>
</table>

**Issue**

Two 110 kV Hamilton–Piako–Waihou circuits supply the Thames Valley Spur, each circuit having a summer/winter capacity of 154/168 MVA. Valley Spur summer and winter peak loads are increasingly similar, with 2014 peaks of approximately 122 MW and 129 MW, respectively.

The peak load on the Valley Spur is forecast to exceed the circuits’ n-1 winter capacity by approximately 6 MW in 2022, increasing to approximately 31 MW in 2030 (see Table 9-6). The circuit overloading issue will only occur between Hamilton and Piako within the forecast period.

Low voltage along the Valley Spur exacerbates the transmission loading issue (see Section 9.8.5 for more information).

**Table 9-6: Valley Spur circuit overload forecast**

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Circuit overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Valley Spur</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

We will investigate the installation of capacitors to relieve the Valley Spur low voltage issues (see Section 9.8.5 for more information). This provides an interim solution to the Hamilton–Piako circuits’ capacity issue, delaying the need for further transmission reinforcement by approximately two years.

In the short-term, the overload can be managed operationally.

Possible longer-term options include:

- constructing a third 110 kV Hamilton–Waihou circuit of a similar capacity to the existing circuits, or
- upgrading the existing 110 kV Hamilton–Piako circuits to increase their summer capacity.

The timing and choice of the capacity reinforcement option will be influenced by load growth and developments within Powerco’s network, such as load transfer from the Valley Spur to the Hinuera grid exit point (see Section 9.8.9). Future investment will be customer driven.

Depending on the solution, we may need to purchase easements for either a new line or for some parts of an upgraded line.

9.8.5 Piako–Waihou–Waikino–Kopu spur low voltage

<table>
<thead>
<tr>
<th>Project description</th>
<th>New capacitors</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Replace Waihou supply transformer</td>
</tr>
<tr>
<td></td>
<td>Replace Waikino supply transformer</td>
</tr>
</tbody>
</table>
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#### Project status/type:
- New capacitors: possible, customer-specific
- Replace Waihou and Waikino supply transformers: possible, Base Capex

#### Indicative timing:
- New capacitors: TBA
- Replace supply transformers: 2020-2024

#### Indicative cost band:
- New capacitors: A
- Replace Waihou supply transformer: B
- Replace Waikino supply transformer: B

### Issue

Supply bus voltages at the Waihou and Waikino grid exit points are forecast to fall below 0.95 pu following an outage of one 110 kV Hamilton–Waihou circuit. In addition, the step voltage change for such an outage will exceed 5%. Both grid exit points have supply transformers with off-load tap changers.

### Solution

We are investigating options to maintain voltage at the Waihou and Waikino buses. Possible options include:

- installing two 20 Mvar capacitors (along the Valley Spur), which will also defer Valley Spur investment (see Section 9.8.4 for more information), or
- replacing the existing transformers at Waikino and Waihou, which are due for replacement in the next 5-10 years, with on-load tap changing transformers, and installing a lesser number of capacitors.

Property issues may arise if there is a need to expand the substation to accommodate the new capacitors. Future investment will be customer driven.

### 9.8.6 Cambridge supply transformer capacity

#### Project description:
Upgrade supply transformer capacity

#### Project status/type:
Possible, Base Capex and customer specific

#### Indicative timing:
TBA

#### Indicative cost band:
Resolve protection A, upgrade transformer capacity B

### Issue

Two 110/11 kV transformers supply Cambridge’s load, providing:
- a total nominal installed capacity of 80 MVA, and
- n-1 capacity of 43/4377 MVA (summer/winter).

The peak load at Cambridge is forecast to exceed the transformers’ n-1 winter capacity by approximately 2 MW in 2015, increasing to approximately 13 MW in 2030 (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.

---

77 The transformers’ capacity is limited by the Cambridge–T3 protection limit; with this limit resolved, the n-1 capacity will be 45/47 MVA (summer/winter).
### Table 9-7: Cambridge supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cambridge</td>
<td>0.98</td>
<td></td>
<td>2</td>
<td>3</td>
</tr>
</tbody>
</table>

### Solution

Resolving the protection limit will increase the transformers’ n-1 capacity to 45/47 MVA (summer/winter), reducing the forecast overload by approximately 1 MW in 2018. The forecast overload increases to approximately 10 MW in 2030. We will discuss the options to increase the supply transformers’ n-1 capacity with Waipa Networks. Future investment will be customer driven.

#### 9.8.7 Hamilton 220/33 kV and 110/11 kV supply transformer capacity

### Issue

The Hamilton grid exit point has both an 11 kV and a 33 kV supply bus.

Two 110/11 kV transformers supply Hamilton’s 11 kV load, providing:
- a total nominal installed capacity of 80 MVA, and
- n-1 capacity of 40/40 MVA (summer/winter).

The peak load at Hamilton 11 kV is forecast to exceed the transformers’ n-1 winter capacity by approximately 2 MW in 2015, increasing to 8 MW by 2030 (see Table 9-8).

Two 220/33 kV transformers supply Hamilton’s 33 kV load, providing:
- a total nominal installed capacity of 220 MVA, and
- n-1 capacity of 124/132 MVA (summer/winter).

The peak load at Hamilton 33 kV is forecast to exceed the transformers’ n-1 winter capacity by approximately 13 MW in 2015, increasing to 36 MW by 2030 (see Table 9-8).

### Table 9-8: Hamilton supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hamilton 11 kV</td>
<td>1.00</td>
<td></td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Hamilton 33 kV</td>
<td>0.99</td>
<td></td>
<td>13</td>
<td>15</td>
</tr>
</tbody>
</table>

WEL Networks is capable of significant load shifting between Hamilton and Te Kowhai, so the combined load is compared with the total supply transformer capacity at both grid exit points.

Four 220/33 kV transformers at Hamilton and Te Kowhai supply the total Hamilton city 33 kV load, providing:
- a total nominal installed capacity of 450 MVA, and
- n-1 capacity of 388/404 MVA (summer/winter).

---

The transformers’ capacity is limited by the 11 kV transformer branch component; with this limit resolved, the n-1 capacity will be 48/51 MVA (summer/winter).
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The total load is forecast to be 217 MW in 2015, increasing to 251 MW by 2030. The total load will not exceed the combined supply transformer n-1 capacity at Hamilton and Te Kowhai within the forecast period.

Solution

The lack of n-1 security at the Hamilton grid exit point will be managed operationally by transferring load to the Te Kowhai grid exit point after a contingency has occurred. Table 9-8 shows that significant load transfers will be required towards the end of the forecast period.

In addition, the Hamilton–T5 transformer has an expected end-of-life within the next 10 years. We will discuss with WEL Networks the appropriate rating and timing for the replacement transformer. Future investment will be customer driven.

9.8.8 Hangatiki supply transformer capacity and low voltage

Project description: Upgrade transformers’ capacity
Project status/type: Possible, customer-specific
Indicative timing: TBA
Indicative cost band: B

Issue

Two 110/33 kV transformers supply Hangatiki’s load, providing:
- a total nominal installed capacity of 40 MVA, and
- n-1 capacity of 22/24 MVA (summer/winter).

Hangatiki winter and summer load peaks are similar. The peak load at Hangatiki is forecast to exceed the transformers’ n-1 summer capacity by 16 MW in 2015, increasing to 25 MW by 2030 (see Table 9-9).

Additionally, the peak load at Hangatiki is forecast to exceed the transformers’ nominal installed capacity by 5 MW in 2015, increasing to 14 MW by 2030.

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Hangatiki</td>
<td>0.91</td>
<td>16</td>
</tr>
</tbody>
</table>

The Hangatiki 33 kV bus has low voltages for some load conditions partially because the supply transformers have no on-load tap changer and also because of low power factor on the 33 kV bus.

Solution

The Hangatiki transformers are single-phase units, with a non-contracted spare available on site.

We are discussing longer-term options with The Lines Company, such as replacing the existing transformers with two 50-60 MVA supply transformers.

Future investment will be customer driven.

---

79 The Lines Company also projects a step increase in load of about 10 MW by 2016. This step increase in load is not included in Table 9-9.
80 There have already been instances where the load at Hangatiki exceeded the transformers’ nominal rating with both supply transformers in service. In this situation both transformers are loaded up to their n-1 capacity, but this is sustainable when used only occasionally and only for the short term.
9.8.9 Hinuera supply transformer capacity

### Project description:
- New grid exit point
- Upgrade supply transformer capacity

### Project status/type:
- New grid exit point: possible, customer-specific
- Upgrade supply transformer capacity: possible, customer-specific

### Indicative timing:
- New grid exit point: 2018
- Upgrade supply transformer capacity: to be advised

### Indicative cost band:
- New grid exit point: C
- Upgrade supply transformer capacity: A

#### Issue

Two 110/33 kV transformers (rated at 30 MVA and 50 MVA) supply Hinuera’s load, providing:
- a total nominal installed capacity of 80 MVA, and
- n-1 capacity of 37/40 MVA (summer/winter).

The peak load at Hinuera is forecast to exceed the transformers’ n-1 winter capacity by approximately 13 MW in 2015.

<table>
<thead>
<tr>
<th>Table 9-10: Hinuera supply transformer overload forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>-------------------------</td>
</tr>
<tr>
<td>Hinuera</td>
</tr>
<tr>
<td>Hinuera – no Putaruru</td>
</tr>
</tbody>
</table>

#### Solution

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 planning to increase transmission security in the Hinuera area with a new grid exit point near Putaruru, which will be connected to the existing 110 kV Arapuni–Kinleith–2 circuit (see Section 9.8.10). This new grid exit point will reduce Hinuera load by approximately 37%, which will resolve the Hinuera supply transformer capacity issue for the forecast period.

In addition, both Hinuera supply transformers have an expected end-of-life towards the end of the forecast period. Any future investment or transformer upgrade will be customer driven.

9.8.10 Hinuera transmission security

### Project description:
- New grid exit point

### Project status/type:
- Proposed, customer-specific

### Indicative timing:
- 2018

### Indicative cost band:
- C

#### Issue

A single 110 kV circuit from Karapiro supplies Hinuera’s load, providing:
- a capacity of 63/77 MVA (summer/winter), and
- no n-1 security (given there is only one supplying circuit).

Peak load in the Hinuera area is forecast to be 49 MW in 2015, increasing to 55 MW in 2030.
Solution

Powerco is planning to increase transmission security to Hinuera’s load with a new grid exit point near Putaruru (connected to the existing 110 kV Arapuni–Kinleith–2 circuit). Land will need to be acquired for the new grid exit point.

For the outage of the Hinuera–Karapiro circuit, the load can be secured by backfeeding within the local lines distribution system from Putaruru or Piako. Future investment will be customer driven.

9.8.11 Kinleith 110/33 kV supply security, supply transformer capacity and low voltage

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Replace supply transformer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, customer-specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2016</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>A</td>
</tr>
</tbody>
</table>

Issue

Two 110/33 kV transformers (rated at 20 MVA and 30 MVA) supply Kinleith’s 33 kV load, providing:
- a total nominal installed capacity of 50 MVA, and
- 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 30 MVA transformer, and there is a loss of supply when transferring load between the two transformers.

The peak 33 kV load at Kinleith is forecast to exceed the 20 MVA transformer’s installed capacity by approximately 1 MW in 2015, increasing to approximately 3 MW in 2030 (see Table 9-11).

Table 9-11: Kinleith 33 kV supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuits/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
<td>2022</td>
</tr>
<tr>
<td>Kinleith 33 kV</td>
<td>0.98</td>
<td>1</td>
<td>2</td>
</tr>
</tbody>
</table>

The Kinleith 33 kV bus has low voltages for some system conditions partially because the transformer has no on-load tap changer.

Solution

We are discussing options with Powerco and Carter Holt Harvey. One possible option is to replace the 20 MVA transformer with a 40 MVA transformer. In addition, the 30 MVA transformer is approaching its expected end-of-life within the next five years. The appropriate rating and vector group for the replacement transformer will also be considered, in conjunction with the replacement work. The replacement transformer will have an on-load tap changer, which will address the low voltage issue. Any future transformer upgrade will be customer driven.

9.8.12 Kinleith 110/11 kV supply security

| Project status/type: | This issue is for information only |

Issue

Four 110/11 kV supply transformers supply the Carter Holt Harvey 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 three of the four supply transformers have no-break security for planned outages.

**Solution**

The lack of n-1 security will be managed operationally.

The 11 kV switchboard and three of the four supply transformers will reach their expected end-of-life within the next five years. We are discussing replacement options, and possible options to resolve the lack of n-1 security with Powerco and Carter Holt Harvey (see Section 9.10.5 for more information).

### 9.8.13 Kopu supply transformer capacity

| Project description: | Resolve protection limits  
|                     | Upgrade transformer capacity  
| Project status/type: | Resolve protection limits: possible, Base Capex  
|                     | Upgrade transformer capacity: to be advised  
| Indicative timing: | Resolve protection limits: 2022  
|                     | Upgrade transformer capacity: 2025-2030  
| Indicative cost band: | Resolve protection limits: A  
|                     | Upgrade transformer capacity: B  

**Issue**

Two 110/66 kV transformers supply Kopu's load, providing:

- a total nominal installed capacity of 120 MVA, and
- n-1 capacity of 59/5981 MVA (summer/winter).

The peak load at Kopu is forecast to exceed the transformers’ n-1 capacity by approximately 2 MW in 2022, increasing to 8 MW by 2030 (see Table 9-12).

#### Table 9-12: Kopu supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
<td>2015</td>
<td>2016</td>
<td>2017</td>
<td>2018</td>
<td>2019</td>
<td>2020</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>6-15 years out</td>
<td>2022</td>
<td>2024</td>
<td>2026</td>
<td>2028</td>
<td>2030</td>
<td></td>
</tr>
<tr>
<td>Kopu</td>
<td>1.00</td>
<td></td>
<td>2</td>
<td>3</td>
<td>5</td>
<td>7</td>
<td>8</td>
<td></td>
</tr>
</tbody>
</table>

**Solution**

Resolving the protection limit will increase the transformers’ n 1 capacity to 64/67 MVA (summer/winter). Following the protection upgrade, the peak load at Kopu is forecast to exceed the transformers’ n 1 winter capacity by approximately 1 MW in 2030 and we will discuss options to increase the supply transformers’ n-1 capacity with Powerco closer to this time. Alternatives may include:

- replacing the existing transformers with higher capacity units, or
- converting some 66 kV feeders to 110 kV operation.

Future investment will be customer driven.

### 9.8.14 Maraetai–Whakamaru transmission capacity

**Project status/type:** This issue is for information only

---

81 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).
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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 output from the Waipapa and Maraetai generation stations to Whakamaru.

An outage of one of the Maraetai–Whakamaru circuits restricts generation to approximately 50% of full capacity in summer and 60% of full capacity in winter.

Solution

In case of a contingency, a generation runback scheme is in place to reduce generation to the available capacity of the remaining circuit. This situation has been considered satisfactory since the generation was first installed, and there are no plans to make transmission network changes at this stage.

9.8.15 Te Awamutu supply transformer capacity

<table>
<thead>
<tr>
<th>Project description</th>
<th>Resolve protection limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing</td>
<td>2020</td>
</tr>
<tr>
<td>Indicative cost band</td>
<td>A</td>
</tr>
</tbody>
</table>

Issue

Two 110/11 kV transformers supply Te Awamutu's load, providing:
- a total nominal installed capacity of 80 MVA, and
- n-1 capacity of 41/41 MVA\(^{82}\) (summer/winter).

The peak load at Te Awamutu is forecast to exceed the transformers' n-1 capacity by approximately 1 MW in 2020, increasing to approximately 3 MW in 2030 (see Table 9-13).

Table 9-13: Te Awamutu supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Te Awamutu</td>
<td>0.99</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
</tbody>
</table>

Solution

Resolving the protection limit will increase the transformers' n-1 capacity to 52/54 MVA (summer/winter) which will provide sufficient n-1 capacity to meet the load growth within the forecast period.

Future investment will be customer driven.

9.8.16 Te Awamutu transmission security

<table>
<thead>
<tr>
<th>Project description</th>
<th>New Hangatiki–Te Awamutu circuit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type</td>
<td>Committed, customer-specific</td>
</tr>
<tr>
<td>Indicative timing</td>
<td>2016</td>
</tr>
<tr>
<td>Indicative cost band</td>
<td>D</td>
</tr>
</tbody>
</table>

Issue

A single 110 kV circuit from Karapiro supplies Te Awamutu's load, providing:

\(^{82}\) The transformers’ capacity is limited by protection equipment; with this limit resolved, the n-1 capacity will be 52/54 MVA (summer/winter).
a capacity of 63/77 MVA (summer/winter), and
• no n-1 security (given there is only one supplying circuit).

Te Awamutu’s peak load is forecast to be 39 MW in 2015, increasing to 42 MW in 2030.

Solution

Waipa Networks has committed to constructing a new 110 kV circuit from Hangatiki to Te Awamutu (to be operated by Transpower) to provide n-1 security. For commercial reasons, Waipa Networks may require the new Hangatiki–Te Awamutu circuit to be operated normally open, and put into service only for an outage of the Karapiro–Te Awamutu circuit. If so, there will be no loss of supply for planned outages of the Karapiro–Te Awamutu circuit but there will be a loss of supply following a fault on the circuit.

9.8.17 Waihou supply transformer capacity

Solution

The issues at Waihou involve the following:
• the peak load at Waihou is forecast to exceed the transformers’ n-1 winter capacity by approximately 4 MW in 2015, increasing to approximately 16 MW in 2030 (see Table 9-15).
• an outage of a supply transformer will cause the supply bus voltage to fall below 0.95 pu from 201583.

Table 9-14: Waihou supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Waihou</td>
<td>0.99</td>
<td>4</td>
<td>5</td>
</tr>
</tbody>
</table>

Solution

Following a supply transformer contingency (for example, a unit failure), restoration of full capacity can be achieved by:
• shifting load to other grid exit points, and
• swapping a transformer unit with an on-site spare unit.

These supply transformers have an expected end-of-life within the next 10 years. We will discuss with Powerco the appropriate rating, timing, and number of replacement transformers. In addition, we will convert the 33 kV outdoor switchyard to an indoor switchboard within the next five years. Future investment will be customer driven.

83 This is due to the Waihou supply transformers not having on-load tap changers.
### 9.8.18 Waikino supply transformer capacity

**Project description:** Replace supply transformer  
**Project status/type:** Possible, Base Capex  
**Indicative timing:** 2020-2022  
**Indicative cost band:** B

#### Issue

Two 110/33 kV transformers supply Waikino’s load, providing:
- a total nominal installed capacity of 60 MVA, and
- n-1 capacity of 37/39 MVA (summer/winter).

The peak load at Waikino is forecast to exceed the transformers’ n-1 winter capacity by approximately 1 MW in 2015, increasing to approximately 10 MW in 2030 (see Table 9-15).

#### Table 9-15: Waikino supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
<td>6-15 years out</td>
</tr>
<tr>
<td>Waikino</td>
<td>1.00</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>

#### Solution

In the short-term, operational measures can be used to manage this issue. We will discuss with Powerco the options to increase the supply transformers’ n-1 capacity.

In addition, the existing supply transformers at Waikino will approach their expected end-of-life within the next 10 years, and conversion of the existing 33 kV outdoor switchyard to an indoor switchboard is planned for around the same time.

### 9.9 Waikato bus security

This section presents issues arising from the outage of a single bus section rated at 50 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).

#### 9.9.1 Transmission bus security

Table 9-16 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 9-16: Transmission bus outages

<table>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arapuni North 110 kV</td>
<td>Hangatiki</td>
<td>-</td>
<td>-</td>
<td>9.9.3</td>
</tr>
<tr>
<td>Atiamuri 220 kV</td>
<td>-</td>
<td>Atiamuri</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Bombay 110 kV</td>
<td>Bombay 33 kV</td>
<td>-</td>
<td>-</td>
<td>See note 2</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Bombay–Hamilton</td>
<td>9.9.4</td>
</tr>
</tbody>
</table>
### Chapter 9: Waikato Region

#### Overloading

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Location</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hamilton 55 kV</td>
<td>-</td>
<td>Hamilton 220/33 kV supply transformer capacity See note 3</td>
</tr>
<tr>
<td>Hamilton 220 kV</td>
<td>-</td>
<td>Hamilton low voltage See note 4</td>
</tr>
<tr>
<td>Hangatiki 110 kV</td>
<td>Hangatiki</td>
<td>- See note 5</td>
</tr>
<tr>
<td>Hinuera 110 kV</td>
<td>Hinuera</td>
<td>- 9.8.10</td>
</tr>
<tr>
<td>Karapiro 110 kV</td>
<td>Hinuera Te Awamutu</td>
<td>Karapiro - See note 6</td>
</tr>
<tr>
<td>Kinleith 110 kV</td>
<td>Kinleith – Carter Holt Harvey Kinleith – Powerco</td>
<td>- 9.9.2</td>
</tr>
<tr>
<td>Ohakuri 220 kV</td>
<td>Ohakuri</td>
<td>- See note 5</td>
</tr>
<tr>
<td>Maraetai 220 kV</td>
<td>Maraetai Waipapa</td>
<td>- See note 7</td>
</tr>
<tr>
<td>Te Awamutu 110 kV</td>
<td>Te Awamutu</td>
<td>- 9.8.16</td>
</tr>
<tr>
<td>Whakamaru 220 kV</td>
<td>Mokai</td>
<td>Maraetai–Whakamaru overloading See note 8</td>
</tr>
<tr>
<td>Waihou 110 kV</td>
<td>Kopu Waikino</td>
<td>- - See note 10</td>
</tr>
<tr>
<td>Waikino 110 kV</td>
<td>Kopu Waikino</td>
<td>- - See note 11</td>
</tr>
</tbody>
</table>

1. All the generators at Atiamuri are connected to the 220 kV same bus section.
2. Both Bombay 110/33 kV supply transformers are connected to the same 110 kV bus section.
3. A bus section outage will disconnect a 220/33 kV supply transformers at Hamilton, which will cause the other supply transformer to overload (see Section 9.8.7).
4. A bus section outage that disconnects the Hamilton–Ohinewai circuit will cause low voltages (see Section 9.10.3).
5. There is no bus protection at Hangatiki or Ohakuri, so a bus fault removes all circuits from service causing loss of supply.
6. There is no bus zone protection at Karapiro. Therefore, a bus fault at Karapiro disconnects the Cambridge spur at the Hamilton 110 kV bus. This causes a loss of connection to Karapiro generation and a loss of supply to Cambridge, Hinuera, and Te Awamutu. See Section 9.8.10 for improving transmission security to Hinuera and Section 9.8.16 for improving transmission security to Te Awamutu.
7. There is a single circuit between Waipapa and Maraetai. A bus outage at Maraetai disconnects the circuit and therefore 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 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 9.8.14).
10. 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.
11. 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.

We have begun preliminary investigations for Mighty River Power to improve bus security at Maraetai. The other customers (KiwiRail, The Lines Company, Powerco, Waipa Networks and WEL Networks) 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.

### 9.9.2 Kinleith 110 kV bus security

#### Project status/type:
This issue is for information only

#### 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 kV Kinleith–T4 supply transformer, and
- 110/11 kV Kinleith–T3 supply transformer.

This bus outage results in a loss of supply to Powerco and Carter Holt Harvey. If the Arapuni bus split is open there will be a loss of connection for the Mighty River Power 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 and 2 circuits
- 110/11 kV Kinleith–T1 supply transformer
- 110/11 kV Kinleith–T2 supply transformer, and
- 110/33/11 kV Kinleith–T5 supply transformer.

This bus outage will result in a loss of supply and generation connection at Kinleith. If the Arapuni bus split is open, the Mighty River Power generation connected to the Arapuni south bus and the remaining Kinleith load will be operating as an island, which is unlikely to be sustainable. A loss of connection for Mighty River Power and a loss of supply for Powerco and Carter Holt Harvey will be required before normal operation can resume.

#### Solution

We are discussing options with Powerco and Carter Holt Harvey to determine if it is economic to resolve the issue. The options will be considered in conjunction with addressing the Kinleith 110/33 kV supply transformer security and capacity issue (see Section 9.8.11) and the Kinleith 110/11 kV supply transformer supply security (see Section 9.8.12).

### 9.9.3 Hangatiki supply security

#### Project status/type:
This issue is for information only

#### Issue

Two 110 kV circuits supply Hangatiki’s load (Arapuni–Hangatiki and Arapuni–Hangatiki–Ongarue) and connect to the same north bus section at Arapuni.

A fault on the north bus will cause a voltage collapse and subsequent loss of supply at Hangatiki.
Solution

The issue can be resolved by closing the Arapuni bus split which can be reconfigured so the two circuits from Hangatiki connect to separate bus sections (see Section 9.10.1 for more information).

9.9.4 Bombay–Hamilton 110 kV transmission capacity

**Project status/type:** This issue is for information only

**Issue**

There are three 110 kV circuits connecting the Waikato and Auckland regions:

- Two Bombay–Hamilton circuits each rated at 51/62 MVA (summer/winter).
- One Arapuni–Bombay circuit rated at 51/62 MVA (summer/winter).

A Bombay 110 kV bus section outage that disconnects the Bombay–Hamilton–2, Bombay–Otahuhu–2, and Arapuni–Bombay–1 circuits may overload the Bombay–Hamilton–1 circuit from around 2022 for:

- high Auckland load
- low Huntly and Auckland area generation, and
- high Waikato generation.

**Solution**

We anticipate this issue will be managed operationally with generation rescheduling and load management.

Additionally, we are investigating options to supply future load growth at Bombay. Some of these options may alleviate or resolve the capacity issues (see Chapter 8, Section 8.8.2).

9.10 Other regional items of interest

9.10.1 Transmission constraints between Hamilton and Tarukenga

**Issue**

The 110 kV circuits between Hamilton and Tarukenga connect local Waikato load and generation. They are also in parallel with the 220 kV network to transfer power between the Waikato and Auckland, Bay of Plenty and Central North Island. The 110 kV circuits are low capacity compared with the local load, generation and parallel 220 kV network which results in constraints in the Waikato region.

Issues that are associated with this area include:

- Arapuni–Hamilton 110 kV transmission capacity, where the Arapuni–Hamilton circuits may overload during periods of high Arapuni generation resulting in pre-contingency limitations on Arapuni generation, (see Section 9.8.1 for more information)
- Arapuni 110 kV bus security, where Hangatiki and Kinleith loads are exposed to a loss of supply for an Arapuni bus fault, due to the configuration required to enable the Arapuni bus split (see Section 9.9.3 for more information)
- Arapuni–Kinleith 110 kV transmission capacity, where the Arapuni–Kinleith circuits may overload for high Arapuni generation (see Section 9.8.2 for more information)
- Kinleith–Tarukenga transmission capacity, where the Kinleith–Tarukenga circuits may overload during periods of low Arapuni or Kinleith generation (see Section 9.8.2 for more information)
• Kinleith low voltage, where there is no on-load tap changer on the Kinleith 110/33 kV supply transformer, enabling the Kinleith 33 kV bus voltage to fall below 0.95 pu for certain contingencies (see Section 9.8.11 for more information), and

• Kinleith 110 kV bus security, where a 110 kV bus outage at Kinleith results in a loss of supply to some of the load supplied from Kinleith (see Section 9.9.2 for more information)

Solution

The following projects are committed or proposed:

• Putaruru new grid exit point proposed for 2018, which will increase the load south of Arapuni, reducing constraints on Arapuni–Hamilton but increasing power flows on Arapuni–Kinleith adding to Kinleith low voltage issues (see Section 9.8.11 for more information)

• Kinleith substation redevelopment. We are in discussions with Powerco and Carter Holt Harvey. We will install on-load tap changers at Kinleith, improving Kinleith low voltage issues (see Section 9.10.5 for more information)

• Hangatiki–Te Awamutu 110 kV circuit. Waipa Networks plan to commission this circuit in 2016. When in service, the circuit will provide a parallel path to the Arapuni–Hamilton circuit which reduces but does not eliminate constraints on Arapuni generation (see Section 9.8.16 for more information)

• Brownhill–Whakamaru series compensation. We will investigate this proposal within the next few years. The series capacitors will reduce the 220 kV impedance path to Auckland reducing power flows in the 110 kV network (see Chapter 6, Section 6.4.3 for more information).

These projects will resolve or relieve some of the transmission issues but we still anticipate major transmission capacity issues between Hamilton and Tarukenga when the new Lichfield loads and Putaruru grid exit points are connected.

We are investigating a range of interim solutions to manage the transmission constraints between Arapuni and Tarukenga. The options include some or all of the following:

• Keep the Arapuni bus split and apply variable line ratings on the Kinleith–Tarukenga–Lichfield circuits to ease limits on generation.

• Keep the Arapuni bus split and modifying the existing Arapuni–Kinleith special protection scheme to a second Arapuni generation runback scheme to allow more generation on the Arapuni north bus pre-contingency.

• Install a special protection scheme at Tarukenga to manage load at Putaruru, Lichfield and/or Kinleith post-contingency.

We are also investigating possible alternative interim options.

We will investigate a range of longer-term options to resolve the capacity issues between Arapuni and Tarukenga (see Section 9.8.2).

Economic analysis indicates that it will not be economic to upgrade the 110 kV circuits until the conductor requires replacement based on a condition assessment.

9.10.2 Cambridge spur capacity

Project status/type: This issue is for information only

Issue

The Cambridge Spur connects three loads (at Cambridge, Te Awamutu, and Hinuera) and generation at Karapiro. Two 110 kV Hamilton–Cambridge circuits supply the spur, each with a capacity of 57/70 MVA (summer/winter).
The combined peak load on the spur is forecast to remain at approximately 108 MW for the next 2-3 years, decrease to 95 MW in 2018\textsuperscript{84}, and increase to 108 MW by the end of the forecast period. Generation from Karapiro is used to avoid exceeding the n-1 capacity of the Hamilton–Cambridge circuits, especially in summer. The minimum generation required for the forecast period is approximately 30-45 MW.

**Solution**

Generation from Karapiro will manage the loading on the Hamilton–Cambridge circuits for the forecast period. Karapiro has an installed capacity of 90 MW and typically generates 40 MW during low load periods and 80-90 MW during peaks.

The proposed Hangatiki–Te Awamutu 110 kV circuit (see Section 9.8.16) may increase or decrease the loading on the spur, depending on the generation and load over a wide part of the power system.

We will continue to monitor the loading on the spur to determine when an issue may arise. Mitigation measures may include reconfiguring the grid or load control when there is an overload, or increasing the capacity of the Hamilton–Cambridge circuits. We will work with the parties connected to the Cambridge spur (Waipa Networks, Mighty River Power and Powerco) to determine a long-term solution.

### 9.10.3 Hamilton low voltage

**Project status/type:** This issue is for information only

**Issue**

During periods of high load and low Waikato 110 kV generation, the Hamilton 220 kV bus will have low voltage (below 0.90 pu) towards the end of the forecast period for the outage of the 220 kV Hamilton–Ohinewai circuit.

**Solution**

We will investigate options to resolve this issue closer to the time it occurs. Some include:
- reactive support in the Waikato 110 kV transmission network, and
- a third 220 kV connection to Hamilton (see Section 9.10.4).

### 9.10.4 Hamilton transmission security during maintenance

**Project status/type:** This issue is for information only

**Issue**

When a 220 kV Hamilton–Whakamaru circuit, a 220 kV Hamilton–Ohinewai circuit or a Hamilton 220/110 kV transformer is out for maintenance, the Waikato 110 kV system is split so it does not form a parallel connection with the 220 kV system. This places a considerable part of the Waikato region on n security\textsuperscript{85}.

\textsuperscript{84} The reduced load forecast is due to load shifting from Hinuera to the new Putaruru grid exit point.

\textsuperscript{85} The load on n security is the Valley Spur (Piako, Waikou, Waikino, and Kopu), the Cambridge spur (Cambridge, Karapiro, Hinuera and Te Awamutu), Bombay (depending on system conditions), and Hamilton (for 220 kV circuit outages only).
Solution

We will investigate if it is economic to provide full or partial n-1 security during maintenance. It is expected this investigation will begin in 2-5 years, after development options are addressed for other issues such as the:

- supply to Wiri (see Chapter 8, Section 8.8.3)
- Te Awamutu transmission security (see Section 9.8.16), and
- Arapuni bus security (see Section 9.10.1).

Options include a:

- third 220 kV circuit into Hamilton, and/or
- third 220/110 kV transformer at Hamilton, or
- 250 MVA 220/110 kV transformer at a new substation, connected to the intersection of the 220 kV Otahuhu–Whakamaru–C line and the 110 kV Hamilton–Waihou–A line.

9.10.5 Kinleith substation developments

Project status/type: This issue is for information only

Issue

Kinleith substation supplies Powerco and Carter Holt Harvey via:

- two low capacity 110 kV circuits from Bay of Plenty (Kinleith–Lichfield–Tarukenga)
- two low capacity 110 kV circuits from the Waikato region (Arapuni–Kinleith)
- three 110/11 kV supply transformers connected to individual 11 kV buses with no automatic post-contingency load shift
- one 110/33/11 kV supply transformer with the 33 kV circuit breaker normally open, connecting a single large industrial machine and a 42 MW generator, and
- one 110/33 kV supply transformer supplying the Powerco distribution network in the Tokoroa area with n security and no on-load tap changers.

The transmission system is normally split at Arapuni to reduce constraints on generation. This system split requires minimum generation at Arapuni to maintain n-1 security to the Kinleith load.

The system split is occasionally shifted to Kinleith to manage outages, either by opening the Kinleith bus section circuit breaker or the two Kinleith–Lichfield circuits at Kinleith. This configuration causes reduced security of supply for Kinleith.

The following issues exist at Kinleith:

- Kinleith–Tarukenga 110 kV transmission capacity limit (see Section 9.8.2 for more information).
- Kinleith 110/11 kV supply transformer security (see Section 9.8.12 for more information).
- Kinleith 110/33 kV supply transformer capacity (see Section 9.8.11 for more information).
- Kinleith 33 kV low voltage (see Section 9.8.11 for more information).

In addition, the supply transformers at Kinleith are reaching their expected end-of-life within the forecast period.
Solution
We are working with Powerco and Carter Holt Harvey to develop a long-term solution to supply Kinleith. This investigation is weighing security, fault level, cost, and constructability limitations.

9.11 Waikato 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

9.11.1 Huntly area generation
There are prospects to connect up to 540 MW to the 220 kV double-circuit transmission line between Huntly and Drury.

The existing grid will be able to cater for this level of prospective generation. We will need to reassess this if the prospective generation is significantly higher.

9.11.2 Hangatiki generation
There are prospects to connect up to approximately 40 MW of generation at Hangatiki. This generation will worsen the overloading issue on the 110 kV Arapuni–Hamilton circuits (see Section 9.8.1 for more information).

To prevent the overloading of these circuits under a wide range of load and generation scenarios, the following upgrades will be required:

- Runback schemes at Arapuni and/or Hangatiki
- Reconductoring the 110 kV Arapuni–Hamilton circuits

In addition, any new generation on the 110 kV transmission network in the Waikato region will add to the 110 kV Arapuni–Kinleith and 110 kV Bombay–Hamilton loading (see Section 9.8.2 and 9.9.4 respectively). Options to enable this level of generation include generation runback schemes, generation re-scheduling, and possibly reconductoring the Bombay–Hamilton circuit. Possible overloading of the two 110 kV Arapuni–Kinleith circuits may need to be addressed, but this may be required irrespective of additional generation at Hangatiki.
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10 Bay of Plenty Regional Plan

10.1 Regional overview

This chapter details the Bay of Plenty regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

Figure 10-1: Bay of Plenty region
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The Bay of Plenty region has a mix of growing provincial cities (Mount Maunganui, Tauranga, and Rotorua) together with smaller, less active rural localities (Waiotahi and Te Kaha) and heavy industry (Kawerau).

We have assessed the Bay of Plenty region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be sufficiently flexible to respond to a range of future service and technology possibilities, taking into consideration:

- the existing transmission network
- forecast demand
- forecast generation
- equipment replacement based on condition assessment, and
- possible technological development.

10.2 Bay of Plenty transmission system

This section highlights the state of the Bay of Plenty regional transmission network. The existing transmission network is set out geographically in Figure 10-1 and schematically in Figure 10-2.

Figure 10-2: Bay of Plenty transmission schematic

10.2.1 Transmission into the region

Bay of Plenty generation is lower than maximum local demand, with the deficit imported through the National Grid during peak load conditions, and any surplus 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 their capacity is expected to be adequate for the next 20
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10.2.2 Transmission within the region

The transmission network in the Bay of Plenty region comprises 220 kV and 110 kV circuits with interconnecting transformers located at Tarukenga, Kaitimako, Edgecumbe, and Kawerau. There is also a single 50 kV circuit between Waiothai and Te Kaha. Reactive power support is provided by 25 Mvar capacitors at Tauranga and Mount Maunganui.

The Bay of Plenty may be on n security when the Atiamuri–Tarukenga–1 or 2 circuit is out of service.

The western Bay of Plenty area is on n security when either one of the following is out of service:
- 220 kV Kaitimako–Tarukenga–1 or 2 circuit, or
- Kaitimako 220/110 kV transformers.

We are also discussing with Powerco and Unison options to:
- increase the capacity into and around Rotorua, which may involve line upgrades between Tarukenga and Rotorua, and/or increase supply transformer capacity at Rotorua and/or Owhata, and
- prevent overloading at Mount Maunganui by transferring load in the Papamoa area to Te Matai.

Generation and interruptible load connected directly or indirectly to the Kawerau 110 kV bus must sometimes be constrained to prevent overloading of the 220/110 kV transformers. There is a total of 227 MW installed generation capacity (Aniwhenua, Kawerau Geothermal, Matahina and Norske-Skog) and other smaller embedded generation stations at Kawerau.

In the medium term, we may carry out work at Kawerau and Edgecumbe to increase the 220/110 kV interconnecting transformer capacity to enable additional generation. The interconnecting transformers are non-core grid so any investment will need to be economically justified.

10.2.3 Longer-term development path

No firm options have been developed for the Bay of Plenty region beyond the planning period. However, long-term planning indicates the following possible developments in the 10-20 year range:
- Capacity upgrades of the Okere–Te Matai, Kaitimako–Te Matai and Okere–Tarukenga circuits, particularly if there is significant load transfer from Mount Maunganui to Te Matai.
- A third interconnecting transformer at Kaitimako
- A third interconnecting transformer at Tarukenga
- Additional reactive support in the western Bay of Plenty area.

In the longer term, one possible development is a connection from north of Tauranga to the existing Waihou substation in the Waikato region. This may be required to meet long-term load growth in the Tauranga area, and improve security during maintenance outages.

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86 See Chapter 9, Section 9.10.1 for more information about the Arapuni bus split.
There is the potential for significant additional geothermal generation in the eastern Bay of Plenty area, around Kawerau. If significant generation eventuates, then a staged transmission capacity upgrade will be required (see Section 10.11.1 for more information).

10.3 Bay of Plenty demand

The after diversity maximum demand (ADMD) for the Bay of Plenty region is forecast to grow on average by 1.1% annually over the next 15 years, from 478 MW in 2015 to 560 MW by 2030. This is the same rate as national average demand growth of 1.1% annually.

Figure 10-3 shows a comparison of the 2014 and 2015 TPR forecast 15-year maximum demand (after diversity\(^{87}\)) for the Bay of Plenty region. The TPR 2015 forecast is derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data, and is used to calculate the real power capacity for power transformers and transmission lines. See Chapter 4 for more information about demand forecasting.

Table 10-1 lists forecasts peak demand (prudent growth) for each grid exit point for the forecast period.

<table>
<thead>
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</tr>
</tbody>
</table>

\(^{87}\) The after diversity maximum demand (ADMD) for the region will be less than the sum of the individual GXP peak demands, as it takes into account the fact that the peak demand does not occur simultaneously at all the GXPs in the region.
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Grid exit point | Power factor | Peak Demand (MW) | Next 5 years | 6-15 Years Out |
<table>
<thead>
<tr>
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<tbody>
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</tr>
<tr>
<td>Mt Maunganui 33 kV²</td>
<td>0.99</td>
<td>69 70 71 70 71</td>
<td>53 56 59 62 65 67</td>
<td></td>
</tr>
<tr>
<td>Owhata</td>
<td>1.00</td>
<td>15 15 15 15 15</td>
<td>15 15 15 14 14</td>
<td></td>
</tr>
<tr>
<td>Rotorua 11 kV</td>
<td>1.00</td>
<td>31 31 31 32 32</td>
<td>32 33 33 34 34 35</td>
<td></td>
</tr>
<tr>
<td>Rotorua 33 kV</td>
<td>0.98</td>
<td>50 50 51 51 51</td>
<td>51 52 53 54 54</td>
<td></td>
</tr>
<tr>
<td>Tanukenga 11 kV</td>
<td>1.00</td>
<td>10 10 10 10 10</td>
<td>10 11 11 11 11 12 12</td>
<td></td>
</tr>
<tr>
<td>Tauranga 11 kV¹</td>
<td>0.99</td>
<td>31 31 32 32 32</td>
<td>28 29 30 31 32 33</td>
<td></td>
</tr>
<tr>
<td>Tauranga 33 kV</td>
<td>0.99</td>
<td>70 72 73 74 76</td>
<td>77 80 83 86 89 92</td>
<td></td>
</tr>
<tr>
<td>Te Kaha</td>
<td>0.98</td>
<td>3 3 3 3 3</td>
<td>3 3 3 3 3</td>
<td></td>
</tr>
<tr>
<td>Te Matai²</td>
<td>0.96</td>
<td>35 36 37 41 41</td>
<td>62 64 65 67 68 70</td>
<td></td>
</tr>
<tr>
<td>Waiohali</td>
<td>0.99</td>
<td>12 12 13 13 13</td>
<td>13 14 14 15 15 16</td>
<td></td>
</tr>
</tbody>
</table>

1. The customer advised us of a planned load transfer from Tauranga 11 kV to Kaitimako in 2019.
2. The customer advised us of a planned load transfer from Mount Maunganui to Te Matai in 2018 and 2020.

10.4 Bay of Plenty generation

The Bay of Plenty region’s generation capacity is approximately 365 MW. This generation is less than the region’s peak demand and the deficit is imported through the National Grid. At low load the region imports and exports power depending on the level of generation dispatched.

Kaimai is a run-of-river scheme that varies between 14 MW and 42 MW, injecting into the Tauranga 33 kV bus. Typically, 14 MW is the minimum generation available from the scheme, which is used to offset peak grid exit point loads, but only if sufficient water is available.

