DISTRIBUTED GENERATION TO MEET GRID RELIABILITY STANDARDS, UPPER SOUTH ISLAND

VERSION 1 25 MAY 2018

Keeping the energy flowing




TRANSPOWER

Transpower New Zealand Limited The National Grid

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Introduction and results

Introduction

This report delivers Transpower's obligation under Part 6 schedule 6.4 clause 6.2A of the Electricity Industry Participation Code.

The obligation is to provide a report to the Authority that identifies which (if any) Distributed Generation (DG) in the upper South Island (USI, a pricing region) is required to meet grid reliability standards (GRS) over a limited period. The period is for 1 April 2017 to 31 March 2020.

The Authority may receive this report and direct Transpower to make changes, as provided by schedule 6.4, 6.2 2B. If the Authority does direct us, we will indicate what it has directed us to change as a revision to this report.

While the power system analysis needed for the analysis is a core competency of Transpower, we did not have capacity available to undertake this work within the statutory timeframe. To bridge this capacity gap, we engaged Mitton ElectroNet (Mitton) to perform the power system analysis using Transpower's models, methodologies and inputs. The results of the analysis are presented in the technical report that accompanies this report.

This report has three sections and four appendices.

- **Section 1** describes our approach to assess which DG (if any) is required to meet grid reliability standards using the N-1 criterion, and how our approach meets our obligation.
- **Section 2** describes the inputs to the power system analysis, accounting for planned investment in the USI.
- **Section 3** is the analysis and conclusions. The technical report (appended) describes the methodology for the analysis.
- **Appendices:** relevant Code references; why we use twenty peaks for analysis; and our reference to a December 2016 document outlining our proposed analytical approach.

Results: DG required to meet GRS

We have reviewed the technical analysis, and the information produced from it, as the basis for our assessment of which DG is required to meet the GRS.

Table 1 summarises the findings of the analysis. The table lists the DG required to meet the GRS by

- Grid exit point (GXP)[1]
- the period (summer, winter, year)
- level: local, regional or grid backbone, under certain system conditions, or through other knowledge such as the Transmission Planning Report (TPR) (see Section 2).

Table 1 GXPs with DG required to meet GRS

GXP	Period (summer, winter, year)	Stage (Local, Regional, Grid Backbone system condition)
Albury	Summer, 2017 and from 2019	Regional
Hokitika	Summer, from 2017	Local
Stoke 33 kV	Winter, from 2017	Local
Stoke 66 kV	Winter and Summer, from 2017	Local

For the USI analysis, we considered thirty-eight GXPs. Of those locations, seventeen included DG. Table 1 identifies the four locations with DG that is required to meet the GRS.

The availability of DG at these GXPs:

- allows the grid to meet the GRS or
- creates positive impacts on the transmission investment required for the grid to meet the GRS.[2]

The technical report includes a commentary (on page 4) about the broader benefits of DG. We agree DG provides benefits that are not assessed as part of this report, for example to mitigate the impact on consumers of grid outages when assets are unavailable due to maintenance or enhancement works.

[1] As discussed with Authority staff, where there are multiple DG at a GXP, we do not identify any DG separately but treat it as a group.
[2] DG defers the investment need date, or allows for a lower capacity investment option.

1 Analytical approach

To meet the Code obligation on Transpower we had to establish a framework for analysing which, if any, DG is required for Transpower to meet the GRS.

1.1 The Grid Reliability Report is the basis for analysis

Our approach has been to adapt the analytical models and processes we use to prepare the Grid Reliability Report (which is part of the TPR). We have had to alter some processes and obtain new information to assess the contribution of DG to grid reliability but have also utilised existing information and parameters.

We acknowledge the Authority's input as we formulated this approach[3] for Transpower to complete the analysis and prepare this report.

The Grid Reliability report and the Transmission Planning report

Transpower produces the Grid Reliability Report (the GRR) under Code 12.76 every two years. The GRR analyses the grid (connection and interconnection assets, including HVDC) against the *N-1 criterion* over a 10-year period into the future.

To make the GRR more accessible and meaningful for stakeholders we add narrative and graphical context (to the core information contained in the GRR) and call this broader report the TPR. The current TPR was produced in July 2017[4], with the next TPR required to be published by mid-2019.

The N-1 criterion

The *N-1 criterion* is defined in Part 1 of the Code. In summary, the grid meets the N-1 criterion if it is in a state where, even if there is a *single credible contingency event* on the grid, none of the following will occur:

- insufficient supply to satisfy demand at any GXP
- unacceptable loading of transmission equipment
- unacceptable voltage conditions
- system instability.

