TEMPORARY GRID RECONFIGURATIONS

NET BENEFIT TEST METHODOLOGY

Keeping the energy flowing
1. Summary

When one part of the grid is facing security of supply risk—where local generation in one region of the grid is not enough for the regional load and there exist constraints on power transfer into that region—the System Operator can request the Grid Owner to implement temporary grid reconfigurations (TGRs) to increase the transfer capacity into that region. While TGRs can enable increased power transfers on the grid they will also change system losses and reliability experienced by grid exit points in the affected region. Before implementing a TGR, Transpower must demonstrate the TGR produces a positive benefit.

This document describes the way in which the Grid Owner applies the net benefit test to the options for implementing temporary grid reconfigurations. It also details the summary of the net benefit test which Transpower publishes on its website.

Grid reconfiguration net benefit refers to the difference between benefits produced by a TGR (e.g. reduction in expected unserved energy required for a normal configuration) and the associated risks and costs (e.g. reduced security and increased system losses after grid reconfiguration). If the net benefit is positive then reconfiguration is recommended.

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1 Electricity Industry Participation Code clause 9.13B: Request for urgent temporary grid reconfiguration
2 Electricity Industry Participation Code clause 12.116AA: Temporary removal of interconnection assets from service or temporary grid reconfiguration
2. Purpose of document
This document presents how the Grid Owner carries out the net benefit test for temporary grid reconfigurations following request from the System Operator\(^3\). The document explains the process triggers, inputs, assumptions and the process of calculating the net benefit.

3. Background
The process is initiated by triggers that the System Operator (SO) considers as having an impact on security of supply. The SO then requests the Grid Owner to assess the benefits of temporary grid reconfiguration.

In extreme cases of security of supply risk, when water storage in the South Island or New Zealand hydro storage lakes respectively shows a risk of shortage of 10% or more and the system operator forecasts that such risk will last for a week or more, Electricity Industry Participation Code (the Code) requires\(^4\) the SO to commence an official conservation campaign.

3.1 Grid reconfiguration
Reconfiguring the grid can increase electricity transfer into a given region, but with reduced security. Clause 12.117 (2) of the Code allows Transpower to temporarily reconfigure the grid to improve security of supply if such a change has net market benefit.

The aim of the temporary grid reconfiguration is to increase transfer capacity into a region for a period when there is an identified supply shortage risk.

Net benefit test
The Code\(^5\) specifies that Transpower must temporarily remove one or more interconnection assets from service, or temporarily reconfigure the grid if the SO requests\(^2\) and the removal or reconfiguration will result in a net benefit. Reconfiguring the grid relieves network constraints, but it can also result in:

- reduced reliability of supply to some customers
- increased power losses in the grid
- dispatch constraints for some generation
- constraints on outages

A positive net benefit is realised when the calculated benefits outweigh the costs. When Transpower is required to apply a net benefit test, the Code specifies components of costs and benefits that Transpower must estimate (see Appendix 1 for a detailed list of the costs and benefits). The net benefit test process has three parts:

- estimating change in generator fuel costs and expected unserved energy:

\(^3\) The Code clause 9.13B
\(^4\) The Code clause 9.23
\(^5\) The Code clause 12.116AA (1)
The Code requires Transpower to use an independent service provider to provide an estimate of the fuel costs. Expected unserved energy associated with any configuration can be calculated from dispatch simulations for various water inflow patterns using the estimated fuel costs.

- estimating the rest of the cost and benefit elements specified in the Code:

These include labour and material costs, change in system losses and the cost of reduced reliability. Reliability of assets is determined from expected performance of relevant assets.

Transpower determines the estimates for the grid in the usual configuration (base case) and for any reconfiguration option considered. The benefits of a reconfiguration will be the reduction in generator fuel costs, reduction of expected unserved energy and avoidance, or reduction in probability, of a public conservation campaign.

