TRANSPOWER

NZ Battery Analysis Input Summary

This document summarises and outlines the scope of inputs to and assumptions made of the initial power system impacts of the proposed South Island Pumped Hydro scheme and Transpower's initial high level analysis of the impacts of these on the existing power system.

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The findings of this report should be used very cautiously. The analysis contained in this report is for scheme feasibility screening purposes only. It uses generic generator/pump models and significant simplifying assumptions commensurate with the stage of the project. This naturally restricts the accuracy of any transfer limits and system implications identified. A substantial piece of analysis is required to better describe the system and components being studied and NZ Battery transmission assumptions (Appendix A) provide greater certainty of the proposed power schemes ability to be integrated and operated within the New Zealand power system.

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1.0 Executive Summary & Purpose

1.1 Executive summary

Since 2021 Transpower as owner and operator of the New Zealand High Voltage electricity transmission system has been periodically engaged and remunerated by MBIE as an advisor on the power systems ability to integrate and operate the proposed Lake Onslow power scheme. Transpower has also been involved in providing initial high-level information including budgetary costs about the practicalities of connecting alternative technologies into various North Island Grid locations.

In its advisory role Transpower has been asked to

- Review and comment on concepts put forward by MBIE from a transmission and power system perspective
- Conceptually conceive and cost options for the connection of proposed schemes to the transmission system
- Review economic dispatch scenarios for power system technical sense
- Undertake high level power system operation and technical screening of proposed scheme designs

Over this time a considerable amount of information has been produced and reviewed, with some work taken forward and other areas being discarded. This report has been prepared to provide a single, simplified reference source of the work undertaken by Transpower for MBIE in establishing the feasibility of the proposed South Island pumped hydro project, Lake Onslow. The information contained in the appendices of this document are copies of the text from various source reports, letters and emails, with updates where necessary. We have endeavoured to include all information that has been produced and where it has not been superseded is still relevant to the project should it continue into a future phase. We have not included general, or summary information contained in letters, emails and other documents where it does not specifically address the possible development and operation of Lake Onslow as an option to meet the “Dry Winter” needs of a 100% renewable electricity future. In this way, this report provides a comprehensive snapshot of analysis to date and will provide a foundation for any future work on “Dry Winter” solutions.

The report is broken down into the key topic areas covered over the period. As MBIEs NZ Battery project as proceeded Transpower has been engaged at different stages by MBIE from 2021 to 2023 to comment on the ability of the proposed Lake Onslow scheme to be introduced into the New Zealand power system. Over this same time period we have also commented on Lake Onslow alternatives and the implications of integrating them into the grid . Details of this work and our findings to date can be found in the sections that follow.

Due to the suspension of work in Q4 2023, there are some areas noted in this report that due to their truncation may require further work to complete or provide a more comprehensive view if the project or one with a similar objective be progressed again in the future.

1.2 Document purpose

The purpose of this document is to summarise Transpower's advice to the Ministry of Business, Innovations and Employment (MBIE)'s NZ Battery Project, as part of the project's feasibility assessment undertaken over 2021 and 2023.

The advice contained in this report was initially delivered through the course of the investigation as a series of reports, letters, emails, workshops and conversations. This report collates this advice where it has not been superseded by more recent work, updates the earlier advice where necessary, and presents it as one package.

This report has been prepared for MBIE as part of contracted services undertaken as part of the project's feasibility.

1.3 Document scope

This document covers the following subjects, with levels of detail commensurate to the complexity of the analysis required and undertaken. The detailed analysis is presented in the following sections and appendices. The following provides a brief summary to guide the reader to the appropriate section.

- NZ Battery transmission assumptions (Appendix A)
- Future Grid upgrade assumptions without NZ Battery (Appendix B)
- Lake Onslow grid connection (Appendix C)
- Lake Onslow power systems analysis (Appendix D)
  - Lake Onslow when generating (Appendix D1)
  - Lake Onslow when pumping with variable-speed turbines (Appendix D2)
  - Lake Onslow when pumping with synchronous turbines (Appendix D3)
- Lake Onslow transmission requirements (Appendix E)
- Lake Onslow transmission charging (Appendix F)
- South Island NZ Battery resilience scenarios (Appendix G)
- Re-alignment of transmission towers over Lake Onslow (Appendix H)
- Lake Onslow treatment by system operator (Appendix I)
- Instantaneous reserves implications of HVDC upgrades (Appendix J)
- Transmission implications of NZ Battery Portfolio options (Appendix K)
- Need, feasibility and cost of a second HVDC link (Appendix L)
- Feasibility and cost of connecting NZ's grid with Australia's (Appendix M)

1.3.1 NZ Battery transmission assumptions (Appendix A)

The NZ Battery Project requested that Transpower review the transmission-related parts of its economic modelling assumptions, and its summary of the transmission implications of NZ Battery options.

Both documents were prepared by the NZ Battery Project based in part on information provided by Transpower and summarised in the appendices here.

In a few cases, Transpower has not had the time or information required to conduct analysis to the level required for the NZ Battery Project's feasibility study. In these cases, as itemised in Appendix A, we accept that the NZ Battery Project has had to make some working assumptions, but we cannot endorse those assumptions or provide alternative assumptions until we have conducted the necessary studies.

1.3.2 Future Grid upgrade assumptions without NZ Battery (Appendix B)

This appendix provides details on Transpower's assumptions of future grid upgrades in a counterfactual future without NZ Battery, especially relating to circuit reconfigurations and upgrades such as duplexing. It is provided at a level of detail required for the MBIE NZ Battery Project's SDDP modelling team to complete satisfactory dispatch modelling. This information supplements that already publicly available and provided through our Net Zero Grid Pathways (NZGP) publications.

1.3.3 Lake Onslow Grid connection (Appendix C)

This appendix presents a conceptual design for the connection of Lake Onslow to the grid.

1.3.4 Lake Onslow power system analysis (Appendix D)

This appendix presents the initial feasibility findings of the Power System Analysis of the SDDP modelled dispatch scenarios for the proposed connection of the Onslow Pumped Hydro generation scheme and how it connects to the grid and its operation within it. It is split into three parts:

1.3.4.1 Lake Onslow when generating (Appendix D1)

This is a summary of the scenarios studied and their limitations as to how Onslow will impact the power system when generating. It also describes the impact on both North Island, South Island and HVDC systems when northward power transfer is dominant.

1.3.4.2 Lake Onslow when pumping with variable-speed turbines (Appendix D2)

This section is a placeholder. As of late 2022, we had not received a workable pumping model of the variable-speed turbines that form the NZ Battery Project's preferred Lake Onslow turbine design. At this time a model is being prepared and when available we will complete the analysis.

1.3.4.3 Lake Onslow when pumping with synchronous turbines (Appendix D3)

This section covers the analysis of a synchronous turbine pumping model. It has been used to study when Onslow is operating in pumping mode. It is acknowledged that it provides a conservative 'worst case' for how Onslow would impact the power system in contrast to the more technically accurate case of variable-speed turbines. This part is a summary of the scenarios studied and their conclusions as to how Onslow will impact the power system when pumping as well as the impact on both North Island, South Island and HVDC systems when southward power transfer is dominant.

1.3.5 Lake Onslow transmission requirements (Appendix E)

This appendix outlines options and the preliminary recommendations for transmission investments to mitigate the constraints identified by the power systems analysis outlined in Appendix D.

1.3.6 Lake Onslow transmission charging (Appendix F)

This appendix considers how the costs of grid connection might be allocated, and in particular what proportion may be allocated fully to Lake Onslow.

1.3.7 South Island NZ Battery resilience scenarios (Appendix G)

This appendix presents a number of HVDC failure scenarios with failure type, capacity consequence, likelihood and time to repair. This work has been undertaken to understand what might be relevant to an assessment of how a failure of the HVDC may impact on the resilience and operational expectations of Lake Onslow.

1.3.8 Re-alignment of existing ROX-TMH_A line around Lake Onslow (Appendix H)

This appendix describes how the transmission line that presently traverses an enlarged Lake Onslow could be re-aligned around the lake should it be required. The grid connection conceptual design described in Appendix C does not require this, but it has been documented and retained should the preferred design case change.

1.3.9 Lake Onslow treatment by System Operator (Appendix I)

This appendix summarises how Lake Onslow when operating as a generator and as a variable load might be treated by the system operator, within the context of present Grid Code and requirements.

1.3.10 Instantaneous reserve implications of HVDC Upgrades (Appendix J)

This appendix details how instantaneous reserve requirements to support increased HVDC transfer might change with Transpower's NZGP proposed enhancement of the existing HVDC link to 1,400 MW north, and how that might affect assumptions made by the NZ Battery Project on the operation of Onslow.

1.3.11 Transmission implications of NZ Battery Portfolio options (Appendix K)

This appendix provides a preliminary view on the grid connection implications of NZ Battery 'Portfolio' option to use geothermal reserve, biomass generation and a hydrogen/ammonia plant.

1.3.12 Need feasibility & costs of a second HVDC link (Appendix L)

This appendix explores the option and costs of a potential second HVDC inter-island link.

1.3.13 Feasibility and costs of NZ-AUS HVDC link (Appendix M)

This appendix is a high level feasibility scoping of the physical practicalities and costs of establishing and operating a new HVDC trans-Tasman link that would join the electricity markets of both countries.

2.0 Appendices

2.1 NZ Battery transmission assumptions (Appendix A)

The NZ Battery Project asked Transpower to review its:

- NZ Battery economic modelling assumptions, which includes that transmission the modelling assumes (version of 14 November 2022)
- Transmission implications of NZ Battery options, which assumes costs for key transmission investment, and indicative Transmission Pricing Methodology implications (version of 11 November 2022)

MBIE has been working with Transpower throughout the NZ Battery Project, and the transmission assumptions in those documents summarise transmission issues raised elsewhere in this report, and discussions at regular project progress meetings. Transpower is familiar with the NZ Battery Project's transmission assumptions as they have been developed.

We believe that the assumptions in the two documents above accurately reflect our present state of knowledge, noting that:

- Transpower cost estimates are, as individually stated, Class 4 or 5, and exclude property costs.
- Work has not been completed on the transmission or power system implications of Lake Onslow when pumping with variable speed turbines. We accept that the NZ Battery Project has had to make a working assumption on this, but we cannot endorse that assumption until we have conducted the necessary studies.
- On potential future expansion of HVDC southwards capacity, beyond the 950 MW envisaged in Transpower's NZGP, we accept that the NZ Battery Project has had to make a working assumption on this, but we cannot endorse that assumption or provide an alternative assumption until we have conducted the necessary studies.
- On application of the new Transmission Pricing Methodology to Lake Onslow from the 2030s, we accept that the NZ Battery Project has had to make a working assumption on this, but we cannot endorse those assumptions or provide alternative assumptions until we have conducted the necessary studies.

We have endeavoured in our transmission and power system analysis to be consistent with the NZ Battery Project's assumptions as we understand them on demand, generation and NZ Battery options, but note that they are working assumptions in their own right, and that transmission and power system analysis implications may change if those assumptions change.

2.2 Future Grid upgrade assumptions without NZ Battery (Appendix B)

This appendix provides details on Transpower's assumptions on future grid upgrades in a counterfactual future without NZ Battery, especially relating to circuit reconfigurations and upgrades such as duplexing. It is provided at a level of detail required by the NZ Battery Project's SDDP modelling, to supplement information provided through our Net Zero Grid Pathways (NZGP) publications.

This information provides a first cut at what changes are likely to occur on the core grid between now and 2030. The focus is only on the core interconnected grid backbone assets (e.g. 220 kV flows) and does not consider regional issues.

The information is for power flows in a DC load flow model under pseudo market dispatch.

By 2030 it is expected the following assets will have the ratings and characteristics stated.

B.1 Central North Island (CNI) grid upgrades

North flow transmission through the CNI region is close to being constrained at times and if any significant new generation south of Bunnythorpe emerged, we would likely see significant constraints. Tiwai Point smelter closure would also result in significant constraints.

Separately, if generation in the Taranaki region is higher this will result in lower transfer limits on the circuits north of Bunnythorpe. The proposed retirement of the Stratford combined cycle plant in 2023 will affect CNI transfer levels and this will be monitored closely.

Previous analysis indicates that the two Tokaanu – Whakamaru 220 kV circuits and the Huntly – Stratford 220 kV circuit can constrain north flow through the CNI region in various scenarios. If constraints are removed on these circuits via upgrade work, then the two Bunnythorpe – Tokaanu 220 kV circuits would then become the limiting constraint.

- ONG CB92 Split (effectively decommission the ONG-RTO-1 circuit within SDDP)
- Duplex TKU–WKM 220 kV Circuits with GoatAC @ 120°C sag or similar
- Duplex BPE–TKU 220 kV Circuits with GoatAC @ 120°C sag or similar
- HLY-SFD-1 220 kV circuit protection upgrade
- TKU CB128 Intertrip Scheme Disabled (remove the split of the TKU 220 kV bus in SDDP)

Table 1: Central North Island grid upgrades by 2030

Line Name	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Voltage (kV)	R (ohms)	X (ohms)
TKU-WKM-1	822.9	863.6	843.6	220	2.80	21.47
TKU-WKM-2	822.9	863.6	843.6	220	2.82	21.36
BPE-TKU-1	822.9	863.6	843.6	220	6.72	51.61
BPE-TKU-2	822.9	863.6	843.6	220	6.71	50.86
HLY-SFD-1*	469.1	492.3	480.9	220	No change	No change

*Only includes a system protection upgrade as HLY-SFD (consisting of the HLY-TMN-A and SFD-TMN-A lines) is a long already optimized line with very low capability to cost effectively increase its capacity. (~280km – for reference the BPE-WKM-A is 215km) The costs to achieve this are expected to be above normal as line traverses over rugged terrain.

B.2 HVDC upgrade

HVDC transfer at any point in time is determined by energy market outcomes. However, periods of high North transfer are typically characterised by moderate to high South Island hydro storage levels coinciding with reduced availability of North Island generators. Conversely periods of high South transfer are typically characterised by low to very low South Island hydro storage levels coinciding with high availability of North Island generators.

The surrounding AC transmission network and the availability of instantaneous reserves in the receiving island also play an important part in determining HVDC transfer limits at any point in time. This investigation will consider options for increasing HVDC Cook Strait capacity, in order to access the higher available existing HVDC converter capacity. Increasing both north and south transfer between the islands will be considered.

- Fourth cable under Cook strait
- Increased overload capacity
- Additional reactive support

Table 2: HVDC capacity upgrades by 2030

North flow limit (MW)	1400
South flow limit (MW)	950
North flow received at max (MW)	1334
South flow received at max (MW)	915

B.3 Wairakei Ring upgrade

The capacity of the Wairakei–Ohakuri–Atiamuri–Whakamaru circuits (see Fig 1-6) may cause a transmission constraint during high generation in the Wairakei Ring, eastern Bay of Plenty or Hawkes Bay areas. This constraint would be exacerbated if there is a reduction in industrial load in the Bay of Plenty region, or if additional generation is developed around the Wairakei, Bay of

Plenty, or Hawkes Bay regions. To a smaller extent, through-transmission from the Central North Island to the Waikato-Upper North Island (WUNI) region also exacerbates the Wairakei Ring constraint.

No further thermal uprating is possible on the limiting circuits in the Wairakei Ring transmission corridor and variable line ratings are already applied. Therefore there is no scope to further increase the transmission capacity using these low cost techniques. As part of our investigations, we will assume the series reactor on the Wairakei–Ohakuri–Atiamuri– Whakamaru line (to balance flows on the Wairakei Ring circuits), has been installed. (Since completed in 2023)

- Thermal upgrade of the WRK-WKM C line to 100°C
- Duplex reconductor the WRK-WKM A line with GoatAC @ 120°C
- New (reinstate existing) interconnecting transformer at Edgecumbe
- install a circuit overload protection scheme on EDG-KAW-3 and KAW-OHK-1 (no need to monitor post contingency overloading on these two circuits, no change to circuit parameters)

Table 3: Wairakei Ring assumed upgrades by 2030

Line Name	From bus	To bus	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Voltage (kV)	R (ohms)	X (ohms)
THI-WRK-1	No change	No change	1098.4	1168.3	1134.2	220	No change	No change
THI-WKM-1	No change	No change	1098.4	1168.3	1134.2	220	No change	No change
WKM-WRK-1	No change	No change	1098.4	1168.3	1134.2	220	No change	No change
OHK-WRK-1	No change	No change	822.9	863.6	843.6	220	1.0659	7.9971
ATI-OHK-1	No change	No change	822.9	863.6	843.6	220	0.2448	1.8346
ATI-WKM-1	No change	No change	822.9	863.6	843.6	220	0.9817	7.3754
EDG-TF-T5	EDG220	EDG110	58	62.5	58	N/A	1.93	46

B.4 Bombay-Otahuhu upgrade

- New 220kV bus at Bombay
- Two new 220/110kV transformers along the Huntly-Drury line at Bombay
- Terminate the Arapuni-Bombay circuit at Hamilton.

Table 4: Bombay-Otahuhu assumed upgrades by 2030

New Circuits	From Bus	To Bus	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Voltage (kV)	R (ohms)	X (ohms)
BOB-TF-T1	BOB220	BOB110	150	150	150	N/A	0.639*	46.506*
BOB-TF-T2	BOB220	BOB110	150	150	150	N/A	0.639*	46.506*
BOB-HLY-1	BOB220	HLY220	694.3	764.4	730.5	220	1.50619	13.21379
BOB-DRY-1	BOB220	DRY220	694.3	764.4	730.5	220	0.27781	2.43721
BOB-HLY-2	BOB220	HLY220	694.3	762.1	730.5	220	1.36680	13.07729
BOB-TAT-2	BOB220	TAT220	694.3	762.1	730.5	220	0.58620	5.60871
ARI-HAM-3	ARI110A	HAM110	50.7	61.9	56.6	110	10.3764	19.9171

*Transformer data is provided in ohms, when converted to data should be similar to GORE T11.

Table 5: Bombay-Otahuhu removed circuits

Remove circuits
BOB-WRT-1
BOB- WRT-2
BOB-HAM-1
BOB-HAM-2
ARI-BOB-1
DRY-HLY-1
HLY-TAT-2

B.5 Clutha and Upper Waitaki lines upgrade (CUWLP)

The Clutha Upper Waitaki Line Project increases capacity on some of our lines between Clutha and the Upper Waitaki Valley to improve electricity supply to Southland during dry periods, and to allow additional generation (should it become available) to be exported from Southland. In December 2020, Transpower completed the work on the Cromwell-Twizel circuits, leaving just the work on the Roxburgh to Livingstone section of the Roxburgh–Islington line, to be completed. In April 2022 the final upgraded lines were commissioned and the CUWLP project is now complete. These works were allowed for in our studies.

- Duplexing the Roxburgh-Livingstone section of line.
- Thermal upgrade the Cromwell-Twizel section of line.

Table 6: Clutha and Upper Waitaki lines upgrade by 2030

Line Name	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Voltage (kV)	R (ohms)	X (ohms)
NSY-ROX-1	610	671	641	220	3.8839	29.1724
LIV-NSY-1	610	671	641	220	1.9819	14.8847
CML-TWZ-1	561	617	590.0	220	3.8204	45.4145
CML-TWZ-2	561	617	590.0	220	3.8206	45.4157

B.6 Additional system splits

To resolve overloads on the 110kV system, the following system splits are likely to be instated:

Table 7: System splits

Remove Circuits
ONG-RTO-1
MGM-MST-1
FHL-WPW-1
FHL-WPW-2
EDG-KAW-1
EDG-KAW-2
GNY-STU-2

B.7 Estimated commissioning dates and high-level costs

Generic assumptions:

- CUWLP was commissioned in April 2022.
- The work below does not compete with any other project (including others listed below)
- All outages needed are given and no bypass lines are required.
- Allowed for generic overheads, property, environmental and design but assuming no significant issues materialize.
- Numbers are Class 4 estimates only and meant to be used for order of magnitude comparison not a cost justification

Table 8: Summary of estimated commissioning dates and high-level costs prior to 2030

Line	Uprating	Cost	Commissioning
SFD-TMN A & HLY-TMN A	Duplex Zebra	$330m-$630m	2028-2030
WRK-WKM-A	Duplex Goat	$30m-$60m	2026-2028
WRK-WKM-C	TTU	$1.5m-$4m	2024-2025
WRK-WKM-D	New line	$80m-$170m	2026-2028
BPE-WRK-A	TTU	$20m-$40m	2025-2026
BPE-WKM-A&B	TTU	$40m-$80m	2025-2026
BPE-WKM-A&B	Duplex Goat/Zebra	$120m -$260m	2026-2028
BPE-WKM-C	New Line	$185-$400m	2028-2030
HVDC 1400MW*	4th cable & reactive plant	$180-230M	2027-2032

*The DC, if it goes ahead, the earliest commissioning is expected by 2027-2032, while the reactive equipment/battery earliest commissioning by 2025-2026 (source: Transpower_NZGP_Scenarios Update_Dec2021.pdf

2.3 Lake Onslow Grid connection (Appendix C)

This appendix presents a conceptual design for the connection of Lake Onslow to the grid.

C.1 Existing line and circuit modifications

The conceptual location for the new powerhouse, its possible relationships to the existing transmission network along with the required changes to integrate it into the system are shown in Figure 1: Conceptual substation location

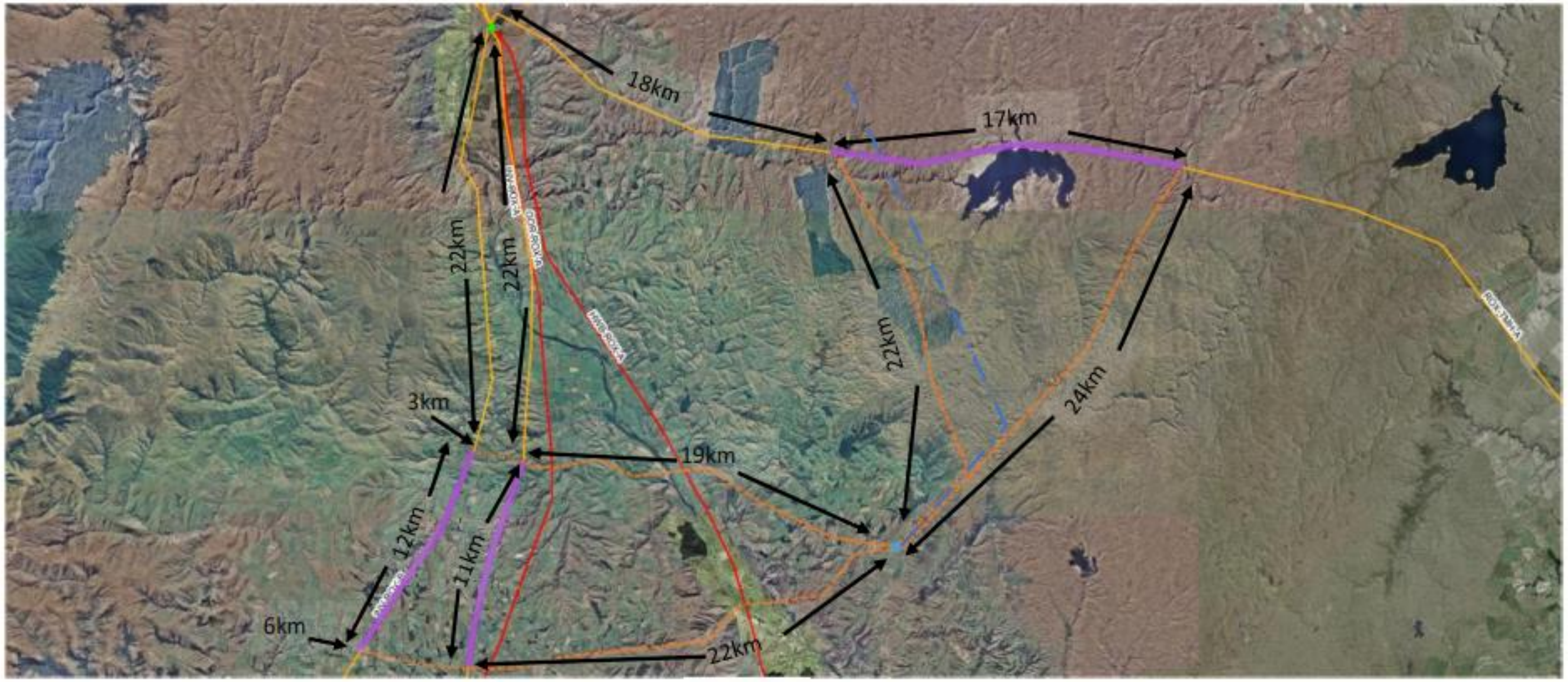


Figure 1 Conceptual powerhouse switchyard grid connection

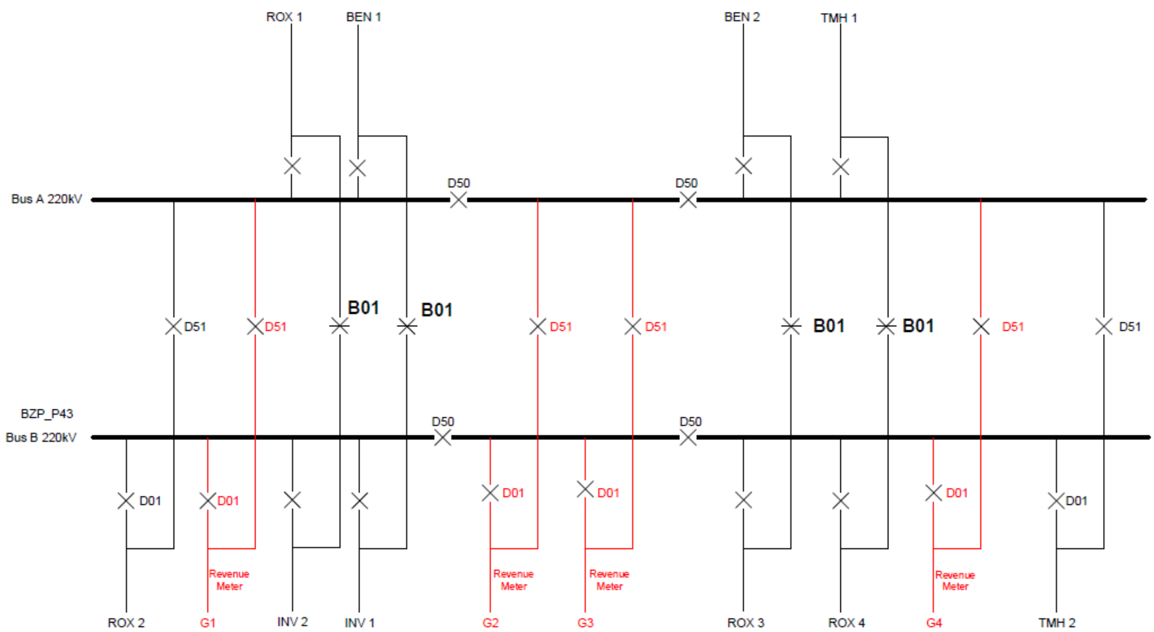
Key	
	Existing 220kV line (INV-ROX_A & B sct) (ROX-TMH_A dct)
	Existing 110kV line
	Existing Roxburgh powerstation switchyard
	New double circuit 220kV line (approx 87km total)
	New single circuit 220kV line (approx 9km total)
	Removed 220kV line (approx 40km total)
	New BEN double circuit 220kV line (approx 180km total)
	Proposed powerhouse switchyard

Figure 1: Conceptual substation location

C.2 Station Configuration

A conceptual switchyard configuration for the new pumped hydro station is shown in the figure below. At this time the exact generator configuration or size has not been confirmed. The proposed Single Line Diagram is flexible enough to accommodate 6, 5 or 4 generators by adding or removing generators across the busbars. Any difference in cost of such changes will be marginal <$5-10m. The bus configuration provides operational flexibility to ensure only one generator is connected per bus section and the existing and new transmission circuits are distributed to minimise extended contingent event constraints needing to be considered.

