Upper North Island

Distributed Generation Impact Study

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Executive Summary

Transpower engaged Mitton ElectroNet (MEL), to undertake network analysis studies, to assist Transpower in meeting its obligations under Part 6 Schedule 6.4 of the Electricity Industry Participation Code, specifically in the Upper North Island (UNI) region.

Methodology

As agreed with Transpower, MEL has undertaken this analysis using previous analysis methodologies, developed as part of the published 2017 Transmission Planning Report [1] (TPR). The latest load forecast data for 2017 was included within the load-flow model, used for the analysis.

The analysis focuses on determining the Distributed Generation (DG) "required", to maintain N-1 security until 2025. Three grid areas were considered sequentially:

1. Supply transformer and spur line capacity for Grid Exit Points (GXPs).
2. Regional interconnected grid capacity (220 kV and 110 kV transmission lines and interconnecting transformers).
3. Grid backbone; principally, 220 kV lines utilised for inter-area transfer. For example, for transferring power from the Lower North Island (LNI) to the Upper North Island (UNI) and HVDC link, or vice versa, when regional generation is low.

In all three grid areas, the analysis was completed by comparing the differences between:

- a "DG ON" scenario, with DG contributing to the network, according to their measured recent contribution, at times of network peak demand; and
- a "DG OFF" scenario, with all DG switched off.

For all three grid areas, the Winter and Summer peaks of years 2017 to 2021 and the year 2025, were considered.

DG found to be required in the supply transformer and spur line analysis was considered ON in the regional grid studies. Similarly, DG found to be required in the supply transformer and spur line analysis, or regional grid studies, were considered ON in the grid backbone DG OFF studies. This approach is consistent with that established during the study of the Lower South Island.

Analysis Results

For the supply transformer and regional line constraint analysis, three GXPs were identified as requiring DG, to meet N-1 security:

- Kaikohe 110 kV (Winter and Summer from 2017)
- Otahuhu (Winter from 2017 and Summer from 2025)
- Takanini (Winter in 2017 only, not required from 2018 following outdoor to indoor conversion)

The availability of DG at these substations means that Transpower can potentially delay grid investment, required to resolve N-1 security issues. These DGs were subsequently assumed to be in service for the DG OFF scenarios in the regional grid and grid backbone studies.

For the regional grid analysis, five additional DG was found to be required for N-1 security issues. Results show that DG contribution is required at the following GXPs, for associated regional supply issues:

- Bombay 110 kV (Winter from 2021 and Summer from 2018)
- Bombay 33 kV (Winter from 2021 and Summer from 2018)
- Glenbrook (Winter from 2025)
- Te Kowhai (Winter from 2025)

Based on these results, all of these DG contributions were assumed ON, for the grid backbone analysis.

Grid backbone analysis was conducted to analyse constraints on the 220 kV network, for the most part, supplying power through the North Island to the UNI region. Assumptions around growth generation to meet future load, and to balance generation which may be offset by DG contribution, have a significant impact on results. This study looked at various scenarios in line with TPR 2017 system conditions with some sensitivity studies conducted on the location of the balancing component of slack generation.

For the grid backbone analysis, thirteen DG was found to be required for N-1 security issues. Results show that DG contribution is required at the following GXPs, for associated grid backbone supply issues:

- Albany 33 kV (Winter from 2017 and Summer from 2017)
- Bombay 110 kV (Winter from 2017 and Summer from 2017)
- Bombay 33 kV (Winter from 2017 and Summer from 2017)
- Bream Bay (Winter from 2017 and Summer from 2017)
- Glenbrook (Winter from 2017 and Summer in 2017 and from 2020)
- Henderson (Summer from 2017)
- Hepburn Rd (Summer from 2017)
- Maungatapere (Winter from 2017 and Summer from 2017)
- Pakuranga (Summer from 2017)
- Penrose 25 kV (Winter from 2017 and Summer from 2017)
- Silverdale (Winter from 2017 and Summer in 2017 and from 2019)
- Takanini (Winter from 2018 and Summer in 2017 and from 2019)
- Te Kowhai (Winter from 2017 and Summer in 2017)

We note that DG impacts on the transmission system are dependent on the regional grid configuration, the capacity of the grid and the distributed generation contribution, at times of peak load.

We recognise that our analysis is limited to Transpower's approach for a hindsight assessment of distributed generation to meet statutory grid reliability standards under Part 12, Schedule 12.2 of the code. We further note that there are factors relating to DG which have not been accounted for within this analysis, including, but not limited to:

- A potential reduction in transmission system losses. DG supplies load close to the point of supply and can reduce loading on the transmission system, which reduces system losses.
- Potential displacement of more expensive marginal generation. By reducing the amount of dispatched market generation, overall generation prices could be lower. Detailed analysis on this has not been undertaken, and it is possible that the DG could be inflationary on energy prices also. Note that this only applies to those DGs which are not market-based; that is, they don't offer into the electricity market.
- Operational flexibility. Transpower may benefit from DG, if it can be contracted "ON", during times of grid maintenance, when the security criteria effectively become N-1-1, where not having the DG available might otherwise introduce system constraints.
- No analysis was completed on time periods other than peak Winter and peak Summer. Consideration of additional scenarios, such as the shoulder period, would improve the robustness of the analysis.

Contents

1 Introduction

Transpower engaged Mitton ElectroNet (MEL) to undertake network analysis studies, to assist Transpower in meeting its obligations, under Part 6 Schedule 6.4 of the Code [2]. This report focuses on those obligations, for the Upper North Island (UNI) region.

2 Background

Under Transpower's obligations for Part 6 Schedule 6.4 of the Code, it must provide a report which identifies which Distributed Generation (DG), located in each of the four defined grid pricing regions, is required by Transpower, to meet the grid reliability standards (GRS).

The four pricing areas are:

- Lower South Island (LSI).
- Upper South Island (USI).
- Lower North Island (LNI).
- Upper North Island (UNI).

Each of these areas shall be investigated separately. This report presents an analysis of the fourth area; the UNI. The UNI region is defined, according to the Code [2], as that part of the North Island situated to the North and West of a line commencing at 38°02'S and 174°42'E, then proceeding in a generally North-Easterly direction directly to 37°36'S and 175°27'E, finally proceeding North along the 175°27'E line of longitude.

Figure 1 shows the region covered by the UNI. Effectively, this includes all North Island substations and assets North of and excluding Hamilton, Piako, Waihou, Waikino and Kopu (all excluded).

We note that the definition of the UNI is based on a pricing region and does not exactly align with GXPs in the electrical network. Nonetheless, this demarcation allows for simple separation of the upper and lower North Island regions for undertaking network studies.

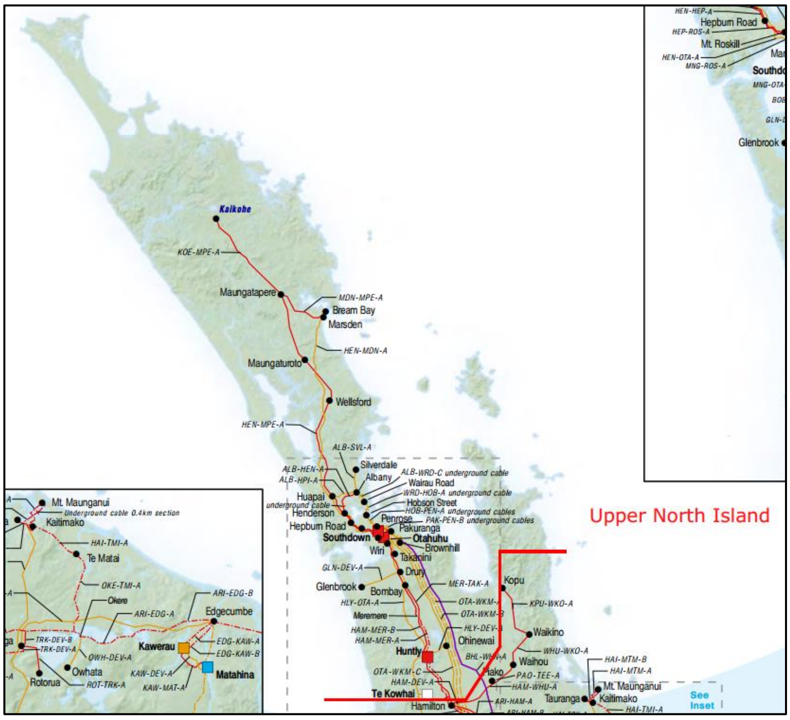

Figure 1 - Upper North Island (UNI) Region

To identify DG required by the grid, the analysis presented in this report undertakes an N-1 contingency analysis, to identify situations where Transpower may not be able to maintain N-1 security to its Grid Exit Points (GXPs) if the DG were not available.

N-1 is a common network planning criterion, used throughout the world. It is the ability of the network to supply all load, in the event of a contingency (fault or equipment outage) of a single network component. Usually, the single network component is a supply transformer or transmission line, but it can also be a substation bus section, or secondary item, such as a Current Transformer (CT), or a Voltage Transformer (VT), where an outage of that single network component may cause a primary component outage.

Consider a typical 110 kV Transpower GXP, shown in Figure 2. The N-1 capacity of the substation is 30 MVA, which is determined following an outage of one of the two supply transformers. If there is a 10 MVA DG at the GXP, which provides an average 10 MVA of capacity at network peak times, then this would increase the N-1 supply capacity of the GXP to 40 MVA. Hence, in this example, the substation can supply 40 MVA of load. Without the DG, the capacity would be 30 MVA.

If the DG were not available to meet the load, then Transpower would have to invest in the substation, by upgrading the transformer capacity, or engage in load shedding (or ask the distribution utility to shift load, if possible) during a transformer outage, at peak times. It follows, in this example, that there is a measurable requirement of the DG to maintain N-1 security.

The example above also applies to so-called "spur lines", which are the only connection to a non-meshed area of the transmission system. The spur line and supply transformer N-1 capacity is considered in the first stage of the analysis, presented within this report.

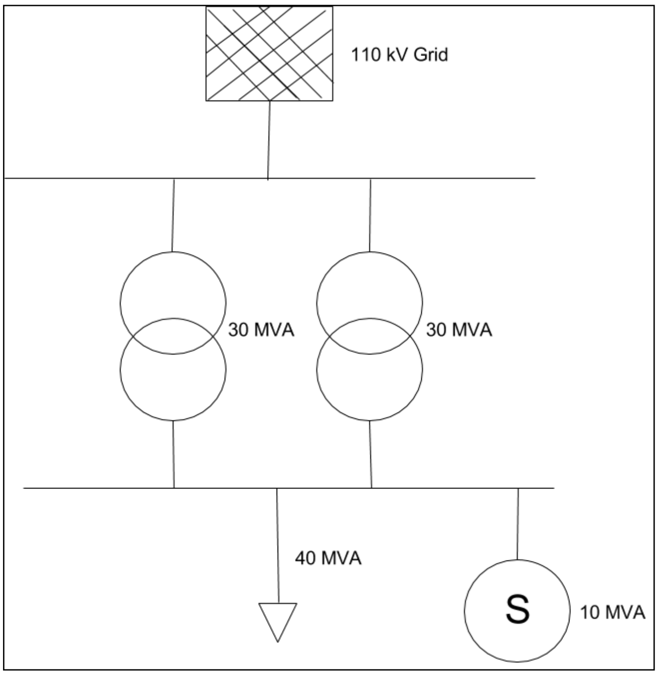

Figure 2 - Typical 110 kV GXP

In the second stage of the analysis, the study is extended to consider the larger area regional security. In this case, it is possible that DG could prevent lines and interconnecting transformers from overloading post contingency and also prevent network voltage excursions outside of the acceptable bands, defined in the Electricity Industry Participation Code.