- calculating the net benefit:

From the estimates Transpower extracts the costs and benefits. The difference between the benefit and costs gives the net benefit. If the net benefit is positive then reconfiguration is recommended. Temporary reconfiguration generally involves changing switch states and/or settings on secondary systems only.

The process described in this document allows for comparative net-benefit assessment of selected grid reconfiguration options.

**Terms used in this document**

<table>
<thead>
<tr>
<th><strong>VoLL (value of lost load)</strong></th>
<th>VoLL is the economic value of unserved amount of electricity as a result of a planned or unplanned outage of one or more components of the electricity grid. The value of VoLL in the Code is $20,000 / MWh.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Expected unserved energy</strong></td>
<td>Estimated amount of energy that the system will not be able to deliver for given circumstances, i.e., load that will be shed pre-contingency to manage supply shortfall. The value of this energy is the amount multiplied by VoLL ($20,000 / MWh)</td>
</tr>
<tr>
<td><strong>Customer advice notice (CAN)</strong></td>
<td>System operator tool for communicating operational information to the industry</td>
</tr>
<tr>
<td><strong>Hydro risk curve (HRC)</strong></td>
<td>graphs produced by System Operator to indicate likelihood of lakes running out of water for electricity generation that reflect the risk of extended energy shortages</td>
</tr>
<tr>
<td><strong>Security of supply:</strong></td>
<td>refers to New Zealand power system’s present and future ability to meet electricity demand at island and national level. The SO uses HRC as metrics for gauging the security of supply risk.</td>
</tr>
</tbody>
</table>

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6 The Code schedule 12.2 cl. 4
4. Time line

Figure 1 illustrates a summary of the process of assessing temporary grid reconfigurations on a timeline from the time the Grid Owner (GO) receives the request from System Operator to determining TGR net benefit.

The SO monitors and reports on security of supply at national level weekly. If there is credible risk of supply shortage in any part of the grid the SO will monitor the region closely. The SO can request the GO for temporary grid reconfiguration\(^7\) to manage the security of supply risk.

\(^7\) Clause 9.13B
Figure 1 - temporary grid reconfiguration net benefit test process
5. Triggers

Temporary grid reconfiguration will be a viable solution in exceptional circumstances (as defined in the Code). Some of the triggers that SO uses to determine when temporary reconfiguration could be a viable solution include the following:

- System Operator’s (SO) security of supply projections — The projections indicate when available generation will not be able to meet demand.
- Regional risk markers: lake level projections at regional level compared to hydro risk curves adjusted for the specific region:
  - One region can be under risk of supply shortage while the island average shows secure energy supply projection.
  - Regional supply risk markers are more appropriate for evaluating security of supply at regional level compared to island level assessments. The key to achieving this is a clear definition of regions including the relevant catchment areas.
- Industry participants raise a request for review of security of supply through the System Operator (SO). The participants can at times identify potential security of supply risk ahead of SO. Upon reviewing the participants request the SO can send request for TGR to Grid Owner (GO).
- Constraints binding for power flow into the region:
  - SO will include line loading in weekly security of supply reports for region at risk of supply shortfall. This requires monitoring of line loading.
  - To consider TGR if loading on transmission lines into a region exceeds 75% of constraints (transmission constraint is > 75% binding).
- Possibility of increasing transmission capacity into or out of a region by reconfiguring the system:
  - for higher transmission capacity for generation export from a region.
  - to allow load in a region to access cheaper generation outside the region.
- Other exceptional circumstances as defined in the Code.

6. Inputs and assumptions

Inputs

The following inputs are necessary for the net benefit process:

- Network constraints — The Operations Planning (SO) team provides a set of equations detailing transfer limits on critical branches and the reasons for the constraints. The constraint equations account for stability limits and reserves.
- Asset reliability statistics — to determine probability of interruptions for loads on reduced security.
- Network model — to calculate system losses.
- Value of lost load (VoLL)\(^9\)
- Marginal cost of generation to calculate the cost of losses. A reasonable estimate will give an indication of which option ranks better.

