Upper South 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 South Island (USI) 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, 110 kV, and 66 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 South Island (LSI) to the Upper South Island (USI) and HVDC link, 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 lines' 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 investigation 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:

- Hokitika 66 kV (Summer from 2017 and Winter from 2021).
- Stoke 33 kV (Winter from 2017).
- Stoke 66 kV (Summer and Winter from 2017).

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, where required, in the regional grid and grid backbone studies.

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

- Albury (Summer from 2019 and Winter from 2025)
- Dobson (Winter from 2021)

- Hororata 66 kV (Winter from 2021)
- Islington 66 kV (Winter from 2021)
- Kumara (Summer from 2025 and Winter from 2021)
- Waipara (Winter from 2025)

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

Grid backbone analysis was conducted to analyse constraints on the 220 kV network, which limit the supply of power to the USI region. No voltage stability issues were observed for the grid backbone, for N-1 conditions for the years studied.

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 lowers 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.

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Abbreviations

DG	Distributed Generation
DGPP	Distributed Generation Pricing Principles
EA	Electricity Authority
GIP	Grid Injection Point
GXP	Grid Exit Point
SLD	Single Line Diagram
SPS	Special Protection Scheme
TPR	Transmission Planning Report
USI	Upper South Island

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 South Island (USI) 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 second area; the USI. The USI region is defined, according to the Code [2], as that part of the South Island situated to the North of a line commencing at 43°30'S and 169°30'E, then proceeding in a generally Easterly direction to 44°40'S and 171°12'E.

Figure 1 shows roughly the region covered by the USI. Effectively, this includes all South Island substations and assets North of and excluding Twizel, Tekapo B, Livingston and Studholme (all excluded).

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

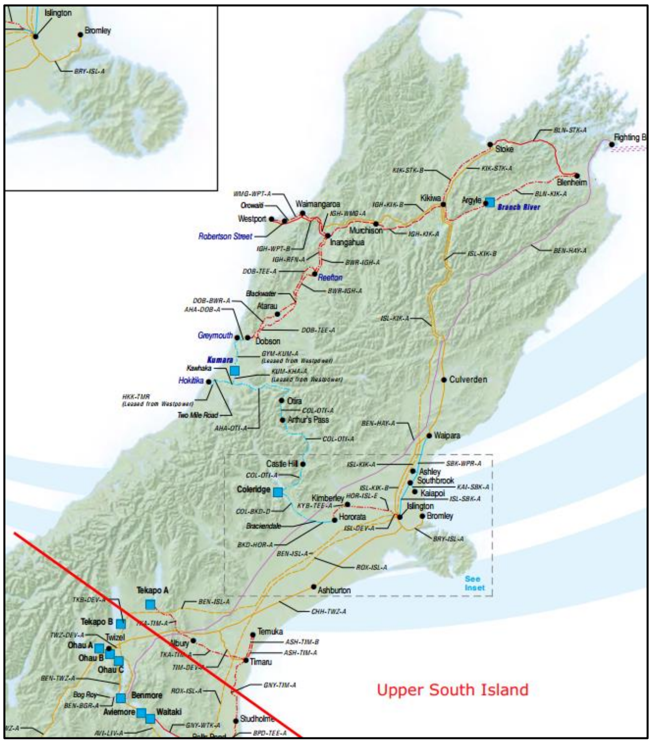

Figure 1 - Upper South Island (USI) Region

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 conventional 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 items, 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 a 40 MVA 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 are considered in the first stage of the analysis, presented within this report.

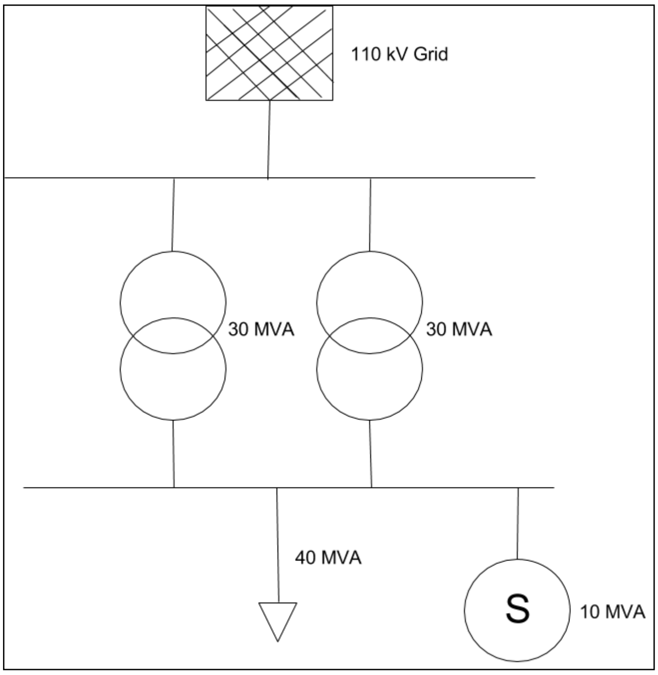

Figure 2 - Typical 110 kV GXP

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:

- A potential reduction in transmission system losses. DG generally supplies load close to the point of supply and can reduce loading on the transmission system, which generally 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.