Figure 2: Conceptual substation arrangement



This arrangement has been used in estimating the substation's cost.

All cost estimates are to Class 4 accuracy unless stated otherwise.

C.3 Connection Option Estimate

Table 9: Onslow connection cost estimate

Item	Unit Cost (NZ/M)	Units	Total (M)
Substation10 diameter CB ½ sectionalised busbars (5 off diameters $42M)	$84	1	$84
ROX_TMH_A 220kV dct Diversion 46km	$2.5	46km	$115
Conversion ROX_TMH_A 220kV dct to tie line 1 off 18km	$2.5	18km	$45
INV-ROX_A & B 220kV dct Diversion 41km	$2.5	41km	$102.5
Extension INV-ROX_A & B 220kV sct lines 9km	$1.5	9km	$13.5
Removal of ROX_TMH_A 220kV dct	$1.5	17km	$25.5
Removal of INV_ROX_A & B 220kV sct	$1	23km	$23
Control and Protection Changes at TMH, ROX, INV	$1	8	$8
Land/Property rights	$0	1	$0
TOTAL Connection Option			$416.5M

CB = circuit breaker, dct = double circuit, sct – single circuit

Possible HVDC connection costs ignored.

All cost estimates are to Class 4 (-30/+50%) accuracy unless stated otherwise.

C.4 Connection circuit parameters

Table 10: Onslow connection circuit parameters

Line Name	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Voltage (kV)	R (ohms)	X (ohms)
INV-Onslow 1	347.1	*382.2*	365.0	220	7.61	48.52
INV-Onslow 2	347.1	382.2	365.0	220	7.43	48.54
Onslow-ROX 1	347.1	382.2	365.0	220	1.98	14.09
Onslow-ROX 2	347.1	382.2	365.0	220	2.05	14.93
Onslow-ROX 3	385.2	469.8	429.8	220	1.29	11.58
Onslow-ROX 4	385.2	469.8	429.8	220	1.29	11.58
Onslow-TMH 1	385.2	469.8	429.8	220	2.97	26.74
Onslow-TMH-2	385.2	469.8	429.8	220	2.97	26.74
BEN-Onslow 1	709.4	781.0	746.2	220	7.60	67.68
BEN-Onslow 2	709.4	781.0	746.2	220	7.60	67.68

2.4 Lake Onslow power system analysis (Appendix D)

This appendix presents the initial feasibility and findings of the Power System Analysis on the SDDP modelled dispatch scenarios for the proposed connection of the Onslow Pumped Hydro generation scheme, how it connects to the grid and its operation within it. It is split into three parts:

- 2.4.1 Lake Onslow when generating (Appendix D.1)
- 2.4.2 Lake Onslow when pumping with variable-speed turbines (Appendix D.2)
- 2.4.3 Lake Onslow when pumping with synchronous turbines (Appendix D.3)

2.4.1 Lake Onslow when generating (Appendix D.1)

This part is a summary of the scenarios studied and their limitations as to how Onslow will impact the power system when generating as well as the impact on both North Island, South Island and HVDC systems when northward power transfer is dominant.

D.1.1 Summary

This appendix D1 presents the initial feasibility findings of the Power System Analysis of the SDDP modelled dispatch scenarios for the proposed connection of the Onslow Pumped Hydro generation scheme to the grid and its operation within it.

The purpose of this work was to determine if there were additional limitations on the transmission grid that were not identified in the DC market dispatch SDDP modelling. This was achieved by modelling 120 SDDP snapshots in DIgSILENT PowerFactory to perform AC load flows, voltage stability and transient angular stability analysis.

D.1.1.1 Generating mode results

The results of the investigation showed that there is an angular stability limitation on transfers between the Clutha and Waitaki Valley. This stability limitation is significantly reduced and likely removed by reinforcing the electrical connection between the Clutha and Waitaki valley power systems. This reinforcement is achieved by constructing a new 220kV double circuit line between the new Onslow grid connection and Benmore grid connection. For the SDDP snapshots provided the worst case transfer was limited to:

- 840 MW with the approved Clutha and Upper Waitaki Lines Projects only (including duplexing Aviemore-Benmore)
- 1,180 MW with the Clyde-Cromwell-Twizel circuits duplexed
- 1,470 MW with a new double circuit Benmore-Roxburgh line instead of the Clyde-Cromwell-Twizel circuit duplexing

D.1.1.3 Next steps

This appendix is an initial, high-level feasibility analysis to understand if the simplified constraints and capabilities identified in the SDDP DC model space are representative of the AC power system, for Lake Onslow generating and with northwards flow.

Work to date has confirmed that the proposed pumped hydro scheme when generating will have interactions with the existing transmission system and that without some transmission investment, it will result in the station's generation operations being constrained. South Island generation and first order transmission constraints and possible mitigations have been identified.

D.1.2 Purpose of this appendix

The purpose of this appendix is to present the findings of a high-level analysis of transmission limitations for the connection of a proposed 1,000 MW pumped hydro generating station at Onslow, south of Roxburgh to the HVAC transmission system, when generating.

All SDDP data and other external information relied on for the analysis referred to in this document has been provided to Transpower by MBIE. This information has been relied on for accuracy and completeness, and no effort has been made to verify the validity, accuracy or applicability of the information provided.

The findings of this appendix should be used very cautiously. Analysis was performed in a very short timeframe which limits the accuracy of these transfer limits as significant simplifying assumptions were made. Refer to the D 1.5 Recommendations for next envelopes

D1.3 Introduction

D.1.3.1 Purpose of the investigation

The purpose of this investigation was to identify transmission constraints that may require significant investment in the High Voltage Alternating Current (HVAC) and High Voltage Direct Current (HVDC) electricity transmission system to allow a new 1,000 MW pumped hydro generating station to be connected at Onslow, when the station is generating.

The intention was to investigate in more detail the extreme AC power flow cases the simplified DC power system models identified through economic modelling using SDDP[1]. To do this analysis we were provided with 120 SDDP snapshots representing the maximum power flows across two interfaces in the transmission network. These 120 snapshots included a range of constraints from high to low northward - southward transfers, high and low south island generation in differing catchments and differing magnitudes of South Island loads. These snapshots were then converted to AC power flow system states to enable voltage and transient analysis to be performed.

The analysis was based on today's HVAC and HVDC system with any of the assumed changes associated with grid backbone enhancements associated with Net Zero Grid Pathways (NZGP) Major Capex Proposal (MCP) being completed by 2030. These were detailed and agreed in the joint assumptions document[2]. It should be noted that any identified project does not have any certainty of being completed by 2030. All projects applications need to have been submitted, considered and approved by the Commerce Commission.

D.1.3.2 Scope of the investigation

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[1] SDDP Stochastic hydrothermal dispatch with network restrictions. SDDP is a hydrothermal dispatch model with representation of the transmission network and is used for short, medium and long term operation studies. The model calculates the least-cost stochastic operating policy of a hydrothermal system

[2] Transpower's assumptions on future grid upgrades for SDDP Team for MBIE on NZ Battery Project

The scope of this investigation was to identify constraints within the transmission network that SDDP DC load flows were not enforcing. It should be noted that the SDDP snapshots provided to Transpower were based on a common assumption set. Within the project constraints the analysis focussed on three areas:

1. DC load flows for the entire New Zealand transmission network
2. AC load flows for the South Island transmission network
3. Transient analysis of high generation cases for the interface between the Clutha and Waitaki Valleys
4. Identification of mitigations to manage identified constraints and provide a cost envelope for them.

This investigation did not include:

- Any AC load flow analysis in the North Island
- Transient analysis of pumping cases
- Options analysis to increase transfer limits
- Optimisation of generation dispatch to increase transfer limits.

D 1.3.3 Outline of this appendix

In this appendix:

- D.1.3.1 Describes the purpose of this appendix
- D.13.2 .Outlines the scope of the investigation
- D.1.4 “Findings and conclusions” provides a summary of our findings
- D.1.5 “Recommendations” provides a summary of any recommendations and next steps
- D.1.6, D.1.7 & D.1.8 “Analysis, Assumptions and Methodology” describes how the analysis was undertaken and is provided to aid in understanding the results and recommendations
- D.1.9 Limitations describes limitations to the analysis
- D.1.10, D.1.11, D.1.12, D.1.13 Provides details on the results of sensitivity analysis and impacts to the South Island and Lower North Island AC networks and the HVDC transfer capability.

D.1.4 Findings and Conclusion

The investigation showed that there are long term voltage stability and transient angular stability limitations on the power flow between the Clutha and Waitaki Valleys. These limitations would need to be addressed or incorporated in economic dispatch modelling to better reflect the true limitations of the power system.

Mitigations proposed are:

- Increasing the transfer capability between Aviemore and Benmore power stations by duplexing the existing line.
- Increasing the transfer capability between the Clutha and Waitaki Valleys. This capacity increase is provided by constructing a new double circuit line (Onslow-Benmore). This line provides 250MW additional transfer capability in addition to resilience, constructability and operational benefits over the duplexing of the existing CYD-TWZ_A double circuit
- Modifications to the existing Clutha 220kV network and Roxburgh power station to accommodate the new Onslow pumped hydro scheme

D.1.5 Recommendations

The analysis presented in this appendix is based on high level analysis performed using a wide range of simplifying assumptions, which was necessary given the scope and duration allowed and the phase of the project. The recommendations that follow include identifying asset investments that will be required and areas of further investigation and analysis. The recommendations are,

- Duplex the existing AVI-BEN_A transmission line
- Construct a new 220kV double circuit line BEN-Onslow between the Clutha and Waitaki valleys
- Construct a new 7 to 10 bay breaker and a half substation at the new power station location and divert the existing INV-ROX_A & B and ROX-TMH_A 220kV lines into it.
- Update the transfer limits within this region
- Refine the pumping models to reflect asynchronous variable speed machines
- Use the revised pumping model and Transpower's enhanced HVDC model to confirm viable pumping scenarios and any HVAC and HVDC limitations
- Complete unconstrained pumping and generation SDDP HVDC dispatch simulations to identify the magnitude and duration of HVDC constraints to guide decision making on further HVAC and HVDC system studies

The additional analysis identified above will need to be performed to confirm the results presented here. This analysis should be performed with more detailed modelling information. We reinforce the message that the project allocates a substantial timeframe and resource capability to this detailed modelling and the real-time tools that would be required to allow substantial increases in power transfer across this interface.

D.1.6 Analysis

This section is provided for clarity and transparency so that readers can understand the approach to the modelling and the rationale for options selected.

D.1.7 Assumptions

D.1.7.1 Demand

Load was provided from MBIE created and supplied SDDP snapshots. SDDP calculations use a DC Loadflow that assumes no AC line losses. To represent losses on the network SDDP assumes additional load. In order to perform AC analysis this additional load must be removed to ensure that the generation dispatch matches the load and losses. To match the dispatch the load was uniformly scaled down across the South Island. The load is scaled down until the HVDC transfer approximately matches the SDDP modelling.

D.1.7.2 Generation Assumptions

As closely as possible the analysis used the dispatch from the SDDP snapshots. When limits arose on the grid backbone only Onslow or Manapouri (in the counter-factual cases) generation was reduced to eliminate these overloads.

SDDP provides data for total generation at a station. This generation is then shared amongst the generating units at each site. The sharing between the units is based on real world data. Historic generation dispatch for the past five years was interrogated. The number of units in service at each site was based on the number of units operating with the given real power dispatch for the ten historical time stamps closest to the SDDP dispatch.

There were some cases where the dispatch from SDDP had not occurred in the past five years. These were generally cases of very low dispatch where minimum flow constraints might presently be a factor. For these cases judgement was applied for a reasonable number of units to be dispatched.

New generators from the generation stack introduced by SDDP, including wind farm repowering, are represented as static generators. They are modelled as:

- PQ sources for load flow analysis and configured so they do not contribute reactive power, as are the existing windfarms
- constant impedance sources for transient analysis.

The existing windfarms and HVDC are also modelled as constant impedances for this high level analysis. For more detailed future analysis a detailed model of the HVDC link is highly recommended. Particularly for pumping cases.

D.1.7.3 Voltage Support assumptions

The analysis attempted to as close as possible keep the voltage plane across the Clutha and Waitaki Valleys consistent. To achieve this the following assumptions were used:

- Benmore 220 kV voltage approximately 1.02 pu
- Generating units in the Clutha and Waitaki Valley schemes were dispatched to no more than approximately 50% of their reactive power injection capability
- Onslow generation was operated in voltage control mode with a setpoint between 1.03-1.04 pu depending on the system state
- No generating units were operated Tail Water Depressed (TWD).

Shunt Capacitors and Reactors in the Upper South Island were used to maintain the output of Islington SVC 9 and Kikiwa STC 2 as close to 0 Mvar pre-contingency as possible. Where necessary additional capacitors were added at Islington 220 kV and Kikiwa 110 kV buses to achieve 0 Mvar pre-contingency loading on SVCs and STCs .

D.1.7.4 Grid planning assumptions

The load flow analysis assumed:

- Circuit loading must not exceed 100% of seasonal rating. Variable line ratings were not applied.
- Transformer loading must not exceed 100% of 24 hour rating for n-1 analysis, only contingencies of interconnecting transformers were considered
- 220 kV and 110 kV bus voltage must remain within +/-10% of nominal
- 66 kV and lower bus voltage must remain within +/- 5% of nominal
- Wider Voltage agreements were considered.

If supply transformers exceeded 80% rating pre-contingency in any snapshot the parallel number of transformers was increased until the loading dropped below 80%. This assumption is to prevent highly overloaded supply transformers from absorbing excess reactive power.

The transient analysis performed was limited by the time allowed. Therefore, transient analysis:

- Was only performed on the interface between the Clutha and Waitaki Valleys
- Was for a three-phase fault applied on the Naseby-Roxburgh circuit at the Roxburgh end and was cleared by removing the Naseby-Roxburgh circuit in six cycles (120 ms). This fault was identified as the worst contingency as a sweep of other circuit contingencies did not reveal any worse contingencies. But more detailed analysis may highlight other limiting constraints
- Only considered first swing transient stability. No analysis of the damping ratio of cases that passed the first swing test were analysed.

D.1.7.5 Other assumptions

The slack generator was located at:

- Haywards for DC load flows, in these cases the deficit represented the losses on the HVDC link
- Benmore for South Island AC load flow analysis, representing any reduction in South Island generation being countered with additional generation in the North Island
- The largest generating unit connected to the network acts as the reference machine in transient analysis, that will be Onslow when it acts as a generator, otherwise Manapouri, or Clyde in the cases with no units on at Manapouri.

D.1.8 Methodology

DIgSILENT Power Factory Version 2019 SP 4 was used to perform the power systems analysis. The North and South Island models were based on the published EMI models from May 2021.

Figure 3 provides a summary of the steps taken to perform the analysis.

Figure 3: Analysis methodology

D.1.8.1 Sensitivity check

Within the time constraints provided, a sensitivity analysis was performed on select representative cases to determine the impact of pre-fault reactive power loading on the transient stability limit.

D.1.9 Limitations

One significant limitation on this analysis is the use of a constant impedance HVDC model to represent the HVDC response to disturbances on the AC network. This assumption is a fairly accurate representation when disturbances are remote from the HVDC link. This model is deemed to be sufficient for this high-level analysis while Onslow is generating. We recommend using the detailed HVDC model for future refinements of limits for Onslow in generating mode. As pumping mode creates a much more severe voltage disturbance on the grid for specific SDDP dispatches a detailed HVDC model will be required.

D.1.10 Generating mode AC analysis results

2.13.1 Case 1: Roxburgh Maximum export north, NZGP developments only

Figure 4 shows the transfer limits north of Clyde and Roxburgh for these ten cases (10-19).

Figure 4: Limits Roxburgh maximum north flow, NZGP developments only

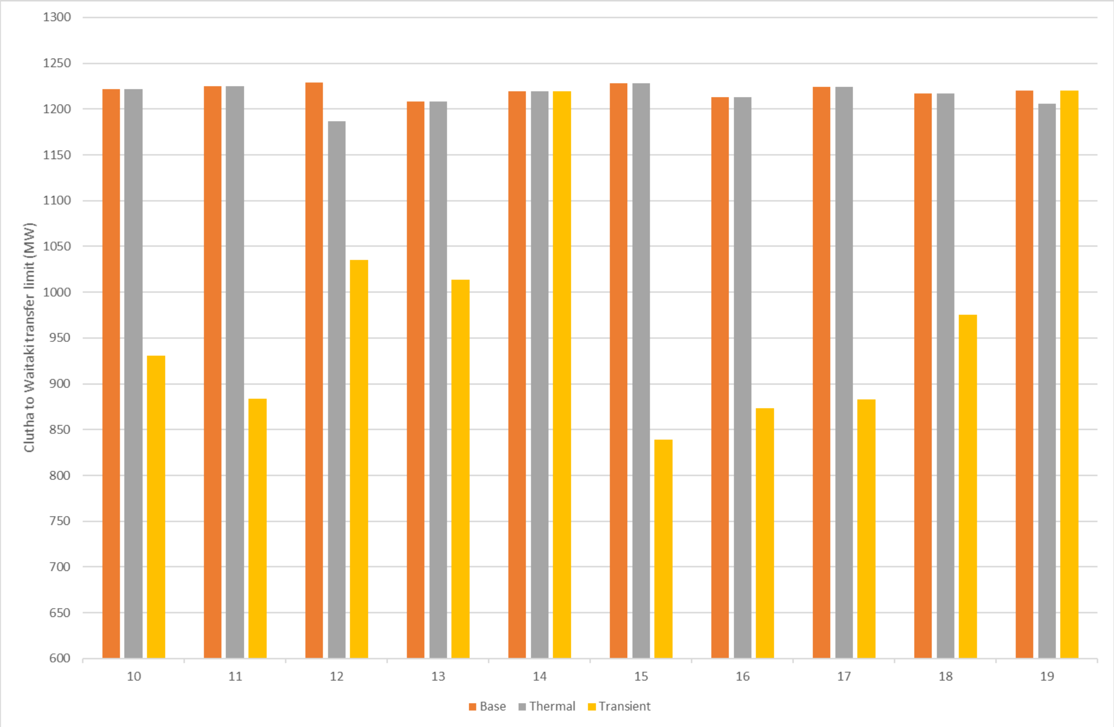


Figure 4 shows the:

- Base dispatch resulted in approximately 1,200 MW of transfer from the Clutha to Waitaki Valleys
- Two cases included a binding thermal limit where Cromwell-Twizel overloaded for a Naseby-Roxburgh contingency.
- Transient limit ranges from 840 MW to 1,220 MW depending on the available generation and HVDC transfers.

Table 11 provides some insights into the minimum and maximum transfer limit case.

Table 11: Case data Roxburgh maximum north flow, NZGP developments only

	Worst case (MW)	Best Case (MW)
Generation		
Lower Waitaki Valley (Aviemore/Waitaki)	18	4
Benmore	6	6
Upper Waitaki Valley (Ohau A, B, C, Tekapo B)	0	0
Clutha	191	191
Manapouri	466	301
Lower South Island Wind (Mahinerangi, White Hill)	109	57
Charging Batteries		
Aviemore	-	113
Clyde	60	54
Other		
South Island Load	1762	1036
HVDC transfer	-92	311
Onslow Limits		
4 units	600	1000
3 units	525	750
2 units	400	500

D.1.10.1 Case 2: Bunnythorpe-Haywards Maximum north flow NZGP developments only

Figure 5 shows the transfer limits north of Clyde and Roxburgh for these ten cases (30-39).

Figure 5: Limits Bunnythorpe-Haywards maximum north flow, NZGP developments only

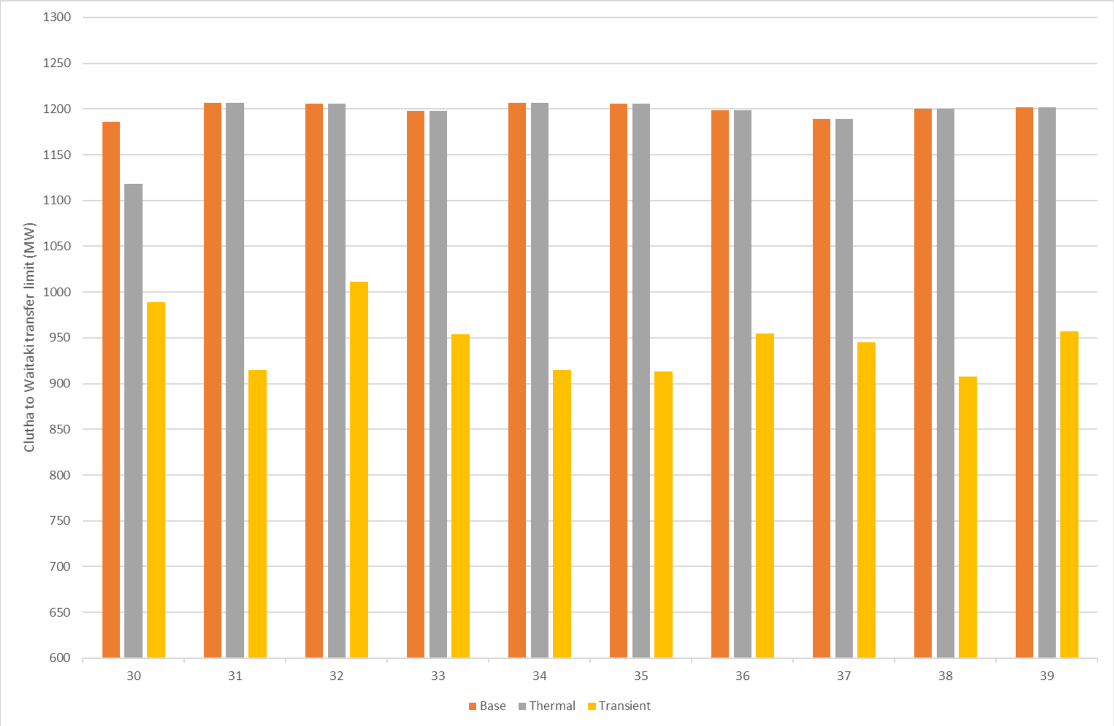


Figure 5 shows the:

- Base dispatch resulted in approximately 1,200 MW of transfer from the Clutha to Waitaki Valleys
- One case included a binding thermal limit where Cromwell-Clyde overloaded for a Clyde-Cromwell-Twizel contingency.
- Transient limit ranges from 910 MW to 1,010 MW depending on the available generation and HVDC transfers.

Table 12 provides some insights into the minimum transfer limit case.

Table 12: Case data Bunnythorpe-Haywards maximum north flow, NZGP developments only

	Worst case	**Best Case**
Generation		
Lower Waitaki Valley (Aviemore/Waitaki)	298	298
Benmore	470	470
Upper Waitaki Valley (Ohau A, B, C, Tekapo B)	743	743
Clutha	64	446
Manapouri	519	130
Lower South Island Wind (Mahinerangi, White Hill)	44	22
Upper Fraser	2	4
Charging Batteries		
Benmore	0	55
Other		
South Island Load	1752	1903
HVDC transfer	1400	1361
Onslow Limits		
4 units	700	800
3 units	600	713
2 units	500	500

D.1.10.2 Case 3: Roxburgh Maximum export north, modelled projects beyond 2033

Figure 6 shows the transfer limits north of Clyde and Roxburgh for these ten cases (50-59).