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\(^8\) 75% chosen during consultations with industry and will be reviewed with experience.
\(^9\) the Code Schedule 12.2 cl. 4 (1)
Assumptions:

- Future rainfall pattern will be in line with historical trends
- Reconfiguration allows a supply constrained region to access remote generation and the process assumes that the market will utilise the increased transfer capacity
- Generator offers will follow available fuel/water – reducing with declining resources
- The calculations do not account for how the load management will be implemented (which could be through commercial contracts or System Operator initiated)
- Forecast demand is not adjusted for demand response as incorporating demand response in the calculations can relax the constraints and distort the comparison between reconfiguration options. Any load that would otherwise be lost as part of demand response is retained in the dispatch simulation and flagged as load at risk
- The market will use the increased transfer capacity
- The market may respond differently - different generators have different fuel cost (water values). Compensating for shortage in generation in one region with generation in another does not guarantee that the cost will be the same

7. The Grid Owner process

The driver for the Grid Owner (GO) to investigate potential benefit of temporary grid reconfiguration is a request to the GO from the System Operator (SO) highlighting the security of supply risk. The GO process includes calculation stages indicated by blocks A, B, C and D in Figure 1:

- Block A: estimating change in generator fuel costs and expected unserved energy
- Block B: estimating the rest of the cost and benefit elements
- Block C: calculating probability of public conservation campaign
- Block D: calculating the net benefit

To drive the process GO will:

- Prepare inputs for the calculation:
  - collect inputs for the dispatch simulations - desired period, system security constraints
  - determine grid reconfiguration options that have potential to relieve transmission constraints
  - specify structure and content of expected report from the service provider
- Engage service provider for estimates of fuels costs and expected unserved energy

7.1 Estimate generator fuel costs and expected unserved energy (block A in Figure 1)

7.1.1 Service provider produces estimates of fuel costs and expected unserved energy

The service provider uses dispatch simulations to estimate generator fuel costs and expected unserved energy for the usual grid configuration (the base case) and selected grid reconfiguration options. The simulations consider forecast demand, transmission constraints and other inputs that Transpower considers relevant, e.g., list of circuits that the service provider

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10 The Code clause 12.117 (5)
should monitor and report on. The simulations are carried out for various water inflow\textsuperscript{11} patterns as the actual inflow pattern is not known ahead of time. A positive net benefit for grid reconfiguration can only be realised in small time window (where there is supply shortage risk). In such situations simulations with trading period resolution provide a better assessment than calculations based on long term average values. This allows determination of net benefit that considers change in expected generator fuel costs. The dispatch simulations establish the generators that can be dispatched, an estimate of the generator fuel costs and an estimate of the expected unserved energy.

- GO will have the service provider select a few lake inflow sequences for use in the dispatch simulations as it is not easy to specify which historic sequences match the current year. For example, for dry year simulation select ten worst historic inflows and if the process cannot identify benefits from the worst dry years it is unlikely to find reconfiguration benefits when the inflow pattern is better.
- Set dispatch simulations start-time to five days after the request from Transpower. This allows for exclusion of the study and decision time from simulations – allowing for the simulation results to reflect expected conditions at the time the actual reconfiguration is expected to be done.
- The service provider will iteratively estimate generator fuel costs and simulate dispatch for each trading period then calculate expected unserved energy.

7.1.2 The service provider delivers report of the dispatch simulations

The service provider delivers a report with a summary of the simulation results and access to the detailed simulation results. The report must:

- show estimates of generator fuel costs for each generator
- identify times when there is insufficient generation to meet regional load and the estimate of expected unserved energy in the region. The estimate of expected unserved energy in the report must not incorporate contracted demand response or assume any other demand response.
- rank the different reconfiguration options through simple tables and graphs in terms of:
  - generator fuel cost: total cost of dispatched generation
  - difference in total cost of dispatched generation for the usual grid configuration and that for each of the grid reconfiguration options gives the change (addition or reduction) in generator fuel costs for the respective option. expected unserved energy
- show power flows on selected lines with constraints marked on the graphs to show the binding constraints

The service provider must supply interactive graphs to support easier comparison of different scenarios.