Finally, in the third stage of the analysis, several known grid backbone issues are examined, to see if DG is required to maintain grid security.

We recognise that our analysis is limited to Transpower's approach for a hindsight assessment of distributed generation to meet statutory grid reliability standards under Part 12, Schedule 12.2 of the code. We further note that there are other factors relating to DG which have not been accounted for within this analysis, including, but not limited to:

- Transmission system losses. DG supplies load close to the point of supply and can reduce loading on the transmission system, which reduces system losses.
- Displacement of more expensive marginal generation. By reducing the amount of dispatched market generation, overall generation prices could be lower. Detailed analysis on this has not been undertaken, and it is possible that the DG could also be inflationary on energy prices. Note that this only applies to those DGs which are not market-based; that is, they don't offer into the electricity market.
- Operational flexibility. Transpower can benefit from DG, if it can be contracted "ON", during times of grid maintenance, when the security criteria effectively become N-1-1, where not having the DG available might otherwise introduce system constraints.
- No analysis was completed on time periods other than peak Winter and peak Summer. Consideration of additional scenarios, such as the shoulder period, would improve the robustness of the analysis.

3 Methodology and Assumptions

Transpower has an existing transmission planning process, which indicates to the industry the grid investment required to maintain grid reliability. The outcome of this process is the biennial production of the Transmission Planning Report (TPR), of which 2017 is the most recent edition [1]. The document considers proposals for possible grid investment, to manage N-1 security issues and uses a planning horizon of 15 years, based on the latest regional load forecasts.

For this analysis, the methodology used within the TPR process has been adapted, to undertake a comparison over a shortened planning horizon of eight years, until 2025. This analysis contrasts grid capability, between a “DG ON” scenario, with DG connected to the grid and contributing, according to its recent measured output at peak demand times, with a “DG OFF” scenario, where all DG is removed from the grid.

Load-flow analysis has been completed within Transpower’s standard grid planning software, DIgSILENT PowerFactory 2016 SP3, using a load-flow model developed by Transpower, for undertaking the 2017 TPR studies. This model has been updated to include the latest 2017 load forecast.

While it may seem somewhat incongruous to be discussing 2017 constraints when we are already in 2018, this work was commenced in early 2017 with the LSI region, and analysis cases were therefore developed at this stage. Results indicating grid constraints in 2017 are still relevant in 2018 if the underlying grid issue has not been resolved.

3.1 Network Overview

An overview single line diagram (SLD) of the Upper North Island (UNI), which includes the Northland, Auckland and part of Waikato networks considered by this analysis, is shown in Figure 3. Note that this diagram shows all 220 kV and 110 kV Transpower assets in the region, including all GXPs, Grid Injection Points (GIPs) and switching stations. A list of all locations and their status as GIP, GXP, or switching station, is included in Appendix B.

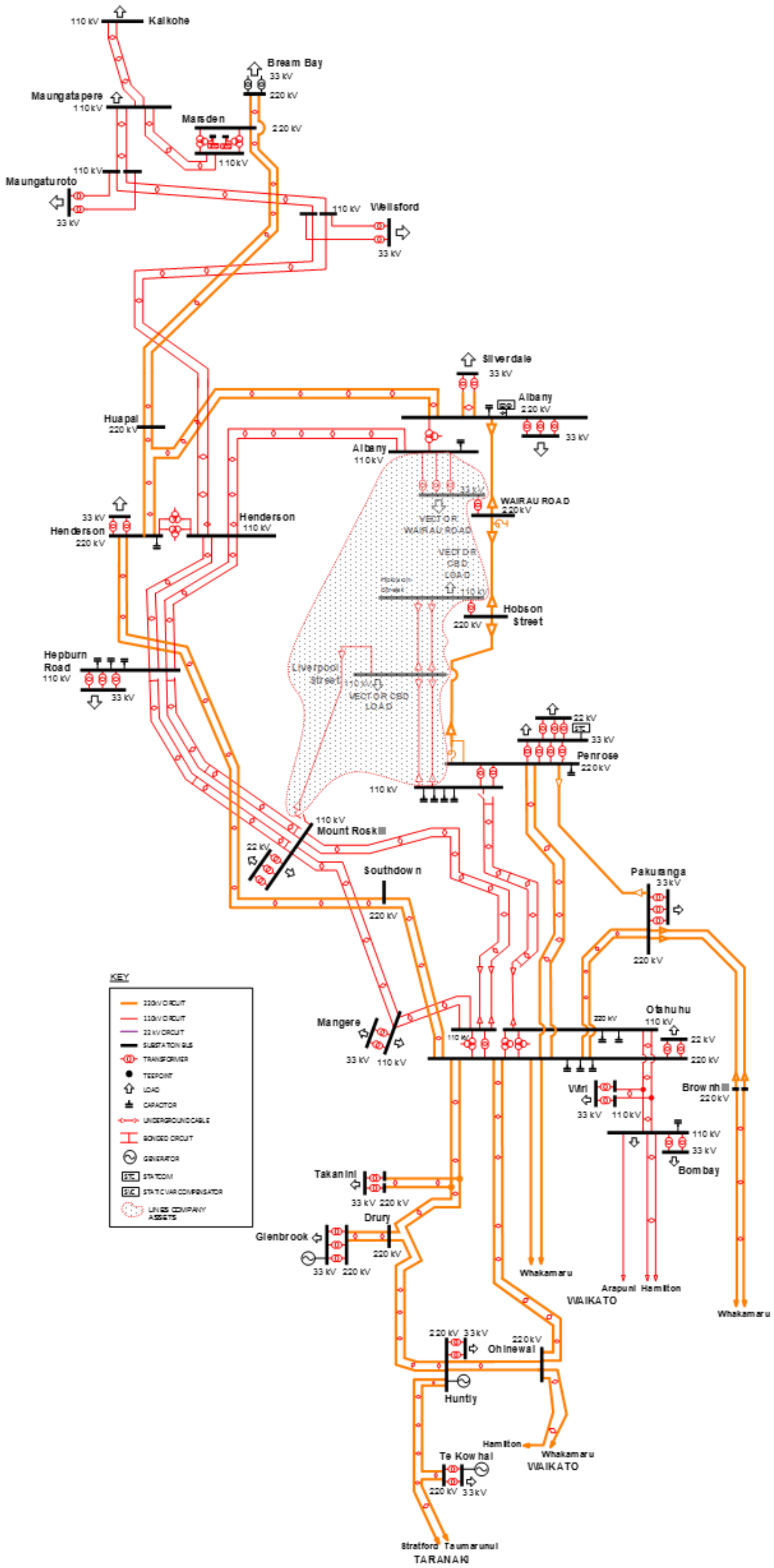

Figure 3 – Upper North Island Study Region showing GIPs and GXPs

3.2 Model Adjustments and Assumptions

As mentioned at the start of this section, the PowerFactory model has been adapted from the 2017 TPR model, used by Transpower. There are several modifications to the base model, which affect the studies completed. These are covered in the following sections.

3.2.1 Committed Upgrade Projects

The analysis model includes the following committed upgrade projects:

- Bunnythorpe interconnecting transformer replacement, in 2017.
- Hangatiki 3rd supply transformer, in 2018.
- Mataroa series reactor install, in 2018.
- Owhata supply transformer replacement, in 2018.
- Haywards supply transformer replacement, in 2019.
- Bunnythorpe-Haywards A&B reconductoring, in 2019.
- Kinleith redevelopment, in 2020.
- Takanini outdoor to indoor conversion, in 2018.
- Wilton 110 kV bus rationalisation, in 2017.

3.2.2 Special Protection Schemes

The analysis model includes the following enabled special protection schemes:

- Arapuni runback.
- Bunnythorpe – Mataroa circuit overload protection.
- Bunnythorpe – Woodville overload protection.
- Edgecumbe – Kawerau overload protection.
- Edgecumbe – Owhata overload protection.
- Hangitiki supply transformer overload protection.
- Hepburn – Mt Roskill overload protection.
- Kaitimako intertrip.
- Maraetai runback.
- Penrose Reactor Bypass Scheme
- Penrose T7, T8, T9, T11 overload protection.
- Tokaanu intertrip.
- Waihou transformer overload protection.

3.2.3 TPR Model Modifications

The following additional modifications were made to the TPR model:

- The base case has been prepared with GXP load and DG separated at the supply bus, rather than being "lumped" together in the GXP load. This separation allows for easily switching ON or OFF the DG, to determine its impact.
- Shoulder load scenarios were not considered, only Summer and Winter peak scenarios.
- All load forecasts are P90 "prudent" forecasts.
- Penrose STATCOM voltage control was adjusted to maintain Penrose 33 kV voltage at 1.01 pu, and limited to approximately +/-60 Mvar capability.

3.2.4 Line and Transformer Ratings

Throughout this analysis, the following thermal ratings were assumed:

- For transformers, the 24 hr post contingency branch rating.
- For lines, the continuous branch rating.

3.3 Distributed Generation Network Contribution

3.3.1 Representation of DG for System Planning Studies

Historically, Transpower has not modelled all DG within its transmission planning model, because it is built into the load forecast; it manifests as a reduction to GXP load. There are several exceptions, for DG which was formerly grid-connected, or which, because of its size and network location, has been modelled explicitly.

Within the context of this study, the models of stations which are usually explicitly modelled in the Transpower model have been modified, to take the same form as the remainder of the DG.

"Other" DG, which includes smaller hydro schemes, diesel units, wind-farms and solar installations, was separated from the load at each GXP. This provides two benefits for modelling:

1. It allows simple inspection and manipulation of DG contribution, to construct 'DG OFF' and 'DG ON' models.
2. It allows for the application of separate load and generation profiles to each.

3.3.2 Average DG GXP Contribution During Network Peak

The DG contribution for the Summer and Winter peaks assumed in this study is the average representative DG contribution during the network peak demand. Specifically, the average contribution of the DG during the 20 highest Summer peaks in 2015, determines the DG contribution in Summer and the average contribution of the DG during the 20 highest Winter peaks in 2015, determines the DG contribution in Winter. The GXP peaks were determined on an island peak basis and also a regional peak basis. Hence there is an island peak DG contribution and a regional peak DG contribution, which are slightly different. This information was provided to Mitton ElectroNet by Transpower.

For this analysis, it was also assumed that the DG was dispatched at unity power factor. That is, it provides no additional voltage support to the network. As the distribution network was not modelled in detail and hence reactive power losses in the distribution system were not considered, then this is a reasonable assumption for most DG, which reflects a typical operating mode of smaller generation units.

3.3.3 The Contribution of Wind Generation

For stand-alone grid-connected wind generation which is typically modelled as part of the base TPR model, the assumed contribution at peak load was 20% of nominal capacity. This is consistent with the TPR methodology. There are no such wind farms in the UNI pricing region considered by this analysis.

Wind generation classified as DG had assumed contributions consistent with other DG methodology discussed in 3.3.2.