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, Unison, or Powerco).⁸⁸

Table 10-2: Forecast annual generation capacity (MW) at Bay of Plenty grid injection points to 2030 (including existing and committed generation)

<table>
<thead>
<tr>
<th>Grid injection point (location if embedded)</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Edgecumbe (Bay Milk)</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10  10  10  10  10</td>
</tr>
<tr>
<td>Kawerau (BOPE)</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6   6   6   6   6</td>
</tr>
<tr>
<td>Kawerau (CHH)</td>
<td>27</td>
<td>27</td>
<td>27</td>
<td>27</td>
<td>27</td>
<td>27</td>
<td>27  27  27  27  27</td>
</tr>
<tr>
<td>Kawerau (KAG)</td>
<td>105</td>
<td>105</td>
<td>105</td>
<td>105</td>
<td>105</td>
<td>105</td>
<td>105 105 105 105</td>
</tr>
<tr>
<td>Kawerau (KA24)</td>
<td>9</td>
<td>9</td>
<td>9</td>
<td>9</td>
<td>9</td>
<td>9</td>
<td>9   9   9   9   9</td>
</tr>
</tbody>
</table>

⁸⁸ Only generating stations with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.
10.5 Bay of Plenty significant maintenance work

Our capital project and maintenance works are integrated to enable system issues to be resolved if possible when assets are replaced or refurbished. Table 10-3 lists the significant maintenance-related work 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 maintenance work

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Edgecumbe supply transformers expected end-of-life</td>
<td>2015-2017</td>
</tr>
<tr>
<td>Edgecumbe interconnecting transformers expected end-of-life</td>
<td>2024-2025</td>
</tr>
<tr>
<td>Kawerau 11 kV switchgear replacement, and</td>
<td></td>
</tr>
<tr>
<td>Kawerau 110/11 kV supply transformers expected end-of-life</td>
<td>2017-2019</td>
</tr>
<tr>
<td>Owhata 110/11 kV supply transformers expected end-of-life, and</td>
<td></td>
</tr>
<tr>
<td>Owhata 11 kV switchgear replacement</td>
<td>2015-2017</td>
</tr>
<tr>
<td>Te Matai 33 kV outdoor to indoor conversion, and</td>
<td></td>
</tr>
<tr>
<td>Te Matai 110/33 kV supply transformer expected end-of-life</td>
<td>2023-2025</td>
</tr>
<tr>
<td>Waiotahi 110/11 kV supply transformers expected end-of-life</td>
<td>2025-2027</td>
</tr>
</tbody>
</table>

1. The electricity market designation for the Norske-Skog generator is Onepu.

10.6 Future Bay of Plenty transmission configuration

Figure 10-4 shows the possible configuration of Bay of Plenty transmission in 2030, with new assets, upgraded assets, and assets undergoing significant maintenance within the forecast period.

---

89 This may include replacement of the asset due to its condition assessment.
10.7 Changes since the 2014 Transmission Planning Report

Table 10-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year’s report.

Table 10-4: Changes since 2014

<table>
<thead>
<tr>
<th>Issues</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rotorua supply transformer capacity</td>
<td>Removed. The Rotorua 110/11 kV transformers have been replaced with higher rated units.</td>
</tr>
<tr>
<td>Atiamuri–Tarukenga 220 kV transmission capacity</td>
<td>New issue.</td>
</tr>
<tr>
<td>Kawerau 220 kV bus security</td>
<td>Issues separated for clarity.</td>
</tr>
<tr>
<td>Rotorua area bus security</td>
<td>Removed. The Rotorua 110/11 kV transformers have been replaced with larger units, enabling a Rotorua 110 kV bus reconfiguration.</td>
</tr>
</tbody>
</table>

10.8 Bay of Plenty transmission capability

Table 10-5 summarises issues within the Bay of Plenty region for the next 15 years. For more information about a particular issue, refer to the listed section number.

Table 10-5: Bay of Plenty region transmission issues

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>10.8.1</td>
<td>Kawerau 110 kV bus constraint</td>
</tr>
<tr>
<td>10.8.2</td>
<td>Tauranga and Mount Maunganui transmission security</td>
</tr>
</tbody>
</table>
## 10.8.1 Kawerau 110 kV bus constraints

### Project status/type:

This issue is for information only

### Issue

Generation at Aniwhenua, Matahina, 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% impedance)
- Kawerau–T13, 220/110 kV transformer (100 MVA, 10% impedance), and
- 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)).

There are constraints on the Kawerau 110 kV bus when there is high generation and low demand at Kawerau:

- An outage of a 110 kV Edgecumbe–Kawerau circuit may overload the other circuit.
- An outage of the 220 kV Edgecumbe–Kawerau–3 circuit may overload the 110 kV Edgecumbe–Owhata–2 circuit.
- An outage of the Kawerau–T12, 220/110 kV transformer may overload the Kawerau–T13, 220/110 kV transformer.

A Kawerau–T13 trip on overload will cause a loss of supply for the load (at Kawerau, Waiohahi and Te Kaha) and a loss of connection for the generation.
Solution

The circuit overloading can be avoided by significantly constraining generation. To avoid generation constraints for circuit outages, the Special Protection Schemes that open the circuit if it overloads include the

- Edgecumbe–Owhata–2 overload protection scheme, and
- Edgecumbe–Kawerau–1 and 2 overload protection scheme.

An outage of the Kawerau–T12, 220/110 kV transformer at high levels of generation and low load may cause the Edgecumbe–Owhata–2 overload protection scheme to operate and automatically open the circuit. All generation then flows through the 100 MVA Kawerau–T13 transformer, which will overload and may trip. Options to manage this include:

- taking no action, as the probability of a transformer trip is low (although there is a risk that Kawerau–T13 will trip due to overloading before the generation can be re-dispatched to remove the overload)
- constrain-down generation pre-contingency so Kawerau–T13 will not overload and trip, and
- enable the Special Protection Scheme on Kawerau–T13 to automatically trip generation at Matahina and Aniwhenua, or KAG, to remove any overloading of Kawerau–T13.

After feedback from stakeholders and an economic assessment, we have elected to take no action because an outage of the Kawerau–T12, 220/110 kV transformer with the usual level of generation and load is not expected to operate the Special Protection Scheme(s) for the circuits, so Kawerau–T13 will not usually trip before operational measures can be taken.

See Section 10.9.4 for information about the effect of a Kawerau–T12 outage due to a bus tripping.

See Section 10.11.1 for information about possible longer-term development options.

10.8.2 Tauranga and Mount Maunganui transmission security

| Project status/type: | This issue is for information only |

Issue

Tauranga and Mount Maunganui are supplied from Kaitimako through the following 110 kV circuits (see Figure 10-5):

- Kaitimako–Tauranga–1, rated at 96/105 MVA (summer/winter)
- Kaitimako–Mount Maunganui–1, rated at 63/77 MVA (summer/winter), and
- 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).
An outage of the Kaitimako–Tauranga–1 circuit during peak load periods will overload\(^9\) the Kaitimako–Poike circuit section from 2015, affecting Tauranga and Mount Maunganui.

An outage of the Kaitimako–Tauranga–1 circuit or Poike–Tauranga circuit section will overload the other circuit from 2021, affecting Tauranga.

**Solution**

The overloading of the Kaitimako–Poike circuit section is addressed by an existing special protection scheme, which will reconfigure the Kaitimako–Tauranga–Mount Maunganui–2 circuit at Tauranga or Mount Maunganui to remove the overload. This addresses the issue only until the load at Tauranga exceeds the rating of the Kaitimako–Poike circuit (2021). We will discuss options to address the Tauranga security issue with Powerco, which include:

- transferring more load from Tauranga to the Kaitimako grid exit point, and
- short-term operational measures to limit the Tauranga load and/or constrain-on generation at Kaimai.

Also, the transmission capacity into Mount Maunganui is limited to approximately 75 MW by the rating of the Kaitimako–Mount Maunganui circuit. This constraint will be addressed by transferring load from Mount Maunganui to Te Matai (see Sections 10.8.6 and 10.8.11).

Future investment will be customer driven.

### 10.8.3 Edgecumbe supply transformer capacity

<table>
<thead>
<tr>
<th>Project description</th>
<th>Upgrade transformer capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type</td>
<td>Possible, base capex</td>
</tr>
<tr>
<td>Indicative timing</td>
<td>Possibly 2015-2017</td>
</tr>
<tr>
<td>Indicative cost band</td>
<td>C</td>
</tr>
</tbody>
</table>

**Issue**

Two 220/33 kV transformers supply Edgecumbe’s load, providing:

- a total nominal installed capacity of 100 MVA, and
- n-1 capacity of 62/67 MVA (summer/winter).

The peak load at Edgecumbe is forecast to exceed the transformers’ n-1 winter capacity by approximately 1 MW in 2017, increasing to approximately 10 MW in 2030 (see Table 10-6).

---

\(^9\) This assumes Kaimai (embedded at Tauranga) is generating 14 MW.
Table 10-6: Edgcumbe supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Edgcumbe</td>
<td>0.97</td>
<td></td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

The two supply transformers have an expected end-of-life within the forecast period. The overload can be managed operationally until the transformers are replaced. We will discuss the rating of replacement supply transformers with the customer closer to the replacement date.

### 10.8.4 Kaitimako supply security

**Project status/type:** This issue is for information only

**Issue**

A single 110/33 kV, 75 MVA transformer supplies load at Kaitimako resulting in no n-1 security. Some of the 11 kV Tauranga load will be shifted to Kaitimako, which is forecast to grow to 35 MW by 2030 (see also Section 10.8.2).

**Solution**

The lack of n-1 security can be managed operationally by transferring load to Tauranga. Future investment will be customer driven.

### 10.8.5 Kawerau–Matahina 110 kV transmission security and capacity

**Project status/type:** This issue is for information only

**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 with high generation at Matahina and Aniwhenua.

**Solution**

The overload can be managed operationally by restricting the maximum generation at Matahina and Aniwhenua. This situation is considered satisfactory, and there are no plans to make transmission network changes at this stage. Future investment will be customer driven.

### 10.8.6 Mount Maunganui supply transformer and transmission capacity

**Project status/type:** This issue is for information only

**Issue**

Two 110/33 kV transformers supply Mount Maunganui’s load, providing:

- a total nominal installed capacity of 150 MVA, and
- n-1 capacity of 87/87\(^{91}\) MVA (summer/winter).

\(^{91}\) The transformers’ capacity is limited by the protection limit; with this limit removed, the n-1 capacity will be 94/98 MVA summer/winter.
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The n-1 transmission capacity into Mount Maunganui is limited to approximately 75 MW by the rating of the Kaitimako–Mount Maunganui circuit (see Section 10.8.2), which limits the maximum load before the transformer limit applies.

Powerco plans to develop the distribution network to transfer load from Mount Maunganui to Te Matai in in 2018 and 2020. If load is not transferred, then load constraints will be required from around 2023.

Solution

Transfer load from Mount Maunganui to Te Matai (see Section 10.8.11).

10.8.7 Owhata supply transformer capacity

<table>
<thead>
<tr>
<th>Project description</th>
<th>Replace supply transformer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing</td>
<td>2015-2017</td>
</tr>
<tr>
<td>Indicative cost band</td>
<td>To be advised</td>
</tr>
</tbody>
</table>

Issue

Two 110/11 kV transformers supply Owhata’s load, providing:

- a total nominal installed capacity of 20 MVA, and
- n-1 capacity of 11/12 MVA (summer/winter).

The peak load at Owhata is forecast to exceed the transformers’ n-1 winter capacity by approximately 3 MW from 2015 (see Table 10-7).

Table 10-7: Owhata supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
<td></td>
</tr>
<tr>
<td>Owhata</td>
<td>1.00</td>
<td>3</td>
<td>3</td>
</tr>
</tbody>
</table>

Solution

Presently, operational measures can be taken to prevent transformer overloads in the event of a transformer failure.

In the short term, Unison has a number of smart grid projects underway to increase load shifting between Owhata and Rotorua, which will also reduce loading on the 110 kV Rotorua–Tarukenga circuits (see Section 10.8.8).

In the medium to long-term, Unison is expected to permanently shift load from Rotorua to Owhata, with both 11 kV and 33 kV feeders. This possible load transfer is not included in the load forecasts.

Additionally, the 110/11 kV supply transformers at Owhata are approaching their expected end-of-life within the next five years. We will discuss transformer replacement options with Unison. In addition the 11 kV switchboard will reach its expected end-of-life within the next 5-10 years.

We anticipate some additional property may be required for the replacement transformers, and to regularise the existing substation boundary. Future investment will be customer driven.
10.8.8 Rotorua–Tarukenga 110 kV transmission capacity and security

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Thermal upgrade, transmission capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, customer-specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>A</td>
</tr>
</tbody>
</table>

**Issue**

The 110 kV Rotorua–Tarukenga line comprises two circuits, each rated at 63/77 MVA (summer/winter). The Rotorua 110 kV bus split was recently reconfigured, 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, and
- one 110/33 kV transformer and one 110/11 kV transformer are both 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, and
- overloads the remaining 110 kV Rotorua–Tarukenga–1 circuit (as it supplies all Rotorua’s load).

The peak load at Rotorua is forecast to exceed the circuits’ n-1 capacity by approximately 2 MW in 2015, increasing to approximately 6 MW in 2030 (see Table 10-8).

**Table 10-8: Rotorua–Tarukenga circuit overload forecast**

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Circuit overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Rotorua–Tarukenga</td>
<td>n/a</td>
<td>2</td>
</tr>
</tbody>
</table>

**Solution**

We are discussing future supply options with Unison (the local lines company) and Trustpower (owner of the embedded generation connecting at Rotorua), which include:

- in the short term, transferring load within Unison’s network to Tarukenga and Owhata to reduce the Rotorua load to within the capacity of the 110 kV Rotorua–Tarukenga circuits, and/or
- in the longer term, thermally upgrading the existing 110 kV Rotorua–Tarukenga circuits to 77/88 MVA (summer/winter), which may require easements over some parts of the line.

Future investment will be customer driven.

10.8.9 Tarukenga supply security

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Second supply transformer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, customer-specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>A</td>
</tr>
</tbody>
</table>

**Issue**

A single 110/11 kV, 20 MVA supply transformer supplies Tarukenga’s load resulting in no n-1 security. Tarukenga’s peak load is forecast to grow to 12 MW by 2030.
Solution

Unison can backfeed the Tarukenga load from the Rotorua 11 kV bus if required. However, at times it may not be possible to backfeed all the load due to the transmission capacity into Rotorua (see Section 10.8.8). The lack of n-1 security can be managed operationally in the short term.

In the longer term, installing a second 110/11 kV transformer to increase the supply security at Tarukenga will address the issue. Future investment will be customer driven.

10.8.10 Tauranga 11 kV supply transformer capacity

Project description: Resolve cable and protection limits
Project status/type: Possible, customer-specific
Indicative timing: To be advised
Indicative cost band: A

Issue

Two 110/11 kV transformers supply Tauranga’s 11 kV load, providing:

- a total nominal installed capacity of 60 MVA, and
- n-1 capacity of 30/30 MVA\(^\text{92}\) (summer/winter).

The peak load on the Tauranga 11 kV bus is forecast to exceed the transformers’ n-1 winter capacity by approximately:

- 3 MW in 2015
- 1 MW in 2022 following some load shifting to Kaitimako, and
- 5 MW in 2030 (see Table 10-9).

Table 10-9: Tauranga 11 kV supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tauranga 11 kV</td>
<td>0.99</td>
<td>3</td>
</tr>
</tbody>
</table>

Solution

A possible option is to limit the load or to transfer additional load to Kaitimako.

In the longer-term, resolving the low voltage cable, metering and protection limits\(^\text{93}\) will provide sufficient n-1 capacity to meet the load growth within the forecast period.

Future investment will be customer driven.

10.8.11 Te Matai supply transformer capacity and low voltage

Project description: Upgrade supply transformer capacity
Project status/type: Possible, customer-specific
Indicative timing: 2020
Indicative cost band: B

---

\(^{92}\) The transformers’ capacity is limited by low voltage cables, protection and metering limits, and the series reactors; with these limits resolved, the n-1 capacity will be 45/45 MVA (summer/winter).

\(^{93}\) Resolving the low voltage cables, metering and protection limits will increase the n-1 capacity to 40/40 MVA (summer/winter), which is the limit of the series reactors. This is sufficient to meet the load growth within the forecast period.
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**Issue**

Two 110/33 kV transformers (rated at 30 MVA and 40 MVA) supply Te Matai’s load, providing:
- a total nominal installed capacity of 70 MVA, and
- n-1 capacity of 36/39 MVA (summer/winter).

Following the load transfer from Mount Maunganui the peak load is forecast to exceed the 30 MVA transformers’ winter capacity pre-contingency by approximately 6 MW in 2020, increasing to approximately 14 MW in 2030 (see Table 10-10).

Additionally, the peak load at Te Matai is forecast to exceed the transformers’ n-1 winter capacity by approximately:
- 1 MW in 2016
- 27 MW in 2020 when load is shifted from Mount Maunganui, and
- 35 MW in 2030 (see Table 10-10).

**Table 10-10: Te Matai supply transformer overload forecast**

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Te Matai – pre-contingency</td>
<td>0.96</td>
<td></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>6</td>
<td>8</td>
<td>9</td>
<td>11</td>
<td>12</td>
<td>14</td>
</tr>
<tr>
<td>Te Matai – post-contingency</td>
<td>0.96</td>
<td></td>
<td>0</td>
<td>1</td>
<td>2</td>
<td>6</td>
<td>6</td>
<td>27</td>
<td>29</td>
<td>30</td>
<td>32</td>
<td>33</td>
<td>35</td>
</tr>
</tbody>
</table>

The Te Matai 110 kV voltage will fall below 0.95 pu for a Kaitimako–Te Matai contingency from 2020, when load is shifted from Mount Maunganui. Only one of the existing supply transformers has on-load tap changers. Using this on-load tap changer to manage the 33 kV bus voltage will cause circulating reactive power flows. This reactive power flow may cause overloading of the 33 kV cable connecting to Te Matai T2 from 2020 for a Kaitimako–Te Matai outage.

**Solution**

The issue will be managed operationally in the short term. The Te Matai 30 MVA supply transformer has an expected end-of-life at the end of the forecast period. We will discuss with Powerco the timing and rating of replacement transformers. Any new supply transformers should have on-load tap changers.

Future investment will be customer driven.

**10.8.12 Waiotahi supply transformer capacity**

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Upgrade supply transformer capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2020-2022</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>B</td>
</tr>
</tbody>
</table>

**Issue**

Two 110/11 kV transformers supply Waiotahi’s load, providing:
- a total nominal installed capacity of 20 MVA, and
- n-1 capacity of 11/12 MVA (summer/winter).

The transformers also supply Te Kaha’s load via an 11/50 kV step-up transformer at Waiotahi. The combined peak load at Waiotahi and Te Kaha is forecast to exceed
the Waiotahi transformers’ n-1 winter capacity by approximately 2 MW in 2015, increasing to 6 MW in 2030 (see Table 10-11).

### Table 10-11: Waiotahi supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Waiotahi (and Te Kaha)</td>
<td>0.99</td>
<td>2 3 3 3 4</td>
</tr>
</tbody>
</table>

**Solution**

We are discussing with Horizon Energy the options and timing to address the transformer capacity issue and developments within the distribution network which also influence the development options for Waiotahi (see Section 10.10.1). Additionally, the 110/11 kV supply transformers at Waiotahi will approach their expected end-of-life within the next 5-10 years.

Future investment will be customer driven.

10.8.13 Waiotahi and Te Kaha supply security

**Project status/type:** This issue is for information only

**Issue**

Waiotahi and Te Kaha are supplied by one transmission circuit (a 110 kV circuit to Waiotahi and a 50 kV circuit to Te Kaha) resulting in no n-1 security.

Both loads are supplied by a single Edgecumbe–Waiotahi circuit with the:

- Waiotahi 11 kV load supplied through two 10 MVA transformers, and
- Te Kaha 11 kV load supplied through one:
  - 11/50 kV, 3 MVA step up transformer at Waiotahi
  - 50 kV Te Kaha–Waiotahi circuit rated at 48/59 MVA (summer/winter), and
  - 50/11 kV, 7.5 MVA transformer at Te Kaha.

Additionally, the Te Kaha load is forecast to exceed the Waiotahi 11/50 kV transformer’s n-1 summer capacity by less than 0.3 MW from 2023.

**Solution**

The lack of n-1 security can be managed operationally. Future investment will be customer driven.

10.9 Bay of Plenty bus security

This section presents issues arising from the outage of a single bus section rated at 50 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).

10.9.1 Transmission bus security

Table 9-16 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 10-12: Transmission bus outages

<table>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Edgecumbe 110 kV</td>
<td>Te Kaha</td>
<td>-</td>
<td>-</td>
<td>10.8.13</td>
</tr>
<tr>
<td></td>
<td>Waiothai</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Edgecumbe 220 kV</td>
<td>Edgecumbe</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Kaitimako 110 kV</td>
<td>Kaitimako</td>
<td>-</td>
<td>220/110 kV transformer overloading</td>
<td>10.9.3</td>
</tr>
<tr>
<td>Kaitimako 220 kV</td>
<td>-</td>
<td>-</td>
<td>Okere–Te Matai overloading</td>
<td>10.9.6</td>
</tr>
<tr>
<td>Kawerau 110 kV</td>
<td>Kawerau – Horizon Energy</td>
<td>KAG</td>
<td>-</td>
<td>10.9.4</td>
</tr>
<tr>
<td>Kawerau 220 kV</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>10.9.5</td>
</tr>
<tr>
<td>Mount Maunganui 110 kV</td>
<td>Mount Maunganui</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Owhata 110 kV</td>
<td>Owhata</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Tarukenga 110 kV</td>
<td>Tarukenga</td>
<td>-</td>
<td>-</td>
<td>10.8.9</td>
</tr>
<tr>
<td>Tarukenga 220 kV</td>
<td>-</td>
<td>-</td>
<td>Atiamuri–Tarukenga overloading</td>
<td>10.9.2</td>
</tr>
<tr>
<td>Tauranga 110 kV</td>
<td>Tauranga 11 kV</td>
<td>Tauranga 33 kV</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Te Matai 110 kV</td>
<td>Te Matai</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Waiotahi 110 kV</td>
<td>Te Kaha</td>
<td>Waiotahi</td>
<td>-</td>
<td>10.8.13</td>
</tr>
</tbody>
</table>

1. There is no bus protection at Edgecumbe, Mount Maunganui, Owhata, Tauranga and Te Matai, so a bus fault causes loss of supply.

The customers (Horizon Energy, Norske Skog, Powerco, Todd Energy, TrustPower, or 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.

#### 10.9.2 Atiamuri–Tarukenga 220 kV transmission capacity

**Project status/type:** This issue is for information only

**Issue**

The outage of a Tarukenga 220 kV bus section disconnects:
- a 220/110 kV Tarukenga interconnecting transformer
- a 220 kV Atiamuri–Tarukenga circuit
- a 220 kV Kaitimako–Tarukenga circuit, and
- both 220 kV Edgecumbe–Tarukenga circuits.

This may overload the Edgecumbe–Owhata circuit, which has a special protection scheme to automatically open the circuit to remove the overload. This may result in the 220 kV Atiamuri–Tarukenga circuit overloading from around 2023, during periods of:
• high western Bay of Plenty and Rotorua area net load, or
• high eastern Bay of Plenty net generation.

Solution

In the medium term this issue can be managed operationally.

In the longer term connecting one of the Edgecumbe–Tarukenga circuits to the other 220 kV bus section at Tarukenga will resolve this issue.

10.9.3 Kaitimako 110 kV bus security

Project status/type: This issue is for information only

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 Mount Maunganui–Kaitimako circuit, and
• 110 kV Kaitimako–Te Matai circuit.

This bus outage is the worst contingency affecting Kaitimako interconnecting transformer capacity.

An outage of another 110 kV bus disconnects the:
• 220/110 kV Kaitimako–T2 interconnecting transformer
• 110 kV Kaitimako–Tauranga–1 circuit, and
• 110/11 kV Kaitimako–T1 supply transformer.

This bus outage results in a loss of supply at Kaitimako (see Section 10.8.4). This load can ordinarily be backfed from Tauranga, but the simultaneous loss of the Kaitimako–Tauranga–1 circuit will result in Tauranga only being supplied from the Kaitimako–Mount Maunganui–Tauranga–2 circuit, which may restrict the amount of load that can be transferred to Tauranga.

Solution

The Kaitimako interconnecting transformer capacity issue is deferred by shifting load from Mount Maunganui to Te Matai in 2020 (see Section 10.8.6).

Capacity constraints into Tauranga can be managed operationally.

10.9.4 Kawerau 110 kV bus security

Project status/type: This issue is for information only

Issue

The outage of a Kawerau 110 kV bus section disconnects:
• the Kawerau–T12, 250 MVA, 220/110 kV transformer
• the 110 kV Edgcumbe–Kawerau–1 circuit
• the 110 kV Kawerau–Matahina–1
• Kawerau Geothermal generation
• Horizon Energy load, and
• two of the four 110/11 kV transformers supplying Norske Skog.
This bus outage reduces the generation on the Kawerau 110 kV bus due to the Kawerau Geothermal generator disconnecting, coupled with a reduction in load and export capacity. This may overload the Edgecumbe–Kawerau–2 circuit, which has a special protection scheme to automatically open the circuit to remove the overload. This may result in the Kawerau–T13, 220/110 kV transformer overloading and tripping, causing a loss of supply to the Kawerau load and a loss of connection to the generation (see Section 10.8.1).

Solution

See Section:
- 10.8.1 for more information about the Special Protection Schemes in the area and options to manage the overloading of the Kawerau–T13, 220/110 kV transformer, and
- 10.11.1 for more information about the longer term options to increase the generation export capacity on the Kawerau 110 kV bus.

When the supply transformers for the Horizon load (T1 and T2) are replaced due to their end of life, they will be put on different bus sections to provide security for bus outages.

### 10.9.5 Kawerau 220 kV bus security

**Project status/type:** This issue is for information only

**Issue**

The outage of a Kawerau 220 kV bus section disconnects:
- the Kawerau–T12, 250 MVA, 220/110 kV transformer
- the 220 kV Edgecumbe–Kawerau–3 circuit, and
- one of the two 220/11 kV transformers supplying Norske Skog.

This may overload the Edgecumbe–Owhata circuit, which has a Special Protection Scheme to automatically open the circuit to remove the overload, resulting in the Kawerau–T13, 220/110 kV transformer overloading and tripping, causing a loss of supply to the Kawerau, Te Kaha and Waiothahi loads and a loss of connection to generation (see Section 10.8.1).

**Solution**

See section:
- 10.8.1 for more information about the Special Protection Schemes in the area and options to manage the overloading of the Kawerau–T13, 220/110 kV transformer, and
- 10.11.1 for more information about the longer term options to increase the generation export capacity on the Kawerau 110 kV bus.

### 10.9.6 Okere–Te Matai 110 kV transmission capacity

**Project status/type:** This issue is for information only

**Issue**

The outage of a Kaitimako 220 kV bus section disconnects a:
- 220/110 kV Kaitimako interconnecting transformer, and
- 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 2022 during periods of:

- high western Bay of Plenty load
- low western Bay of Plenty generation, or
- high eastern Bay of Plenty net generation.

**Solution**

A third interconnecting transformer and third 220 kV bus section at Kaitimako will resolve the overloading issue for the forecast period and beyond.

10.10 Other regional items of interest

10.10.1 Opotiki grid exit point

<table>
<thead>
<tr>
<th>Project description:</th>
<th>New or upgrade grid exit point</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Customer specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2017-2022</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>To be advised.</td>
</tr>
</tbody>
</table>

Opotiki township is approximately 8 kilometres west of the Waiotahi grid exit point and is the main load supplied from Waiotahi. The Te Kaha–Waiotahi circuit passes close to Opotiki.

Load growth at Opotiki will require an upgrade within the distribution network. In addition, the supply transformers at Waiotahi are nearing their expected end-of-life and the existing load exceeds the transformers’ n-1 capacity (see Section 10.8.12).

This presents the opportunity for synergies combining the distribution network upgrade and the replacement of the supply transformers. Options include:

- upgrading the Te Kaha–Waiotahi circuit from Waiotahi to Opotiki to 110 kV, establishing a new grid exit point at Opotiki and decommissioning the Waiotahi grid exit point, or
- Replacing the Waiotahi 110/11 kV supply transformers with 110/33 kV supply transformers, converting Te Kaha–Waiotahi to 33 kV operation, and establishing a 33 kV grid exit point at Opotiki.

We are in discussion with Horizon Energy to determine the best overall solution.

10.11 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

10.11.1 Generation connection at Kawerau

There are a number of other future generation connection proposals at Kawerau (Section 10.8.1 for information about the existing constraints on Kawerau 110 kV generation), as the area has significant geothermal resources. If more than approximately 40-50 MW of additional generation connects directly or indirectly to the Kawerau 110 kV bus, then the likely system developments will involve:
• replacing the Kawerau–T13 transformer (220/110 kV, 100 MVA) with a 250 MVA transformer
• splitting the 110 kV Kawerau–Edgecumbe circuits, and
• replacing the Edgecumbe 220/110 kV transformers and returning them to service.

If there is little change in the generation connected to the Kawerau 110 kV bus, then the Edgecumbe 220/110 kV transformer will be decommissioned and not replaced.

Connecting more than approximately 60 MW of generation at Kawerau (to the 110 kV or 220 kV busses), however, will also overload the 220 kV Edgecumbe–Kawerau or Kawerau–Ohakuri circuits if the other circuit is out of service. Options to address the issue include either:
• automatically reducing or tripping generation if an overload occurs
• increasing the thermal rating of the circuits, or
• a second 220 kV Edgecumbe–Kawerau circuit.

The increased generation at Kawerau may increase the 11 kV supply bus and distribution system fault levels sufficiently to exceed their fault-level capacities. This particularly applies if new generation is connected directly to the supply bus, and may also be an issue if the generation is embedded within the distribution system. This may require the replacement of the existing supply transformers with higher-impedance transformers and/or replacement of the existing 11 kV switchboard.

We are currently in discussions with Horizon Energy regarding the 11 kV fault level issue. The 11 kV switchboard and the 110/11 kV supply transformers at Kawerau are due for replacement within the next 10 years (see Section 10.5). We will consider options to reduce the 11 kV fault level when the equipment is due for replacement.

10.11.2 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, with the potential for approximately 250 MW of generation to connect to these circuits, depending on developments at Kawerau, before system upgrades are required. This capability decreases for outages of some 220 kV circuits in the Bay of Plenty region.

10.11.3 Generation connection to the Okere–Te Matai circuit

Some generation prospects exist close to the 110 kV Okere–Te Matai circuit, or close to Okere on one of the other circuits passing through the area. 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

This chapter details the Central North Island regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

Figure 11-1: Central North Island region
The Central North Island region includes a mix of grid exit points, from the large load at Palmerston North and environs (supplied from Bunnythorpe and Linton) to numerous medium to small loads. There is also a large industrial load at Tangiwai.

We have assessed the Central North Island region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be flexible to respond to a range of future service and technology possibilities, taking into consideration:

- the existing transmission network
- forecast demand
- forecast generation
- equipment replacement based on condition assessment, and
- possible technological development.

### 11.2 Central North Island transmission system

This section highlights the state of the Central North Island regional transmission network. The existing transmission network is set out geographically in Figure 11-1 and schematically in Figure 11-2.

#### 11.2.1 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 set by generation and loads outside the region.
Chapter 11: Central North Island 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, plus 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.

We recently replaced the 220 kV single circuit Wairakei–Poihipi–Whakamaru line connecting to the Waikato region with a double-circuit line.

Most of the Central North Island’s generation capacity is connected to the 220 kV circuit and is significantly in excess of the local demand. Surplus generation is exported over the National Grid to other demand centres.

11.2.2 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 impose constraints under certain operating conditions. Operational measures taken to ensure the 110 kV circuits operate within their thermal capacity are:

- normally splitting the 110 kV system at Waipawa, for the Fernhill–Waipawa circuits, and
- managing generation output to avoid overloading of the 110 kV:
  - Bunnythorpe–Woodville circuits
  - circuits between Bunnythorpe and Arapuni (Waikato region), and
  - circuits between Bunnythorpe and Stratford (Taranaki region).

Special protection schemes at Tokaanu and Woodville are also used to automatically reconfigure the grid or reduce generation to ensure the circuits operate within their thermal capacity.

11.2.3 Longer-term development path

Longer-term development plans are being formed as part of the Lower North Island investigation.

The transmission development in this region will largely depend on the magnitude and location of future generation, and the commissioning of new generation in the region may bring forward the need for transmission investment. Possible upgrades include duplexing the existing 220 kV lines, and rebuilding some of the 110 kV lines for 220 kV operation.

11.3 Central North Island demand

The after diversity maximum demand (ADMD) for the Central North Island region is forecast to grow on average by 0.6% annually over the next 15 years, from 313 MW in 2015 to 340 MW by 2030. This is lower than the national average demand growth of 1.1% annually. Figure 11-3 shows a comparison of the 2014 and 2015 TPR forecast 15-year maximum demand (after diversity\(^\text{94}\)) for the Central North Island region. The forecasts are derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data. See Chapter 4 for more information about demand forecasting.

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\(^{94}\) The after diversity maximum demand (ADMD) for the region will be less than the sum of the individual grid exit point peak demands, as it takes into account the fact that the peak demand does not occur simultaneously at all the grid exit points in the region.
Table 11-1 lists forecasts peak demand (prudent growth) for each grid exit point for the forecast period.

<table>
<thead>
<tr>
<th>Grid exit point</th>
<th>Power factor</th>
<th>Peak demand (MW)</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
<td>2022 2024 2026 2028 2030</td>
</tr>
<tr>
<td>Bunnythorpe</td>
<td>0.98</td>
<td>109 110 111 105 107 108</td>
<td>110 112 115 117 120</td>
</tr>
<tr>
<td>33 kV</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bunnythorpe NZR</td>
<td>1.00</td>
<td>6 6 6 7 7 7</td>
<td>7 7 7 7</td>
</tr>
<tr>
<td>Dannevirke</td>
<td>0.97</td>
<td>16 16 16 16 16 16</td>
<td>16 16 17 17 17</td>
</tr>
<tr>
<td>Linton</td>
<td>0.99</td>
<td>62 63 64 72 73 74</td>
<td>76 78 80 82 84</td>
</tr>
<tr>
<td>Mangahao</td>
<td>0.96</td>
<td>37 38 38 38 38 38</td>
<td>39 39 39 40 40</td>
</tr>
<tr>
<td>Mangamairi</td>
<td>0.97</td>
<td>13 19 19 19 19 19</td>
<td>19 19 20 20 20</td>
</tr>
<tr>
<td>Marton</td>
<td>0.94</td>
<td>18 18 18 19 19 19</td>
<td>20 20 21 21 22</td>
</tr>
<tr>
<td>Mataora</td>
<td>0.98</td>
<td>7 8 8 8 8 8</td>
<td>8 8 8 9 9</td>
</tr>
<tr>
<td>National Park</td>
<td>0.97</td>
<td>7 7 7 7 7 7</td>
<td>7 8 8 8 8</td>
</tr>
<tr>
<td>Ohakune</td>
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<td>10 10 10 10 10 11</td>
<td>11 11 12 12 12</td>
</tr>
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<td>Ongarue</td>
<td>1.00</td>
<td>9 10 10 10 10 10</td>
<td>10 11 11 11 12</td>
</tr>
<tr>
<td>Tangiwiwai</td>
<td>1.00</td>
<td>41 42 42 42 42 43</td>
<td>43 43 44 44 45</td>
</tr>
<tr>
<td>11 kV</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tangiwiwai NZR</td>
<td>1.00</td>
<td>9 9 9 9 9 9</td>
<td>9 9 10 10 10</td>
</tr>
<tr>
<td>Tokaanu</td>
<td>0.98</td>
<td>11 11 11 11 11 11</td>
<td>12 12 12 12 13</td>
</tr>
<tr>
<td>Wairakei</td>
<td>1.00</td>
<td>23 23 23 23 23 24</td>
<td>24 25 25 25 26</td>
</tr>
<tr>
<td>Woodville</td>
<td>0.99</td>
<td>3 3 3 3 3 3</td>
<td>3 3 3 3 3</td>
</tr>
</tbody>
</table>

1. Powerco advised a load shift from Bunnythorpe to Linton from 2018.
2. Powerco advised a step load increase in 2016 due to a dairy factory upgrade.
Chapter 11: Central North Island Region

11.4 Central North Island generation

The Central North Island region’s generation capacity is 1,453 MW. This generation contributes a significant portion of the total North Island generation and exceeds local demand. Surplus generation is exported over the National Grid to other demand centres.

Table 11-2: Forecast annual generation capacity (MW) at Central North Island grid injection points to 2030 (including existing and committed generation)

<table>
<thead>
<tr>
<th>Grid injection point (location if embedded)</th>
<th>Next 5 years</th>
<th>7-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aratiatia</td>
<td>78</td>
<td>78</td>
</tr>
<tr>
<td>Bunnythorpe (Tararua Wind Stage 2)</td>
<td>36</td>
<td>36</td>
</tr>
<tr>
<td>Linton (Tararua Wind Stage 1)</td>
<td>32</td>
<td>32</td>
</tr>
<tr>
<td>Linton (Totara Road)</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Mangahao</td>
<td>42</td>
<td>42</td>
</tr>
<tr>
<td>Nga Awa Purua</td>
<td>140</td>
<td>140</td>
</tr>
<tr>
<td>Nga Awa Purua – Ngatamariki</td>
<td>82</td>
<td>82</td>
</tr>
<tr>
<td>Ohaaki</td>
<td>46</td>
<td>46</td>
</tr>
<tr>
<td>Ongarue (Mokauiti, Kuratau and Waikato Falls)</td>
<td>13</td>
<td>13</td>
</tr>
<tr>
<td>Poihipi</td>
<td>51</td>
<td>51</td>
</tr>
<tr>
<td>Rangipo</td>
<td>120</td>
<td>120</td>
</tr>
<tr>
<td>Tararua Wind Central – Tararua Stage 3</td>
<td>93</td>
<td>93</td>
</tr>
<tr>
<td>Tararua Wind Central (Te Rere Hau)</td>
<td>49</td>
<td>49</td>
</tr>
<tr>
<td>Te Mihi</td>
<td>166</td>
<td>166</td>
</tr>
<tr>
<td>Tokaanu</td>
<td>240</td>
<td>240</td>
</tr>
<tr>
<td>Wairakei (Hinemaia)</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>Wairakei (Rotokawa)</td>
<td>35</td>
<td>35</td>
</tr>
<tr>
<td>Wairakei (Te Huka)</td>
<td>23</td>
<td>23</td>
</tr>
<tr>
<td>Woodville – Te Apiti</td>
<td>90</td>
<td>90</td>
</tr>
</tbody>
</table>

11.5 Central North Island significant maintenance work

Our capital projects and maintenance works are integrated to enable system issues to be resolved if possible when assets are replaced or refurbished. Table 11-3 lists the significant maintenance-related work proposed for the Central North Island region for the next 15 years that may significantly impact related system issues or connected parties.

Table 11-3: Proposed significant maintenance work

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bunnythorpe interconnecting transformers expected end-of-life</td>
<td>2016-2018</td>
</tr>
</tbody>
</table>

95 This may include replacement of the asset due to its condition assessment.
11.6 Future Central North Island projects and transmission configuration

Figure 11-4 shows the possible configuration of Central North Island transmission in 2030, with new assets, upgraded assets, and assets undergoing significant maintenance within the forecast period.

Figure 11-4: Possible Central North Island transmission configuration in 2030

11.7 Changes since the 2014 Transmission Planning Report

Table 11-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year's report.
Table 11-4: Changes since 2014

<table>
<thead>
<tr>
<th>Issues</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>National Park and Ohakune low voltage</td>
<td>Removed. Replaced supply transformers.</td>
</tr>
<tr>
<td>Ohakune supply transformer capacity</td>
<td>Removed. Replacement transformer commissioned.</td>
</tr>
</tbody>
</table>

### 11.8 Central North Island transmission capability

Table 11-5 summarises issues involving the Central North Island region for the next 15 years. For more information about a particular issue, refer to the listed section number.

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional</td>
<td></td>
</tr>
<tr>
<td>11.8.1</td>
<td>Bunnythorpe interconnecting transformer capacity</td>
</tr>
<tr>
<td>11.8.2</td>
<td>Bunnythorpe–Mataroa 110 kV transmission capacity</td>
</tr>
<tr>
<td>11.8.3</td>
<td>Bunnythorpe–Woodville 110 kV transmission capacity</td>
</tr>
<tr>
<td>Site by grid exit point</td>
<td></td>
</tr>
<tr>
<td>11.8.4</td>
<td>Bunnythorpe supply transformer capacity</td>
</tr>
<tr>
<td>11.8.5</td>
<td>Linton supply transformer capacity</td>
</tr>
<tr>
<td>11.8.6</td>
<td>Mangahao supply transformer capacity</td>
</tr>
<tr>
<td>11.8.7</td>
<td>Marton low voltage</td>
</tr>
<tr>
<td>11.8.8</td>
<td>Marton supply transformer capacity</td>
</tr>
<tr>
<td>11.8.9</td>
<td>Mataroa supply transformer security and low voltage</td>
</tr>
<tr>
<td>11.8.10</td>
<td>National Park transmission and supply transformer security</td>
</tr>
<tr>
<td>11.8.11</td>
<td>Ohakune supply transformer security</td>
</tr>
<tr>
<td>11.8.12</td>
<td>Ongarue supply transformer security</td>
</tr>
<tr>
<td>11.8.13</td>
<td>Tokaanu supply transformer security</td>
</tr>
<tr>
<td>11.8.14</td>
<td>Waipawa low voltage</td>
</tr>
<tr>
<td>11.8.15</td>
<td>Waipawa supply transformer capacity and security</td>
</tr>
<tr>
<td>Bus security</td>
<td></td>
</tr>
<tr>
<td>11.9.1</td>
<td>Transmission bus security</td>
</tr>
<tr>
<td>11.9.2</td>
<td>Central North Island region low voltage</td>
</tr>
</tbody>
</table>

#### 11.8.1 Bunnythorpe interconnecting transformer capacity

**Project description:** Upgrade transformer capacity

**Project status/type:** Possible, Base Capex

**Indicative timing:** 2016-2018

**Indicative cost band:** B

**Issue**

Three interconnecting transformers at Bunnythorpe, each rated at 50 MVA, provide:

- a total nominal installed capacity of 150 MVA, and
- n-1 capacity of 116/125 MVA (summer/winter).
Loading on the Bunnythorpe interconnecting transformers may exceed their n-1 capacity for high Central North Island and Wellington loads, coupled with low local generation in Wellington.

Solution

This issue can be managed operationally by constraining either:
- Mangahao generation on
- HVDC transfer to high north flow, or
- Central North Island regional load down.

The Bunnythorpe interconnecting transformers have an expected end-of-life within the forecast period. One option is to replace these with two 150 MVA transformers.

11.8.2 Bunnythorpe–Mataroa 110 kV transmission capacity

Project description: Install a series reactor
Project status/type: Possible, Base Capex. This project is part of the lower North Island transmission capacity investigation.
Indicative timing: To be advised
Indicative cost band: A

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, low Arapuni generation, and an outage of a 220 kV Huntly–Stratford, Stratford–Taumarunui, Bunnythorpe–Tokaanu, Tokaanu–Whakamaru or Rangipo–Wairakei circuit.

Solution

This issue can be managed operationally by:
- limiting the HVDC north power flow, and/or
- increasing Arapuni generation, and/or
- opening the Arapuni–Ongarue circuit (leaving Ongarue, National Park, Ohakune, and Mataroa on n security).

Other options include:
- a special protection scheme to automatically open the circuit when it overloads
- install a series reactor
- reconductor the circuit from Bunnythorpe to Arapuni.