The service provider should also ensure a full range of simulation output data is available for download to Transpower and other parties for further studies. For each grid configuration option (including the base case) the data sets should include:

- Storage: lake levels, inflows
- Generation: output from each station
- Demand: forecast for each node
- Line flows: on power flows on relevant circuits for the region

\textsuperscript{11} Historical patterns for water inflow into lakes used for electricity generation
• Constraints: indicate when binding
• Nodal prices: show an estimate of the generator fuel costs at load serving nodes

7.2 Calculate change in system losses, reliability and other costs (block B in Figure 1)

7.2.1 Change in system reliability
Reconfiguration can reduce the level of reliability at some grid exit points (GXP), increasing the probability of load interruption. For example, removing from service one of two circuits connecting a GXP to the grid means that failure of the remaining circuit will lead to total interruption of load. Calculate the cost of potential lost load to determine the impact of reduced reliability - show potential lost load for tripping of a circuit during the reconfiguration that would lead to lost load.
• Using the probability of such a trip, calculate the cost of the corresponding lost load. The value of lost load is, currently set at $20,000 per MWh\textsuperscript{12}
• Use historic asset performance data to determine expected number of forced outages per year for circuits that lead to loss of supply
- Consider permanent faults only, not faults cleared by auto reclose operation.
- Where there are automatic changeover schemes the loss of supply duration will be very small (in the order of seconds)
• From the annual expected forced outages rate, calculate the probability of a fault during the grid reconfiguration period for circuits that lead to loss of supply
• Multiply the probability of forced outage above with forecast demand at the GXPs where loss of supply is expected and multiply by VoLL. Using peak demand gives the upper bound of lost load.

7.2.2 Labour and material cost
Labour cost includes switching, control and protection systems programming and temporary change in operational arrangements. This includes the cost of:
• reconfiguring existing hardware (such as, changing switch states and/or changing settings for secondary systems)
• new hardware needed to achieve each configuration option if any. Temporary reconfigurations do not include installation of new primary equipment as it is impractical in the working timeframes.
• additional system operations if non-routine operational work is needed
Labour and material costs can be neglected as they are expected to be insignificant compared to the other cost components. They will also be similar between options as the lead times to assess and implement grid reconfiguration does not allow for complex tasks.

7.2.3 Change in maintenance cost
Change in maintenance costs not expected to be significant as temporary reconfiguration does not involve retiring assets or removing need for planned maintenance. Maintenance work will be shifted to another period if it becomes impossible due to an asset being removed from service for the purposes of reconfiguring the grid.

7.2.4 Change in system losses
• Calculate the MWh losses for each reconfiguration option:
  Calculate the upper bound of system losses at peak using loadflow simulations

\textsuperscript{12} The Code: Schedule 12.2 Clause 4
Multiply the losses with the marginal cost of generation. A reasonable estimate of the marginal cost of generation will give an indication of which option ranks better.

Compare system losses for reconfigured grid with the base case and multiply the difference in system losses by the marginal cost of generation to obtain cost of change in losses.

7.3 Calculate probability of public conservation campaign (block C in Figure 1)

When there is a 10% chance that water for generation from the nation’s lakes will run out, i.e., when the total lake storage projection reaches the 10% hydro risk curve, the System Operator can call for a Public Conservation Campaign (PCC) where electricity consumers are requested to reduce demand for the duration of the campaign. The cost of the exercise includes:

- Advertising for the public conservation campaign
- Cost of customer compensation following PCC
- Energy not served

Estimate the probability of public conservation campaign for all options including base case. PCC is only considered at island level, so only options that have an impact on HDVC transfers, i.e., constraining or relieving constraints on the HVDC link, will have an impact on the chance of PCC.