3.3.4 Combined DG Contribution by GXP

Appendix C shows the DG contributions which have been assumed for each GXP. Note that the DG includes both major stations and any smaller DG, such as grid-connected solar, hydro and wind.

3.4 Load Forecasts

The Transpower planning process considers three different load forecasts, each with a different purpose and applicability. The GXP peak forecast is based on the maximum load at each GXP and is a P90 prudent forecast. This forecast is applicable for studies looking at supply transformer capacity and future needs, at GXP level.

The regional peak forecast is the GXP peak load, adjusted for coincidence within the region. It is the maximum load which occurs in the region, but it is not necessarily the peak load at each GXP. This forecast is also a P90 prudent forecast. This forecast is used for assessing the capacity of regional interconnections, such as 220 kV and 110 kV transmission lines and interconnecting transformers.

The island peak is a similar concept to the regional peak forecast but applied to the entire island. At the individual GXP level, it is usually lower than the regional and GXP peak. This forecast, also a P90 forecast, is applicable for grid backbone studies, assessing the capacity of the grid for transfer between regions.

Refer to Appendix D for the assumed load values for the GXP peak forecast.

3.5 Methodology for Identifying Required DG

The methodology used for determining the required DG is described in Figure 4. The process considers each of the grid areas sequentially. The analysis and results conducted in each area of analysis influence the assumptions of what DG is assumed to be in service in the 'DG OFF' scenarios in the remaining grid area studies.

For the local supply analysis, each GXP is assessed to determine whether it can maintain N-1 supply, with DG available and with DG unavailable. DG at a GXP is determined to be required by the grid, if a line or transformer overloads, following a single contingency, when there is no contribution from the DG, and DG reduces or clears the overload when it is available. In addition to thermal overloads, if a single contingency results in low voltage in the network, outside of the permitted operating band when DG is not available, if DG improves the voltage or clears the voltage violation when it is available, then such DG is also considered as being required.

The regional grid analysis builds on the local supply analysis, by undertaking an N-1 contingency analysis for all interconnecting transformers and lines within a region, then determining if any thermal overloads or voltage problems could be avoided with DG available. DG which was identified in the local supply analysis as required is assumed as 'ON' in the 'DG OFF' scenarios for this analysis. As for the local supply analysis, any additional DG which is required to meet the security criteria in this analysis is assumed to be required by the grid. The analysis of regional issues is not limited to UNI regions; this assessment aims to determine if UNI DG is beneficial to regional issues throughout the North Island power system.

Finally, the grid backbone is studied to see if the DG is required for any issues involving transfer capacity into or out of the region. In this case, any DG identified as required by the local supply transformer and spur line analysis, or regional grid analysis, is assumed as 'ON' for the 'DG OFF' scenario.

For the regional and grid backbone analysis, an effectiveness acceptance criteria of 0.1%/MW has been applied to determine whether DG is required.

This process is repeated for the years of interest, including 2017 through 2021, and 2025.

This methodology was established during the first round of studies, looking at the Lower South Island region.

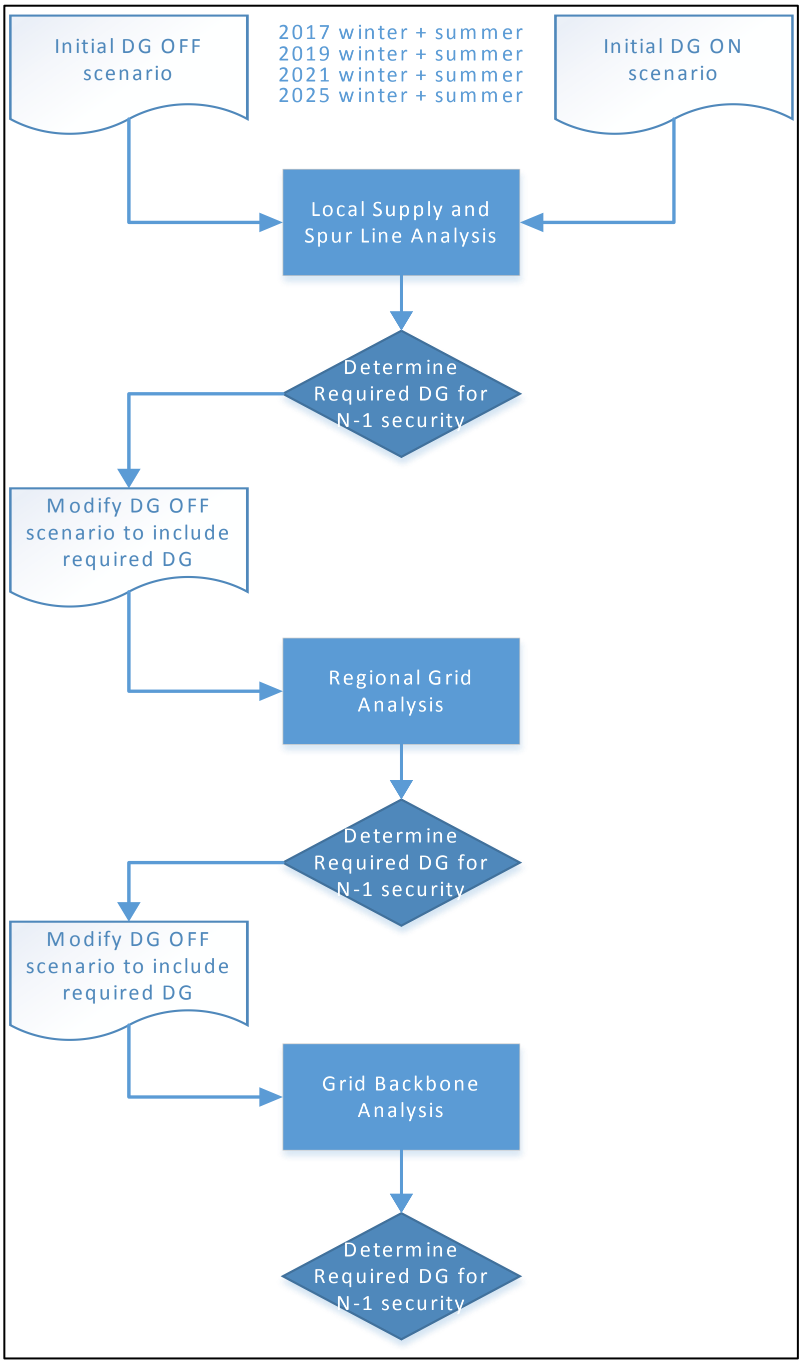

Figure 4 - Analysis Flowchart

3.6 Influence of the Slack Generation on Grid Backbone Issues

Due to the underlying numerical analysis procedure used for system planning load-flow analysis, it is always required to designate one or more machines as a so-called "slack" machine. This machine is responsible for ensuring convergence of the load flow by balancing the load power draw with the power input from the generation and the system losses. Because the system losses cannot be determined ahead of time, they must be solved iteratively as part of the load flow solution process.

Within the scope of this study is to assess future scenarios, taking into account forecast load growth. Forecast load may exceed existing generation capacity, and necessitate "growth generation" to be added to the model. The location of this growth generation will have an impact on overloads and constraints. In reality, by the time forecast load eventuates generation will likely be built to meet the demand. The power system model, however, will only contain new generation if it is committed at this time. Slack generation can serve the purpose of providing growth generation to compensate for generation capacity shortfall in the model to meet the forecast load.

Typically, system planners pick the largest generator, or groups of generators, in the power system to act as slack generation. Slack generation should be positioned such that the location does not have a material impact on the results of the study. This is usually not an issue for local and regional studies, but may not always be straightforward in grid backbone analysis. Consequently, to accurately study these issues, it is standard procedure to undertake sensitivity analysis with the slack machine at a variety of locations.

3.6.1 HVDC and Slack Generation by Scenario

In this North Island power system study, slack generation has been distributed between Wairakei, Stratford, and the HVDC. The base model has been configured to only adjust HVDC from its dispatch setpoint as a last priority once Stratford and Wairakei have reached their limits. A summary of the slack generation modelling is given in Table 1 below.

Table 1: Slack generation modelling

Slack Generation	Min MW limit	Max MW Limit	Base Model Dispatch	
			Summer	Winter
SFD	0	350	0	0
WRK	0	1700	0	0
HVDC	0	1700	1100	1100

The HVDC dispatch setpoint was adjusted for grid backbone scenarios if required, to avoid pre-contingency circuit overload. Generally, Bunnythorpe – Mataroa circuit loading was the limiting component. Table 2, below, shows the scenarios where the HVDC dispatch setpoint was adjusted from the 1100 MW setpoint given in the base model.

Table 2: Scenarios with adjusted HVDC dispatch setpoint

Scenario	HVDC dispatch MW
Regional - Summer 2025	900
Grid Backbone SC1 – Winter 2017	800
Grid Backbone SC1 – Winter 2018	750
Grid Backbone SC1 – Winter 2019 to Winter 2025	950
Grid Backbone SC2 – Summer 2017	850
Grid Backbone SC2 – Summer 2018 to Summer 2025	950
Grid Backbone SC5 – Summer 2017 to Summer 2025	slack (no SFD/WRK slack gen)

The grid backbone scenarios system conditions (SC) 1, 2 and 5 contain generation profile adjustments from the base model. This is discussed further in Section 4.3.

4 Analysis of DG Effect on the Transmission System

This section details the analysis which has been completed to determine what DG would be required in the UNI, to maintain grid security until 2025. The analysis has been separated into three sections:

1. Local supply and spur line[1] analysis.
2. Regional grid analysis.
3. Grid backbone analysis.

4.1 Local Supply Issues

To determine the GXP capacity, the GXP load was increased during a single N-1 transformer, or spur line contingency, until either:

- The remaining transformer or spur line reaches 100% of its 24 hr post-contingency rating for transformers, or 100% of the branch rating for lines.
- The supply bus voltage drops below 0.95 pu.
- The core grid (220 kV/110 kV bus falls below 0.9 pu.

Table 3 shows the maximum value of load, which can be supplied in a 'DG ON' and a 'DG OFF' scenario, for each GXP, for Winter and Summer scenarios. The first column in the table shows the name of the GXP and the limiting component in parentheses. For example, Albany 33 kV (ALB-TF-T6/T8).

Note that capacity differences exist between Summer and Winter scenarios, due to the difference in assumed load power factors, the difference between Summer and Winter ratings for equipment, and regional loading affecting bus voltages.

To determine if the supply is adequate, the N-1 limits, identified in Table 3, are compared with the single GXP forecast load, shown in Appendix D. Cells highlighted red indicate the forecast load exceeds the N-1 limit.

Note that where there is only a single supply transformer for a GXP, the N-1 security limit does not include the single supply transformer as this would result in a loss of supply to the GXP. Instead, one of the circuits supplying the supply transformer HV bus is used as the contingency, and the load limit may be based on the capacity of the single transformer or the N-1 limit of the circuits supplying the HV bus.