The term *single credible contingency event* is also defined in Part 1 of the Code and means a failure of a single component of the grid, such as a transmission circuit. The "minus 1" in N-1 refers to the single component failure test. [5]

[3] And described in Appendix 4. This document was prepared by Transpower in consultation with Authority staff.
[4] https://www.transpower.co.nz/resources/transmission-planning-report-july-2017
[5] N-1 is the only specific reliability level recognised in the Code. Higher levels of reliability (N-X where X>1) may be economically justifiable at places in the grid, but it is not a requirement of the Code that any higher level of reliability be achieved.

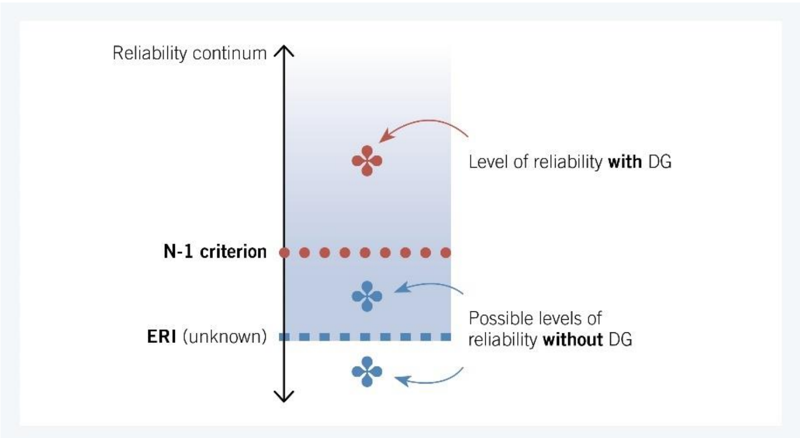
Under the Code and Transpower's transmission agreements with its customers, if the GRR identifies an investment in the grid that is required to meet the N-1 criterion then Transpower must investigate whether to propose the investment. Whether the investment is proposed and ultimately carried out will (in most cases) depend on whether achieving the N-1 criterion through the investment is economically justifiable (i.e. has a positive net benefit). If the investment is economically justifiable then it is referred to as an economic reliability investment (ERI). ERIs are referred to in the first limb of the GRS.[6]

1.2 Approach to assessing whether DG is required

The power system analysis for this report examines the effect removing DG would have on grid offtake demand, and whether the changed grid offtake would result in a breach of the N-1 criterion. If removal of the DG results in a breach of the N-1 criterion, we conclude that all DG behind the relevant grid exit point is required to meet the GRS (as investment in the grid may be required if the DG was not present).

We have not investigated whether the notional grid investment the DG avoids is an ERI (i.e. what the economic level of reliability is).[7] The economic level of reliability is referred to as the "ERI level", and is the minimum level of reliability required to satisfy the GRS. The level of reliability without the DG may be above or below the ERI level, as shown in Figure 1 below (blue markers). The existing level of reliability with the DG (red marker) is *above* the N-1 criterion level. The absence of the DG makes the level of reliability fall.

Figure 1 N-1 is above the ERI



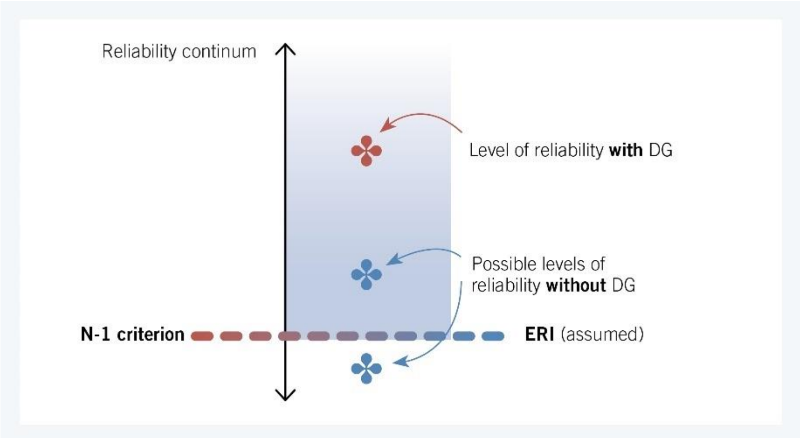
If reliability falls below the ERI level, then the grid does not satisfy the GRS and investment would be needed to bring the reliability of the grid up to or above the ERI level. If the reliability level reduces but is still above the ERI level, then the grid will satisfy the GRS even without the DG. However, we do not know where the ERI level is to make the distinction between these two scenarios.