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 South Island (USI), which includes the Nelson/Marlborough, West Coast, Canterbury and South Canterbury 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 A.

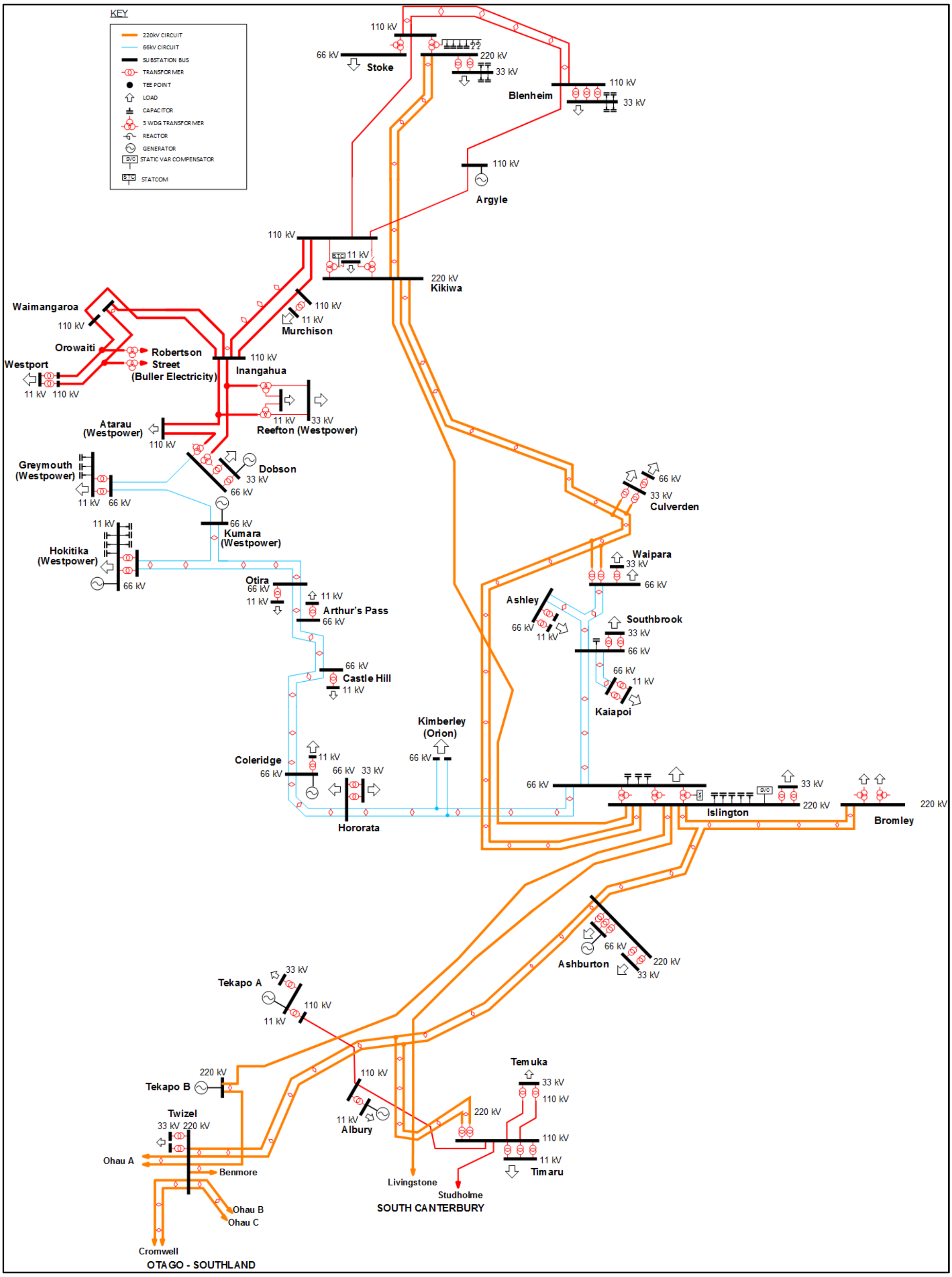

Figure 3 – Upper South Island Study Region showing GIPs and GXPs

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:

- Albury supply transformer replacement, in 2017.
- Bromley T5 and T6 replacement, in 2018.
- Murchison supply transformer replacement, in 2018.
- Timaru 110 kV bus update, in 2018.
- Timaru interconnecting transformer replacement, in 2018.