The analysis presented in Table 3, shows that there are three GXPs where DG is required to meet N-1 security, in the eight year planning horizon investigated:

- Kaikohe 110 kV (Winter and Summer from 2017)
- Otahuhu (Winter from 2017 and Summer from 2025)
- Takanini (Winter in 2017 only, not required from 2018 following outdoor to indoor conversion)

[1] *Spur line is used as a "catch all" phrase to refer to actual spur lines, but also lines which are not technically spur lines, but are best considered as part of a local supply analysis.*

*Table 3: Impact of DG on the N-1 security of supply for upper North Island GXPs**

Grid Exit Point (Limitation)	N-1 Capacity Limit (MW)			
	Winter		Summer	
	DG OFF	DG ON	DG OFF	DG ON
Albany 33 kV (ALB-TF-T6/T8)	213.0	213.0	207.7	208.9
Bombay 33 kV (BOB-TF-T3/BOB 33 kV)	36.6	39.6	33.6	0.0
Bream Bay (BRB-TF-T2)	67.9	73.6	69.6	69.6
Glenbrook (NZ Steel / Counties Power) (GLN-TF-T6)	128.4	156.5	128.5	153.5
Henderson[2] (HEN-TF-T3)	134.3 (2017)	134.3 (2017)	131.5	131.5
Hepburn Rd (HEP-TF-T2)	218.8	218.8	209.1	209.1
Hobson St[3] (PEN-TF-T10)	303.0	303.0	287.2	287.2
Kaikohe 110 kV (KOE-MPE-1)	68.2 (2017)	93.5	55.3 (2017)	77.2 (2020)
Otahuhu[4] (OTA-TF-T11)	56.5 (2017)	57.0 (2017)	56.5 (2025)	57.0 (2025)
Pakuranga (PAK-TF-T2)	260.5	260.5	255.0	255.0
Penrose 33 kV[5] (PEN-TF-T11)	397.8	397.8	371.0	371.0
Mt Roskill 22 kV[6] (ROS-TF-T2)	123.9 (2017)	123.9 (2017)	126.2	126.2
Mt Roskill 110 kV - KING (HEP-ROS-2)	264.6	264.6	251.5	251.5
Silverdale (SVL-TF-T1)	124.8	133.6	122.1	130.6
Takanini[7] (TAK-TF-T5)	119.0 (2017) Ok from 2018	121.2 (2017) Ok from 2018	119.0	122.4
Te Kowhai (TWH-TF-T2)	127.6	158.6	121.9	171.5
Wairau Rd (WRD-TF-T7)	201.7	201.7	210.8	210.8

**Note that the year in parentheses, following the MW limit, indicates what forecast year the load will exceed the GXP capacity. The issue applicable to the specific row of the table is indicated in parentheses.*

[2] Henderson T2 and T3 have winter post-contingency branch limits of 141.12 MVA, but post-contingency transformer limits of 152.7 MVA.

[3] Contingency which overloads Penrose T10 is either Hobson st-Penrose-1 or Hobson T12, the overload is due to increased flow through Vector assets supplying Hobson st from Penrose.

[4] Otahuhu T11 and T12 have post-contingency branch limits of 58.7 MVA, but T11 has post-contingency summer/winter transformer limits of 72/75 MVA, and T12 has post-contingency summer/winter transformer limits of 67/71 MVA.

[5] Penrose 33 kV DG is assessed based on the coincident Penrose 33 kV and 22 kV GXP peaks, as this represents the maximum loading on Penrose 220/33 kV transformers. The limit in the table does not consider the Penrose T8, which is available to be switched into service for an outage of another 220/33 kV transformer.

[6] Mt Roskill T3 and T4 have winter post-contingency branch limits of 81.1 MVA, but winter post-contingency transformer limits of 83.9 MVA. The summer post-contingency transformer and branch limit is 80.5 MVA

[7] Takanini transformers currently have a branch limit of 126.2 MVA which is alleviated in early 2018 following the outdoor to indoor conversion.

4.2 Regional Grid Issues

4.2.1 Bombay – Wiri – Otahuhu Lines

From Summer 2018 and Winter 2021, the Otahuhu – Wiri tee component of Bombay – Wiri – Otahuhu 110 kV lines may overload during peak loading time for a contingency of the parallel Bombay – Wiri – Otahuhu 110 kV line.

Otahuhu – Wiri tee 1 and 2 110 kV circuits have variable line ratings (VLR) applied to them. The analysis approach taken here is to use the minimum VLR rating for each summer and winter period, 572 A and 636 A respectively.

This overload is alleviated by DG located at Bombay 110 kV and Bombay 33 kV. DG at Wiri is also positioned to alleviate this overload but has 0 MW contribution at summer and winter regional peak, so does not assist in alleviating this overload.

Most other DG in the UNI has a slightly detrimental effect to this overload, as they push more power to Bombay/Wiri from Otahuhu, worsening the overload on Otahuhu – Wiri tee line.

Table 4: DG effect on Bombay – Wiri - Otahuhu overloading (based on Winter 2021)

DG ON Scenario	Reduction in Loading (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
BOB-110	1.58%	0.47%	0.56
BOB-33	1.07%	0.47%	0.56
SVL	-0.16%	-0.02%	-0.02
GLN-33-2-NZST	-0.84%	-0.02%	-0.02

Table 5: DG effect on Bombay – Wiri - Otahuhu overloading (based on Summer 2018)

DG ON Scenario	Reduction in Loading (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
BOB-110	1.11%	0.48%	0.52
BOB-33	0.85%	0.47%	0.52
SVL	-0.17%	-0.02%	-0.02
GLN-33-2-NZST	-0.90%	-0.02%	-0.02

Based on these results, without placing any subjective value judgement on which DG is preferred, Bombay 110 kV and Bombay 33 kV DG are considered necessary from Summer 2018 and Winter 2021.

4.2.2 Otahuhu T2 interconnecting transformer

In Summer 2025, the Otahuhu T2 interconnecting transformers may overload during peak load for a contingency of the parallel T4 interconnecting transformer. Otahuhu T2 and T4 supply the Otahuhu 110 kV bus which supplies Bombay and Wiri, a Penrose-Otahuhu 110 kV circuit is also connected to the bus which is normally open. Otahuhu T2 has a summer post-contingency 24-hour rating of 135 MVA, a lower rating than Otahuhu T4.

The effect of DG on this overload is similar to the Bombay – Wiri – Otahuhu Lines discussed in section 4.2.1. The overload is alleviated by DG located at Bombay 110 kV and Bombay 33 kV, and most other DG has a slightly detrimental effect on the overload.

Table 6: DG effect on Otahuhu T2 overloading (based on Summer 2025)

DG ON Scenario	Reduction in Loading (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
BOB-110	1.06%	0.45%	0.61
BOB-33	0.83%	0.45%	0.61
SVL	-0.12%	-0.01%	-0.02
GLN-33-2-NZST	-0.58%	-0.01%	-0.01

Based on these results, without placing any subjective value judgement on which DG is preferred, Bombay 110 kV and Bombay 33 kV DG are considered necessary from Summer 2025.

4.2.3 Hamilton Interconnecting Transformers

From Summer 2021 and Winter 2025, Hamilton T9 interconnecting transformer may overload during peak load for a contingency of the interconnecting transformer Hamilton T6. Hamilton T9 has a post-contingency 24 hr branch limit of 243.2 MVA, slightly lower rating than T6 which is rated at 263.4 MVA.

Operation of the Bunnythorpe – Mataroa circuit overload protection scheme (COPS) significantly affects Hamilton T9 overload. If the Bunnythorpe-Mataroa COPS operates, there is a split on Ohakune-Mataroa 110 kV circuit, which requires more supply to the 110 kV from Hamilton.

In Winter 2025, Glenbrook and Te Kowhai being "ON" result in Bunnythorpe-Mataroa COPS not operating, this produces a high reduction in loading of Hamilton ICT's. This is possibly an exaggerated result, as in reality system conditions will not fall exactly like this, and Glenbrook and Te Kowhai being marginal for Bunnythorpe – Mataroa OPS operation is unlikely.

In summer, Bombay 110 kV and 33 kV have a significantly higher MW loading reduction per DG MW than other DG, as they are well positioned to reduce the power flow through Hamilton interconnecting transformers to supply the 110 kV network. Te Kowhai reduces the overload by only 0.08% in this scenario, significantly lower MW loading reduction per DG than other DG.

Table 7: DG effect on Hamilton T9 overloading (based on Winter 2025)

DG ON Scenario	Reduction in Loading (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
GLN-33-2-NZST	12.16%	0.22%	0.54
TWH	11.83%	0.27%	0.67
BOB-110	0.35%	0.20%	0.48
BOB-33	0.24%	0.10%	0.25
SVL	0.10%	0.01%	0.03

Table 8: DG effect on Hamilton T9 overloading (based on Summer 2021)

DG ON Scenario	Reduction in Loading (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
GLN-33-2-NZST	0.51%	0.01%	0.01
BOB-33	0.27%	0.12%	0.16
BOB-110	0.21%	0.12%	0.16
SVL	0.10%	0.01%	0.02

Based on these results, without placing any subjective value judgement on which DG is preferred, Glenbrook, Bombay 110 kV, Bombay 33 kV, and Te Kowhai DG are considered necessary from Winter 2025, and Bombay 110 kV and Bombay 33 kV DG are considered necessary from Summer 2025.

Regional Contingency Analysis Summary

Based on the results of this analysis, the following DG can be considered necessary (additional to that required following the local study):

Table 9: Regional DG required for Winter years

	Winter					
Required DG	**2017**	**2018**	**2019**	**2020**	**2021**	**2025**
BOB-110					✓	✓
BOB-33					✓	✓
GLN-33-2-NZST						✓
TWH						✓

Table 10:Regional DG required for Summer years

	Summer					
Required DG	**2017**	**2018**	**2019**	**2020**	**2021**	**2025**
BOB-110		✓	✓	✓	✓	✓
BOB-33		✓	✓	✓	✓	✓

4.3 Summary of Grid Backbone Assessment

Transpower's grid planning process under the TPR has identified system conditions to use to test for transmission constraints in the North Island:

1. Low Waikato and UNI generation in Winter.
2. Low Waikato and UNI generation in Summer.
3. HVDC South transfer in Winter.
4. HVDC South transfer in Summer.
5. Low Eastern Bay of Plenty industrial load.
6. Extreme low North Island Hydro.
7. Light load.

System conditions 3 and 4 were not studied for the impact of UNI DG. UNI DG is behind the main generation source, including the slack generation, so is not expected to impact areas of interest (e.g. Rangipo, Tokaanu, Bunnythorpe, Haywards) for HVDC south flow system conditions.

System condition 6 was not studied for the impact of DG, because the impact of the slack generation in this scenario tends to create overloads which are unlikely to be observed on the real system. This is because removing most of the North Island hydro causes a substantial increase in the North Island slack generators, which creates overloads around the Wairakei ring (if the slack is located at Wairakei). In reality, any new generation which is built, will not all be concentrated at Wairakei, so these overloads are not pertinent to this study, with respect to DG impact.

System condition 7 was not studied for the impact of DG, because it is a light load scenario and there are no overloads of relevance that occur.

The remaining system conditions 1, 2, and 5 are screened for all years, for the impact of DG on the overloads that occur. The results for specific years only are shown in the appendices, because they best demonstrate the impact which DG has on alleviating or worsening specific backbone overloads of concern.

The HVDC transfer for each scenario was adjusted slightly in each year to avoid Bunnythorpe-Mataroa overloading pre-contingency in the base case. Grid-connected wind generation was set to 100% for system conditions 1, 2 and 5.