[6] Schedule 12.2 of the Code. The second limb of the GRS relates to investments that are needed to satisfy the N-1 criterion following a single credible contingency event on the "core grid". Such investments are not required to be Economic Reliability Investments (i.e. they may have a negative net benefit).

[7] The investigation to establish the ERI is a separate and considerably more involved analytical task than the GRR level analysis.

For the analysis in this report we have made the pragmatic assumption that the ERI level is at the N-1 criterion level (as shown in Figure 2 below).

Figure 2 N-1 is assumed to be the ERI



If the removal of the DG does not result in the N-1 criterion being breached at the GXP level, we do not conclude the DG is not needed to meet the GRS. Instead we move deeper into the grid to understand whether the removal of the DG operation from one or more GXPs in combination creates any issues on interconnection assets.

In going deeper into the grid, the challenge for the analysis is how to combine DG operation from several GXPs, each with a different capacity/output, across the region. We outline our approach to this issue in chapter 2.

2 Overview of analysis

As described earlier in this report, Transpower engaged Mitton to perform the power system analysis using Transpower's models, methodologies and inputs.

2.1 Key inputs

Load forecasts

We prepared prudent[8] load forecasts with and without DG operation, for the GXPs in the USI pricing region[9]. We used time-series data, obtained from the Reconciliation Manager, for DG operation and created a process to import and align the large data set with our propriety load data, for all points of supply. We used both a top down and bottom up forecasting process to produce gross (without DG) and net (with DG) prudent demand forecasts at regional and island level. [10]

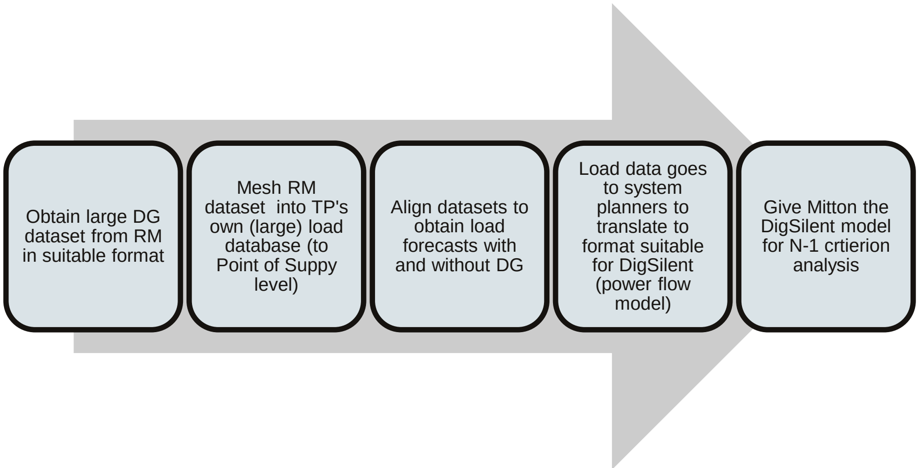
The load forecasts (net and gross) were used to update our DigSilent PowerFactory model[11] from the 2017 TPR to create power flow cases. The power flow cases were used for the technical analysis and contained the following parameters:

- load data for six discrete years, i.e. 2017, 2018, 2019, 2020, 2021, 2025 to create a dataset that shows the impact of DG at the boundaries of, and within, the analysis period
- 2021 captures end effects of the period of interest and 2025 identifies if there are expected changes in results shortly after the period of interest concludes
- in our TPR process we consider some wind generation is large enough to model explicitly and we assume 20% output at peak. For the USI all wind generation is identified as DG, in which case we use the same approach for dispatch as other fuel sources
- the power factor for the DG is assumed to be 1, and would be sensitivity tested in cases where adding DG does not resolve a voltage issue, to understand any impact of this assumption. For load, the power factors were part of the forecast load.[12]

Figure 3 provides an overview of the process we followed in preparing inputs to apply in power system modelling.