3.2.2 Special Protection Schemes

The analysis model includes the following enabled special protection schemes:

- Blenheim – Kikiwa overload protection.
- Bells Pond – Waitaki overload protection.
- Hororata automatic under-voltage load shedding (AUVLS).
- Temuka transformer overload protection scheme.
- Timaru supply transformer hot standby scheme.
- Timaru interconnecting transformer overload scheme.

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.
- During the Summer cases, a system split has been included at Studholme, opening the Glenavy-Studholme circuit, if the Bells Pond – Waitaki circuit exceeds 95% of its thermal rating pre-contingency. This split is included in all Summer scenarios, except 2018.
- An additional load has been included at Studholme to represent a possible new substation, St Andrews, which has been included to assess issues at a regional and grid backbone level.

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, for example, West Wind, Te Apiti, Tararua Wind Central, the assumed contribution at peak load, was 20% of nominal capacity. This is consistent with the TPR methodology.

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 B 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 C 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 USI regions; this assessment aims to determine if USI DG is beneficial to regional issues throughout the South 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.

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.

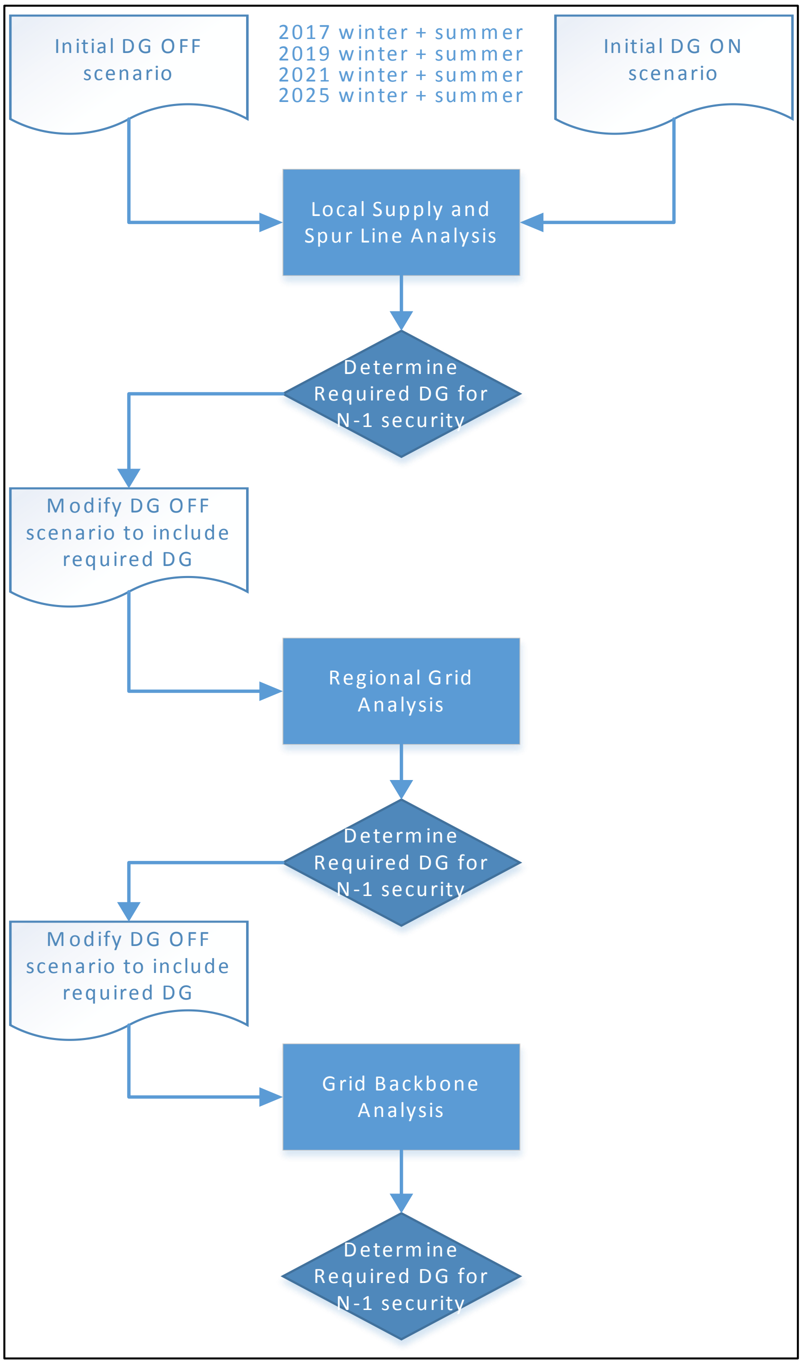

Figure 4 - Analysis Flowchart

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 Upper South Island (USI), to maintain grid security until 2025. The investigation has been separated into three sections:

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

4.1 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 C for the assumed load values for each forecast.