Figure 6: Limits Roxburgh maximum north flow, modelled projects beyond 2033

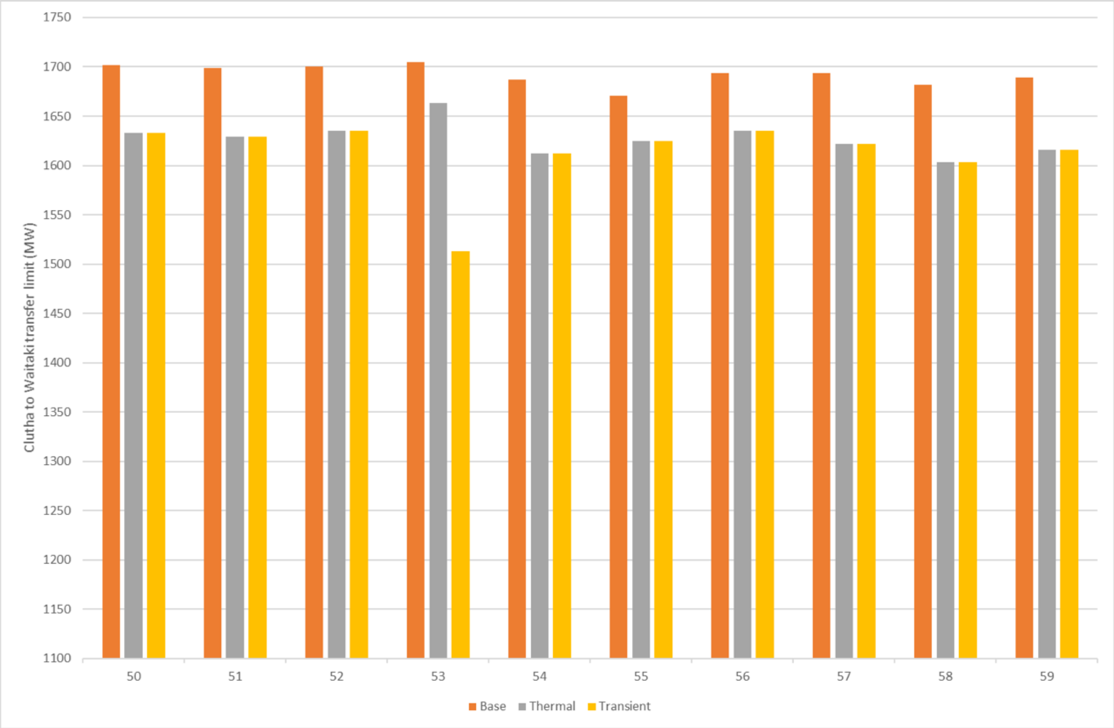


Figure 6 shows the:

- Base dispatch resulted in approximately 1,700 MW of transfer from the Clutha to Waitaki Valley
- Thermal limit ranges from 1,600 MW (Clyde-Roxburgh overloading for a parallel Clyde-Roxburgh contingency) to 1,660 MW (Naseby-Roxburgh overloading for a Clyde-Cromwell-Twizel contingency)
- Transient limit ranges from 1,510 MW to 1,630 MW depending on the available generation and HVDC transfers. There is only one case where the transfer is limited by transient stability.

Table 13 provides some insights into the minimum transfer limit case.

Table 13: Case data Roxburgh maximum north flow, modelled projects beyond 2033

	Worst case	**Best Case**
Generation		
Lower Waitaki Valley (Aviemore/Waitaki)	238	228
Benmore	470	470
Upper Waitaki Valley (Ohau A, B, C, Tekapo B)	240	13
Clutha	567	567
Manapouri	491	575
Lower South Island Wind (Mahinerangi, White Hill)	25	73
Additional Generators		
Upper Fraser	3	3
North Makarewa	-	35
Discharging Batteries		
Aviemore	55	-
Clyde	52	-
Other		
South Island Load	1837	2129
HVDC transfer	1300	750
Onslow Limits		
4 units	775	902
3 units	680	750
2 units	500	500

D.1.10.3 Case 4: Bunnythorpe-Haywards Maximum north flow, modelled projects beyond 2033

Figure 7 shows the transfer limits north of Clyde and Roxburgh for these ten cases (70-79).

Figure 7: Limits Bunnythorpe-Haywards maximum north flow, modelled projects beyond 2033

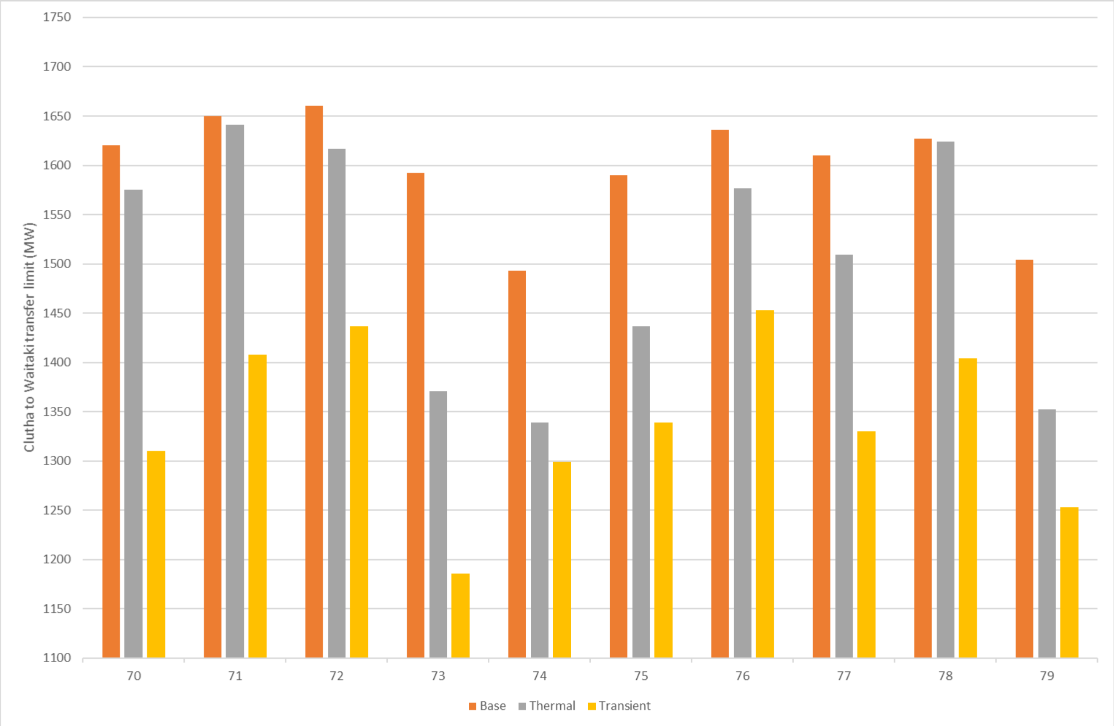


Figure 7 shows the:

- Base dispatch resulted in a range of transfer from the Clutha to Waitaki Valley between 1,490 MW to 1,660 MW
- Thermal limit ranges from 1,340 MW (Clyde-Roxburgh overloading for a parallel Clyde-Roxburgh contingency) to 1,640 MW (Naseby-Roxburgh overloading for a Clyde-Cromwell-Twizel contingency)
- Transient limit ranges from 1,190 MW to 1,450 MW depending on the available generation and HVDC transfers. There is only one case where the transfer is limited by transient stability.

Table 14 provides some insights into the minimum transfer limit case.

Table 14: Case data Bunnythorpe-Haywards maximum north flow, modelled projects beyond 2033

	Worst case	Best Case
Generation		
Lower Waitaki Valley (Aviemore/Waitaki)	298	298
Benmore	470	470
Upper Waitaki Valley (Ohau A, B, C, Tekapo B)	698	724
Clutha	206	362
Manapouri	740	592
Lower South Island Wind (Mahinerangi, White Hill)	56	55
Additional Generators		
Upper Fraser	3	10
North Makarewa	156	207
Discharging Batteries		
Aviemore	-	55
Other		
South Island Load	2118	2295
HVDC transfer	1400	1400
Onslow Limits		
4 units	550	780
3 units	420	700
2 units	300	

D.1.11 Sensitivity analysis

We tested the sensitivity of the assumptions around voltage management in the Waitaki Valley. The intent of this analysis was to gain an understanding of how pre-fault reactive power loading impacted the transfer limits. It should be noted due to time constraints, only one representative case was selected for this sensitivity analysis and that additional cases should be assessed as the number of generators in service will highly impact these results.

A sensitivity analysis of the high north flow Bunnythorpe-Haywards cases showed that although duplexing the Clyde-Cromwell-Twizel circuits can increase the transient stability limit constructing a new double circuit line increases the transfer capability by a further 250 MW.

D.1.11.1 Allowing Benmore voltage to deviate from 1.02 pu:

Keeping a Benmore voltage at approximately 1.02 pu is in line with how the HVDC is typically operated and is considered a reasonable voltage to set up a voltage plane in the South Island that facilitates good grid operation. However, at times with particularly high transfer from the Clutha valley to the Waitaki valley, a significant amount of reactive power is required from the generation in the area to support a Benmore voltage of 1.02 pu. To assess the impact of generation reactive power support, we gradually turned down the amount of reactive power provided by the generation which in turn reduced the pre-fault voltage at Benmore. This resulted in the following impact on transfer limits for this representative case. The increments for increasing the transfer was 10MW.

Table 7 outlines the findings of the Benmore voltage profile.

Table 15: Sensitivity of results to reactive power injection assumption Initial Benmore Voltage

Benmore Voltage (pu)	Area Reactive Power Loading pre-fault	Transfer Limit (MW)
1.025	50%	954
1.02	48.3%	954
1.015	46.8%	964
1.01	45.2%	964
1.005	43.8%	964
1	42.2%	973
0.995	41.8%	983
0.99	39.2%	983
0.985	37.8%	983
0.98	36.4%	993
0.975	35%	993
0.97	33.5%	1003
0.965	32.2%	1003
0.96	31%	1012
0.955	29.6%	1022

Table 7 shows lowering the pre-fault voltage results in less reactive power loading of the generators which in turn increased the transfer limits across the interface. However, operating the system at the lower voltage range is not practical. Also, modelling the HVDC as a constant impedance makes the disturbance less severe during a fault as the current drawn from the model reduces as the voltage reduces.

D.1.11.2 Using additional static capacitors to retain 1.02 pu at Benmore and increase dynamic reserves

Another sensitivity performed was keeping the Benmore voltage at approximately 1.02 pu by placing 50 Mvar capacitors at Twizel and reducing the reactive loading on the generators in the area. This shows the impact on the stability limit if generator reactive power was replaced by static reactive power generation. Table 8 summarises the impact on reactive power flows and transfer limits.

Table 16: Sensitivity of results to additional shunt compensation at Twizel

Initial Benmore Voltage (pu)	Area Reactive Power Loading pre-fault	TWZ reactive power (Mvar)	Transfer Limit (MW)
1.029	50%	0	954
1.02	41.50%	50	944
1.02	34.75%	100	954
1.02	30.50%	150	944

This sensitivity shows that keeping the Benmore voltage fixed, the transfer limits essentially remains constant. This is due at least in part to the HVDC model behaving in a similar way in each simulation. It is recommended to use the detailed HVDC model if further investigation is required to better quantify the effect the DC system has upon this sensitivity.

As a result from this analysis, the initial selection of keeping Benmore at 1.02 pu and loading the generators up 50% reactive power output seems to be a reasonable selection.

D.1.11.3 Would a new double circuit line raise the stability limits?

Figure 8 shows the transient stability limits with a new 200 km double circuit line between Benmore and Roxburgh. The Clyde-Cromwell-Twizel circuits are not reconductored in this case.

Figure 8: Comparison of duplexing Clyde-Cromwell-Twizel and new Benmore-Roxburgh line

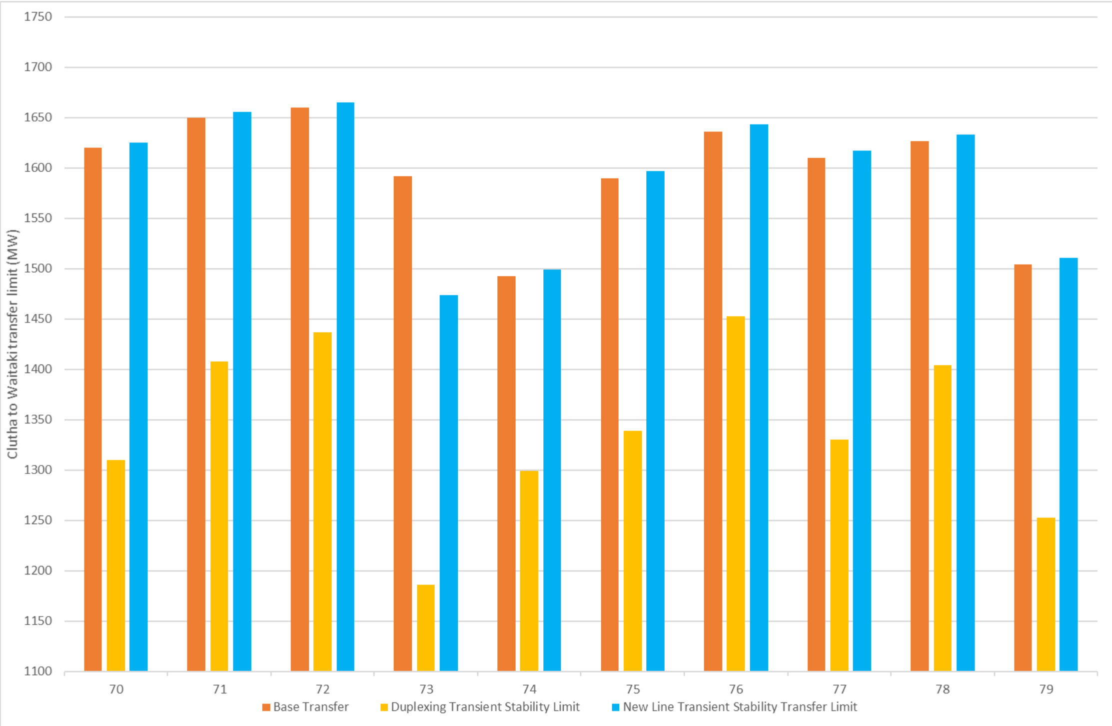
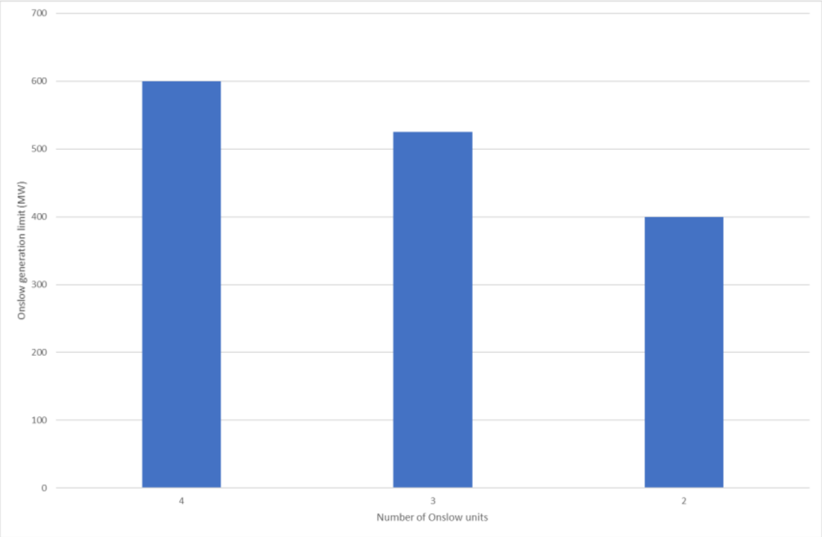


Figure 8 shows there is only one case where applying the SDDP dispatch causes a transient stability limit. In that case the transient stability limit is still around 300 MW higher than for the duplexing option. On average there is around 250-290 MW additional transfer capability with the new line. Although it is important to note that generation dispatch was not increased above the SDDP dispatch and there could be more capability.

D.1.11.4 Impact of number of units connected

The limits shown in section 0 are calculated by scaling down the generation at Onslow, but retaining four units. The total limit on Onslow generation with a different number of units for the cases represented the lowest transfer limit of 840 MW, shows that the total generation limit reduces with the number of units connected at Onslow, however the generation per unit increases from 150 MW with four units to 200 MW with two units.

Figure 9: Example of impact of number of units connected at Onslow



D.11.5 Short Circuit Ratio

For the HVDC to function correctly a minimum short circuit ratio (SCR) of 2.5 is required at Benmore.

Table 17 shows the calculated SCR for the base case for all sixty generating cases.

Table 17: Short circuit ratio results

Case 1		Case 2		Case 3		Case 4	
10	3.1	30	5.8	50	3.9	70	5.8
11	3.9	31	5.7	51	3.1	71	5.6
12	**2.2**	32	5.8	52	4.3	72	5.8
13	**1.6**	33	5.7	53	4.8	73	5.7
14	**1.6**	34	5.7	54	3.8	74	5.8
15	**2.3**	35	5.5	55	3.8	75	5.5
16	**1.9**	36	5.6	56	3.6	76	5.8
17	4.3	37	5.7	57	3.6	77	5.8
18	**1.9**	38	5.8	58	3.1	78	5.8
19	**1.6**	39	5.7	59	3.1	79	5.7

Table 17 shows that the minimum SCR of 2.5 was not met for some of the snapshots in case 1 (Roxburgh maximum export north NZGP upgrades only). Which would mean some additional generating units would need to be connected.

D.1.12 Pumping Cases

The pumping model proved to be unstable for all cases. This seems likely to be a modelling issue.

Therefore, we have only presented one sample of results to highlight our concerns over the modelling approach.

D.1.12.1 Long Term Voltage Stability

It is important to note that for many cases the pumping scenarios provided represented cases with very little generation in the Lower South Island. There is a significant voltage stability limitation on sending such a considerable amount of power from the North Island to be consumed in the Clutha Valley.

Figure 10 shows some representative PV curves for transfer across the interface.

Figure 10: Example of high Roxburgh south flow voltage stability limit

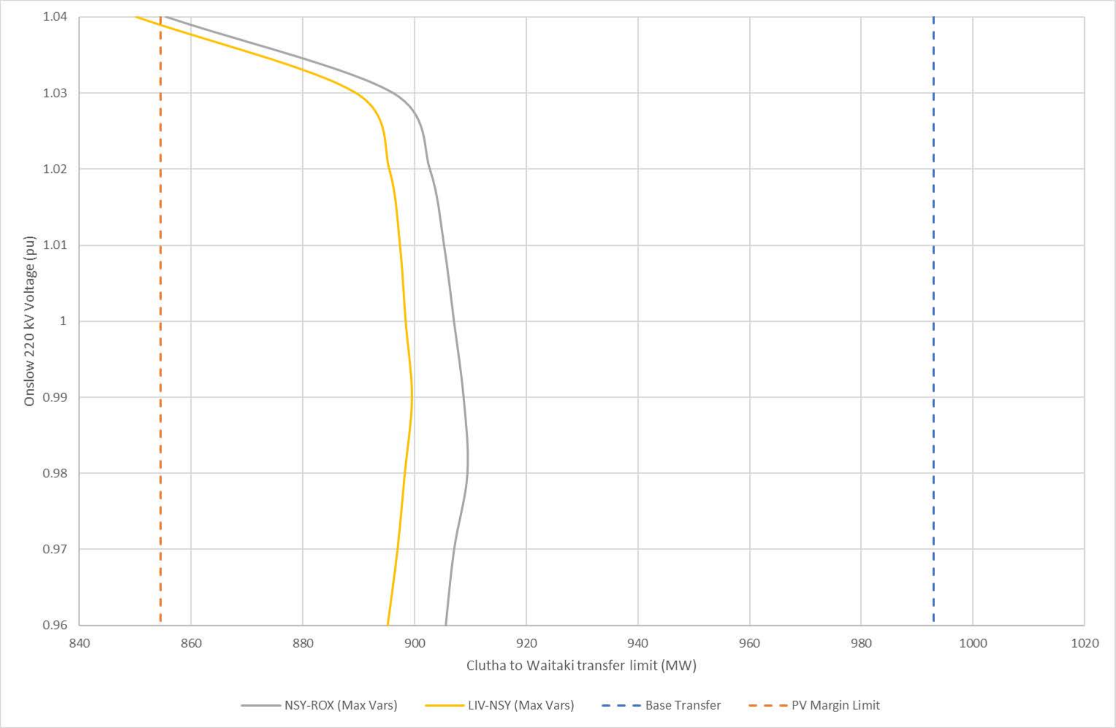


Figure 10 shows that the transfer limit cannot be achieved due to long term voltage stability. Normal operating procedure is to maintain a 5% margin to the 'nose point', which is the point where the maximum transfer capability begins to reduce with reduced voltage. This graph shows that the transfer is limited to approximately 140 MW less than the base dispatch by the PV transfer capability. This would represent around 210 MW per pump, which is less than the advised minimum design level.

D.1.12.2 Transient analysis

Our analysis shows that with four units this operating point is unstable as the rotor angle of the Onslow pumps varies by more than 360°. This appears to be a modelling artifact as no other generating units are experiencing rotor angle instability.

The results of a representative case are provided here to illustrate the significance of the modelling assumptions.

The representative case is from week 33 of 2044. This is the second case of the high Roxburgh south flow cases with NZGP developments only. For this snapshot the three phase IEC 60909 fault level was 17.4 kA with four units in service at the Onslow 220 kV bus. This represents the closest case to the average fault level for the ten high Roxburgh south flow cases with NZGP developments only.

In order to prevent the instability the output of the motors is reduced depending on how many units are in service. With:

- four units the limit is 550 MW, or 137.5 MW per unit.
- three units the limit is 450 MW, or 150 MW per unit
- two units the limit is 400 MW, or 200 MW per unit.
- one unit the limit is 270 MW.

D.1.13 DC Loadflow results

D.1.13.1 Matching SDDP Powerflows

The first step of the analysis was to ensure that the DC Power flow results match data provided from the SDDP team. Figure 11 shows a comparison of the power flow on the interface north of the Clutha Valley, that is on Cromwell-Clyde 1 & 2 and Naseby-Roxburgh circuits.

Figure 11: Illustration of DC load flow matching between SDDP and PowerFactory

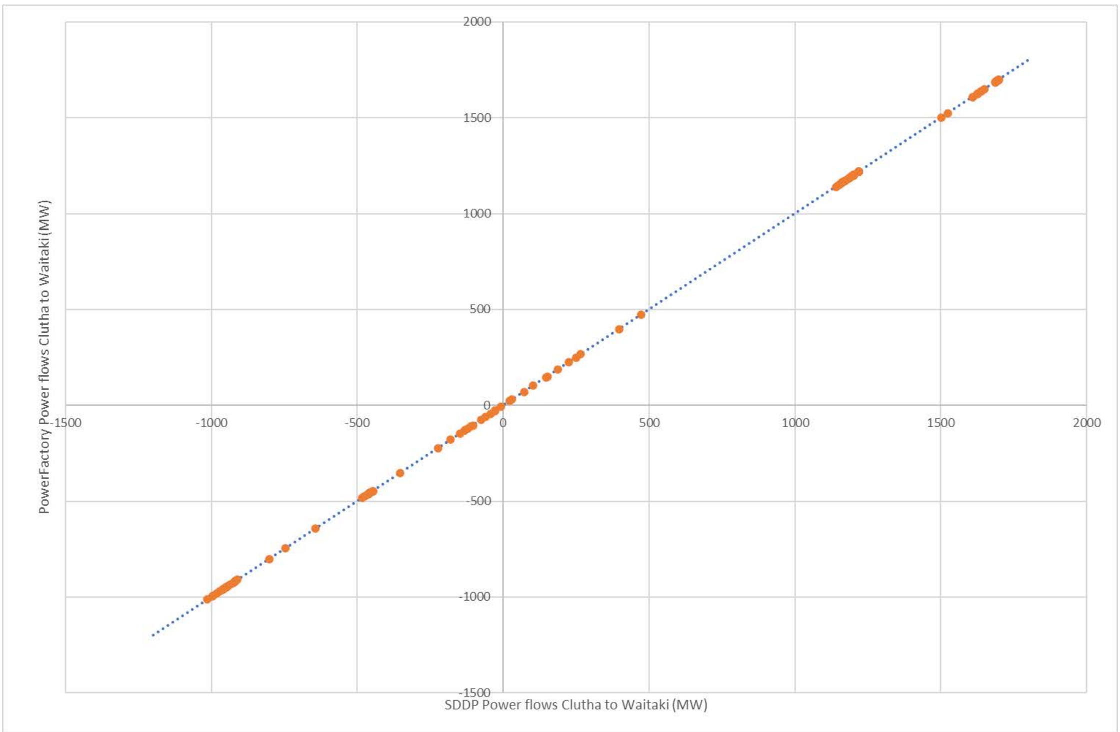


Figure 11 shows that the PowerFactory power flows on the interface between the Clutha and Waitaki Valley matches the SDDP snapshot power flows.

D.1.13.2 Pre-contingency overloads

Table 18 shows the circuits that overloaded pre-contingency and the frequency of that occurrence across the 120 cases.

Table 18: DC Load flow pre-contingency overloads

Circuit	Voltage	Number snapshots overloaded Pre-contingency
BPE-WDV-1	110 kV	43
BPE-WDV-2	110 kV	43
TWC-TWT-1	**220 kV**	**24**
MPE-MTO-2	110 kV	13
MPE-MTO-1	110 kV	12
KPO-TMU-1	110 kV	6
MTO-WEL-2	110 kV	5
CBG-HAM-1	110 kV	3
CBG-HAM-2	110 kV	3
MTO-WEL-1	110 kV	3
ABY-TIM-1	110 kV	2
ABY-TKA-1	110 kV	2
DOB-GYM-1	66 kV	2
HPI-MDN-1	**220 kV**	**2**
INV-NMA-1	**220 kV**	**2**
BRB-HPI-1	**220 kV**	**1**
HEN-WEL-1	110 kV	1
HEN-HPI-1	**220 kV**	**1**
HEN-WEL-2	110 kV	1

Table 18 shows that most of the pre-contingent overloads were not on the 220 kV network. There are five exceptions which are highlighted in the table.

Tararua Central-Tararua Tee

The Tararua Central - Tararua Tee circuit is a single tee circuit connecting the Tararua Central and Te Rere Hau windfarms to the grid backbone. Although the circuit operates at 220 kV it is not part of the grid backbone. The overload is caused by significant increases in generation at Tararua Central. This overload is managed by constructing a second tee circuit.

Huapai-Marsden, Bream Bay-Marsden, Henderson-Huapai

These circuits are the main 220 kV network into the Northland region. Although these circuits operate at 220 kV they are not part of the grid backbone they are considered to be regional circuits connecting Northland to the grid backbone. The overload is caused by significant new generation in

Northland. In the worst case 1,270 MW of new generation is installed at Bream Bay, Marsden and Maungatapere. To accommodate this additional generation a new 120 km double circuit 220 kV line is modelled between Marsden and Henderson.

Invercargill-North Makarewa

This circuit forms part of the 220 kV network in Southland. This circuit is part of the grid backbone. Therefore, no modelled project is assumed to manage this overload. In later analysis generation at Manapouri is constrained to prevent this overload from occurring. The overloads are caused by significant new generation at North Makarewa. In the worst case 610 MW of new generation is installed at North Makarewa, in addition to very high dispatch at Manapouri.