Using lake storage projections from the service provider’s report plot both storage projections and hydro risk curves on the same graph to show the proximity of the lake levels to emergency level (10% Hydro Risk Curve)

- the calculation considers the ratio of the storage projections entering the emergency zone to the total number of trajectories used give the probability of PCC
- compare the ratio of storage projections falling below emergency zone for the reconfigured grid to that of the base case to obtain an indication of the impact of the reconfiguration. This is the benefit of reduction in the risk of incurring the cost of a PCC.

7.4 Calculate the reconfiguration net benefit (block D in Figure 1)

Determining the net benefit involves extracting and comparing the benefit and cost components from calculations above. Subtracting the sum of costs from the sum of benefits gives the net benefit. A positive net benefit indicates that it is beneficial to proceed with the grid reconfiguration.

Benefit and cost figures must have the same units – value expressed in monetary terms. The monetary value of PCC requires extensive information and is not practical in the time window for assessing TGRs. Instead the process compares the probability of PCC for each of the grid configuration options studied support the distinction between the options.

7.4.1 Benefits

Benefits of reconfiguration will be a reduction in:

- generator fuel costs –Reduction in generator fuel costs due to reconfiguration is realised if the reconfiguration allows dispatch of generator with cheaper fuel costs. The reduction in total cost of dispatched generation for the base case compared to the reconfigured grid provides the change in cost of fuel with the reconfiguration.


14 In 2008 advertising for the public conservation campaign was approximately $8 million
• estimate of expected unserved energy – multiplying the estimated amount of unserved energy by VoLL ($20,000 / MWh) gives the total cost of expected unserved energy. A benefit is realised if the cost for the reconfigured grid is lower compared to that for the base case.
• maintenance costs
• probability of a public conservation campaign compared to the base case
• other relevant benefits as defined in the Code

7.4.2 Costs
Costs of reconfiguration will include the following:
• Increase in generator fuel costs
If generation with cheaper fuel costs is constrained by reconfiguration more expensive generation is dispatched leading to an increase in the overall fuel costs. The change in the total cost of dispatched generation for the base case and for the reconfigured grid will indicate the overall increase in fuel costs.
• Cost of reduced reliability
Increase in the value of expected lost load due to failure of assets (e.g. circuit tripping) for reconfigured grid compared to base case gives the cost of reduce reliability
• Labour and material costs where the costs are significant and readily available
• System losses
Reconfiguring the grid alters power flows in the grid resulting in changes in system losses
• probability of a public conservation campaign
This value is not added to the rest of the cost elements, the probabilities for PCC for each configuration option are compared separately

8. Output
The final report of the net benefit test that the GO produces will have a high level summary highlighting the outcome of the net benefit test. For each reconfiguration option considered the report will show the calculated values for each of cost and benefit components:
• Ranking the reconfiguration options based on net benefit. The option with highest the positive net benefit is recommended for implementation. The net benefit should be greater than possible variations due to assumptions used in the analysis to justify reconfiguration
• The summary should also have high level graphs to provide a visual picture of the projections for:
  - Power flows on selected circuits and binding constraints
  - estimated generator costs and calculated output
  - distribution of expected unserved energy
  - the controlled storage and risk curves without the grid reconfiguration and with the grid reconfiguration respectively
• the report should also provide link to the full simulation data set of for participants interested in further analysis
The GO will provide a link for interested market participants to access and download the files from dispatch simulations. After establishing the net benefit for each reconfiguration option the GO will publish the net benefit summary15.