[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. For example, the Hororata-Kimberley-Islington lines.*

4.2 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 bus voltage falls below 0.9 pu for 220 kV/110 kV buses, or below 0.95 pu for 66 kV buses, unless a wide voltage agreement exists at the bus.

Table 1 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, Albury 33 kV (ABY-TF-T2).

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 1, are compared with the single GXP forecast load, shown in Appendix C. 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 (for example, Albury), 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 continuous rating of the transformer is also considered as a worst-case scenario.

There are several instances in the upper South Island region where the supply transformers are not Transpower assets. In these cases, load at the GXP has been increased until a contingent event on a connected spur line will cause either the remaining line to overload or bus voltages to fall below the accepted voltage range. In many instances, this limit is much higher than the connected party's transformer capacity. However, this approach means results are still valid if the connected parties upgrade their assets.

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

- Hokitika 66 kV (Summer from 2017 and Winter from 2021).
- Stoke 33 kV (Winter from 2017).
- Stoke 66 kV (Summer and Winter from 2017).

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

Grid Exit Point (Limitation)	N-1 Capacity Limit (MW)			
	Winter		Summer	
	DG OFF	DG ON	DG OFF	DG ON
Albury 33 kV[2] (ABY-TF-T2)	19.8	26.2	19.2	25.1
Ashburton 66 kV (ASB-TF-T8)	238.8	240.3	222.5	223.5
Blenheim 33 kV (BLN-TF-T1)	116.9	118.5	112.4	113.2
Bromley 66 kV (BRY-TF-T6)	250.8	251.6	215.9	216.0
Dobson 33 kV (DOB-TF-T1)	15.8	18.5	16.0	17.8
Hokitika 66 kV^ (HKK-OTI-2)	N/A[3]	N/A	21.4 (2017)	31.5
Hokitika 66 kV^ (Hokitika 66 kV Voltage)[4]	23.5 (2021)	32.4	N/A[5]	N/A
Hororata 33 kV[6] (HOR-TF-T5)	20.6 (2021)	20.6 (2021)	19.3 (2017)	19.3 (2017)
Hororata 66 kV[7]	N/A	N/A	N/A	N/A
Islington 33 kV (ISL-TF-T1)	101.5	101.8	99.6	99.7
Islington 66 kV[8] (ISL-TF-T3)	N/A	N/A	N/A	N/A
Kaiapoi 11 kV[9] (KAI-TF-T1)	34.3 (2020)	34.3 (2020)	33.6	33.6
Kumara 66 kV^ (Kumara 66 kV Voltage)[10]	19.4	29.0	12.6	19.1
Orowaiti 110 kV^ (Orowaiti 110 kV Voltage)	57.1	61.0	46.2	49.6
Stoke 33 kV (STK-TF-T6)	137.2 (2017)	137.3 (2017)	138.6	138.8
Stoke 66 kV (STK-TF-T3)[11]	18.7 (2017)	42.8	18.4 (2017)	39.9

[2] The supply transformer at Albury has been replaced by a new transformer with a 20 MVA continuous rating in late 2017. This mitigates the transformer overloading issues identified in the model in Summer 2017.
[3] Voltage Collapse occurs prior to line overloading.
[4] Hokitika has a wider voltage agreement, where the agreed voltage range is ± 10% (0.9 – 1.1 pu).
[5] Model does not converge due to severe overloading (Hokitika- Otira overloaded to greater than 165%).
[6] The DG at the Hororata 33 kV bus has been modelled as not providing any MW contribution at GXP peak load, and has therefore not been noted as required.
[7] At the Hororata 66 kV bus, Orion takes a supply directly from the 66 kV system. Hororata is not supplied from a spur line, so 66 kV supply issues have been assessed at a regional level only.
[8] Islington 220/66 kV transformers feed a wider area, and have been considered a regional level.
[9] The DG at Kaiapoi has been modelled as not providing any MW contribution at GXP peak load, and has therefore not been noted as required.
[10] Kumara has a wider voltage agreement, where the agreed voltage range is ± 10% (0.9 – 1.1 pu).
[11] The transformer continuous rating has been used, as this is the most restriciting condition on GXP supply.

Grid Exit Point (Limitation)	N-1 Capacity Limit (MW)			
	Winter		Summer	
	DG OFF	DG ON	DG OFF	DG ON
Timaru 11 kV[12] (TIM-TF-T4)	86.1	86.1	80.2	80.3
Waipara 66 kV (WPR-TF-T12)	N/A	N/A	N/A	N/A

**Note that the year in parentheses, following the MW limit, indicates what forecast year the load will exceed the GXP capacity. Some GXPs appear in the table twice, as there are multiple issues to consider, such as spur line capacity and voltage constraints. The issue applicable to the specific row of the table is indicated in parentheses.*
^ Supply transformers are not Transpower assets. Therefore, the effects of DG on the loading of these transformers have not been considered within this study.

