DISTRIBUTED GENERATION TO MEET GRID RELIABILITY STANDARDS, LOWER SOUTH ISLAND

VERSION 1 APRIL 21 2017

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 lower South Island (LSI, 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 time frame. We discussed various options for bridging this capacity gap before engaging Mitton ElectroNet (Mitton) to perform the power system analysis using Transpower's models, methodologies and inputs.

We acknowledge and appreciate assistance provided by the Authority's technical staff in formulating the analytical approach for this report and for making those staff available to help with certain aspects of the analysis.

This report has three sections.

- Section 1 describes our approach using the N-1 criterion and how it meets our obligation
- Section 2 describes the inputs to the power system analysis, accounting for planned investment in the lower South Island
- Section 3 is the analysis and conclusions. The Mitton report describes the methodology for the analysis, the report is appended separately.

The report also has four appendices: including relevant Code references, a letter from Authority to Transpower authorising an extension to report delivery date from 15 March 2017 to 21 April 2017, and a document we sent to the Authority in December 2016 outlining our proposed approach to the analysis.

Results: DG required to meet GRS

We have reviewed Mitton's analysis, and the information produced from it, which forms 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, by GXP[1], the period and the level (local, regional or grid backbone, see Chapter 2) where DG is required to meet the GRS

Table 1 GXPs with DG required to meet GRS

GXP	Period	Stage (local, regional, grid backbone)
Balclutha	Summer 2017	Regional
Berwick	Summer 2017	Regional
Cromwell	Winter from 2018 and Summer from 2020	Local
Frankton	Winter, from 2019	Local
Gore	Summer 2017	Regional
Halfway Bush	Winter from 2017 Summer 2017	Local Regional
Naseby	Winter and Summer, from 2017	Local

The availability of DG at these GXPs means that the grid meets the GRS.

We note Mitton's commentary (on page 4) about the broader benefits of DG. We agree DG provides benefits that are not assessed as part of this report and confirm that DG in the LSI region helps to mitigate the impact on consumers of grid outages (removing grid assets for maintenance or enhancement purposes).

[1] As discussed with Authority staff, where there is multiple DG at a GXP, we do not identify any DG separately but treat it as a group.

1 Analytical approach

To meet the new 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 that we use to prepare the Grid Reliability Report (which is part of the Transmission Planning Report). 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[2] , and the granting of an extension (from 15 March to 21 April) 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 Transmission Planning Report (TPR). The current TPR was produced in July 2015[3], with the next TPR to be published in mid-2017.

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. [4]

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

[2] And described in Appendix 4. This document was prepared by Transpower in consultation with Authority staff.
[3] https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/TPR2015CompleteFINAL.pdf
[4] 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.

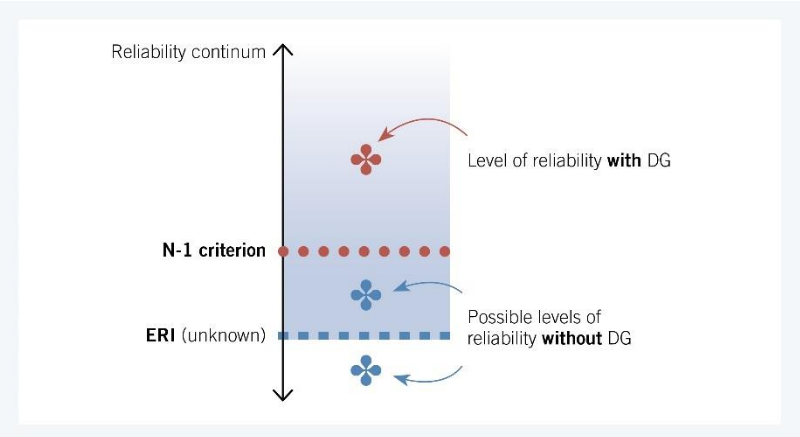
Transpower must investigate whether to propose the investment. Whether the investment is proposed and ultimately carried out will (in most cases) depend on whether achieving the N-1 criterion through the investment is economically justifiable (i.e. has a positive net benefit). If the investment is economically justifiable then it is referred to as an economic reliability investment (ERI). ERIs are referred to in the first limb of the GRS.[5]

1.2 Approach to assessing whether DG is required

The power system analysis for this report examines the effect that 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 that the DG avoids is an ERI (i.e. what the economic level of reliability is).[6] 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