Lower voltage modelled projects

Table 19 provides a summary of modelled projects on the lower voltage networks used to prevent pre-contingent overloads.

Table 19: Modelled projects for lower voltage pre-contingency overloads

Overloaded circuits	Modelled project
Bunnythorpe-Woodville	Reconductor Bunnythorpe-Woodville
Maungatapere-Maungaturoto Maungaturoto-Wellsford Henderson-Wellsford	220 kV Northland circuit and 110 kV system split
Karapiro-Te Awamutu Cambridge-Hamilton	Modelled 220 kV GXPs west of Cambridge and Te Awamutu
Albury-Tekapo A Albury-Timaru	Reconductor circuit
Dobson-Greymouth	Relocate large Hokitika load to Dobson. This is in lieu of modelling a new circuit

D.1.13.3 DC Contingency analysis

Table 20 shows the occurrence and frequency of overloads on the 220 kV network for n-1 contingency analysis for all circuits and interconnecting transformers in the country.

Table 20: 220 kV DC load flow contingency analysis results

Monitored Circuit	Contingent Circuit	Number of snapshots with overload	Worst case loading (%)	Modelled project
AVI-BEN-1	AVI-BEN-2	45	182	Duplex
BPE-TNG-1	TKU-WKM-1	23	124	
BPE-TWT-1	BPE-LTN-WIL-1	21	134	
CML-TWZ-2	CYD-CML-TWZ-1	18	118	
BRB-MDN-1	HPI-MDN-1	17	169	New Northland Double circuit line
LIV-WTK-1	CYD-CML-TWZ-2	14	110	
INV-ROX-1	INV-ROX-2	12	127	
ALB-HPI-1	HEN-HPI-1	11	155	New Northland Double circuit line
CYD-ROX-2	CYD-ROX-1	11	122	
MTI-WKM-1	MTI-WKM-2	10	142	Enable existing SPS
BEN-TWZ-1	OHB-TWZ-3	10	128	
NSY-ROX-1	CYD-CML-TWZ-2	9	101	
AVI-WTK-1	CYD-CML-TWZ-2	8	109	
CML-TWZ-1	CYD-CML-TWZ-2	8	115	
RPO-TNG-1	TKU-WKM-1	7	112	
RPO-WRK-1	TKU-WKM-1	3	104	
BPE-LTN-1	BPE-TWC-LTN-1	3	113	
BHL-PAK-2	BHL-WKM-1	3	110	Short term overload
OPI-TIM-1	ASB-TIM-TWZ-2	2	102	
TIM-TF-T8B	ASB-TIM-TWZ-1	2	102	Modelled 220 kV Timaru bus
OHB-TWZ-3	OHC-TWZ-4	2	104	
LTN-TWT-1	BPE-LTN-WIL-1	2	107	
OHC-TWZ-4	OHB-TWZ-3	1	101	
OPI-TWZ-1	ASB-TIM-TWZ-2	1	105	Orari/Rangitata

Table 21 shows the n-1 overloads on the lower voltage network.

Table 21: Lower voltage DC contingency analysis results

Monitored Circuit	Contingent Circuit	Number of snapshots with overload	Modelled project
KAW-TF-T13	KAW-TF-T12	100	Replace KAW T13
OKE-TRK-1	KMO-TMI-1	65	Upgrade EDG T5 and return to service
HAM-TF-T9	HAM-TF-T6	55	Modelled New 220 kV GXPs in Waikato
HAM-MVE-1	HAM-PAO-WHU-2	40	Third HAM-WHU circuit
TIM-TMK-1	TIM-TMK-2	24	Existing SPS
EDN-INV-1	GOR-NMA-TMH-1	16	Modelled splitting SPS
FHL-RDF-1	FHL-RDF-2	15	Reconductor
HKK-KUM-1	HKK-OTI-2	15	Relocate HKK load to DOB
HKK-OTI-2	HKK-KUM-1	15	Relocate HKK load to DOB
HWA-SFD-1	WGN-WVY-1	14	Upgrade runback SPS
SBK-WPR-1	ASY-WPR-1	14	New runback SPS
ISL-KBT-1	ISL-KBY-HOR-2	14	Add thermal component to existing SPS
BPC-OAM-1	WTK-TF-T23	13	Enable existing SPS
SFD-TF-T10	SFD-TF-T9	13	Replace SFD T10
MVE-WHU-1	HAM-PAO-WHU-2	12	Third HAM-WHU circuit
CML-FKN-2	CML-FKN-1	12	Upgrade CML-FKN with larger simplex conductor
LFT-TRK-1	KIN-LFD-TRK-2	11	Modelled SPS
KIN-LFT-1	KIN-LFD-TRK-2	9	Modelled SPS
BRY-TF-T7	BRY-TF-T5	8	Tertiary capacitors
ARI-HTI-1	KPO-TMU-1	8	Modelled New 220 kV GXPs in Waikato
ARI-RTO-1	KPO-TMU-1	8	Modelled New 220 kV GXPs in Waikato
ASY-WPR-1	SBK-WPR-1	8	Modelled runback SPS
RDF-TF-T3	RDF-TF-T4	7	Third Redclyffe interconnecting transformer
BPE-MTT-2	BPE-MTN-WGN-1	6	Assumed SPS
BDT-WTK-2	WTK-TF-T24	5	Existing SPS
BPC-WTK-1	WTK-TF-T23	5	Existing SPS
CLH-COL-1	DOB-GYM-1	4	Relocate HKK load to DOB
HTI-RTO-1	KPO-TMU-1	3	Modelled New 220 kV GXPs in Waikato
KMO-TMI-1	TRK-TF-T3	3	Upgrade EDG T5 and return to service
APS-CLH-1	DOB-GYM-1	2	Relocate HKK load to DOB
COL-OTI-2	DOB-GYM-1	2	Relocate HKK load to DOB
TIM-TF-T8	ASB-TIM-TWZ-1	2	Modelled 220 kV Timaru bus

KIK-STK-3	STK-TF-T7	2	Assumed SPS
BPE-TF-T2	BPE-TF-T3	2	Third Bunnythorpe interconnecting transformer
WIL-TF-T8	HAY-WIL-1	2	Judgeford Tee
BDE-GOR-1	EDN-INV-1	2	Assumed SPS
GYM-KUM-1	ISL-KBY-HOR-2	1	Relocate HKK load to DOB
ARI-HAM-1	KPO-TMU-1	1	Modelled New 220 kV GXPs in Waikato
KMO-TF-T2	KMO-TF-T4	1	Upgrade EDG T5 and return to service
ISL-TF-T3	ISL-TF-T6	1	Fourth Islington interconnecting transformer
GOR-ROX-1	INV-ROX-2	1	Assumed SPS
BAL-BWK-1	BAL-GOR-1	1	Modelled SPS
BAL-GOR-1	BAL-BWK-HWB-1	1	Modelled SPS

D.1.13.4 AC load flow analysis

AC load flow analysis was performed only on the South Island network. There were a number of additional projects that were required to ensure that the steady state conditions provided a good initial condition for the transient analysis.

Clutha and Waitaki

For consistency a target voltage of 1.02 pu at Benmore and target pre-contingent reactive power injection of 50% of capacity was used for all Clutha and Waitaki generating units. In order to achieve this at very high transfer initial states some additional reactive support was required in the area. This reactive support was added in 50 Mvar capacitor banks at Cromwell, Livingstone and Twizel as necessary. The Cromwell support in particular was required to maintain voltage stability for Naseby-Roxburgh contingencies which caused very high power flows on the simplex Clyde-Cromwell-Twizel circuits. Enough reactive support was added to ensure convergence for a Naseby-Roxburgh contingency, no margin was applied.

Filters were operated at Benmore according to the HVDC operating policy.

For counterfactual cases additional shunt capacitors were required at Roxburgh.

Onslow

Onslow generation was dispatched controlling the 220 kV bus voltage at Onslow. The voltage setpoint was between 1.03-1.04 pu.

For pumping cases the motors were assumed to be unity power factor PQ machines. An SVC was installed on the 220 kV bus to measure the amount of reactive support required pre-contingency to retain 1.03 pu at Onslow 220 kV bus. The output of this SVC was then converted into a static capacitor for contingency analysis.

Upper South Island

To ensure that the voltage plane in the Upper South Island was realistic the following actions were taken:

- Orari and Rangitata switching stations were assumed

- Kikiwa 220 kV bus voltage was set to 1.03 pu. Kikiwa Statcom was maintained within +/- 5 Mvar. This was achieved where possible using the existing shunt capacitors and reactor at Stoke, Blenheim and Kikiwa. In some higher load growth scenarios additional reactive support was required, in which case a 50 Mvar capacitor was installed on the Kikiwa 110 kV bus.

- Islington 220 kV bus voltage was set to 1.03 pu. Islington SVC 9 was maintained where possible within +/-10 Mvar. This was achieved where possible using the existing shunt capacitors at Islington and Bromley. In some higher load growth scenarios additional reactive support was required, in which case a second 75 Mvar capacitor was installed on the Islington 220 kV bus.

- Timaru interconnecting transformer taps were fixed in a position where the sharing between T5 and T8 was similar and the Timaru 110 kV bus voltage was between 1.03-1.04 pu. In cases where Tekapo A was connected the generating unit was modelled as a PQ generator with a set point of 50% of installed capacity.

Southland

Many of the dispatch cases had no generation on at Manapouri. Rather than operate this generation in TWD we elected to remove transmission circuits to keep the voltage in the Southland 220 kV network reasonable. The following rules were applied:

- The North Makarewa 220 kV voltage was monitored to remain less than 1.045 pu

- The first step to reduce voltage was to remove the North Makarewa capacitors

- Secondly if there is no generation connected at Manapouri up to three of the four 220 kV circuits can be removed. Manapouri-North Makarewa 1 was selected as the circuit to remain in service.

- Thirdly circuits between Invercargill, Tiwai and North Makarewa are removed. They are removed in pairs where possible to ensure if possible that a second circuit remains between Invercargill and North Makarewa via Tiwai.

- On rare occasions a North Makarewa-Gore-Three Mile Hill circuit was also removed.

In some cases thermal issues arose on the 110 kV circuits into Balclutha. In that case a third 4 Mvar capacitor was assumed on the Balclutha 33 kV bus.

2.4.2 Lake Onslow when pumping with variable-speed turbines (Appendix D.2)

This part is a place-holder because, as of March 2023, we had not received a workable pumping model in either DigSilent Power Factory or in PSSE formats of the variable-speed turbines that form the NZ Battery Project's preferred Lake Onslow turbine design..

Due to the size of the proposed power scheme when pumping compared to the power system it is connected to we have had to use more conservative synchronous machine assumptions when conducting our analysis to date as variable-speed turbine models have not been available. To provide more informative and likely realistic power system results the following assumptions and work will be required

- For high HVDC southflow cases we consider that our simplifying assumption around the modelling of the HVDC link, as a constant impedance, is no longer adequate. To perform more accurate transient analysis of southflow cases we are recommending that a detailed model of the actual control system action of the HVDC link be used.

Until more representative pumping models and HVDC control action models are available to allow more granular transient analysis to be undertaken we will not be able to confirm higher pumping limits than 500-600MW when four machines are operating in pumping mode.

2.4.3 Lake Onslow when pumping with synchronous turbines (Appendix D.3)

We received a pumping model of synchronous turbines in DigSilent Power Factory format. This model is recognised as a simplification of the system and is not representative of how a scheme would be constructed. It does however allow Transpower to test the system in a conservative manner to understand the impact the Onslow scheme could have when pumping with significant Southward HVDC transfer as it provides a 'worst case' which highlights issues such as capacity and reactive power impacts that would need to be addressed. This part is a summary of the scenarios studied and their limitations as to how Onslow will impact the power system when in pumping mode as well as the impact on both North Island, South Island and HVDC systems when southward power transfer is dominant.

2.4.3.1 Power System Analysis – Phase Two

The purpose of this section is to present the analysis that has been performed to illustrate how a synchronous pumping solution comprising four off 250MW machines totalling 1,000MW capacity would impact but be accommodated in the Lower South Island power system.

A DigSilent Power Factory model of a variable speed pumped hydro machine is not presently available, and we can therefore not at this time realistically and with certainty evaluate the likely impact of the Onslow scheme when operating in pumping mode. To allow the project to move forward we have undertaken this modelling using a conservative set of assumptions that will define the outer edge of performance and should be seen as a theoretical exercise to establish boundary conditions. Therefore, the available synchronous machine model was intended to represent a pessimistic set of assumptions to test for these boundary conditions. If the synchronous model could be easily accommodated in the power system then we could confidently expect that a more complex and controllable, inverter connected variable speed model would also be acceptable. However, given that the initial model of the synchronous machines could not be easily accommodated a decision was made to determine how the synchronous model could be made acceptable using common power system components. This exercise included using tail water depression, which had pessimistically been completely disallowed in the initial analysis (D1) and the addition of synchronous condensers in the Lower South Island.

The analysis was performed in two parts.

1. Analysis of past system states using significant tail water depression to provide an outline of possible generating states to represent a constraint in SDDP that would not allow states where the existing fleet of generation could not provide sufficient TWD
2. Analysis of a significant number of SDDP hourly system state snapshots (referred to below as 'cases') to confirm that the constraints established in the first step were 'reasonable'.

It is important to note that because a need was identified for additional capacity in the first stage of studies a new double circuit line was assumed in later studies, even though for simplified analysis some SDDP snapshots were calculated with the Clyde-Cromwell-Twizel circuits duplexed, rather than a new line.

2.4.3.2 Analysis of historic system states

To perform analysis of some historic system states a range of different dispatch and load patterns were collected. These system states were added to PowerFactory by:

- matching load within an area to the closest hour of the initial 120 SDDP cases provided, then scaling to match the time stamp. The load was divided into Upper South Island, Southland, Lower Waitaki Valley and Central Otago.
- Dispatch for each generating station in the Waitaki, Clutha and Manapouri schemes was matched to the historic snapshot, the number of units in service was based on the methodology used in the initial studies.

The load at Tiwai was reduced to 0 MW, allowing the load at Onslow to be increased to 970 MW, the HVDC south transfer was increased to compensate for the 350 MW difference.

A total of 159 unique system states were analysed in this way. The data was then plotted on a graph of Lower South Island generation vs Waitaki Valley generation. The results indicated that with high generation in the South Island the instability shown by the pumps was more likely to occur. The reasoning for this was clear that the more generation available to operate in TWD, and therefore ramp up in response to a fault the better the response. And the less generation dispatched in the South Island the higher the south flow across the HVDC which is capable of recovering from the disturbance faster. Intuitively this makes sense. The Onslow pumps represent a huge percentage of the South Island power system when at full pump. The more responsive equipment there is connected to the network when they are disturbed by a fault the more likely the system is to recover.

To simplify the analysis the new 220 kV double circuit line between the Clutha and Waitaki valley systems was assumed to connect between the two strong existing nodes, Benmore and Roxburgh.

A curve was developed to illustrate the maximum amount of generation that could be accommodated in the South Island while Onslow was operating at maximum pumping.

We observed that if there was more than one pump connected the same phenomenon would be expected. In the interests of expediency, rather than develop curves for different operating points at Onslow the following assumption was made:

- A pumping variable was required to ensure the constraint was applied only when pumping
- There were no restrictions observed if one pump was operating
- A linear assumption was applied to the difference in pumping output.

This assumption is not ideal. However, given the uncertainties already included in the market modelling it is hoped sufficient to illustrate the limitations on the operating area when Onslow is in pumping operation.

2.4.3.3 Analysis of SDDP system states

In total 526 SDDP system states were analysed (including the 120 cases analysed in the initial work stream).

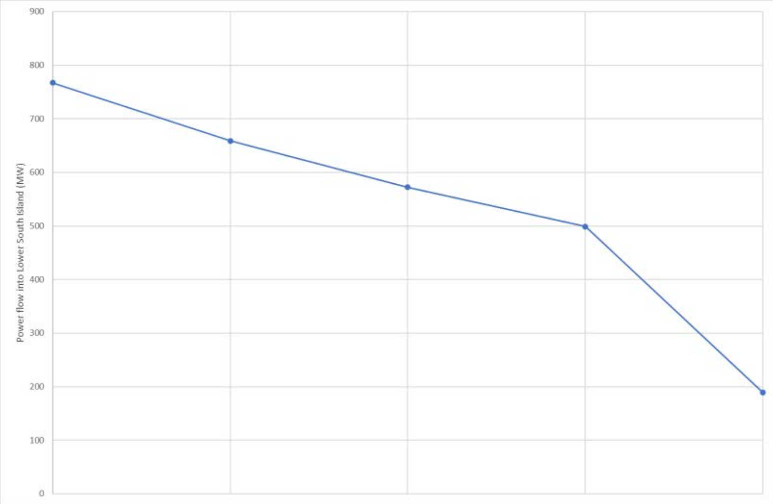
These snapshots were provided in ten blocks:

- Cases 0-119 represented the initial analysis performed in March 2022
- Cases 120-124 are five cases that represented a duration curve for the power flows across the boundary between the Clutha and Waitaki valleys refer *'SDDP snapshots_2022-06-08a'*
- Cases 126-175 were fifty cases provided to test out the proposed SDDP constraints refer *'SDDP_system_states_max_Onslow_pump_2020-08-09a'*
- Cases 176-225 were fifty very high south flow cases refer *'SDDP_system_states_max_Ben_to_ROX_flow_2022-08-09a'*
- Cases 227-276 were fifty high south flow cases refer *'SDDP_system states_max_pump_2022-08-17a'*
- Cases 277-326 were fifty high south flow refer *'SDDP_system_states_max_ROX_to_BEN_flow_2022-08-17a'*
- Cases 327-377 were fifty high south flow cases refer *'SDDP_system_states_min_and_max_ROX_to_BEN_flow_2022-09-20a'*
- Cases 377-426 were fifty high north flow cases refer *'SDDP_system_states_min_and_max_ROX_to_BEN_flow_2022-09-20a'*
- Cases 427-476 were the high southflow cases refer final set of cases in the dataset *'SDDP_syst_states_min_max_Onslow_and_ROX_to_BEN_flow_20222-10-05a'*
- Cases 477-526 were the high northflow cases refer final SDDP runs provided in the dataset *'SDDP_syst_states_min_max_Onslow_and_ROX_to_BEN_flow_20222-10-05a'*

2.4.3.4 Additional dataset to confirm pumping modelling limitations

The intention of these five cases was to determine if the identified instability was related to the very high southflow in the data analysed in the first stage of the project. The figure below shows a 'flow duration' curve for the five south flow cases.

Figure 12: Flow duration curve for south flow case set



The analysis of these system states showed that:

- Despite substantially reduced transfer across the transmission grid the instability with multiple pumps remained
- By operating all unused units in the Waitaki Valley, Clutha and Manapouri schemes in TWD the first swing stability issue could be fixed, however damping remained poor.

2.4.3.5 First datasets including pumping constraints

An initial constraint equation for generation in the South Island during pumping had been provided to the market modellers. A new dataset was provided with these constraints included. This data was provided in two sets a set with maximum Onslow pumping and a set with maximum south flow from the Waitaki to the Clutha Valley.

Cases 126-175

'SDDP_system_states_max_Onslow_pump_2020-08-09a'

These cases represented the maximum pumping states.

The base analysis assumed only that the Clyde-Cromwell-Twizel circuits were duplexed, there was no new line constructed between the Clutha and Waitaki Valleys. The following results were observed:

- With generation dispatched with a realistic unit dispatch and no TWD none of the provided cases were stable
- When all units that were out of service were returned to service in TWD mode 34 of the fifty cases were stable
- With a new line connected between Onslow and Benmore two cases were still observed not to remain stable, these represented cases that were right on the boundary of the constraint curve.

These results indicate that a new line is required

We identified that in all of these cases the Waitaki Valley generation was limited to 700 MW. This limit did not match the constraint provided so some additional data processing was performed by the market modellers to ensure the worst cases had been identified.

Cases 176-225:

'SDDP_system_states_max_Ben_to_ROX_flow_2022-08-09a'

These cases represented the maximum south flow into the Lower South Island from the Waitaki Valley. In these cases the Onslow pumping load was not necessarily a multiple of the installed capacity of the pumps. The pumping load was spread over the minimum number of pumps possible to achieve the total dispatch. Any unused pumps were assumed to be out of service.

This analysis showed that with or without a line upgrade these cases all remained stable with all available generators operating in TWD.

2.4.3.6 Second datasets including pumping constraints

Because of the 700 MW limit identified in cases 126-175 a new dataset was provided without this limitation included.

Cases 227-276:

'SDDP_system states_max_pump_2022-08-17a'

This dataset represented the maximum pumping states.

Again the base analysis was performed with duplexing of the Clyde-Cromwell-Twizel circuits.

We identified that in thirty of the fifty states there was a thermal issue with the base dispatch. The loading on the Benmore-Twizel circuit was a particular limitation overloading for a contingency of Benmore-Ohau B, Benmore-Ohau C or Aviemore-Waitaki.

The transient analysis showed:

- With generation dispatched with a realistic unit dispatch and no TWD none of the provided cases were stable
- All units that were out of service were returned to service in TWD mode 31 of the fifty cases were stable
- With a new Onslow-Roxburgh line all cases passed were stable with TWD.

Cases 277-326:

'SDDP_system_states_max_ROX_to_BEN_flow_2022-08-17a'

This data represents the maximum south flow from the Waitaki Valley to the Lower South Island.

We identified that in eighteen of the fifty states there was a thermal issue with base dispatch. The limiting circuit was Benmore-Twizel.

The transient analysis showed:

- With all available units on TWD eighteen of the fifty provided cases were stable

- With a new Onslow-Benmore double circuit line four of the fifty cases were unstable with all available units on TWD
- The cases that were unstable with the new line and TWD suggested that different generators at specific locations had a significant impact on the stability. Rather than focus too closely on this relationship we proceeded to confirm the impact of synchronous condensers on the number of TWD units required.

2.4.3.7 New North and Southflow datasets

Following additional market modelling a new set of maximum transfer cases across the Waitaki Valley/Clutha interface were provided. The intention of providing this data was to confirm previous analysis of the north flow cases for consistency, and ensure that nothing had changed between the north flow analysis completed in April 2022,and the most recent market modelling.

Cases 327-376:

'SDDP_system_states_min_and_max_ROX_to_BEN_flow_2022-09-20a'

These cases represented the maximum southflow cases across the Waitaki Valley/Clutha interface. These cases were not specifically analysed, as they were understood to be similar to the data set discussed earlier.

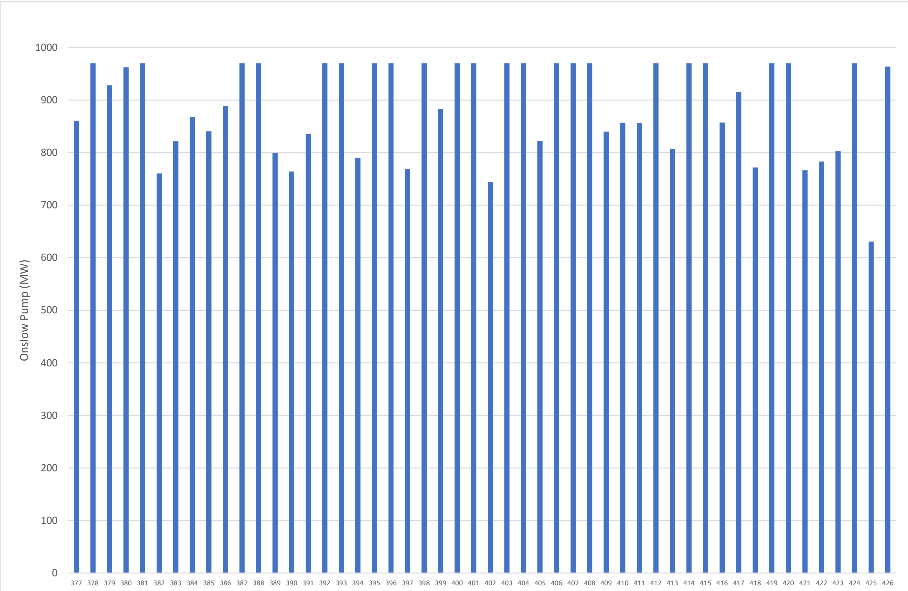
Cases 377-426

'SDDP_system_states_min_and_max_ROX_to_BEN_flow_2022-09-20a'

These cases represented the maximum northflow cases across the Waitaki Valley/Clutha interface.

In analysing these cases we noted that although the transfer across the boundary was high it was not always the case that Onslow generation was particularly high and the figure below shows the range of Onslow dispatch for these cases.

Figure 13: Onslow generation for maximum northflow cases



The analysis also showed:

- There were considerable thermal issues with only the Clyde-Cromwell-Twizel circuits when duplexed with overloads occurring in all cases. The limiting circuit was Naseby-Roxburgh. There were additionally overloads on Invercargill-Onslow circuits due to the substantial new generation that SDDP assumed would evolve in the Southland region and assumed for modelling simplicity to be represented at North Makarewa and Invercargill.
- Fifteen of the cases were not stable with only the Clyde-Cromwell-Twizel circuits duplexed
- With a new Benmore-Onslow double circuit line thermal issues remained on the Invercargill-Onslow circuits but did not appear otherwise
- All cases were stable with a new Benmore-Onslow double circuit line.

Cases 427-476

Following on from the previous analysis identifying that the northflow cases did not necessarily represent the greatest impact of Onslow on the power system a further data set was provided.

These cases represented maximum southflow across the Waitaki/Clutha interface.

The first step in this analysis was to remove any thermal constraints. This was achieved by increasing generation in the Otago and Southland regions to remove overloads on the Benmore-Twizel circuits and further to increase generation in Southland further if the Clyde-Roxburgh circuits overloaded.