[12] *There is a hot standby system installed on the Timaru 110/11 kV transformers, where the tripping of one transformer will cause another to be automatically switched in, if available.*

4.3 Regional Grid Issues

An N-1 contingency analysis was completed on the regional interconnected grid, to determine the influence of distributed generation on any regional transmission issues. The following discussion explains each identified regional transmission issue and provides some explanation on the influence of DG for each one.

For this analysis, the DG at Hokitika and Stoke have been assumed to be in service for the DG OFF scenario, where required, based on the local supply analysis.

To provide a comparison of the impact of DG on regional grid issues, the extent which each DG alleviates the issue has been tabulated. Because the DG is of different sizes, the overall effect can be misleading. It is also instructive to view the generator "effectiveness" on a per MW basis. This is a way of comparing like for like DG contributions. Mostly, this answers the question: how does a 1 MW change in DG output, at each of these GXP's, affect the loading on the circuit?

4.3.1 Kimberly and Hororata Power Quality

From Summer 2018, low voltages are observed at the Hororata and Kimberley 66 kV buses for the loss of either of the Islington – Kimberley – Hororata lines. In addition to this, the remaining Islington – Kimberley – Hororata line may overload, depending on system conditions. The generation output at Coleridge has a significant impact on the voltages at these two sites.

An AUVLS (Automatic Under-Voltage Load Shedding) scheme is installed at Hororata, which manages the post-contingency voltage quality at Hororata and Kimberley, in the short-term. This alleviates the voltage issues at Hororata and Kimberley. The load limit for voltage is lower than for thermal issues on the Islington–Kimberly–Hororata circuits, meaning the undervoltage scheme will also resolve potential thermal capacity constraints.

In the case studied, no voltage violations are observed after load shedding at Hororata, assuming that the DG required to mitigate local supply issues is in service.

4.3.2 Islington Interconnecting Transformer Capacity

By Winter 2021, the Islington interconnecting transformers may overload during an outage of a parallel transformer, if no DG is in service, depending on the load and generation profile in the Canterbury and West Coast Regions. Coleridge generation levels have a significant bearing on the loading of the interconnecting transformers, with the DG at Dobson, Islington, Kumara, and Waipara having smaller and varying degrees of influence on the loading.

Orion has indicated that they will transfer some of the load from Islington to Bromley in 2025, which will alleviate the issue following the transfer.

Islington transformer T6 has a higher rating than the other two interconnecting transformers and is, therefore, the worst case outage. The Winter 2021 case has been used to determine the impact of the DG on the transformer loading, with results summarised in Table 2 below.

Table 2: DG effect on Islington T3 overload

Scenario	ISL-TF-T3 loading for ISL-TF-T6 outage (%)	Effectiveness (MW loading reduction per MW DG)
Winter 2021	100.170	-
Winter 2021 + DOB DG	100.029	0.13
Winter 2021 + HOR 33 DG	100.108	0.41
Winter 2021 + ISL 66 DG	99.761	0.45
Winter 2021 + KUM DG	99.603	0.19
Winter 2021 + WPR 66 DG	100.126	0.10

While some of the changes in the transformer loadings appear small, this is due to the impact of the DG being split between the two remaining interconnectors, and the size of the DG being small when compared with that of the Islington transformers.

4.3.3 West Coast Low Voltages

Low voltages on the 66 kV network on the West Coast are a known issue, and wider voltage agreements are in place at most sites, allowing the operating voltage to fall outside of normal operating limits. In most instances, the 66 kV sites are allowed to operate down to 0.9 pu.

Following an outage of one of several lines in the region, low voltages, and in some instances voltage collapse can occur without DG. Due to the need at a local supply level, Hokitika, Hororata, and Stoke provide enough support to mitigate these issues before Winter 2025. It should be noted that if these generators were not in service, voltage collapse issues would arise earlier.

From Summer 2025, voltage collapse will occur for an outage of the Dobson – Greymouth line, if DG at Kumara is not in service.

4.3.4 Timaru Interconnecting Transformers

The two interconnecting transformers at Timaru are supplied from separate tees into the Ashburton-Timaru-Twizel lines. Removing one of Timaru interconnecting transformers means the area will be supplied from a single line and transformer and will result in load shedding at peak times. The interconnecting transformer capacity is due to be increased in late 2018.

Before the installation of the new transformers, generation at Albury assists with alleviating the overloading issue occurring during the loss of a parallel transformer. The TOPS scheme at Timaru will partially mitigate the overloading, however, will leave the remaining transformer overloaded, as per the table below.