15 The Code clause 12.116AC
9. Appendix 1: TGR costs and benefits

**Costs**

<table>
<thead>
<tr>
<th>Costs</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>12.117 (2) (a) estimate the following costs:</td>
<td></td>
</tr>
<tr>
<td>(i) any additional fuel costs incurred by a <strong>generator</strong> in respect of any <strong>generating units</strong> that will be <strong>dispatched</strong> or are likely to be <strong>dispatched</strong> during or after the removal of the <strong>interconnection asset</strong> or the reconfiguration of the <strong>grid</strong>, arising as a result of the removal or reconfiguration:</td>
<td></td>
</tr>
<tr>
<td>(ii) any direct labour and material costs that will be incurred by <strong>Transpower</strong> and the <strong>designated transmission customers</strong> undertaking the removal of the <strong>interconnection asset</strong> or the reconfiguration of the <strong>grid</strong>;</td>
<td></td>
</tr>
<tr>
<td>(iii) any increase in the estimate of <strong>expected unserved energy</strong> in MWh multiplied by the value per MWh of that <strong>expected unserved energy</strong>, arising as a result of the removal of the <strong>interconnection asset</strong> or the reconfiguration of the <strong>grid</strong>:</td>
<td></td>
</tr>
</tbody>
</table>

- Simulations by an independent service provider (clause 12.117 (5)) establish fuel costs for each trading period in the study time for usual grid configuration and for each of the grid reconfiguration options considered and any increase in expected unserved energy:
  - The fuel costs are estimated through an iterative process:
    - Initial estimate of fuel cost (for the initial trading period in the period under study)
    - Dispatch simulation to establish
      - required generation for the trading period (the cheapest generator is dispatched first until a constraint binds - transmission constraint or available generator capacity (the simulation considers fuel/water availability and cost)
      - The next generator is dispatched in the same way and the process continues on to the next available generator until the total dispatched generation matches the forecast demand; and
      - the fuel cost for the available generation
  - Step ii. is repeated until all trading periods in the study period are covered and for each grid configuration option
  - difference in total cost of dispatched generation for the usual grid configuration and that for each of the grid reconfiguration options gives the additional fuel costs for the respective option (a)(i)
  - the dispatch simulation also establishes increase in expected unserved energy (a)(iii) as the difference between the total generation that can be dispatched and the forecast demand for the trading period
  - This value is multiplied by VoLL from the Code schedule
<table>
<thead>
<tr>
<th>(iv) any relevant cost specified in clause 12.43(1)(a)(iv):</th>
<th>12.2 clause 4(1) ($20,000/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>12.43 (1) (a) (iv) any of the following costs, if the cost is to a person that produces, transmits, retails, or consumes electricity in New Zealand:</td>
<td>TGR is limited to change in settings for secondary systems and operating arrangements. No changes to primary equipment so labour costs not significant enough to differentiate options and therefore not included</td>
</tr>
<tr>
<td>(A) changes in fuel costs of existing assets, committed projects and modelled projects:</td>
<td>(A) Changes in fuel costs of existing assets captured in dispatch simulations. Fuel costs for committed projects and modelled projects are not expected to change with temporary grid reconfiguration</td>
</tr>
<tr>
<td>(B) changes in the value of involuntary demand curtailment:</td>
<td>(B) Involuntary demand curtailment is the expected unserved energy calculated through the dispatch simulation</td>
</tr>
<tr>
<td>(C) changes in the costs of demand-side management:</td>
<td>• Scope for items (C) to (G) too broad to accommodate in timeframe (12.116AC (b) by no later than 5 business days after receiving the notice, a summary of Transpower’s application of the net benefit test that relates to the exceptional circumstances stated in the notice.)</td>
</tr>
<tr>
<td>(D) changes in costs resulting from deferral of capital expenditure on modelled projects:</td>
<td>• TGRs only have positive net benefits in limited a time window so not comparable to investment projects meant for long term benefits, therefore</td>
</tr>
<tr>
<td>(E) changes in costs resulting from differences in the amount of capital expenditure on modelled projects:</td>
<td>(C) N/A</td>
</tr>
<tr>
<td>(F) changes in costs resulting from differences in operations and maintenance expenditure on existing assets, committed projects, and modelled projects:</td>
<td>(D) N/A</td>
</tr>
<tr>
<td>(G) changes in costs for ancillary services:</td>
<td>(E) N/A</td>
</tr>
<tr>
<td>(H) changes in losses, including local losses:</td>
<td>(F) N/A</td>
</tr>
<tr>
<td>(I) subsidies or other benefits provided under or arising pursuant to all applicable laws, regulations and administrative determinations:</td>
<td>(G) N/A</td>
</tr>
<tr>
<td>(J) the value of the expected change in economic surplus due to a change in competition among participants arising as a result of the removal of the connection asset or the reconfiguration of the connection assets, excluding any expected change in economic surplus due to a change in another cost in this net benefit test:</td>
<td>(H) Included. Changes in losses obtained from load flow calculations.</td>
</tr>
<tr>
<td>(v) any other relevant cost to a person that produces, transmits, retails or consumes electricity in New Zealand;</td>
<td>(I) Scope too broad to accommodate in timeframe</td>
</tr>
<tr>
<td></td>
<td>(J) Work needs to be done to clarify scope. This cost element to be included in future</td>
</tr>
<tr>
<td></td>
<td>no other costs identified</td>
</tr>
</tbody>
</table>
Benefits