The transient analysis showed that with the base network:

- None of the fifty states provided were stable without TWD being available
- With all 22 TWD units available and committed only 22 of the fifty cases were stable

A new double circuit line was then included between Benmore and Onslow. The dispatch was returned to the base case dispatch. And the following results observed:

- the maximum loading on the Benmore-Twizel circuit was 84% for an Ohau B-Twizel circuit contingency[3]
- four of the cases were not stable with all available TWD units dispatched

2.4.3.8 Alternative to TWD

The analysis to date was performed by utilising every existing generating unit in the Waitaki, Clutha and Manapouri schemes in TWD mode. We understand that this is unrealistic and was done for modelling simplicity to establish the base requirements of the power system should Onslow be introduced. We are fully aware that there are significant practical and economic limitations on putting an entire station on TWD. We do not want to give the impression that this is a reasonable or practical operational approach for such a large and complex system such as the power system as there will always be equipment needing to be maintained, water flow rates to be managed and outages on the transmission network. It is not reasonable to expect to rely on the availability of all of the existing assets in the South Island to maintain system stability. Without obtaining more complex models of a non-synchronous variable speed hydro machine the simplified model

[3] It should be noted that no thermal issues with the new line were anticipated as the SDDP calculations were performed without the line so we would expect the loading to be limited.

approach that won't constrain the pumping to one unit, is to conceptually add traditional reactive plant to the system to understand both the technical and economic magnitude of the issue to be addressed.

To illustrate what the potential order of cost magnitude was of providing this capability without requiring an unrealistic full system availability we tested an alternative approach by installing additional synchronous condensers at a nearby bus until satisfactory system performance was obtained. It needs to be stressed that this is a theoretical approach that lets us electrically model the system and that it is not to be interpreted as an actual real-world implementation. We would therefore caution that the following results should be viewed through the lens of providing a possible cost to accommodate large synchronous pumps within the South Island transmission network and is not to be considered an actual proposed design.

We reiterate that like the initial analysis a more sound design is likely to involve installing more sophisticated and costly inverter connected pumping which is not expected to experience the same stability issues identified in the analysis to date. However until a power system model of such units is provided we will not be able to confirm this assumption and the impact these large machines will have on the power systems ability to operate and remain stable both before, during and after a fault. We eagerly await a suitable alternative model to confirm this.

Alternative operational approaches that did not include providing less than N-1 security to Onslow have not been considered to date. These include allowing the pumps to not ride-through power system faults and disturbances but instead to remove them from service. This may form part of additional works when a new model is provided.

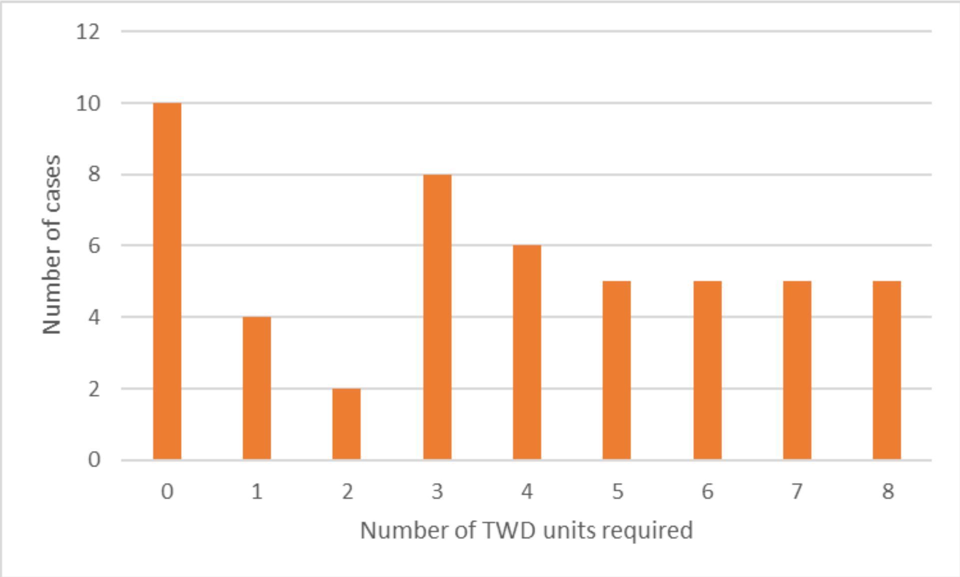
2.4.3.9 Synchronous Condenser Results

Including the additional dedicated reactive plant capability, substantially reduced the need to commit all South Island generators to be available for reactive support. Instead for each of the fifty cases we included 10 x 60 MVA synchronous condensers. There were some cases that still required some TWD but it was no longer necessary at every site. As a working assumption NZ$150M was budgeted to provide up to 500MVars of reactive support which is commensurate with recently completed projects.

The use of synchronous condensers was again a conceptual engineering simplification to illustrate the effect of the required reactive support. Any alternative source of dynamic response may provide the same stabilising capability.

In the worst cases in addition to the 10 x 60 MVA condensers, eight TWD units were required. This represented in all cases less than 50% of the unused units. The figure below shows the distribution of TWD units required across the fifty cases.

Figure 14: Number of TWD units required for stable operation with synchronous condensers



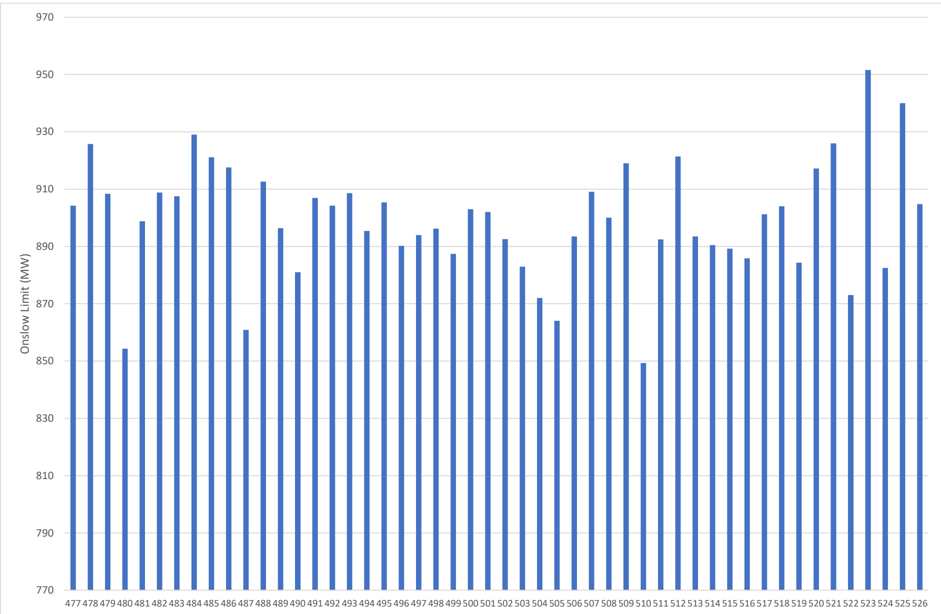
The plot shows that half of the cases required less than four additional TWD units.

Cases 477-526

These cases represented maximum northflow across the Waitaki/Clutha interface.

The first step was to remove any thermal issues by reducing the output at Onslow. **Error! Reference source not found.**shows the dispatch limits at Onslow to manage overloading of Naseby-Roxburgh. In all cases the initial dispatch was 970 MW.

Figure 15: Limit on Onslow generation due to thermal constraints



With a new double circuit line these thermal limitations were removed. The maximum loading is 95% on Cromwell-Clyde for a Clyde-Cromwell-Twizel contingency.

2.4.3.10 Summary

The modelling work to date indicates that to accommodate Onslow in the power system that

- A new double circuit 220 kV line between Onslow and Benmore is required for system stability and thermal overloads in other parts of the network to be managed
- A significant amount of reactive support is required to allow Onslow to operate in pumping mode should fixed speed machines be utilised. It is anticipated that variable speed machine would be procured to limit the schemes system impact and reduce the requirement for additional reactive support.
- The reactive support could be provided by dedicated synchronous condensers, FACTs devices, or specifying the new Onslow machines with this capability
- Additional detailed power system studies are required utilising machine specific non-synchronous models to confirm the transient dynamic impacts Onslow could have on the power system across all operating envelops.

2.5 Lake Onslow transmission requirements (Appendix E)

This appendix outlines options for and the preliminary recommendations for transmission investments to mitigate the constraints identified by the power systems analysis

One of the MBIE SDDP identified soloutions to the transfer limits between the Clutha and Waitaki valleys is the duplexing of the existing Clyde–Cromwell–Twizel 220kV double circuit line. This is certainly a possible option and one Transpower also identified and would place on a long list of options for consideration due to its apparent simplicity, maximisation of existing assets and cost.

Transpower identified this option as well in addition to a new build 220kV double circuit line between the Clutha (Onslow) and Waitaki (Benmore) regions.

The choice between options includes a number of criteria and some of those that heavily influence Transpower's decision include those described below. Due to these reasons and the additional transfer capacity provided, Transpower's preferred option to improve the transfer capability between regions is a new build double circuit 220kV line.

The options have been compared below, indicating the potential capacity between the Clutha and Waitaki Valley. These potential capacity values represent the numeric sum of the parallel circuits. In reality, the power flow across these circuits will share depending on their relative impedances and the location of load and generation between the regions. In addition, the voltage plane and reactive power flows will influence the total capacity between the regions. Therefore, the numbers presented below should be taken as an indicative representation of the n-1 maximum capacity between the regions based on total thermal conductor rating.

E.1 Existing situation

At this time there are two 220kV lines carrying three circuits between the Clutha and Waitaki valley.

- Clyde–Cromwell–Twizel (ROX-TWZ_A double circuit approx 600 MW per circuit)
- Roxburgh–Naseby–Livingstone (ROX-ISL_A single circuit approx 650 MW)

This provides an n-1 maximum transfer capability of approximately 1,200 MW between the two regions.

An n-2 contingent loss of a tower on the double circuit line removes two circuits leaving only 600MW of capacity between the regions. And in the event of a longer term outage of the double circuit line this transfer may be further limited by frequency and stability concerns.

E.2 Reliability and availability

With the addition of Onslow to the power system and the need for additional transfer capability between regions the reliability and availability of these circuits for maintenance increases. Having one of the circuits out for maintenance limits the n-1 maximum transfer capability to 650 MW.

E.3 Constructability

The circuits between the two regions are already highly loaded through the year. To be able to reconductor the double circuit line would place the system at a reduced level of security for long periods of time while the double circuit line had one circuit being reconductored and the other out of service so the work could be undertaken safely. For this reason it is assumed that temporary sections of bypass line would be required to be constructed adding to the cost and disruption of the reconductoring option.

E.4 Security and resilience

The existing double circuit line is presently considered as a credible contingent event due to lightning and is managed as such when lightning is in the area. Duplexing the existing line to double its capacity to 1,200 MW per circuit, significantly increases this risk of a major system event should one or both circuits trip.

To address this additional lightning mitigations such as transmission line surge arrestors fitted to each phase of each circuit on each tower and adding increased lightning protection shield wires will add to structure loading, complexity and cost.

The importance of the duplexed line would also increase the consequences of its exposure to natural catastrophe events such as wind storms, land movement, snow storms and seismic activity. The consequence of a physical tower or circuit failure would need to be mitigated by reinforcing and strengthening the towers, foundations and hardware again increasing cost.

E.5 Summary

Construction of a double circuit third line directly between Onslow and Benmore will mitigate the security, resilience, reliability and availability concerns of duplexing two of the three existing circuits by providing an additional two circuits of approximately 800 MW capacity each. This will provide three geographically diverse line routes, one of which is directly from Onslow to the HVDC terminal at Benmore. The five circuits will provide a maximum capacity of 3,400MW and a maximum n-1 capacity of 2,600MW (2,200 MW during lightning storms) between the Clutha and Waitaki regions. It will remove the construction and operational challenges associated with duplexing the existing Clyde—Cromwell—Twizel circuits. Overall construction cost will be similar to the duplexing option once additional lightning mitigation, tower strengthening and temporary line works are included. This approach also provides an additional 250 MW of capacity over the duplexing option.

For these reasons Transpower would select the construction of a new double circuit line over the duplexing option.

E.6 Supporting Transmission works cost estimate

The costs associated with the South Island HVAC system issues and possible modifications contained in this feasibility study are based on similar recently completed Transpower projects such as CUWLP and BPE-HAY_A & B reconductoring and the WRK-WKM_C new build lines project.

For transparency the cost of all modifications initially identified is provided. However when allowing for the ability to construct assets, gain outages or consider other factors such as system resilience the only options that are viable and have been used in the power system modelling analysis are the new 220kV double circuit Clutha to Waitaki transmission line and the duplex AVI-BEN_A line.

All cost estimates are to Class 4 (-30/+50%) accuracy unless stated otherwise.

The preferred transmission investments into eh existing South Island HVAC system is the construction of the new 220kV double circuit line from Onslow to Benmore and the Duplexing of the existing 220kV Aviemore – Benmore line for a total cost of $488 - $580m

Table 22: Onslow South Island AC transmission mitigations

Project	Capacity achieved	Modification	Distance (km)	Cost (NZ$/km) (NZ$M)	Project Cost (NZ$M)
CYD-CML-TWZ	As needed	Duplex existing	~140	0.5	70
CYD-CML-TWZ	Additional construction costs	Security, resilience, constructability	~140	175-205	175-205
CYD-CML-TWZ	As needed	New Line	~140	2.5-3.0	350-420
Clutha-Waitaki	As needed +250MW	New Line	~180	2.5-3.0	450-540
AVI-BEN_A	As needed	Duplex existing[4]	~19	2	38

North Island HVAC power system analysis has not been undertaken for generation or pumping modes. At this initial feasibility stage and from inspection we can assume that any increase in the present Southward transfer limits of approximately 900MW will require the works outlined below to obtain approximately HVDC 1,400MW.

Table 23: Onslow North Island AC transmission mitigations

Project	Capacity achieved	Modification	Distance (km)	Cost (NZ$/km) (NZ$M)	Project Cost (NZ$M)
Existing HVDC Reactive augmentation	400-500MW	Additional STATCOMs	NA	NA	150-200
HVAC BPE-HAY transfer increase	400-500MW	Duplex BPE-HAY_A & B	~119 + 119	0.55-0.65	128-150
HVAC BPE-WRK transfer increase	As needed	Duplex BPE-WRK_A	~215	0.83-0.95	180-204

[4] AVI-BEN_A is a highly loaded circuit that is difficult to remove from service, crossing challenging topography. System Solution Report (SSR) level costs indicate reconductoring requires temporary lines etc and will therefore be similar to a new build line.

The power system connection requirements and implications that might impact on the Lake Onslow power station design choices are summarised in the table below. Please not HVDC costs are to Class 5 not Class 4.

Table 2: Summary of Power System Connection Costs for 3 of many scenarios[3]

Power System Connection Costs **All cost estimates are to Class 4 (-30/+50%) accuracy unless stated otherwise**				
Investment	Costs	Onslow SI only	Onslow SI + HVDC and NI upgrades	Onslow SI + New HVDC
HVAC South Island	$488M-$700M	$488M-$700M	$488M-$700M	$488M-$700M
Existing HVDC South	$150-200M		$150-200M	
New HVDC	$3B-$4B			$3B-$4B
HVAC North Island	$388M-$354M		$388M-$354M	
TOTAL		**$488-700M**	**$1,026M-$1,254M**	**$3,488M-$4,700M**

Taken collectively these power system developments will require the following investment profiles

Item	Assumption	Cost
Increase transfer Roxburgh to Waitaki	There is a need to increase transfer capacity from the Roxburgh region to the Waitaki Valley. We estimate the costs as: • New double-circuit line Onslow substation to Benmore $488 M to $580 M • Aviemore-Benmore duplexing $38 M	$526 M – $618 M
Increase southwards transfer to the South Island	Maximising Onslow operations will benefit from upgrading two North Island HVAC lines, beyond what is currently planned in Transpower's NZGP. We estimate the costs as: • Bunnythorpe – Haywards duplexing $128 M to $150 M • Bunnythorpe – Wairaki duplexing $180 M to $ 204 M HVDC southwards capability will be increased by the Bunnythorpe – Haywards duplexing, and can be further increased with improved reactive support in the lower North Island. We estimate the costs as: • Additional StatComs in the lower North Island $150 M to $200 M	$458 M – $554 M
New HVDC	A second HVDC link, if required, is assumed to: • have the same 1400 MW of inter-island capacity as the existing (upgraded) link • be from Onslow to the central North Island, e.g. Whakamaru or Huntly • be on a separate route to the existing HVDC to maximise resilience	$3B - $4B

These initial impacted assets and the proposed modifications are for the wider power system developments and costs associated with connecting the Onslow power station and include

- Modifying the South Island HVAC network to include a new 220kV Onslow-Benmore line connecting the Clutha and Waitaki valleys and increasing the Waitaki Valley transfer capacity
- Additional HVDC reactive plant to increase southward transfer over and above that which may be approved by the Commerce Commission in our planned NZGP 2030 Major Capital Proposal (MCP)
- Additional North Island HVAC network southward capacity over and above that which may be approved in the NZGP 2030 Major Capital Proposal (MCP)
- A new HVDC link between Onslow and Huntly should it be justified. Such a significant investment may remove the need for other grid upgrade expenditure identified in this table or likely but yet to be scoped under NZGP post 2030. This is subject to further detailed integrated analysis that was beyond the scope of this commission.

2.6 Lake Onslow transmission charging (Appendix F)

With changes to the Transmission Pricing Methodology (TPM) the NZ Battery Project has requested if Transpower is able to determine what magnitude the transmission connection costs will be and how they may be allocated, and in particular what proportion will be allocated fully to Lake Onslow.

Broadly Transpower assets that form the Grid can be grouped into two major asset classes. These asset classes are

- Connection assets which are easily identifiable to one or a number of discrete parties
- Interconnection assets that provide wider transmission services that all electricity customers pay for.

Transpower has not provided an estimate of the likely interconnection charge that Onslow will need to pay as the TPM is changing from its present arrangement to be a more reflective Benefits Based Charge model where generators and load will share costs of the interconnected network dependant on the benefits they receive.

The new Onslow power station will be responsible to meeting the following charges:

- Capital recovery of all new assets created or modified over an agreed timeframe. Once repaid these charges cease
- Annual and ongoing connection charge that is for operations, maintenance of created substation assets
- Annual and ongoing interconnection charge that is for a contribution to the operation and maintenance of the wider interconnected network.

Regarding Onslow, direct capital investment of approximately NZ$84 million under a Transpower works agreement (TWA) would be required (under the conceptual Lake Onslow connection design outlined in Appendix C) for the entire new grid customer connection GIP required to connect Onslow power station to the Grid and this will be attributable to Onslow.

It should be noted that this is only a component of the actual cost to connect to the network as it excludes the line diversions and new line works required to connect the new GIP into the wider transmission network.

F.1 Capital Recovery of new Investment (TWA)

The new substation associated with the Onslow power station development will primarily be considered a Grid Injection Point (GIP) when generating although it will also function as a Grid Exit Point (GXP) when it is pumping. The cost to construct the new substation is estimated to be NZ$84 million for the substation only, and excludes line diversion, new line construction and remote end construction costs. Onslow will be regarded as a GIP as its primary function for the the new power station to inject electricity into the network. It could however also act as a Grid Exit Point (GXP) if it was to provide a local service power supply to the power station, or a local distribution company.

These costs would need to be recovered either via a major capital proposal (MCP) or TWA.

Construction cost estimate on which these were based were to Class 4 accuracy

F.2 Annual connection charge

The calculations provided are an estimate based on the current TPM (effective until 1 April 2023) for pricing year 2022/23, and still includes Injection Overhead.

The connection costs are for the operation and maintenance and future management of the assets created using either an MCP or TWA:

- Estimated yearly connection charge if the new GIP is built with TWA: ~$2.5 million – $5 million depending on final capital cost (with TWA, there will be extra TWA charge to Onslow, which we do not know at this stage)
- Estimated yearly connection charge if the new GIP is built with MCP: ~$5.4 million – $10.8 million depending on final capital cost

F.3 Annual interconnection costs

We have not estimated annual interconnection costs at this time as the present Transmission Pricing Methodology (TPM) is under review and will be altered in 2023.

F.4 Disclaimer

The calculations we've provided are an estimate based on the current TPM (effective until 1 April 2023). On 12 April 2022, the Electricity Authority approved a new TPM ("new TPM") to take effect from 1 April 2023.

The new TPM retains most of the features of connection charges under the current TPM, however there are some changes to the way connection charges will be calculated under the new TPM, including (but not limited to) the removal of the injection overhead component (currently paid by generators).

Nothing in this response is a formal calculation of charges for any pricing year.

Actual charges may be different to the indicative charges.

Transpower specifically disclaims, and has no, liability to you or any other person for the accuracy or completeness of the indicative connection charges in this response or reliance on that information. Reliance on the indicative connection charges is at your or their own risk.

We recommend you:

- consult the TPM and any records of relevant input information you may have access to, and
- seek independent expert advice before making any decision based on the indicative charges in this response.

2.7 South Island NZ Battery resilience scenarios (Appendix G)

This appendix presents a number of HVDC failure scenarios with failure, capacity consequence, likelihood and time to repair, that might be relevant to an assessment of the resilience of Lake Onslow to HVDC failure. Various hazards have been considered including local flooding and land movement to large wide area events such as large seismic movements such as an Alpine Fault rupture (AF8) or tsunami. It is important when considering these events to note how different components of the power system are impacted by each event. For example, transmission lines are generally quite resilient to earthquakes unless an individual tower is affected by the localised land movement around it, whereas powerstation or substation physical components may have more components affected by shaking around it. It is also important to consider the interrelationship between the assets that serve an area and the area affected by the particular hazard. This is most marked when considering Tsunami. For example, should a Tsunami affect an urban area, then the infrastructure that serves the same area may not be required to be available as there is no community to serve.

The following HVDC risk and repair scenarios was prepared as part of the MBIE and Transpower workshop, November 2021.

The following table illustrates HVDC risks with repair time greater than one week

Table 24: Resilience scenarios for a South Island NZ Battery solution

	Assumptions needed for SDDP modelling (assuming the 4th Cook Straight cable is in)			**Post-processing**	**Context**		
	Transmission asset failure scenario	**HVDC transfer limitation (1400 N and 950 S MW normal)**	**Average repair time (assuming urgency)**	**Frequency / likelihood**	**Most likely causation**	**History**	**Reference**
a	Single cable, in shallow waters	1200 MW N (700MW and 500MW) 950 MW S unchanged	6 months		Mechanical: trawling or anchor or propellor drop Electrical	• None on power • Have not lost power cable but have had sheath damage to it. Have lost fibre twice • Historically there has been single-cable	HVDC fault cases
b	Two cables, shallow	1000 MW 950 MW S unchanged	8 months		Mechanical: trawling or anchor drop		HVDC fault cases

					Double electrical failure unlikely	electrical failures, i.e. cable failure in 2005 on cable 6, took ~6 months to repair at an approx. cost of $20M) • Cigre reports include other cases	
c	Single cable, deep	1200 MW 950 MW S unchanged	15 months	Return period 2,500 years (see CIGRE report)	Anchor or propeller drop Earthquake Electrical	None, but have been two near misses in last 13 years	HVDC fault cases
d	Two cables, deep	1000 MW 950 MW S unchanged	15 months	Return period 2,500 years	Anchor or propeller drop Earthquake		HVDC fault cases
f	Overhead tower collapse	0 MW both ways (HVDC bipole outage)	2 weeks	1:100 – 1:300 years	Wind, floods on river crossings, malicious damage, earthquake	Multiple wind and flood events	HVDC fault cases
g	Cable termination station flooded (tsunami)	0 MW both ways (HVDC bipole outage)	6 months	Return period 2,500 years	Specific earthquake: worst case rupture on the Hikurangi subduction zone, big enough for water to enter building	None	
h	Valve hall fire	700 MW N 700 MW S	12 months	1 in 300 years	Electrical fire (also some fire risk to control room but lower probability and consequence)	Valve hall has sprinklers run manually.	

NOTES

For transformers and fires

- We have a transformer fleet population of 340 transformers
- We have had no transformers catastrophically fail and be engulfed in flames although we have had small bushing fires which have not progressed into a fire that is talked about i.e. catastrophic. Note the time to restore the unit to service depends on fire propagation within the unit but is a minimum of 3-6months
- We should use the Cigre[5] reliability survey/brochure numbers from 2015-17. These are an overall major failure rate of 0.53% and 13% of these are estimated to have caused either an explosion or fire.[6]
- Attached in email to CE is a recent paper on Australian/New Zealand failures and fires which can be reference and provides more accurate details. We use this data in our AHI tools for transformers.

In the last 6 years SE 7 to 10.

- 57% all machines in
- 31% 3 machines in
- 11% 2 machines in
- 0.65% machine in

Scheduled maintenance discounting faults is about 10 days per year on maintenance outages.

Every 10 years there is a 10 days extra outage (Pole 2 half-life refurbishment, to extend operation for 30 more years). Primary equipment at Pole 2 is old.

[5] Cigre, established in 1921 it is a global organisation of power system professionals who actively engage, develop and share knowledge and experience relating to the design, operation, maintenance, of high voltage power systems and their components across all technical, environmental, commercial and regulatory disciplines.

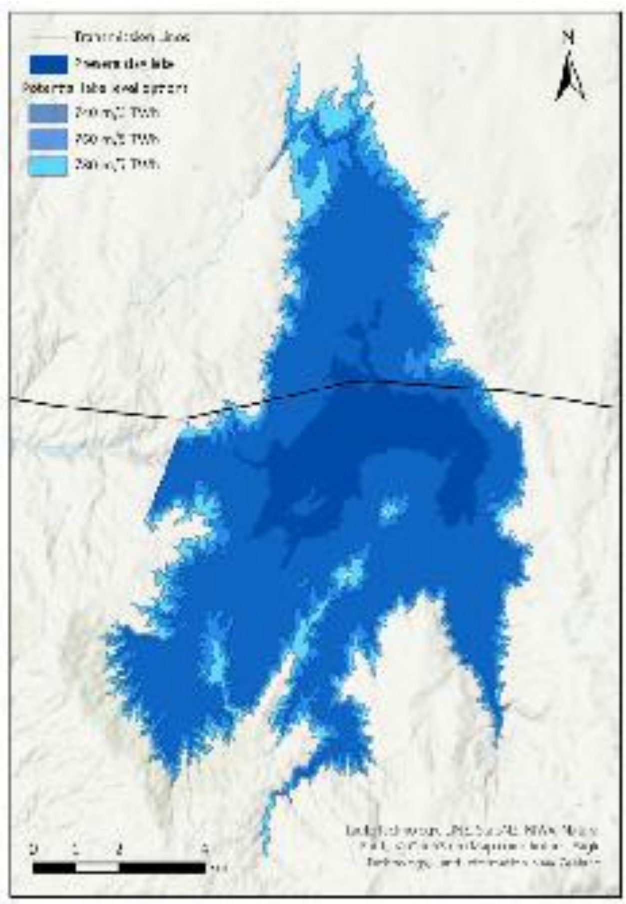
1.1 6 Cigre Technical Brochures, 537 Guide for Transformer Fire Safety Practices, 642 Transformer reliability survey,

2.8 Re-alignment of existing ROX-TMH_A line around Lake Onslow (Appendix H)

Note that the analysis in this Appendix was conducted before the conceptual Lake Onslow connection design outlined in Appendix C was developed. The Appendix C conceptual connection design locates the new GIP to the South of the expanded Lake Onslow and thus requires the Southerly diversion of the ROX-TMH_A line south into and out of Lake Onslow substation, obviating the need for the re-alignment discussed here. We have recorded this analysis here for transparency and in case the connection design changes and there is a need for re-alignment.