Table 3: Overloading of Timaru Interconnecting Transformers in Summer 2017

Outage	Remaining Tx loading, no Albury DG	Remaining Tx loading, with Albury DG
ASB-TIM-TWZ-1	114.43 %	109.14 %
ASB-TIM-TWZ-2	112.29 %	106.93 %
TIM-TF-T5	107.81 %	105.34 %
TIM-TF-T8	110.01 %	107.50 %

Note that for these studies, it has been assumed that Tekapo A is generating 20 MW.

4.3.5 South Canterbury Voltage Quality and Transmission capacity

The prudent forecast for the South Canterbury contains high load growth, including localised growth which has been included in this study as a possible future substation, located between Studholme and Timaru. As a result of this, low voltages can occur throughout the 110 kV network in the Timaru region, which has the potential to lead to voltage collapse in later years.

Details of how this possible load will be supplied from the grid are yet to be confirmed, however for planning and modelling purposes, the load has been included at a new substation, St Andrews. The load has been modelled as being directly connected to the Studholme bus. The load is forecast to be 5.1 MW in Summer 2019 and 2020, with a further increase to 36.3 MW in 2021. Consequently, additional upgrades in the area will be required, as the existing Timaru – Studholme line will become overloaded. The extent of these upgrades have not been determined, however, will impact the results of the DG studies beyond 2021.

Low voltages are observed at the 110 kV buses during Ashburton – Timaru – Twizel line outages during peak times in the following seasons:

- Temuka from Summer 2019 and Winter 2025,
- Timaru from Summer 2019,

- Studholme from Summer 2019[13].

In all instances listed, low voltage issues are alleviated by the DG at Albury.

If the existing Timaru – Studholme line is assumed as remaining unchanged following the additional load at St Andrews being added, voltage collapse occurs for numerous outages in 2021 and beyond. While it is unrealistic to use this for drawing conclusions, voltage stability is an existing issue in the area and is more likely to occur following the additional load being added. Albury DG will continue to assist with alleviating voltage issues in the area, although the extent of this cannot be accurately determined until more details of future upgrades are known.

[13] *Low voltages do not occur in 2017 due to the Timaru SPS scheme disconnecting the Studholme load. Low voltages do not occur in 2018 due to the Studholme split being closed pre-contengecy, and the Bells Pond – Waitaki SPS operating.*

4.4 Regional Contingency Analysis Discussion

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

Table 4: USI Regional DG required for Winter years

	Winter					
Required DG	**2017**	**2018**	**2019**	**2020**	**2021**	**2025**
Albury						✓
Dobson					✓	✓
Hororata 66					✓	✓
Islington 66					✓	✓
Kumara					✓	✓
Waipara					✓	✓

Table 5:USI Regional DG required for Summer years

	Summer					
Required DG	**2017**	**2018**	**2019**	**2020**	**2021**	**2025**
Albury			✓	✓	✓	✓
Kumara						✓

4.5 Summary of Grid Backbone Assessment

The USI region is a significant load centre, with minimal local generation. The USI region is supplied by four 220 kV lines, which transfer power north, predominantly sourced from the Waitaki Valley, the Clutha region, and via the HVDC from the North Island (when power flow is southwards). The USI region is located to the north of all of these regions, so the generation configuration does not significantly impact the ability to import power into the USI. In other words, different generation patterns will not alter the outcome of this analysis.

Both thermal and voltage stability constraints have been studied, with the impact of DG established in each case.

The assumptions used for studying the ability to transfer power into the USI region are as follows:

- South Island Peak Load (Summer and Winter)
- Typical generation in the Upper South Island
- High generation in the Clutha Upper Waitaki Valley and Lower South Island areas
- Generation and load balance are achieved using the HVDC (Slack machine).

4.5.1 Voltage Stability Limits

This analysis considered the voltage stability of the USI, for a loss of crucial transmission lines, between the LSI and USI. To create a worst-case analysis, a scaling factor of 1.05 was applied to all loads, within the Nelson/Marlborough, West Coast, Christchurch, Canterbury and South Canterbury regions. Load flow convergence was tested for the following outages:

a) ASB-TIM-TWZ-1.
b) ASB-TIM-TWZ-2.
c) ISL-LIV-1.
d) ISL-TKB-1.

For the 'DG ON' case, all DG was assumed to be in service. For the 'DG OFF' case, all DG in the LSI region was assumed on, and the DG identified as being required in the local and regional analysis assumed to be on. Checks were performed for both Summer and Winter cases because the load profile changes significantly between these cases.

No grid backbone voltage stability issues were identified for N-1 conditions in the years studied. It should be noted that USI voltage stability issues are known to Transpower, however, are generally only seen under N-1-1[14] conditions. The TPR states that it is likely USI voltage stability will become an issue to meet N-1 requirements beyond the 15 year period considered in this study.