System condition 5 contains an upgrade to Kawerau T13, modelled as an identical transformer to Kawerau T12. Aniwhenua and Matahina generation is also increased to maximum (100 MW power transfer from Matahina 110 kV to Kawerau 110 kV), and the industrial load on Kawerau 110 kV switched off.

An important consideration with these results is whether a reduction in loading is based on DG location, or slack[8] generation location. To minimise this impact, slack generation at Wairakei and Stratford was set fixed, and only the HVDC was allowed to adjust for MW balance. By limiting the slack to the furthest location from the studied issue, any artificial impact of slack location on results is minimised. For each slack sensitivity scenario, the Wairakei and Stratford generation was fixed such that the HVDC could maintain its setpoint according to Table 2, Section 3.6.1.

In practice, DG may offset generation anywhere in the power system, so a slack sensitivity was also carried out where Stratford and Wairakei slack generation was also allowed to adjust for MW balance, as per the base slack generation model.

The impact of DG on voltage stability limits relevant to the UNI is also investigated, based on the outage of generation or major transmission lines connecting the LNI to the UNI.

[8] *Refer to Section 3.6 for background on the concept of slack generation*

4.3.1 System Condition 1 – Low Waikato and UNI Generation in Winter

The issues identified for this system condition are as follows:

- In 2017 and 2018, Bunnythorpe - Mataroa may overload, for a contingency of a 220 kV circuit. The most severe contingencies are a Tokaanu – Whakamaru circuit, Hamilton - Whakamaru, or 220 kV circuits between Stratford and Huntly. This is alleviated by Winter 2019 once the Mataroa reactor and COPS are commissioned.
- From 2018, the Wairakei – Ohakuri - Atiamuri circuits may overload, for a contingency of Te Mihi – Whakamaru or Whakamaru - Wairakei circuit.
- From 2019, Tokaanu - Whakamaru may overload, for a contingency of a parallel circuit.

The effectiveness of each DG in alleviating these issues has been calculated and may be found in Appendix A. The DG elements which provide the greatest positive impact for each issue, are summarised in the tables below.

Table 11: Greatest impact by DG on Bunnythorpe-Mataroa overload – results from Winter 2017 (parallel Tokaanu – Whakamaru contingency)

DG Name	BPE-MTR Loading Reduction (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
GLN-33-2-NZST	6.29%	0.118%	0.082
TWH	6.00%	0.106%	0.074
SVL	1.04%	0.122%	0.085
BRB	0.99%	0.127%	0.088
MPE	0.59%	0.131%	0.091
BOB-110	0.53%	0.148%	0.103
TAK (2018)	0.33%	0.160%	0.111
BOB-33	0.31%	0.148%	0.103
ALB-33	0.01%	0.120%	0.084
PEN-25	0.01%	0.120%	0.084

Table 12: Greatest impact by DG on Atiamuri-Ohakuri overload – results from Winter 2018 (Te Mihi – Whakamaru contingency)

DG Name	ATI-OHK Loading Reduction (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
GLN-33-2-NZST	1.23%	0.023%	0.082
TWH	1.16%	0.020%	0.073
SVL	0.20%	0.024%	0.086
BRB	0.19%	0.025%	0.088
MPE	0.12%	0.026%	0.092
BOB-110	0.09%	0.024%	0.086
TAK	0.06%	0.024%	0.085
BOB-33	0.05%	0.024%	0.087
PEN-25	0.00%	0.030%	0.107
ALB-33	0.00%	0.030%	0.107

Table 13: Greatest impact by DG on Tokaanu-Whakamaru overload – results from Winter 2019 (parallel Tokaanu – Whakamaru contingency)

DG Name	TKU-WKM Loading Reduction (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
GLN-33-2-NZST	7.10%	0.133%	0.447
TWH	6.77%	0.120%	0.402
SVL	1.19%	0.140%	0.469
BRB	1.13%	0.145%	0.486
MPE	0.68%	0.150%	0.504
BOB-110	0.51%	0.142%	0.477
TAK	0.37%	0.139%	0.464
BOB-33	0.30%	0.143%	0.479
ALB-33	0.01%	0.140%	0.469
PEN-25	0.01%	0.140%	0.469

For most of the results, all DG have similar effectiveness for mitigating grid backbone overload issues, except:

- DG at Bombay has higher effectiveness than others for Bunnythorpe-Mataroa overload due to its location on the 110 kV network more significantly reducing power flow through the Bunnythorpe-Mataroa 110 kV circuit.
- DG at Te Kowhai has slightly lower effectiveness on 220 kV overloads between Bunnythorpe and Whakamaru.

Te Kowhai, Glenbrook, Silverdale, Bream Bay, Maungatapere, Takanini, Albany 33 kV and Penrose 25 kV meet the 0.1%/MW thresholds for Bunnythorpe-Mataroa in 2017 and 2018, and for Tokaanu-Whakamaru from 2019.

Based on these results, without placing any subjective value judgement on which DG is preferred, Glenbrook, Te Kowhai, Bombay 110 kV, Bombay 33 kV, Silverdale, Bream Bay, Maungatapere and Takanini, Albany 33 kV and Penrose 25 kV DG are considered necessary from Winter 2017.

4.3.2 System Condition 2 – Low Waikato and UNI Generation in Summer

The issues identified for this system condition are as follows:

- In 2017, Bunnythorpe - Mataroa may overload, for a contingency of a 220 kV circuit. The most severe contingencies are a Tokaanu – Whakamaru circuit, Hamilton-Whakamaru, or 220 kV circuits between Stratford and Huntly. This is alleviated by Summer 2018 once the Mataroa reactor and COPS are commissioned.
- From 2018, the Wairakei – Ohakuri - Atiamuri circuits may overload, for a contingency of Te Mihi – Whakamaru circuit. From 2019, a Whakamaru – Wairakei circuit contingency may also overload Wairakei – Ohakuri - Atiamuri circuits.
- From 2025, Otahuhu – Wiri tee may overload, for a contingency of Hamilton-Whakamaru[9].

The effectiveness of each DG in alleviating these issues has been calculated and may be found in Appendix A. The DG elements which provide the greatest positive impact for each issue, are summarised in the tables below.

[9] *None of the DG analysed in summer 2025 have a beneficial impact to Otahuhu - Wiri tee overload. DG at Bombay 110 kV and 33 kV may have a positive impact, but being already considered necessary in summer 2025 based on regional results, the impact was not investigated.*

Table 14: Greatest impact by DG on Bunnythorpe-Mataroa overload – results from Summer 2017 (Tokaanu-Whakamaru contingency)

DG Name	BPE-MTR Loading Reduction (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
GLN-33-2-NZST	7.54%	0.124%	0.071
TWH	4.81%	0.113%	0.065
SVL	1.10%	0.129%	0.074
BOB-33	0.45%	0.161%	0.092
BOB-110	0.29%	0.161%	0.092
MPE	0.22%	0.136%	0.078
TAK	0.20%	0.128%	0.073
OTA	0.06%	0.130%	0.074
BRB	0.03%	0.135%	0.077
ALB-33	0.03%	0.130%	0.074
HEP	0.01%	0.130%	0.074
HEN	0.01%	0.130%	0.074
PEN-25	0.01%	0.130%	0.074
PAK	0.01%	0.130%	0.074

Table 15: Greatest impact by DG on Atiamuri-Ohakuri overload – results from Summer 2018 (Te Mihi – Whakamaru contingency)

DG Name	ATI-OHK Loading Reduction (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
GLN-33-2-NZST	1.322%	0.022%	0.073
TWH	0.833%	0.020%	0.065
SVL	0.192%	0.023%	0.075
MPE	0.038%	0.024%	0.079
TAK	0.035%	0.022%	0.073

DG at Bombay has higher effectiveness than others for the Bunnythorpe - Mataroa overload due to its location on the 110 kV network more significantly reducing power flow through the Bunnythorpe - Mataroa 110 kV circuit. All DG contributing MW in this scenario reach the 0.1%/MW effectiveness threshold in 2017 for the Bunnythorpe – Mataroa overload.

None of the DG is effective at reducing overload on Atiamuri-Ohakuri circuit overload.

Based on these results, without placing any subjective value judgement on which DG is preferred, Glenbrook, Te Kowhai, Silverdale, Bombay 110 kV, Bombay 33 kV, Maungatapere, Takanini, Otahuhu, Albany 33 kV, Bream Bay, Hepburn, Henderson, Penrose 25 kV, and Pakuranga are considered necessary in Summer 2017 only.

4.3.3 System Condition 5 – Low Eastern Bay of Plenty Industrial Load

The issues identified for this system condition which are similar to system condition 3 are as follows:

Further to system condition 2 overloads, system condition 5 also identifies the following issues:

- From 2017, Atiamuri-Ohakuri may overload, for a contingency of Edgecumbe-Kawerau 3 220 kV circuit.
- From 2017, Kawerau T12 and T13 interconnecting transformers may overload for a contingency of the parallel interconnecting transformer. Note that this is assuming Kawerau is replaced by an identical transformer to T12, and both transformers have the same branch limit that T12 currently does.

The effectiveness of each DG in alleviating these issues has been calculated and may be found in Appendix A. The DG elements which provide the greatest positive impact for each issue, are summarised in the tables below.

Table 16: Greatest impact by DG on Atiamuri - Ohakuri overload – results from Summer 2017 (Edgecumbe – Kawerau 3 contingency)

DG Name	ATI-OHK Loading Reduction (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
GLN-33-2-NZST	0.78%	0.013%	0.007
TWH	0.49%	0.012%	0.007
SVL	0.11%	0.013%	0.008

Table 17: Greatest impact by DG on Kawerau T12/T13 overload – results from Summer 2017 (parallel Kawerau T12/T13 transformer)

DG Name	KAW T12/T13 Loading Reduction (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
GLN-33-2-NZST	-0.006%	-0.00010%	-0.00015
TWH	-0.003%	-0.00008%	-0.00012
SVL	-0.001%	-0.00010%	-0.00016

For most of the results, all DG have similar effectiveness for mitigating Atiamuri – Ohakuri 220 kV circuit overload issues. None of the DG analysed have a significant effect on Kawerau T12/T12 interconnecting transformer overloads.

Based on these results, none of the UNI DG has a high enough effectiveness to significantly reduce overloads seen in SC5.

4.3.4 Slack generation location sensitivity

An important consideration with these results is whether the reduction in loading is based on DG location, or slack[10] generation location. To test this, a sensitivity was carried out with slack generation at Wairakei, Stratford, and HVDC as per the base model configuration.

The grid backbone analysis studies the constraints on the power system, for the most part, transmitting power north to the UNI. The DG effectiveness results display the impact of DG offsetting the power required to be transmitted to the UNI through the grid backbone. The results are dependent on the location of the generation which is being offset by DG, i.e. the slack generation.

In practice, it is difficult to say with certainty which generation will be offset by DG at peak loading times.

With HVDC as the only slack, UNI DG effectiveness at alleviating Atiamuri – Ohakuri is low. Slack sensitivity scenarios have been tested with Wairakei and Stratford slacks enabled to find whether there is an increase in DG effectiveness from the HVDC only scenario. The summer SC2 sensitivity scenarios have no generation at Stratford, so all the slack generation balance is located at Wairakei.