One option that NZ Battery is considering is a Pumped Hydro Energy Storage (PHES) Scheme, located at Onslow. The potential characteristics of such a scheme are under investigation, with pre-feasibility work due to be completed by Q4 2021. Information has been sought from Transpower based on the 'first approximation' characteristics described below, especially as there may need to be iterations in optimising NZ Battery design within the wider electricity system.

Figure 16: Potential Lake Onslow flooded area



The ROX-TMH_A 220kV double circuit line crosses the fringes of the existing Lake Onslow. If the potential Onslow pumped hydro energy storage scheme goes ahead, the lake perimeter will expand, and a section of this line will need to be shifted. The present lake surface height is 684m above sea level. A 5 TWh Onslow would have a reservoir surface height of around 760m above sea level, a 3 TWh 740m and 7 TWh 780m.

H.1 Objective

MBIE seeks from Transpower indicative cost and risk estimates of this option, to allow it to confirm this conclusion or to explore the option in greater detail. A realistic view from an independent third party with in-depth domain knowledge that will be used to inform the NZ Battery project.

H.2 Response

Our response will be to describe how the existing ROX-TMH_A 220kV double circuit line could be diverted around the new lake

We assume that:

- Stay within land obtained for new lake
- Divert to north as shorter than southern route
- Build to Transpower's design standards

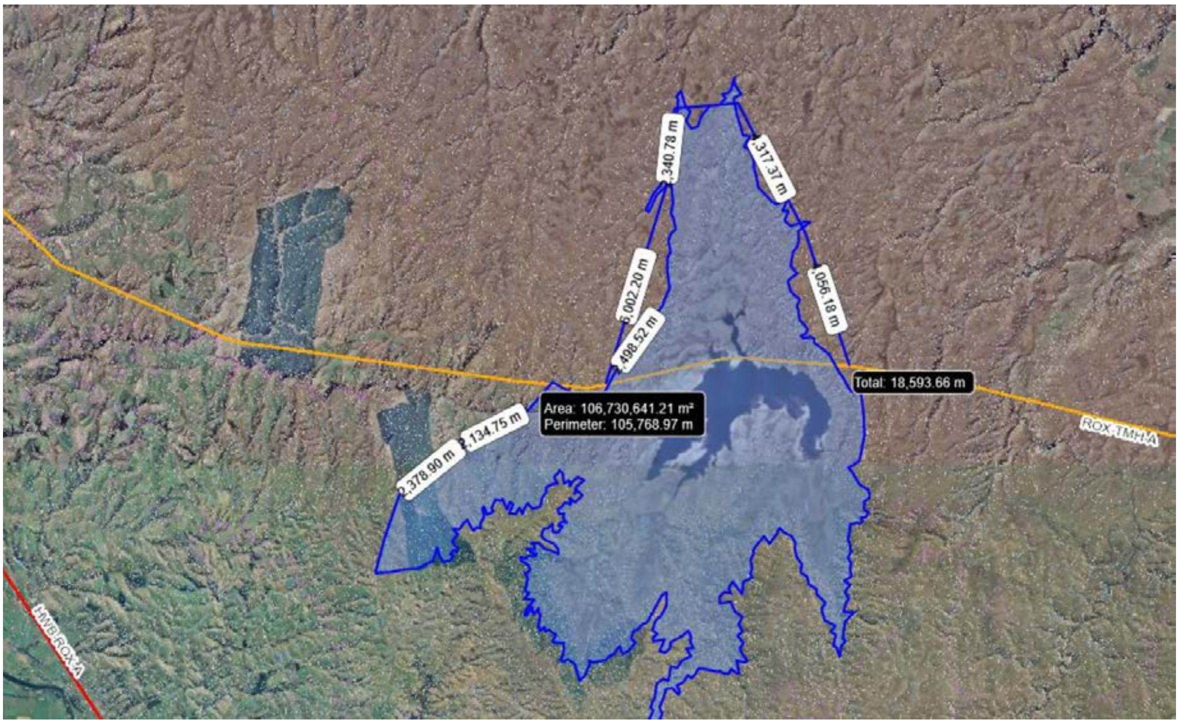
Assumptions

- Physical: Line diversion with same design standard as existing
- Legal/Policy
  - Project obtains property rights and consents
  - Assume all sensitive environments cannot be avoided (despite a robust route selection process). Assume any biophysical bottom lines under the proposed Natural and Built Environments Act, the proposed NPS-Indigenous Biodiversity or the NPS-Freshwater/NES- Freshwater can be overcome.
- Time:
  - Assume [2-3 years] for WRK- C under the RMA will be reduced under any replacement legislation.
  - Assume barriers in other legislation is overcome (e.g. Heritage New Zealand Pohere Taonga Act, Conservation Act, Wildlife Act, Public Works Act), and any necessary approvals are obtained in a timely manner.
- Financial: Budget $2 million per km

H.3 Feasibility and cost of connecting re-alignment of transmission towers over Lake Onslow

The existing ROX-TMH_A double circuit 220kV line crosses the existing Lake Onslow. Should the PHES scheme progress the size of the lake would require a section of approximately 6-7km of the existing line to be relocated by diverting the line around the northern end of the lake before returning to the existing alignment This completed diversion would be approximately 18-20km in length.

Figure 17: Potential realignment of transmission towers over Lake Onslow



Note: the line diversion shown is indicative and has not been subject to a route selection process.

H.4 Solution financial quantum and accuracy

Cost and time estimates assumed to be as per AACEI 69R-12 hydro and 96R-18 transmission estimate standards Class 5 (concept screening -20%+100%), at best Class 4 (Feasibility -15%+50%).

Assuming the PHES project obtains all property and consenting rights, the cost to construct the diverted line including access tracks, crane pads, towers, wiring and changes to the protection scheme at each end would be approximately NZ$40M to Class5. Five years to complete from commencement of project.

H.5 Summary

This approximately 18km long diversion of an existing transmission line around the proposed new lake is estimated to cost $30-40M with at least a three-four year design and construction period following a consenting timeframe of one year (assuming use of the existing RMA fast track call-in process). All costs exclude the cost of property procurement.

2.9 Lake Onslow treatment by System Operator (Appendix I)

The NZ Battery Project has asked Transpower how Lake Onslow may be treated by the System Operator. Our observations follow.

I.1 General

Making a comment on a future market participant and how they may operate in a market that is at least 10 years in the future is challenging as the landscape is very hard to determine.

To try and assist any comments made in how Lake Onslow may operate are made in respect to today's market only.

Any issues or challenges that may occur can be considered as a pointer to future work that MBIE and others may need to consider.

From the market perspective at present things would appear to be relatively straight-forward.

Conceptually we do not see the value in considering Onslow as a Battery due to modelling and change treatments being of a different scale. For example 'state-of-charge' which is key for probably battery modelling/treatment changes is not very relevant due to the magnitude of storage.

For these reasons we would anticipate that Onslow would be treated as a Generator or a non-conforming load and why we would recommend the pumping load is dispatchable demand (DD) and ramp-rates suitable for load are considered.

Further details follow.

I.2 Generation

It is anticipated that Lake Onslow would be offered like every other generator.

Our only query is whether it would be offered by station (sum of all units) or by individual unit? Our suggestion being by individual unit.

The reason for wishing to understand this is all hydro to date in NZ is offered by station.

This means our modelling and security computer modelling tools (SPD/RMT) cannot see the actual contingent event risk (a unit tripping) for the South Island (SI) and a standing manual risk of 125MW (= largest unit in the SI, at Manapouri) is what is covered most of the time for Instantaneous Reserves (IR).

If the same happened for Lake Onslow with 250MW units we'd have doubled the risk in the SI and the units may not be running.

Therefore, our suggested recommendation would be that offers would need to be by unit so we were not procuring IR to cover a risk which did not exist.

If offered by unit SPD can see the actual SI Contingent Event (CE) Alternating Current (AC) risk and schedule IR to cover that amount.

In practice this means 4 times as many offers to be submitted by the station.

Station dispatch compliance rules mean the actual operation of the Onslow generation would be against the cleared station total, with the rider of no unit could go above the highest cleared unit value from SPD (or 125MW, standing SI AC CE risk) – otherwise we would be unable to cover the SI AC CE Risk.

As part of dispatch instructions, the max allowable unit limit is sent – this is presently done now for Huntly (HLY).

If all 4 units are offered identically then there is a greater chance dispatch will end up being per unit in practice because of this requirement e.g. the ability to switch dispatched volumes around between the units is reduced i.e. if all 4 units clear to 140MW the SI AC CE risk will be 140MW and they could not meet station energy dispatch value by producing 187MW on 3 units because the system would be 47MW short for IR (SI AC CE risk would be 140MW).

I.3 Load

Onslow would be extremely likely to be defined as a non-conforming Grid Exit Point (GXP). This would require the Electricity Authority (EA) to make that determination and have it documented as such. The impact of this would require Onslow to bid their load – simply the opposite of generation offers; how much quantity they wish to buy and how much are they are willing to pay for it.

If staying as a normal non-conforming GXP then their bids are not binding and they are not dispatched for load – unlike Tiwai or Glenbrook etc..

If Lake Onslow elected to become a dispatchable demand (DD) purchaser then their bids will become binding and they will be dispatched like any other DD load. For example SKOG did this for a while.

The real-time pricing project will move DD to being dispatched equivalently to generation in real-time.

Note DD is not a paid product, Lake Onslow would still be buying electricity, but it does provide a little insurance via constrained on/off payments if the settlement price differs is contrary to their received dispatch instructions.

I.4 Ramp Rates

Load is modelled in the market either as non-conforming or Dispatchable Demand (DD) bids but does not include a ramp rate component.

This ramp rate of how quickly Onslow would or could change from generating to pumping or from inaction to pumping (and vice-versa for both) may necessitate some changes in Code and tools to better reflect real world applications.

Worst case scenarios would be a ‘noticeable delay’ in these actions and no change to the existing tools and Code. This would result in a step-change in dispatch which was not reflected physically e.g. dispatch changes from 0MW load to pumping 400MW load, SPD would see this as instantaneous and dispatch generation to meet that load in 5mins time. If the 400MW of load took 10mins to start and then 15mins to ramp there would be a significant misalignment which would be operationally problematic.

This example is worse if the load is not bid as DD because non-conforming loads are not cleared in Real Time Dispatch (RTD) the Operator uses actual system load. Therefore the System Operator would be assuming the current pumping load continues whether it is zero or non-zero and would not see the change coming until Frequency was affected.

There are maximum rates of change of load which are in the Code and Policy Statement which would need to be considered for starting and stopping pumping. Presently large planned load changes between Tiwai and Manapoui (TWI-MAN) coordinate and balance potline shuts/restarts so as not to cause avoidable events on the power system. How Onslow would be able to manage its ramp rate impacts is unclear as there does not seem to be a suitable TWI-MAN type solution.

Clause 8.18 of the Electricity Industry Participation Code (Code) states that the System Operator is required to state limits on rates of change to offtake, in the case of Onslow this would include the rate of change in both pumping and generating capacity:

8.18 Contributions by purchasers to overall frequency management

Each **purchaser** must limit the magnitude of any instantaneous change in the **offtake** of **electricity** and net rate of change in **offtake** to the levels the **system operator** reasonably requires. In setting those requirements, the **system operator** must have regard to the impact of the **offtake** on the **system operator's** ability to comply with the **principal performance obligations** concerning frequency (as set out in clause 7.2A to 7.2C) and the **dispatch objective**.

The system operator's approach to this is detailed in its policy statement[7], incorporated by reference in the Code:

[7] https://www.ea.govt.nz/development/work-programme/operational-efficiencies/system-operator-documents-incorporated-into-the-code-by-reference/development/replaced-policy-statement-26-july-2022/

Purchaser Step Changes

39. *[Revoked]*

39A Clause 8.18 of the **Code** provides that **purchasers** must limit the magnitude of any instantaneous change in the **offtake** of **electricity** and net rates of change in **offtake** to the levels the system **operator** requires.

39B As at the date this **policy statement** comes into effect, the **maximum instantaneous demand change limit** and net rates of change in **offtake** for **electricity** allowable for each **purchaser** within each **island** is 40 **MW** per minute with no more than a 75 **MW** change in any 5 minute period.

39C The **system operator** may specify a **maximum instantaneous demand change limit** and rate of change in **offtake** in relation to a particular **purchaser** that is different from the limit and the rate specified in clause 39B.

39D Clauses 39A and 39B do not apply to step changes and rates of change occurring during independent action or restoration in a **grid emergency**.

The system operator has not as yet conducted the required analysis on what maximum instantaneous demand change limits and rate of change in offtake it would specify for Onslow when pumping, generating or alternating between the two modes. The reason for this is the ability of the selected machines and their performance and ability to respond cannot be analysed at this time as a specific machine has yet to be selected. It is to be noted that this is not stating that more onerous conditions would be required but is an observation that the individual units that make up Onslow and the station itself will be the largest in the South Island power system and caution is required.

I.5 Ancillary services

At this time we anticipate that there would be nothing unique or different in connecting the proposed Onslow scheme when compared to any other new generator wishing to offer ancillary services to the market should Onslow wish to so. However there will be key studies required to help inform further works. Some of these are noted below.

Performance based assessments will be required for the provision of products – That is what can Onslow prove they can provide on a reliable and consistent basis? e.g. Instantaneous Reserves (IR) and Frequency Keeping (FK) services, possibly black start and over-frequency reserves.

Onslow could also be considered as a provider of other ancillary services such as IR as injection (PLSR or TWD) and load (IL) – while being aware of potential issues around coordination of offers, for example Onslow could not offer IL if the station is not pumping on a unit and cannot offer PLSR/TWD if pumping on all 4 units. Forecast scheduling of processes would mean periods when generating and periods when pumping will be need to be identified and IR offers updated to reflect expected energy behaviour.

Depending on how the electricity system develops over the coming years, the use of electricity, the community's reliance on it, the generation and loads that are connected to it the resilience expectations and required ancillary services will change and evolve in parallel. What ever future "Dry Winter" cover is provided it is anticipated that it would need to work within and co-ordinate and be treated like any other technology or participant.

I.6 Coordination

Assuming that there will be a price below which the station is pumping and a price above which the station is generating bids and offers should be able to be structured in such a way as to create sensible outcomes.

Issues could arise if the price is the same because then within a trading period Onslow might be dispatched to pump or generate in 5min cycles as the marginal price drops below/rises above that price.

Bid and offer prices can be used to lock-in outcomes as best as they can be by adjusting bid/offer prices relative to how the market is forecast to play out or they can be left as solid trading positions

2.10 Instantaneous reserve implications of HVDC Upgrades (Appendix J)

The NZ Battery Project has advised us that it has been assuming that, in the 100% renewables scenario, instantaneous reserve constraints will not affect the NZ Battery operation. This is based on the assumption that the single largest generator plant will be much smaller than now (in the North Island anyway) and its modelling shows extensive grid-scale batteries that can provide IR services, plus improved IL with smart EV charging etc will become available.

The NZ Battery Project wishes to confirm that its assumption that instantaneous reserve constraints are probably not relevant to NZ Battery, and is reasonable.

Our present assessment is that this assumption is reasonable as we can assume for now that:

- While the size of the bipole failure risk will be 1400MW not 1200MW, that is an Extended Contingent Event (ECE)
- The size of the Contingent Event (CE) risk of a single-pole failure will not increase (and may even decrease)

Our response to the NZ Battery Project's question is broken into the following four sub-questions:

J.1 Once the HVDC is upgraded to 1400MW, what is the bipole ECE and single pole CE risk and the reserves needed?

Risk reserves are based on the MW received, the present situation being:

- Bipole ECE risk = 1120 MW,
- Pole CE risk = 470 MW (Pole risk = Bipole received – Pole received)
- Monopole 700 MW sent, received = 650 MW (present short term assumption for Pole 2, 1 cable overload if Pole 3 trips)
- Monopole 1000MW sent, received = 898 MW
- Bipole 1400 MW sent, received = 1300 MW
- Bipole 1200 MW sent (780/420 split), received = 1120 MW

Presently the 1200MW HVDC link has a CE risk of 1120MW (sent) with a risk subtractor of approximately 650MW (received). That means when sending approximately 1200MW we need to have approximately 1130-650 = 480MW of reserves in the North Island to cover the loss of a pole.

As part of the HVDC upgrade to 1400MW we are also improving the Pole 2 15 minute overload rating to increase the risk subtractor to approximately 900MW (received).

Once the bipole upgrade to 1400 MW and Pole 2 1000MW 15-minute overloads enhancement are completed then:

- Bipole ECE risk = 1300 MW,
- A single Pole CE risk = 402 MW (Pole risk = Bipole received – Pole received)

That means when sending 1400MW we would need to have approximately 1300-900 = 400MW of reserves in the North Island to cover the loss of a pole.

In summary, reserve requirements for the HVDC contingent event will be significantly less once the 1400MW upgrade is completed

The above is for the North Island only – as the bipole cannot achieve 1400MW south even after the proposed upgrade - so the CE and ECE risk MW during DC south are lower.

J.2 The ECE risk is still the bipole failure of the line at 1400MW?

For the bipole operating at 1400MW the ECE risk MW would be 1300 MW to the receiving island. At this high level of HVDC transfer the ECE is usually a bipole trip and is covered by reserves and up to 32% load shedding in the North Island (AUFLS).

J.3 When in pumping mode would we have the option to trip Onslow if it was the risk setter should we lose either a single or bipole?

For high HVDC south flow this would be helpful. For high HVDC north flow tripping if generating would also be helpful.

J.4 When generating we assume there will be sufficient generation or FIR in the North Island market to cover a contingent event of 750MW as we do today?

After the 1,400MW upgrade the reserve requirement for the HVDC CE will be less due to the increased risk subtractor. Therefore the assumption there will be sufficient generation or FIR to cover the event is valid as it would be less than the present risk covered for the existing HVDC link capability of 1,200MW.

2.11 Transmission implications of NZ Battery Portfolio options (Appendix K)

The NZ Battery Project has developed a 'Portfolio' option of non-hydro solutions, consisting of:

- Geothermal reserve
- Biomass generation
- Hydrogen-ammonia

For the purposes of estimating transmission implications, the NZ Battery Project has assumed for locations:

- Geothermal reserve will require transmission export for four new 100MW geothermal generation stations, spread across several greenfield geothermal sites in the Taupo volcanic zone.
- Biomass generation site would balance the proximity to the forest resource with the availability of land transport and transmission infrastructure. Many areas could be possible for this, but for modelling purposes we assume a site in a plantation forest area of the central North Island, in the eastern Waikato or Southern Bay of Plenty region.
- The hydrogen-ammonia option is assumed to be located close to a port and transmission. Transmission is required to service a range between a 370 MW load and 150 MW generation.

For the purposes of estimating the transmission implications of the hydrogen-ammonia option, we have considered two of the many possible locations, as at or close to:

- Around New Plymouth, close to Port Taranaki
- Around Marsden, close to Port Whangārei.

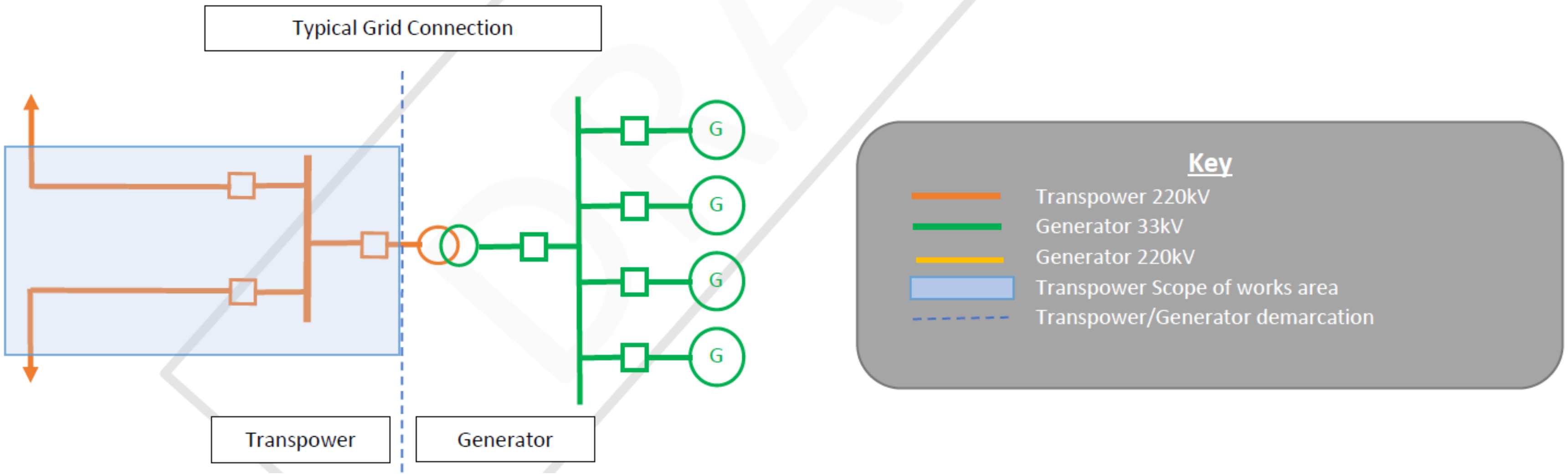
K.1 Geothermal reserve

OBJECTIVE: To provide a grid connection for 4 off 100MW geothermal plants as per S9 in the central North Island Volcanic zone (Waikato and Bay of Plenty)

SCOPE: Standard 220kV 100MW grid connection

Initial: Establish a simple in and out grid connection that includes

- Upto 10-20km of in-out line deviation to new site. (Other options possible budgeting at this time is for in and out)
- AIS switchyard complete with earthgrid, security fencing, oil containment, lighting, lightning, and other ancillary services
- 3 off 220kV AIS switchgear bays
- Ability to connect single 220/33kV 100MVA supply bank
- control/relay room complete with all ancillary supplies, protection, automation, control, metering, and communications
- Access roads, property rights and designations,
- All scope and costs associate with the 220/33kV supply transformer, its foundation, MV & LV connections, protection control, MV switchgear and associated building are all assumed to be at generators cost



K.1.1 Geothermal reserve estimated grid connection costs

NZBB Geothermal alternative scope and price estimate (Class 4)

New GIP (100MW connection)	**NZ$(M)**	
Allowance for a dct loop in loop out diversion up to 10km -20km	$ 20.00	$ 40.00
1 x Property	$ 1.00	
1 x Switchyard establishment	$ 3.00	
1 x relay and control building (inclusive security, potable and sanitary services)	$ 2.00	
2 x 220kV Line deviation	$ 1.00	
3 x 220 kV bays + bus work	$ 2.50	
2 x line protection	$ 1.00	
2 x remote end line protection	$ 0.50	
Auxilliary supply establishment 400VAC	$ 1.00	
Auxilliary supply establishment duplicate 110VDC & 48VDC	$ 1.00	
Investigation and design	$ 1.50	
Contractor construction overheads	$ 1.00	
1x 100 MVA 220/33 kV transformers - supply on plinth	*$ 5.00*	
1x tansformer foundations	*$ 0.60*	
Oil containment	*$ 0.50*	
1 x 33 kV incomer cable circuits (by others)	*$ 0.50*	
1 x 33kV switchboard (by others)	*$ 2.50*	
33kV Protection control and automation (by others)	*$ 2.00*	
1 x transformer protection	*$ 0.50*	
1 x transformer metering	*$ 0.50*	
33kV Swgear building	*$ 2.00*	
Estimated Transpower Connection Costs (Including Line & Substation)	**$ 35.50**	**$ 55.50**
Estimated Transpower Connection Cost (Substation Only Excluding Line)	**$ 15.50**	
Assumed Generator Costs (Transformer & Incomer)	**$ 12.10**	
Estimated Line and Substation Total	**$ 49.60**	**$ 69.60**

Other Costs Assoicated with new GIP	**NZ$(M)**
OHK-EDG_A (115km OHK-KAW-EDG) Recon to 600MW if new Gen >100MW	$ 69.00
Generation >300MW BPE-WRK_A recon (220km)	$132.00
Assume WRK Ring Upgrade WHN-ATI-OHK-WRK compleetd as part NZGP	$ -
Assume BPE-WKM_A & B recon completed as part NZGP	$ -