[14] *Meaning loss of a 220 kV backbone line during an outage of a parallel line.*

5 Conclusions

Mitton ElectroNet has completed an analysis on behalf of Transpower, to determine required DG in the USI. 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:

- Hokitika 66 kV (Summer from 2017 and Winter from 2021).
- Stoke 33 kV (Winter from 2017).
- Stoke 66 kV (Summer and Winter from 2017).

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

- Albury (Summer from 2019 and Winter from 2025)
- Dobson (Winter from 2021)
- Hororata 66 kV (Winter from 2021)
- Islington 66 kV (Winter from 2021)
- Kumara (Summer from 2025 and Winter from 2021)
- Waipara (Winter from 2025)

Study of the grid backbone showed that no voltage stability issues were observed for N-1 conditions in the period considered by this study. Consequently, DG in addition to that identified by the regional and local supply analysis is not required.

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

GIP and GXP List

Appendix A: GIP and GXP List

Substation	GIP	GXP	Switching Station
Albury		✓	
Arthurs Pass		✓	
Argyle	✓		
Ashburton		✓	
Ashley		✓	
Atarau		✓	
Blenheim		✓	
Bromley		✓	
Castle Hill		✓	
Coleridge	✓		
Culverden		✓	
Dobson		✓	
Greymouth		✓	
Hokitika		✓	
Hororata		✓	
Inangahua			✓
Islington		✓	
Kaiapoi		✓	
Kimberley		✓	
Kikiwa		✓	
Kumara	✓		
Murchison		✓	
Orowaiti		✓	
Otira		✓	
Reefton		✓	
St Andrews[15]		✓	
Southbrook		✓	
Stoke		✓	
Timaru		✓	
Tekapo A	✓	✓	
Temuka		✓	
Waimangaroa			✓
Waipara		✓	
Westport		✓	

[15] *Provisional future GXP*

Appendix B

DG Contribution

Appendix B: DG Contribution

Table 6 - 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)
ABY	6.4	5.9	5.8	5.3	5.5	5.6
ASB-66	3.9	1.2	28.5	1.2	29.1	1.5
BLN	1.7	0.8	1.5	1.5	1.5	1.5
BRY-66	0.8	0.1	4.8	0.3	3.1	0.1
DOB	2.9	1.8	2.9	2	3.1	2.4
HKK	11.1	11.5	10.0	11.5	10.5	10.9
HOR-33	0	0	0.4	0	0.4	0
HOR-66	0.1	0	0	0	0	0
ISL-33	0.3	0.1	0.9	0.1	0.8	0
ISL-66	2.0	0.6	2.4	0.6	2.1	0.5
KAI	0	0	0	0.1	0	0.1
KUM	7.9	6.8	7.9	6.8	9.8	7.6
ROB-11	1.75	1.9	1.75	1.9	2.0	2.0
ROB-33	1.75	1.9	1.75	1.9	2.0	2.0
STK-33	0.1	0.2	0.2	0.3	0	0.1
STK-66	34.1	30.0	28.6	28.1	31.5	26.5
TIM	0	0.1	0	0	0	0
WPR-66	1.2	1.8	1.1	1.4	1.1	1.4