[10] *Refer to Section 3.6 for background on the concept of slack generation*

Table 18: Greatest impact by DG on Atiamuri-Ohakuri overload (slack sensitivity) – results from SC1 Winter 2018 (Te Mihi – Whakamaru contingency)

DG Name	ATI-OHK Loading Reduction (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
GLN-33-2-NZST	3.11%	0.058%	0.209
TWH	3.07%	0.054%	0.195
SVL	0.51%	0.060%	0.214
BRB	0.48%	0.062%	0.222
MPE	0.29%	0.064%	0.229
BOB-110	0.22%	0.060%	0.216
TAK	0.16%	0.059%	0.212
BOB-33	0.13%	0.060%	0.217
PEN-25	0.01%	0.060%	0.215
ALB-33	0.01%	0.060%	0.215

Table 19: Greatest impact by DG on Atiamuri-Ohakuri overload (slack sensitivity) – results from SC2 Summer 2018-2025 (Te Mihi – Whakamaru contingency)

DG Name	ATI-OHK Loading Reduction (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
GLN-33-2-NZST	6.089%	0.098% (2018) 0.100% (2020)	0.335
TWH	4.190%	0.094% (2018) 0.099% (2025)	0.328
SVL	0.862%	0.099% (2018) 0.101% (2019)	0.338
MPE	0.168%	0.105% (2018)	0.350
TAK	0.161%	0.099% (2018) 0.101% (2019)	0.335
OTA	0.050%	0.100% (2018)	0.333
BRB	0.021%	0.105% (2018)	0.350
ALB-33	0.020%	0.100% (2018)	0.333
PEN-25	0.010%	0.100% (2018)	0.333
PAK	0.010%	0.100% (2018)	0.333
HEP	0.010%	0.100% (2018)	0.333
HEN	0.010%	0.100% (2018)	0.333

With the slack at Wairakei and closer to the Atiamuri-Ohakuri overload, the effectiveness of UNI DG on the overload has increased.

In winter, with SC1, the effectiveness is still far below the 0.1%/MW thresholds, due in part to slack being distributed between Wairakei and Stratford.

In summer, with SC2, the effectiveness is at the 0.1%/MW thresholds for all DG. The differences lie in the third decimal place, which is beyond the level of accuracy expected from an offline power system study. It’s noted that this scenario has all slack movement at Wairakei, which is an optimistic scenario for DG effectiveness at alleviating Atiamuru – Ohakuri overload.

Based on the sensitivity results, without placing any subjective value judgement on which DG is preferred and applying consistent methodology to the study, the following DG is required for Atiamuri-Ohakuri overload:

- Summer 2018: Maungatapere, Otahuhu, Bream Bay, Albany 33 kV, Penrose 25 kV, Pakuranga, Hepburn Rd and Henderson.
- Summer 2019: Silverdale and Takanini.
- Summer 2020: Glenbrook.

However, considering the borderline nature of these results, consideration should be made to regard all DG listed in Table 19 above as having the same effectiveness for the summer overload of Atiamuri – Ohakuri.

4.3.5 Voltage Stability Limits

This analysis considered the WUNI (Waikato and Upper North Island) voltage stability, for a loss of major transmission lines and generation plant, between the LNI and UNI. The Winter 2021 scenario was assessed by scaling WUNI load[11] until voltage collapse, considering the following contingencies:

a) Huntly unit 5.
b) Pakuranga – Whakamaru - 1.

For the 'DG OFF' case, all DG in the LNI region was assumed on, and the DG identified as being required in the local and regional analysis assumed to be ON.

The generation profile is as per the Regional and GXP studies scenarios, with the following adjustments:

- Huntly Rankine units out of service.
- Arapuni G5 is connected to the Arapuni North bus.
- Stratford slack has been removed, and all slack generation is at Wairakei.
- Voltage support is enabled from Wairakei slack.
- All capacitors in WUNI region switched on except Bombay, Wairau Rd and Albany C1. Capacitors at Kaitaia and Kaikohe are not explicit in the model as the network beyond Kaikohe is reduced to a load on the Kaikohe 110 kV bus.

Results presented in Table 20**Error! Reference source not found.** show the difference in voltage stability limit with each DG ON compared to the 'DG OFF' case, i.e. the improvement in voltage stability limit. Cells highlighted yellow indicate DG have a notable effect on the voltage stability limit.

Voltage stability analysis was performed by scaling WUNI load incrementally. The simulation step size was limited to 0.1% of WUNI load, which is about 3 MW. MW effectiveness values have not been calculated, as the step size is the same order of magnitude to the DG MW contributions, so the results are not likely to be meaningful.

Table 20 Effect of DG on WUNI voltage stability

DG	DG MW output (Winter Island Peak)	MW/% Impact to WUNI Voltage Stability by contingency			
		HLY UN5		PAK-WKM	
		ΔMW	Δ%	ΔMW	Δ%
ALB-33	0.1	0.0	0.0%	0.0	0.0%
BRB	7.8	11.9	0.4%	5.9	0.2%
GLN-33-2-NZST	53.3	41.5	1.3%	35.2	1.1%
HEN	0.0	0.0	0.0%	0.0	0.0%
HEP	0.0	0.0	0.0%	0.0	0.0%
HLY	0.0	0.0	0.0%	0.0	0.0%
HOB	0.0	0.0	0.0%	0.0	0.0%
MNG-33	0.0	0.0	0.0%	0.0	0.0%
MPE	4.5	5.9	0.2%	5.9	0.2%
MTO	0.0	0.0	0.0%	0.0	0.0%
PAK	0.0	0.0	0.0%	0.0	0.0%
PEN-22	0.0	0.0	0.0%	0.0	0.0%
PEN-25	0.1	0.0	0.0%	0.0	0.0%
PEN-33	0.0	0.0	0.0%	0.0	0.0%
ROS-22	0.0	0.0	0.0%	0.0	0.0%
ROS-KING	0.0	0.0	0.0%	0.0	0.0%

[11] *Excluding Kinleith and Litchfield, due to the Arapuni bus split these sites are supplied from Tarukenga 220 kV rather than Hamilton.*

DG	DG MW output (Winter Island Peak)	MW/% Impact to WUNI Voltage Stability by contingency			
		HLY UN5		PAK-WKM	
		ΔMW	Δ%	ΔMW	Δ%
SVL	8.5	11.9	0.4%	5.9	0.2%
TAK	2.7	5.9	0.2%	0.0	0.0%
TWH	56.5	29.7	0.9%	29.3	0.9%
WEL	0.0	0.0	0.0%	0.0	0.0%
WIR	0.0	0.0	0.0%	0.0	0.0%
WRD	0.0	0.0	0.0%	0.0	0.0%

Results show that DG increases the voltage stability limit roughly equal to the MW injection from the DG. However, determination of whether DG is required for voltage stability is inconsequential to this study, since all DG shown to have benefit to voltage stability are already deemed required in winter.

4.3.6 Grid Backbone Contingency Analysis Summary

Based on the results of this analysis, the following DG can be considered necessary (additional to that required following the local and regional study):

Table 21: Regional DG required for Winter years

	Winter					
Required DG	**2017**	**2018**	**2019**	**2020**	**2021**	**2025**
ALB-33	✓	✓	✓	✓	✓	✓
BOB-110	✓	✓	✓	✓	*Already ON*	*Already ON*
BOB-33	✓	✓	✓	✓	*Already ON*	*Already ON*
BRB	✓	✓	✓	✓	✓	✓
GLN-33-2-NZST	✓	✓	✓	✓	✓	*Already ON*
MPE	✓	✓	✓	✓	✓	✓
PEN-25	✓	✓	✓	✓	✓	✓
SVL	✓	✓	✓	✓	✓	✓
TAK	*Already ON*	✓	✓	✓	✓	✓
TWH	✓	✓	✓	✓	✓	*Already ON*

Table 22: Regional DG required for Summer years

	Summer					
Required DG	**2017**	**2018**	**2019**	**2020**	**2021**	**2025**
ALB-33	✓	✓	✓	✓	✓	✓
BOB-110	✓	*Already ON*	*Already ON*	*Already ON*	*Already ON*	*Already ON*
BOB-33	✓	*Already ON*	*Already ON*	*Already ON*	*Already ON*	*Already ON*
BRB	✓	✓	✓	✓	✓	✓
GLN-33-2-NZST	✓			✓	✓	✓
HEN	✓	✓	✓	✓	✓	✓
HEP	✓	✓	✓	✓	✓	✓
MPE	✓	✓	✓	✓	✓	✓
OTA	✓	✓	✓	✓	✓	*Already ON*
PAK	✓	✓	✓	✓	✓	✓
PEN-25	✓	✓	✓	✓	✓	✓
SVL	✓		✓	✓	✓	✓
TAK	✓		✓	✓	✓	✓
TWH	✓					

5 Conclusions

Mitton ElectroNet has completed an analysis on behalf of Transpower, to determine required DG in the UNI. This analysis was undertaken to fulfil Transpower's requirements, under Part 6, Schedule 6.4 of the Code.

The analysis involved three components, assessing the impact of the DG on:

1. Local supply transformer and spur line asset capacity.
2. Regional transmission capacity.
3. Grid backbone transfer limits.

Results show that DG contribution is required at the following GXPs, for local supply issues:

- Kaikohe 110 kV (Winter and Summer from 2017)
- Otahuhu (Winter from 2017 and Summer from 2025)
- Takanini (Winter in 2017 only, not required from 2018 following outdoor to indoor conversion)

Results show that DG contribution is required at the following GXPs, for regional supply issues:

- Bombay 110 kV (Winter from 2021 and Summer from 2018)
- Bombay 33 kV (Winter from 2021 and Summer from 2018)
- Glenbrook (Winter from 2025)
- Te Kowhai (Winter from 2025)

Results show that DG contribution is required at the following GXPs, for grid backbone supply issues:

- Albany 33 kV (Winter from 2017 and Summer from 2017)
- Bombay 110 kV (Winter from 2017 and Summer from 2017)
- Bombay 33 kV (Winter from 2017 and Summer from 2017)
- Bream Bay (Winter from 2017 and Summer from 2017)
- Glenbrook (Winter from 2017 and Summer in 2017 and from 2020)
- Henderson (Summer from 2017)
- Hepburn Rd (Summer from 2017)
- Maungatapere (Winter from 2017 and Summer from 2017)
- Pakuranga (Summer from 2017)
- Penrose 25 kV (Winter from 2017 and Summer from 2017)
- Silverdale (Winter from 2017 and Summer in 2017 and from 2019)
- Takanini (Winter from 2018 and Summer in 2017 and from 2019)
- Te Kowhai (Winter from 2017 and Summer in 2017)

Many of the summer grid backbone results are based on the sensitivity scenario with slack generation located at Wairakei. The results for this scenario were borderline on the acceptance criteria for many DG, and consideration should be made to regard all DG listed in that scenario as having the same effectiveness.

Table 23 and Table 24 below summarises the DG required in summer and winter from 2017 to 2025.