[8] As per our TPR approach. A prudent peak forecast represents a 10% probability that the load will be exceeded, or conversely, a 90% chance of being under the load that is forecast (also called a 'P90' forecast) for the first 7 years of the forecast and then is assumed to grow at the expected growth rate.
[9] The GXPs for the USI is a subset of data created for **all** GXPs.
[10] For more information on Transpower load forecast approach, refer https://www.transpower.co.nz/about-us/our-purpose-values-and-people/planning-inputs
[11] Transpower's grid planning software.
[12] Provided in the technical report.

Figure 3 Data preparation process



GXP contribution deeper into the grid (regional level)

To assess the impact on reliability at a regional level, we did not test all possible combinations of GXPs as this would materially increase the scale of work and time required to complete the analysis.

We identified those GXPs with DG that individually had a positive impact on reducing a transmission N-1 overload by at least 0.1% per MW of total injection (see following subsection 'Effectiveness Hurdle' for explanation). We conclude all DG at those GXPs is needed to meet the GRS for the region.

The table below (next page) illustrates the regional assessment approach. With no DG (DG all OFF) the circuit overloads. All DG at each GXP is switched ON and OFF individually, in turn, to establish the effect on circuit loading. All DG that reduces loading by at least 0.1% per MW injection is counted as required for not breaching the N-1 criterion.

Table 2 Illustration of treatment of DG for regional analysis

GXP (DG ON or OFF)	Circuit loading	Reduction in circuit loading per MW injected (%)	Effect
DG all OFF	105.9%		Circuit overload
DG ON GXP A only (32 MW)	95.2%	0.3%	Reduces loading
DG ON GXP B only (5.6 MW)	101.0%	0.8%	Reduces loading
DG ON GXP C only (0.1 MW)	105.8%	1.0%	Reduces loading
DG all ON (at A and B and C)	90.0%		Conclude all DG at all GXPs is needed

Effectiveness Hurdle

The approach taken in the USI follows the same methodology as the previous LSI analysis[13] with one exception: we introduced an 'effectiveness' hurdle for the lower North Island (LNI) analysis, which is also applied to the USI analysis. For DG at a GXP to be considered required the DG must improve any transmission issue by at least 0.1%/MW injected.

The hurdle is needed because interactions between regional and grid backbone power flows can show DG improving transmission issues by percentages within the margin of modelling accuracy. The hurdle ensures that only DG directly linked to a regional transmission issue is assessed as required to manage that issue.

Seasonality

For the regional analysis, we assumed any seasonal variation identified at the local level. For example, if DG is needed for winter 2019 and summer 2021 in the local analysis, the regional analysis assumes DG OFF for summer 2019. However, if the DG OFF assumption results in a regional N-1 security issue arising in summer 2019 then further analysis is undertaken with the DG ON for the period (summer 2019).

2.2 DG contribution over top twenty trading periods

We used historical DG contributions at the time of the top 20 gross demand periods for summer and winter, at GXP regional and island levels to estimate future DG contribution. In appendix A2 we describe the rationale for choosing top 20 periods to establish DG contribution.

[13] Our LSI report is available at the Authority's site.

For the DG contribution analysis, the grid connected generation at Kumara 66 kV was treated as a distributed generator.

2.3 Relevant operating conditions for staged analysis

For the GRS assessment, the "power system must be assessed using the range of relevant operating conditions that could reasonably be expected to occur"[14]. We outline below the relevant operating conditions for each of the three stages of its power system analysis.

Stage 1: Local supply analysis

The study aim is to identify *N-1 criterion* issues at a single GXP:

- supply (connection asset) transformer overloads
- spur circuit (thermal) overloads and
- local voltage issues.

We consider DG as the only generation that can have a substantial impact on whether issues arise, and carry out the studies with the DG (as a group), operating either all ON or all OFF behind a GXP as the two relevant operating conditions.

Stage 2: Regional analysis

The study aim is to identify *N-1 criterion* issues as with stage 1 above, where these impact more than one grid exit point including:

- interconnecting transformer overloads
- regional circuit (thermal) overloads and
- wider area voltage issues.

The study uses Transpower's prudent regional forecast peak load and a standard dispatch[15] as the relevant operating condition. Results are then sensitivity-tested to indicate if we are relying on the availability of a specific generator.[16]

[14] Schedule 12.2 Grid Reliability Standards, clause 2 (4). Refer appendix A1.
[15] 'Standard dispatch' is a part of our DigSilent Powerfactory Master Case for each island. The dispatch includes all existing generation and is relatively high because of using a prudent regional peak forecast.
[16] We will report in the TPR if we require a minimum or maximum (e.g. level of generation at a location), but it does not follow that we would invest to remove these limits.