Appendix C

Load Forecasts

Appendix C: Load Forecasts

GXP Peak Forecast

	Winter Peak						Summer Peak					
GXP	**2017**	**2018**	**2019**	**2020**	**2021**	**2025**	**2017**	**2018**	**2019**	**2020**	**2021**	**2025**
ABY	5.5	5.6	5.7	5.8	5.9	8.4	4.6	4.7	4.8	4.9	6.0	8.3
APS	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3
ASB-33	8.9	0	0	0	0	0	8.9	0	0	0	0	0
ASB-66	96.9	106.2	106.8	107.3	107.8	110.0	179.4	189.2	190.1	191.0	192.0	195.9
ASY-11-MPAS	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
ASY-11-MPOW	6.1	7.1	7.7	7.7	7.8	8.1	6.1	7.1	7.7	7.7	7.8	8.1
ATU	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
BLN	74.2	75.6	76.9	78.3	79.7	85.3	67.6	68.8	70.1	71.3	72.6	77.7
BRY-66	163.6	164.4	165.2	166.0	166.8	226.1	107.7	108.2	108.8	109.3	109.8	140.1
CLH	0.8	1.1	5.9	5.9	5.9	5.9	0.4	0.4	2.4	2.4	2.4	2.4
COL	0.4	0.4	0.5	0.5	0.5	0.5	0.2	0.3	0.3	0.3	0.3	0.3
CUL-33	11.0	11.0	11.0	11.0	11.0	11.0	24.2	18.3	18.4	18.6	18.7	19.2
CUL-66	4.4	4.6	4.9	5.1	5.4	5.8	4.4	4.6	4.9	5.1	5.4	5.8
DOB	7.1	7.2	7.3	7.3	7.4	7.7	9.2	9.3	9.4	9.5	9.6	10.0
GYM	15.3	15.7	16.1	16.5	16.9	18.5	11.4	11.7	12.0	12.3	12.6	13.8
HKK	21.4	21.9	22.5	23.0	23.6	25.8	21.4	21.9	22.5	23.0	23.6	25.8
HOR-33	19.5	20.3	20.4	20.5	20.6	21.0	19.5	19.5	21.0	20.3	20.6	21.9
HOR-66	25.5	26.4	26.5	26.7	26.8	27.5	25.5	24.0	26.3	26.5	26.6	27.3
ISL-33	83.1	83.9	84.7	85.6	86.4	89.9	69.3	70.0	70.7	71.4	72.1	75.0
ISL-66	463.0	477.6	482.3	493	497.8	461.4	319.0	332.2	335.4	344.7	347.9	333.4
KAI	33.0	33.6	34.1	34.7	35.3	37.6	24.2	24.6	25.0	25.5	25.9	27.6
KBY	15.6	15.8	15.9	16.1	16.3	16.9	16.5	17.4	18.0	18.3	22.7	24.0
KIK	2.7	2.7	2.8	2.8	2.9	3.0	3.5	3.6	3.6	3.7	3.7	3.9
KUM	3.4	3.4	3.5	3.5	3.5	3.7	3.4	3.4	3.5	3.5	3.5	3.7
MCH	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.8	2.8	2.8	2.8
ROB	11.3	12.6	12.8	13.0	13.2	14.0	10.2	11.3	11.5	11.7	11.9	12.7

OTI	0.6	0.7	0.7	0.7	0.7	2.0	0.6	0.7	0.7	0.7	0.7	2.0
RFN	7.9	8.1	8.3	8.5	8.7	9.4	7.6	7.8	7.9	8.1	8.3	9.0
SAW	0	0	0	6.0	6.0	6.0	0	0	6.0	37.0	38.0	40.0
SBK-33	29.7	29.7	29.7	30.7	31.7	34.2	23.3	23.3	23.3	23.8	24.3	26.3
SBK-66	17.8	17.9	18.0	18.1	18.2	18.6	31.9	32.0	32.6	32.7	32.8	33.2
STK-33	138.6	140.4	142.2	144.1	145.9	153.6	106	107.4	108.8	110.2	111.7	117.5
STK-66	27.8	28.4	28.9	29.5	30.1	32.4	27.8	28.4	28.9	29.5	30.1	32.4
TIM	74.8	76.8	77.5	75.2	75.9	76.8	66.4	68.3	68.9	66.5	69.7	70.8
TKA	5.8	6.8	8.5	8.6	8.7	9.1	4.3	5.2	6.9	7.0	7.0	7.3
TMK-33	55.9	58.0	58.5	59.1	59.6	61.9	68.9	71.0	71.6	72.2	72.9	83.4
WPR-33	9.0	9.0	9.0	9.0	9.1	9.5	8.9	8.9	8.9	8.9	9.0	9.2
WPR-66	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
WPT	1.0	0	0	0	0	0	0.9	0	0	0	0	0

Appendix D

Load Power Factor

Appendix D: Load Power Factor

Table 7 - Single GXP Peak Assumed Power Factor

GXP	Summer	Winter
ABY	0.953	0.972
APS	0.999	0.999
ASB-33	0.926	0.984
ASB-66	0.945	0.964
ASY-11-MPAS	0.977	0.882
ASY-11-MPOW	0.887	0.909
ATU	0.978	0.973
BLN	0.971	0.990
BRY-66	-0.991	-0.994
CLH	-0.990	-0.998
COL	-0.986	-0.997
CUL-33	0.955	0.962
CUL-66	0.947	0.994
DOB	0.987	0.973
GYM	0.999	0.999
HKK	0.956	0.956
HOR-33	0.959	0.971
HOR-66	0.951	0.954
ISL-33	0.979	0.988
ISL-66	1.000	1.000
KAI	0.995	0.997
KBY	0.970	0.975
KIK	-0.993	-0.995
KUM	0.995	-0.996
MCH	0.975	0.975
ORO	0.992	-0.996
OTI	0.757	0.764
RFN	0.930	0.937
SAW	1.000	1.000
SBK-33	0.960	0.994
SBK-66	0.967	0.982
STK-33	0.997	0.996
STK-66	0.959	0.979
TIM	0.966	0.988
TKA	-1.000	-1.000
TMK-33	0.958	0.963
WPR-33	0.965	0.978
WPR-66	0.937	0.976
WPT	0.958	0.966

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