11.8.3 Bunnythorpe–Woodville 110 kV transmission capacity

Project description: Increase Bunnythorpe–Woodville transmission capacity
Project status/type: Possible, Base Capex and/or Major Capex Project. This project is part of the lower North Island transmission capacity investigation.
Indicative timing: Special protection scheme upgrade: to be advised
Circuit reconductoring or convert circuit’s operating voltage: to be advised
Indicative cost band: Special protection scheme upgrade: A
Circuit reconductoring or convert circuit’s operating voltage: to be advised

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 levels and the load in Wellington, Wairarapa, Dannevirke, and Waipawa. The circuits may overload for an outage of:
• one circuit overloading the remaining circuit during high south flow, or
• some 220 kV circuits between Bunnythorpe and Haywards, overloading the Bunnythorpe–Woodville circuits.

A special protection scheme at Woodville prevents overloading for a Bunnythorpe–Woodville outage 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
• removing Te Apiti generation if the overload on Bunnythorpe–Woodville remains.

Solution
The existing special protection scheme will resolve the issue caused by an outage of a Bunnythorpe–Woodville 110 kV circuit.

The overloading for a 220 kV circuit outage between Bunnythorpe and Haywards can be managed operationally by:
• restricting HVDC south power flow, and/or
• opening either the 110 kV Mangamaire–Woodville circuit or the Mangamaire–Masterton circuit, leaving Mangamaire on n security.

Longer-term options, which do not require operational measures include either:
• upgrading the existing special protection scheme to operate for a 220 kV circuit outage (also requiring a bus protection upgrade at Woodville)
• reconductoring the 110 kV Bunnythorpe–Woodville circuits with a higher rated conductor, or
• converting the Bunnythorpe–Woodville circuits to 220 kV operation.

11.8.4 Bunnythorpe supply transformer capacity

Project status/type: This issue is for information only

Issue
Two 220/33 kV transformers supply Bunnythorpe’s load, providing:
• a total nominal installed capacity of 166 MVA, and
• n-1 capacity of 100/100 MVA96 (summer/winter).

The peak load at Bunnythorpe is forecast to exceed the transformers’ n-1 winter capacity by approximately:
• 14 MW in 2015
• 10 MW in 2018 following some load transfer to Linton, and
• 24 MW in 2030 (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.

96 The transformers’ capacity is limited by cable ratings; with this limit resolved, the n-1 capacity will be 101/106 MVA (summer/winter).
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Table 11-6: Bunnythorpe supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Bunnythorpe</td>
<td>0.98</td>
<td>14</td>
</tr>
</tbody>
</table>

**Solution**

Powerco can transfer load within the distribution system to Linton following a contingency. Longer-term options include a third supply transformer at Bunnythorpe.

Future investment will be customer driven.

#### 11.8.5 Linton supply transformer capacity

**Issue**

Two 220/33 kV transformers (rated at 60 MVA and 100 MVA) supply Linton’s load, providing:

- a total nominal installed capacity of 160 MVA, and
- n-1 capacity of 77/81 MVA (summer/winter).

The peak load at Linton is forecast to exceed the transformers’ n-1 summer capacity by approximately 3 MW in 2024, increasing to approximately 9 MW in 2030 (see Table 11-7). Tararua wind generation (Stage 1) is connected to the Linton 33 kV bus, and the forecast assumes that the wind farm is not generating during peak load periods.

Table 11-7: Linton supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Linton</td>
<td>0.99</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

Linton normally has two 100 MVA transformers, but one failed and has been temporarily replaced with a 60 MVA system spare transformer. We are committed to replacing the 60 MVA transformer with a 120 MVA transformer, which will address the supply transformer capacity issue (see also Section 11.8.4 for information about load transfer from Bunnythorpe).

We will discuss with Powerco converting the Linton 33 kV outdoor switchyard to an indoor switchboard. Future investment will be customer driven.

#### 11.8.6 Mangahao supply transformer capacity

**Issue**

Two 110/33 kV transformers supply Mangahao’s load, providing:

- a total nominal installed capacity of 60 MVA, and
- n-1 capacity of 37/39 MVA (summer/winter).
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The peak load at Mangahao is forecast to exceed the transformers’ n-1 winter capacity by approximately 3 MW in 2015, increasing to approximately 6 MW in 2030 (see Table 11-8). The Mangahao generation station is connected to the 33 kV bus, and the forecast assumes that Mangahao is not generating during peak load periods.

Table 11-8: Mangahao supply transformer overload forecast

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Mangahao</td>
<td>0.96</td>
<td></td>
<td>3</td>
<td>3</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>6</td>
<td>6</td>
</tr>
</tbody>
</table>

Solution

If Mangahao generates at 10 MW or more, this issue can be delayed beyond the forecast period. The supply transformer overload is managed operationally as Mangahao generation is usually available during peak load periods.

We will also convert the Mangahao 33 kV outdoor switchgear to an indoor switchboard within the next five years. In addition, both Mangahao supply transformers will approach their expected end-of-life within the next 5-10 years. We will discuss the timing and options for these works with Electra and Todd Energy. Future investment will be customer driven.

11.8.7 Marton low voltage

Project status/type: This issue is for information only

Issue

The supply bus voltage at Marton is forecast to fall below 0.95 pu following an outage of a Bunnythorpe–Marton–Wanganui circuit.

Marton has supply transformers with off-load tap changers.

Solution

This issue can be managed operationally in the short term by managing Taranaki generation and HVDC transfer during peak load periods.

The issue will be partially addressed when the Bunnythorpe 220/110 kV transformers, which have off-load tap changers, are replaced with transformers having on-load tap changers (see Section 11.8.1).

In addition, both Marton supply transformers will approach their expected end-of-life within the forecast period. The replacement transformers will have on-load tap changers, addressing this issue for the long term.

11.8.8 Marton supply transformer capacity

Project description: Resolve transformers’ metering equipment limit
Project status/type: Possible, Base Capex
Indicative timing: 2018
Indicative cost band: A

Two 110/33 kV transformers (rated at 20 MVA and 30 MVA) supply Marton’s 33 kV load, providing:

- a total nominal installed capacity of 50 MVA, and
• n-1 capacity of 20/20 MVA\(^97\) (summer/winter).

The peak load at Marton is forecast to exceed the transformers’ n-1 summer capacity by approximately 1 MW in 2018, increasing to approximately 4 MW in 2030 (see Table 11-9).

### Table 11-9: Marton supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>5-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marton</td>
<td>0.94</td>
<td></td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

Resolving the metering equipment limit will solve the transformers’ n-1 capacity issue within the forecast period.

In addition, both Marton supply transformers will approach their expected end-of-life within the forecast period. We will discuss with Powerco the rating and timing for the replacement transformers. Future investment will be customer driven.

#### 11.8.9 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 no n-1 security.

The supply bus voltage at Mataroa is forecast to fall below 0.95 pu following an outage of a Bunnythorpe–Mataroa–1 circuit.

**Solution**

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. Powerco considers the lack of n-1 security can be resolved operationally for the forecast period.

The Mataroa supply transformer is approaching its expected end-of-life within the forecast period. We will discuss with Powerco the future supply options at Mataroa. Future investment will be customer driven.

The low voltage issue can be managed operationally by constraining on generation at Arapuni.

#### 11.8.10 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 no n-1 security.

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\(^97\) The transformers’ capacity is limited by metering equipment, followed by an LV bushing limit (24 MVA) and a protection limit (25 MVA); with these limits resolved, the n-1 capacity will be 26/27 MVA (summer/winter).
Solution

Some load can also be backfed through The Lines Company distribution system and they consider the lack of n-1 security can be resolved operationally for the forecast period.

In addition, the substation has recently been modified for the rapid connection of our mobile substation for transformer outages. Future investment will be customer driven.

11.8.11 Ohakune supply transformer security

| Project status/type: | This issue is for information only |

Issue

The load at Ohakune is supplied by a single 110/11 kV, 20 MVA supply transformer, resulting in no n-1 security.

Solution

The issue can be managed operationally. The substation was recently modified for the rapid connection of our mobile substation for transformer maintenance outages. The local lines companies, Powerco and The Lines Company, have not requested a higher security level at Ohakune.

Future investment will be customer driven.

11.8.12 Ongarue supply transformer security

| Project status/type: | This issue is for information only |

Issue

The load at Ongarue is supplied by a single 110/33 kV, 20 MVA supply transformer comprising three single-phase units, resulting in no n-1 security.

Solution

Most of the load can be backfed through The Lines Company’s distribution system. The Lines Company considers the lack of n-1 security can be resolved operationally for the forecast period. In addition, the supply transformer will reach its expected end-of-life towards the end of the forecast period. Future investment will be customer driven.

11.8.13 Tokaanu supply transformer security

| Project status/type: | This issue is for information only |

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 seamless n-1 security. Tripping the on-load transformer will result in a loss of supply until the other transformer is manually switched into service.

Solution

The Lines Company considers the lack of n-1 security can be resolved operationally for the forecast period. Future investment will be customer driven.
11.8.14 Waipawa low voltage

**Project status/type:** This issue is for information only

**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 5%.

The Waipawa supply transformers and Bunnythorpe interconnecting transformers have off-load tap changers, so these transformers cannot be used to manage the voltage.

**Solution**

Replacing the Bunnythorpe interconnecting transformer with 150 MVA transformers with on-load tap changers (see Section 11.8.1) will improve, 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.

In addition, the supply transformers will reach their expected end-of-life towards the end of the forecast period. The replacement transformers will have on-load tap changers. Future investment will be customer driven.

11.8.15 Waipawa supply transformer capacity and security

**Project description:** Resolve transformers’ metering and protection limits

**Project status/type:** Possible, Base Capex

**Indicative timing:** 2017

**Indicative cost band:** A

**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:

- a total nominal installed capacity of 50 MVA, and
- n-1 capacity of 26/26 MVA\(^{98}\) (summer/winter).

The peak load at Waipawa is forecast to exceed the transformers’ n-1 summer capacity by approximately 1 MW from 2020 (see Table 11-10).

**Table 11-10: Waipawa supply transformer overload forecast**

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Waipawa</td>
<td>0.92</td>
<td></td>
<td>2015 2016 2017 2018 2019 2020</td>
<td>2022 2024 2026 2028 2030</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>0 0 0 0 0 1</td>
<td>1 1 1 1 1</td>
</tr>
</tbody>
</table>

A single 33/11 kV, 10 MVA transformer supplies Waipawa’s 11 kV load, resulting in no n-1 security.

\(^{98}\) The transformers’ capacity is limited by a metering limit, followed by LV protection and transformer bushing (27 MVA) limits; with these limits resolved, the n-1 capacity will be 29/30 MVA (summer/winter).
Solution

Resolving the 110/33 kV transformers’ metering and protection limits will resolve the issue within the forecast period.

Centralines considers the lack of n-1 security for Waipawa’s 11 kV load can be resolved operationally within the forecast period. Future investment will be customer driven.

11.9 Central North Island bus security

This section presents issues arising from the outage of a single bus section rated at 50 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).

11.9.1 Transmission bus security

Table 9-16 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 11-11: Transmission bus outages

<table>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aratiatia 220 kV</td>
<td>-</td>
<td>Aratiatia</td>
<td>Bunnythorpe–Woodville overloading</td>
<td>See note 1</td>
</tr>
<tr>
<td>Bunnythorpe 110 kV</td>
<td>-</td>
<td>-</td>
<td>Regional low voltage and Bunnythorpe 220/110 kV transformer overloading</td>
<td>See note 2</td>
</tr>
<tr>
<td>Bunnythorpe 220 kV</td>
<td>-</td>
<td>-</td>
<td>Bunnythorpe–Woodville overloading</td>
<td>See note 3</td>
</tr>
<tr>
<td>Mangamaire 110 kV</td>
<td>Mangamaire</td>
<td>-</td>
<td>-</td>
<td>See note 4</td>
</tr>
<tr>
<td>Mataroa 110 kV</td>
<td>Mataroa</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Nga Awa Purua 220 kV</td>
<td>-</td>
<td>Nga Awa Purua Ngatamanaki</td>
<td>-</td>
<td>See note 5</td>
</tr>
<tr>
<td>Ohakune 110 kV</td>
<td>Ohakune</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Ongarue 110 kV</td>
<td>Ongarue</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Rangipo 220 kV</td>
<td>Rangipo</td>
<td>-</td>
<td>-</td>
<td>See note 4</td>
</tr>
<tr>
<td>Tokaanu 220 kV</td>
<td>Tokaanu</td>
<td>-</td>
<td>-</td>
<td>11.8.13</td>
</tr>
<tr>
<td>Wanganui 110 kV</td>
<td>Marton</td>
<td>Wanganui</td>
<td>-</td>
<td>See note 6</td>
</tr>
<tr>
<td>Woodville 110 kV</td>
<td>Dannevirke</td>
<td>Waipawa</td>
<td>-</td>
<td>See note 7</td>
</tr>
<tr>
<td>Wairakei 220 kV</td>
<td>-</td>
<td>Aratiatia</td>
<td>-</td>
<td>See note 8</td>
</tr>
</tbody>
</table>
1. There is a single bus section at Aratiatia, Mataroa, Ohakune and Ongarue, so a bus fault will cause loss of connection and loss of supply.

2. 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 11.8.3).

3. 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 Section 11.8.3).

4. There is no bus protection at Mangamaire and Rangipo, so bus faults cause loss of supply.

5. 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.

6. 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 a loss of supply at Marton and Wanganui (see Section 12.9.1).

7. 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 a loss of supply.

8. Aratiatia is connected to Wairakei through a single circuit. A Wairakei bus outage that disconnects this circuit disconnects the Aratiatia generation station.

The customers (Mighty River Power, Scanpower, Powerco, The Lines Company, Electra or Centralines) 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.

### 11.9.2 Central North Island region low voltage and Bunnythorpe 220/110 kV transformer overloading

#### Project description:
Replace Bunnythorpe interconnecting transformer
220 kV bus reconfiguration

#### Project status/type:
Possible, Base Capex

#### Indicative timing:
2016-2018

#### Indicative cost band:
B

#### Issue

Many of the supply transformers and the Bunnythorpe interconnecting transformers in the Central North Island cannot be used to manage voltage because the transformers have off-load tap changers. During periods of high Wellington load and low local generation, one of the Bunnythorpe interconnecting transformers may thermally overload, and the supply bus voltages in the region are forecast to fall below 0.95 pu following an outage of the Bunnythorpe 220 kV bus section that disconnects the:

- 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, and
- 220/33 kV Bunnythorpe–T10 supply transformer.

The low supply bus voltages may occur at Ongarue, Mataroa, Waipawa, Marton, and Brunswick and Wanganui (in the Taranaki region), depending on system conditions.

In addition, the step voltage change for this outage will exceed 5% at some grid exit points.
Solution

Replacing the Bunnythorpe interconnecting transformer with 150 MVA transformers with on-load tap changers (see Section 11.8.1) will resolve the thermal overload issue and improve the supply bus voltages. This will also lower the 220 kV voltages, which in turn restricts power transfer between Bunnythorpe and Wellington.

Rearranging the bus connections at Bunnythorpe and/or installing a fourth 220 kV bus coupler will provide n-1 bus security.

11.10 Other regional items of interest

There are no other items of interest identified to date beyond those in Section 11.8 and Section 11.9. See Section 11.11 for specific generation scenarios, proposals and opportunities relevant to this region.

11.11 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

11.11.1 Additional geothermal generation

There are a number of geothermal generating stations in the region connecting into or near the Wairakei Ring, with the potential for further geothermal developments. We recently replaced the Wairakei–Poihipi–Whakamaru–1 circuit with a new double-circuit line between Wairakei and Whakamaru. This increased the power flow capacity through the Wairakei Ring (see Chapter 6 for more information).

11.11.2 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. Possible wind generation stations (Maungaharuru / Hawke’s Bay Wind in the Hawke’s Bay region) may also connect to the same circuit (see Chapter 13, Section 13.11.2), which has enough capacity for 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 area. This additional potential generation will require Tauhara 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.

11.11.3 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 can 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 approximately 830 MW maximum generation injection into both
the 220 kV Bunnythorpe–Tararua Wind Central–Linton and Bunnythorpe–Linton circuits will not cause system issues.

The wind generation resource under investigation is so large, however, that it is unlikely to be economical to connect it all to these 220 kV circuits because of transmission constraints.

11.11.4 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 enables the connection of approximately 80 MW of additional generation, depending on where the generation is connected. Higher levels of generation may require occasional generation constraints or incremental and/or major system upgrades (including new lines).

11.11.5 Puketoi ranges

There are several prospective wind generation sites in the Puketoi ranges, with a combined capacity of many hundreds of megawatts. The closest network is the 110 kV transmission network (see Section 11.11.4), which is not nearby. If wind generation is developed in this area, then a single new transmission line may possibly connect all this wind generation to the National Grid at Bunnythorpe.

Generation from the Puketoi ranges can also connect along the 220 kV double-circuit line from Bunnythorpe to Wellington. However, care is required to ensure that the total generation from the Puketoi ranges, plus other generation along the 220 kV Bunnythorpe–Wellington line, does not become too high (see Section 11.11.3). It is also possible that some of the 110 kV lines may be rationalised as part of this work.
Chapter 12: Taranaki Region

12 Taranaki Regional Plan

12.1 Regional overview

This chapter details the Taranaki regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

Figure 12-1: Taranaki region
The Taranaki region includes a mix of medium-sized and small grid exit points, and industrial loads, as well as a number of small to large generation connections mainly involving gas-fired generation.

We have assessed the Taranaki region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be sufficiently flexible to respond to a range of future service and technology possibilities, taking into consideration:

- the existing transmission network
- forecast demand
- forecast generation
- equipment replacement based on condition assessment, and
- possible technological development.

### 12.2 Taranaki transmission system

This section highlights the state of the Taranaki regional transmission network. The existing transmission network is set out geographically in Figure 12-1 and schematically in Figure 12-2.

**Figure 12-2: Taranaki transmission schematic**

#### 12.2.1 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, generation exceeds demand in this region and power is exported to the rest of the National Grid.

Between Stratford and Bunnythorpe there is a 110 kV line in parallel with the 220 kV line. Power transfer south of Stratford can be constrained by the parallel 110 kV circuits under certain operating conditions.
We reconducted the 110 kV circuits between Stratford and Wanganui with a higher-rated conductor to maximise the through flow on the 220 kV circuits. The full benefit of the higher-rated conductor is limited by the rating of the Hawera 110 kV bus, which will be upgraded as part of redeveloping the Hawera substation (scheduled for completion in 2017).

12.2.2 Transmission within the region

Most of the 220 kV Taranaki transmission network forms part of the grid backbone. The parallel 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 and new generation connections will need to occur at points where there is spare capacity, or transmission upgrades may be required.

12.2.3 Longer-term development path

No significant new transmission is expected to be required in the Taranaki region. New generation connection may require nearby circuits to be thermally upgraded or reconducted for additional capacity to export the generation.

High levels of new generation, such as two or more combined cycle gas turbines, may require additional transmission circuits to transfer generation out of the region.

The conductor on the Brunswick–Stratford–B line\(^{99}\) is expected to reach its end-of-life within the next 5-10 years. Options include reconductoring the Brunswick–Stratford–B line or dismantling the Brunswick–Stratford–B line and uprating the Brunswick–Stratford–A line.

High expenditure will be required at New Plymouth due to equipment condition and as a result of decommissioning the generation station. Options to rationalise the New Plymouth site are being investigated. This includes transferring the 33 kV load to Carrington Street, operating the 220 kV New Plymouth–Stratford–1 and 2 circuits at 110 kV and connecting them directly onto the 110 kV Carrington Street–New Plymouth circuits, and installing a second 220/110 kV transformer at Stratford.

12.3 Taranaki demand

The after diversity maximum demand (ADMD) for the Taranaki region is forecast to grow on average by 1.0% annually over the next 15 years, from 220 MW in 2015 to 260 MW by 2030. This is lower than the national average demand growth of 1.1% annually.

Figure 12-3 shows a comparison of the 2014 and 2015 TPR forecast 15-year maximum demand (after diversity\(^{100}\)) for the Taranaki region. The TPR 2015 forecast is derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data, and is used to calculate the real power capacity for power transformers and transmission lines. See Chapter 4 for more information about demand forecasting.

---

99 Brunswick–Stratford–B is a 220 kV single circuit line. It is in parallel with the double circuit 220 kV Brunswick–Stratford–A line.

100 The after diversity maximum demand (ADMD) for the region will be less than the sum of the individual GXP peak demands, as it takes into account the fact that the peak demand does not occur simultaneously at all the GXPs in the region.
12.4 Taranaki generation

The Taranaki region’s generation capacity is 831 MW. The region imports and exports power to the National Grid depending on the level of generation dispatched.
Table 12-2 lists the generation forecast at 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 (Powerco).101

Table 12-2: Forecast annual generation capacity (MW) at Taranaki grid injection points to 2030 (including existing and committed generation)

<table>
<thead>
<tr>
<th>Grid injection point (location if embedded)</th>
<th>Generation capacity (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carrington St (Mangorei)</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>Hawera – Kiwi Dairy (Whareroa)</td>
<td>70</td>
<td>70</td>
<td>70</td>
</tr>
<tr>
<td>Hawera – Patea</td>
<td>31</td>
<td>31</td>
<td>31</td>
</tr>
<tr>
<td>Huirangi (Mangahewa)</td>
<td>9</td>
<td>9</td>
<td>9</td>
</tr>
<tr>
<td>Huirangi (Motukawa)</td>
<td>5</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>McKee</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Taranaki Combined Cycle</td>
<td>385</td>
<td>385</td>
<td>385</td>
</tr>
<tr>
<td>Stratford Peaker</td>
<td>200</td>
<td>200</td>
<td>200</td>
</tr>
<tr>
<td>Stratford (Stratford Austral Pacific)</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>

12.5 Taranaki significant maintenance work

Our capital project and maintenance works are integrated to enable system issues to be resolved if possible when assets are replaced or refurbished. Table 12-3 lists the significant maintenance-related work102 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 maintenance work

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brunswick supply transformer expected end-of-life, and</td>
<td>2016-2018</td>
</tr>
<tr>
<td>Brunswick 33 kV outdoor to indoor conversion</td>
<td>2023-2025</td>
</tr>
<tr>
<td>Brunswick–Stratford–B line reconductoring</td>
<td>2019-2023</td>
</tr>
<tr>
<td>Carrington Street 33 kV outdoor to indoor conversion</td>
<td>2022-2024</td>
</tr>
<tr>
<td>Hawera 110 kV rebuild, and</td>
<td>2013-2016</td>
</tr>
<tr>
<td>Hawera 33 kV outdoor to indoor conversion</td>
<td>2016-2018</td>
</tr>
<tr>
<td>Motunui 11 kV switchgear replacement</td>
<td>2021-2022</td>
</tr>
<tr>
<td>New Plymouth outdoor to indoor conversion, and</td>
<td>2020-2022</td>
</tr>
<tr>
<td>New Plymouth interconnecting transformer expected end-of-life</td>
<td>2021-2022</td>
</tr>
<tr>
<td>Opunake 33 kV outdoor to indoor conversion</td>
<td>2017-2019</td>
</tr>
<tr>
<td>Stratford interconnecting transformer expected end-of-life</td>
<td>2023-2024</td>
</tr>
<tr>
<td>Wanganui supply transformers expected end-of-life</td>
<td>2020-2022</td>
</tr>
</tbody>
</table>

12.6 Future Taranaki projects summary and transmission configuration

Figure 12-4 shows the possible configuration of Taranaki transmission in 2030, with new assets, upgraded assets, and assets undergoing significant maintenance within the forecast period.

---

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

102 This may include replacement of the asset due to its condition assessment.
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Figure 12-4: Possible Taranaki transmission configuration in 2030

12.7 Changes since the 2014 Transmission Planning Report

Table 12-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year’s report.

**Table 12-4: Changes since 2014**

<table>
<thead>
<tr>
<th>Issues</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carrington Street supply transformer capacity</td>
<td>New issue</td>
</tr>
<tr>
<td>Hawera supply transformer capacity</td>
<td>New issue</td>
</tr>
<tr>
<td>Stratford supply transformer capacity</td>
<td>New issue</td>
</tr>
</tbody>
</table>

12.8 Taranaki transmission capability

Table 12-5 summarises issues involving the Taranaki region for the next 15 years. For more information about a particular issue, refer to the listed section number.

**Table 12-5: Taranaki region transmission issues**

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional</td>
<td></td>
</tr>
<tr>
<td>12.8.1</td>
<td>North Taranaki transmission capacity</td>
</tr>
<tr>
<td>12.8.2</td>
<td>Stratford–Hawera–Waverley–Wanganui 110 kV transmission capacity</td>
</tr>
<tr>
<td>Site by grid exit point</td>
<td></td>
</tr>
<tr>
<td>12.8.3</td>
<td>Brunswick supply security and capacity</td>
</tr>
<tr>
<td>12.8.4</td>
<td>Carrington Street supply transformer capacity</td>
</tr>
<tr>
<td>12.8.5</td>
<td>Hawera voltage quality</td>
</tr>
<tr>
<td>12.8.6</td>
<td>Hawera (Kupe) supply security</td>
</tr>
<tr>
<td>12.8.7</td>
<td>Hawera supply transformer capacity</td>
</tr>
</tbody>
</table>
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### Section 12.9.1 North Taranaki transmission capacity

<table>
<thead>
<tr>
<th>Project description</th>
<th>Upgrade Taranaki transmission capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type</td>
<td>Stratford interconnecting transformer capacity: possible, Base Capex</td>
</tr>
<tr>
<td></td>
<td>Reconfigure 220 kV to 110 kV operation: to be advised</td>
</tr>
<tr>
<td>Indicative timing</td>
<td>New interconnecting transformer: 2017-2022</td>
</tr>
<tr>
<td></td>
<td>Reconfigure 220 kV to 110 kV operation: to be advised</td>
</tr>
<tr>
<td>Indicative cost band</td>
<td>New interconnecting transformer: B</td>
</tr>
<tr>
<td></td>
<td>Reconfigure 220 kV to 110 kV operation: to be advised</td>
</tr>
</tbody>
</table>

### Issue

The 220/110 kV, 100 MVA interconnecting transformer at Stratford operates in parallel with the 220/110 kV, 200 MVA interconnecting transformer 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.

The Stratford and New Plymouth transformers provide:

- a total nominal installed capacity of 295 MVA, and
- 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 (the loading on this interconnecting transformer depends on the 110 kV Taranaki generation).

### Solution

Possible solutions include:

- installing a second 220/110 kV interconnecting transformer at either Stratford or at (or near) New Plymouth (we anticipate land acquisition is required for a second transformer at New Plymouth)
- operating the 220 kV New Plymouth–Stratford circuits at 110 kV, decommissioning the New Plymouth 220/110 kV interconnection and installing two higher capacity interconnecting transformers at Stratford, or
- constraining-on generation or procuring demand response in the 110 kV network to reduce loading and maintain voltage quality.

In addition, the interconnecting transformers at New Plymouth and Stratford have an expected end-of-life within the forecast period. We will investigate the rating and timing of the replacement transformers, and a possible alternative transmission configuration.
12.8.2 Stratford–Hawera–Waverley–Wanganui 110 kV transmission capacity

**Project description:** Release Stratford–Wanganui capacity
**Project status/type:** Committed, Base Capex
**Indicative timing:** 2015-2016
**Indicative cost band:** A

**Issue**

The 110 kV Stratford–Hawera–Waverley–Wanganui transmission capacity sometimes constrains high south power flow for an outage of a parallel 220 kV circuit between Stratford and Bunnythorpe. This is due to the low rating of the Hawera 110 kV bus.\(^{103}\)

A series reactor and automatic bus splitting scheme at Hawera are available for use during prolonged periods of low South Island hydro storage.\(^{104}\) The series reactor (when switched in) limits the power flow through the bus to within its rating.

During an outage of a 220 kV circuit between Stratford and Bunnythorpe, an automatic protection scheme splits the bus, resolving the overload. Patea and the 33 kV load will be connected only to the Hawera–Stratford circuit. Whareroa and Kupe will be connected only to the 110 kV Hawera–Waverley circuit. These measures raise the constraint level but do not eliminate the issue completely.

**Solution**

The limiting equipment will be replaced as part of the Hawera bus refurbishment, after which the series reactor at Hawera will be decommissioned.

12.8.3 Brunswick supply security and capacity

**Project description:** A second supply transformer
**Project status/type:** Possible, customer-specific
**Indicative timing:** 2018-2020
**Indicative cost band:** B

**Issue**

A single 220/33 kV, 50 MVA transformer bank supplies load at Brunswick resulting in no n-1 security.

There is a non-contracted on-site spare transformer, allowing possible replacement within 8-14 hours following a unit failure (if the spare unit is available). The peak load at Brunswick is forecast to exceed the transformer’s continuous capacity by approximately 1 MW in 2022, increasing to approximately 5 MW in 2030 (see Table 12-6).

Some load may need to be curtailed during the transformer outage period, as there is only limited capacity within the Powerco network to transfer load.

**Table 12-6: Brunswick supply transformer overload forecast**

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brunswick</td>
<td>0.95</td>
<td>0</td>
</tr>
</tbody>
</table>

---

\(^{103}\) The 110 kV Stratford to Wanganui transmission capacity is limited to 76/76 MVA (summer/winter) by station equipment at Hawera.

\(^{104}\) The series reactor and the automatic bus splitting scheme are normally disabled. The need for the Hawera reactor has largely been removed since the upgrade of the 110 kV circuits between Wanganui and Stratford in 2012.
Solution

We are discussing longer-term future supply options with Powerco, one of which is to install a second supply transformer to provide n-1 security.

The existing transformer will also approach its expected end-of-life within the next five years. We will discuss with Powerco the appropriate rating and timing for the replacement transformers.

12.8.4 Carrington Street supply transformer capacity

| Project description: | Upgrade protection  
|                      | Upgrade branch components |
| Project status/purpose: | Upgrade protection: possible, Base Capex  
|                      | Upgrade branch components: possible, customer-specific |
| Indicative timing: | Upgrade protection: 2016  
|                      | Upgrade branch components: to be advised |
| Indicative cost band: | Upgrade protection: A  
|                      | Upgrade branch components: A |

Issue

Two 110/33 kV transformers supply Carrington Street’s load, providing:

- a total nominal installed capacity of 150 MVA, and
- n-1 capacity of 64/64 MVA\(^{105}\) (summer/winter).

The transformers’ capacity is limited by their 33 kV equipment. The peak load at Carrington Street is forecast to exceed the n-1 winter capacity by approximately (see Table 12-7):

- 3 MW in 2015
- zero MW in 2016 following the Bell Block load shift from Carrington Street to Huirangi, and
- 35 MW in 2030.

<table>
<thead>
<tr>
<th>Circuit/Grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carrington Street</td>
<td>0.98</td>
<td>3</td>
</tr>
</tbody>
</table>

Solution

In the short-term the overload can be managed operationally. In the medium-term, options include:

- shifting load to the Huirangi grid exit point (see Section 12.8.10), and
- upgrading the 33 kV equipment.

This will resolve the issue for the forecast period and beyond. Future investment will be customer driven.

12.8.5 Hawera voltage quality

| Project description: | Reactive support at Hawera |
| Project status/type: | Possible, Base Capex |

\(^{105}\) The transformers’ capacity is limited by a protection relay (64 MVA), followed by LV bus section and disconnector limits (69 MVA), a current transformer limit (71 MVA) and circuit breaker limit (91 MVA); with these limits resolved, the n-1 capacity will be 104/109 MVA (summer/winter).
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### Indicative timing:
- 2020-2025

### Indicative cost band:
- A

#### Issue

An outage of the 110 kV Hawera–Stratford circuit can result in low voltage and voltage drops greater than 5% when there is no local generation available at Hawera. When this occurs, Hawera is supplied from a 143 kilometre spur line from Bunnythorpe. As the spur load grows, the voltage quality issues progressively arise at Waverley, and Wanganui.

Patea (31 MW) and Whareroa (70 MW) inject into the Hawera 110 kV bus, but have difficulty providing voltage support.

#### Solution

There is an undervoltage load shedding capability at Hawera. Other options for resolving the low voltage issues include:
- obtaining greater reactive support from the generators, and/or
- installing reactive support at the Hawera 33 kV bus.

Installing approximately 17 Mvar of capacitors at the Hawera 33 kV bus, in blocks of approximately 2.5 to 3.0 Mvar per capacitor, will maintain a minimum bus voltage of 95% until 2030.

#### 12.8.6 Hawera (Kupe) supply security

**Project status/type:** This issue is for information only

#### Issue

A single 110/33 kV, 30 MVA supply transformer supplies the Origin Energy Resources Kupe load, resulting in no n-1 security.

#### Solution

The load can be transferred to the other supply transformers at Hawera by closing the 33 kV bus coupler. The load is fixed industrial, supplied by a dedicated transformer that meets the customer's requirements.

#### 12.8.7 Hawera supply transformer capacity

**Project status/purpose:** This issue is for information only

#### Issue

Two 110/33 kV transformers supply Hawera’s load, providing:
- a total installed capacity of 60 MVA, and
- n-1 capacity of 35/35 MVA\(^{106}\) (summer/winter).

The peak load at Hawera is forecast to exceed the transformers’ n-1 winter capacity by 3 MW in 2015, increasing to approximately 8 MW in 2030 (see Table 12-8).

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\(^{106}\) The transformers’ capacity is limited by a 33 kV bus section limit; with this limit resolved, the n-1 capacity will be 37/39 MVA (summer/winter).
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Table 12-8: Hawera supply transformer overload forecast

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hawera</td>
<td>0.96</td>
<td>3</td>
<td>4</td>
<td>4</td>
<td>5</td>
<td>5</td>
<td>6</td>
<td>6</td>
</tr>
</tbody>
</table>

Solution
The interim solution is to close the 33 kV bus coupler and supply the Powerco load from the remaining Hawera supply transformer and the single Kupe supply transformer.

A possible longer-term option is to replace the existing transformers with two 50-60 MVA units. We will discuss with Powerco the appropriate rating and timing for the replacement transformers. Future investment will be customer driven.

12.8.8 Kapuni supply security

| Project status/type: | This issue is for information only |

Issue
Kapuni is connected to the grid through a single tee connection on the 110 kV Opunake–Stratford–2 circuit, resulting in no n-1 security.

Solution
The customer agrees with the current level of security. Future investment will be customer driven.

12.8.9 McKee supply security

| Project status/type: | This issue is for information only |

Issue
McKee is connected to the grid through a single tee connection on the 110 kV Motunui–Stratford–1 circuit, resulting in no n-1 security.

Solution
The customer agrees with the current level of security. Future investment will be customer driven.

12.8.10 Huirangi supply transformer capacity

| Project status/type: | This issue is for information only |

Issue
Two 110/33 kV transformers supply Huirangi’s load, providing:
- a total installed capacity of 120 MVA, and
- n-1 capacity of 72/74 MVA (summer/winter).

The peak load at Huirangi is forecast to exceed the transformers’ n-1 summer capacity by 2 MW in 2022, increasing to approximately 8 MW in 2030 (see Table 12-9).
Table 12-9: Huirangi supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Huirangi</td>
<td>0.94</td>
<td>0</td>
</tr>
</tbody>
</table>

Powerco will permanently transfer the Bell Block load from Carrington Street to Huirangi in 2016 (which is accounted for in Table 12-9).

Solution

Operational measures will be used to prevent transformer overloading. Future investment will be customer driven.

12.8.11 Stratford supply transformer capacity

Project description: Resolve transformer branch limit
Project status/purpose: Possible, Base Capex
Indicative timing: 2016
Indicative cost band: A

Issue

Two 110/33 kV transformers supply Stratford’s load, providing:
- a total nominal installed capacity of 80 MVA, and
- n-1 capacity of 27/27 MVA\(^{107}\) (summer/winter).

The peak load at Stratford already exceeds the transformers’ n-1 summer capacity and the overload is forecast to increase to approximately 12 MW by 2030 (see Table 12-10).

Table 12-10: Stratford supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/Grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Stratford</td>
<td>0.93</td>
<td>5</td>
</tr>
</tbody>
</table>

Solution

Resolving the meter accuracy limit will solve the issue beyond the forecast period. Future investment will be customer driven.

12.8.12 Wanganui supply transformer capacity

Project description: Upgrade Wanganui transformer capacity
Project status/type: Possible, Base Capex
Indicative timing: 2020-2022
Indicative cost band: B

Issue

There are two 110/33 kV transformers (20 MVA and 30 MVA) at Wanganui, providing:
- a total nominal installed capacity of 50 MVA, and
- n-1 capacity of 24/24 MVA\(^{108}\) (summer/winter).

\(^{107}\) The transformers’ winter capacity is limited by the LV meter accuracy limit; with this limit resolved, the n-1 capacity will be 55/57 MVA.

\(^{108}\) The transformers’ winter capacity is limited by the LV meter accuracy limit; with this limit resolved, the n-1 capacity will be 55/57 MVA.
The peak load at Wanganui already exceeds the transformers’ n-1 winter capacity and the overload is forecast to increase to approximately 27 MW in 2030 (see Table 12-11).

### Table 12-11: Wanganui supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Wanganui</td>
<td>0.95</td>
<td>15</td>
</tr>
</tbody>
</table>

**Solution**

In the short term, load can be shifted to Brunswick, although some load restriction may be needed because of limited capacity within the Powerco network and the capacity of the Brunswick transformer. Both transformers will reach their expected end of life within about 10 years. We will discuss with Powerco the appropriate rating and timing for the replacement transformers.

### 12.8.13 Waverley supply security

#### Project status/type:

This issue is for information only

#### Issue

A single 110/11 kV, 10 MVA transformer supplies load at Waverley resulting in no n-1 security.

#### Solution

There is a national off-site spare transformer, allowing replacement within 2-4 weeks following a unit failure. Powerco considers the issue can be resolved operationally for the forecast period. Any future investment will be customer driven.

### 12.9 Taranaki bus security

This section presents issues arising from the outage of a single bus section rated at 50 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).

#### 12.9.1 Transmission bus security

Table 12-12 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.

#### Table 12-12: Transmission bus outages

<table>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hawera 110 kV</td>
<td>Hawera – Kupe</td>
<td>Patea</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td></td>
<td>Hawera – Powerco</td>
<td>Whareroa</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

---

108 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).
Chapter 12: Taranaki Region

Transmission

<table>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Plymouth 110 kV</td>
<td>New Plymouth</td>
<td>-</td>
<td>-</td>
<td>See note 2</td>
</tr>
<tr>
<td>Opunake 110 kV</td>
<td>-</td>
<td>Kapuni</td>
<td>-</td>
<td>12.9.2</td>
</tr>
<tr>
<td>Stratford 110 kV</td>
<td>Kapuni</td>
<td></td>
<td>-</td>
<td>12.9.2</td>
</tr>
<tr>
<td>Wanganui 110 kV</td>
<td>Marton</td>
<td>Wanganui</td>
<td>-</td>
<td>11.9.1 See note 3</td>
</tr>
<tr>
<td>Waverley 110 kV</td>
<td>Waverley</td>
<td></td>
<td>-</td>
<td>See note 3</td>
</tr>
</tbody>
</table>

1. The Hawera rebuild (see Section 12.10.1) includes a bus security upgrade which will provide n-1 security to Powerco and Whareroa. Security will not be increased to Kupe or Patea, which only have single connections.
2. This is a grid backbone bus, but only the local load is affected.
3. There is no bus protection at Wanganui and Waverley, so bus faults cause loss of supply.

The customers (Origin or Powerco) have not requested a higher security level. If increased bus security is required, the options typically include bus reconfiguration and/or additional bus circuit breakers. Future investment is likely to be customer driven.

12.9.2 Stratford bus security

<table>
<thead>
<tr>
<th>Project status/type:</th>
<th>This issue is for information only</th>
</tr>
</thead>
</table>

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 disconnects Kapuni. Similarly a fault on the Opunake bus section which this circuit connects to will also automatically disconnect Kapuni.

Solution

This issue is managed operationally. If n-1 security is required, options include:

- upgrading Kapuni to a ‘double tee’ connection, and
- installing line circuit breakers at Opunake and operating the bus solid.

Future investment will be customer driven.

12.10 Other regional items of interest

12.10.1 Hawera 110 kV bus rebuild

The Hawera 110 kV bus is being rebuilt due to its condition, to rationalise the bus to facilitate maintenance, and to increase the bus rating to match the Stratford and Waverley circuits’ ratings. Completed in stages between 2014 and 2016, the rebuild will involve periods when Hawera is on reduced security or capacity, and periods when generation is disconnected.

The rebuild includes installing a two-zone Bus Zone Protection scheme to improve security to Powerco and Whareroa.

12.10.2 New Plymouth developments

The New Plymouth substation’s land and buildings are owned by Ports of Taranaki and our occupancy rights are regulated by the Electricity Act. Ports of Taranaki is working with us to rationalise our presence at New Plymouth. Options include the following:
• Shift the control and relay room from the centre of the site to a new location closer to the indoor switchyard (at the site’s edge), and retain the 220 kV and 110 kV equipment at New Plymouth.

• Decommission and dismantle the 220 kV covered switchyard and the 220/110 kV transformer, convert the New Plymouth–Stratford line from 220 kV operation to 110 kV operation, retain the 110 kV substation at New Plymouth to supply the customer (Powerco) load, and install a second 220/110 kV transformer at Stratford.

• Transfer the customer (Powerco) load to another grid exit point and dismantle the substation, convert the New Plymouth–Stratford line from 220 kV operation to 110 kV operation, connect the New Plymouth–Stratford line to the 110 kV Carrington Street–New Plymouth line at a suitable location near the existing New Plymouth substation, and install a second 220/110 kV transformer at Stratford.

12.11 Taranaki 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

12.11.1 Maximum regional generation

For generation connections at the Stratford 220 kV bus, the maximum generation that can be injected under n-1 is approximately 500 MW in addition to the existing 385 MW Taranaki combined cycle, 200 MW Stratford peakers, and 100 MW McKee generators. The maximum generation that can be injected into the Stratford 220 kV bus depends on the direction of HVDC power flows and system constraints around the Wairakei Ring.

Generation stability issues may also need to be addressed.

12.11.2 Wind generation near Waverley

There is a potential for wind generation near Waverley. Connection options include the nearby 110 kV Hawera–Wanganui circuit, or the three nearby 220 kV Brunswick–Stratford circuits.

We have upgraded the 110 kV Stratford–Wanganui circuits (see Section 12.8.2), and approximately 165 MW of additional generation can be connected between Stratford and Wanganui. However, the Stratford interconnecting transformer will need to be upgraded and the protection limit at Waverley resolved to utilise the full capacity of the circuits for generation export.

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. In order to maintain the existing transfer capacity, a large wind generation station will need to be connected to all three circuits, or the capacity of one or more of the circuits will need to be increased.

12.11.3 Additional generation at other locations

There are no issues with connecting new generation at the New Plymouth 220 kV bus (other than stability issues). However, the maximum generation injection into the 110 kV New Plymouth bus is approximately 180 MW. Generation injection into
Carrington Street–Stratford circuit is restricted to approximately 85 MW at n-1 security. Any generation injecting into northern Taranaki region will play a significant role in regulating the 110 kV bus voltages in the region.

Exploration for more gas inshore and offshore continues in the Taranaki region, creating the potential for further gas-fired generation development. Depending on the size of 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.