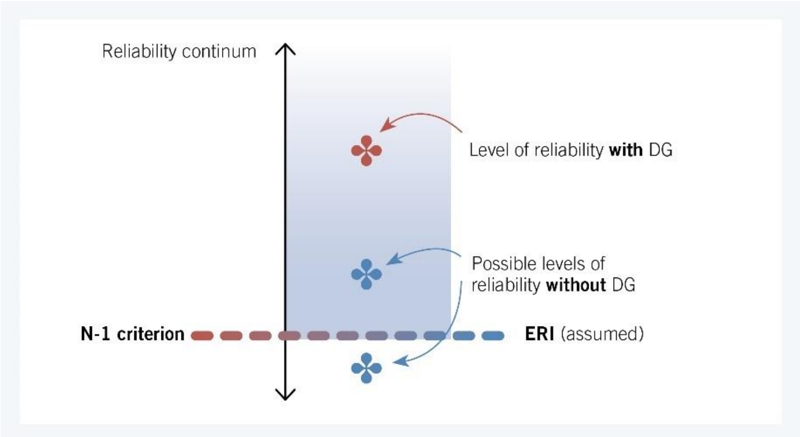
[5] Schedule 12.2 of the Code. The second limb of the GRS relates to investments that are needed to satisfy the N-1 criterion following a single credible contingency event on the "core grid". Such investments are not required to be Economic Reliability Investments (i.e. they may have a negative net benefit).

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

without the DG. However, we do not know where the ERI level is to make the distinction between these two scenarios.

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 that 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[7] load forecasts with and without DG operation, for the GXPs in the Lower South Island pricing region. [8] 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[9].

The load forecasts (net and gross) were used to update our DIgSILENT PowerFactory model[10] from the 2015 TPR to create power flow cases. The power flow cases were given to Mitton. The cases contain the following parameters:

- Load data for four discrete years, i.e. 2017, 2019[11], 2021[12], 2025 to create a dataset that shows the impact of DG at the boundaries of, and within, the analysis period.
    - 2017 and 2019 are either side of significant grid configuration changes at Gore and Halfway Bush, 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 Lower South Island the wind generation is at White Hill and Lake Mahinerangi.
- 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. [13] For load, the power factors were part of the forecast load.[14]

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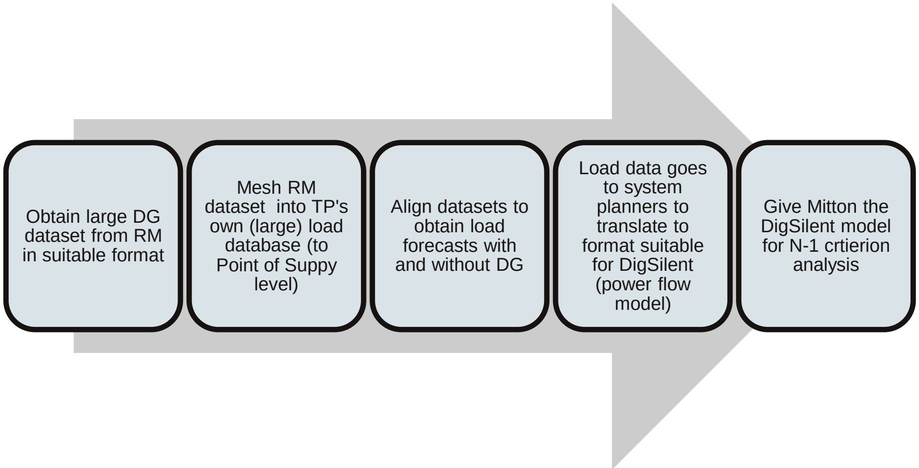
7 As per our TPR approach. A prudent peak forecast represents a 10% probability that the load will be exceeded, or conversely, a 90% chance of being under the load that is forecast (also called a 'P90' forecast) for the first 7 years of the forecast and then is assumed to grow at the expected growth rate.
8 The GXPs for the LSI is a subset of data created for **all** GXPs
9 For more information on Transpower load forecast approach, refer https://www.transpower.co.nz/about-us/our-purpose-values-and-people/planning-inputs
10 Transpower's grid planning software.
11 For the next report, we may specify 2018 as a snapshot year. For any DG identified as needed for the first time in 2019 we checked to see if needed in 2018.
12 For the next report, we may specify 2020 as a snapshot year. For any DG identified as needed for the first time in 2021 we checked to see if needed in 2020.
13 Not an issue for the lower South Island.
14 Provided in Mitton report

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

Figure 3 Data preparation process



GXP contribution deeper into the grid (regional level)

To assess the impact on reliability at a regional level, we instructed Mitton in its analysis of DG from several GXPs. Our instruction to Mitton was to not test all possible GXP combinations of GXPs as this would materially increase the scale of work and time required to complete the analysis.