Stage 3: Grid backbone analysis

The study aim is to identify *N-1 criterion* issues caused by a grid backbone[17] contingency including:

- 220 kV and regional circuit overloads, and
- voltage stability limits.

The studies use a prudent forecast peak load at an island level.[18] We use several realistically challenging system conditions to assess the capability of the South Island grid. The challenging system conditions provide snapshots to identify transmission constraints that may limit the bulk power transfer between regions of the South Island following an outage.[19] The LSI analysis tested the impact of DG availability on the transmission constraints seen in the grid backbone.

One (of four[20]) system conditions identified as 'realistically challenging' in the South Island Grid Backbone section of the Transmission Planning Report is used:

- Low USI generation

[17] Grid backbone - main North and South Island transmission corridors, and the HVDC link. Refer Transmission Planning Report 2017 https://www.transpower.co.nz/resources/transmission-planning-report-july-2017.
[18] Takes into account the difference in timing between regional peaks.
[19] See TPR 2017, page 40
[20] The other three system conditions are High LSI generation, Low generation south of Clyde (summer) and light load conditions.

3 Overview of findings

As per our TPR approach, the technical report presents results as the possible investment need in grid assets, and when, that would remedy the N-1 criterion breach. We have used the possible investment need to infer that the DG presence is required to deliver a reliability level that satisfies the GRS.

3.1 Results overview

Table 4 summarises the USI GXPs behind which DG is required to meet the GRS and for what period, plus the level in the grid at which the DG is required.

Table 3 GXPs where DG is required to meet GRS

GXP	Period (summer, winter, year)	Stage (local, regional, grid backbone)
Albury	Summer, 2017 and from 2019	Regional
Hokitika	Summer, from 2017	Local
Stoke 33 kV	Winter, from 2017	Local
Stoke 66 kV	Winter and Summer, from 2017	Local

The following section expands on the summary table.

3.2 Results: stages

Local supply (GXP level)

The results presented are from the supply transformer and spur asset analysis. DG is required at the following GXPs:

- Hokitika: to defer the need for transmission investment required to meet the N-1 criterion, on the 66 kV Hokitika-Otira circuit in summer 2017-2020.
- Stoke 33 kV: to defer the need for transmission investment required to meet the N-1 criterion, set by 33 kV protection, on the Stoke 220/33 kV supply transformers in winter 2017-2020.
- Stoke 66 kV: to defer the need for transmission investment required to meet the N-1 criterion, on the Stoke 110/66 kV supply transformer in the period 2017-2020.

The availability of DG at these locations means that Transpower can delay (or has already delayed) potential grid investment to maintain N-1 security.

Regional level

The regional grid analysis identified N-1 security issues in three locations:

- the voltage quality around Kimberley and Hororata which is limited by the Hororata 66 kV bus voltage
- the Christchurch 220/66 kV interconnecting transformer capacity, which is limited by the Islington T3 220/110 kV interconnecting transformer
- the West Coast low voltage which is limited by voltage stability for a Dobson–Greymouth circuit outage
- the Timaru area interconnecting transformer capacity and voltage quality.

Kimberley and Hororata voltage quality

The N-1 issue supplying Hororata and Kimberley loads occurs due to the Hororata 66 kV bus voltage. The low voltage at Hororata is managed by the Hororata Automatic Undervoltage Load Shedding scheme. There are no issues within the forecast period that are not managed by the scheme with or without DG.

This issue does not arise in the forecast period, so no DG was identified as having value in reducing the N-1 issue on Hororata 66 kV voltage in the period until 2020.

Christchurch interconnecting transformer capacity

The N-1 issue supplying 66 kV network in the Christchurch area occurs due to the loading on the Islington interconnecting transformers for a 220/110 kV Islington T6 outage. The loading issues does not occur until winter-2021.

This issue does not arise in the forecast period, so no DG was identified as having value in reducing the N-1 issue on Islington interconnecting transformers in the period until 2020.

West Coast Low Voltage

The N-1 issue supplying 66 kV network in the West Coast region occurs due to low voltage and voltage instability for a Dobson–Greymouth outage. The West Coast voltages issues do not occur until summer 2025.

This issue does not arise in the forecast period, so no DG was identified as having value in reducing the N-1 issue on West Coast low voltage in the period until 2020.