The Opunake–Stratford circuit has sufficient capacity for approximately 50 MW of new generation on a secure double circuit.
Chapter 13: Hawke’s Bay Region

13 Hawke’s Bay Regional Plan

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<th>Regional overview</th>
</tr>
</thead>
<tbody>
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<td>13.2</td>
<td>Hawke’s Bay transmission system</td>
</tr>
<tr>
<td>13.3</td>
<td>Hawke’s Bay demand</td>
</tr>
<tr>
<td>13.4</td>
<td>Hawke’s Bay generation</td>
</tr>
<tr>
<td>13.5</td>
<td>Hawke’s Bay significant maintenance work</td>
</tr>
<tr>
<td>13.6</td>
<td>Future Hawke’s Bay projects summary and transmission configuration</td>
</tr>
<tr>
<td>13.7</td>
<td>Changes since the 2014 Transmission Planning Report</td>
</tr>
<tr>
<td>13.8</td>
<td>Hawke’s Bay transmission capability</td>
</tr>
<tr>
<td>13.9</td>
<td>Hawke’s Bay bus security</td>
</tr>
<tr>
<td>13.10</td>
<td>Other regional items of interest</td>
</tr>
<tr>
<td>13.11</td>
<td>Hawke’s Bay generation proposals and opportunities</td>
</tr>
</tbody>
</table>

13.1 Regional overview

This chapter details the Hawke’s Bay regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

Figure 13-1: Hawke’s Bay region
The Hawke’s Bay region load includes a mix of significant provincial cities (Napier, Hastings and Gisborne), heavy industry (the Panpac Mill), and smaller towns (Wairoa and Havelock North).

We have assessed the Hawke’s Bay region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be sufficiently flexible to respond to a range of future service and technology possibilities, taking into consideration:

• the existing transmission network
• forecast demand
• forecast generation
• equipment replacement based on condition assessment, and
• possible technological development.

13.2 Hawke’s Bay transmission system

This section highlights the state of the Hawke’s Bay regional transmission network. The existing transmission network is set out geographically in Figure 13-1 and schematically in Figure 13-2.
13.2.1 Transmission into the region

Transmission into the Hawke’s Bay region is via two 220 kV circuits from Wairakei that supply the Whirinaki and Whakatu loads directly, and via two 220/110 kV interconnecting transformers at Redclyffe.

Two 110 kV circuits also connect Fernhill to Waipawa in the south and are normally open at Waipawa.

13.2.2 Transmission within the region

220/110 kV interconnection

The majority of the region’s load is supplied via the 220/110 kV transformers at Redclyffe. The transformer capacity may need to be increased as load grows, and/or new generation is connected to the 110 kV transmission network.

110 kV circuits

Transmission within the region is predominantly at 110 kV. For new generation or load connections that exceed the current forecasts in this TPR, some 110 kV lines may require capacity upgrades.

13.2.3 Longer-term development path

The two 220 kV circuits from Wairakei are expected to be adequate for the next 30-40 years of regional load growth. Additional reactive support will be required over this period, and the region will be on n security whenever one circuit is out of service for maintenance.

The two 220 kV circuits may need to be thermally upgraded to export power from the region during low load periods if there is a large increase in new generation. A new 220 kV line from the Bunnynthorpe area to the Hawke’s Bay region may also be considered if an increase in security is required.

We expect the development of new generation in the Hawke’s Bay region to drive the need for system upgrades.

13.3 Hawke’s Bay demand

The after diversity maximum demand (ADMD) for the Hawke’s Bay region is forecast to grow on average by 0.5% annually over the next 15 years, from 316 MW in 2015 to 342 MW by 2030. This is lower than the national average demand growth of 1.1% annually.

Figure 13-3 shows a comparison of the 2014 and 2015 TPR forecast 15-year maximum demand (after diversity) for the Hawke’s Bay region. The forecasts are derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data. See Chapter 4 for more information about demand forecasting.

---

109 The after diversity maximum demand (ADMD) for the region will be less than the sum of the individual grid exit point peak demands, as it takes into account the fact that the peak demand does not occur simultaneously at all the grid exit points in the region.
Table 13-1 lists forecast peak demand (prudent growth) at each grid exit point for the forecast period.

**Table 13-1: Forecast annual peak demand (MW) at Hawke’s Bay grid exit points to 2030**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Fernhill</td>
<td>0.94</td>
<td></td>
<td>54</td>
<td>54</td>
<td>55</td>
<td>55</td>
<td>56</td>
<td>56</td>
<td>57</td>
<td>59</td>
<td>60</td>
<td>61</td>
<td>62</td>
</tr>
<tr>
<td>Redclyffe</td>
<td>0.99</td>
<td></td>
<td>66</td>
<td>66</td>
<td>67</td>
<td>67</td>
<td>68</td>
<td>68</td>
<td>69</td>
<td>69</td>
<td>70</td>
<td>71</td>
<td>72</td>
</tr>
<tr>
<td>Tuai</td>
<td>0.98</td>
<td></td>
<td>56</td>
<td>57</td>
<td>57</td>
<td>57</td>
<td>58</td>
<td>58</td>
<td>59</td>
<td>59</td>
<td>60</td>
<td>60</td>
<td>61</td>
</tr>
<tr>
<td>Whakatu</td>
<td>0.98</td>
<td></td>
<td>89</td>
<td>90</td>
<td>90</td>
<td>91</td>
<td>92</td>
<td>92</td>
<td>94</td>
<td>95</td>
<td>97</td>
<td>99</td>
<td>100</td>
</tr>
<tr>
<td>Whirinaki</td>
<td>1.00</td>
<td></td>
<td>80</td>
<td>80</td>
<td>80</td>
<td>80</td>
<td>80</td>
<td>80</td>
<td>80</td>
<td>80</td>
<td>80</td>
<td>80</td>
<td>80</td>
</tr>
</tbody>
</table>

**13.4 Hawke’s Bay generation**

The Hawke’s Bay region’s generation capacity is 329 MW. Generation from Tuai, Kaitawa, and Piripaua hydro generation stations are collectively referred to as the Waikaremoana Hydro Scheme and connect to the Tuai 110 kV bus.

Embedded within the 110 kV distribution system connected at Tuai grid exit point are two 2.5 MW Waihi generating units, and the 2 MW Matawai generation and mobile diesel generating units at Gisborne and Tikomaru Bay. Trustpower has recently constructed a new 4 MW hydro generating unit in the Esk Valley in 2013.

Table 13-2 lists the generation forecast at 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 (Unison or Eastland Networks).110

---

110 Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.
Table 13-2: Forecast annual generation capacity (MW) at Hawke’s Bay grid injection points to 2030 (including existing and committed generation)

<table>
<thead>
<tr>
<th>Grid injection point (location if embedded)</th>
<th>Generation capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Kaitawa</td>
<td>36</td>
</tr>
<tr>
<td>Piripaua</td>
<td>42</td>
</tr>
<tr>
<td>Redclyffe (Ravensdown) (Esk River)</td>
<td>8</td>
</tr>
<tr>
<td>Tuai</td>
<td>60</td>
</tr>
<tr>
<td>Tuai (Gisborne)</td>
<td>4</td>
</tr>
<tr>
<td>Tuai (Matawai)</td>
<td>2</td>
</tr>
<tr>
<td>Tuai (Waahi)</td>
<td>5</td>
</tr>
<tr>
<td>Whirinaki</td>
<td>155</td>
</tr>
<tr>
<td>Whirinaki (Pan Pac)</td>
<td>13</td>
</tr>
</tbody>
</table>

13.5 Hawke’s Bay significant maintenance work

Our capital project and maintenance works are integrated to enable system issues to be resolved if possible when assets are replaced or refurbished. Table 13-3 lists the significant maintenance-related 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 maintenance work

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fernhill 33 kV outdoor to indoor conversion, and supply transformers expected end-of-life</td>
<td>2021-2023, 2023-2024</td>
</tr>
<tr>
<td>Whirinaki 11 kV Bus B and C switchboard replacement</td>
<td>2023-2024</td>
</tr>
</tbody>
</table>

13.6 Future Hawke’s Bay projects summary and transmission configuration

Figure 13-4 shows the possible configuration of Hawke’s Bay transmission in 2030, with new assets, upgraded assets, and assets undergoing significant maintenance within the forecast period.

111 This may include replacement of the asset due to its condition assessment.
13.7 Changes since the 2014 Transmission Planning Report

Table 13-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year’s report.

Table 13-4: Changes since 2014

<table>
<thead>
<tr>
<th>Issues</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gisborne voltage quality</td>
<td>Removed. Assets were transferred to Eastland Network Limited.</td>
</tr>
<tr>
<td>Gisborne supply transformer capacity</td>
<td>Removed. Upgraded supply transformer.</td>
</tr>
<tr>
<td>Redclyffe supply transformer capacity</td>
<td>Removed. Assets were transferred to Eastland Network Limited.</td>
</tr>
<tr>
<td>Tuai supply security</td>
<td>Removed. Assets were transferred to Eastland Network Limited.</td>
</tr>
<tr>
<td>Whakatu supply transformer capacity</td>
<td>Removed. Lower load forecast at Whakatu.</td>
</tr>
</tbody>
</table>

13.8 Hawke’s Bay transmission capability

Table 13-5 summarises the issues involving the Hawke’s Bay region for 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

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
</table>
Chapter 13: Hawke's Bay Region

Section number | Issue
--- | ---
Regional |  
13.8.1 | Hawke’s Bay voltage quality
13.8.2 | Fernhill–Redclyffe 110 kV transmission capacity
13.8.3 | Redclyffe–Tuai 110 kV transmission capacity
13.8.4 | Redclyffe interconnecting transformer capacity
Site by grid exit point |  
13.8.5 | Fernhill supply transformer capacity
Bus security |  
13.9.1 | Transmission bus security

### 13.8.1 Hawke’s Bay voltage quality

**Project status/type:** This issue is for information only

**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 Fernhill supply bus, and the Fernhill supply transformers do not have on-load tap changers. This issue progressively arises at other high-voltage buses as load increases.

**Solution**

The low voltage risk is managed operationally by constraining-on generating units at Waikaremoana so that generation reactive support is available. As the Hawke’s Bay load increases, a 220 kV circuit outage will require more Waikaremoana generating units to be in service for reactive support.

We will discuss with Unison the supply transformer replacement at Fernhill\(^\text{112}\). Replacement transformers with on-load tap changers will resolve low voltage on the Fernhill supply bus.

We consider the issue can be resolved operationally within the forecast period.

### 13.8.2 Fernhill–Redclyffe 110 kV transmission capacity

**Project status/type:** This issue is for information only

**Issue**

There are two 110 kV Fernhill–Redclyffe circuits, each rated at 51/62 MVA (summer/winter). During periods of high load and low Tuai generation, power flows from Redclyffe to Tuai via the 110 kV:

- Redclyffe–Tuai circuits, and
- Fernhill–Redclyffe circuits and Fernhill–Tuai circuit (as per the blue load arrows in Figure 13-5).

---

\(^{112}\) The supply transformers at Fernhill have an expected end-of-life within the next 10 years and are scheduled for replacement within the next 5-10 years.
In these situations, an outage of one Fernhill–Redclyffe circuit can overload the other circuit.

**Figure 13-5: Power flow from Redclyffe to Tuai during high load and low Tuai generation**

![Diagram showing power flow from Redclyffe to Tuai](image)

**Solution**

Options to relieve a remaining Fernhill–Redclyffe circuit from overloading include the following:

- Constraining-on the Waikaremoana hydro generation with a minimum value that controls the Fernhill–Redclyffe circuit power flows. Minimum generation for the 2015 winter peak is approximately 20 MW, increasing to approximately 45 MW in 2030.

- Unbonding the 110 kV 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 requirement to constrain-on Waikaremoana generation but does reduce the level of minimum generation.

An investigation showed that unbonding the Fernhill–Tuai circuit is not economically viable. The estimated generation and demand growth in the region shows that this option is more likely to have an economic benefit beyond the forecast period.

Future investment will be customer driven.

**13.8.3 Redclyffe–Tuai 110 kV transmission capacity**

**Project status/type:** This issue is for information only

**Issue**

There are two 110 kV Redclyffe–Tuai circuits, each rated at 57/70 MVA (summer/winter). During periods of low load and high Tuai generation, power flows from Tuai to Redclyffe (as per the blue load arrows in Figure 13-6) via the 110 kV:

- Redclyffe–Tuai circuits, and
- Fernhill–Tuai circuit.

In these situations, an outage of the Fernhill–Tuai circuit can overload both Redclyffe–Tuai circuits.
Solution

The 110 kV Redclyffe–Tuai circuit constraints are managed operationally by limiting the maximum Waikaremoana hydro scheme generation.

We consider the issue can be resolved operationally for the forecast period.

13.8.4 Redclyffe interconnecting transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Special Protection Scheme</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Committed, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2015-2016</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>To be advised</td>
</tr>
</tbody>
</table>

Issue

Two 220/110 kV interconnecting transformers at Redclyffe supply the majority of the Hawke’s Bay load (except the load at Whirinaki and Whakatu, which is supplied from the 220 kV transmission system). The transformers provide:

- a nominal installed capacity of 200 MVA, and
- n-1 capacity of 101/107 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.

The peak 110 kV load is forecast to exceed the transformers’ n-1 winter capacity by approximately 46 MW in 2015, increasing to approximately 62 MW in 2030 (see Table 13-6). The forecast assumes minimal Waikaremoana generation of 12 MW.
Table 13-6: Redclyffe 220/110 kV transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Redclyffe</td>
<td>46</td>
</tr>
</tbody>
</table>

**Solution**

For planned outages, the overload is managed operationally by transferring load (within Unison’s network) from the 110 kV transmission network to the 220 kV transmission network, and by constraining-on generation at Waikaremoana. As the Hawke’s Bay load continues to grow, more Waikaremoana generation will need to be constrained-on more frequently during an outage of an interconnecting transformer at Redclyffe.

The application of the Investment Test shows that installing a third 220/110 kV transformer or replacing the existing transformers with higher rated units is uneconomic at present. The application of the Investment Test also shows it is uneconomic to constrain-on generation or manage load pre-contingency to prevent transformer overloading leading to a trip and regional loss of supply.

Therefore, we will install a Special Protection Scheme to automatically increase generation and/or reduce load post-contingency to reduce the risk of a transformer overload and trip.

**13.8.5 Fernhill supply transformer capacity**

**Issue**

Two 110/33 kV transformers (rated at 30 MVA and 50 MVA) supply Fernhill’s load, providing:

- a nominal installed capacity of 80 MVA, and
- n-1 capacity of 35/35 MVA\(^{113}\) (summer/winter).

The peak load at Fernhill already exceeds the transformers’ n-1 summer capacity by approximately 22 MW, and the overload is forecast to increase to approximately 30 MW in 2030 (see Table 13-7).

Table 13-7: Fernhill supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Fernhill</td>
<td>0.94</td>
<td>22</td>
</tr>
</tbody>
</table>

**Solution**

The short-term operational solution involves a load transfer within the Unison network following a transformer outage.

\(^{113}\) The transformers’ capacity is limited by the rating of the LV bushings limits (36 MVA), 33 kV overhead bus (37 MVA), and LV meter accuracy limit (41 MVA); with these limits resolved, the n-1 capacity will be 42/45 MVA (summer/winter).
Possible longer-term solutions include replacing the 30 MVA transformer with an 80 MVA transformer.

Both the existing single-phase supply transformers at Fernhill will approach their expected end-of-life within the next 5-10 years. In addition, we also plan to convert the Fernhill 33 kV outdoor switchgear to an indoor switchboard within the next 5-10 years.

We will discuss with Unison the future supply options as well as the coordination of the transformer capacity upgrade with the transformer replacement work. Future investment will be customer driven.

13.9  **Hawke’s Bay bus security**

This section presents issues arising from the outage of a single bus section rated at 50 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).

13.9.1  **Transmission bus security**

Table 13-11 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>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fernhill 110 kV</td>
<td>Fernhill</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Redclyffe 110 kV</td>
<td>-</td>
<td>-</td>
<td>Redclyffe 220/110 kV transformer overloading</td>
<td>See note 2</td>
</tr>
<tr>
<td>Redclyffe 220 kV</td>
<td>-</td>
<td>-</td>
<td>Redclyffe 220/110 kV transformer overloading</td>
<td>See note 2</td>
</tr>
<tr>
<td>Tuai 110 kV</td>
<td>Tuai</td>
<td>-</td>
<td>-</td>
<td>See note 3</td>
</tr>
<tr>
<td>Whirinaki 220 kV</td>
<td>Whirinaki</td>
<td>Whirinaki</td>
<td>-</td>
<td>See note 4</td>
</tr>
</tbody>
</table>

1. There is no bus protection at Fernhill, so bus faults cause loss of supply.
2. An outage of a Redclyffe 110 kV or 220 kV bus section disconnects a 220/110 kV transformer. This may cause the remaining transformer to overload (see Section 13.8.4).
3. There is a loss of supply to the 110 kV feeder supplying Eastland’s 110/11 kV transformer at Tuai only. There is no loss of supply to the 110 kV feeders supplying Eastland’s Gisborne and Wairoa feeders.
4. 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.

The customers (Genesis, Contact, Unison, Eastland, or Pan Pac) 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.
13.10 Other regional items of interest

There are no other items of interest identified to date beyond those in Sections 13.8 and 13.9. See Section 13.11 for information about generation proposals and opportunities relevant to this region.

13.11 Hawke’s Bay 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

13.11.1 Maximum regional generation

All generation in excess of the load is exported from the Hawke’s Bay region over the 220 kV double-circuit line from Redcliff 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 as these circuits are relatively long (137 kilometres), and they 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 Redcliff interconnecting transformers. Each interconnecting transformer has a 24-hour post-contingency rating of 101/107 MVA (summer/winter).

Estimates for maximum generation assume a North Island light load profile and that existing generation is high (Waikaremoana is generating 121 MW).

For generation connected at the Redcliff 220 kV bus, the maximum generation that can be injected under n-1 is approximately 470 MW or approximately 580 MW if the 220 kV circuit constraints are removed. The constraint is due to an overload of the 220 kV Redcliff–Whirinaki circuit when the 220 kV Redcliff–Wairakei circuit is out of service.

For generation connected at the Redcliff 110 kV bus, the maximum generation that can be injected under n-1 is approximately 70 MW. The constraint is due to an overload of the Redcliff interconnecting transformer when the other interconnecting transformer is out of service.

13.11.2 Maungaharuru wind and Tauhara geothermal generation stations

Maungaharuru wind generation station (formerly known as the Titiokura and Hawke’s Bay wind farms) is approximately 27 kilometres from Whirinaki, with a capacity of up to approximately 330 MW. A 220 kV double-circuit line traverses the site, and is the main supply to the Hawke’s Bay area from Wairakei.

The proposed Tauhara geothermal generation station in the Central North Island region also connects to one of the 220 kV circuits to Wairakei.

There are no issues with connecting the wind and geothermal generation into the same 220 kV circuits to Wairakei (see Chapter 11, Section 11.11.2).
13.11.3 Additional generation connected to the 110 kV network

There are a number of potential wind and hydro generation prospects that may connect into one or more of the 110 kV circuits in the region.

The impact new generation has on circuit loading depends on the connection’s location and configuration. For some connection locations and configurations, altering the hydro generation at Tuai resolves the circuit overloads, although this may adversely impact the energy market. To increase transmission capacity, the circuits will need to be reconductored and/or the Fernhill–Tuai circuit unbonded.

The Redclyffe 220/110 kV interconnecting transformer capacity 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

This chapter details the Wellington regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

Figure 14-1: Wellington region
Chapter 14: Wellington Region

The Wellington region is the major load centre (comprising both residential and central business district loads) of the southern North Island.

We have assessed the Wellington region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be flexible to respond to a range of future service and technology possibilities, taking into consideration:

- the existing transmission network
- forecast demand
- forecast generation
- equipment replacement based on condition assessment, and
- possible technological development.

14.2 Wellington transmission system

This section highlights the state of the Wellington regional transmission network. The existing transmission network is set out geographically in Figure 14-1 and schematically in Figure 14-2.

Figure 14-2: Wellington transmission schematic

14.2.1 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. A main corridor for through transmission between the North and South Islands, the loading of these circuits depends largely on HVDC power flow from the South Island, and generation from the Central North Island.
Chapter 14: Wellington Region

The HVDC’s link 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 1200 MW from the South Island (see Section 6.8).

The Wellington region’s generation capacity is much lower than the local load, requiring power to be imported into the region.

14.2.2 Transmission within the region

The region has some of the higher load densities in the North Island, coupled with relatively low levels of local generation.

Transmission within the Wellington region comprises:

- 220 kV circuits entering the region from Bunnythorpe
- 110 kV circuits entering the region from Mangamaire
- the HVDC link supporting the 220 kV transmission network at Haywards, and
- interconnecting transformers located at Haywards and Wilton.

The reactive support in the region is mainly provided from the Haywards substation, with some contribution from the West Wind generation station.

14.2.3 Longer-term development path

It is expected that no new major transmission lines will be required into the Wellington region.

Within the region, it is possible that additional circuit(s) and/or a new substation may be required for increased security to Wellington city, if this is shown to be economically justified.

In addition, there will be incremental upgrades within existing substations to increase security of supply within the region, particularly to Wellington city.

14.3 Wellington demand

The after diversity maximum demand (ADMD) for the Wellington region is forecast to grow on average by 1.1% annually over the next 15 years, from 720 MW in 2015 to 850 MW by 2030. This is the same rate as the national average demand growth.

Figure 14-3 shows a comparison of the 2014 and 2015 TPR forecast 15-year maximum demand (after diversity) for the Wellington region. The 2015 TPR forecast is derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data, and is used to calculate the real power capacity for power transformers and transmission lines. See Chapter 4 for more information about demand forecasting.

---

114 The after diversity maximum demand (ADMD) for the region will be less than the sum of the individual GXP peak demands, as it takes into account the fact that the peak demand does not occur simultaneously at all the GXPs in the region.
Table 14-1 lists the peak demand forecast (prudent growth) at each grid exit point for the forecast period.

Table 14-1: Forecast annual peak demand (MW) for Wellington grid exit points to 2030

<table>
<thead>
<tr>
<th>Grid exit point</th>
<th>Power factor</th>
<th>Next 5 years</th>
<th>Peak demand (MW)</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Park 11 kV</td>
<td>0.99</td>
<td>27 27 27 27 28 28 28 28</td>
<td>29 29 30 30 31</td>
<td></td>
</tr>
<tr>
<td>Central Park 33 kV</td>
<td>0.98</td>
<td>177 178 180 182 184 186</td>
<td>189 193 197 201 205</td>
<td></td>
</tr>
<tr>
<td>Gracefield</td>
<td>0.99</td>
<td>66 67 68 68 69 70</td>
<td>71 73 74 76 77</td>
<td></td>
</tr>
<tr>
<td>Greymouth</td>
<td>1.00</td>
<td>15 15 15 16 16 16</td>
<td>17 17 18 18 19</td>
<td></td>
</tr>
<tr>
<td>Haywards 11 kV</td>
<td>1.00</td>
<td>19 19 20 20 20 20</td>
<td>21 21 21 22 22</td>
<td></td>
</tr>
<tr>
<td>Haywards 33 kV</td>
<td>0.99</td>
<td>21 21 22 22 22 23</td>
<td>23 24 24 25 26</td>
<td></td>
</tr>
<tr>
<td>Kaiwharawhara</td>
<td>0.98</td>
<td>36 36 37 37 37 38</td>
<td>38 39 40 41 42</td>
<td></td>
</tr>
<tr>
<td>Masterton</td>
<td>0.98</td>
<td>50 51 52 53 54 54</td>
<td>56 58 60 61 63</td>
<td></td>
</tr>
<tr>
<td>Melling 11 kV</td>
<td>0.99</td>
<td>30 30 30 30 31 31</td>
<td>31 31 32 32 32</td>
<td></td>
</tr>
<tr>
<td>Melling 33 kV</td>
<td>1.00</td>
<td>49 49 49 49 48 48</td>
<td>48 48 48 48 48</td>
<td></td>
</tr>
<tr>
<td>Paraparaumu</td>
<td>0.99</td>
<td>64 65 66 66 67 68</td>
<td>69 70 72 73 75</td>
<td></td>
</tr>
<tr>
<td>Pauatahanui</td>
<td>0.99</td>
<td>22 22 23 23 23 23</td>
<td>24 24 25 25 26</td>
<td></td>
</tr>
<tr>
<td>Takapu Rd</td>
<td>0.99</td>
<td>109 110 112 113 114 116</td>
<td>119 122 124 127 130</td>
<td></td>
</tr>
<tr>
<td>Upper Hutt</td>
<td>1.00</td>
<td>33 33 34 34 35 35</td>
<td>36 38 39 40 41</td>
<td></td>
</tr>
<tr>
<td>Wilton</td>
<td>1.00</td>
<td>60 60 61 61 62 63</td>
<td>64 65 67 68 69</td>
<td></td>
</tr>
</tbody>
</table>

14.4 Wellington generation

The Wellington region’s generation capacity is 227 MW, which is 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 relevant local lines company’s network (Wellington Electricity Lines Limited, Powerco, and Electra).\textsuperscript{115}

Mill Creek is a recently commissioned wind generation project in the Wellington region.

Table 14-2: Forecast annual generation capacity (MW) for Wellington grid injection points to 2030 (including existing and committed generation)

<table>
<thead>
<tr>
<th>Grid injection point (location if embedded)</th>
<th>Generation capacity (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Park (Southern Landfill)</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Central Park (Wellington Hospital\textsuperscript{1})</td>
<td>10</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Greytown (Hau Nui)</td>
<td>9</td>
<td>9</td>
<td>9</td>
</tr>
<tr>
<td>Haywards (Silverstream)</td>
<td>3</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>Masterton (Kourarau A and B)</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>West Wind</td>
<td>143</td>
<td>143</td>
<td>143</td>
</tr>
<tr>
<td>Wilton (Mill Creek)</td>
<td>60</td>
<td>60</td>
<td>60</td>
</tr>
<tr>
<td>Haywards 220 kV (HVDC North transfer\textsuperscript{2})</td>
<td>1200</td>
<td>1200</td>
<td>1200</td>
</tr>
</tbody>
</table>

1. The Wellington Hospital generation is standby only.
2. The fourth cable may be installed in future as an additional stage in the HVDC development, increasing the HVDC link capacity to 1,400 MW.

14.5 Wellington significant maintenance work

Our capital projects and maintenance works are integrated to enable system issues to be resolved if possible when assets are replaced or refurbished. Table 14-3 lists the significant maintenance-related work\textsuperscript{116} proposed for the Wellington region for the next 15 years that may significantly impact related system issues or connected parties.

Table 14-3: Proposed significant maintenance work

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central Park 110/33 kV transformers (T3, T4) expected end-of-life, and Central Park 11 kV switchgear replacement</td>
<td>2020-2023, 2028-2029</td>
</tr>
<tr>
<td>Central Park–Wilton–2 and 3 circuits reconductoring (zebra section), and Central Park–Wilton–1, 2 and 3 circuits reconductoring (chukar section)</td>
<td>2016-2019, 2020-2025</td>
</tr>
<tr>
<td>Gracefield 33 kV switchgear replacement</td>
<td>2020-2022</td>
</tr>
<tr>
<td>Greytown 33 kV outdoor to indoor conversion</td>
<td>2021-2023</td>
</tr>
<tr>
<td>Haywards 33 kV outdoor to indoor conversion, and Haywards supply transformers expected end-of-life</td>
<td>2017-2020, 2016-2019</td>
</tr>
<tr>
<td>Melling 110/33 kV supply transformers expected end-of-life</td>
<td>2020-2022</td>
</tr>
<tr>
<td>Pauatahanui supply transformer T1 expected end-of-life, and Pauatahanui 33 kV outdoor to indoor conversion</td>
<td>2019-2021, 2024-2026</td>
</tr>
<tr>
<td>Upper Hutt supply transformers expected end-of-life, and</td>
<td>2026-2028</td>
</tr>
</tbody>
</table>

\textsuperscript{115} Only generators with capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

\textsuperscript{116} This may include replacement of the asset due to its condition assessment.
14.6 Future Wellington transmission configuration

Figure 14-4 shows the possible configuration of Wellington transmission in 2030, with new assets, upgraded assets, and assets undergoing significant maintenance within the forecast period.

Figure 14-4: Possible Wellington transmission configuration in 2030

14.7 Changes since the 2014 Transmission Planning Report

Table 14-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year’s report.

Table 14-4: Changes since 2014

<table>
<thead>
<tr>
<th>Issue</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Paraparaumu transmission security and supply transformer capacity</td>
<td>Removed. Paraparaumu 220 kV conversion commissioned.</td>
</tr>
</tbody>
</table>
14.8 Wellington transmission capability

Table 14-5 summarises issues involving the Wellington region for the next 15 years. For more information about a particular issue, refer to the listed section number.

Table 14-5: Wellington region transmission issues

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional</td>
<td></td>
</tr>
<tr>
<td>14.8.1</td>
<td>Wellington interconnecting transformer capacity</td>
</tr>
<tr>
<td>Site by grid exit point</td>
<td></td>
</tr>
<tr>
<td>14.8.2</td>
<td>Central Park supply transformer capacity</td>
</tr>
<tr>
<td>14.8.3</td>
<td>Haywards supply transformer capacity and security</td>
</tr>
<tr>
<td>14.8.4</td>
<td>Kaiwharawhara supply capacity and security</td>
</tr>
<tr>
<td>14.8.5</td>
<td>Melling supply capacity and voltage quality</td>
</tr>
<tr>
<td>14.8.6</td>
<td>Pauatahanui supply transformer capacity</td>
</tr>
<tr>
<td>14.8.7</td>
<td>Takapu Road supply transformer capacity</td>
</tr>
<tr>
<td>14.8.8</td>
<td>Upper Hutt supply transformer capacity</td>
</tr>
<tr>
<td>Bus security</td>
<td></td>
</tr>
<tr>
<td>14.9.1</td>
<td>Transmission bus security</td>
</tr>
<tr>
<td>14.9.2</td>
<td>Wellington interconnecting</td>
</tr>
<tr>
<td>14.9.3</td>
<td>Wairarapa low voltage</td>
</tr>
<tr>
<td>14.9.4</td>
<td>Central Park and West Wind bus security</td>
</tr>
<tr>
<td>14.9.5</td>
<td>Wilton voltage quality</td>
</tr>
</tbody>
</table>

14.8.1 Wellington interconnecting transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Fifth Wellington 220/110 kV interconnecting transformer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2026</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>B</td>
</tr>
</tbody>
</table>

Issue

The Wellington 110 kV transmission network is predominantly supplied by 220/110 kV interconnecting transformers, with three transformers at Haywards and one transformer at Wilton.

The three Haywards transformers have:
- a nominal installed capacity of 600 MVA, and
- n-1 capacity of 465/486 MVA (summer/winter).

The Wilton transformer has:
- a nominal installed capacity of 250 MVA, and
- n-1 capacity of 293/306 MVA (summer/winter).

The loading of these interconnecting transformers depends on the Wellington regional load, wind generation, and the HVDC transfer level and direction (north or south power flow).

The Haywards interconnecting transformers may exceed their n-1 winter capacity from around 2026 (depending on Wellington load, HVDC transfer magnitude, and direction).
**Solution**

One possible long-term solution is to install a fifth 220/110 kV interconnecting transformer in Wellington.

We will investigate the full range of options closer to the time the issue arises.

### 14.8.2 Central Park supply transformer capacity

*Project description:* Upgrade transformer capacity  
*Project status/type:* Possible, Base Capex  
*Indicative timing:* 2021  
*Indicative cost band:* C

#### Issue

Three 110/33 kV transformers (one rated at 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:

- a total nominal installed capacity of 320 MVA, and
- n-1 capacity of 217/223 MVA\(^{117}\) (summer/winter).

The peak load at Central Park for the combined 33 kV and 11 kV load is forecast to exceed the transformers’ n-1 winter capacity by approximately 1 MW in 2017, increasing to approximately 28 MW in 2030 (see Table 14-6).

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>110/33 kV</td>
<td>0.98</td>
<td>0 0 1 3 5 7</td>
<td>11 15 20 24 28</td>
</tr>
<tr>
<td>Central Park</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Solution

Possible solutions include:

- resolving the LV cable limit (will solve the issue until 2020)
- replacing the transformers with higher capacity units
- limiting the load to within the capacity of the transformers and load transferring to Wilton, and/or
- constructing a new grid exit point.

In addition, the two 100 MVA supply transformers at Central Park are approaching their expected end-of-life within the next ten years.

We will discuss future supply options with Wellington Electricity.

### 14.8.3 Haywards supply transformer capacity and security

*Project description:* Upgrade transformer capacity  
*Project status/type:* Possible, Base Capex  
*Indicative timing:* 2017  
*Indicative cost band:* C

\(^{117}\) The transformers’ capacity is limited by the LV cable; with this limit resolved, the n-1 capacity will be 217/228 MVA (summer/winter).
**Chapter 14: Wellington Region**

**Issue**

The Haywards grid exit point supplies load at 33 kV and 11 kV.

One 110/33 kV, 20 MVA transformer supplies the load at the 33 kV bus resulting in no n-1 security. This load can be back fed through the Wellington Electricity network.

The Haywards 33 kV peak load is forecast to exceed the transformer’s capacity by approximately 1 MW in 2015, increasing to approximately 6 MW in 2030 (see Table 14-7).

One 110/11 kV, 20 MVA transformer supplies the load at the 11 kV bus resulting in no n-1 security. Wellington Electricity can backfeed some load through their network and the Haywards local service transformer.

The Haywards 11 kV peak load is forecast to exceed the transformers’ capacity by approximately 1 MW in 2018, increasing to approximately 3 MW in 2030 (see Table 14-7).

### Table 14-7: Haywards supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Haywards 33 kV</td>
<td>0.99</td>
<td>1</td>
</tr>
<tr>
<td>Haywards 11 kV</td>
<td>1.00</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

We are discussing future supply options with Wellington Electricity. The short-term solution is to manage the load operationally. A possible long-term option is to replace the supply transformers with two new 110/33/11 kV, 60/30/30 MVA transformers, providing n-1 security to both the 11 kV and 33 kV buses.

Both supply transformers at Haywards are approaching their expected end-of-life within the next five years. We will discuss the appropriate rating and timing of the replacement transformers with Wellington Electricity.

### 14.8.4 Kaiwharawhara supply capacity and security

**Project status/type:** This is for information only

**Issue**

The Kaiwharawhara load is supplied by:

- two 110 kV circuits, each rated at 57/66 MVA\(^{118}\) (summer/winter) from Wilton, and
- two 110/11 kV supply transformers, providing:
  - a total nominal installed capacity of 60 MVA, and
  - n-1 capacity of 38/38 MVA\(^{119}\) (summer/winter).

The Kaiwharawhara substation is configured with no 110 kV bus (each transformer is connected to only one 110 kV circuit in a transformer-feeder arrangement) and is operated with a split 11 kV bus. Tripping either one of the transformer feeders will result in a loss of supply to half the load. If this load is transferred to the remaining

---

\(^{118}\) The Kaiwharawhara–Wilton circuits are limited by the cable rating; with this limit resolved, the n-1 capacity will be 57/68 MVA (summer/winter).

\(^{119}\) 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 41/43 MVA (summer/winter).
transformer feeder, the total Kaiwharawhara peak load is forecast to exceed the transformers’ n-1 summer capacity by approximately 3 MW in 2015, increasing to approximately 8 MW in 2030 (see Table 14-8).

Table 14-8: Kaiwharawhara supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kaiwharawhara</td>
<td>0.98</td>
<td></td>
<td>2015 2016 2017 2018 2019 2020</td>
<td>2022 2024 2026 2028 2030</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>3 3 3 4 4 5</td>
<td>5 6 7 8 8</td>
</tr>
</tbody>
</table>

**Solution**

Wellington Electricity considers the issue can be managed operationally by transferring excess load to other grid exit points through the distribution network. Future investment will be customer driven.

### 14.8.5 Melling supply capacity and voltage quality

**Project description:** Resolve protection limits

**Project status/type:** Possible, customer-specific

**Indicative timing:** To be advised

**Indicative cost band:** A

**Issue**

The Melling load is supplied by two:

- 110 kV circuits, each rated at 95/101 MVA\(^{120}\) (summer/winter) from Haywards
- 110/33 kV transformers supplying Melling’s 33 kV load, providing:
  - a total nominal installed capacity of 100 MVA, and
  - n-1 capacity of 63/65 MVA\(^{121}\) (summer/winter)
- 110/11 kV transformers supplying Melling’s 11 kV load, providing:
  - a total nominal installed capacity of 50 MVA, and
  - n-1 capacity of 30/30 MVA\(^{122}\) (summer/winter).

In terms of Melling’s peak load:

- The 11 kV load is forecast to exceed the transformers’ n-1 winter capacity by 3 MW in 2015, increasing to approximately 5 MW in 2030 (see Table 14-9).
- The 33 kV bus voltage is forecast to fall below 0.95 pu from 2015.

Table 14-9: Melling supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>3 3 3 3 3 3</td>
<td>4 4 4 5 5</td>
</tr>
</tbody>
</table>

**Solution**

Resolving the protection limit will solve the transformers’ n-1 winter capacity issue until 2022.

---

\(^{120}\) 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).

\(^{121}\) 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).

\(^{122}\) The transformers’ capacity is limited by HV protection equipment; with this limit resolved, the n-1 capacity will be 32/34 MVA (summer/winter).
We will discuss future supply options with Wellington Electricity.

In addition, both Melling 110/33 kV supply transformers have an expected end-of-life within the next 10 years. Any replacement supply transformers will have on-load tap changers, which will resolve the low voltage issues. We will discuss the appropriate rating and timing for the replacement transformers with Wellington Electricity. Future investment will be customer driven.

14.8.6 Pauatahanui supply transformer capacity and low voltage

Project description: Upgrade transformer capacity
Project status/type: Possible, customer-specific
Indicative timing: 2020
Indicative cost band: B

Issue

The Pauatahanui load is supplied by two:

- 110 kV circuits, each rated at 78/78 MVA\(^{123}\) (summer/winter), from Takapu Road, and
- 110/33 kV transformers, providing:
  - a total nominal installed capacity of 40 MVA, and
  - n-1 capacity of 22/24 MVA (summer/winter).

In terms of Pauatahanui’s peak load:

- The peak load at Pauatahanui is forecast to exceed the transformers’ n-1 winter capacity by approximately 1 MW in 2017, increasing to approximately 4 MW in 2030 (see Table 14-10).
- An outage of a Pauatahanui–Takapu Road circuit will cause the supply bus voltage to fall below 0.95 pu from winter 2020.

Table 14-10: Pauatahanui supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/Grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Pauatahanui</td>
<td>0.99</td>
<td>0</td>
</tr>
</tbody>
</table>

Solution

In the short-term, the lack of n-1 capacity for the transformers can be managed operationally.

Longer term, one supply transformer at Pauatahanui will approach its expected end-of-life within the next 5-10 years. The replacement supply transformer will have an on-load tap changer, which will resolve the low voltage issue. Wellington Electricity is also considering a new zone substation within their distribution network to transfer load from Takapu Road to Pauatahanui (see Section 14.8.7). If this occurs, then the overload will be greater than forecast in Table 14-10 and an increase in the supply transformers’ capacity will be required. Future investment will be customer driven.

14.8.7 Takapu Road supply transformer capacity

Project description: Upgrade transformer capacity
Project status/type: Possible, customer-specific
Indicative timing: To be advised

\(^{123}\) The Pauatahanui-Takapu Road circuits are limited by the Pauatahanui 110 kV bus rating; with this limit resolved, the n-1 capacity will be 95/105 MVA (summer/winter).
### Chapter 14: Wellington Region

**Indicative cost band:** B

**Issue**

Two 110/33 kV transformers supply Takapu Road’s load, providing:
- a total nominal installed capacity of 180 MVA, and
- n-1 capacity of 111/116 MVA (summer/winter).

The peak load at Takapu Road is forecast to exceed the transformers’ n-1 winter capacity by approximately 2 MW in 2015, increasing to approximately 24 MW in 2030 (see Table 14-11).

**Table 14-11: Takapu Road supply transformer overload forecast**

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Takapu Road</td>
<td>0.99</td>
<td>2 4 5 7 8 10</td>
</tr>
</tbody>
</table>

**Solution**

We will discuss future options with Wellington Electricity. Possible longer-term options include:
- replacing the existing supply transformers with two 120 MVA units and limiting the load growth to the transformer’s n-1 capacity
- installing a third supply transformer, or
- transferring load to the Pauatahanui grid exit point (see Section 14.8.6).

Future investment will be customer driven.

### 14.8.8 Upper Hutt supply transformer capacity

**Project description:** Resolve protection and metering limits

**Project status/type:** Proposed, Base Capex

**Indicative timing:** 2015

**Indicative cost band:** A

**Issue**

Two 110/33 kV transformers supply Upper Hutt’s load, providing:
- a total nominal installed capacity of 80 MVA, and
- n-1 capacity of 38/38 MVA (summer/winter).

The peak load at Upper Hutt is forecast to exceed the transformers’ n-1 winter capacity by approximately 1 MW in 2022, increasing to approximately 5 MW in 2030 (see Table 14-12).

**Table 14-12: Upper Hutt supply transformer overload forecast**

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upper Hutt</td>
<td>1.00</td>
<td>0 0 0 0 0 0</td>
</tr>
</tbody>
</table>

124 The transformers’ capacity is limited by protection equipment, followed by the metering (41 MVA) limits; with these limits resolved, the n-1 capacity will be 51/54 MVA (summer/winter).
Solution

Resolving the protection equipment limit and recalibrating the metering parameters will provide sufficient n-1 capacity for the forecast period.

In addition, the Upper Hutt 33 kV outdoor switchgear will be converted to an indoor switchboard within the next five years. Also, both the supply transformers have an expected end-of-life towards the end of the forecast period. We will discuss the rating and timing of replacement transformers with Wellington Electricity. Future investment will be customer driven.

14.9 Wellington bus security

This section presents issues arising from the outage of a single bus section rated at 50 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).

14.9.1 Transmission bus security

Table 9-16 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 14-13: Transmission bus outages

<table>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Haywards 110 kV</td>
<td>Haywards</td>
<td>-</td>
<td>Wellington interconnecting transformer overloading</td>
<td>See note 1 14.9.2</td>
</tr>
<tr>
<td>Masterton 110 kV</td>
<td>Masterton</td>
<td>-</td>
<td>-</td>
<td>See note 2</td>
</tr>
<tr>
<td></td>
<td>Greytown</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upper Hutt 110 kV</td>
<td>Upper Hutt</td>
<td>-</td>
<td>Wairarapa low voltage</td>
<td>14.9.3</td>
</tr>
<tr>
<td>Wilton 110 kV</td>
<td>Central Park</td>
<td>West Wind</td>
<td></td>
<td>14.9.4 See note 3</td>
</tr>
<tr>
<td></td>
<td>Kaiwharawhara</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Wilton voltage quality</td>
<td>14.9.5</td>
</tr>
</tbody>
</table>

1. Haywards has a single 110/33 kV and a single 110/11 kV supply transformer. A bus outage will disconnect one but not both supply transformers, causing a partial loss of supply. Replacing the transformers with two 110/33/11 kV banks (see Section 14.8.3) will provide bus security.
2. Masterton does not have bus zone protection and there are no line circuit breakers at Greytown. A fault on the Masterton 110 kV bus will result in a loss of supply at Masterton and Greytown. We will investigate whether there is economic benefit to improve the bus security at Masterton.
3. An outage of a Wilton bus section will 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 14.8.4).