Instead, we asked Mitton to identify those GXPs with DG that individually had a positive impact on reducing a transmission N-1 overload. We conclude that 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. Each DG is switched ON individually to establish the effect on circuit loading. All DG that reduces loading 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	Effect
DG all OFF	106%	Circuit overload
DG ON GXP A only	95%	Reduces loading
DG ON GXP B only	101%	Reduces loading
DG ON GXP C only	105%	Reduces loading
DG all ON (at A and B and C)	90.0%	Conclude all DG at all GXPs is needed

The approach described may need to evolve following feedback from stakeholders. We note that while it might be possible to test multiple combinations of GXPs in the LSI region it will not necessarily be possible in other regions where interdependencies are greater.

We also instructed Mitton on how to treat N-1 issues identified at local supply level that are seasonal. 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

To consider the DG contribution, we decided to use the top 20 demand periods for summer and winter, at GXP regional and island levels. In appendix A2 we describe the rationale for choosing top 20 periods to establish DG contribution. The approach may need to evolve following feedback from stakeholders.

Notionally embedded generation

For the DG contribution analysis, the grid connected generation at the 110kV at Berwick is treated as distributed generation, because it is classed as notionally embedded at Halfway Bush. Notionally embedded generation is provided for under schedule 12.4 of the Code, under prudent discount (PDA) policy[15] [16].

Our treatment of notionally embedded generation may need to evolve following feedback from stakeholders.

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[15] The summary information on the Berwick (Waipori) PDA is contained here: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Waipori-PDA-Summary.pdf.

[16] Mitton report (in tables 3 – 5) denotes Berwick 110kV as Halfway Bush 110kV.

2.3 Relevant operating conditions for staged analysis

For the grid reliability standards assessment, the "power system must be assessed using the ranged of relevant operating conditions that could reasonably be expected to occur"[17]. We outline below the relevant operating conditions provided to Mitton 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 grid exit point (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[18] as the relevant operating condition. Results are then sensitivity-tested to indicate if we are relying on the availability of a specific generator. [19]

Stage 3: Grid backbone analysis

The study aim is to identify *N-1 criterion* issues caused by a grid backbone[20] contingency including:

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

[17] Schedule 12.2 Grid Reliability Standards, clause 2 (4). Refer appendix A1.
[18] '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 we are looking at a prudent regional peak forecast load.
[19] 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.
[20] Grid backbone - main North and South Island transmission corridors, and the HVDC link. Refer Transmission Planning Report 2015 https://www.transpower.co.nz/resources/transmission-planning-report-2015#downloads

The studies use a prudent forecast peak load at an island level. [21] We use a small number of realistically challenging system conditions to assess the capability of the existing South Island grid. The challenging system conditions provide snapshots to identify transmission constraints that may require minimum or maximum generation limits to avoid overloading the power system following an outage[22]. For the DG analysis, these grid-connected generation limits were used to prevent the two limiting issues from arising from both with and without DG.

[21] Takes into account the difference in timing between regional peaks
[22] See TPR 2015 page 64

3 Overview of findings

As per our TPR approach, Mitton describes its 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 LSI 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	Stage (local, regional, backbone)
Balclutha	Summer 2017	Regional
Berwick	Summer 2017	Regional
Cromwell	Winter from 2018 and Summer from 2020	Local
Frankton	Winter, from 2019	Local
Gore	Summer 2017	Regional
Halfway Bush	Winter from 2017 Summer 2017	Local Regional
Naseby	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:

- Cromwell: to meet the N-1 criterion, set by the 33 kV protection and circuit breaker thermal rating, on the Cromwell 220/33 kV supply transformers in the period 2018-2020[23] in winter. The DG is required in 2020[24] to meet the N-1 criterion in summer
- Frankton: to meet the N-1 criterion on the 110 kV Cromwell-Frankton circuits in the period 2019-2020[25] in winter
- Halfway Bush: to meet the N-1 criterion on the existing Halfway Bush 220/33 kV supply transformers in the winter 2017 and to meet the N-1 criterion on the replacement Halfway Bush 220/33 kV supply transformers in the period winter 2018-2020
- Naseby: to meet the N-1 criterion on the Naseby 220/33 kV supply transformers in the period 2017-2020

The availability of DG at these locations means that Transpower can delay potential grid investment to maintain N-1 security.