Timaru area interconnecting transformer capacity and voltage quality

The N-1 issues supplying the Timaru area 110 kV network occur due to Timaru interconnecting transformer loading, low voltage and voltage instability for a 220 kV Ashburton–Timaru–Twizel outage. The thermal issue is managed with the Timaru T5/T8 overload protection scheme. The technical report includes the committed project to increase the Timaru interconnecting transformer capacity prior to summer 2018. The overload protection scheme will no longer operate for a 220 kV Ashburton-Timaru-Twizel outage once this upgrade is completed.

The low voltage issue arises in summer from 2019. The regional analysis has concluded that all DG at Albury has some value in reducing the N-1 low voltage issue in the Timaru 110 kV network in summer for the period 2019-2020.

The technical report presents analysis using regional dispatch, which includes 20 MW at Tekapo A. Low voltage and voltage stability issues are worsened if Tekapo A generation is unavailable, in which case there is a possible voltage stability issue introduced in summer 2017. The Timaru T5/T8 overload protection scheme can be used to manage low voltages but cannot be used for voltage stability purposes as the scheme is relatively slow to act. Therefore, all DG at Albury has some value in reducing the N-1 voltage stability issue in the Timaru 110 kV network in summer 2017.

Grid Backbone Level

As stated in Chapter 2, the grid backbone analysis studied one of the four system conditions identified as ‘realistically challenging’ in the South Island Grid Backbone section of the TPR. That system condition is system condition 1 low USI generation. The other three conditions are not impacted by generation in the USI.

System condition 1: Low USI generation

System condition 1 analysis identifed that voltage stability issues caused by low USI generation do not occur in the forecast period for this analysis with or without DG. Therefore, no DG was identified as required to manage grid backbone limitations in the USI.

A.1 Code references

Our analysis and approach is underpinned by the following Code.

Code	Content
Schedule 6.4 6.2 2A (below)	New obligation on Transpower for DG report
Schedule 6.4 6.2 2B	New power for Authority for direction
12.76	Grid Reliability Report
Part 1 'N-1 criterion'	What the N-1 criterion means
Schedule 12.2	The GRS

Schedule 6.4 Distributed Pricing Principles

6.2 2A Transpower to provide reports to Authority in relation to DG

(1) **Transpower** must, by 15 March 2017 (or such later date as the **Authority** may allow), provide a report to the **Authority** that identifies which (if any) **DG** located in the Lower South Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.

(2) **Transpower** must, by 30 August 2017, provide a report to the **Authority** that identifies which (if any) **DG** located in the Lower North Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.

(3) **Transpower** must, by 31 January 2018, provide a report to the **Authority** that identifies which (if any) **DG** located in the Upper North Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.

(4) **Transpower** must, by 31 January 2018, provide a report to the **Authority** that identifies which (if any) **DG** located in the Upper South Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.

(5) In this clause,—

(a) Upper North Island is that part of the North Island situated on, or north and west of, a line—

(i) commencing at 38°02'S and 174°42'E; then

(ii) proceeding in a generally north-easterly direction directly to 37°36'S and 175°27'E; then

(iii) proceeding north along the 175°27'E line of longitude; and

(b) Lower North Island is that part of the North Island not referred to in subclause (a);

and

(c) Upper South Island is that part of the South Island situated on, or north of, a line passing through 43°30'S and 169°30'E, and 44°40'S and 171°12'E; and

(d) Lower South Island is that part of the South Island not referred to in subclause (c).
Clause 2A: inserted, on 9 January 2017, by clause 5 of the Electricity Industry Participation Code Amendment (DG) 2016.

6.2 2B Authority to review Transpower's reports in relation to DG

(1) The **Authority** must, as soon as practicable after receiving a report from **Transpower**

under clause 2A,—

(a) approve the report; or

(b) decline to approve the report.

(2) If the **Authority** declines to approve the report,—

(a) the **Authority** must, as soon as practicable,—

(i) advise **Transpower** of its reasons for declining to approve the report; and

(ii) direct **Transpower** as to how it should amend the report before resubmitting it; and

(b) **Transpower** must amend the report in accordance with the **Authority's** direction, and resubmit the report to the **Authority**,—

(i) for the report provided under clause 2A(1), within 10 **business days**.

A.2 Top Twenty peaks, summer and winter

This appendix outlines how we established the top twenty gross load peaks for DG contribution assessments at regional and (north) island levels, for summer and winter peaks. **Winter** is 10 May – 19 October, and **Summer is** 1 December – 14 March.