Other assumptions

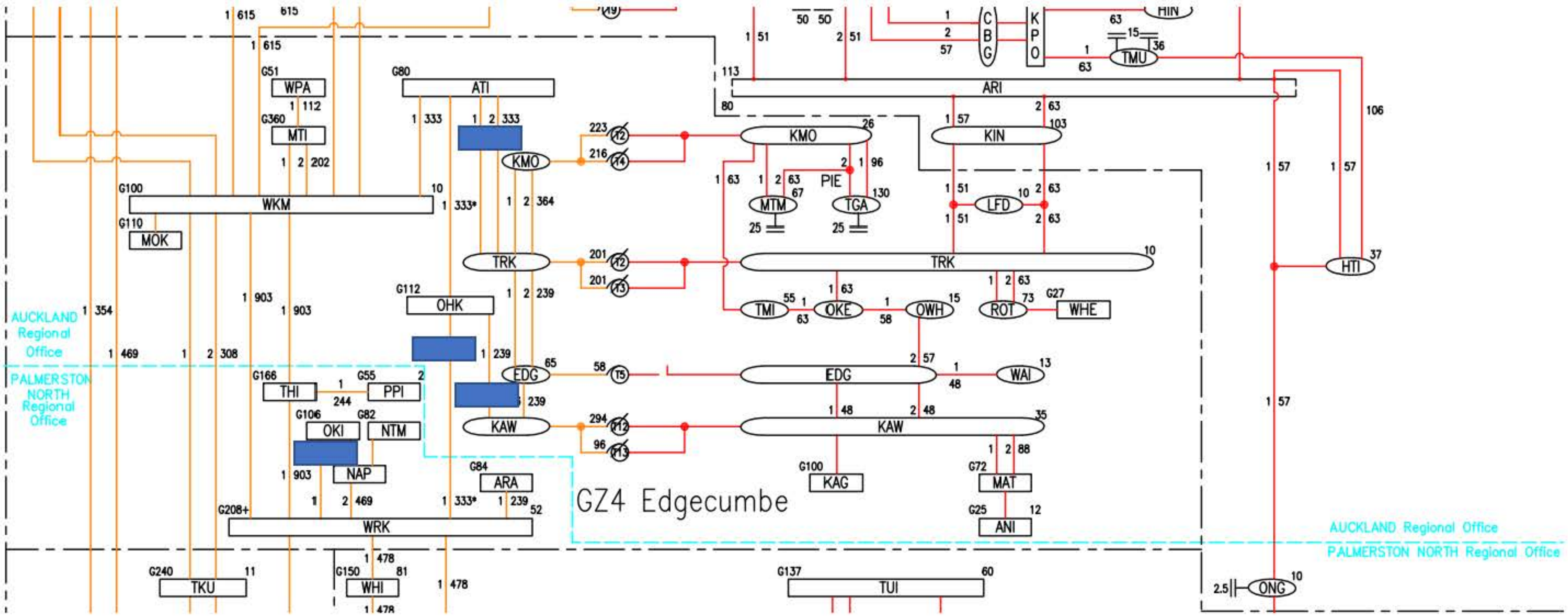
- Note any physical location representation is only conceptual so that consideration of impacts on the existing transmission grid can be considered and budgeted for.
- Located in central North Island volcanic zone between WKM, WRK and KAW
- BPE-WKM_A & B completed as part of NZGP and other Transpower work
- WHN-ATI-OHK-WRK completed as part of NZGP and other Transpower work
- The OHK-EDG_A line is relatively low capacity and additional generation >100MW connecting into that circuit will require a line upgrade this is not part of planned Transpower work
- The BPE-WRK_A line is not part of NZGP at this time and should this additional Central North Island generation proceed additional line uprating will be required
- There is sufficient capacity in the OKI-WRK line for one 100MW plant to be accommodated before an upgrade is required

K.1.2 Geothermal reserve location assumption

We assume that each of the four geothermal, reserve stations are located in the Taupo volcanic zone. As locations are hypothetical, we have to assume locations for the purposes of indicate transmission cost estimation. We assume that the four locations are:

- Within 20 Km of the OHK-EDG-A line
- Within 20 Km of the ATI-TRK-A line
- Within 20 Km of the OKI-WRK-A line
- Within 20 Km of the WRK-WKM-A line

With the points where the connection would join, or be diverted from, the existing lines marked as blue rectangles in the following single line diagram:



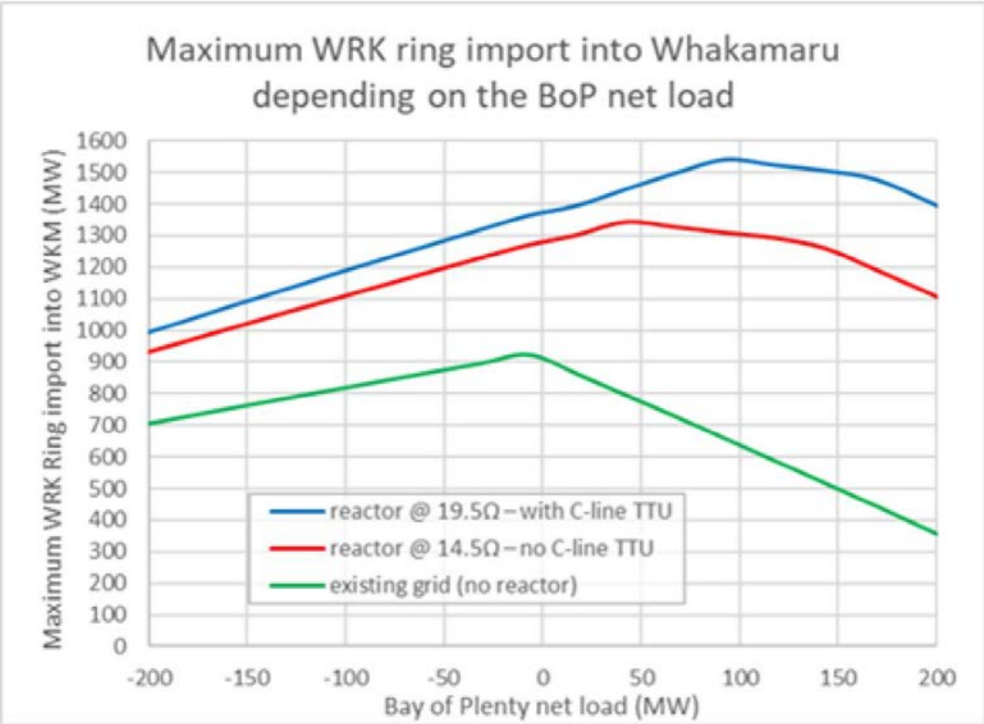
K.1.3 Geothermal reserve additional information

Transpower has some planned investment investigations to consider as part of our TPR/NZGP work, where it is expressed as: “Investigate options and routes plus progress detailed design to either replace Transpower’s 220 kV Wairakei-Whakamaru A line or build a new 220 kV Wairakei- Whakamaru D line”. The following provides more information on these investigations.

Geothermal transmission limits

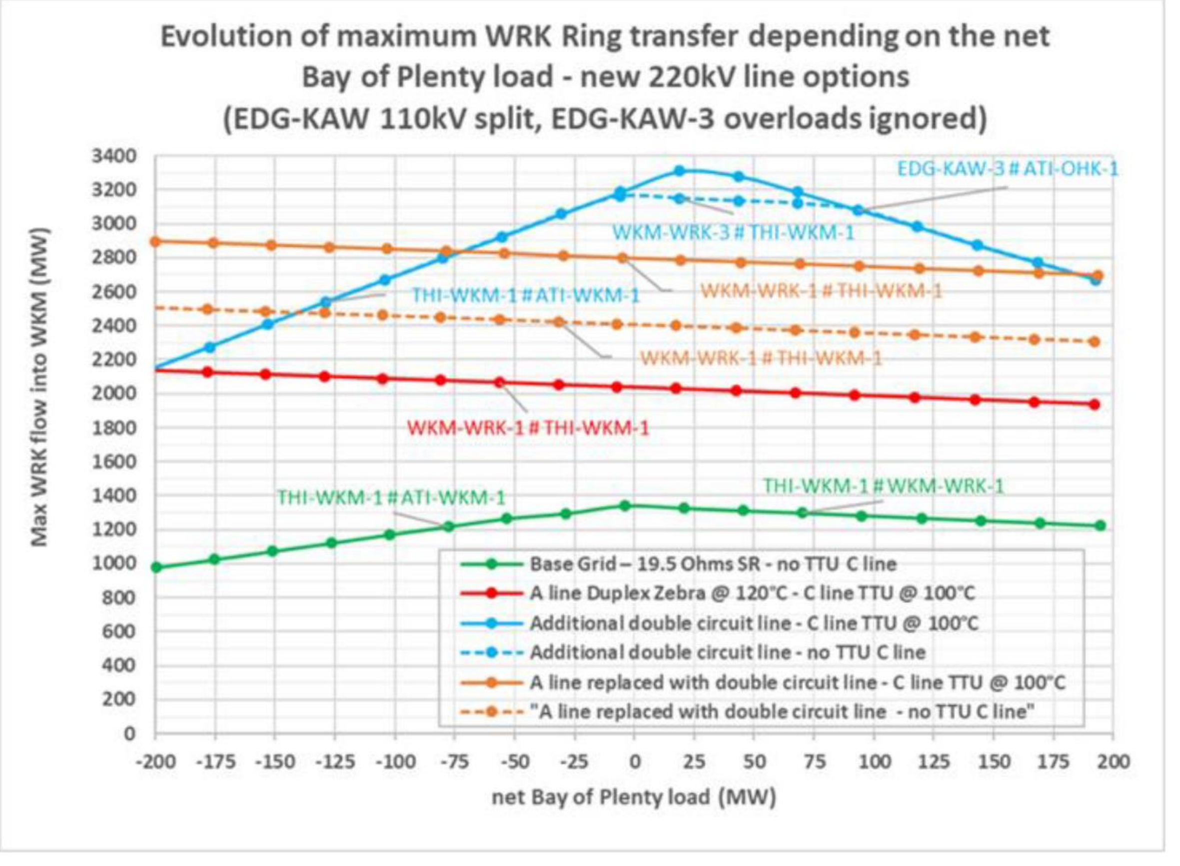
The graph below shows the approximate additional 75-300MW of generation, (difference between the red and blue lines) that can be accommodated with the existing WRK-WKM C line if a Tactical Thermal Uprate is completed. It is a modest increase, but enough to accommodate, a modest solar or geothermal plant at a modest cost of approximately. $5m. This is the only cost effective short term option.

Figure 18: Maximum Wairakei ring import into Whakamaru



The graph below shows the situation post building a new line. The solid blue line is for a new WRK-WKM D line.

Figure 19: New 220kV line options for Wairakei ring transfer



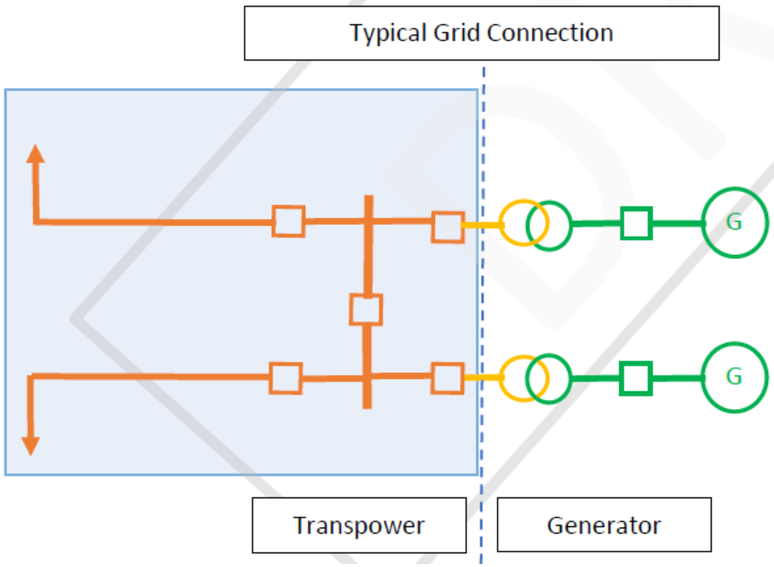
K.2 Biomass option

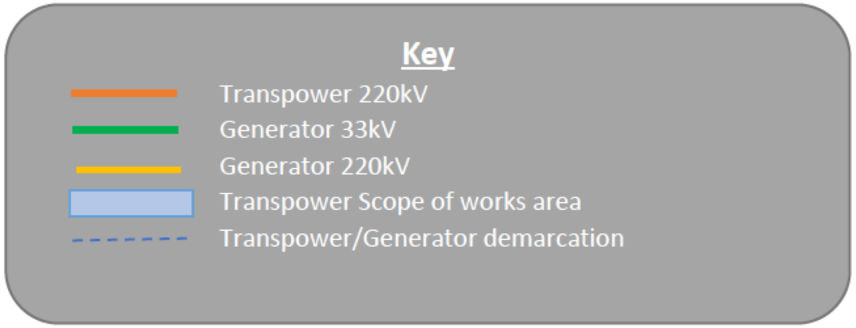
OBJECTIVE: To provide a grid connection for 1 off 500MW biomass fuelled steam generator plant as per S10 in the central North Island around large forestry reserves such as Kawerau and Kaingaroa (Waikato and Bay of Plenty)

SCOPE: Standard 220kV 500MW grid connection for 2 x 250MW generators

Initial: Establish a simple in and out grid connection that includes

- Upto 20km of in-out line deviation to new site. (Other options possible budgeting at this time is for in and out)
- AIS switchyard complete with earthgrid, security fencing, oil containment, lighting, lightning, and other ancillary services
- 6 off 220kV AIS switchgear bays
- Ability to connect two 220/33kV 250MVA supply banks
- control/relay room complete with all ancillary supplies, protection, automation, control, metering, and communications
- Access roads, property rights and designations,
- All scope and costs associate with the 220/33kV supply transformers, its foundation, MV & LV connections, protection control, MV switchgear and associated building are all assumed to be at generators cost





K.2.1 Biomass option estimated grid connection costs

NZBB Biomass alternative scope and price estimate (Class 4)

New GIP (500MW connection)	**NZ$(M)**	
Allowance for a new 600MW dct 220kV line of 70km to WKM	$150.00	select 1
Allowance for a new 600MW dct 220kV line of 50km to WRK	$110.00	select 1
OHK-EDG_A (115km OHK-KAW-EDG) Recon to 600MW	$ 69.00	select 1
Allowance for 600MW dct 220kV line diversion of 20km	$ 40.00	
1 x Property	$ 1.50	
1 x Switchyard establishment	$ 4.00	
1 x relay and control building (inclusive security, potable and sanitary services)	$ 2.00	
2 x 220kV Line	$ 2.00	
1 x 220kV Bus Coupler	$ 1.00	
6 x 220 kV bays + bus work	$ 4.00	
2 x line protection	$ 1.00	
2 x remote end line protection	$ 0.50	
1 x bus zone protection	$ 1.00	
Auxilliary supply establishment 400VAC	$ 1.00	
Auxilliary supply establishment duplicate 110VDC & 48VDC	$ 1.00	
Investigation and design	$ 1.50	
Contractor construction overheads	$ 1.00	
2x 250 MVA 220/33 kV transformers - supply on plinth	*$ 12.00*	
2x tansformer foundations	*$ 1.50*	
Oil containment	*$ 0.50*	
2 x 33 kV incomer cable circuits (by others)	*$ 1.50*	
1 x 33kV switchboard (by others)	*$ 3.50*	
33kV Protection control and automation (by others)	*$ 3.00*	
2 x transformer protection	*$ 1.00*	
2 x transformer metering	*$ 1.00*	
33kV Swgear building	*$ 2.50*	
Estimated Transpower Connection Costs (Including Line & Substation)	**$ 130.50**	**$ 211.50**
Estimated Transpower Connection Cost (Substation Only Excluding Line)	**$ 21.50**	
Assumed Generator Costs (Transformer & Incomer)	**$ 26.50**	
Estimated Line and Substation Total	**$ 157.00**	**$ 238.00**

Other assumptions

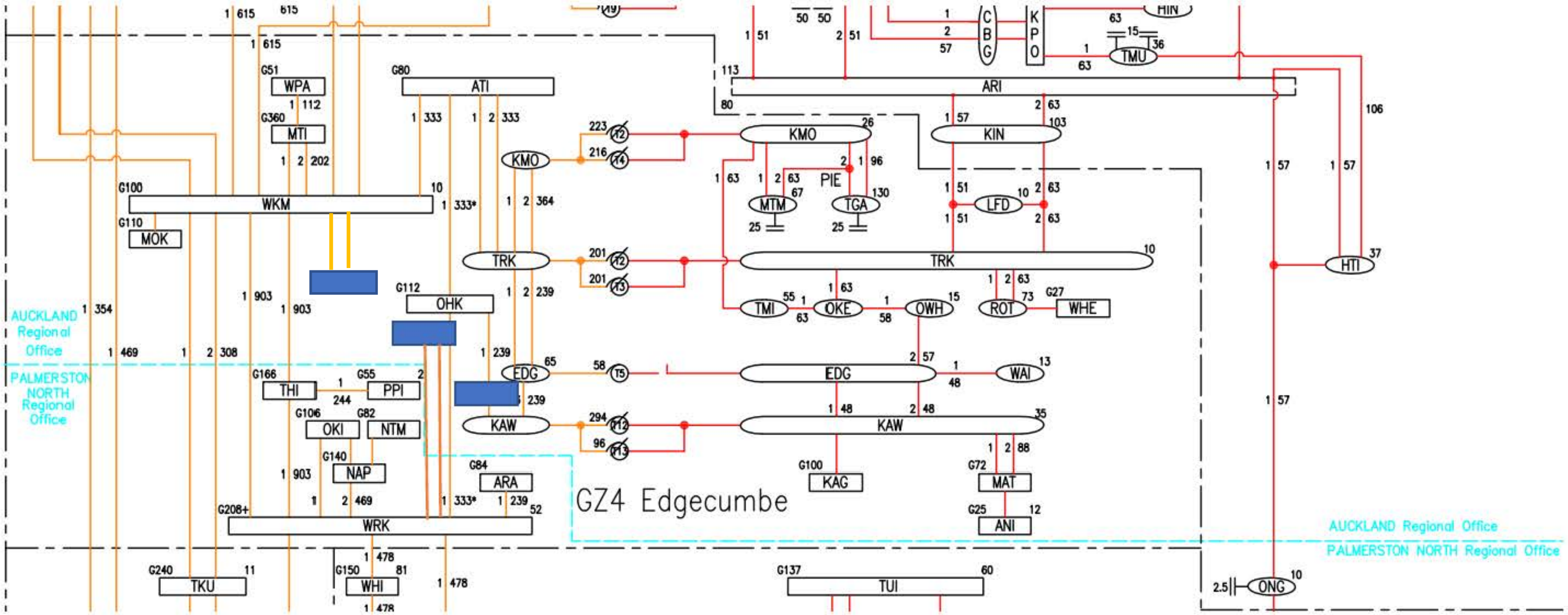
- Note any physical location representation is only conceptual so that consideration of impacts on the existing transmission grid can be considered and budgeted for.
- BPE-WKM_A & B completed as part of NZGP and other Transpower work
- WHN-ATI-OHK-WRK completed as part of NZGP and other Transpower work
- The BPE-WRK_A line is not part of NZGP at this time and should this additional Central North Island generation proceed additional line uprating will be required
- Connection of the new generator requires the selection of one option from three, either
  - A new 220kV dct line to WKM
  - A new dct line to WRK
  - Or the uprating of the low capacity OHK-EDG_A line connecting into that circuit will require a line upgrade this is not part of planned Transpower work
- Depending on option selected direct connection costs, excluding other upgrade works range from NZ$130.5M to $211.5M

K.2.3 Biomass option location assumption

We assume that two 250MW plants are collocated as a 500MW generation station. Different locations will have different transmission implications, but for budgeting purposes we assume three scenarios:

- Some 70km from WKM substation, connected to it with a new 600MW double-circuit 220kV line,
- Some 50km from WRK substation, connected to it with a new 600MW double-circuit 220kV line, or
- Somewhere close to the OHK-EDG_A (115km OHK-KAW-EDG) line, which would need to be reconductored 600MW

These scenarios are illustrated as blue rectangles, with new lines as appropriate, in the following single line diagram:



K.3 Hydrogen / ammonia option

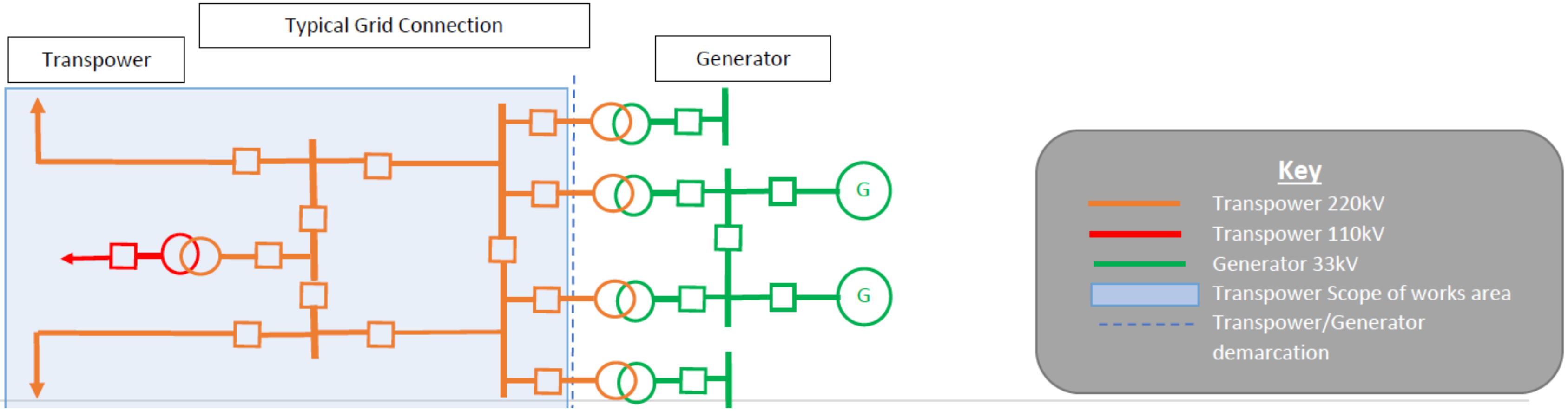
K.3.1 Hydrogen / ammonia option estimated grid connection costs (NPL scenario)

OBJECTIVE: To provide a grid connection for 1 off 370MW H2NH3 load that can then generate up to 150MW via 2 off 75MW Gas Turbines as per S11 located in the vicinity of Port Taranaki.

SCOPE: Establish a new Grid switching station adjacent to the 220kV and 110kV line reconfiguration in the vicinity of Port Taranaki, provision it for a GIP with connection for a load of 370MW and 2 x 150MW generators, and reconfigure the Taranaki 220kV and 110kV networks in New Plymouth and Stratford

Initial: Upgrade the existing grid connection that includes

- Establish a new switching station and grid injection point in the vicinity of the 220kV and 110kV lines near Port Taranaki
- Construct a new AIS switchyard complete with earthgrid, security fencing, oil containment, lighting, lightning, and other ancillary services
- Install an outdoor 5 section 220kV bus complete with all associated switchgear
- Install a new 220/110kV interconnecting transformer and associated equipment and connect it to the line supply CST
- Reconfigure the 220kV and 110kV network at SFD and CST
- Install four 220/33kV 120MVA supply banks
- Construct a new control/relay room complete with all ancillary supplies, protection, automation, control, metering, and communications
- Establish new access roads, property rights and designations,
- All scope and costs associate with the 220/33kV supply transformers, its foundation, MV & LV connections, protection control, MV switchgear and associated building are all assumed to be at generators cost



K.3.1 Hydrogen / ammonia option estimated grid connection costs (NPL scenario)

NZBB H2NH3 NPL alternative scope and price estimate (Class 4)

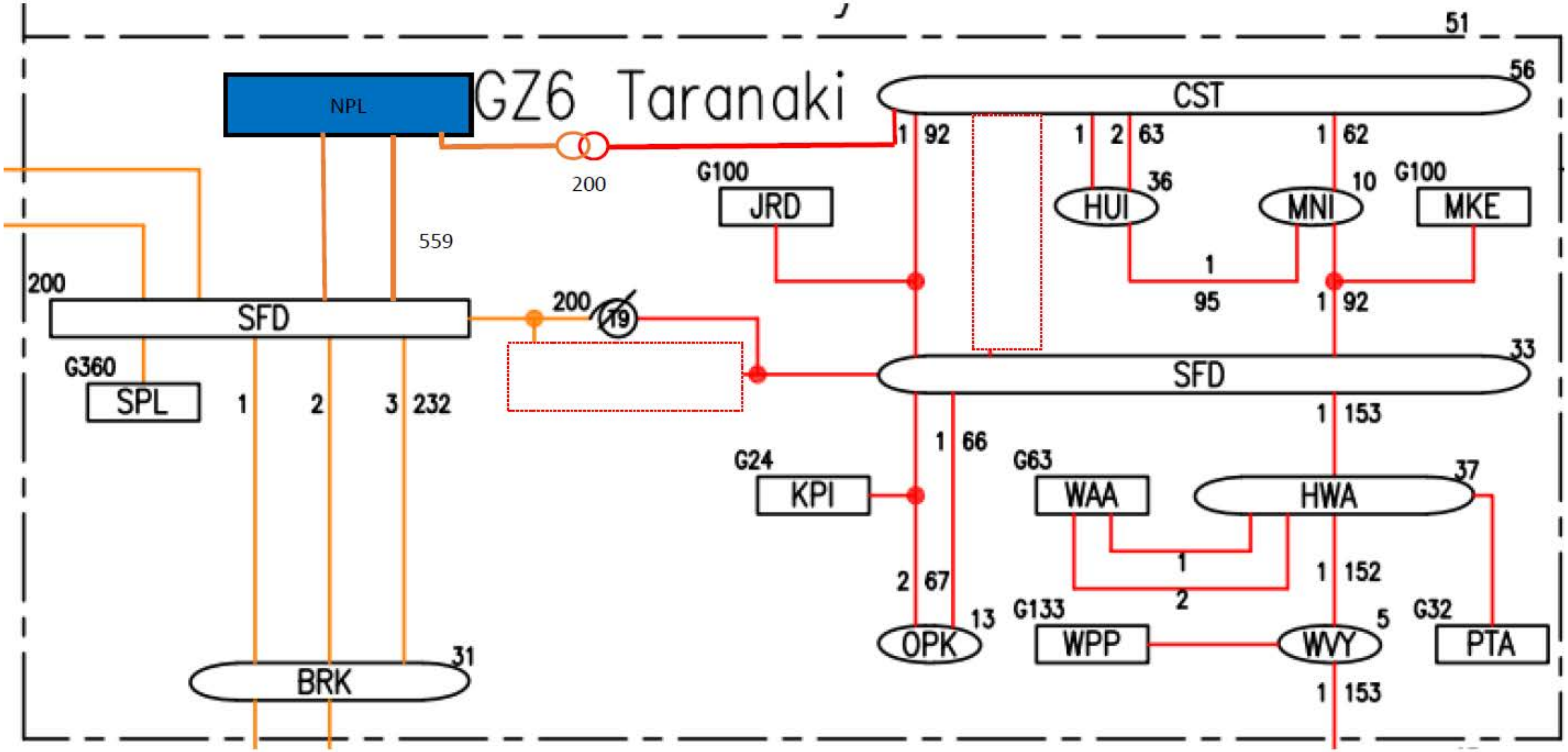
New Build GXP (370/150MW connection)	**NZ$(M)**
Reconfigure NPL-SFD 220kV & CST-NPL lines	$ 5.00
Reconfigure SFD Substation	$ 5.00
1 x Property	$ 4.00
1 x Switchyard establishment	$ 4.00
1 x relay and control building (inclusive security, potable and sanitary services)	$ 2.00
2 x 220kV Line	$ 2.00
3 x 220kV Bus Coupler	$ 3.00
14 x 220 kV bays + bus work	$ 10.00
1 x 110kV line	$ 1.00
1 x 220/110kV 200MVA interconnector transformer	$ 6.00
4 x 220 kV bays + bus work	$ 4.00
2 x bus zone protection	$ 2.00
3 x line protection	$ 1.50
3 x remote end line protection	$ 1.50
Investigation and design	$ 2.50
Contractor construction overheads	$ 1.50
Oil containment	$ 1.50
4 x 120 MVA 220/33 kV transformers - supply on plinth	*$ 24.00*
4 x tansformer foundations	*$ 3.00*
6 x 33 kV incomer cable circuits (by others)	*$ 3.00*
3 x 33kV switchboard (by others)	*$ 6.00*
33kV Protection control and automation (by others)	*$ 3.00*
4 x transformer protection	*$ 2.00*
4 x transformer metering	*$ 2.00*
33kV Swgear building	*$ 4.00*
Estimated Transpower Connection Costs (Including Line & Substation)	**$ 56.50**
Estimated Transpower Connection Cost (Substation Only Excluding Line)	**$ 46.50**
Assumed Generator Costs (Transformer & Incomer)	**$ 47.00**
Estimated Line and Substation Total	**$ 103.50**