The customers (Wellington Electricity, Powerco, Electra, or Meridian) 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.
14.9.2 Wellington interconnecting transformer overloading

<table>
<thead>
<tr>
<th>Project reference:</th>
<th>Bus reconfiguration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2018-2020</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>B</td>
</tr>
</tbody>
</table>

**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, and the HVDC transfer level and direction (north or south power flow).

The worst contingency affecting the Wellington 110 kV supply capacity is an outage of a bus section at Haywards that disconnects several components, including the loss of:

- two of the three 220/110 kV transformers
- reactive voltage support (condensers 7 and 8, and filter 1), and
- several circuits.

The loss of the circuits increases reactive power absorption and decreases voltage.

The remaining Haywards–T2 interconnecting transformer will exceed its n-1 winter capacity from 2015. The Wilton interconnecting transformer will exceed its n-1 winter capacity from approximately 2019 (depending on Wellington load, HVDC transfer magnitude, and direction).

**Solution**

We will investigate a Haywards 110 kV bus split to manage the bus fault to address the low voltage and Wellington interconnecting transformer overloading.

14.9.3 Wairarapa low voltage

<table>
<thead>
<tr>
<th>Project reference:</th>
<th>Upper Hutt bus coupler</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>Upper Hutt bus coupler: A</td>
</tr>
<tr>
<td></td>
<td>Masterton capacitor bank: A</td>
</tr>
</tbody>
</table>

**Issue**

Following an outage of the Upper Hutt 110 kV bus, depending on the availability of wind generation at Te Apiti the:

- transmission bus voltages at Greytown and Masterton are forecast to fall below 0.90 pu from winter 2015
- supply bus voltage at Greytown is forecast to fall below 0.95 pu from winter 2021, and
- supply bus voltage at Masterton is forecast to fall below 0.95 pu from winter 2025.

**Solution**

Possible options to address the low voltages include either:

- a wider voltage agreement at Greytown and Masterton to allow 110 kV voltages of 0.85 pu, which will solve the issue until 2020

2015 Transmission Planning Report © Transpower New Zealand Limited 2015. All rights reserved.
• installing a bus coupler at Upper Hutt, or
• installing a 14 Mvar capacitor at Masterton.

The solution will need to be compatible with plans to improve bus security at Masterton, and we do not expect any option to address low voltage issues to be economic.

### 14.9.4 Central Park and West Wind bus security

<table>
<thead>
<tr>
<th>Project reference:</th>
<th>Wilton bus upgrade</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Committed, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2017</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>C</td>
</tr>
</tbody>
</table>

#### Issue

Three 110 kV circuits from Wilton are directly connected to the supply transformers at Central Park, where there is no 110 kV bus.

The worst contingency affecting Central Park supply security is an outage of a 110 kV Wilton bus section that disconnects several circuits, including the Central Park–West Wind–Wilton–2 and 3 circuits, after which only one 110 kV circuit and one 110/33 kV supply transformer remain in service.

The combined 33 kV and 11 kV load at Central Park exceeds the capacity of the remaining:

- 110 kV Central Park–Wilton–1 circuit from 2015, and
- 110/33 kV Central Park–T5 supply transformer from 2015.

In addition, the Wilton bus fault that disconnects the Central Park–West Wind–Wilton–2 and 3 circuits also disconnects the West Wind wind farm.

#### Solution

We have committed to constructing a third Wilton 110 kV bus section. This will reduce the loading on the Central Park–Wilton circuit and Central Park supply transformer for a Wilton 110 kV bus outage. It will also disconnect only half of the West Wind wind farm. This project is expected to be completed in 2017.

With the new Wilton 110 kV bus configuration, an outage of the middle bus section may cause the combined 33 kV and 11 kV peak load at Central Park to exceed the capacity of the 110/33 kV Central Park–T5 supply transformer from around 2020 (with no West Wind generation).

### 14.9.5 Wilton voltage quality

<table>
<thead>
<tr>
<th>Project reference:</th>
<th>A third 110 kV bus section</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Committed, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2017</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>C</td>
</tr>
</tbody>
</table>

The Wellington 110 kV network is predominantly supplied via the Haywards and Wilton 220/110 kV interconnecting transformers. An outage of a Wilton 110 kV bus section disconnects several components, including the Wilton 220/110 kV interconnecting transformer and a Takapu Road–Wilton circuit. This outage may result in low voltages at Central Park, Kaiwharawhara and Wilton, and high loading on the remaining Takapu Road–Wilton circuit.

Depending on the generation output and reactive support from West Wind, the:

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125 West Wind is operated as two half stations, each on n security.
Chapter 14: Wellington Region

- transmission bus voltages may fall below 0.90 pu at Central Park by 2018, and Kaiwharawhara and Wilton by 2023
- supply bus voltage at Central Park 33 kV may fall below 0.95 pu by 2021, and Takapu Road–Wilton circuit will overload by 2026.

Solution

We have committed to constructing a third Wilton 110 kV bus section. This project is expected to be completed in 2017. The low voltage issue is solved by connecting the Wilton–T8 interconnecting transformer and Takapu Road–Wilton–1 and 2 circuits to different bus sections (see Section 14.9.4).

14.10 Other regional items of interest

14.10.1 Central Park supply security during maintenance

Three 110 kV Central Park–Wilton circuits supply the Central Park load. There is no 110 kV bus at Central Park, so an outage of one circuit will cause the loss of one transformer connected in series with the circuit.

When a circuit is taken out of service for maintenance, a loss of another circuit during high load periods will cause the third supply transformer to overload and trip, resulting in a total loss of supply.

This issue is addressed, in the short term, by a 110/33 kV special protection scheme at Central Park to automatically shed load. In the long term, the issue can be addressed by installing a 110 kV bus at Central Park, or transferring load to Wilton or a new grid exit point in Wellington.

14.11 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

See also Chapter 11, Section 11.11.4 for more information about connecting wind generation in the lower North Island.

14.11.1 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 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 the 220/110 kV interconnection capacity.

However, the capacity of the grid backbone between regions may constrain the generation.

14.11.2 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 depends on its location along the 110 kV line, and any line upgrades. Approximately 180 MW of generation can connect at Masterton under normal operating conditions. Other generation locations and upgrade options may result in maximum generation levels ranging from approximately 0 (zero) to 180 MW.
Chapter 15: Nelson-Marlborough Region

15 Nelson-Marlborough Regional Plan

15.1 Regional overview

This chapter details the Nelson-Marlborough regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

Figure 15-1: Nelson-Marlborough region
The Nelson-Marlborough region includes a mix of significant and growing provincial cities (Nelson, Richmond, and Blenheim) together with smaller rural localities (the Golden Bay area).

We have assessed the Nelson-Marlborough region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be flexible to respond to a range of future service and technology possibilities, taking into consideration:

- the existing transmission network
- forecast demand
- forecast generation
- equipment replacement based on condition assessment, and
- possible technological development.

15.2 Nelson-Marlborough transmission system

This section highlights the state of the Nelson-Marlborough regional transmission network. The existing transmission network is set out geographically in Figure 15-1 and schematically in Figure 15-2.

Figure 15-2: Nelson-Marlborough transmission schematic

15.2.1 Transmission into the region

The Nelson-Marlborough region is connected to the rest of the National Grid via 220 kV circuits at Kikiwa.

The regional generation is lower than the regional demand, so most of the region’s load is supplied from remote generation in the Waitaki Valley via 220 kV circuits, with significant load off-take in the South Canterbury and Canterbury regions. Therefore, supply to the Nelson-Marlborough region is affected by transmission capacity from the Waitaki Valley.
15.2.2 Transmission within the region

The transmission within the region comprises:

- 220 kV circuits from Kikiwa to Stoke
- parallel 110 kV circuits forming a ‘triangle’ between Kikiwa, Stoke, and Blenheim, and
- 220/110 kV interconnecting transformer at Stoke.

The reactive power support in this region is provided from the 60 Mvar capacitors at Stoke and 20.4 Mvar capacitors at Blenheim.

15.2.3 Longer-term development path

The two existing 220 kV Kikiwa–Stoke circuits have enough capacity to provide n-1 security within the region for the next 20-30 years.

As the Nelson-Marlborough region relies on generation several hundred kilometres away, there will be an on-going need for investment in reactive support (such as the STATCOM at Kikiwa and additional capacitors) to support the voltage.

The 110 kV Blenheim–Argyle–Kikiwa line may need upgrading if there is more than one significant new generator connected along the line, at Blenheim or embedded behind the Blenheim grid exit point.

Increased 220/110 kV interconnecting transformer capacity will be required beyond the forecast period at Kikiwa and/or Stoke. The capacity of the 110 kV Kikiwa–Stoke circuit may also need to be increased as this circuit is an important connection between the 220/110 kV transformers at Kikiwa and Stoke.

15.3 Nelson-Marlborough demand

The after diversity maximum demand (ADMD) for the Nelson-Marlborough region is forecast to grow on average by 1.4% annually over the next 15 years, from 215 MW in 2015 to 260 MW by 2030. This is higher than the national average demand growth of 1.1% annually.

Figure 15-3 shows a comparison of the 2014 and 2015 TPR forecast 15-year maximum demand (after diversity\textsuperscript{126}) for the Nelson-Marlborough region. The forecasts are derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data. See Chapter 4 for more information about demand forecasting.

\textsuperscript{126} The after diversity maximum demand (ADMD) for the region will be less than the sum of the individual grid exit point peak demands, as it takes into account the fact that the peak demand does not occur simultaneously at all the grid exit points in the region.
Table 15-1 lists the peak demand forecast (prudent growth) for each grid exit point for the forecast period.

Table 15-1: Forecast annual peak demand (MW) at Nelson-Marlborough grid exit points to 2030

<table>
<thead>
<tr>
<th>Grid exit point</th>
<th>Power factor</th>
<th>Peak demand (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blenheim</td>
<td>0.99</td>
<td>78 79 81 82 83 84</td>
<td>86 89 91 93 95</td>
<td></td>
</tr>
<tr>
<td>Stoke 33 kV</td>
<td>1.00</td>
<td>134 135 137 138 139 141</td>
<td>144 147 150 153 156</td>
<td></td>
</tr>
<tr>
<td>Stoke 66 kV</td>
<td>0.97</td>
<td>23 23 24 24 24</td>
<td>25 25 26 26 27</td>
<td></td>
</tr>
</tbody>
</table>

4. Stoke 66 kV includes a seasonal estimated generation from Cobb (embedded).

15.4 Nelson-Marlborough generation

The Nelson-Marlborough region’s generation capacity is 57 MW, which is lower than local demand, requiring power to be imported through the National Grid.

Table 15-2 lists the generation forecast for each grid injection point for the forecast period. This includes all known generation stations, including those embedded within the relevant local lines company’s network (Network Tasman or Marlborough Lines).

Table 15-2: Forecast annual generation capacity (MW) at Nelson-Marlborough grid injection points to 2030 (including existing and committed generation)

<table>
<thead>
<tr>
<th>Grid injection point (location if embedded)</th>
<th>Generation capacity (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blenheim (Lulworth Wind)</td>
<td>1 1 1 1 1</td>
<td>1 1 1 1 1</td>
<td></td>
</tr>
</tbody>
</table>

127 Only generators with capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.
### 15.5 Nelson-Marlborough significant maintenance work

Our capital project and maintenance works are integrated to enable system issues to be resolved if possible when assets are replaced or refurbished. Table 15-3 lists the significant maintenance related work 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 maintenance work

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blenheim 33 kV capacitor banks replacement, and Blenheim supply transformers expected end-of-life</td>
<td>2019-2025</td>
</tr>
<tr>
<td>Blenheim supply transformers expected end-of-life</td>
<td>2023-2025</td>
</tr>
<tr>
<td>Stoke 11 kV capacitor bank replacement, Stoke 110/66 kV T3 transformer expected end-of-life, and Stoke 33 kV capacitor bank replacement</td>
<td>2015-2016</td>
</tr>
<tr>
<td></td>
<td>2017-2022</td>
</tr>
<tr>
<td></td>
<td>2029-2030</td>
</tr>
</tbody>
</table>

### 15.6 Future Nelson-Marlborough projects summary and transmission configuration

Figure 15-4 shows the possible configuration of Nelson-Marlborough transmission in 2030, with new assets, upgraded assets, and assets undergoing significant maintenance within the forecast period.

#### Figure 15-4: Possible Nelson-Marlborough transmission configuration in 2030

---

128 This may include replacement of the asset due to its condition assessment.
15.7 Changes since the 2014 Transmission Planning Report

Table 15-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year’s report.

Table 15-4: Changes since 2014

<table>
<thead>
<tr>
<th>Issues</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cobb–Motueka 66 kV transmission capacity.</td>
<td>Removed. Transmission lines were transferred to Network Tasman.</td>
</tr>
<tr>
<td>Motueka supply transformer capacity.</td>
<td>Removed. Motueka was transferred to Network Tasman.</td>
</tr>
<tr>
<td>Motupipi single supply security.</td>
<td>Removed. Motupipi was transferred to Network Tasman.</td>
</tr>
</tbody>
</table>

15.8 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

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional</td>
<td></td>
</tr>
<tr>
<td>15.8.1</td>
<td>Stoke 220/110 kV interconnecting transformer capacity</td>
</tr>
<tr>
<td>Site by grid exit point</td>
<td></td>
</tr>
<tr>
<td>15.8.2</td>
<td>Kikiwa–Stoke 110 kV transmission capacity</td>
</tr>
<tr>
<td>15.8.3</td>
<td>Stoke 220/33 kV supply transformer capacity</td>
</tr>
<tr>
<td>15.8.4</td>
<td>Stoke 110/66 kV supply transformer capacity and supply security</td>
</tr>
<tr>
<td>Bus security</td>
<td></td>
</tr>
<tr>
<td>15.9.1</td>
<td>Transmission bus security</td>
</tr>
<tr>
<td>15.9.2</td>
<td>Blenheim supply security and voltage</td>
</tr>
</tbody>
</table>

15.8.1 Stoke 220/110 kV interconnecting transformer capacity

Project description: Resolve interconnecting transformer branch limits
Project status/type: Possible, Base Capex
Indicative timing: 2023-2028
Indicative cost band: A

Issue

A single 220/110 kV interconnecting transformer at Stoke provides a 110 kV interconnection to the Nelson-Marlborough region. This transformer has:

- a nominal installed capacity of 150 MVA, and
- n-1 capacity of 160/160\(^1\) MVA (summer/winter).

The Stoke 220/110 kV transformer is effectively operating in parallel with the 150 MVA interconnecting transformer at Kikiwa. An outage of the Kikiwa transformer results in the Stoke transformer supplying the Nelson-Marlborough and West Coast

---

\(\text{129}\) Stoke has only one 220/110 kV, 150 MVA interconnecting transformer. The n-1 capacity is the result of the transformer essentially operating in parallel with the Kikiwa–T2 (150 MVA).

\(\text{130}\) The transformer’s capacity is limited by 110 kV disconnectors; with this limit resolved, the n-1 capacity will be 180/188 MVA (summer/winter).
regions. This may cause the Stoke transformer to overload and low voltage issues within the West Coast region (see Chapter 16). The loading on the Stoke transformer depends on the generation in the Nelson-Marlborough and West Coast regions.

**Solution**

In the short term, these issues will be managed operationally via generation rescheduling and load management. Resolving station equipment constraints on the interconnecting transformer and managing the generation level in the Nelson–Marlborough and West Coast regions will resolve the issue for the forecast period.

In the longer term, a second 220/110 kV transformer may be required at Kikiwa or Stoke.

### 15.8.2 Kikiwa–Stoke 110 kV transmission capacity

**Project description:** Thermal upgrade transmission capacity

**Project status/type:** Possible, Base Capex

**Indicative timing:** Beyond 2020

**Indicative cost band:** A

**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), and
- Kikiwa–Argyle–Blenheim–Stoke–1 circuit rated at 56/68 MVA (summer/winter).

An outage of a Stoke 220/110 kV interconnecting transformer results in Nelson–Marlborough region supply from the interconnection at Kikiwa via the two 110 kV circuits. The Kikiwa–Stoke–3 circuit may overload when Nelson-Marlborough region load is high coupled with low local generation during summer season.

**Solution**

This issue can be managed operationally by controlling load and generation levels in the region. A longer-term solution is to thermally upgrade the 110 kV Kikiwa–Stoke circuit.

### 15.8.3 Stoke 220/33 kV supply transformer capacity

**Project description:** Upgrade protection

**Project status/type:** Possible, customer-specific

**Indicative timing:**
- Upgrade protection: 2017
- New grid exit point: To be advised

**Indicative cost band:**
- Upgrade protection: A
- New grid exit point: C

**Issue**

Two 220/33 kV transformers supply Stoke’s 33 kV load, providing:

- a total nominal installed capacity of 240 MVA, and
- n-1 capacity of 136/136 MVA (summer/winter).  

---

131 The normal operating arrangement is that only Kikiwa–T2 (150 MVA) provides a 110 kV interconnection to the West Coast region, and Kikiwa–T1 (50 MVA) supplies the local 11 kV load.

132 The transformers’ capacity is limited by protection equipment of 136 MVA; with this limit resolved, the n-1 capacity will be 143/143 MVA (summer/winter) constrained by low voltage switchgear.
The peak load at Stoke is forecast to exceed the transformers’ n-1 winter capacity by approximately 1 MW in 2017, increasing to approximately 20 MW in 2030 (see Table 15-6).

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stoke 33 kV</td>
<td>1.00</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
</tbody>
</table>

Solution

Resolving the protection issue will reduce overloading in the forecast period. The transformer overloading issue can be further resolved by operational measures and in the longer-term by a possible new grid exit point at Brightwater connected to one of the 220 kV Kikiwa–Stoke circuits (see Section 15.10.1). Network Tasman has designated land for a new grid exit point.

15.8.4 Stoke 110/66 kV supply transformer capacity and supply security

Project description: Install a second 110/66 kV transformer and upgrade existing transformer capacity

Project status/type: Possible, customer-specific


Indicative cost band: A

Issue

The Stoke 66 kV (Golden Bay area) load is supplied by a single 110/66 kV, 23 MVA transformer at Stoke, resulting in no n-1 security. The shoulder peak load at Stoke 66 kV is forecast to exceed the transformer’s continuous rating by approximately 5 MW in 2015, increasing to approximately 9 MW in 2030 (see Table 15-7).

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>6-15 Years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stoke 66 kV</td>
<td>0.97</td>
<td>5</td>
<td>6</td>
<td>6</td>
</tr>
</tbody>
</table>

Solution

The short-term operational solution requires Cobb generation embedded within the 66 kV network to generate at or above a minimum output to avoid overloading the Stoke transformer.

Network Tasman has requested a 40 MVA transformer in parallel with the existing transformer. This (in conjunction with some generation from Cobb) will provide secure supply to the Golden Bay area for the forecast period and beyond. In addition, the existing transformer has an expected end-of-life within the next 5-10 years.

Future investment will be customer driven.

15.9 Nelson-Marlborough bus security

This section presents issues arising from the outage of a single bus section rated at 50 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).

15.9.1 Transmission bus security

Table 9-16 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.

Table 15-8: Transmission bus outages

<table>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Argyle 110 kV</td>
<td>-</td>
<td>Argyle</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Blenheim 110 kV</td>
<td>Blenheim</td>
<td>Argyle</td>
<td>-</td>
<td>15.9.2 See note 1</td>
</tr>
<tr>
<td>Stoke 66 kV</td>
<td>Golden Bay load</td>
<td>-</td>
<td>-</td>
<td>See note 2</td>
</tr>
<tr>
<td>Stoke 110 kV</td>
<td>Blenheim</td>
<td>Golden Bay load</td>
<td>-</td>
<td>15.9.2 See note 2</td>
</tr>
<tr>
<td>Stoke 220 kV</td>
<td>-</td>
<td>-</td>
<td>Possible overload</td>
<td>Kikiwa-Stoke-3 See note 3</td>
</tr>
</tbody>
</table>

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 Golden Bay area, including Cobb generation. 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 15.8.2).

The customers (Network Tasman or Marlborough Lines) 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.

15.9.2 Blenheim supply security and voltage quality

<table>
<thead>
<tr>
<th>Project status/type:</th>
<th>This is for information only</th>
</tr>
</thead>
</table>

**Issue**

There is a single 110 kV bus section at Blenheim, resulting in no n-1 security. Additionally, there are three 110 kV circuits (two circuits 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 the load, and
- Stoke 110 kV bus fault will cause a low voltage issue, which may lead to voltage collapse resulting in a loss of supply at Blenheim. The Blenheim load will be constrained to approximately 50 MW due to the voltage stability and the capacity of the 110 kV Blenheim–Argyle–Kikiwa circuit.

**Solution**

The faulted bus section at Blenheim and Stoke can be isolated via bus disconnectors, restoring supply to Blenheim. If n-1 connection security is eventually required, then a 110 kV bus coupler will need to be installed. Future investment will be customer driven.
Chapter 16: Nelson-Marlborough Region

15.10 Other regional items of interest

15.10.1 Brightwater grid exit point

<table>
<thead>
<tr>
<th>Project description:</th>
<th>New grid exit point</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, customer-specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>C</td>
</tr>
</tbody>
</table>

Brightwater is a proposed new 220/33 kV grid exit point connected to a Kikiwa–Stoke circuit. Load will be transferred from Stoke to Brightwater, so the load at Stoke remains within the capacity of the Stoke supply transformers (see Section 15.8.3). It will also provide diversity for the Stoke load.

The timing for the new Brightwater grid exit point will be determined by Network Tasman which has selected land for the new grid exit point.

15.11 Nelson-Marlborough 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

15.11.1 Maximum regional generation

The maximum generation estimates assume a light South Island load profile and high generation in the Nelson-Marlborough region (with Cobb generating 27 MW).

For generation connected at the Stoke 220 kV bus, the maximum generation that can be injected under n-1 is approximately 380 MW. The constraint is due to 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 of generation injection under n-1) require a thermal upgrade of the 110 kV Kikiwa–Stoke–3 circuit and a protection upgrade on the Blenheim–Stoke–1 circuit. Further increases require a thermal upgrade of the 110 kV Blenheim–Argyle–Kikiwa circuit.

15.11.2 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 the location of the connection. With all circuits in service, approximately 50 MW can be connected, in addition to the existing generation injected at Argyle. Generation levels above this 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 possible.

15.11.3 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, Cobb generation and the capacity of Stoke 110/66 kV transformer.
Approximately 30 MW of additional generation can be connected if controls are installed to automatically reduce generation for some scenarios.
16 West Coast Regional Plan

16.1 Regional overview

This chapter details the West Coast regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

Figure 16-1: West Coast region
The West Coast region includes a mix of significant provincial towns (Dobson, Greymouth, Hokitika), and smaller, lower-growth rural localities.

We have assessed the West Coast region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be flexible to respond to a range of future service and technology possibilities, taking into consideration:

- the existing transmission network
- forecast demand
- forecast generation
- equipment replacement based on condition assessment, and
- possible technological development.

16.2 West Coast transmission system

This section highlights the state of the West Coast regional transmission network. The existing transmission network is set out geographically in Figure 16-1 and schematically in Figure 16-2.

Figure 16-2: West Coast transmission schematic
16.2.1 Transmission into the region

The West Coast region is connected to the National Grid via a 220/110 kV interconnection at Kikiwa and two 66 kV circuits from Coleridge. The 220/110 kV interconnection at Kikiwa is effectively operating in parallel with the transformer at Stoke (in the Nelson–Marlborough region).

The regional generation is lower than the regional demand. Most of the regional load is supplied from remote generation in the Waitaki Valley, with significant load off-take in the South Canterbury and Canterbury regions.

16.2.2 Transmission within the region

The transmission within the region:
- comprises 110 kV and 66 kV transmission circuits, with two 110/66 kV interconnecting transformers at Dobson
- connects to the rest of the National Grid through two 220/110 kV interconnecting transformers at Kikiwa (one on standby) and two 66 kV circuits at Coleridge, and
- derives reactive support from a STATCOM at Kikiwa and capacitor banks at Greymouth and Hokitika.

Most of the assets at Robertson Street, Reefton, Atarau, Greymouth, and Hokitika are owned by the associated local lines company (Westpower or Buller Network).

The West Coast load is mostly supplied from the northern infeed, with power flowing through the region via the 110 kV:
- circuits from Kikiwa to Dobson via Inangahua, and
- spur from Inangahua to Robertson Street and Westport.

Some loads are fed from the south via low capacity 66 kV circuits from Coleridge, which also provide significant voltage support to the region.

16.2.3 Longer-term development path

The 220/110 kV interconnection at Kikiwa is effectively operating in parallel with the 220/110 kV interconnecting transformer at Stoke. In the longer-term, the transformer capacity needs to increase at Kikiwa and/or Stoke to meet load growth and transmission security requirements to the West Coast region.

Possible transmission reinforcement via a third 110 kV circuit connecting between Kikiwa and Inangahua, additional reactive support, 66 kV transmission reconfiguration (Kawhaka bonding), and Dobson–Greymouth capacity upgrades may be required to support the load growth and transmission security in the West Coast region in the longer-term.

Transmission system developments may also be required if there is further generation development, a significant increase of which may require some circuits between Kikiwa and Inangahua to be operated at 220 kV.

16.3 West Coast demand

The after diversity maximum demand (ADMD) for the West Coast region is forecast to grow on average by 1.3% annually over the next 15 years, from 70 MW in 2015 to 85 MW by 2030. This is higher rate than the national average demand growth of 1.1% annually.
Figure 16-3 shows a comparison of the 2014 and 2015 TPR forecast 15-year maximum demand (after diversity\textsuperscript{133}) for the West Coast region. The new record peak demand recorded in 2014 occurred in the shoulder season.

The forecasts are derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data. See Chapter 4 for more information about demand forecasting.

![Figure 16-3: West Coast region after diversity maximum demand forecast](image)

Table 16-1 lists forecast peak demand (prudent growth) for each grid exit point in the West Coast region for the forecast period.

Table 16-1: Forecast annual peak demand (MW) at West Coast grid exit points to 2030

<table>
<thead>
<tr>
<th>Grid exit point</th>
<th>Power factor</th>
<th>Next 5 years</th>
<th>Peak demand (MW)</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arthur's Pass</td>
<td>1.00</td>
<td>0.4</td>
<td>0.4</td>
<td>0.4</td>
</tr>
<tr>
<td>Atarau</td>
<td>0.97</td>
<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>Castle Hill</td>
<td>1.00</td>
<td>0.7</td>
<td>0.8</td>
<td>0.8</td>
</tr>
<tr>
<td>Dobson</td>
<td>0.97</td>
<td>9</td>
<td>9</td>
<td>10</td>
</tr>
<tr>
<td>Greymouth</td>
<td>0.98</td>
<td>15</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>Hokitika</td>
<td>0.86</td>
<td>20</td>
<td>21</td>
<td>23</td>
</tr>
<tr>
<td>Kikiria</td>
<td>1.00</td>
<td>2.9</td>
<td>2.9</td>
<td>2.9</td>
</tr>
<tr>
<td>Kumara</td>
<td>1.00</td>
<td>1.6</td>
<td>1.6</td>
<td>1.7</td>
</tr>
<tr>
<td>Murchison</td>
<td>0.97</td>
<td>2.7</td>
<td>2.8</td>
<td>2.8</td>
</tr>
<tr>
<td>Robertson Street\textsuperscript{1}</td>
<td>0.99</td>
<td>10</td>
<td>11</td>
<td>14</td>
</tr>
<tr>
<td>Otira</td>
<td>0.76</td>
<td>0.7</td>
<td>0.7</td>
<td>0.7</td>
</tr>
<tr>
<td>Reefton\textsuperscript{2}</td>
<td>0.98</td>
<td>14</td>
<td>9</td>
<td>9</td>
</tr>
</tbody>
</table>

\textsuperscript{133} The after diversity maximum demand (ADMD) for the region will be less than the sum of the individual grid exit point peak demands, as it takes into account the fact that the peak demand does not occur simultaneously at all the grid exit points in the region.
Chapter 16: West Coast Region

Grid exit point | Power factor | Peak demand (MW) |
---|---|---|
| | | Next 5 years 6-15 years out |
Westport | 0.97 | 10 2 2 3 3 3 3 4 4 4 4 |

1. The step increase in demand from 2016 to 2017 is due to the expected Denniston Plateau mine development and Buller Wharf coal loading facility (1 MW), Waimangaroa coal handling and rail loading facility (0.5 MW) and Waimangaroa coal processing plant and aerial conveyor (3 MW).
2. The fall in peak demand at Reefton (5 MW) in 2016 reflects closure of Oceana Gold mine.
3. The fall in peak demand at Westport (8 MW) in 2016 reflects the planned closure of Holcim Cement’s Cape Foulwind plant.

16.4 West Coast generation

The West Coast region’s generation capacity is 30 MW, which is lower than the local demand and the deficit is imported through the National Grid.

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 generation stations including those embedded within the relevant local lines company’s network (Westpower, Buller Networks, Network Tasman, or Orion).

<table>
<thead>
<tr>
<th>Grid injection point (location if embedded)</th>
<th>Generation capacity (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dobson (Arnold)</td>
<td>3 3 3 3 3 3</td>
<td>3 3 3 3 3</td>
<td></td>
</tr>
<tr>
<td>Hokitika (Amethyst)</td>
<td>6 6 6 6 6 6</td>
<td>6 6 6 6 6</td>
<td></td>
</tr>
<tr>
<td>Hokitika (McKays Creek)</td>
<td>1 1 1 1 1 1</td>
<td>1 1 1 1 1</td>
<td></td>
</tr>
<tr>
<td>Hokitika (Wahapo-Okarito Forks)</td>
<td>3 3 3 3 3 3</td>
<td>3 3 3 3 3</td>
<td></td>
</tr>
<tr>
<td>Kumara (Hokitika Diesel)</td>
<td>3 3 3 3 3 3</td>
<td>3 3 3 3 3</td>
<td></td>
</tr>
<tr>
<td>Kumara (Kumara and Dillmans)</td>
<td>10 10 10 10 10</td>
<td>10 10 10 10 10</td>
<td></td>
</tr>
<tr>
<td>Robertson Street (Kawatiri Hydro)</td>
<td>4 4 4 4 4 4</td>
<td>4 4 4 4 4</td>
<td></td>
</tr>
</tbody>
</table>

1. Kumara and Dillmans share the same water and are offered into the market as a single 10 MW generator. Kumara does not have significant water storage but is expected to supply an average of 4 MW during summer peaks.

16.5 West Coast significant maintenance work

Our capital projects and maintenance works are integrated to enable system issues to be resolved if possible when assets are replaced or refurbished. Table 16-3 lists the significant maintenance-related work proposed for the West Coast region for the next 15 years that may significantly impact related system issues or connected parties.

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134 Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.
135 This may include replacement of the asset due to its condition assessment.
### Table 16-3: Proposed significant maintenance work

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arthur’s Pass supply transformer expected end-of-life</td>
<td>2015-2017</td>
</tr>
<tr>
<td>Castle Hill supply transformer expected end-of-life</td>
<td>2015-2017</td>
</tr>
<tr>
<td>Kikiwa interconnecting transformer (T1) expected end-of-life</td>
<td>2022-2023</td>
</tr>
<tr>
<td>Murchison supply transformer expected end-of-life</td>
<td>2017-2019</td>
</tr>
</tbody>
</table>

#### 16.6 Future West Coast projects summary and transmission configuration

Figure 16-4 shows the possible configuration of West Coast transmission in 2030, with new assets, upgraded assets and assets undergoing significant maintenance within the forecast period.

![Figure 16-4: Possible West Coast transmission configuration in 2030](image-url)
16.7 Changes since the 2014 Transmission Planning Report

Table 16-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year’s report.

<table>
<thead>
<tr>
<th>Issues</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>No new, resolved or removed issues</td>
<td>No changes</td>
</tr>
</tbody>
</table>

16.8 West Coast transmission capability

Table 16-5 summarises issues involving the West Coast region for the next 15 years. For more information about a particular issue, refer to the listed section number.

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional</td>
<td></td>
</tr>
<tr>
<td>16.8.1</td>
<td>Inangahua–Murchison–Kikiwa transmission capacity</td>
</tr>
<tr>
<td>16.8.2</td>
<td>Kikiwa interconnecting transformer capacity</td>
</tr>
<tr>
<td>16.8.3</td>
<td>West Coast low voltage</td>
</tr>
<tr>
<td>Site by grid exit point</td>
<td></td>
</tr>
<tr>
<td>16.8.4</td>
<td>Arthur’s Pass transmission and supply security</td>
</tr>
<tr>
<td>16.8.5</td>
<td>Castle Hill transmission and supply security</td>
</tr>
<tr>
<td>16.8.6</td>
<td>Hokitika transmission capacity</td>
</tr>
<tr>
<td>16.8.7</td>
<td>Kikiwa supply security</td>
</tr>
<tr>
<td>16.8.8</td>
<td>Murchison transmission and supply security</td>
</tr>
<tr>
<td>16.8.9</td>
<td>Otira supply security</td>
</tr>
<tr>
<td>Bus security</td>
<td></td>
</tr>
<tr>
<td>16.9.1</td>
<td>Transmission bus security</td>
</tr>
<tr>
<td>16.9.2</td>
<td>West Coast voltage quality and transmission capacity</td>
</tr>
</tbody>
</table>

16.8.1 Inangahua–Murchison–Kikiwa transmission capacity

| Project description:          | Upgrade Inangahua–Murchison–Kikiwa thermal capacity  |
| Project status/type:          | Possible, Base Capex                                 |
| Indicative timing:            | To be advised                                        |
| Indicative cost band:         | Thermal upgrade: A                                   |
|                              | Special protection scheme: to be advised              |

Issue

There are two parallel 110 kV circuits between Inangahua and Kikiwa, the 110 kV:
- Inangahua–Murchison–Kikiwa circuit, rated at 56/68 MVA (summer/winter), and
- Inangahua–Kikiwa–2 circuit, rated at 92/101 MVA (summer/winter).

An outage of the 110 kV Inangahua–Kikiwa–2 circuit will cause:
- the parallel 110 kV Inangahua–Murchison–Kikiwa circuit to overload from approximately 2025, and
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- low voltage at the West Coast 110 kV bus from approximately 2022 (see Section 16.8.3 for more information).

Solution

Possible options to resolve the transmission capacity issue include:
- thermally upgrading the 110 kV Inangahua–Murchison–Kikiwa circuit, or
- a special protection scheme to trip load post-contingency.

The preferred option is to thermally upgrade the 110 kV Inangahua–Murchison–Kikiwa circuit. However, initial application of the Investment Test indicates that this option has no overall economic benefit. We will investigate other options to resolve this issue closer to the need date.

See Section 16.8.3 for possible options to resolve the low voltage issue.

Easements may be required for some parts of the thermal upgrade project.

16.8.2 Kikiwa interconnecting transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Upgrade transformer capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2023</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>B</td>
</tr>
</tbody>
</table>

Issue

There are two 220/110 kV interconnecting transformers at Kikiwa, T1 and T2 rated at 50 MVA and 150 MVA, respectively. The normal operating arrangement is to have Kikiwa–T1 supply the local 11 kV load only and Kikiwa–T2 providing the 220/110 kV interconnection with the West Coast region. Kikiwa–T2 also operates in parallel with the 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 means the Kikiwa interconnecting transformer supplies both the West Coast and Nelson-Marlborough load, which may overload for:
- high West Coast and Nelson-Marlborough loads, and
- low generation in the West Coast and Nelson-Marlborough regions.

Solution

This issue may be managed operationally with generation from Cobb and Kumara for the forecast period (provided water is available). We will work with the generators to manage this constraint.

The 50 MVA (T1) transformer is expected to approach its end-of-life in about 10 years. A possible longer-term option is to replace Kikiwa–T1 with a higher-rated transformer that can operate in parallel with Kikiwa–T2 and Stoke–T7.

16.8.3 West Coast low voltage

<table>
<thead>
<tr>
<th>Project description:</th>
<th>New capacitors at Dobson</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2023</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>New capacitors: A</td>
</tr>
<tr>
<td></td>
<td>Special Protection Scheme: to be advised</td>
</tr>
</tbody>
</table>
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Issue

Low voltage will occur on the 110 kV transmission system in the region from approximately 2022 following an outage of the:

- Kikiwa–T2 interconnecting transformer, or
- 110 kV Inangahua–Kikiwa–2 circuit.

Solution

The 110 kV low voltage issues can be addressed by a local voltage quality agreement if appropriate for the short term. Possible transmission solutions include:

- installing new capacitors at Dobson
- a special protection scheme to shed load post contingency, and /or
- replacing Kikiwa–T1 with a higher-rated transformer, which will address the low voltage issue following a Kikiwa–T2 outage (this option also resolves the Kikiwa interconnecting transformer capacity issue described in Section 16.8.2).

We will investigate options closer to the need date.

16.8.4 Arthur’s Pass transmission and supply security

Project status/type: This issue is for information only

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.

Additionally, a single 66/11 kV, 3 MVA transformer supplies load at Arthur’s Pass, resulting in no n-1 security. Load growth is not forecast to exceed the transformer rating within the forecast period.

Solution

The lack of n-1 security can be managed operationally. There is a non-contracted on-site spare transformer, allowing possible replacement within 8-14 hours following a unit failure (if the spare unit is available).

This transformer is also approaching its expected end-of-life within the next five years. We will discuss with Orion options for increasing security and coordinating outages to minimise supply interruptions when replacing this transformer.

16.8.5 Castle Hill transmission and supply security

Project status/type: This issue is for information only

Issue

The two circuits supplying Castle Hill only have line circuit breakers and protection at Coleridge and Otra. A fault on any section of the Coleridge–Castle Hill–Arthur’s Pass–Otra circuits will result in a loss of supply to Castle Hill load.

Additionally, a single 66/11 kV, 3.75 MVA transformer supplies load at Castle Hill, resulting in no n-1 security. Load growth is not forecast to exceed the transformer rating within the forecast period.
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Solution

The lack of n-1 security can be managed operationally. There is a non-contracted on-site spare transformer, allowing possible replacement within 8-14 hours following a unit failure (if the spare unit is available).

This transformer is also approaching its expected end-of-life within the next five years. We will discuss with Orion options for increasing security and coordinating outages to minimise supply interruptions when replacing this transformer.

16.8.6 Hokitika transmission capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Enhance transmission capacity into Hokitika</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>C</td>
</tr>
</tbody>
</table>

Issue

Two circuits supply the Hokitika grid exit point, the:

- Hokitika–Kumara rated at 27/32 MVA (summer/winter), and
- Hokitika–Otira rated at 27/32 MVA (summer/winter).

An outage of one circuit will cause the other to exceed its thermal capacity from summer 2020.

The 66 kV line from Coleridge to Kumara is predominantly strung with a copper conductor, and so cannot be thermally upgraded.

Solution

Previous investigations identified a system reconfiguration including:

- decommissioning the Kumara–Otira circuit
- bonding the circuits between Kumara and Kawhaka\(^{136}\), and between Otira and Kawhaka, and
- reconductoring the low-capacity section of the line from Kawhaka to Hokitika, and thermally upgrading the other section.

This maintains n-1 security to Hokitika by providing two higher-capacity circuits.

The overloading then shifts to the Dobson–Greymouth circuit. Options to address this issue include constraining on generation at Kumara, thermally upgrading the circuit, or transferring load from Greymouth to Dobson.

Previous investigations, however, also indicated that the system reconfiguration may be uneconomic. An alternative is to automatically reduce load at Hokitika following a circuit outage, causing a partial loss of supply.

We will investigate the appropriate solution for this issue closer to the need date.

16.8.7 Kikiwa supply security

| Project status/type: | This issue is for information only |

Issue

The Kikiwa load is normally supplied from the 11 kV tertiary winding of the Kikiwa–T1 interconnecting transformer, with a backup supply from the T2 interconnecting

\(^{136}\) Kawhaka is the point where the lines carrying the Kumara–Otira, Otira–Hokitika and Hokitika–Kumara circuits meet.
transformer. Transferring the load between T1 and T2 requires a short interruption to the load.

An outage of the 11 kV switchgear or fault limiting reactor requires a total loss of supply, so there is no n-1 security for these assets.

**Solution**

The brief interruption to load and lack of n-1 security can be managed operationally. Future investment will be customer driven.

**16.8.8 Murchison transmission and supply security**

<table>
<thead>
<tr>
<th>Project status/type:</th>
<th>This issue is for information only</th>
</tr>
</thead>
</table>

**Issue**

The load at Murchison is supplied by:

- two circuits, which do not have line protection at Murchison, and
- a single 110/11 kV, 5 MVA transformer.

A fault on either circuit or the supply transformer will result in a loss of supply to Murchison. In addition, the supply transformer is reaching the end-of-life.

**Solution**

The lack of n-1 security can be managed operationally.

**16.8.9 Otira supply security**

<table>
<thead>
<tr>
<th>Project status/type:</th>
<th>This issue is for information only</th>
</tr>
</thead>
</table>

**Issue**

Otira is supplied by a single 66/11 kV, 2.5 MVA transformer, resulting in no n-1 security. Load growth is not forecast to exceed the transformer rating within the forecast period.

**Solution**

The Otira transformer is a three-phase unit. The lack of n-1 security can be managed operationally.

**16.9 West Coast bus security**

This section presents issues arising from the outage of a single bus section rated at 50 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).

**16.9.1 Transmission bus security**

Table 16-6 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.
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Table 16-6: Transmission bus outages

<table>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arthur’s Pass 66 kV</td>
<td>Arthur’s Pass</td>
<td>-</td>
<td>-</td>
<td>16.8.4</td>
</tr>
<tr>
<td>Atarau 110 kV</td>
<td>Atarau</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Castle Hill 66 kV</td>
<td>Castle Hill</td>
<td>-</td>
<td>-</td>
<td>16.8.5</td>
</tr>
<tr>
<td>Coleridge 66 kV</td>
<td>Arthur’s Pass</td>
<td>-</td>
<td>-</td>
<td>See note 2</td>
</tr>
<tr>
<td>Dobson 66 kV</td>
<td>Dobson</td>
<td>-</td>
<td>-</td>
<td>See note 3</td>
</tr>
<tr>
<td>Kikiwa 110 kV</td>
<td>West Coast load</td>
<td>-</td>
<td>-</td>
<td>16.9.2</td>
</tr>
<tr>
<td>Kikiwa 220 kV</td>
<td>Kikiwa</td>
<td>-</td>
<td>-</td>
<td>16.8.7</td>
</tr>
<tr>
<td>Inangahua 110 kV</td>
<td>Robertson Street</td>
<td>West Coast load</td>
<td>-</td>
<td>16.9.2</td>
</tr>
<tr>
<td>Murchison 110 kV</td>
<td>Murchison</td>
<td>-</td>
<td>-</td>
<td>16.8.8</td>
</tr>
<tr>
<td>Otira 66 kV</td>
<td>Arthur’s Pass</td>
<td>Castle Hill</td>
<td>Otira</td>
<td>See note 2</td>
</tr>
</tbody>
</table>

1. There is no bus protection at Atarau, so bus faults cause loss of supply.
2. There is no bus protection at Coleridge or Otira, so bus faults remove all connected circuits from service. This includes the Coleridge–Castle Hill–Arthur’s Pass–Otira circuit, causing a loss of supply at Castle Hill and Arthur’s Pass.
3. There is no bus protection at Dobson, so bus faults cause loss of supply.