Why twenty trading periods (ten hours)

Twenty peaks are fewer than the number of trading periods considered in calculating Regional Coincident Peak Demand (RCPD) for the upper South Island pricing region. Our decision to consider the DG contribution during twenty trading periods with the highest gross load in each season represents a trade-off between:

- providing a good indication of the tendency of the DG to follow load, and
- the volatility from considering too few trading periods.

For example, selecting the single highest gross peak could result in a peak contribution that is unreasonably high or low – for an expected DG forecast – due to random volatility. This is particularly true of technologies where the generation is driven by the immediate climatic conditions - such as solar or wind – rather than strategic decisions of the operator.

Conversely, choosing too many trading periods would smooth out the DG contribution too much and result in an assumption that is very close to assuming average generation at peaks. This would tend to understate the contribution of dispatchable generation such as hydro and thermal plant.

We recognise judgement is involved in determining the number of trading periods to include. We undertook some testing with different numbers of trading periods and consider twenty to be a reasonable trade-off between volatility and the risk of under-estimating the contribution of peak-following DG.

Below, we outline the forecasting steps (modelled on the TPR process) and information in table 4 to show the inputs to the power system analysis. For the local and regional stage analysis, we use the same regional forecast, as per our TPR process.

Regional level gross forecast (used for local and regional analysis stages)

Calculate gross load at each GXP for all trading periods. We add the half-hourly distributed generation actual (2014-2016)[21] data to the metered load at the GXP to obtain the gross load at each GXP for each trading period.

[21] We have increased the historical data set in this calculation since completing our LSI DGPP analysis. We now use 2014 to 2016 data rather than only 2015 data. The data increase ensures a more robust approach (greater diversity of historical DG contribution at time of peak load) to producing a prudent DG forecast for System Planning purposes but had only marginal impact on the expected DG contribution used in this analysis.

Find top 20 gross peaks for the LSI region and the associated DG contribution:

1. sum half-hourly *GXP* gross load to find *region* gross load
2. rank the trading periods from largest *region* gross load to smallest, for summer and winter each year
3. identify the top 20 trading periods per season and year from the regional ranking above
4. find the DG in the 20 trading periods per year, for summer and winter, for the region
5. calculate the average contribution of DG in the above trading periods to estimate the expected DG contribution at time of gross peak *region* load.

Island level (used for grid backbone analysis stage)

Find top 20 gross peaks for each *island* and the associated DG contribution.

1. sum half-hourly *GXP* gross load to find *island* gross load
2. rank the trading periods in each season and year from largest *island* gross load to smallest
3. identify the top 20 trading periods per season and year from the ranking above
4. find the generation in the trading periods above for all DG embedded in the *island*
5. calculate the average contribution of DG in the above trading periods to estimate the expected DG contribution at time of gross peak *island* load.

Example of DG contribution assessment

The following table shows the contribution of the distributed generators embedded at the Hokitika GXP at time of the West Coast region winter peaks from 2014 to 2017.

Table 4 Contribution of all DG at Ongarue GXP to winter peak trading periods (2014-2017)

Date and Trading period	Rank	Hokitika DG (MW)	Hokitika Gross Load (MW)	West Coast Gross Load (MW)
2014-10-06#18	1	11.6	18.5	66.0
2014-09-19#16	2	10.8	17.9	65.9
2014-09-29#17	3	11.7	18.0	65.9
2014-10-06#19	4	11.6	17.7	65.7
2014-09-19#17	5	10.8	17.8	65.5
2014-09-15#36	6	8.8	16.4	65.4
2014-10-06#17	7	11.6	18.6	65.3
2014-09-15#35	8	8.8	16.6	65.3
2014-10-06#20	9	11.6	17.6	65.2
2014-09-03#16	10	4.5	16.1	65.1
2014-09-29#16	11	11.7	17.8	65.0