12.117 (2) (b) estimate the following benefits:

(i) any reduction in maintenance costs arising as a result of the removal of the interconnection asset or the reconfiguration of the grid (including Transpower’s and any designated transmission customer’s costs):

(ii) any reduction in fuel costs incurred by a generator in respect of any generating units, arising or likely to arise during or after the removal of the interconnection asset or the reconfiguration of the grid, as a result of the removal or reconfiguration:

(iii) any decrease in the estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy, arising as a result of the removal of the interconnection asset or the reconfiguration of the grid:

- Temporarily removing an asset from service not expected to reduce maintenance costs. Maintenance work will be shifted to another period if it becomes impossible due to an asset being removed from service for the purposes of reconfiguring the grid

- Reduction in generator fuel costs ( (b)(ii) ), due to removal of constraints through reconfiguration, will show in the form of lower total cost of dispatched generation

- the dispatch simulations provide an estimate of the decrease in expected unserved energy ( (b)(iii) ) as the difference between the total generation that can be dispatched and the forecast demand for the trading period.
  This value is multiplied by VoLL from the Code schedule 12.2 clause 4(1) ($20,000/MWh)

(iv) any relevant benefit specified in clause 12.43(1)(b)(iv):  
12.43 (1) (b) (iv) any of the following benefits, if the benefit is to a person that produces, transmits, retails or consumes electricity in New Zealand:

(A) changes in fuel costs of existing assets, committed projects and modelled projects:

(B) changes in the value of involuntary demand curtailment:

(C) changes in the costs of demand-side management:

(D) changes in costs resulting from the deferral of capital expenditure on modelled projects:

(E) changes in costs resulting from differences in the amount of capital expenditure on modelled projects:

(F) changes in costs resulting from differences in operations and maintenance expenditure on existing assets, committed projects, and modelled projects:

(G) changes in costs for ancillary services:

(H) changes in losses, including local losses:

(I) subsidies or other benefits provided under or arising pursuant to all applicable laws, regulations and administrative determinations:

(A) Changes in fuel costs of existing assets captured in dispatch simulations. Fuel costs for committed projects and modelled project not expected to change with temporary grid reconfiguration

(B) Involuntary demand curtailment is the expected unserved energy calculated through the dispatch simulations

Scope for items (C) to (G) and (I) too broad to accommodate in timeframe (12.116AC (b) by no later than 5 business days after receiving the notice, a summary of Transpower’s application of the net benefit test that relates to the exceptional circumstances stated in the notice.)

TGRs only have positive net benefits in limited a time window so not comparable to investment projects meant for long term benefits, therefore

(C) N/A
(J) the value of the expected change in economic surplus due to a change in competition among participants arising as a result of the removal of the connection asset or the reconfiguration of the connection assets, excluding any expected change in economic surplus due to a change in another benefit in this net benefit test:

<table>
<thead>
<tr>
<th>(D)</th>
<th>N/A</th>
</tr>
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<tbody>
<tr>
<td>(E)</td>
<td>N/A</td>
</tr>
<tr>
<td>(F)</td>
<td>N/A</td>
</tr>
<tr>
<td>(G)</td>
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<td>(H)</td>
<td>Included. Changes in losses obtained from load flow calculations.</td>
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<tr>
<td>(J)</td>
<td>Work needs to be done to clarify scope. This benefit element to be included in future</td>
</tr>
</tbody>
</table>

| (v) | any other relevant benefit to a person that produces, transmits, retails or consumes electricity in New Zealand; | No other benefits identified |
10. Appendix 2: Code provisions

Code provision for temporary grid reconfiguration

12.116AA Temporary removal of interconnection assets from service or temporary grid reconfiguration

(1) Transpower must temporarily remove 1 or more interconnection assets from service, or temporarily reconfigure the grid for the purposes of clause 12.112(1) (b) (iaa), if—

(a) the removal or reconfiguration is requested by the system operator in accordance with clause 9.13B; and

(b) the removal or reconfiguration will result in a net benefit, as calculated under the test set out in clause 12.117.

(2) If Transpower temporarily removes interconnection assets from service or temporarily reconfigures the grid in response to a notice given under clause 9.13B, Transpower must, as soon as is reasonably practicable after the circumstances specified in that notice cease to exist—

(a) restore the interconnection assets to service; or

(b) restore the grid to its original configuration.

12.116AC Information to be made publicly available

If Transpower receives a notice given in accordance with clause 9.13B, Transpower must make publicly available at no cost, on an Internet site maintained by or on behalf of Transpower,—

(a) as soon as practical, a copy of the notice; and

(b) by no later than 5 business days after receiving the notice, a summary of Transpower’s application of the net benefit test that relates to the exceptional circumstances stated in the notice.
Net benefit test set out in clause 12.117

12.117

(2) When Transpower is required to apply a net benefit test, Transpower must—

(a) estimate the following costs: (See Table A1 for the list of cost components)

(i) any additional fuel costs incurred by a generator . . .

(ii) any direct labour and material costs . . .

(iii) any increase in the estimate of expected unserved energy . . .

(iv) any relevant cost specified in clause 12.43(1) (a) (iv):

(v) any other relevant cost . . .

(b) estimate the following benefits: (See Table A2 for the list of benefit components)

(i) any reduction in maintenance costs. . .

(ii) any reduction in fuel costs incurred by a generator . . .

(iii) any decrease in the estimate of expected unserved energy in MWh multiplied by the value per MWh of that expected unserved energy, arising as a result of the removal of the interconnection asset or the reconfiguration of the grid:

(iv) any relevant benefit specified in clause 12.43(1) (b) (iv):

(v) any other relevant benefit . . .

(c) deduct the costs estimated under paragraph (a) from the benefits estimated under paragraph (b) to determine the net benefit of the proposed removal of the interconnection asset or the reconfiguration of the grid.

12.117

(5) Transpower's estimate of fuel costs under subclause (2) must—

(a) in relation to thermal generating stations, be a reasonable estimate of the fuel costs, based on the economic value of the fuel required for the relevant thermal generating station, and justified by Transpower with reference to opinions on the economic value of the fuel, provided by 1 or more independent and suitably qualified persons; and

(b) in relation to hydroelectric generating stations—

(i) be a reasonable estimate of the fuel costs, based on the economic value of the water stored at a hydroelectric generating station, provided by a suitably qualified person other than—

(A) Transpower; or

(B) an employee of Transpower; and
(ii) be **published**, as provided for in the **Outage Protocol**.

12.117

(9) The estimate of **expected unserved energy** in MWh multiplied by the value per MWh of that **expected unserved energy** under subclause (2) must be based on the **value of expected unserved energy** and **Transpower's** estimate of the **expected unserved energy** in respect of each affected **designated transmission customer** and **end use customer**.

10.1 **Value of expected unserved energy**

Schedule 12.2

4 **Value of expected unserved energy**

(1) The value of expected unserved energy is—

(a) $20,000 per **MWh**; or

(b) such other value as the **Authority** may determine.