Regional level

The regional grid analysis identified N-1 security issues in two regions; the Lower Waitaki Valley and the 110 kV grid in Southland.

The N-1 issues arising in the Lower Waitaki Valley occur on both Oamaru—Waitaki circuits and the Waitaki interconnecting transformers. There is no existing DG in the region to impact the need to resolve these security issues. However, resolving the security issues identified could include the connection of new DG.

The N-1 issue arising in Southland 110 kV network is overloading of the Edendale—Invercargill circuit when the Gore—Roxburgh circuit is out of service in summer 2017. With Gore—Roxburgh out of service more power flows northwards from Invercargill on the 110 kV circuits to supply loads in the 110 kV network[26]. With DG ON at Balclutha, Berwick, Gore and/or Halfway Bush the amount of power flowing from Invercargill towards Edendale reduces, reducing the overload and the N-1 security issue.

This issue arises only during summer 2017 due to the grid development at Gore in 2018, connecting Gore to the 220 kV network. Once this redevelopment is complete the Southland 110 kV network will be split at Gore, a Gore—Roxburgh circuit outage will no longer impact the power flows on the 110 kV circuit between Edendale and Invercargill.

The regional analysis has concluded that all DG in the area between Edendale and Dunedin has some value in reducing the N-1 issue on Edendale—Invercargill circuit in summer 2017.

[23] Table 6 in the Mitton report states that DG is required in winter from 2019 for Cromwell. We have checked any DG considered as ‘required’ in 2019 to see if it was first ‘required’ in 2018. For the Cromwell supply transformers, the supply transformer N-1 limit is exceeded in 2018 based on the winter load forecast

[24] Table 6 in the Mitton report states that DG is required in summer from 2021 for Cromwell. We have checked any DG considered as ‘required’ in 2021 to see if it was first ‘required’ in 2020. For the Cromwell supply transformers, the supply transformer N-1 limit is exceeded in 2020 based on the summer load forecast

[25] Table 6 in the Mitton report states that DG is required in winter from 2019 for the Cromwell—Frankton circuits. We have checked the N-1 limit against the load forecast and find the DG is required from 2019.

[26] The base case generation dispatch assumes a high dispatch at Manapouri, this N-1 issue could also be removed by lowering the dispatch at Manapouri. However, the reduction in generation at Manapouri would have to be substantially larger than the DG injection to obtain the same level of overload reduction.

Therefore, distributed generation is required, to meet the N-1 criterion on the Edendale-Invercargill circuit for a 110 kV Gore—Roxburgh circuit outage in summer 2017, at:

- Balclutha
- Berwick
- Gore, and
- Halfway Bush.

Grid Backbone Level

The grid backbone analysis studied the ability to import and export power to and from the lower South Island region. Whether the region is importing or exporting power is dependent on the load and generation profile. High regional generation results in power export northwards towards Twizel and Benmore. Low generation, usually driven by low hydro inflows, results in importing power to the lower South Island region from the upper Waitaki Valley Region and south transfer on the HVDC link.

For north transfer, the Livingstone—Naseby—Roxburgh transmission circuit is the constraint on power export out of the region. The studies show that with DG on the north transfer limit may be more likely to bind. This is because more of the lower South Island load is supplied by the DG, releasing the generation from the grid connected hydro stations of Clyde, Roxburgh and Manapouri to be transferred north towards Twizel. However, this was only observed in summer periods and the difference between the DG on and DG off scenarios is small.

The constraint on south transfer of power into the lower South Island is voltage stability within the region. This was tested, through power flow modelling, by progressively lowering Manapouri generation output until voltage collapse occurred. The DG on scenario allowed the Manapouri generation output to be reduced further, compared with the DG off scenario, before voltage collapse was observed. The DG is supplying regional load, allowing for a reduction in the minimum Manapouri generation required to maintain system stability. However, the studies show that the observed benefit in voltage stability from DG is small and regional, that is, it is difficult to identify the exact impact of individual DG's.