Table 23: Regional DG required for Winter years

	Winter					
Required DG	**2017**	**2018**	**2019**	**2020**	**2021**	**2025**
ALB-33	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
BOB-110	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - regional	✓ - regional
BOB-33	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - regional	✓ - regional
BRB	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
GLN-33-2-NZST	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - regional
KOE-110	✓ - GXP	✓ - GXP	✓ - GXP	✓ - GXP	✓ - GXP	✓ - GXP
MPE	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
OTA	✓ - GXP	✓ - GXP	✓ - GXP	✓ - GXP	✓ - GXP	✓ - GXP
PEN-25	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
SVL	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
TAK	✓ - GXP	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
TWH	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - regional

Table 24: Regional DG required for Summer years

	Summer					
Required DG	**2017**	**2018**	**2019**	**2020**	**2021**	**2025**
ALB-33	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
BOB-110	✓ - backbone	✓ - regional	✓ - regional	✓ - regional	✓ - regional	✓ - regional
BOB-33	✓ - backbone	✓ - regional	✓ - regional	✓ - regional	✓ - regional	✓ - regional
BRB	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
GLN-33-2-NZST	✓ - backbone			✓ - backbone	✓ - backbone	✓ - backbone
HEN	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
HEP	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
KOE-110	✓ - GXP	✓ - GXP	✓ - GXP	✓ - GXP	✓ - GXP	✓ - GXP
MPE	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
OTA	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - GXP
PAK	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
PEN-25	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
SVL	✓ - backbone		✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
TAK	✓ - backbone		✓ - backbone	✓ - backbone	✓ - backbone	✓ - backbone
TWH	✓ - backbone					

6 Bibliography

[1] Transpower NZ Ltd, "Transmission Planning Report," 2017.
[2] Electricity Authority, "Electricity Industry Participation Code 2010 (Revision 19 Jan 2017)," 2017.

Appendix A

Grid Backbone Study Results

Appendix A: Grid Backbone Study Results

SC1 2017 BPE-MTR Overload

Year	2017
Season	Winter
System Condition	1
Description	Bunnythorpe-Mataroa Overload
Contingency	Tokaanu-Whakamaru
SFD Growth	178 MW
WRK Growth	178 MW
HAY Slack	800 MW
BPE-MTR pre-contingent loading	92.5%

DG Name	New Line Load (%)	Line Delta Load (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
ALB-33	109.2	0.01%	0.120%	0.084
BOB-110	108.7	0.53%	0.148%	0.103
BOB-33	108.9	0.31%	0.148%	0.103
BRB	108.2	0.99%	0.127%	0.088
DGOFF	109.2	0.00%		
GLN-33-2-NZST	102.9	6.29%	0.118%	0.082
HEN	109.2	0.00%		
HEP	109.2	0.00%		
HLY	109.2	0.00%		
HOB	109.2	0.00%		
MNG-33	109.2	0.00%		
MPE	108.6	0.59%	0.131%	0.091
MTO	109.2	0.00%		
PAK	109.2	0.00%		
PEN-22	109.2	0.00%		
PEN-25	109.2	0.01%	0.120%	0.084
PEN-33	109.2	0.00%		
ROS-22	109.2	0.00%		
ROS-KING	109.2	0.00%		
SVL	108.1	1.04%	0.122%	0.085
TAK (2018)	114.4	0.33%	0.124%	0.087
TWH	103.182	6.00%	0.106%	0.074
WEL	109.183	0.00%		
WIR	109.183	0.00%		
WRD	109.183	0.00%		

SC1 2018 ATI-OHK Overload

Year	2018
Season	Winter
System Condition	1
Description	Atiamuri-Ohakuri Overload
Contingency	Te Mihi – Whakamaru
SFD Slack	269 MW
WRK Slack	269 MW
HAY Slack	750 MW
BPE-MTR pre-contingent loading	97.2%

DG Name	New Line Load (%)	Line Delta Load (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
ALB-33	105.0	0.00%	0.020%	0.072
BOB-110	104.9	0.09%	0.024%	0.085
BOB-33	104.9	0.05%	0.024%	0.085
BRB	104.8	0.19%	0.024%	0.088
DGOFF	105.0	0.00%		
GLN-33-2-NZST	103.8	1.22%	0.023%	0.082
HEN	105.0	0.00%		
HEP	105.0	0.00%		
HLY	105.0	0.00%		
HOB	105.0	0.00%		
MNG-33	105.0	0.00%		
MPE	104.9	0.11%	0.025%	0.091
MTO	105.0	0.00%		
PAK	105.0	0.00%		
PEN-22	105.0	0.00%		
PEN-25	105.0	0.00%	0.020%	0.072
PEN-33	105.0	0.00%		
ROS-22	105.0	0.00%		
ROS-KING	105.0	0.00%		
SVL	104.8	0.20%	0.024%	0.085
TAK	104.9	0.06%	0.023%	0.084
TWH	103.8	1.15%	0.020%	0.073
WEL	105.0	0.00%		
WIR	105.0	0.00%		
WRD	105.0	0.00%		

SC1 2018 ATI-OHK Overload (WRK+SFD slack sensitivity)

Year	2018
Season	Winter
System Condition	1
Description	Atiamuri-Ohakuri Overload
Contingency	Te Mihi – Whakamaru
SFD Slack	269 MW
WRK Slack	269 MW
HAY Slack	750 MW
BPE-MTR pre-contingent loading	97.2%

DG Name	New Line Load (%)	Line Delta Load (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
ALB-33	104.3	0.01%	0.060%	0.215
BOB-110	104.1	0.22%	0.060%	0.216
BOB-33	104.2	0.13%	0.060%	0.217
BRB	103.9	0.48%	0.062%	0.222
DGOFF	104.4	0.00%		
GLN-33-2-NZST	101.2	3.11%	0.058%	0.209
HEN	104.4	0.00%		
HEP	104.4	0.00%		
HLY	104.4	0.00%		
HOB	104.4	0.00%		
MNG-33	104.4	0.00%		
MPE	104.1	0.29%	0.064%	0.229
MTO	104.4	0.00%		
PAK	104.4	0.00%		
PEN-22	104.4	0.00%		
PEN-25	104.3	0.01%	0.060%	0.215
PEN-33	104.4	0.00%		
ROS-22	104.4	0.00%		
ROS-KING	104.4	0.00%		
SVL	103.8	0.51%	0.060%	0.214
TAK	104.2	0.16%	0.059%	0.212
TWH	101.3	3.07%	0.054%	0.195
WEL	104.4	0.00%		
WIR	104.4	0.00%		
WRD	104.4	0.00%		

SC1 2019 TKU-WKM Overload

Year	2019
Season	Winter
System Condition	1
Description	Tokaanu - Whakamaru Overload
Contingency	Tokaanu – Whakamaru
SFD Growth	266 MW
WRK Growth	266 MW
HAY Slack	950 MW
BPE-MTR pre-contingent loading	93.9%

DG Name	New Line Load (%)	Line Delta Load (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
ALB-33	107.4	0.01%	0.140%	0.469
BOB-110	106.9	0.51%	0.142%	0.477
BOB-33	107.1	0.30%	0.143%	0.479
BRB	106.3	1.13%	0.145%	0.486
DGOFF	107.4	0.00%		
GLN-33-2-NZST	100.3	7.10%	0.133%	0.447
HEN	107.4	0.00%		
HEP	107.4	0.00%		
HLY	107.4	0.00%		
HOB	107.4	0.00%		
MNG-33	107.4	0.00%		
MPE	106.8	0.68%	0.150%	0.504
MTO	107.4	0.00%		
PAK	107.4	0.00%		
PEN-22	107.4	0.00%		
PEN-25	107.4	0.01%	0.140%	0.469
PEN-33	107.4	0.00%		
ROS-22	107.4	0.00%		
ROS-KING	107.4	0.00%		
SVL	106.2	1.19%	0.140%	0.469
TWH	107.1	0.37%	0.139%	0.464
WEL	100.7	6.77%	0.120%	0.402
WIR	107.4	0.00%		
WRD	107.4	0.00%		

SC2 2017 BPE-MTR Overload

Year	2017
Season	Summer
System Condition	1
Description	Bunnythorpe-Mataroa Overload
Contingency	Hamilton-Whakamaru
SFD Growth	0 MW
WRK Growth	261 MW
HAY Slack	850 MW
BPE-MTR pre-contingent loading	91.8%

DG Name	New Line Load (%)	Line Delta Load (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
ALB-33	104.9	0.03%	0.130%	0.074
BOB-110	104.7	0.29%	0.161%	0.092
BOB-33	104.5	0.45%	0.161%	0.092
BRB	104.9	0.03%	0.135%	0.077
DGOFF	105.0	0.00%	-	-
GLN-33-2-NZST	97.4	7.54%	0.124%	0.071
HEN	105.0	0.01%	0.130%	0.074
HEP	105.0	0.01%	0.130%	0.074
HLY	105.0	0.00%	-	-
HOB	105.0	0.00%	-	-
MNG-33	105.0	0.00%	-	-
MPE	104.8	0.22%	0.136%	0.078
MTO	105.0	0.00%	-	-
OTA	104.9	0.06%	0.130%	0.074
PAK	105.0	0.01%	0.130%	0.074
PEN-22	105.0	0.00%	-	-
PEN-25	105.0	0.01%	0.130%	0.074
PEN-33	105.0	0.00%	-	-
ROS-22	105.0	0.00%	-	-
ROS-KING	105.0	0.00%	-	-
SVL	103.9	1.10%	0.129%	0.074
TAK	104.8	0.20%	0.128%	0.073
TWH	100.2	4.81%	0.113%	0.065
WEL	105.0	0.00%	-	-
WIR	105.0	0.00%	-	-
WRD	105.0	0.00%	-	-

SC2 2018 ATI-OHK Overload

Year	2018
Season	Summer
System Condition	1
Description	Atiamuri-Ohakuri Overload
Contingency	Te Mihi-Whakamaru
SFD Growth	0 MW
WRK Slack	310 MW
HAY Slack	950 MW
BPE-MTR pre-contingent loading	87.8%

DG Name	New Line Load (%)	Line Delta Load (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
ALB-33	120.3	0.004%	0.020%	0.067
BRB	120.3	0.004%	0.020%	0.067
DGOFF	120.3	0.000%	-	-
GLN-33-2-NZST	118.9	1.322%	0.022%	0.073
HEN	120.3	0.002%	0.020%	0.067
HEP	120.3	0.002%	0.020%	0.067
HLY	120.3	0.000%	-	-
HOB	120.3	0.000%	-	-
MNG-33	120.3	0.000%	-	-
MPE	120.2	0.038%	0.024%	0.079
MTO	120.3	0.000%	-	-
OTA	120.3	0.011%	0.022%	0.073
PAK	120.3	0.002%	0.020%	0.067
PEN-22	120.3	0.000%	-	-
PEN-25	120.3	0.002%	0.020%	0.067
PEN-33	120.3	0.000%	-	-
ROS-22	120.3	0.000%	-	-
ROS-KING	120.3	0.000%	-	-
SVL	120.1	0.192%	0.023%	0.075
TAK	120.2	0.035%	0.022%	0.073
TWH	119.4	0.833%	0.020%	0.065
WEL	120.3	0.000%	-	-
WIR	120.3	0.000%	-	-
WRD	120.3	0.000%	-	-

SC2 2018 ATI-OHK Overload (WRK slack only)

Year	2018
Season	Summer
System Condition	1
Description	Atiamuri-Ohakuri Overload
Contingency	Te Mihi-Whakamaru
SFD Growth	0 MW
WRK Slack	310 MW
HAY Slack	950 MW
BPE-MTR pre-contingent loading	87.8%