The customers (Buller Networks, Westpower, Network Tasman, or Orion) 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.

16.9.2 West Coast voltage quality and transmission capacity

Project status/type: This issue is for information only

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 at Inangahua, so a bus outage will disconnect both circuits. This will cause:
- low voltage issues at all 110 kV and 66 kV buses, and
- transmission circuit capacity issues in the West Coast region.

The effect of the low voltages and circuit overloading is difficult to predict. The outcome is 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 so 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, an outage of the Kikiwa 220 kV bus, which disconnects the Kikiwa–T2 interconnecting transformer, will cause the transmission bus voltages in the region to fall below 0.90 pu towards the end of the forecast period.
Chapter 16: West Coast Region

Solution

The customers (Westpower, Buller Networks, Network Tasman, and Orion) have not requested a higher security level and there are no plans to increase bus security.

Replacing the Kikiwa–T1 interconnecting transformer with a higher rated unit (see Sections 16.8.2 and 16.8.3) will address the issue of a Kikiwa 220 kV bus outage.

16.10 Other regional items of interest

16.10.1 West Coast high voltage

High voltage will occur on the 110 kV transmission system under light load conditions and high generation from the embedded and grid connected generators.

This issue can be easily managed operationally at present. If there are increased levels of embedded generation, this issue will become more significant and may require more intensive operational control of the generating units’ voltage set-points.

16.11 West Coast 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

16.11.1 Maximum regional generation

Maximum generation estimates assume a South Island light load profile and that the generation in the West Coast region is high (with 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.

For a West Coast load of 35 MW, the estimated maximum generation injection\(^\text{137}\) at the two key busses is as follows:

- At the Kikiwa 110 kV bus, under normal operating conditions, the maximum is 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, the maximum is 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–Kikiwa–2 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.

\(^{137}\) 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.
16.11.2 Generation connected to the Inangahua to Westport spur

Two circuits form the Inangahua to Westport spur, with substations at Waimangaroa, Robertson Street and Westport. The Inangahua–Waimangaroa–1 circuit is rated at 101/111 MVA\textsuperscript{138} (summer/winter) and the Inangahua–Waimangaroa–2 circuit is rated at 56/68 (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 generation injection, and/or
- increase the circuit capacity between Waimangaroa, Inangahua, and Kikiwa.

Generation connected to the spur also forms part of the maximum level of generation that can be connected within the region (see Section 16.11.1).

\textsuperscript{138} The circuit is presently limited to 76/76 MVA by substation equipment.
Chapter 17: Canterbury Region

17 Canterbury Regional Plan

17.1 Regional overview

This chapter details the Canterbury regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

Figure 17-1: Canterbury region
Chapter 17: Canterbury Region

The Canterbury region load includes Christchurch together with smaller rural localities.

We have assessed the Canterbury region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be flexible to respond to a range of future service and technology possibilities, taking into consideration:

- the existing transmission network
- forecast demand
- forecast generation
- equipment replacement based on condition assessment, and
- possible technological development.

17.2 Canterbury transmission system

This section highlights the state of the Canterbury regional transmission network. The existing transmission network is set out geographically in Figure 17-1 and schematically in Figure 17-2.

Figure 17-2: Canterbury transmission schematic

17.2.1 Transmission into the region

The Canterbury region has some of the highest load densities in the South Island, coupled with relatively low levels of local generation. As Canterbury’s peak electricity demand is supplied by generation located in the South Canterbury region, transmission is necessary for power flow into and through the region to the top of the South Island.

17.2.2 Transmission within the region

From the Waitaki Valley, the region is supplied by four 220 kV transmission circuits, three from Twizel and one from Livingstone. The transmission network within this...
region comprises 220 kV and 66 kV transmission circuits, with 220/66 kV interconnecting transformers at Islington and Waipara.

There are 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, and capacitor banks at Islington
- capacitor banks at Bromley, and
- a single 33 Mvar capacitor at Southbrook.

### 17.2.3 Longer-term development path

We are investigating transmission capacity enhancement and future reactive support requirements in the Canterbury region and the Upper South Island to increase both thermal and voltage stability limits. This is to ensure that Canterbury has secure transmission into and through the region as demand continues to grow.

Beyond the next 30 years, new transmission capacity may be required into the Canterbury region, provided by a new 220 kV line, an HVDC tap-off, or the refurbishment of the existing lines. New generation in the Upper South Island or a demand-side response may defer transmission investment.

New grid exit points may also be required to between Ashburton and Christchurch for Electricity Ashburton and Orion to supply load growth in the region.

### 17.3 Canterbury demand

The after diversity maximum demand (ADMD) for the Canterbury region is forecast to grow on average by 1.1% annually over the next 15 years, from 790 MW in 2015 to 930 MW by 2030. This is at the same rate forecast for national peak demand growth.

The after effects of the September 2010 earthquake and the significant February 2011 aftershock centred in Christchurch have affected electricity demand in the Canterbury region. The latest forecast was determined after discussion with Orion. We allow for growth as the rebuild progresses but note that the winter peak demand recorded in any particular year is heavily influenced by the load control applied in the Orion network.

Figure 17-3 shows a comparison of the 2014 and 2015 TPR forecast 15-year maximum demand (after diversity\(^2\)) for the Canterbury region. The forecasts are derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data. See Chapter 4 for more information about demand forecasting.

---

\(^2\) The after diversity maximum demand (ADMD) for the region will be less than the sum of the individual grid exit point peak demands, as it takes into account the fact that the peak demand does not occur simultaneously at all the grid exit points in the region.
Table 17-1 lists forecast peak demand (prudent growth) for each grid exit point for the forecast period.

### Table 17-1: Forecast annual peak demand (MW) at Canterbury grid exit points to 2030

<table>
<thead>
<tr>
<th>Grid exit point</th>
<th>Power factor</th>
<th>Peak demand (MW)</th>
<th>2022</th>
<th>2024</th>
<th>2026</th>
<th>2028</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ashburton 33 kV</td>
<td>0.98</td>
<td>2015 2016 2017 2018 2019 2020</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Ashburton 66 kV</td>
<td>0.95</td>
<td>153 156 168 180 184 188</td>
<td>195  203 211 219 227</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ashley</td>
<td>0.93</td>
<td>17 17 17 17 17 17</td>
<td>18  18 18 18 18 18</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bromley 66 kV</td>
<td>1.00</td>
<td>156 160 163 175 178 216</td>
<td>221  226 231 236 241</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coleridge</td>
<td>1.00</td>
<td>0.4 0.4 0.4 0.4 0.4 0.4</td>
<td>0.5  0.5 0.5 0.5 0.5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Culverden 33 kV</td>
<td>0.96</td>
<td>23 24 25 26 27</td>
<td>30  32 34 36 38</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Culverden 66 kV</td>
<td>0.96</td>
<td>13 14 14 14 14 14</td>
<td>15  15 16 16 17</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hororata 33 kV</td>
<td>0.96</td>
<td>24 25 19 19 20 20</td>
<td>13  13 14 14 15</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hororata 66 kV</td>
<td>0.96</td>
<td>17 17 18 18 18 18</td>
<td>26  27 27 28 29</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Islington 33 kV</td>
<td>0.99</td>
<td>79 79 80 81 82 83</td>
<td>84   86 88 90 91</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Islington 66 kV</td>
<td>1.00</td>
<td>443 456 466 466 477 451</td>
<td>471  492 513 533 553</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kaiapoi</td>
<td>1.00</td>
<td>30 30 31 31 32 32</td>
<td>33  34 35 36 37</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kimberley</td>
<td>0.97</td>
<td>15 17 17 21 21 21</td>
<td>21   21 21 21 21</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Southbrook 33 kV</td>
<td>0.99</td>
<td>30 31 32 32 33 34</td>
<td>36   38 40 42 44</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Southbrook 66 kV</td>
<td>0.99</td>
<td>22 23 23 24 25 25</td>
<td>27   28 29 30 31</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Waipara 33 kV</td>
<td>0.97</td>
<td>10 10 10 10 11</td>
<td>11   11 11 12 12</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Waipara 66 kV</td>
<td>0.98</td>
<td>11 12 12 12 12 13</td>
<td>13   14 15 15 16</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1. A staged migration is planned from Ashburton 33 kV to 66 kV over 2017 to 2018.
2. The customer AMP indicates some load at Southbrook 33 kV will be shifted to Ashley in 2015.
3. The customer advised of a future load shift from Islington to Bromley tentatively in 2018 and 2020.
5. The customer advised of a Kimberley step load increase in 2016 from irrigation and 2018 from dairy processing.
17.4 Canterbury generation

The Canterbury region’s generation capacity is 79 MW, which is lower than local demand and the deficit is imported through the National Grid from the Waitaki Valley.

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 within the relevant local lines company’s network (Electricity Ashburton, Orion or Mainpower).

<table>
<thead>
<tr>
<th>Grid injection point (location if embedded)</th>
<th>Generation capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Ashburton (Montalto)</td>
<td>2 2 2 2 2 2</td>
</tr>
<tr>
<td>Bromley (City Waste)</td>
<td>3 3 3 3 3 3</td>
</tr>
<tr>
<td>Bromley (QE2 diesel)¹</td>
<td>4 4 0 0 0 0</td>
</tr>
<tr>
<td>Coleridge</td>
<td>45 45 45 45 45 45</td>
</tr>
<tr>
<td>Islington (QE2 diesel)¹</td>
<td>0 0 4 4 4 4</td>
</tr>
</tbody>
</table>

¹. The customer advised that QE2 diesel generation will be shifted to the Islington 66 kV GXP in 2017.

17.5 Canterbury significant maintenance work

Our capital projects and maintenance works are integrated to enable system issues to be resolved if possible when assets are replaced or refurbished.

Table 17-3 lists the significant maintenance-related work¹⁰¹ proposed for the Canterbury region for the next 15 years that may significantly impact related system issues or connected parties.

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ashburton 33 kV outdoor to indoor conversion</td>
<td>2024-2026</td>
</tr>
<tr>
<td>Bromley T5 and T6 transformers expected end-of-life</td>
<td>2015-2017</td>
</tr>
<tr>
<td>Culverden 33 kV outdoor to indoor conversion</td>
<td>2024-2026</td>
</tr>
<tr>
<td>Hororata 33 kV outdoor to indoor conversion</td>
<td>2018-2020</td>
</tr>
<tr>
<td>Islington Synchronous Condenser SC4 and SC5 mothballing,</td>
<td>2015-2017</td>
</tr>
<tr>
<td>Islington 33 kV outdoor to indoor conversion, and</td>
<td>2021-2023</td>
</tr>
<tr>
<td>Islington T3 and T7 interconnecting transformers expected-end-of-life</td>
<td>2022-2023</td>
</tr>
<tr>
<td>Kaiapoi 11 kV switchgear replacement</td>
<td>2017-2019</td>
</tr>
<tr>
<td>Waipara 33 kV outdoor to indoor conversion</td>
<td>2024-2026</td>
</tr>
</tbody>
</table>

17.6 Future Canterbury projects summary and transmission configuration

Figure 17-4 shows the possible configuration of Canterbury transmission in 2030, with new assets, upgraded assets, and assets undergoing significant maintenance within the forecast period.

¹³⁹ Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

¹⁴⁰ This may include replacement of the asset due to its condition assessment.
17.7 Changes since the 2014 Transmission Planning Report

Table 13-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year’s report.

Table 17-4: Changes since 2014

<table>
<thead>
<tr>
<th>Issues</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ashburton supply transformer capacity</td>
<td>Added, change of study period to include 2030.</td>
</tr>
<tr>
<td>Ashley supply transformer capacity</td>
<td>Removed, transformers replaced.</td>
</tr>
<tr>
<td>Islington 220/66 kV transformer capacity</td>
<td>Removed, reduced load forecast.</td>
</tr>
</tbody>
</table>

17.8 Canterbury transmission capability

Table 17-5 summarises issues involving the Canterbury region for the next 15 years. For more information about a particular issue, refer to the listed section number.

Table 17-5: Canterbury region transmission issues

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>17.8.1</td>
<td>Ashburton supply transformer capacity</td>
</tr>
<tr>
<td>17.8.2</td>
<td>Bromley supply transformer capacity</td>
</tr>
</tbody>
</table>
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17.8.1 Ashburton supply transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>A new grid exit point</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, customer-specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2019-2025</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>C</td>
</tr>
</tbody>
</table>

**Issue**

Three 220/66 kV transformers supply Ashburton’s load, providing:
- a total nominal installed capacity of 340 MVA, and
- n-1 capacity of 269/273 MVA (summer/winter).

The peak load at Ashburton is forecast to exceed the transformers’ n-1 summer capacity by approximately 3 MW in 2030 (see Table 17-6).

**Table 17-6: Ashburton 66 kV supply transformer overload forecast**

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ashburton</td>
<td>0.95</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

Electricity Ashburton is planning to develop a separate 66 kV grid exit point on a different site to diversify their risk and lower their 66 kV sub-transmission losses when the load at Ashburton exceeds 180 MW or 190 MVA (see Section 17.10.1). Some of the Ashburton load will be transferred to the new grid exit point.

17.8.2 Bromley supply transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Replace transformers with higher-rated units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2015-2017</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>B (cost band for one transformer)</td>
</tr>
</tbody>
</table>

**Issue**

Three 220/66 kV transformers supply Bromley’s 66 kV load, providing:
- a total nominal installed capacity of 380 MVA, and
• n-1 capacity of 250/264 MVA (summer/winter).

Orion is planning to transfer load from Islington to Bromley between 2018 to 2020, which will exceed the existing transformers’ n-1 capacity by 2 MW in 2024 increasing to approximately 17 MW in 2030 (see Table 17-7).

Additionally, due to end-of-life, we plan to replace the two older 220/66 kV transformers (T5 and T6) with a single 180 MVA unit within the next two years. The existing T7 and the new transformer will provide:

• a total nominal installed capacity of 360 MVA, and
• n-1 capacity of 215/225 MVA (summer/winter)

The peak load at Bromley is forecast to exceed the new supply transformers’ n-1 winter capacity by approximately 4 MW in 2020, increasing to approximately 29 MW in 2030 (see Table 17-7).

Table 17-7: Bromley supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Bromley (existing)</td>
<td>1.00</td>
<td>0</td>
</tr>
<tr>
<td>Bromley (future)</td>
<td>1.00</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

We anticipate this issue will be managed by load shifting between Bromley and Islington within Orion’s network. A third transformer will be installed when the 220/66 kV transformers at Bromley and Islington run out of capacity. Future investment will be customer driven.

17.8.3 Coleridge supply transformer security

**Issue**

A single 66/11 kV, 2.5 MVA three phase supply transformer supplies the load at Coleridge, resulting in no n-1 security.

**Solution**

There is an off-site spare transformer that can take several days to install. Orion accepts this level of security. Future investment will be customer driven.

17.8.4 Culverden supply transformer capacity

**Issue**

Two 220/33 kV transformers supply the 33 kV and 66 kV loads at Culverden, providing:

• a total nominal installed capacity of 60 MVA, and
• n-1 capacity of 31/32 MVA (summer/winter).
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The peak load at Culverden is forecast to exceed the supply transformers’ n-1 summer capacity by approximately 1 MW in 2015, increasing to approximately 16 MW in 2030 (see Table 17-8).

Table 17-8: Culverden supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Culverden</td>
<td>0.96</td>
<td>1</td>
</tr>
</tbody>
</table>

Solution

In the short term the issue can be managed with operational measures. In the medium term, the existing 220/33 kV supply transformers will be replaced with higher rated 220/66 kV transformers. The timing of the upgrade will be determined by the possible increase in irrigation and in discussion with MainPower. Future investment will be customer driven.

17.8.5 Hororata and Kimberley voltage quality and transmission capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>New capacitors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>A</td>
</tr>
</tbody>
</table>

Issue

Hororata and Kimberley substations are supplied from:

- Islington by two 66 kV Hororata–Kimberley–Islington circuits, each rated at 59/62 MVA (summer/winter), and
- Coleridge and the West Coast by two 66 kV Coleridge–Hororata circuits, each rated at 30/37 MVA (summer/winter).

There is a wider voltage agreement (WVA) at Hororata and Kimberley 66 kV busses to allow a normal operating voltage band of between 0.9 and 1.05 pu.

With low Coleridge generation (three of the five units out of service), and high load at Hororata and Kimberley, a Hororata–Kimberley–Islington circuit outage may cause voltages on the Hororata and Kimberly 66 kV busses to drop below 0.9 pu.

In addition, the combined load may exceed the n-1 thermal capacity of the Islington–Kimberley–Hororata circuits. However, this issue will not constrain the load because the voltage constraint bounds first.

Solution

There is an automatic under voltage load shedding (AUVLS) scheme installed at Hororata to manage the voltage quality (post contingency) at Hororata and Kimberley in the short-term. We are investigating the option of installing capacitors at Hororata in the longer term. We anticipate that the solution to the voltage issue will also resolve the circuit thermal constraint.

17.8.6 Hororata supply transformer capacity

| Project status/type: | This issue is for information only |

Issue

Two 66/33 kV transformers supply Hororata 33 kV load, providing:
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- a total nominal capacity of 34 MVA, and
- n-1 capacity of 23/23 MVA\(^{141}\) (summer/winter).

The peak load on the Hororata 33 kV bus is forecast to exceed the transformers’ n-1 summer capacity by approximately 4 MW in 2015 and increasing to approximately 5 MW in 2016 (see Table 17-9).

Table 17-9: Hororata supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hororata 33 kV</td>
<td>0.96</td>
<td>4</td>
</tr>
</tbody>
</table>

**Solution**

The supply transformer capacity issue can be managed operationally. From 2017, it is understood Orion will shift load from the 33 kV to the 66 kV bus. Future investment will be customer driven.

### 17.8.7 Kaiapoi supply transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Resolve branch component limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2025-2027</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>A</td>
</tr>
</tbody>
</table>

**Issue**

Two 66/11 kV transformers supply load at Kaiapoi, providing:

- a total nominal installed capacity of 80 MVA, and
- n-1 capacity of 38/38\(^{142}\) MVA (summer/winter).

The peak load at Kaiapoi is forecast to exceed the supply transformers’ n-1 winter capacity by approximately 1 MW in 2028, increasing to approximately 2 MW in 2030 (see Table 17-10).

Table 17-10: Kaiapoi supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kaiapoi</td>
<td>1.00</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

Resolving all transformers’ branch component limits will solve the overloading issue beyond the forecast period. In addition, the existing switchboard is approaching end-of-life. We will discuss options with MainPower closer to the need date. Future investment will be customer driven.

### 17.8.8 Southbrook supply transformer capacity

| Project status/type: | This issue is for information only |

---

\(^{141}\) The transformers’ capacity is limited by bus section rating; with this limit resolved, the n-1 capacity will be 23/24 MVA (summer/winter).

\(^{142}\) 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).
Issue

Two 66/33 kV transformers supply Southbrook’s load, providing:

- a total nominal installed capacity of 80 MVA, and
- n-1 capacity of 47/47 MVA\(^{143}\) (summer/winter).

Southbrook’s peak load, which occurs in the shoulder period, is forecast to exceed the transformer’s n-1 summer capacity by approximately 2 MW in 2028, increasing to approximately 4 MW in 2030 (see Table 17-11).

### Table 17-11: Southbrook supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Southbrook</td>
<td>0.96</td>
<td>0</td>
</tr>
</tbody>
</table>

Solution

Resolving all transformers’ branch component limits will solve the overloading issue beyond the forecast period. Future investment will be customer driven.

17.8.9 Waipara supply transformer security

### Project status/type:

This issue is for information only

Issue

A single 66/33 kV, 16 MVA transformer supplies load at Waipara resulting in no n-1 security.

Solution

MainPower is capable of transferring load from the 33 kV to 66 kV network, and has indicated it will continue with the present level of security. Future investment will be customer driven.

17.9 Canterbury bus security

This section presents issues arising from the outage of a single bus section rated at 50 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).

17.9.1 Transmission bus security

Table 9-16 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 17-12: Transmission bus outages

---

\(^{143}\) The transformers’ capacity is limited by a circuit breaker and disconnector (46 MVA), followed by the LV cable (49 MVA) and protection equipment (50 MVA) limits; with these limits resolved, the n-1 capacity will be 55/57 MVA (summer/winter).
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<table>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ashburton 220 kV</td>
<td>Ashburton 33 kV</td>
<td>-</td>
<td>Upper South Island voltage stability</td>
<td>17.9.2</td>
</tr>
<tr>
<td>Ashley 66 kV</td>
<td>Ashley</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Coleridge 66 kV</td>
<td>Coleridge</td>
<td>Coleridge</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Hororata 66 kV</td>
<td>Hororata</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Islington 220 kV</td>
<td>-</td>
<td>Upper South Island voltage stability</td>
<td>17.9.3</td>
<td></td>
</tr>
<tr>
<td>Kaiapoi 66 kV</td>
<td>Kaiapoi</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Waipara 66 kV</td>
<td>Waipara</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
</tbody>
</table>

1. There is no bus protection at Ashley, Coleridge, Hororata, Kaiapoi and Waipara, so bus faults cause loss of supply.

The customers (Orion, Electricity Ashburton, MainPower, or TrustPower) 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.

17.9.2 Ashburton bus security

Project status/type: This issue is for information only

Issue

Ashburton has two 220/33 kV supply transformers on the same bus section. A bus outage disconnects both transformers.

Ashburton also has three 220/66 kV supply transformers on different bus sections, so a bus outage at peak load does not cause an issue for the 66 kV grid exit point.

Solution

In the short term, the 220/33 kV transformer issue can be managed operationally. In the medium term, the 33 kV load will be transferred to the 66 kV (see Section 17.10.1) and the 220/33 kV transformers will be decommissioned.

17.9.3 Regional voltage stability limit

Project description: Upper South Island voltage stability (see Chapter 6, Section 6.7.1)

Issue

The voltage stability limit for the Upper South Island (in this case defined as the South Island north of the Waitaki Valley) is forecast to be reached by around 2022. The binding contingency is an outage of the Ashburton 220 kV bus section C. This removes from service the Ashburton–Islington–1 and Ashburton–Twizel–2 circuits.

Bus section contingencies in order of voltage stability limit are:

<table>
<thead>
<tr>
<th>Rank</th>
<th>Contingency</th>
<th>USI load limit (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Loss of Ashburton bus C with no fault</td>
<td>1287</td>
</tr>
<tr>
<td>2</td>
<td>Loss of Islington bus A with no fault</td>
<td>1296</td>
</tr>
<tr>
<td>3</td>
<td>Loss of Ashburton bus A with no fault</td>
<td>1304</td>
</tr>
<tr>
<td>4</td>
<td>Loss of Islington bus B with no fault</td>
<td>1327</td>
</tr>
</tbody>
</table>
Solution

Projects to address Upper South Island voltage stability are outlined in Chapter 6, Section 6.7.1.

17.10 Other regional items of interest

17.10.1 New Ashburton grid exit point

We are investigating a second Ashburton grid exit point to supply the distribution load to the west of Ashburton. The connection configuration for the new grid exit point is yet to be finalised. It will be supplied from one or both the 220 kV Islington–Livingstone and Islington–Tekapo B circuits and will be required in 4-10 years.

17.10.2 New southern grid exit point for Orion

Orion is planning for a new 220/66 kV grid exit point in the Rolleston-Springston area south of Christchurch. The new grid exit point may connect to the 220 kV Islington–Livingstone circuit or one of the Ashburton–Islington/Ashburton–Bromley circuits and will be required by around 2025.

17.11 Canterbury 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

17.11.1 Maximum regional generation

The Canterbury region has some of the highest load densities in the South Island, coupled with relatively low levels of local generation so there is no practical limit to the generation that can be connected within the region. However, there will be limits on the generation that can be connected at a particular substation or along an existing line due to the rating of the existing circuits.

17.11.2 Mount Cass wind generation station

There is a proposal to install a 60 MW (approximately) wind generation station at Mount Cass, which can 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.

17.11.3 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 Islington–Hororata circuits rated at 60/63 MVA, and two Hororata–Coleridge circuits rated at 30/37 MVA (reconductoring a section of which increases this rating to 50/55 MVA). It is possible to connect over 85 MW of generation if connected 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 of which depends on the location of the connection point 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\textsuperscript{144} of generation to this circuit will overload it, reducing the amount of load that can be supplied.

\textsuperscript{144} More generation connection if the circuit section from the Rangitata River to Islington is thermally upgraded.
18 South Canterbury Regional Plan

18.1 Regional overview

This chapter details the South Canterbury regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

Figure 18-1: South Canterbury region

Construction voltages shown. System as at March 2014.
The South Canterbury region includes a mix of significant and growing provincial cities (Timaru and Oamaru) and agricultural industries (Bells Pond, Black Point, Studholme, Temuka, and Waitaki).

We have assessed the South Canterbury region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be flexible to respond to a range of future service and technology possibilities, taking into consideration:

- the existing transmission network
- forecast demand
- forecast generation
- equipment replacement based on condition assessment, and
- possible technological development.

18.2 South Canterbury transmission system

This section highlights the state of the South Canterbury regional transmission network. The existing transmission network is set out geographically in Figure 18-1 and schematically in Figure 18-2.
18.2.1 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, and 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. Peak load in the region (approximately 180 MW in 2014/15) is approximately 10% of the region's generation capacity, so the need for transmission capacity into the region is driven by generation export requirements, and the need to transfer power from the lower South Island to the upper South Island. In dry years with low generation south of Clyde, there may also be need to transfer power to the lower South Island, see chapter 6 Section 6.6.3

18.2.2 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 the loads in the South Canterbury region are supplied via the 110 kV transmission network running up the east coast from Oamaru to Temuka.

The 110 kV transmission network is normally split at Studholme, but this split is closed during the peak dairy season (October–April) to increase the supply security to Studholme. The split creates two radial feeds incorporating the:
- Timaru 220/110 kV interconnecting transformers supplying Timaru, Albury, Tekapo A and Temuka, and
- Waitaki 220/110 kV interconnecting transformers supplying Studholme, Bells Pond, Black Point, and Oamaru.

Up to 25 MW of generation is injected directly into the 110 kV transmission network from Tekapo A.

Much of the 110 kV transmission network is reaching its capacity, as are the interconnecting transformers at Timaru. This is mainly due to growth associated with the dairy industry, and irrigation in particular.

We have a number of investigations and projects planned or underway to support demand growth and supply security in the South Canterbury region. These include investigating:
- short- and long-term options to address capacity constraints on the 110 kV system between Waitaki and Timaru, and between Timaru and Temuka
- options to supply significant new loads in the Bells Pond area
- options to address the Timaru 220/110 kV transformer capacity constraints, and
- options to increase the security provided by the Waitaki 220/110 kV transformers.

18.2.3 Longer-term development path

Long-term development plans may include new 220 kV connections to offload the highly loaded 110 kV transmission network.

In the Timaru area, options include upgrading the Timaru 220/110 kV interconnection capacity, or building a new 220 kV connection west of Temuka at Orari.

In the Waitaki Valley, options include upgrading the existing 110 kV supply out of Waitaki, or building a new grid exit point connected to the 220 kV at Waihao (north of the Waitaki River). There may also be a new grid exit point connected to the 110 kV at Saint Andrews. These new grid exit points would allow the Bells Pond and Studholme grid exit points to be decommissioned.
Some demand-side response may be appropriate to allow the economic connection of large rural loads such as irrigation.

18.3 South Canterbury demand

The after diversity maximum demand (ADMD) for the South Canterbury region is forecast to grow on average by 3.3% annually over the next 15 years, from 220 MW in 2015 to 360 MW by 2030. This is higher than the national average demand growth of 1.1% annually.

Figure 18-3 shows a comparison of the 2014 and 2015 TPR forecast 15-year maximum demand (after diversity\textsuperscript{145}) for the South Canterbury region. The forecasts are derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data, and is used to calculate the real power capacity for power transformers and transmission lines. See Chapter 4 for more information about demand forecasting.

Table 18-1 lists forecast peak demand (prudent growth) for each grid exit point for the forecast period.

\textsuperscript{145} The after diversity maximum demand (ADMD) for the region will be less than the sum of the individual grid exit point peak demands, as it takes into account the fact that the peak demand does not occur simultaneously at all the grid exit points in the region.
18.4 South Canterbury generation

The South Canterbury region’s generation capacity is 1,731 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.

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 the relevant local lines company’s network (either Network Waitaki or Alpine Energy).\textsuperscript{146}

Table 18-2: Forecast annual generation capacity (MW) at South Canterbury grid injection points to 2030 (including existing and committed generation)

<table>
<thead>
<tr>
<th>Grid injection point (location if embedded)</th>
<th>Generation capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Next 5 years</td>
</tr>
<tr>
<td>Albury (Opuha)</td>
<td>8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8</td>
</tr>
<tr>
<td>Benmore</td>
<td>540 540 540 540 540 540 540 540 540 540 540 540 540 540 540</td>
</tr>
<tr>
<td>Ohau A</td>
<td>264 264 264 264 264 264 264 264 264 264 264 264 264 264 264</td>
</tr>
<tr>
<td>Ohau B</td>
<td>212 212 212 212 212 212 212 212 212 212 212 212 212 212 212</td>
</tr>
<tr>
<td>Ohau C</td>
<td>212 212 212 212 212 212 212 212 212 212 212 212 212 212 212</td>
</tr>
<tr>
<td>Waitaki</td>
<td>90 105 105 105 105 105 105 105 105 105 105 105 105 105 105</td>
</tr>
</tbody>
</table>

18.5 South Canterbury significant maintenance work

Our capital projects and maintenance works are integrated to enable system issues to be resolved if possible when assets are replaced or refurbished. Table 18-3 lists the significant maintenance-related work\textsuperscript{147} proposed for the South Canterbury region.

\textsuperscript{146} Only generators with capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.

\textsuperscript{147} This may include replacement of the asset due to its condition assessment.
for the next 15 years that may significantly impact related system issues or connected parties.

**Table 18-3: Proposed significant maintenance work**

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albury supply transformer expected end-of-life</td>
<td>2017-2019</td>
</tr>
<tr>
<td>Studholme supply transformer expected end-of-life</td>
<td>2018-2020</td>
</tr>
<tr>
<td>Timaru 110 kV bus rationalisation</td>
<td>2016-2017</td>
</tr>
<tr>
<td>Twizel 33 kV outdoor to indoor conversion</td>
<td>2016-2017</td>
</tr>
<tr>
<td>Waitaki interconnecting transformers refurbishment</td>
<td>2016-2017</td>
</tr>
</tbody>
</table>

**18.6 Future South Canterbury projects summary and transmission configuration**

Figure 18-4 shows the possible configuration of South Canterbury transmission in 2030, with new assets, upgraded assets, and assets undergoing significant maintenance within the forecast period.

**Figure 18-4: Possible South Canterbury transmission configuration in 2030**

**18.7 Changes since the 2014 Transmission Planning Report**

Table 18-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year's report.
Table 18-4: Changes since 2014

<table>
<thead>
<tr>
<th>Issues</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Timaru supply transformer capacity</td>
<td>Removed – supply transformers replacement completed.</td>
</tr>
</tbody>
</table>

18.8 South Canterbury transmission capability

Table 18-5 summarises issues involving the South Canterbury region for the next 15 years. For more information about a particular issue, refer to the listed section number.

Table 18-5: South Canterbury region transmission issues

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional</td>
<td></td>
</tr>
<tr>
<td>18.8.1</td>
<td>Oamaru–Waitaki voltage quality and transmission capacity</td>
</tr>
<tr>
<td>18.8.2</td>
<td>Timaru interconnecting transformer capacity</td>
</tr>
<tr>
<td>18.8.3</td>
<td>Waitaki 220/110 kV interconnecting transformer capacity</td>
</tr>
<tr>
<td>Site by grid exit point</td>
<td></td>
</tr>
<tr>
<td>18.8.4</td>
<td>Albury supply security and supply transformer capacity</td>
</tr>
<tr>
<td>18.8.5</td>
<td>Albury and Tekapo A transmission security</td>
</tr>
<tr>
<td>18.8.6</td>
<td>Bells Pond single supply security</td>
</tr>
<tr>
<td>18.8.7</td>
<td>Black Point capacity and single supply security</td>
</tr>
<tr>
<td>18.8.8</td>
<td>Oamaru supply transformer capacity</td>
</tr>
<tr>
<td>18.8.9</td>
<td>Studholme single supply security</td>
</tr>
<tr>
<td>18.8.10</td>
<td>Studholme supply transformer capacity</td>
</tr>
<tr>
<td>18.8.11</td>
<td>Tekapo A supply security and supply transformer capacity</td>
</tr>
<tr>
<td>18.8.12</td>
<td>Temuka transmission security and supply transformer capacity</td>
</tr>
<tr>
<td>18.8.13</td>
<td>Twizel supply security</td>
</tr>
<tr>
<td>18.8.14</td>
<td>Waitaki single supply security and supply transformer capacity</td>
</tr>
<tr>
<td>Bus security</td>
<td></td>
</tr>
<tr>
<td>18.9.1</td>
<td>Transmission bus security</td>
</tr>
<tr>
<td>18.9.2</td>
<td>Timaru 110 kV transmission security</td>
</tr>
</tbody>
</table>

18.8.1 Oamaru–Waitaki voltage quality and transmission capacity

Project Description: Post-contingency load shedding
New grid exit point
Upgrade existing 110 kV line

Project status/type: Load shedding: possible, base capex
New grid exit point: possible, customer-specific
Line upgrade: possible, Major Capex Project

Indicative timing: Load shedding: summer 2016/17
New grid exit point: to be advised
Line upgrade: to be advised

Indicative cost band: Load shedding: A
New grid exit point: D
Line upgrade: D

Issue

Two 110 kV circuits from Waitaki supply the Oamaru, Black Point, Bells Pond, and Studholme grid exit points:
• Oamaru–Black Point–Waitaki–1 circuit (which supplies Black Point via a tee connection), and
• Oamaru–Studholme–Bells Pond–Waitaki–2 circuit (which supplies the Bells Pond and Studholme loads from tee connections).

The underlying load growth forecast for this area is considerably higher than the national average, and is mainly due to irrigation and the dairy industry. A new dairy factory, commissioned in 2014, is supplied from the Bells Pond grid exit point and is anticipated to expand in stages over the next few years.

Expansion of the irrigation scheme supplied from Black Point is committed. Black Point is forecast to expand by 2 MW for summer 2016/17, with a further 6 MW anticipated to be added after that in 2 MW stages. Timing for the additional 6 MW is uncertain but could be as early as summer 2017/18.

Voltage

The load at these four grid exit points peaks in summer. The voltage at the Oamaru 110 kV bus can fall below 0.9 pu with the loss of the:
• Oamaru–Black Point–Waitaki circuit, or
• Oamaru–Studholme–Bells Pond–Waitaki circuit.

There is a wider voltage agreement in place with Network Waitaki, extending the voltage lower range to 0.875 pu. Combined with the improved power factor of the Oamaru load, this has resolved the immediate voltage issue with the thermal limit typically constraining the load first.

If there is a connection to Timaru via Studholme (i.e. the Studholme Split is closed – see Section 18.8.9), significant voltage support is provided to Oamaru from Timaru.

There is also a voltage quality issue with a large voltage step immediately following the outage of either 110 kV circuit. The lack of availability of tap changing at the Waitaki interconnecting transformers limits voltage control flexibility on the 110 kV Oamaru–Waitaki circuits. There are no steady state voltage issues at Oamaru 33 kV, due to the range of the supply transformer on-load tap changers.

In the medium term, there are voltage stability issues. The limits are highly dependent on the location of load growth, the load power factor and the system configuration (particularly whether the system is split between Studholme and Timaru).

As a general guide, voltage stability issues could be expected to occur when the Oamaru load exceeds 48 MW with the Studholme–Timaru circuit out of service, and 55 MW with that circuit in service. This is beyond the present thermal limit, and depends to some extent on the Studholme, Black Point and Bells Pond loads.

Thermal overloading

Thermal n-1 limits on the 110 kV Glenavy–Oamaru section of the Oamaru–Studholme–Bells Pond–Waitaki–2 circuit were exceeded in summer 2014/15. The critical contingency is an outage of the parallel circuit. This has required load management by Network Waitaki.

The thermal limit of the 110 kV Bells Pond–Waitaki section was exceeded in summer 2014/15. Critical contingencies are the parallel 110 kV circuit as well as either 220 kV Ashburton–Timaru–Twizel circuit.

A special protection scheme at Waitaki detects an overload on the 110 kV Bells Pond–Waitaki circuit and splits the 110 kV circuit north or south of Studholme (depending on whether the 110 kV Oamaru–Black Point–Waitaki circuit is in service or not). This will resolve the issue until summer 2016/17.
The thermal limit of the 110 kV Black Point–Waitaki section of the Oamaru–Black Point–Waitaki–1 circuit may be exceeded in summer 2016/17. The critical contingency is an outage of the parallel circuit. This is a marginal overload and depends on voltage operating points and the power factor of the loads at Black Point and Oamaru.

**Solution**

We are investigating a range of short-term options, and the solution may include one or more of the following:

- pre- or post-contingency load management or standby generation at the Oamaru, Bells Pond, and/or Black Point grid exit points
- implementing a permanent 110 kV system split between Glenavy and Studholme
- load shifting within Network Waitaki’s network from Oamaru to Waitaki
- improved load power factors at Oamaru and/or Black Point, and/or
- increasing the operating voltage at Waitaki during peak load periods.

A range of possible long-term options to resolve the capacity issue, include:

- transferring load from Bells Pond (and possibly Studholme) to a new grid exit point near the Islington–Livingstone circuit at Waihao
- transferring load from Oamaru to a new grid exit point at the existing Livingstone switching station (see Section 18.10.1)
- reconductoring and thermally upgrading the existing 110 kV circuits and providing additional reactive support, and
- transferring additional Oamaru load to an upgraded grid exit point at Waitaki.

Easements may be required for the line upgrade work, and will be required for any new lines.

We are discussing development options with the local lines companies (Network Waitaki and Alpine Energy).

**18.8.2 Timaru interconnecting transformer capacity**

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Additional interconnecting transformer capacity, or New grid exit point near Orari</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Interconnector capacity: Possible, Base Capex New grid exit point: Possible, customer specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>Both: 2018-2020</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>Interconnector capacity: C New grid exit point: D</td>
</tr>
</tbody>
</table>

**Issue**

Two 220/110 kV interconnecting transformers at Timaru supply the loads at Timaru, Temuka, Albury and Tekapo A, providing:

- a total nominal installed capacity of 240 MVA, and
- n-1 capacity of 122/127 MVA (summer/winter).

The peak recorded Timaru area load is approximately 108/100 MW (summer/winter), assuming Tekapo A is generating. If Tekapo A is not generating, an outage of one transformer may cause:

- the other transformer to exceed its n-1 capacity during peak summer periods, resulting in load shedding, and
- voltage instability once the Timaru area loads exceed 126 MW.
With Tekapo A at maximum generation, the transformers’ n-1 thermal limit will be reached when the Timaru area load is approximately 120 MW. The n-1 voltage stability limit will be approximately 135 MW.

Some development options for the Lower Waitaki Valley area might increase the loading on these transformers (for example, supplying Studholm from Timaru instead of Waitaki - see Section 18.8.1 for more information).

In addition, we recently installed an automatic load shedding scheme that will reduce load at Timaru if either interconnector becomes overloaded. This allows load above the n-1 limit to be supplied as long as both interconnectors are in service.

**Solution**

The options to address this issue include one or more of the following:

- reducing reactive power flow through the Timaru interconnecting transformers (for example by improving the load power factor or installing 110 kV reactive support)
- shifting load to a new grid exit point (see section 18.8.12 for more information), and/or
- increasing installed capacity using one of several possible configurations of the existing and new interconnecting transformers.

**18.8.3 Waitaki 220/110 kV interconnecting transformer capacity**

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Refurbishment of Waitaki interconnecting transformers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2017-2019</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>A</td>
</tr>
</tbody>
</table>

**Issue**

Two 220/110 kV interconnecting transformers (T23 and T24) at Waitaki supply the Waitaki 110 kV loads at Black Point, Bells Pond, Oamaru, and Studholm, providing:

- a total nominal installed capacity of 130 MVA, and
- n-1 capacity of 80/85 MVA (summer/winter).

The loading on the two transformers is unequal because of the system configuration (there is no 110 kV bus at Waitaki and only Oamaru is connected to both circuits). These transformers have a higher capacity than the circuits they supply, so they are not the first constraint. However, under some 110 kV Oamaru–Waitaki transmission upgrade scenarios, the capacity of the Waitaki–Oamaru circuits will exceed the interconnecting transformers’ n-1 capacity.

In addition, some of the transformer bushings require replacement and the tap changers on these transformers cannot be operated due to their condition. The lack of operable tap changers worsens voltage issues on the Lower Waitaki 110 kV transmission system (see Section 18.8.1 for more information).

**Solution**

These transformers have an expected end-of-life within the next 10-15 years if the bushings are replaced. We intend to replace the 110 kV and 220 kV bushings and repair existing oil leaks.

We will consider the appropriate replacement transformer size and configuration when the need arises (this may be driven by load growth, changes in the 110 kV transmission system or transformer condition).
18.8.4 Albury supply security and supply transformer capacity

**Project status/type:** This issue is for information only

**Issue**

A single 110/11 kV, 5 MVA transformer supplies load at Albury resulting in no n-1 security.

In addition, Albury has embedded generation at Opuha, which may export power to the National Grid during periods of low demand.

The peak load at Albury is forecast to exceed the transformer’s summer capacity by approximately 1 MW in 2018, increasing to approximately 3 MW in 2030 (see Table 18-6).

Alpine Energy has requested that the Albury 11 kV bus voltage be managed within a narrow range. The transformer taps cannot be operated on-load when there is power flow in the export direction, which affects the ability to manage voltage.

| Table 18-6: Albury supply transformer overload forecast |
|---------------------------------------------|------------|
| **Circuit/grid exit point** | **Power factor** | **Transformer overload (MW)** |
| Albury | 0.95 | 0 | 0 | 0 | 1 | 1 | 2 | 3 | 3 | 3 | 3 |

**Solution**

The Albury load forecast does not separate Opuha generation from actual load. Therefore, the transformer overload forecast assumes historical generation patterns.

There is some ability for Opuha generation to supply the local load during planned outages. Alpine Energy can supply a limited amount of Albury’s load from adjacent substations. In addition, Transpower’s mobile substation can be used at Albury to cover a transformer planned outage.

Therefore, the issue can be managed operationally for the forecast period. Future investment will be customer driven.

The supply transformer has an expected end-of-life within the next five years. We have discussed transformer replacement options with Alpine Energy to provide for load growth and coordinating outages to minimise supply interruptions when replacing this transformer. Further investment will be customer driven.

18.8.5 Albury and Tekapo A transmission security

**Project status/type:** This issue is for information only

**Issue**

A single 110 kV Tekapo A–Albury–Timaru circuit connects Tekapo A, Albury, and Opuha to the National Grid. If the circuit trips, demand located at Albury and Tekapo A will lose supply, and generation located at Tekapo A and Opuha will disconnect from the National Grid.