The grid backbone analysis shows there is some benefit to having DG available for south transfer and that having DG available for north transfer makes the transmission constraint more likely to bind in summer. In both cases the differences were minimal and are not significant to influence grid investment, for N-1 security, or to relieve generation dispatch constraints.

The grid backbone analysis is complex, with DG impact depending on whether the lower South Island region is importing or exporting power. DG can impact transmission security in both positive and negative ways and cannot be considered required for grid backbone N-1 security in the LSI. However, DG does impact power flows on the grid backbone so cannot be ignored in detailed grid investment analysis.

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 (south) 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 lower 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 that judgement is involved in determining the number of trading periods to include. We 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 Mitton's 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 (2015) data to the metered load at the GXP to obtain the gross load at each GXP for each trading period

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
3. identify the top 20 trading periods from the regional ranking above
4. find the DG in the 20 trading periods, 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 from largest *island* gross load to smallest
3. identify the top 20 trading periods 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 Naseby GXP at time of the Otago/Southland region peaks.

Table 4 Contribution of all DG at Naseby GXP

Date #Trading Period	Rank	DG MW	Naseby GXP gross MW	Region gross MW
2015-08-05 #17	1	13.5	24.4	1,092.0
2015-09-07 #16	2	13.5	28.7	1,090.2
2015-07-13 #36	3	13.2	28.7	1,088.6
2015-05-25 #35	4	10.9	27.1	1,088.3
2015-05-25 #36	5	12.1	27.1	1,085.5
2015-09-01 #38	6	13.5	28.5	1,085.5
2015-09-01 #39	7	13.4	28.4	1,084.0
2015-07-13 #37	8	13.1	28.7	1,083.4
2015-07-06 #37	9	13.5	28.4	1,083.3
2015-06-15 #36	10	13.5	28.7	1,082.7
2015-08-17 #17	11	13.5	28.6	1,082.4
2015-09-01 #36	12	13.4	28.7	1,082.0
2015-08-05 #16	13	13.5	24.2	1,081.7
2015-07-06 #36	14	13.4	28.0	1,081.7
2015-06-23 #16	15	13.5	26.5	1,081.3
2015-07-13 #38	16	13.1	28.9	1,081.0
2015-07-20 #37	17	13.1	28.7	1,080.9
2015-06-17 #17	18	13.2	28.4	1,079.7
2015-09-11 #17	19	10.7	26.4	1,079.5
2015-08-17 #18	20	13.5	28.7	1,078.9

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 Authority grants delivery date extension

ELECTRICITY AUTHORITY
TE MANA HIKO

15 March 2017

Alison Andrew
Chief Executive
Transpower
PO Box 1021
WELLINGTON

Dear Alison

Due date for Lower South Island report under Part 6 Schedule 6.4 (2A) of the Code

Thank you for your letter dated 16 February 2017. In that letter you requested an extension of time until 21 April 2017 to provide a report to the Authority that identifies which distributed generation 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.

The Authority has decided to grant the extension you have requested for the lower South Island report. However, the Authority expects that the three further reports (regarding distributed generation in the Lower North Island, Upper North Island and the Upper South Island) will be provided on time.

I note your advice that you will continue to treat this with priority and that you will provide your Lower South Island report sooner than 21 April if you are able to complete the work early. That would be appreciated. Further, I would encourage you to continue to work with Authority staff, particularly by sharing preliminary results of your analysis as it becomes available and sharing a draft of your report prior to submitting the final version. This will help the Authority to understand the material, the underlying assumptions and the methodology and help to avoid potentially time-consuming interaction after the report is provided.

In your letter you said that your report would clearly set out the analytical methodology and assumptions and will be prepared with a view to its publication (it will use accessible language and terminology). This approach would meet the Authority's expectations.

Thank you for your team's efforts on this matter. We want to continue the positive interaction between our teams that has occurred to date.

Yours sincerely

Carl Hansen

Carl Hansen
Chief Executive

CC: Jeremy Cain

A.4 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 is appended, titled *Approach to DG analysis to EA 15Dec2016*. [27]

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

[27] 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).