DG Name	New Line Load (%)	Line Delta Load (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
ALB-33	108.487	0.02%	0.100%	0.000
BRB	108.486	0.02%	0.105%	0.000
DGOFF	108.507	0.00%		
GLN-33-2-NZST	102.586	5.92%	0.098%	0.000
HEN	108.497	0.01%	0.100%	0.000
HEP	108.497	0.01%	0.100%	0.000
HLY	108.507	0.00%		
HOB	108.507	0.00%		
MNG-33	108.507	0.00%		
MPE	108.339	0.17%	0.105%	0.000
MTO	108.507	0.00%		
OTA	108.457	0.05%	0.100%	0.000
PAK	108.497	0.01%	0.100%	0.000
PEN-22	108.507	0.00%		
PEN-25	108.497	0.01%	0.100%	0.000
PEN-33	108.507	0.00%		
ROS-22	108.507	0.00%		
ROS-KING	108.507	0.00%		
SVL	107.662	0.84%	0.099%	0.000
TAK	108.349	0.16%	0.099%	0.000
TWH	104.529	3.98%	0.094%	0.000
WEL	108.507	0.00%		
WIR	108.507	0.00%		
WRD	108.507	0.00%		

SC5 2017 ATI-OHK Overload

Year	2017
Season	Summer
System Condition	1
Description	Atiamuri-Ohakuri Overload
Contingency	Edgecumbe-Kawerau
SFD Growth	0 MW
WRK Growth	0 MW
HAY Slack	802 MW
BPE-MTR pre-contingent loading	87.7%

DG Name	New Line Load (%)	Line Delta Load (%)	DG Effectiveness (%/MW)	DG Effectiveness (MW/MW)
ALB-33	110.3	0.00%	0.01%	0.033
BOB-110	110.3	0.02%	0.01%	0.044
BOB-33	110.2	0.04%	0.01%	0.044
BRB	110.3	0.00%	0.01%	0.033
DGOFF	110.3	0.00%	-	-
GLN-33-2-NZST	109.5	0.78%	0.01%	0.043
HEN	110.3	0.00%	0.01%	0.033
HEP	110.3	0.00%	0.01%	0.033
HLY	110.3	0.00%	-	-
HOB	110.3	0.00%	-	-
MNG-33	110.3	0.00%	-	-
MPE	110.3	0.02%	0.01%	0.046
MTO	110.3	0.00%	-	-
OTA	110.3	0.01%	0.01%	0.040
PAK	110.3	0.00%	0.01%	0.033
PEN-22	110.3	0.00%	-	-
PEN-25	110.3	0.00%	0.01%	0.033
PEN-33	110.3	0.00%	-	-
ROS-22	110.3	0.00%	-	-
ROS-KING	110.3	0.00%	-	-
SVL	110.2	0.11%	0.01%	0.044
TAK	110.3	0.02%	0.01%	0.044
TWH	109.8	0.49%	0.01%	0.038
WEL	110.3	0.00%	-	-
WIR	110.3	0.00%	-	-
WRD	110.3	0.00%	-	-

Appendix B

GIP and GXP List

Appendix B: GIP and GXP List

Substation	GIP	GXP	Switching Station
Albany		✓	
Bombay		✓	
Bream Bay		✓	
Brown Hill			✓
Drury			✓
Glenbrook	✓	✓	
Henderson		✓	
Hepburn Rd		✓	
Huapai			✓
Huntly	✓	✓	
Hobson		✓	
Kaikohe		✓	
Mangere		✓	
Maungatapere		✓	
Maungaturoto		✓	
Otahuhu		✓	
Pakuranga		✓	
Penrose		✓	
Mt Roskill		✓	
Silverdale		✓	
Takanini		✓	
Te Kowhai		✓	
Wellsford		✓	
Wiri		✓	
Wairau Road		✓	

Appendix C

DG Contribution

Appendix C: DG Contribution

Table 25 - Considered Distributed Generation by GXP

GXP	Assumed Contribution GXP Peak Load		Assumed Contribution Regional Peak Load		Assumed Contribution Island Peak Load	
	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)
Albany 33kV	0.1	0.2	0.1	0.2	0.1	0.2
Bombay 110kV	2.9	1.7	3.4	1.8	3.6	1.8
Bombay 33kV	3.2	2.2	2.3	2.3	2.1	2.8
Bream Bay	6.4	0.1	7.4	0.0	7.8	0.2
Glenbrook - NZ Steel	29.6	26.9	55.7	54.8	53.3	60.6
Henderson	0.0	0.1	0.0	0.2	0.0	0.1
Hepburn Rd	0.0	0.1	0.0	0.1	0.0	0.1
Huntly	0.0	0.0	0.0	0.0	0.0	0.0
Hobson	0.3	0.2	0.0	0.0	0.0	0.0
Kaikohe 110kV	25.4	24.5	24.0	21.8	24.3	22.2
Mangere 33kV	0.0	0.0	0.0	0.0	0.0	0.0
Maungatapere	4.7	1.4	4.5	1.8	4.5	1.6
Maungaturoto	0.0	0.0	0.0	0.0	0.0	0.0
Otahuhu	0.5	0.5	0.5	0.5	0.5	0.5
Pakuranga	0.0	0.1	0.0	0.1	0.0	0.1
Penrose 22kV	0.0	0.0	0.0	0.0	0.0	0.0
Penrose 25kV	0.1	0.1	0.1	0.1	0.1	0.1
Penrose 33kV	0.0	0.1	0.0	0.1	0.0	0.0
Mt Roskill 22kV	0.0	0.0	0.0	0.1	0.0	0.0
Mt Roskill 110kV - KING	0.0	0.0	0.0	0.1	0.0	0.0
Silverdale	8.5	8.6	8.5	8.4	8.5	8.5
Takanini	2.7	2.1	2.7	2.1	2.7	1.6
Te Kowhai	33.0	53.5	58.0	43.1	56.5	42.5
Wellsford	0.0	0.0	0.0	0.0	0.0	0.0
Wiri	0.0	0.0	0.0	0.0	0.0	0.0
Wairau Road	0.0	0.1	0.0	0.1	0.0	0.0

Appendix D

GXP Load Forecast

Appendix D: GXP Load Forecast

GXP	Winter GXP Peak							Summer GXP Peak						
	2017	2018	2019	2020	2021	2025	Power Factor	2017	2018	2019	2020	2021	2025	Power Factor
Bream Bay	55	55.3	55.7	56	56.3	57.7	0.977	54.5	54.8	55.1	55.4	55.8	57.1	0.984
Kaikohe 110kV	85.8	86.4	87	87.6	88.2	90.7	-0.963	75.9	76.4	76.9	77.4	77.9	80	-0.921
Maungatapere	117.8	119.6	121.4	123.2	125	132.5	0.993	103.2	104.7	106.3	107.9	109.5	116	0.983
Maungaturoto	18.8	19.1	19.4	19.7	20	21.2	0.999	18.1	18.4	18.7	18.9	19.2	20.4	0.997
Wellsford	37.1	37.9	38.7	39.5	40.3	43.6	-0.999	28	28.6	29.2	29.8	30.4	32.9	-0.996
Albany 33kV	174.8	184.5	183.6	182.7	182.7	184.7	0.994	113.7	123.7	123.1	122.5	122.5	124.5	0.978
Bombay 110kV	101.1	106.7	112.4	118.2	141.2	160.3	0.995	80.2	84.6	89.2	93.8	111.2	126.3	0.986
Bombay 33kV	17.1	17.5	17.8	18.2	0	0	0.987	12.8	13.1	13.3	13.6	0	0	0.969
Glenbrook - NZ Steel load only	125	125	125	125	125	125	0.986	125	125	125	125	125	125	0.998
Glenbrook - Counties	36.9	37.8	38.7	39.6	40.6	44.3	0.979	28.9	29.6	30.3	31	31.7	34.6	0.955
Glenbrook Subregion	63.3	64	64.7	65.5	66.2	69.2		56.9	57.5	58.1	58.6	59.2	61.5	
Glenbrook - NZ Steel	44.8	44.8	44.8	44.8	44.8	44.8	1	44.8	44.8	44.8	44.8	44.8	44.8	-1
Henderson	138.9	145.8	153.1	160.8	168.5	200.2	0.997	87	91.4	95.9	100.7	105.6	125.4	0.996
Hepburn Rd	162.7	172.6	174.6	176.6	178.6	187	1	108.9	118.3	119.6	120.9	122.3	127.9	1
Hobson	106.4	112.6	117.1	124.5	127.9	141.4	0.994	115	121.5	126.3	133.9	137.6	152.2	0.996
Liverpool Street	106.4	112.6	117.1	124.5	127.9	141.4	1	115	121.5	126.3	133.9	137.6	152.2	1
Meremere	5.6	5.7	5.7	5.8	5.8	6.1	0.973	3.5	3.5	3.6	3.6	3.7	3.8	0.961
Mangere 110kV	21.2	21.2	21.2	21.2	21.2	21.2	0.872	21.2	21.2	21.2	21.2	21.2	21.2	0.872
Mangere 33kV	109	114.6	119.3	122	124.8	135.7	0.983	92.2	97.4	101.7	104	106.3	115.6	0.965
Otahuhu	63.4	66.9	67.5	68	68.5	70.6	0.99	51.6	55	55.4	55.8	56.2	58	0.991
Pakuranga	157.6	158.6	158.6	158.6	158.6	158.6	0.989	102.6	103.6	103.6	103.6	103.6	103.6	0.977
Penrose 22kV	53.5	54.1	54.8	55.4	56.1	58.9	0.965	43.8	44.3	44.8	45.4	45.9	48.1	0.966
Penrose 25kV	8.6	8.6	8.6	8.6	8.6	8.6	0.996	8.6	8.6	8.6	8.6	8.6	8.6	0.996
Penrose 33kV	278.2	290.5	306.3	309.1	312	323.8	0.98	216.9	228.6	243.8	246	248.2	257.4	0.964
Penrose Subregion	315.1	327.4	343	346.3	349.7	363.5		247.7	259.3	274.2	276.8	279.4	290.3	
Mt Roskill 22kV	135.7	134.6	133.5	132.5	132.5	132.5	0.978	77.8	77.2	76.6	76	76	76	0.983
Mt Roskill 110kV - KING	69	68.4	67.9	67.4	67.4	67.4	0.996	46	45.6	45.3	44.9	44.9	44.9	0.965
Silverdale	100.3	102.5	104.8	107.1	109.4	118.6	0.998	63.4	64.8	66.2	67.7	69.1	74.9	-1
Southdown 25kV	8.4	8.4	8.4	8.4	8.4	8.4	1	8.4	8.4	8.4	8.4	8.4	8.4	1
Takanini	126.4	129.8	130.2	130.6	131	132.5	0.994	78.1	81.3	81.6	81.8	82	83	0.998
Wiri	92.9	96.9	99	101.1	103.3	111.8	0.99	83.7	87.5	89.4	91.3	93.2	100.9	0.979
Wairau Road	156.4	155.9	155.4	154.9	154.9	156.4	0.999	83.5	83.2	83	82.7	82.7	84.2	-0.996
Huntly	28.1	28.3	28.6	28.9	29.2	30.4	-0.996	23.5	23.7	23.9	24.2	24.4	25.4	0.999
Te Kowhai	104.9	105.5	106.1	106.8	107.4	110	0.991	80.7	81.2	81.7	82.1	82.6	84.6	0.986

For regional and backbone studies, power factors are as per the provided model.