**Solution**

Albury and Tekapo A demand may be restored by local Opuha and Tekapo A generation. Alpine Energy considers the issue can be managed operationally for the forecast period. Future investment will be customer driven.
18.8.6 Bells Pond single supply security

<table>
<thead>
<tr>
<th>Project description:</th>
<th>n-1 security at Bells Pond</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, customer-specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>See Section 18.8.1</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>See Section 18.8.1</td>
</tr>
</tbody>
</table>

**Issue**

Bells Pond has a single 110 kV circuit with a hard-tee connection to Oamaru–Waitaki–2 circuit, resulting in no n-1 security. Additionally, the capacity of the 110 kV circuit between Bells Pond and Waitaki can already be exceeded at peak load periods during an outage of the parallel 110 kV circuit.

**Solution**

Alpine Energy has requested a higher capacity and security level, and we are discussing possible options. The preferred option is to shift the Bells Pond load to a new 220/110 kV grid exit point connected to the Islington–Livingstone circuit at Waihao, near Waimate (see Section 18.8.1 for more information).

Future investment will be customer driven.

18.8.7 Black Point capacity and single supply security

| Project status/type: | This issue is for information only |

**Issue**

Black Point has a single 110 kV circuit with a hard-tee connection to the Oamaru–Waitaki–1 circuit, resulting in no n-1 security.

The Black Point load is forecast to increase over the next three to five years to a level that will see constraints on the section between Black Point and Waitaki (refer to section 18.8.1).

Additionally, there are constraints on maintenance during the irrigation season, which now extends from September to May. These constraints are becoming unmanageable as some maintenance cannot be done during winter.

**Solution**

We are discussing options with the customer, which include:

- agreement on a more flexible maintenance outage schedule
- a changeover system at the tee point to allow connection to the parallel Oamaru–Waitaki circuit
- a second tee circuit from the parallel Oamaru–Waitaki circuit
- a post-contingency load management scheme, and/or
- improving the load power factor.

18.8.8 Oamaru supply transformer capacity

| Project status/type: | This issue is for information only |

**Issue**

Two 110/33 kV transformers supply Oamaru’s load, providing:

- a total nominal installed capacity of 120 MVA, and
• n-1 capacity of 63/63 MVA\textsuperscript{148} (summer/winter).

Due to voltage drop and power factor considerations at Oamaru, this translates to a load limit approximately 50 MW.

The peak load at Oamaru is forecast to exceed the transformers’ n-1 summer capacity by approximately 3 MW in 2022, increasing to approximately 9 MW in 2030 (see Table 18-7).

Table 18-7: Oamaru supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oamaru</td>
<td>0.96</td>
<td>0</td>
</tr>
</tbody>
</table>

Solution

The 110 kV circuits supplying these transformers have a lower capacity\textsuperscript{149} than the transformers (see Section 18.8.1). Therefore, the transformers are not the first constraint on Oamaru load.

The customer is considering options (see Sections 18.8.1 and 18.8.14 for more information):
• to enable load to exceed the existing transmission capacity, and/or
• limit Oamaru load growth or shift load from Oamaru, keeping the Oamaru load within the existing n-1 capacity of the 110 kV circuits.

Future investment will be customer driven.

18.8.9 Studholme single supply security

Project status/type: See Sections 18.8.1 and 18.8.10 for more information

Issue

The Studholme–Timaru circuit is split during the dairy off-season (May to September), and Studholme is supplied by the Oamaru–Studholme–Bells Pond–Waitaki circuit. This reduces losses that occur when power flows through the 110 kV system from Waitaki to Timaru. If the Oamaru–Studholme–Bells Pond–Waitaki circuit has a fault, the supply to Studholme automatically transfers to the Studholme–Timaru line. This results in approximately a 25 second loss of supply at Studholme before the switching occurs.

Even a brief loss of supply can cause significant economic loss for the dairy factory at Studholme, so the split is closed for the peak dairy season (October to April).

Closing the split increases the loading on the circuits between Waitaki and Studholme, as some power flows from Studholme to Timaru. However, this is to some extent balanced by the voltage support for the Oamaru area that the connection through to Timaru provides.

A special protection scheme at Waitaki detects an overload on the Bells Pond–Waitaki section of the 110 kV Oamaru–Studholme–Bells Pond–Waitaki circuit and splits the 110 kV circuit north or south of Studholme (depending on whether the

\textsuperscript{148} The Oamaru transformers’ capacity is limited by protection equipment limits, followed by the circuit breaker (71 MVA) limits; with these limits resolved, the n-1 capacity will be 72/76 MVA (summer/winter).

\textsuperscript{149} The lowest rated circuit section (Black Point–Oamaru) is rated at 49/60 MVA summer/winter.
110 kV Oamaru–Black Point–Waitaki circuit is in service or not). See Section 18.8.1 for more information.

In the medium term it may be necessary to permanently split the 110 kV system between Studholme and Glenavy, to reduce loading on the Bells Pond–Waitaki circuit. This will leave Studholme normally supplied from Timaru.

**Solution**

In the short-term, we will investigate the economic benefit of closing the split over winter.

Long-term, the solutions to the Oamaru–Waitaki voltage quality and transmission security issue (see Section 18.8.1 for more information) and the Timaru interconnecting transformer capacity (see Section 18.8.2) will determine the options available at Studholme.

### 18.8.10 Studholme supply transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Upgrade transformer capacity or New grid exit point</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Upgrade transformer capacity: possible, customer-specific New grid exit point: possible, customer-specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>Upgrade transformer capacity: 2018-20 (subject to Alpine Energy agreement) New grid exit point: to be advised</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>Upgrade transformer capacity: B New grid exit point: D</td>
</tr>
</tbody>
</table>

**Issue**

Two 110/11 kV transformers supply Studholme's load, providing:
- a total nominal installed capacity of 20 MVA, and
- n-1 capacity of 11/12 MVA (summer/winter).

The peak load at Studholme already exceeds the transformers' n-1 summer capacity, and the overload is forecast to increase to approximately 27 MW in 2030 (see Table 18-8). The load forecast is driven by an anticipated dairy factory expansion and new irrigation schemes.

**Table 18-8: Studholme supply transformer overload forecast**

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Studholme</td>
<td>0.96</td>
<td>9</td>
</tr>
</tbody>
</table>

Studholme has an unusual 110 kV bus arrangement, where the two transformers have no dedicated 110 kV circuit breakers. This means that both supply transformers will be tripped to clear a transformer fault, causing a loss of supply at Studholme. Supply can be restored after the faulted transformer is disconnected.

**Solution**

Possible solutions include:
- replacing the existing transformers with higher-rated units, or
- supplying the load from a new grid exit point south-west of Studholme at Waihao on the 220 kV Islington–Livingstone circuit and decommissioning Studholme (see section 18.8.1), and
- possibly a new grid exit point on the 110 kV Studholme-Timaru circuit near Saint Andrews.
Acquisition of substation land will be required for establishing new grid exit point(s).

Both supply transformers are programmed for replacement within the next five years based on their age and condition assessment. Transformer replacement is unlikely to be economic if irrigation developments are likely to occur, as these developments are expected to result in a new grid exit point. In this case the transformer replacement would be deferred.

If the transformers are to be replaced, we will discuss the transformer capacity with Alpine Energy.

### 18.8.11 Tekapo A supply security and supply transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Resolve Tekapo A supply transformer branch limits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Proposed, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2015/16</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>A</td>
</tr>
</tbody>
</table>

**Issue**

A single 110/11 kV, 35 MVA transformer in series with a single 33/11 kV, 10 MVA transformer supplies load at Tekapo, resulting in no n-1 security.

The peak load at Tekapo A is forecast to exceed the 33/11 kV transformer’s winter branch rating by approximately 1 MW from 2018, increasing to 3 MW by 2030 (see Table 18-9).

#### Table 18-9: Tekapo A supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/Grid exit point</th>
<th>Power factor</th>
<th>Next 5 years</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tekapo A</td>
<td>1.00</td>
<td>0 0 0 1 1 1</td>
<td>1 2 2 2 3</td>
</tr>
<tr>
<td>6-15 years out</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Solution**

Transpower’s mobile substation is an option for use at Tekapo A during planned outages, and Alpine Energy considers that the lack of n-1 security can be managed operationally for the forecast period.

We will investigate resolving the CT limit, which will provide sufficient capacity for the forecast period. Future investment will be customer driven.

### 18.8.12 Temuka transmission security and supply transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Special protection scheme</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upgrade Temuka–Timaru circuit capacity</td>
<td></td>
</tr>
<tr>
<td>New grid exit point near Orari</td>
<td></td>
</tr>
<tr>
<td>Project status/type:</td>
<td>Possible, customer-specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2015–2019</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>Special protection scheme: A</td>
</tr>
<tr>
<td>AdditionaL transformer: B</td>
<td></td>
</tr>
<tr>
<td>Upgrade circuit capacity: to be advised</td>
<td></td>
</tr>
<tr>
<td>New grid exit point: to be advised</td>
<td></td>
</tr>
</tbody>
</table>

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150 The transformer’s branch limit of 4.5 MVA (due to a CT rating) prevents the full nominal installed capacity being available.
### Issue

Two 110 kV Timaru–Temuka circuits, rated at 71/79 MVA and 73/80 MVA (summer/winter), supply the Temuka 33 kV load. The Clandeboye dairy factory represents approximately half the Temuka 33 kV peak load. This creates the potential for significant economic loss during interruptions at this grid exit point.

An outage of one of these circuits is forecast to cause the other circuit to exceed its thermal capacity during summer peak demand periods by summer 2015/16. There is also no 110 kV bus at Temuka. Therefore, a circuit outage will also result in the loss of the 110/33 kV supply transformer connected to this circuit.

At Temuka, two 110/33 kV transformers supply the 33 kV load, providing:
- a total nominal installed capacity of 108 MVA, and
- n-1 capacity of 61/63 MVA (summer/winter).

The peak load at Temuka is forecast to exceed the transformers’ n-1 summer capacity by approximately 14 MW in 2015, increasing to approximately 43 MW in 2030 (see Table 18-10).

#### Table 18-10: Temuka supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temuka</td>
<td>0.96</td>
<td>14</td>
<td>16</td>
<td>17</td>
</tr>
</tbody>
</table>

### Solution

We are discussing options with Alpine Energy. Short-term options include:
- pre-contingency load management
- a demand response scheme, and/or
- a special protection scheme to manage load post-contingency.

Long-term options include:
- paralleling the existing transformers and installing a new 120 MVA transformer, and
- upgrading the 110 kV circuits between Timaru and Temuka, or
- a new connection to one or more of the 220 kV circuits west of Temuka at Orari.

The addition of a new transformer will not raise new property issues as it can be implemented within the existing substation boundary. However, upgrading the capacity of the 110 kV Timuka–Timaru circuits may require easements.

We have begun a project to investigate the full range of long-term options for Temuka along with the Timaru interconnection capacity (see Section 18.8.2).

### 18.8.13 Twizel supply security

| Project status/type: | This issue is for information only |

### Issue

Two 220/33 kV transformers supply the Twizel load, providing:
- a total nominal installed capacity of 40 MVA, and
- n-1 capacity of 26/27 MVA (summer/winter).

The loads supplied from the Twizel 33 kV bus have ‘n’ transformer security, because the supply bus is split. Hydro generation and control structures in the area (Ohau A,
B and C, Tekapo B, Ruataniwha and Pukaki) take their local supply from this bus, and it is split to reduce the risk of losing connection to all sites simultaneously.

Alpine Energy takes 33 kV supply from one side of the split, and Network Waitaki takes supply from the other side of the split.

The bus split can be closed to avoid loss of supply during transformer maintenance, and in a short time following an unplanned transformer outage.

**Solution**

Alpine Energy, Network Waitaki, Meridian and Genesis consider that the present level of security can be managed operationally.

The 33 kV switchyard is scheduled to be converted to an indoor switchboard within the next five years, and may include a bus section breaker, which will allow the bus to be run solid while maintaining a high level of security. The design will be confirmed as part of the replacement project.

### 18.8.14 Waitaki single supply security and supply transformer capacity

<table>
<thead>
<tr>
<th>Project reference:</th>
<th>Customer to take supply from our 11 kV (generation) bus</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Committed, customer-specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2015</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>N/A</td>
</tr>
</tbody>
</table>

**Issue**

A single 33/11 kV, 5.5 MVA transformer supplies load at Waitaki resulting in no n-1 security.

Network Waitaki can supply some of the Waitaki load from Twizel after a short loss of supply. However, the peak Waitaki load is forecast to exceed the continuous supply transformer capacity by approximately 6 MW in 2015, increasing to approximately 10 MW in 2030 (see Table 18-11).

**Table 18-11: Waitaki supply transformer overload forecast**

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Next 5 years</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>2015 2016 2017 2018 2020 2021</td>
<td>6-15 years out</td>
</tr>
<tr>
<td>Waitaki</td>
<td>0.97</td>
<td>6 7 8 9 9 9</td>
<td>10 10 10 10 10 10</td>
</tr>
</tbody>
</table>

**Solution**

Network Waitaki is installing a new 20/24 MVA transformer at Waitaki to increase capacity. The existing 5 MVA transformer will be retained in the short term. In the medium term Network Waitaki may install a second 25 MVA transformer to increase security (enabling decommissioning of the 5 MVA transformer).

This, along with developments in the distribution network, will allow Network Waitaki to meet increased load growth in the Upper Waitaki Valley. (See also section 18.8.1).

### 18.9 South Canterbury bus security

This section includes issues arising from the outage of a single bus section rated at 50 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).

### 18.9.1 Transmission bus security

Table 9-16 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

<table>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albury 110 kV</td>
<td>Albury</td>
<td>Opuha</td>
<td>Tekapo A</td>
<td>See note 1</td>
</tr>
<tr>
<td></td>
<td>Tekapo A</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aviemore</td>
<td>-</td>
<td>Aviemore</td>
<td>-</td>
<td>See note 4</td>
</tr>
<tr>
<td>Oamaru 110 kV 1</td>
<td>Black Point</td>
<td>-</td>
<td>-</td>
<td>See note 2</td>
</tr>
<tr>
<td>Oamaru 110 kV 2</td>
<td>Bells Pond</td>
<td>-</td>
<td>-</td>
<td>See note 2</td>
</tr>
<tr>
<td></td>
<td>Studholme</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ohau A</td>
<td>-</td>
<td>Ohau A</td>
<td>-</td>
<td>See note 4</td>
</tr>
<tr>
<td>Studholme 110 kV</td>
<td>Studholme</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Tekapo B</td>
<td>-</td>
<td>Tekapo B</td>
<td>-</td>
<td>See note 4</td>
</tr>
<tr>
<td>Timaru 110 kV</td>
<td>Albury</td>
<td>Opuha</td>
<td>Tekapo A</td>
<td>18.9.2</td>
</tr>
<tr>
<td></td>
<td>Studholme</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Tekapo A</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>Temuka</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Timaru</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Waitaki 220 kV-A</td>
<td>Bells Pond</td>
<td>-</td>
<td>-</td>
<td>See note 3</td>
</tr>
<tr>
<td></td>
<td>Studholme</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Waitaki 220 kV-B</td>
<td>Black Point</td>
<td>-</td>
<td>-</td>
<td>See note 3</td>
</tr>
</tbody>
</table>

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 breaker, the bus becomes an extension of a long circuit, and adds a small level of additional risk of that circuit tripping.
3. This is a minor issue where loads on n security are at risk from a circuit outage, and that risk extends to an outage of the transformer and 220 kV bus because there is no 110 kV bus.
4. Disconnection of local generation only.

The customers (Alpine Energy, Meridian and Genesis) have not requested a higher security level (excluding the Timaru 110 kV bus). 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.

#### 18.9.2 Timaru 110 kV transmission security

<table>
<thead>
<tr>
<th>Project reference:</th>
<th>Timaru 110 kV bus rationalisation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Committed, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2016–2017</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>A</td>
</tr>
</tbody>
</table>
Chapter 18: South Canterbury Region

Issue

The Timaru 110 kV bus operates as a single zone and supplies the entire loads at Timaru and Temuka, connects directly to Albury and Tekapo A via a single 110 kV circuit, and supplies Studholme when the system is split between Studholme and Glenavy (see Section 18.8.9). A 110 kV bus fault at Timaru will cause:

- a total loss of supply to Timaru and Temuka
- a total loss of supply at Tekapo A and the disconnection of the Tekapo A generation
- the disconnection of Albury, possibly causing a loss of supply to Albury, and the disconnection of Opuha generation if islanding is unsuccessful, and
- a loss of supply to Studholme if the system is split between Glenavy and Studholme.

Solution

We are committed to converting the Timaru 110 kV bus to three zones, which will secure the Timaru area load. This is scheduled for completion by summer 2017/18.

There may still be a loss of supply and generation disconnection at Tekapo A, Albury and Opuha for an outage of the bus section connecting the single Tekapo A–Albury–Timaru circuit. Similarly, there will still be a loss of supply to Studholme (if the system is split between Studholme and Glenavy) for an outage of the bus section connecting the Studholme–Timaru circuit.

18.10 Other regional items of interest

18.10.1 New grid exit points

Development of a 220/110 kV Waihao grid exit point connected to the Islington–Livingstone circuit (see also Sections 18.8.1 and 18.8.6) will supply new irrigation load and also has the potential to shift load from the Bells Pond and Studholme substations. Load at Waihao is not separately listed in the load forecast but is included in the load forecasts for Bells Pond and Studholme (see Section 18.3 for more information).

St Andrews is our generic name for a possible new 110/11 kV grid exit point between Studholme and Timaru. It will supply principally irrigation load. This substation is considered as part of the annual peak demand forecast from 2019. It is likely the load at Bells Pond and Studholme will need to be shifted to Waihao to free up capacity on the 110 kV circuits for Saint Andrews.

Installing supply transformers at the Livingstone switching station is one option to address a number of issues on the south side of the Waitaki River. The issues include:

- Oamaru–Waitaki voltage quality and transmission security (see Section 18.8.1).
- Black Point single supply security (see Section 18.8.7).
- Oamaru supply transformer capacity (see Section 18.8.8).
- Waitaki supply transformer capacity (see Section 18.8.14).

It could also release capacity on the existing 110 kV circuits and allow increased security to load connected to Bells Pond.

Future investment will be customer driven.
18.11 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

18.11.1 Wind generation

There are no issues with connecting wind or other generation at existing substations within the Waitaki Valley at 220 kV.

Connecting too much generation to one of the four circuits to Christchurch, however, may cause that circuit to overload and reduce the maximum load that can be supplied across all four circuits.

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 enable 400–700 MW of generation. The worst-case location and circuit will not support the dispatch of generation.

Unless the 110 kV Tekapo A–Albury–Timaru circuit is upgraded, there is limited opportunity to connect new generation without the risk of constraints. This is because of the existing generation at Tekapo A, and the Opuha generation embedded at Albury.

The other 110 kV circuits in the South Canterbury region can support generation connections up to or slightly higher than the circuit rating.
## Chapter 19: Otago-Southland Region

### 19.1 Regional overview

This chapter details the Otago-Southland regional transmission plan. We base this regional plan on an assessment of available data, and welcome feedback to improve its value to all stakeholders.

**Figure 19-1: Otago-Southland region**
The Otago-Southland region includes a mix of provincial cities (Dunedin and Invercargill) together with New Zealand’s largest electricity consumer, the Tiwai Point Aluminium Smelter, and the smaller but still significant tourist/rural service centres of Queenstown, Wanaka and Cromwell.

We have assessed the Otago-Southland region’s transmission needs over the next 15 years while considering longer-term development opportunities. Specifically, the transmission network needs to be flexible to respond to a range of future service and technology possibilities, taking into consideration:

- the existing transmission network
- forecast demand
- forecast generation
- equipment replacement based on condition assessment, and
- possible technological development.

19.2 Otago-Southland transmission system

This section highlights the state of the Otago-Southland regional transmission network. The existing transmission network is set out geographically in Figure 19-1 and schematically in Figure 19-2.

19.2.1 Transmission into the region

There are issues with the transmission capacity to transfer power into or out of the Otago-Southland region.

When Otago-Southland generation is high, transmission capacity from Roxburgh may constrain generation dispatch within the region for some outages. With low Otago-Southland generation, the transmission capacity of the circuits from Twizel and
Livingstone to Roxburgh may exceed their thermal ratings to supply the deficit power to the region.

Under the Clutha-Upper Waitaki Lines Project (formerly known as Lower South Island Facilitating Renewables), we have upgraded the Clyde–Roxburgh and Aviemore-Waitaki circuits and are upgrading the Waitaki–Livingstone circuits in 2016. At the end of 2013, we reviewed the need, scope and timing for the delivery of the remaining sections, namely:

- reconductoring the Livingstone–Naseby–Roxburgh circuits
- reconductoring the Aviemore–Benmore circuits, and
- thermally upgrading the Cromwell–Twizel circuits.

Following stakeholder consultation, the review concluded that design should continue and the timing for implementation would be reviewed again in 2015. The review identified a refined preferred scope, namely (in order):

- thermally upgrading the Cromwell–Twizel circuits
- reconductoring the Livingstone–Naseby–Roxburgh circuits
- installing a special protection scheme to split the system at Aviemore to prevent overloading of an Aviemore–Benmore circuit for an outage of the other circuit (which differed from the original plan to reconductor the Aviemore–Benmore circuits)

The earliest completion date is 2018-2019. As an interim upgrade, we have installed a special protection scheme to automatically reconfigure the 220 kV bus at Roxburgh if an overload on the Naseby-Roxburgh circuit is detected. This provides a small increase in transmission capacity for generation export from Otago-Southland towards the Waitaki Valley before the full implementation of these circuit upgrades.

See Chapter 6, Sections 6.5.2 and 6.7.2, for more information.

### 19.2.2 Transmission within the region

The transmission within the Otago-Southland region comprises 220 kV and 110 kV transmission circuits with interconnecting transformers located at Cromwell, Halfway Bush, Roxburgh and Invercargill.

Capacitors are installed at North Makarewa to improve the system voltage and voltage stability performance. There are also capacitors on the supply bus 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 region, comprising 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 region, comprising South Dunedin and Halfway Bush, is predominantly supplied via Three Mile Hill.
- The Southland 110 kV network is supplied via the three interconnecting transformers at Halfway Bush, Roxburgh, and Invercargill.
- The Central Otago area represents load 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 arise during outages, especially during the summer and shoulder seasons. In addition, many of the transformers connected to the 110 kV transmission network are older, single-phase units, with an expected end-of-life within the next 20 years.

We have committed to implementing the Lower South Island Reliability Project to increase the capacity of the 110 kV and 220 kV transmission network within the
region. It addresses existing issues and provides the foundation for future increases in transmission capacity when required. As part of the project, we recently replaced the Invercargill and Halfway Bush 220/110 kV transformers and are implementing a new 220/110 kV interconnection at the Gore substation. The project also included a series capacitor on a North Makarewa—Three Mile Hill circuit. However, due to a reduced load forecast, the series capacitor is not expected to be required until around 2025 or later, but this will be periodically reassessed. See Chapter 6, Section 6.5, for more information.

### 19.2.3 Longer-term development path

The Lower South Island Reliability Project addresses existing issues and provides the foundation for future upgrades when required, which will potentially include additional reactive support and increased line compensation.

### 19.3 Otago-Southland demand

The after diversity maximum demand (ADMD) for the Otago-Southland region is forecast to grow on average by 0.6% annually over the next 15 years, from 1,080 MW in 2015 to 1,170 MW by 2030. This is lower than the national average demand growth of 1.1% annually.

Figure 19-3 shows a comparison of the 2014 and 2015 TPR forecast 15-year maximum demand (after diversity\(^{151}\)) for the Otago-Southland region. The forecasts are derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point is also derived from historical data. See Chapter 4 for more information about demand forecasting.

![Figure 19-3: Otago-Southland region after diversity maximum demand forecast](image)

Table 19-1 lists forecast peak demand (prudent growth) for each grid exit point for the forecast period.

---

\(^{151}\) The after diversity maximum demand (ADMD) for the region will be less than the sum of the individual grid exit point peak demands, as it takes into account the fact that the peak demand does not occur simultaneously at all the grid exit points in the region.
### Table 19-1: Forecast annual peak demand (MW) at Otago-Southland grid exit points to 2030

<table>
<thead>
<tr>
<th></th>
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<th></th>
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</thead>
<tbody>
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<td>30</td>
<td>31</td>
<td>31</td>
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<td>32</td>
</tr>
<tr>
<td>Brydone</td>
<td>0.79</td>
<td></td>
<td>11</td>
<td>11</td>
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<tr>
<td>Cromwell</td>
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<td>Edendale&lt;sup&gt;1&lt;/sup&gt;</td>
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<td>42</td>
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<td>44</td>
<td>45</td>
<td>46</td>
<td>47</td>
<td>48</td>
</tr>
<tr>
<td>Frankton</td>
<td>1.00</td>
<td></td>
<td>58</td>
<td>59</td>
<td>60</td>
<td>62</td>
<td>63</td>
<td>64</td>
<td>67</td>
<td>69</td>
<td>72</td>
<td>74</td>
<td>77</td>
</tr>
<tr>
<td>Gore</td>
<td>0.97</td>
<td></td>
<td>33</td>
<td>33</td>
<td>33</td>
<td>33</td>
<td>34</td>
<td>34</td>
<td>35</td>
<td>36</td>
<td>37</td>
<td>37</td>
<td>38</td>
</tr>
<tr>
<td>Halfway Bush 110 kV&lt;sup&gt;1&lt;/sup&gt;</td>
<td>0.97</td>
<td></td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>6</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Halfway Bush 33 kV&lt;sup&gt;1,2&lt;/sup&gt;</td>
<td>1.00</td>
<td></td>
<td>81</td>
<td>66</td>
<td>67</td>
<td>67</td>
<td>74</td>
<td>74</td>
<td>75</td>
<td>76</td>
<td>77</td>
<td>78</td>
<td>79</td>
</tr>
<tr>
<td>Halfway Bush 33 kV&lt;sup&gt;2&lt;/sup&gt;</td>
<td>1.00</td>
<td></td>
<td>54</td>
<td>54</td>
<td>54</td>
<td>55</td>
<td>55</td>
<td>55</td>
<td>55</td>
<td>56</td>
<td>57</td>
<td>57</td>
<td>58</td>
</tr>
<tr>
<td>Invercargill</td>
<td>0.99</td>
<td></td>
<td>105</td>
<td>106</td>
<td>108</td>
<td>109</td>
<td>110</td>
<td>112</td>
<td>114</td>
<td>117</td>
<td>120</td>
<td>122</td>
<td>125</td>
</tr>
<tr>
<td>Naseby</td>
<td>0.98</td>
<td></td>
<td>32</td>
<td>32</td>
<td>32</td>
<td>33</td>
<td>33</td>
<td>33</td>
<td>34</td>
<td>35</td>
<td>35</td>
<td>36</td>
<td>37</td>
</tr>
<tr>
<td>North Makarewa</td>
<td>0.98</td>
<td></td>
<td>54</td>
<td>55</td>
<td>56</td>
<td>57</td>
<td>58</td>
<td>58</td>
<td>60</td>
<td>62</td>
<td>64</td>
<td>65</td>
<td>67</td>
</tr>
<tr>
<td>South Dunedin&lt;sup&gt;3&lt;/sup&gt;</td>
<td>0.99</td>
<td></td>
<td>74</td>
<td>89</td>
<td>89</td>
<td>90</td>
<td>90</td>
<td>90</td>
<td>91</td>
<td>91</td>
<td>92</td>
<td>92</td>
<td>93</td>
</tr>
</tbody>
</table>

1. The prudent forecast includes the new expansion at the Edendale Dairy plant and allows for some incremental demand growth in the future.
2. The load at Halfway Bush 110 kV is an interim arrangement to supply Palmerston and surrounding areas. This load will be transferred to 33 kV once works related to replacement of supply transformers and the outdoor to indoor conversion at Halfway Bush are commissioned.
3. The peak demand forecast at Halfway Bush 1 and 2 is shown as an average historical percentage of the expected aggregated demand at Halfway Bush. Historically there has been load shifting between the two, giving much higher individual peak demands.

### 19.4 Otago-Southland generation

The Otago-Southland region’s generation capacity is 1,838 MW.<sup>152</sup> This generation usually contributes a major portion of the total South Island generation and exceeds local demand. Surplus generation is exported over the National Grid to other demand centres in the South Island.

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 relevant local lines company’s network (PowerNet, OtagoNet, or Aurora).<sup>153</sup>

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<sup>152</sup> This excludes the resource consent applications for the Clyde and Roxburgh generation station capacity increases.

<sup>153</sup> Only generators with a capacity greater than 1 MW are listed. Generation capacity is rounded to the nearest megawatt.
Table 19-2: Forecast annual generation capacity (MW) at Otago-Southland grid injection points to 2030 (including existing and committed generation)

<table>
<thead>
<tr>
<th>Grid injection point (location if embedded)</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>Next 5 years</th>
<th>Generation capacity (MW)</th>
<th>6-15 years out</th>
<th>2022</th>
<th>2024</th>
<th>2026</th>
<th>2028</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clyde</td>
<td>432</td>
<td>432</td>
<td>432</td>
<td>432</td>
<td>432</td>
<td>432</td>
<td>432</td>
<td>432</td>
<td>432</td>
<td>432</td>
<td>432</td>
<td>432</td>
<td>432</td>
<td></td>
</tr>
<tr>
<td>Manapouri</td>
<td>840</td>
<td>840</td>
<td>840</td>
<td>840</td>
<td>840</td>
<td>840</td>
<td>840</td>
<td>840</td>
<td>840</td>
<td>840</td>
<td>840</td>
<td>840</td>
<td>840</td>
<td></td>
</tr>
<tr>
<td>Roxburgh</td>
<td>320</td>
<td>320</td>
<td>320</td>
<td>320</td>
<td>320</td>
<td>320</td>
<td>320</td>
<td>320</td>
<td>320</td>
<td>320</td>
<td>320</td>
<td>320</td>
<td>320</td>
<td></td>
</tr>
<tr>
<td>Berwick/Halfway Bush (Waipori and Mahinerangi)</td>
<td>84</td>
<td>84</td>
<td>84</td>
<td>84</td>
<td>84</td>
<td>84</td>
<td>84</td>
<td>84</td>
<td>84</td>
<td>84</td>
<td>84</td>
<td>84</td>
<td>84</td>
<td></td>
</tr>
<tr>
<td>Balclutha (Mt. Stuart)</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td></td>
</tr>
<tr>
<td>Balclutha (Fraser)</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Clyde (Horseshoe Bend hydro and wind)</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Clyde (Talla Burn)</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Clyde (Fraser)</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Clydne (Horseshoe Bend hydro and wind)</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Halfway Bush (Deep Stream)</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>Halfway Bush (Deep Stream)</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Halfway Bush (Deep Stream)</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td></td>
</tr>
<tr>
<td>North Makarewa (Paerau)</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td></td>
</tr>
<tr>
<td>North Makarewa (Monowai)</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td></td>
</tr>
<tr>
<td>North Makarewa (White Hill)</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td></td>
</tr>
</tbody>
</table>

19.5 Otago-Southland significant maintenance work

Our capital projects and maintenance works are integrated to enable system issues to be resolved if possible when assets are replaced or refurbished. Table 19-3 lists the significant maintenance-related work\textsuperscript{154} 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 maintenance work

<table>
<thead>
<tr>
<th>Description</th>
<th>Tentative year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cromwell 33 kV outdoor to indoor conversion</td>
<td>2021-2023</td>
</tr>
<tr>
<td>Edendale 110/33 kV supply transformers expected end-of-life</td>
<td>2027-2028</td>
</tr>
<tr>
<td>Gore 110/33 kV supply transformers expected end-of-life, and Gore 33 kV outdoor to indoor conversion</td>
<td>2025-2026, 2019-2021</td>
</tr>
</tbody>
</table>

\textsuperscript{154} This may include replacement of the asset due to its condition assessment.
### 19.6 Future Otago-Southland projects summary and transmission configuration

Figure 19-4 shows the possible configuration of Otago-Southland transmission in 2030, with new assets, upgraded assets, and assets undergoing significant maintenance within the forecast period.

**Figure 19-4: Possible Otago-Southland transmission configuration in 2030**

### 19.7 Changes since the 2014 Transmission Planning Report

Table 19-4 lists the specific issues that are either new or no longer relevant within the forecast period when compared to last year's report.

**Table 19-4: Changes Since 2014**

<table>
<thead>
<tr>
<th>Issues</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balclutha supply transformer capacity</td>
<td>Removed. Outdoor to indoor conversion and capacitors commissioned. Transformer branch constraint removed.</td>
</tr>
<tr>
<td>Frankton transmission and supply security</td>
<td>Added. Overload at end of forecast period.</td>
</tr>
<tr>
<td>South Dunedin supply transformer capacity</td>
<td>Removed. Outdoor to indoor conversion commissioned. Transformer branch constraint removed.</td>
</tr>
</tbody>
</table>
19.8 Otago-Southland transmission capability

Table 19-5 summarises issues involving the Otago-Southland region for the next 15 years. For more information about a particular issue, refer to the listed section number.

Table 19-5: Otago-Southland region transmission issues

<table>
<thead>
<tr>
<th>Section number</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional</td>
<td></td>
</tr>
<tr>
<td>19.8.1</td>
<td>Southland transmission capacity and low voltage</td>
</tr>
<tr>
<td>Site by grid exit point</td>
<td></td>
</tr>
<tr>
<td>19.8.2</td>
<td>Cromwell supply transformer capacity</td>
</tr>
<tr>
<td>19.8.3</td>
<td>Edendale supply transformer capacity</td>
</tr>
<tr>
<td>19.8.4</td>
<td>Frankton transmission and supply security</td>
</tr>
<tr>
<td>19.8.5</td>
<td>Gore supply transformer capacity</td>
</tr>
<tr>
<td>19.8.6</td>
<td>Halfway Bush supply transformer capacity</td>
</tr>
<tr>
<td>19.8.7</td>
<td>Invercargill supply transformer capacity</td>
</tr>
<tr>
<td>19.8.8</td>
<td>Naseby supply transformer capacity</td>
</tr>
<tr>
<td>19.8.9</td>
<td>Waipori transmission security</td>
</tr>
<tr>
<td>Bus security</td>
<td></td>
</tr>
<tr>
<td>19.9.1</td>
<td>Transmission bus security</td>
</tr>
<tr>
<td>19.9.2</td>
<td>Halfway Bush bus security</td>
</tr>
</tbody>
</table>

19.8.1 Southland transmission capacity and low voltage

Project context: Lower South Island Reliability
Project status/type: Committed, Major Capex Project
Indicative timing: 2012-TBC
Indicative cost band: E

Issue

The 220 kV Southland transmission network forms a geographical triangle linking the substations at Roxburgh, Halfway Bush and Invercargill. At each corner of this triangle, a 220/110 kV interconnecting transformer supplies the 110 kV network.

The 110 kV network features a similar geographical triangle between Roxburgh, Halfway Bush and Gore, with a single 110 kV circuit from Gore to Brydone, Edendale, and Invercargill.

This configuration can result in 110 kV network overloading and low voltages. The 220 kV network may also overload when Manapouri generation is low.

Overloading

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
- one of the 220 kV Invercargill–Roxburgh circuits, or
- one of the 220 kV Roxburgh–Three Mile Hill circuits.

A 220 kV Invercargill–Roxburgh circuit may also overload for an outage of the parallel circuit.
The severity of these overloads depends on Roxburgh, Manapouri, and Waipori generation at the time of the outage.

**Low voltages**

An outage of some of the Southland transmission circuits or interconnecting transformers may result in low voltages at Gore, Brydone and Edendale.

**Solution**

The overloading issues can be managed operationally by regulating the amount of generation at Manapouri, Waipori and Roxburgh. The extent to which generation may need to be regulated will depend on the generation dispatched in the South Island at the time. In addition, some load can be transferred from the Halfway Bush 110 kV bus to the 220 kV bus, and some low voltage problems can be resolved using the existing transformer off-load tap changers. If these measures are not sufficient then a 110 kV system split is necessary, which puts the 110 kV load on a security.

We have committed to implementing the Lower South Island Reliability Project, a suite of projects to increase the transmission capacity between Roxburgh and Invercargill. The remaining project includes the following:

- Installing Special Protection Schemes to allow sufficient build time for Gore interconnection.
- Installing a new 220/110 kV interconnection point comprising two 220/110 kV transformers at Gore. A two kilometre 220 kV double-circuit line is connected from the Gore substation to the 220 kV Three Mile Hill–North Makarewa line.

Designation and acquisition of property rights will be required for the two kilometre 220 kV double-circuit line, which will tee connect from the 220 kV Three Mile Hill–North Makarewa line to Gore substation.

Until the commissioning of the 220 kV interconnection at Gore it may be necessary to occasionally manage load offtake in the 110 kV network.

### 19.8.2 Cromwell supply transformer capacity

<table>
<thead>
<tr>
<th>Project description</th>
<th>Upgrade protection limit</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Upgrade branch limiting components</td>
</tr>
<tr>
<td>Project status/type</td>
<td>Upgrade protection limit: possible, Base Capex</td>
</tr>
<tr>
<td></td>
<td>Upgrade branch limiting components: possible, customer-specific</td>
</tr>
<tr>
<td>Indicative timing</td>
<td>Upgrade protection limit: 2026</td>
</tr>
<tr>
<td></td>
<td>Upgrade branch limiting components: 2028</td>
</tr>
<tr>
<td>Indicative cost band</td>
<td>Upgrade protection limit: A</td>
</tr>
<tr>
<td></td>
<td>Upgrade branch limiting components: A</td>
</tr>
</tbody>
</table>

**Issue**

Two 220/110/33 kV transformers (rated at 73 MVA\(^{155}\) and 50 MVA) supply Cromwell’s 33 kV loads, with:

- a total nominal installed capacity of 123 MVA, and
- n-1 capacity of 41/41 MVA\(^{156}\) (summer/winter).

---

\(^{155}\) 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.

\(^{156}\) The transformers’ capacity is limited by the protection limit of 41 MVA, followed by the current transformer, circuit breaker and disconnector limit of 46 MVA, a protection limit of 49 MVA, a bus section limit of 50 MVA, and another protection limit of 55 MVA; with these limits resolved, the n-1 capacity will be 65/68 MVA (summer/winter).
The peak load at Cromwell is forecast to exceed the transformers’ n-1 winter capacity by approximately 2 MW in 2026, increasing to approximately 5 MW in 2030 (see Table 19-6).

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cromwell</td>
<td>1.0</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

Resolving the protection limit will provide sufficient n-1 capacity until 2028. Upgrading other transformer branch limiting components will resolve the issue for the forecast period and beyond. Future investment will be customer driven.

### 19.8.3 Edendale supply transformer capacity

**Project description:** Upgrade transformer capacity

**Project status/type:** Possible, customer-specific

**Indicative timing:** To be advised

**Indicative cost band:** Upgrade transformer capacity: B

**Issue**

Two 110/33 kV transformers supply Edendale’s load, providing:

- a total nominal installed capacity of 60 MVA, and
- n-1 capacity of 32/32 MVA\(^{157}\) (summer/winter).

The peak load at Edendale is forecast to exceed the n-1 shoulder capacity by approximately 12 MW in 2015, increasing to approximately 20 MW in 2030 (see Table 19-7).

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Edendale</td>
<td>0.95</td>
<td>12</td>
</tr>
</tbody>
</table>

**Solution**

We are adding a parallel 33 kV cable (customer specific) which will reduce the possible overload. We are discussing future supply options with PowerNet, including:

- operational management by transferring or limiting the load within the capability of the supply transformer
- adding transformer fans to increase cooling, and
- replacing the existing transformers with two higher-rated units.

In addition, both supply transformers at Edendale have an expected end-of-life towards the end of the forecast period. We will discuss the rating and timing for the replacement transformers with PowerNet. Future investment will be customer driven.

---

\(^{157}\) The transformers’ capacity is limited by a 33 kV cable limit; with this limit resolved, the n-1 capacity will be 34/36 MVA (summer/winter).
19.8.4 Frankton transmission and supply security

| Project description: | Upgrade protection and metering  
|                     | Upgrade line thermal capacity  
|                     | Upgrade transformer capacity  

| Project status/type: | Upgrade protection and metering: possible, Base Capex  
|                     | Upgrade line and transformer capacities: possible, customer-specific  

| Indicative timing: | Upgrade protection and metering: to be advised  
|                    | Upgrade line thermal capacity: to be advised  
|                    | Upgrade transformer capacity: to be advised  

| Indicative cost band: | Upgrade protection and metering: A  
|                      | Upgrade line thermal capacity: to be advised  
|                      | Replace bank transformers with higher-rated unit: B  

**Issue**

The Frankton’s load is supplied by:

- two 110 kV circuits from Cromwell, with a total nominal installed capacity of 127/152 MVA (summer/winter) and n-1 capacity of 63/76 MVA\(^\text{158}\) (summer/winter), and

- two 110/33 kV supply transformers rated at 66 MVA\(^\text{159}\) and 85 MVA, providing:
  - a total nominal installed capacity of 158 MVA, and
  - n-1 capacity of 80/80 MVA\(^\text{160}\) (summer/winter).

There is no 110 kV bus at Frankton, so fault on either a circuit or Frankton supply transformer will cause both the circuit and supply transformer to be taken out of service.

The peak load at Frankton is forecast to exceed the circuits’ n-1 winter thermal capacity from approximately 2026, and the transformers’ n-1 winter capacity by approximately 2 MW in 2030 (see Table 19-8).

**Table 19-8: Frankton supply transformer and Cromwell–Frankton circuit overload forecast**

<table>
<thead>
<tr>
<th>Grid exit point</th>
<th>Power factor</th>
<th>Transformer/circuit overload (MW)</th>
<th>Next 5 years</th>
<th>6-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frankton supply</td>
<td>1.0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>transformer</td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Cromwell–Frankton circuits</td>
<td>1.0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

We will discuss future supply options with Aurora closer to the time the issue arises. Possible options are:

- implementing Variable Line Rating (VLR) and/or thermally upgrading the Cromwell–Frankton circuits
- resolving the transformer protection limit, and
- replacing the existing bank of transformers with a higher-rated unit.

Easements on parts of the line may be required for the thermal upgrade work. Future investment will be customer driven.

---

158 The circuits’ capacity is limited by a line trap and protection; with these limits resolved, the n-1 capacity will be 63/77 MVA (summer/winter).

159 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.

160 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).
19.8.5 Gore supply transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Upgrade transformer capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type:</td>
<td>Possible, customer-specific</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>To be advised</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>Replace transformers with higher-rated units: B</td>
</tr>
</tbody>
</table>

**Issue**

Two 110/33 kV transformers supply Gore’s load, providing:
- a total nominal installed capacity of 60 MVA, and
- n-1 capacity of 37/39 MVA (summer/winter).

The peak load at Gore is forecast to exceed the transformers’ n-1 winter capacity by approximately 1 MW in 2026, increasing to approximately 3 MW in 2030 (see Table 19-9).

**Table 19-9: Gore supply transformer overload forecast**

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gore</td>
<td>0.97</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

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, or
- replacing the existing transformers with two higher-rated units.

In addition, both supply transformers have an expected end-of-life within the forecast period. We also plan to convert the Gore 33 kV outdoor switchgear to an indoor switchboard within the next five years.

The solutions do not raise property issues as the existing substation has sufficient room to accommodate the transformers and an indoor switchboard.