Date and Trading period	Rank	Hokitika DG (MW)	Hokitika Gross Load (MW)	West Coast Gross Load (MW)
2014-09-29#18	12	11.7	17.5	64.7
2014-10-09#17	13	11.7	18.3	64.6
2014-09-30#18	14	11.1	18.1	64.5
2014-10-06#21	15	11.6	17.5	64.5
2014-09-12#16	16	4.6	17.3	64.5
2014-09-01#16	17	6.8	15.9	64.4
2014-10-03#20	18	11.4	17.1	64.4
2014-09-30#17	19	11.1	18.2	64.3
2014-09-03#17	20	4.6	16.0	64.2
2015-10-07#16	1	6.6	18.0	64.5
2015-09-30#16	2	6.9	18.0	64.2
2015-09-17#16	3	10.7	17.9	64.0
2015-10-07#17	4	8.5	17.9	63.7
2015-09-15#18	5	9.7	16.8	63.7
2015-09-16#16	6	11.4	17.4	63.5
2015-09-17#17	7	10.7	17.5	63.5
2015-09-15#16	8	9.7	15.8	63.5
2015-09-29#17	9	6.5	17.2	63.4
2015-09-07#16	10	4.8	16.2	63.4
2015-09-18#16	11	11.4	17.8	63.3
2015-09-30#17	12	6.9	17.7	63.3
2015-10-05#17	13	10.8	17.9	63.1
2015-10-07#18	14	8.5	17.2	63.0
2015-08-24#35	15	11.3	14.7	63.0
2015-09-16#17	16	11.4	16.8	62.8
2015-09-30#18	17	6.9	17.4	62.8
2015-09-21#17	18	11.2	17.1	62.7
2015-07-20#23	19	11.4	12.8	62.7
2015-10-07#15	20	6.5	17.6	62.7
2016-09-14#16	1	7.8	17.9	56.0
2016-05-20#17	2	12.2	15.7	55.8
2016-10-11#17	3	10.6	19.4	55.8
2016-10-13#16	4	11.8	20.1	55.6
2016-10-13#17	5	11.8	19.5	55.3
2016-10-18#16	6	12.1	19.2	55.2
2016-09-21#17	7	11.1	17.0	55.2
2016-09-12#17	8	10.4	17.3	55.1
2016-05-20#18	9	12.2	15.6	54.8
2016-09-14#17	10	7.8	17.6	54.8
2016-10-19#16	11	12.1	18.9	54.7
2016-10-10#18	12	11.1	18.4	54.6
2016-10-18#17	13	12.1	19.1	54.6

Date and Trading period	Rank	Hokitika DG (MW)	Hokitika Gross Load (MW)	West Coast Gross Load (MW)
2016-10-12#17	14	11.7	17.4	54.5
2016-09-13#16	15	9.2	16.7	54.4
2016-09-07#16	16	12.0	17.2	54.4
2016-10-11#16	17	10.6	18.2	54.4
2016-09-12#18	18	10.3	17.2	54.3
2016-05-20#16	19	12.2	15.0	54.3
2016-05-11#16	20	11.6	15.5	54.2
2017-09-27#16	1	11.8	18.1	55.2
2017-09-12#19	2	9.6	17.7	55.1
2017-09-12#15	3	9.5	18.5	54.8
2017-09-12#16	4	9.6	18.5	54.6
2017-09-18#16	5	11.9	18.5	54.6
2017-09-27#17	6	11.9	18.1	54.5
2017-09-18#17	7	11.9	18.0	54.4
2017-09-18#18	8	12.0	17.9	54.3
2017-09-21#16	9	12.0	18.9	54.1
2017-09-12#18	10	9.7	18.1	54.0
2017-09-19#16	11	11.9	16.7	54.0
2017-09-12#17	12	9.7	18.1	53.9
2017-09-05#34	13	8.9	14.9	53.9
2017-09-20#16	14	11.9	17.3	53.9
2017-09-28#17	15	11.9	18.4	53.7
2017-09-21#17	16	11.9	18.8	53.7
2017-09-07#34	17	10.9	16.6	53.4
2017-09-25#18	18	11.9	19.3	53.3
2017-09-28#16	19	11.9	18.5	53.3
2017-09-18#19	20	11.9	17.3	53.1

The trading periods with zero contribution from DG during the top twenty gross peaks are included in the calculation as they contain important information. A zero figure for the trading period will reduce the expected DG contribution and capture some of the volatility in the data, particularly for technologies that do not necessarily follow load well.

A.3 Draft approach to Authority December 2016

In December 2016, we provided the Authority with a document outlying our proposed approach to the analysis for delivering our obligation under Part 6 6.2 2A.

The document was appended to our first report for the lower South Island, titled *Approach to DG analysis to EA 15Dec2016*[22] available here

Where the information in the December 2016 document is different from the information in this report, the report information prevails.

[22] Sent by email to Authority, 15 December 2016. The document heading is *DG impact assessment approach under Code xx,* (the 'xx' means the location for the new Code provision was not then known).