19.8.6 Halfway Bush supply transformer capacity

<table>
<thead>
<tr>
<th>Project description:</th>
<th>Replace 110/33 kV transformers</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Replace 220/33 kV transformer</td>
</tr>
<tr>
<td>Project status/type:</td>
<td>Replace 110/33 kV transformers: proposed, Base Capex</td>
</tr>
<tr>
<td></td>
<td>Replace 220/33 kV transformer: proposed, Base Capex</td>
</tr>
<tr>
<td>Indicative timing:</td>
<td>2018-2025</td>
</tr>
<tr>
<td>Indicative cost band:</td>
<td>To be advised</td>
</tr>
</tbody>
</table>

**Issue**

Three transformers supply Halfway Bush’s 33 kV load, comprising:
- two 110/33 kV transformers, each with nominal capacity of 50 MVA, and n-1 capacity of 54/57 MVA (summer/winter), and
- one 220/33 kV transformer, with a nominal capacity of 100 MVA, and n-1 capacity of 112/112 MVA\(^{161}\) (summer/winter).

We operate the 33 kV bus split with:

\(^{161}\) The transformers’ capacity is limited by a protection limit; with this limit resolved, the n-1 capacity will be 113/119 MVA (summer/winter).
• both 110/33 kV transformers connected in parallel supplying one bus section, and
• 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.

The peak load at Halfway Bush is forecast to exceed the transformer’s n-1 winter capacity by approximately 4 MW in 2015. Load transfer from Halfway Bush to South Dunedin in 2016 reduces the load to within the transformers’ n-1 capacity until 2024 when 2 MW overload appears increasing to approximately 6 MW in 2030.\footnote{This forecast assumes that Waipori generation station injects 16 MW of power into the Halfway Bush 33 kV bus.}

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>5-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Halfway Bush–1 and 2</td>
<td>1.0</td>
<td>4</td>
<td>0</td>
</tr>
</tbody>
</table>

**Solution**

The Halfway Bush supply transformer loading may be reduced by using one or more of the following options:
• transferring load between the Halfway Bush 110 kV and 220 kV buses with the 33 kV bus split
• increasing the output from Waipori generation injecting into the Halfway Bush 33 kV bus, and/or
• transferring up to 5 MW via Aurora’s distribution network to South Dunedin.

All three supply transformers have an expected end-of-life within the forecast period. After discussions with Aurora, we intend to replace the:
• two 110/33 kV, 50 MVA supply transformers with a single 220/33 kV, 120 MVA supply transformer by 2018 (this will also allow the 33 kV bus to be operated solid, improving security), and
• existing 220/33 kV, 100 MVA supply transformer with a 120 MVA unit by 2025.

This transformer replacement programme provides a small increase in n-1 transformer capacity with each replacement transformer. This, together with generation from Mahinerangi and Waipori, is expected to be sufficient to provide n-1 security to the load well beyond the forecast period.

Converting the 33 kV outdoor switchgear to an indoor switchboard is also scheduled within the next five years. We will coordinate this with the transformer replacements and Aurora’s feeder rationalization project.

The two 110 kV Halfway Bush–Palmerston circuits and the Palmerston site were transferred to OtagoNet (local lines company) in March 2014, providing for load offtake both at 33 kV and 110 kV.

OtagoNet will convert both circuits for operation at 33 kV in two stages to coordinate with our supply transformer replacement (giving a small increase in capacity) and 33 kV outdoor to indoor conversion:
• up to 2017-2018 there will be 33 kV and 110 kV load at Halfway Bush, with the 33 kV bus remaining split, and
• after 2018, single 33 kV load offtake after commissioning the replacement transformer and indoor 33 kV switchboard.

Future investment will be customer driven.

19.8.7 Invercargill supply transformer capacity

<table>
<thead>
<tr>
<th>Project description</th>
<th>Resolve transformer metering constraint</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing</td>
<td>2015</td>
</tr>
<tr>
<td>Indicative cost band</td>
<td>A</td>
</tr>
</tbody>
</table>

**Issue**

Two 220/33 kV transformers supply Invercargill’s load, providing:

• a total nominal installed capacity of 240 MVA, and
• n-1 capacity of 109/109 MVA\(^{163}\) (summer/winter).

The peak load at Invercargill is forecast to exceed the transformers’ n-1 winter capacity by approximately 1 MW in 2015, increasing to approximately 21 MW in 2030 (see Table 19-11).

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>5-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Invercargill</td>
<td>0.99</td>
<td></td>
<td>1</td>
<td>2</td>
</tr>
</tbody>
</table>

**Solution**

Recalibrating the metering parameters at Invercargill will solve the issue within the forecast period.

19.8.8 Naseby supply transformer capacity

<table>
<thead>
<tr>
<th>Project description</th>
<th>Upgrade transformer capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project status/type</td>
<td>Possible, Base Capex</td>
</tr>
<tr>
<td>Indicative timing</td>
<td>2018</td>
</tr>
<tr>
<td>Indicative cost band</td>
<td>B</td>
</tr>
</tbody>
</table>

**Issue**

Two 220/33 kV transformers supply Naseby’s load, providing:

• a total nominal installed capacity of 70 MVA, and
• n-1 capacity of 35/35 MVA (summer/winter).

The peak load at Naseby\(^{164}\) is forecast to exceed the transformers’ n-1 summer capacity by approximately 1 MW in 2022, increasing to approximately 4 MW in 2030 (see Table 19-12).

---

\(^{163}\) The transformers’ capacity is limited by metering equipment; with this limit resolved, the n-1 capacity will be 143/143 MVA (summer/winter).

\(^{164}\) The forecast peak load at Naseby assumes that the embedded generation in the area (Paearu and Falls Down) will continue providing a similar support as previous years during peak times.
Table 19-12: Naseby supply transformer overload forecast

<table>
<thead>
<tr>
<th>Circuit/grid exit point</th>
<th>Power factor</th>
<th>Transformer overload (MW)</th>
<th>Next 5 years</th>
<th>5-15 years out</th>
</tr>
</thead>
<tbody>
<tr>
<td>Naseby</td>
<td>0.98</td>
<td></td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Solution

We will discuss future supply options with PowerNet, which include:

- managing the load to within the capability of the existing transformers, or
- replacing the existing transformers with two higher-rated units.

In addition, both supply transformers have an expected end-of-life within the next five years. We will discuss the rating and timing for the replacement transformers with PowerNet. Future investment will be customer driven.

19.8.9 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 end, and both circuits will trip in the event of a line fault. This will disconnect the portion of Waipori generation connected at 110 kV from the National Grid, resulting in no n-1 connection security.

Solution

Trustpower has not requested a higher security level and there are no plans to increase supply security at this grid injection point. Future investment will be customer driven. If n-1 connection security is eventually required, then line protection, together with the associated 110 kV current transformers and a voltage transformer at Berwick, will need to be installed.

19.9 Otago-Southland bus security

This section presents issues arising from the outage of a single bus section rated at 50 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).

19.9.1 Transmission bus security

Table 9-16 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 19-13: Transmission bus outages

<table>
<thead>
<tr>
<th>Transmission bus outage</th>
<th>Loss of supply</th>
<th>Generation disconnection</th>
<th>Transmission issue</th>
<th>Further information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balclutha 110 kV</td>
<td>Balclutha</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
<tr>
<td>Brydone 110 kV</td>
<td>Brydone</td>
<td>-</td>
<td>-</td>
<td>See note 1</td>
</tr>
</tbody>
</table>
Chapter 19: Otago-Southland Region

Transmission bus outage | Loss of supply | Generation disconnection | Transmission issue | Further information
---|---|---|---|---
Edendale 110 kV | Edendale | - | - | See note 1
Gore 110 kV | Gore | - | - | See note 1
Halfway Bush 110 kV | Halfway Bush 33 kV and 110 kV | - | - | 19.9.2
Halfway Bush 220 kV | Halfway Bush 33 kV | - | - | 19.9.2

1. There is no bus protection at Balclutha, Brydone, Edendale and Gore, so bus faults cause loss of supply.

The customers (Aurora, PowerNet, OtagoNet, Solid Energy, or Dongwha Patinna) 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.

### 19.9.2 Halfway Bush bus security

**Project status/type:** This issue is for information only

**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.

**Solution**

This issue is managed operationally. Following a 220 kV or 110 kV bus outage, the 33 kV bus split is closed, restoring the 33 kV supply.

The two 110/33 kV supply transformers will be replaced with one 220/33 kV transformer and the 33 kV bus split will be closed (See Section 19.8.6 for more information). The two 220/33 kV supply transformers (the existing transformer and the new transformer) will each be on a separate 220 kV bus. Supply will be maintained for an outage of a 220 kV bus.

### 19.10 Other regional items of interest

There are no other items of interest identified to date beyond those in Section 19.8 and Section 19.9. See Section 19.11 for more information about generation scenarios, proposals and opportunities relevant to this region.

### 19.11 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 usually falls within a range. Generation developers should consult with us at an early stage of their investigations to discuss connection issues.

19.11.1 Maximum regional generation

Otago-Southland is a generation-rich region. Surplus generation export is constrained by the 220 kV Naseby–Roxburgh–Livingstone circuit ratings. At times, existing generation needs to be constrained under light load conditions to avoid overloading of the 220 kV Naseby–Roxburgh–Livingstone circuit under both normal operating conditions and during contingency events.

The Clutha-Upper Waitaki Lines Project (formerly known as the Lower South Island Facilitating Renewables Project) is an approved project to upgrade the circuits between the Waitaki Valley and Roxburgh. This in turn increases the generation export limit from the region, which removes the existing constraints that occur at times and enables new generation connections (see Section 19.2.1 and Chapter 6 for more information).

19.11.2 Mahinerangi wind generation station

Expansion of the Mahinerangi wind generation station beyond stage 1 can be accommodated on the National Grid via the two 110 kV Halfway Bush–Roxburgh circuits.

Only minor upgrades within the Otago-Southland region are 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. These upgrades may not be required, depending on the staged development of the wind generation station, load growth, and the economic level of trade-off between Mahinerangi generation, Waipori, and generation connections to the Roxburgh 110 kV bus.

19.11.3 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 will 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  Generation Scenarios

This section details the timing, type, location and size of new generators assumed in each of the generation scenarios.

We have based our scenarios on the Ministry of Business, Innovation and Employment’s (MBIE’s) draft Electricity Demand and Generation Scenarios and work done recently on disruptive technologies by the New Zealand Smart Grid Forum. The EDGS will replace the Statement of Opportunities as the set of scenarios Transpower must consider for Major Capital Projects (MCPs).

For this year’s TPR we have not explicitly considered MBIE’s draft EDGS scenarios 5-8. They are similar to MBIE’s mixed renewables scenario except they have different demand assumptions, such as about the future levels of demand from Tiwai and future demand growth rates. However, the system states that we have considered are broad and encompass significant regional differences in demand, such as what could occur if Tiwai was to close.

Note that for a given investment decision, we could need to modify the EDGS build schedules to ensure that there is enough diversity between scenarios to test the robustness of the investment in question, and ensure they reflect the latest information that is available.

The scenarios have been designed to cover a range of potential futures, from a scenario which sees the majority of new generation coming from renewables sources, (Global Low Carbon) to a scenario which is heavily reliant on new thermal generation namely (Low-cost fossil fuels) – see the figure below.

![Renewable electricity generation chart](chart.png)

---


A.1 Scenario 1: Mixed Renewables

The major features of the Mixed Renewables scenario are:

- No significant reduction in the cost of existing technologies
- Fuel prices follow expected forecasts and carbon prices remain low in the near term, increasing to $75 per tonne CO₂-equivalent by the mid-2030s.
- Uptake of disruptive technologies such as distributed solar photovoltaics, energy storage and electric vehicle is relatively muted
- Remaining coal-fired baseload generation is phased out in the next 5-10 years and replaced with new geothermal and wind plant
- Installed wind capacity reaches over 1600 MW by 2030

### Installed capacity by technology – Mixed renewables (Scenario 1)

![Graph showing installed capacity by technology for Mixed renewables scenario.]

### Projects and commission dates – Mixed renewables scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>Plant</th>
<th>Technology</th>
<th>Capacity (MW)</th>
<th>Substation</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>Mill Creek</td>
<td>Wind</td>
<td>60</td>
<td>Wilton</td>
</tr>
<tr>
<td>2015</td>
<td>Southdown E105</td>
<td>OCGT</td>
<td>0</td>
<td>Southdown (Decomm.)</td>
</tr>
<tr>
<td>2016</td>
<td>Southdown</td>
<td>GasPkr</td>
<td>0</td>
<td>Southdown (Decomm.)</td>
</tr>
<tr>
<td>2016</td>
<td>ToddPeaker-JunctionRd</td>
<td>GasPkr</td>
<td>100</td>
<td>Stratford</td>
</tr>
<tr>
<td>2016</td>
<td>Cogen Bio generic 1</td>
<td>OthCog</td>
<td>45</td>
<td>Rotorua</td>
</tr>
<tr>
<td>2017</td>
<td>Lake Pukaki</td>
<td>HydPk</td>
<td>35</td>
<td>Twizel</td>
</tr>
<tr>
<td>2018</td>
<td>Huntly coal unit 1</td>
<td>Coal</td>
<td>0</td>
<td>Huntly (Decomm.)</td>
</tr>
<tr>
<td>2018</td>
<td>Tauhara stage 2</td>
<td>Geo</td>
<td>250</td>
<td>Wairakei</td>
</tr>
<tr>
<td>2020</td>
<td>Huntly coal unit 4</td>
<td>Coal</td>
<td>0</td>
<td>Huntly (Decomm.)</td>
</tr>
</tbody>
</table>

167 (Decomm) denotes a generator that is decommissioned.
## Appendix A: Generation Scenarios

<table>
<thead>
<tr>
<th>Year</th>
<th>Scenario</th>
<th>Type</th>
<th>MW</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>CastleHill stage1</td>
<td>Wind</td>
<td>8.22</td>
<td>Greytown</td>
</tr>
<tr>
<td>2020</td>
<td>Turitea</td>
<td>Wind</td>
<td>183</td>
<td>Linton</td>
</tr>
<tr>
<td>2020</td>
<td>Glenbrook upgrade</td>
<td>OthCog</td>
<td>80</td>
<td>Glenbrook</td>
</tr>
<tr>
<td>2020</td>
<td>Hawea Control Gate Retrofit</td>
<td>HydPk</td>
<td>17</td>
<td>Cromwell</td>
</tr>
<tr>
<td>2020</td>
<td>Demand side NI 1 Northland1</td>
<td>DSR</td>
<td>5.05</td>
<td>Marsden</td>
</tr>
<tr>
<td>2020</td>
<td>Demand side SI 3 Southland1</td>
<td>DSR</td>
<td>4.8</td>
<td>Tiwai Point</td>
</tr>
<tr>
<td>2021</td>
<td>Hawkes Bay wind farm Maungaharuru</td>
<td>Wind</td>
<td>27.72</td>
<td>Redcliffy</td>
</tr>
<tr>
<td>2021</td>
<td>Wairau</td>
<td>HydRR</td>
<td>70</td>
<td>Blenheim</td>
</tr>
<tr>
<td>2022</td>
<td>Hawkes Bay wind farm Maungaharuru</td>
<td>Wind</td>
<td>65.41</td>
<td>Redcliffy</td>
</tr>
<tr>
<td>2022</td>
<td>CCGT Cogen generic 1</td>
<td>GasCog</td>
<td>40</td>
<td>Hamilton</td>
</tr>
<tr>
<td>2022</td>
<td>Stockton Mine</td>
<td>HydRR</td>
<td>35</td>
<td>Waimangaroa</td>
</tr>
<tr>
<td>2023</td>
<td>Rotokawa generic1</td>
<td>Geo</td>
<td>130</td>
<td>Wairakei</td>
</tr>
<tr>
<td>2023</td>
<td>Tauhara generic1</td>
<td>Geo</td>
<td>80</td>
<td>Wairakei</td>
</tr>
<tr>
<td>2024</td>
<td>Taranaki CC</td>
<td>CCGT</td>
<td>0</td>
<td>Stratford (Decomm.)</td>
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<tr>
<td>2024</td>
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<td>CCGT</td>
<td>475</td>
<td>Stratford</td>
</tr>
<tr>
<td>2027</td>
<td>Hawkes Bay windfarm Maungaharuru</td>
<td>Wind</td>
<td>225</td>
<td>Redcliffy</td>
</tr>
<tr>
<td>2028</td>
<td>CastleHill stage1</td>
<td>Wind</td>
<td>54.47</td>
<td>Greytown</td>
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<tr>
<td>2029</td>
<td>CastleHill stage1</td>
<td>Wind</td>
<td>155.64</td>
<td>Greytown</td>
</tr>
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<td>2029</td>
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<td>Huntly (Decomm.)</td>
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<td>2030</td>
<td>Ngatamariki generic1</td>
<td>Geo</td>
<td>100</td>
<td>Ohaaki</td>
</tr>
</tbody>
</table>

### A.2 Scenario 2: High geothermal access

The key features of the High Geothermal Access scenario are:

- Access to geothermal resource is higher than in scenario 1.
- All other assumptions are unchanged from scenario 1.
- Installed geothermal capacity reaches over 1500 MW by 2030
- Installed wind capacity reaches 1400 MW by 2030
### Installed capacity by technology – High geothermal access (Scenario 2)

![Graph showing installed capacity by technology from 2016 to 2030.]

### Projects and commission dates – South Island Renewables scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>Plant</th>
<th>Technology</th>
<th>Capacity (MW)</th>
<th>Substation</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>Mill Creek</td>
<td>Wind</td>
<td>60</td>
<td>Wilton</td>
</tr>
<tr>
<td>2015</td>
<td>Southdown E105</td>
<td>OCGT</td>
<td>0</td>
<td>Southdown (Decomm.)</td>
</tr>
<tr>
<td>2016</td>
<td>Southdown</td>
<td>GasPkr</td>
<td>0</td>
<td>Southdown (Decomm.)</td>
</tr>
<tr>
<td>2016</td>
<td>ToddPeaker-JunctionRd</td>
<td>GasPkr</td>
<td>100</td>
<td>Stratford</td>
</tr>
<tr>
<td>2016</td>
<td>Cogen Bio generic 1</td>
<td>OthCog</td>
<td>45</td>
<td>Rotorua</td>
</tr>
<tr>
<td>2018</td>
<td>Huntly coal unit 1</td>
<td>Coal</td>
<td>0</td>
<td>Huntly (Decomm.)</td>
</tr>
<tr>
<td>2018</td>
<td>Tauhara stage 2</td>
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Appendix A: Generation Scenarios

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A.3 Scenario 3: Low-cost fossil fuels

The key features of the Low-cost Fossil Fuels scenario are:

- Gas prices are lower than in the previous two scenarios. Carbon prices remain low over the forecast horizon.
- Baseload thermal generation capacity remains steady in the long term with the remaining coal-fired units at Huntly remaining in service and additional combined-cycle gas turbines meeting demand growth.
- Ready access to thermal fuels suppresses growth in geothermal and wind capacity, which reach 1300 MW and 700 MW respectively by 2030.
- Installed capacity of combined-cycle gas turbines exceeds 1600 MW by 2030.

**Installed capacity by technology – Low cost fossil fuels (Scenario 3)**

**Projects and commission dates – Low cost fossil fuels**

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### Scenario 4: Global low carbon

The key features of the Coal scenario are:

- Carbon prices increase rapidly from 2015 onward, increasing the variable cost of thermal plant.
- The remaining coal-fired units at Huntly shut-down by 2020.
- Otahuhu B becomes a peaking unit from 2017.
- Installed wind capacity reaches over 2300 MW by 2030, supported by an additional 240 MW of new hydro peaking capacity and demand-side initiatives.
- Geothermal build is also slightly curtailed by the high carbon price, reaching 1350 MW by 2030.
- Uptake of distributed solar photovoltaics, battery storage and electric vehicle demand is higher than in the previous scenarios. This leads to slightly flatter peaks due to the storage, but an overall increase in energy demand due electric vehicles.

#### Generation Scenarios

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### Installed capacity by technology – Global low carbon (Scenario 4)

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### Appendix A: Generation Scenarios

#### 2019
- **Huntly coal unit 4**
  - **Energy Type:** Coal
  - **Capacity:** 0
  - **Location:** Huntly (Decomm.)

#### 2019
- **Turitea**
  - **Energy Type:** Wind
  - **Capacity:** 180.43
  - **Location:** Linton

#### 2020
- **Glenbrook upgrade**
  - **Energy Type:** OthCog
  - **Capacity:** 80
  - **Location:** Glenbrook

#### 2021
- **CastleHill stage1**
  - **Energy Type:** Wind
  - **Capacity:** 200
  - **Location:** Greytown

#### 2021
- **Hawkes Bay wind farm Maungaharuru**
  - **Energy Type:** Wind
  - **Capacity:** 225
  - **Location:** Redcliffye

#### 2022
- **CastleHill stage2**
  - **Energy Type:** Wind
  - **Capacity:** 200
  - **Location:** Greytown

#### 2022
- **Project CentralWind**
  - **Energy Type:** Wind
  - **Capacity:** 120
  - **Location:** Matahina

#### 2022
- **Taharoa**
  - **Energy Type:** Wind
  - **Capacity:** 54
  - **Location:** Hangatiki

#### 2022
- **Waitahora**
  - **Energy Type:** Wind
  - **Capacity:** 156
  - **Location:** Woodville

#### 2022
- **Taranaki CC**
  - **Energy Type:** CCGT
  - **Capacity:** 0
  - **Location:** Stratford (Decomm.)

#### 2022
- **Demand side NI 3 Auckland1**
  - **Energy Type:** DSR
  - **Capacity:** 26.82
  - **Location:** Otahuhu

#### 2022
- **Demand side SI 3 Southland1**
  - **Energy Type:** DSR
  - **Capacity:** 4.8
  - **Location:** Tiwai Point

#### 2023
- **Rotokawa generic1**
  - **Energy Type:** Geo
  - **Capacity:** 130
  - **Location:** Wairakei

#### 2023
- **CastleHill stage3**
  - **Energy Type:** Wind
  - **Capacity:** 200
  - **Location:** Greytown

#### 2025
- **GenericMediumWind3**
  - **Energy Type:** Wind
  - **Capacity:** 152.99
  - **Location:** Bunnythorpe

#### 2025
- **Arnold**
  - **Energy Type:** HydPk
  - **Capacity:** 46
  - **Location:** Dobson

#### 2025
- **GenericMediumWind3**
  - **Energy Type:** Wind
  - **Capacity:** 165.97
  - **Location:** Bunnythorpe

#### 2026
- **Lake Coleridge 2**
  - **Energy Type:** HydPk
  - **Capacity:** 70
  - **Location:** Culverden

#### 2027
- **North Bank Tunnel**
  - **Energy Type:** HydSC
  - **Capacity:** 260
  - **Location:** Waitaki

#### 2027
- **Stockton Plateau**
  - **Energy Type:** HydRR
  - **Capacity:** 25
  - **Location:** Waimangaroa

#### 2028
- **GenericMediumWind3**
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  - **Capacity:** 200
  - **Location:** Bunnythorpe

#### 2028
- **Hauauru ma raki stage1**
  - **Energy Type:** Wind
  - **Capacity:** 60.21
  - **Location:** Huntly

#### 2028
- **Mahinerangi stage 2**
  - **Energy Type:** Wind
  - **Capacity:** 41.4
  - **Location:** Nth Makarewa

#### 2029
- **Hauauru ma raki stage1**
  - **Energy Type:** Wind
  - **Capacity:** 211.8
  - **Location:** Huntly

#### 2029
- **Mahinerangi stage 2**
  - **Energy Type:** Wind
  - **Capacity:** 52.61
  - **Location:** Nth Makarewa

#### 2029
- **Huntly unit 6 (P40)**
  - **Energy Type:** OCGT
  - **Capacity:** 0
  - **Location:** Huntly (Decomm.)

#### 2030
- **Ngatamariki generic1**
  - **Energy Type:** Geo
  - **Capacity:** 100
  - **Location:** Ohaaki

#### 2030
- **Otahuhu C**
  - **Energy Type:** CCGT
  - **Capacity:** 400
  - **Location:** Otahuhu

#### 2030
- **Otahuhu B Peaker**
  - **Energy Type:** GasPkr
  - **Capacity:** 0
  - **Location:** Otahuhu (Decomm.)

### A.5 Scenario 5: Disruptive Technologies

The key features of the Disruptive Technologies scenario are:

- Rapid uptake of distributed solar photovoltaics, battery storage and electric vehicles. This leads to significantly flatter peaks and a greater proportional of energy demand met by off-grid generation but higher consumer energy demand due to electric vehicles.
- Fuel costs and carbon prices are as in scenario 1.
- The remaining coal-fired units at Huntly are retired by 2021.
- Load-shifting through battery storage largely reduces the need for additional demand-side response and interruptible load capacity.
## Installed capacity by technology – Disruptive technologies (Scenario 5)

![Installed capacity by technology – Disruptive technologies (Scenario 5)](image)

## Projects and commission dates – Disruptive technologies scenario

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<td>Wairakei</td>
</tr>
<tr>
<td>2025</td>
<td>CastleHill stage2</td>
<td>Wind</td>
<td>88.86</td>
<td>Greytown</td>
</tr>
<tr>
<td>2025</td>
<td>CastleHill stage1</td>
<td>Wind</td>
<td>200</td>
<td>Greytown</td>
</tr>
<tr>
<td>2026</td>
<td>CastleHill stage2</td>
<td>Wind</td>
<td>200</td>
<td>Greytown</td>
</tr>
<tr>
<td>2026</td>
<td>CastleHill stage3</td>
<td>Wind</td>
<td>84.81</td>
<td>Greytown</td>
</tr>
<tr>
<td>2027</td>
<td>CastleHill stage3</td>
<td>Wind</td>
<td>200</td>
<td>Greytown</td>
</tr>
<tr>
<td>2029</td>
<td>Project CentralWind</td>
<td>Wind</td>
<td>88.64</td>
<td>Matahina</td>
</tr>
<tr>
<td>2029</td>
<td>Waitahora</td>
<td>Wind</td>
<td>105.37</td>
<td>Woodville</td>
</tr>
<tr>
<td>2029</td>
<td>Huntly unit 6 (P40)</td>
<td>OCGT</td>
<td>0</td>
<td>Huntly (Decomm.)</td>
</tr>
<tr>
<td>2029</td>
<td>Demand side NI 1 Northland1</td>
<td>DSR</td>
<td>8</td>
<td>Marsden</td>
</tr>
<tr>
<td>2029</td>
<td>Demand side NI 10 Northland2</td>
<td>DSR</td>
<td>8</td>
<td>Marsden</td>
</tr>
<tr>
<td>2029</td>
<td>New IL 1</td>
<td>IL</td>
<td>14.71</td>
<td>Otahuhu</td>
</tr>
<tr>
<td>2030</td>
<td>Ngatamariki generic1</td>
<td>Geo</td>
<td>100</td>
<td>Ohaaki</td>
</tr>
</tbody>
</table>
A.6 Plots of installed capacity for major generation technologies

Installed capacity of coal and lignite

Installed capacity of gas baseload
Appendix A: Generation Scenarios

Installed capacity of interruptible load and price responsive curtailment

Installed capacity of thermal peakers
## Appendix B  Glossary

<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>After Diversity Maximum Demand</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>automatic under frequency load shedding</strong></td>
<td>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 tripped in two, nominally, 20% groups.</td>
</tr>
<tr>
<td><strong>availability</strong></td>
<td>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).</td>
</tr>
<tr>
<td><strong>bay (of a station)</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>breaker-and-a-half station</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>bus</strong></td>
<td>The common primary conductor of power from a power source to two or more separate circuits.</td>
</tr>
<tr>
<td><strong>bus coupler circuit-breaker</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>bus section</strong></td>
<td>Part of a bus that can be isolated from another part of the same bus.</td>
</tr>
<tr>
<td><strong>cable</strong></td>
<td>One or more insulated conductors forming a transmission circuit above or below ground.</td>
</tr>
<tr>
<td><strong>capacitor bank</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>charging current (line)</strong></td>
<td>The current taken by a transmission circuit to energise its conductors due to the capacitive effect of the circuit.</td>
</tr>
<tr>
<td><strong>circuit (transmission) (cct)</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>circuit-breaker</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>co-generation</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>commissioned</strong></td>
<td>The operational state of equipment that has undergone the commissioning process and is brought under the operational control of a service centre/controller.</td>
</tr>
<tr>
<td><strong>committed projects</strong></td>
<td>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:</td>
</tr>
<tr>
<td></td>
<td>• land has been acquired for construction of the project</td>
</tr>
<tr>
<td></td>
<td>• planning consents, construction approvals and licences have been obtained</td>
</tr>
<tr>
<td></td>
<td>• construction has begun, or a firm commencement date has been set</td>
</tr>
<tr>
<td></td>
<td>• contracts for supply and construction have been finalised, and</td>
</tr>
<tr>
<td></td>
<td>• financing arrangements are largely complete.</td>
</tr>
<tr>
<td><strong>constraint</strong></td>
<td>A local limitation in the transmission capacity of the grid required to maintain grid security or power quality.</td>
</tr>
<tr>
<td><strong>contingency</strong></td>
<td>The uncertainty of an event occurring, and the planning to cover for this. For example, a single contingency could be:</td>
</tr>
<tr>
<td></td>
<td>a. in relation to transmission, the unplanned tripping of a single item of equipment, or</td>
</tr>
<tr>
<td></td>
<td>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.</td>
</tr>
<tr>
<td><strong>contingent event</strong></td>
<td>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...</td>
</tr>
<tr>
<td>Term</td>
<td>Description</td>
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<tr>
<td>------------------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>sheddng of demand</td>
<td></td>
</tr>
<tr>
<td>continuous rating</td>
<td>The maximum rating to which equipment can be operated continuously.</td>
</tr>
<tr>
<td>decommissioned</td>
<td>The status of equipment which is permanently disconnected from the power system, made permanently inoperable, and free of any operational identification.</td>
</tr>
<tr>
<td>demand</td>
<td>A measure of the rate of consumption of electrical energy.</td>
</tr>
<tr>
<td>demand-side management</td>
<td>Initiatives or mechanisms used to control electricity demand. Examples include ripple controls on water heating or contracted shedding of load (demand).</td>
</tr>
<tr>
<td>disconnector</td>
<td>A switch that, when in the open position, provides an isolating distance in accordance with specified requirements.</td>
</tr>
<tr>
<td>dispatch</td>
<td>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.</td>
</tr>
<tr>
<td>distribution (of electricity)</td>
<td>The transfer of electricity between the transmission network and end users through a local network.</td>
</tr>
<tr>
<td>distribution line</td>
<td>An electric line that is part of a local network.</td>
</tr>
<tr>
<td>double circuit line</td>
<td>A transmission line carrying two circuits.</td>
</tr>
<tr>
<td>duplicate protection</td>
<td>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.</td>
</tr>
<tr>
<td>electricity distributor</td>
<td>An asset owner whose assets are predominantly for the distribution of electricity to customers.</td>
</tr>
<tr>
<td>Electricity Industry Act 2010</td>
<td>The Act setting out the present framework including the Electricity Industry Participation Code.</td>
</tr>
<tr>
<td>Electricity Industry</td>
<td>The requirements on the electricity industry made pursuant to the Electricity Industry Act 2010.</td>
</tr>
<tr>
<td>Participation Code</td>
<td></td>
</tr>
<tr>
<td>embedded generators</td>
<td>Embedded generators are smaller power plants connected to a regional electricity line business’s distribution network (as opposed to the high voltage transmission network).</td>
</tr>
<tr>
<td>end user</td>
<td>An entity connected to the power system for the primary purpose of consuming electricity.</td>
</tr>
<tr>
<td>event</td>
<td>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.</td>
</tr>
<tr>
<td>feeder</td>
<td>A circuit that provides a direct connection to a customer.</td>
</tr>
<tr>
<td>firm capacity</td>
<td>Power capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.</td>
</tr>
<tr>
<td>forced outage</td>
<td>The automatic or urgent removal from service of an item of equipment.</td>
</tr>
<tr>
<td>frequency (power)</td>
<td>The rate of cyclic change in value of current and voltage, quantified by the international standard term ‘Hertz’ (Hz).</td>
</tr>
<tr>
<td>frequency excursion</td>
<td>A variation of the power system frequency above 50.25 Hz or below 49.75 Hz.</td>
</tr>
<tr>
<td>gas turbine (GT)</td>
<td>A heat engine that uses the energy of expanding gases passing through a multi-stage turbine to create rotational power.</td>
</tr>
<tr>
<td>generating set</td>
<td>A group of rotating machines transforming mechanical or thermal energy into electricity.</td>
</tr>
<tr>
<td>generation</td>
<td>The electrical energy produced by a generator, a generating station or within a power system as a whole. The process of producing electricity.</td>
</tr>
</tbody>
</table>
## Appendix B: Glossary

<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>generator</td>
<td>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.</td>
</tr>
<tr>
<td>grid</td>
<td>That part of the New Zealand electricity transmission system, the operation of which is undertaken by the grid operator.</td>
</tr>
<tr>
<td>grid asset owner</td>
<td>Transpower New Zealand Limited.</td>
</tr>
<tr>
<td>grid assets</td>
<td>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.</td>
</tr>
<tr>
<td>grid exit point (GXP)</td>
<td>A point of connection where electricity may flow out of the grid.</td>
</tr>
<tr>
<td>grid injection point</td>
<td>A point of connection where electricity may flow into the grid.</td>
</tr>
<tr>
<td>HVAC</td>
<td>High voltage alternating current.</td>
</tr>
<tr>
<td>HVDC</td>
<td>High voltage direct current.</td>
</tr>
<tr>
<td>in service</td>
<td>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.</td>
</tr>
<tr>
<td>instantaneous load</td>
<td>The maximum instantaneous current drawn. It consists of continuous, non-continuous and momentary currents.</td>
</tr>
<tr>
<td>intertrip</td>
<td>A protection signalling system whereby a signal initiated at one station trips a circuit-breaker at another station.</td>
</tr>
<tr>
<td>islanded operation</td>
<td>The condition that arises when a section of the power system is disconnected from and operating independently of the remainder of the power system.</td>
</tr>
<tr>
<td>life expectancy</td>
<td>The date where replacement/major refurbishment is necessary.</td>
</tr>
<tr>
<td>line [overhead]</td>
<td>A series of structures carrying overhead one or more transmission circuits.</td>
</tr>
<tr>
<td>load control</td>
<td>Types of load control include:</td>
</tr>
<tr>
<td></td>
<td>• automatic under frequency load shedding (see MW reserve of a power system)</td>
</tr>
<tr>
<td></td>
<td>• interruptible load (see MW reserve of a power system), and</td>
</tr>
<tr>
<td></td>
<td>• manual load shedding (see manual load shedding).</td>
</tr>
<tr>
<td>load shedding</td>
<td>The forced disconnection of load, in stages. This is either manual (see load control) or automatic (see MW reserve [of a power system]).</td>
</tr>
<tr>
<td>main protection</td>
<td>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.</td>
</tr>
<tr>
<td>manual load shedding</td>
<td>The forced disconnection of load by an operator/controller.</td>
</tr>
<tr>
<td>maximum continuous rating (MCR)</td>
<td>The value assigned to an equipment parameter by the manufacturer, and at which the equipment may be operated for an unlimited period without damage.</td>
</tr>
<tr>
<td>maximum demand</td>
<td>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.</td>
</tr>
<tr>
<td>MegaVoltAmpere (MVA)</td>
<td>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).</td>
</tr>
<tr>
<td>n-1, “n”</td>
<td>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:</td>
</tr>
<tr>
<td></td>
<td>• a single transmission circuit interruption</td>
</tr>
<tr>
<td></td>
<td>• the failure or removal from operational service of a single generating unit</td>
</tr>
<tr>
<td></td>
<td>• an HVDC link single pole interruption</td>
</tr>
<tr>
<td></td>
<td>• the failure or removal from service of a single bus section</td>
</tr>
<tr>
<td></td>
<td>• a single interconnecting transformer interruption, and</td>
</tr>
<tr>
<td></td>
<td>• 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.</td>
</tr>
<tr>
<td>nominal rating</td>
<td>The design rating of the equipment or transmission circuit. For equipment, this is often referred to as the 'nameplate rating'.</td>
</tr>
<tr>
<td>nominal system</td>
<td>50 Hertz.</td>
</tr>
<tr>
<td>Term</td>
<td>Description</td>
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<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>frequency</td>
<td>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.</td>
</tr>
<tr>
<td>non-continuous load</td>
<td>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.</td>
</tr>
<tr>
<td>normal system conditions</td>
<td>Equipment fitted to a power transformer by which the voltage ratio between the windings can be varied while the transformer is on-load.</td>
</tr>
<tr>
<td>outage</td>
<td>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.</td>
</tr>
<tr>
<td>overhead line</td>
<td>A transmission line.</td>
</tr>
<tr>
<td>overload</td>
<td>A load greater than the maximum continuous rating.</td>
</tr>
<tr>
<td>peak demand</td>
<td>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.</td>
</tr>
<tr>
<td>planned outage</td>
<td>A deliberate outage scheduled for maintenance purposes.</td>
</tr>
<tr>
<td>power factor</td>
<td>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.</td>
</tr>
<tr>
<td>power flow analysis</td>
<td>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.</td>
</tr>
<tr>
<td>power system stability</td>
<td>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.</td>
</tr>
<tr>
<td>power transformer</td>
<td>A transformer that primarily changes voltage and current for the efficient conveyance of electricity over the circuits connected to it.</td>
</tr>
<tr>
<td>protection</td>
<td>The equipment provided for detecting abnormal conditions in a power system and then initiating fault clearance or actuating signals or indications.</td>
</tr>
<tr>
<td>reactive power</td>
<td>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.</td>
</tr>
<tr>
<td>relay</td>
<td>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.</td>
</tr>
<tr>
<td>reliability</td>
<td>The failure rate. For example, the number of failures per year based on experience over a long time period, say 10 years or more.</td>
</tr>
<tr>
<td>resource consent</td>
<td>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.</td>
</tr>
<tr>
<td>return period</td>
<td>The statistical return period of a weather-related event, load or load effect.</td>
</tr>
<tr>
<td>runback scheme</td>
<td>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.</td>
</tr>
<tr>
<td>security</td>
<td>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.</td>
</tr>
<tr>
<td>short circuit rating</td>
<td>The three second fault rating of equipment.</td>
</tr>
<tr>
<td>short term rating</td>
<td>The maximum rating to which equipment can be operated for a specified duration.</td>
</tr>
<tr>
<td>single-circuit line</td>
<td>A transmission line carrying one circuit.</td>
</tr>
<tr>
<td>spur circuit</td>
<td>A circuit connected to the transmission system at only one point.</td>
</tr>
<tr>
<td>stability limit</td>
<td>The critical value of a given system state variable that cannot be exceeded without endangering power system stability.</td>
</tr>
<tr>
<td></td>
<td>For a power system without a fault, this concept is related to the steady state stability of</td>
</tr>
<tr>
<td>Term</td>
<td>Description</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>steady state stability</td>
<td>A power system stability in which disturbances have only small rates of change and small relative magnitudes.</td>
</tr>
<tr>
<td>substation</td>
<td>A building, structure or enclosure incorporating equipment used principally for the control of the transmission or distribution of electricity.</td>
</tr>
<tr>
<td>switchgear</td>
<td>A collective term for switches of all types and their associated equipment, including circuit-breakers, disconnectors, and earthing switches.</td>
</tr>
<tr>
<td>switchgear group</td>
<td>A circuit-breaker and related disconnectors. The relationship is determined by switchgear numbering.</td>
</tr>
<tr>
<td>switching station</td>
<td>A station existing solely for the purpose of transmission rather than supply.</td>
</tr>
<tr>
<td>synchronous condenser</td>
<td>A synchronous machine running without mechanical load and supplying or absorbing reactive power to regulate local voltage.</td>
</tr>
<tr>
<td>system frequency</td>
<td>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.</td>
</tr>
<tr>
<td>system normal</td>
<td>The power system is operating in the normal state when:</td>
</tr>
<tr>
<td></td>
<td>• generation meets the demand at 50Hz (±0.2 Hz)</td>
</tr>
<tr>
<td></td>
<td>• voltage requirements are met</td>
</tr>
<tr>
<td></td>
<td>• grid equipment is operated within design ratings, and</td>
</tr>
<tr>
<td></td>
<td>• reserve margins and the power system configuration provide an adequate level of operational security.</td>
</tr>
<tr>
<td>system operator</td>
<td>The person responsible from time to time for the operation of the grid system. The system operator is Transpower New Zealand Limited.</td>
</tr>
<tr>
<td>tee (or T) point</td>
<td>The point at which a branch transmission circuit is solidly and permanently connected to a main circuit, usually without switchgear. See also tee-off.</td>
</tr>
<tr>
<td>tee-off</td>
<td>A branch transmission circuit joining a main circuit and that is protected as part of the main circuit.</td>
</tr>
<tr>
<td>thermal constraints/limits/ capacities</td>
<td>Refers to the temperature ratings of the assets (lines, generators, transformers) connected to the power system, beyond which the assets cannot securely be operated.</td>
</tr>
<tr>
<td>thermal upgrade</td>
<td>The increase in temperature ratings of assets to provide more capacity.</td>
</tr>
<tr>
<td>transformer</td>
<td>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.</td>
</tr>
<tr>
<td>transient (in)stability</td>
<td>Refers to the response of the power system when it experiences a large disturbance like a line fault or outage of a generator.</td>
</tr>
<tr>
<td>transmission</td>
<td>The conveying of bulk electricity from power stations to points of supply (compared with distribution).</td>
</tr>
<tr>
<td>transmission circuit</td>
<td>An electrical circuit the primary purpose of which is the transmission of electricity from one geographical location to another.</td>
</tr>
<tr>
<td>transmission line</td>
<td>A series of structures carrying one or more transmission circuits overhead.</td>
</tr>
<tr>
<td>transmission system</td>
<td>That part of the power system primarily intended for the conveyance of bulk electricity.</td>
</tr>
<tr>
<td>voltage</td>
<td>The nominal potential difference between conductors or the nominal potential difference between a conductor and earth, whichever is applicable.</td>
</tr>
<tr>
<td>voltage collapse</td>
<td>A sudden and large decrease in the voltage of the electrical system.</td>
</tr>
<tr>
<td>voltage (in)stability</td>
<td>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.</td>
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</table>
### Appendix C Grid Exit and Injection Points

#### Table C-1: North Island Grid Exit and Injection Points

<table>
<thead>
<tr>
<th>North Isthmus</th>
<th>Auckland</th>
<th>Waikato</th>
<th>Bay of Plenty</th>
<th>Central North Island</th>
<th>Taranaki</th>
<th>Hawkes Bay</th>
<th>Wellington</th>
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### Appendix C: Grid Exit and Injection Points

**North Island**

<table>
<thead>
<tr>
<th>North Isthmus</th>
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<th>Waikato</th>
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<th>Hawkes Bay</th>
<th>Wellington</th>
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**South Island**

<table>
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<tr>
<th>Nelson/Marlborough</th>
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<th>Canterbury</th>
<th>South Canterbury</th>
<th>Otago/Southland</th>
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GXP – Grid Exit Point  
GIP – Grid Injection Point  
SWI – Switching Station