Other Costs Assoicated with new GIP	**NZ$(M)**
	$ -
	$ -
	$ -

Other assumptions

- Note any physical location representation is only conceptual so that consideration of impacts on the existing transmission grid can be considered and budgeted for.
- Construction of a new Switching station and GIP
- Reconfiguration of the 110kV and 220kV circuits into NPL and CST
- Reconfiguration of 220kV and 110kV assets at SFD
- Ownership of 220/33kV transformer and switchgear could be Transpower or Generators
- Kept SLD similar to MDN alternative for direct comparison, road transport into region is easier so expect transformer configurations to reduce in scope and complexity

K.3.2 Hydrogen / ammonia option location assumption (NPL scenario)



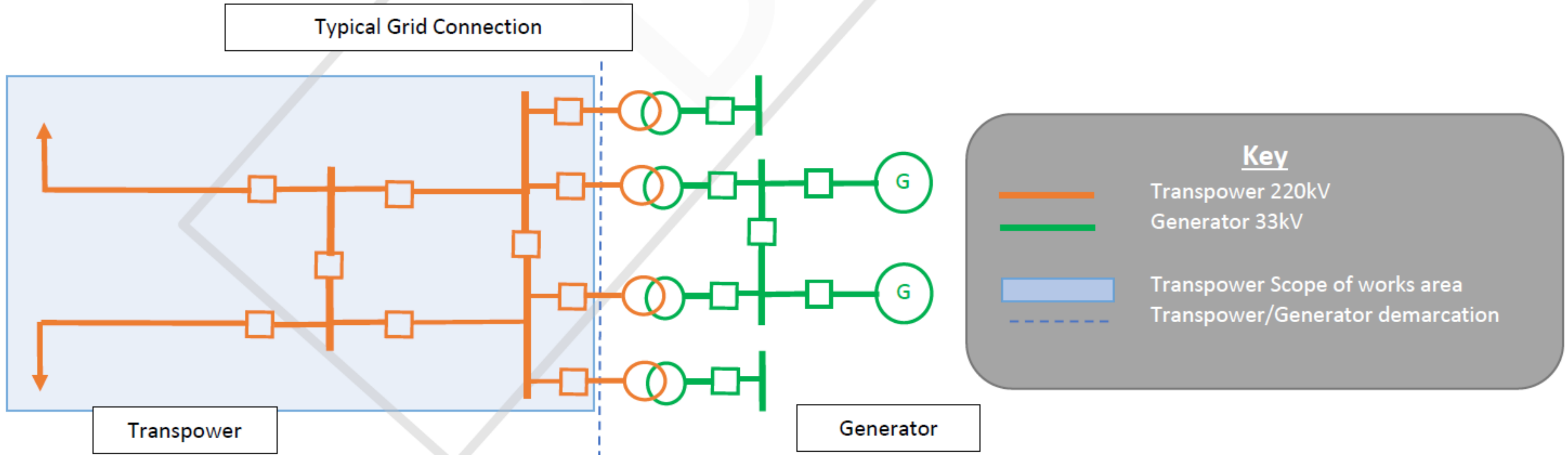
K.3.3 Hydrogen / ammonia option estimated grid connection costs (MDN scenario)

OBJECTIVE: To provide a grid connection for 1 off 370MW H2NH3 load that can then generate upto 150MW via 2 off 75MW Gas Turbines as per S11 located at BreamBay in Northland.

SCOPE: Repurpose and upgrade the existing 220kV BRB connection for a load of 370MW and 2 x 150MW generators

Initial: Upgrade the existing grid connection that includes

- Repurpose the existing 220kV GIS connection
- Repurpose the existing AIS switchyard complete with earthgrid, security fencing, oil containment, lighting, lightning, and other ancillary services
- Install an outdoor 2 section 220kV bus with 5 circuit breakers
- Replace the existing 220kV cables from GIS to new outdoor busbar
- Replace the existing two 220/33kV 70MVA supply banks with four 220/33kV 120MVA supply banks
- Reuse the control/relay room complete with all ancillary supplies, protection, automation, control, metering, and communications
- Reuse the existing access roads, property rights and designations,
- All scope and costs associate with the 220/33kV supply transformers, its foundation, MV & LV connections, protection control, MV switchgear and associated building are all assumed to be at generators cost
- Reconductor single 220kV circuit from Henderson to Marsden and Bream Bay



K.3.4 Hydrogen / ammonia estimated grid connection costs (MDN scenario)

ESTIMATED COST RANGE: Note costs are initial estimates to Class 4,

NZBB H2NHS MDN alternative scope and price estimate (Class 4)

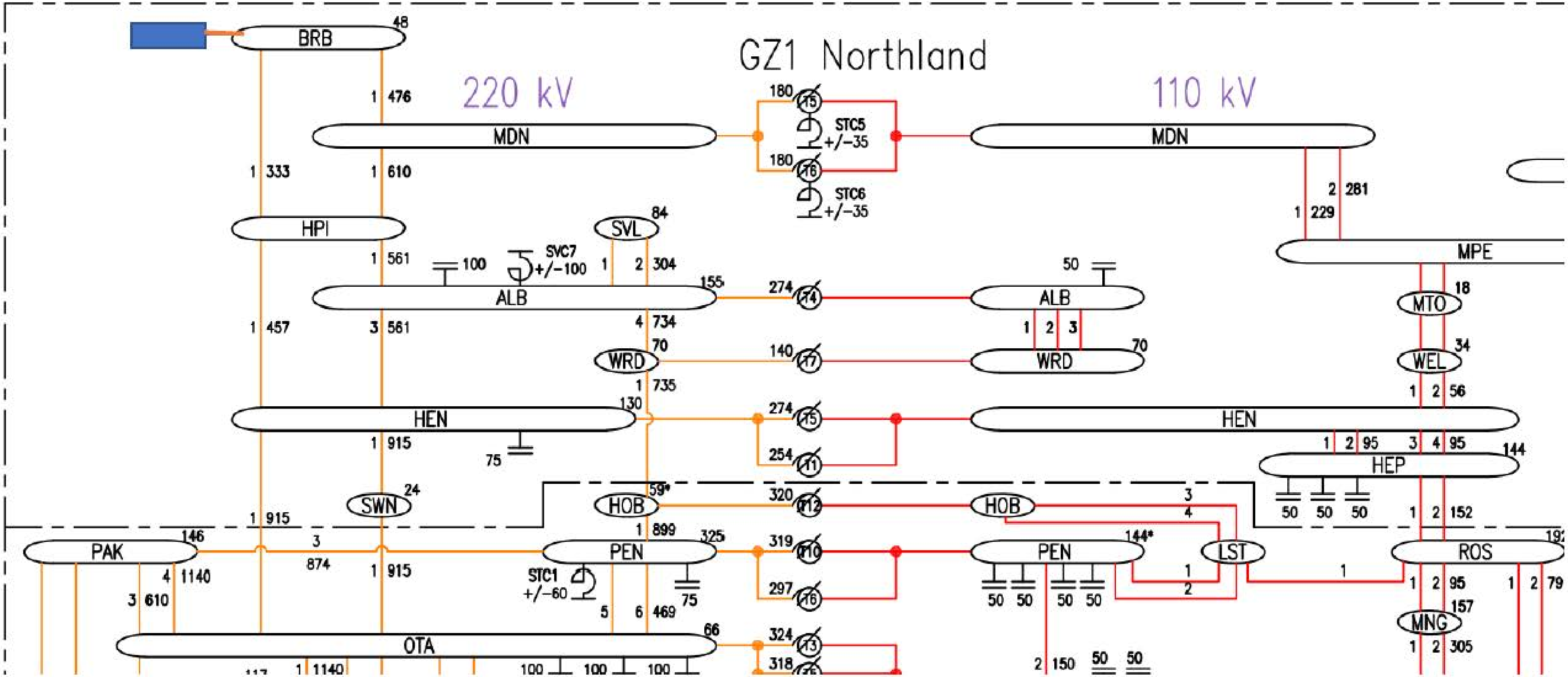
Repurposed GXP (370/150MW connection)	**NZ$(M)**
Reconductor 1cct of HEN-MDN_A and BRB-MDN_A dct 220kV lines 125km	$ 75.00
1 x Property	$ 1.50
1 x Switchyard establishment	$ 4.00
1 x relay and control building (inclusive security, potable and sanitary services)	$ 2.00
2 x 220kV Line	$ 2.00
1 x 220kV Bus Coupler	$ 1.00
6 x 220 kV bays + bus work	$ 4.00
2 x line protection	$ 1.00
2 x remote end line protection	$ 0.50
1 x bus zone protection	$ 1.00
Auxilliary supply establishment 400VAC	$ 1.00
Auxilliary supply establishment duplicate 110VDC & 48VDC	$ 1.00
Investigation and design	$ 1.50
Contractor construction overheads	$ 1.00
4 x 250 MVA 220/33 kV transformers - supply on plinth	*$ 24.00*
4 x tansformer foundations	*$ 3.00*
Oil containment	*$ 1.50*
6 x 33 kV incomer cable circuits (by others)	*$ 3.00*
3 x 33kV switchboard (by others)	*$ 6.00*
33kV Protection control and automation (by others)	*$ 3.00*
4 x transformer protection	*$ 2.00*
4 x transformer metering	*$ 2.00*
33kV Swgear building	*$ 4.00*
Estimated Transpower Connection Costs (Including Line & Substation)	**$ 96.50**
Estimated Transpower Connection Cost (Substation Only Excluding Line)	**$ 21.50**
Assumed Generator Costs (Transformer & Incomer)	**$ 48.50**
Estimated Line and Substation Total	**$ 145.00**

Other Costs Assoicated with new GIP	**NZ$(M)**
Generation >300MW BPE-WRK_A recon (220km)	$
Assume WRK Ring Upgrade WHN-ATI-OHK-WRK compleetd as part NZGP	$ -
Assume BPE-WKM_A & B recon completed as part NZGP	$ -

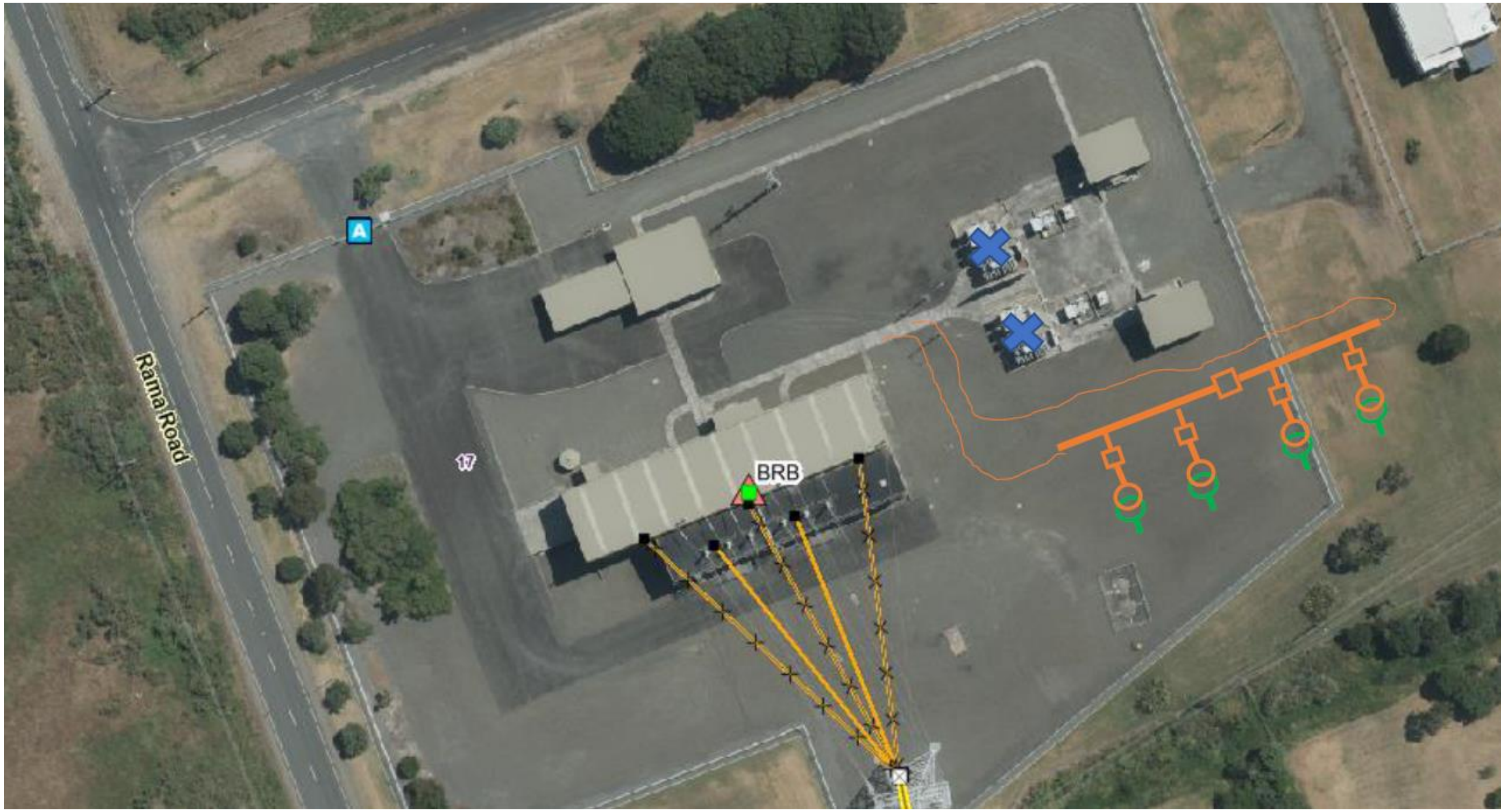
Other assumptions

- Note any physical location representation is only conceptual so that consideration of impacts on the existing transmission grid can be considered and budgeted for.
- Repurposing of the existing BRB substation as the point of connection
- Reconductoring the existing HEN-MDN_A and BRB-MDN_A
- Ownership of 220/33kV transformer and switchgear could be Transpower or Generators
- Due to road transport limitations and timing for coastal shipping traffic have limited transport mass to 120/150MVA transformer dimensions

K.3.5 Hydrogen / ammonia option location assumption (MDN scenario)



K.3.6 Hydrogen / ammonia option location assumption (MDN scenario) assumed repurposed switchyard



2.12 Feasibility & costs of a second HVDC link (Appendix L)

We have raised with the NZ Battery Project team the issue of whether a second HVDC link may be needed to increase the inter-island transfer capacity and resilience of Lake Onslow.

Our analysis indicates that to enable a South Island located PHES scheme to provide energy into the North Island in a 100% renewable dry winter scenario that an additional HVDC link is likely to be required. This is supported by the anecdotal observation that at non peak times in April more than 1,000MW of North Island thermal generation and 336MW of HVDC northward transfer (1,378MW) was required to meet the 5.2GW of demand. Assuming the 568MW of Tiwai South Island generation was also available this supports that an additional HVDC link will be required as the existing upgraded HVDC link would be insufficient to move this energy into the North Island.

Following completion of the Clutha and Upper Waitaki line reconductoring projects between Otago and Southland regions and the Waitaki Valley a firm transmission capacity of approximately 1,100MW will be provided. Even during periods of low hydro inflows this capacity can be expected to be insufficient to accommodate even a smaller PHES scheme's output.

For a smaller 8,000MW scheme with Tiwai remaining and extensive South Island electrification occurring it is anticipated that additional HVAC transmission capacity between Roxburgh and the Waitaki Valley of approximately 400-600MW may be required.

For the larger 1,200MW scheme and Tiwai exiting it is highly likely an additional HVDC link of a similar scale as the existing will be required. Should a new HVDC link need to be developed then consideration of the following is required

- Opportunity to avoid other investments in HVAC infrastructure
- Resilience to system events and common mode failures
- Avoidance of natural and manmade hazards
- Terminal locations in both islands as close to their production and consumption nodes as economically possible

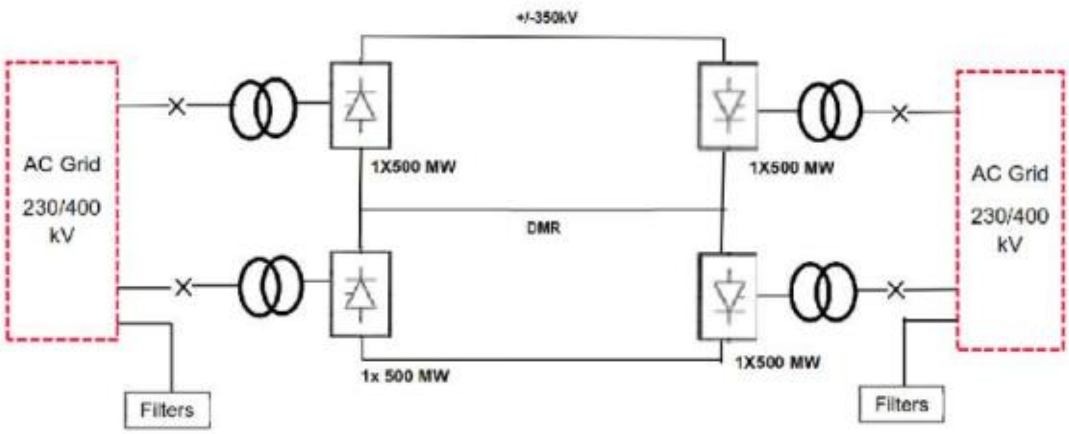
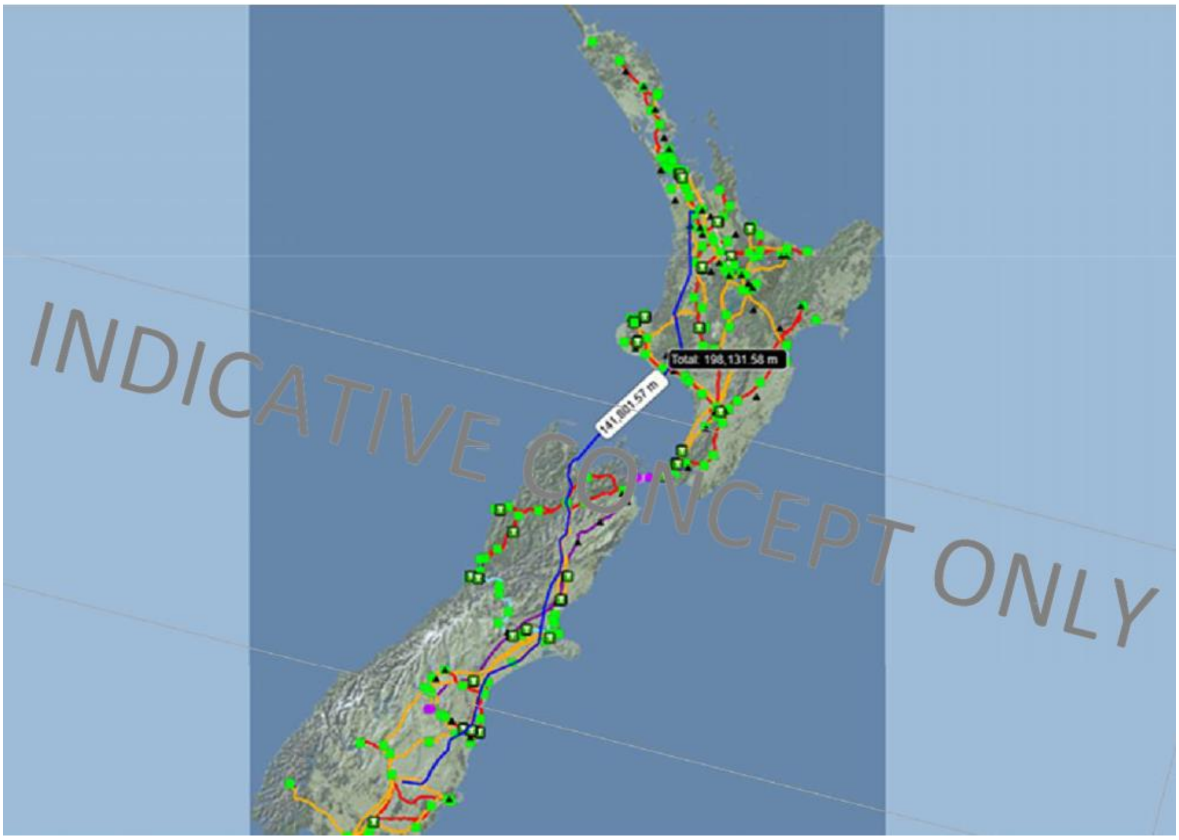


Figure 20 Conceptual 2nd HVDC BiPole Link

Figure 21: Second HVDC link indicative route



Note: the HVDC route is indicative and has not been subject to a route selection process it has been indicatively located to maximise resilience from known seismic and volcanic activities.

L.1 Second HVDC link financial quantum and accuracy

Additional network investment for a second HVDC link:

Table 25: Second HVDC link cost estimation (Class 5 (-20% to +100%)

Table 1 HVDC Link Provisional Class 5 Cost estimate

Item	Description	NZ$(m)
1	2 of, 200km 350 kV 500MW continuous HVDC submarine cables	960
2	+/- 350kV DC Bipole terminal equipment only incl. HVAC filters	880
3	HVAC substation connection too HVDC terminals incl. filters	100
4	870km +/- 350kV Overhead HVDC transmission line	1,680
	TOTAL	**3,620**

2.13 Feasibility and costs of NZ-AUS HVDC link (Appendix M)

M.1 Project Need/Issue/Problem

As Transpower has noted in Whakamana i Te Mauri Hiko, an option for managing dry year risk could be to connect our grid to Australia's and import power during dry years.

The NZ Battery team discussed this option, with a preliminary ' conclusion that it may be feasible but would be expensive at, say, $NZ20 B, with two cables required for security, and nevertheless a continuing high security risk given the number of cable joints required and long repair times in case of failure.

MBIE sought from Transpower, as an independent third party with deep domain knowledge, an indicative cost and risk estimates of this option, to confirm if this option should be explored in greater detail as a cost-effective means of providing Dry Winter cover in a 100% renewable electricity system. MBIE sought a realistic evaluation of the proposed option to a commensurate level of detail to allow ranking and go/no-go consideration of option for further analysis.

M.2 Findings

Our response describes the high-level feasibility of connecting New Zealand to Australia via a HVDC submarine cable link. It does not include connection of the cable to the AC network.

M.2.1 Constraints and assumptions

We have constrained the analysis to:

- Physical: Ignore international CPZ requirements
- Legal/Policy: Ignore energy security issues of tying markets
- Financial: Initial cost of cable

We have assumed:

- Physical: Assume 1,000MW 400kV DC Bi-Pole
- Legal/Policy:
    - Environmental and property rights acquired as part of the project.
    - Assume all sensitive environments could be avoided.
    - Assume any legislative barriers in both Australia and New Zealand could be overcome.

M.2.2 Comparison to existing submarine links

High capacity, high voltage DC submarine transmission links are common across the world. Recently completed or under construction submarine cable projects are compared to a possible Tasman Sea crossing:

Table 26: HVDC link across Tasman comparison with existing HVDC links

Item	Bass Strait	North Sea	North Atlantic	Tasman Sea
Status	Operational	Operational	Design	Concept
Width/Distance	240km	580km	3,800km	2,200km
Depth – average	60m	95m	100-250m	4,200m
Depth – max	155m	700m	700-900m	5,500m
Cable Project	Basslink	Viking	XLinks	TBA
Length	290km	760km	4,000km	2,500km
Capacity	500MW	1,400MW	2 x 1,800MW	1,000MW
DC Voltage	400kV	525kV	400-525kV	400kV

The most ambitious submarine interconnector project under consideration is the 3,800km long 3.6GW HVDC submarine cable XLinks project to link renewables from Morocco to supply up to 7% of the UKs electricity demand. The project is estimated to cost UK$18B (NZ$36B). The cable is planned to comprise of two 1,800MW links that utilise 2 cables each and are run in average water depths of up to 250m with a maximum water depth of 700-900m. This longer cable route is planned to deliberately avoid the abyssal depths off the Spanish coast that average 1700m with a maximum depth of 4,735m.

Launched during 2021 the Prysmian cable ship Leonardo da Vinci is the world's largest high voltage cable laying and support ship. The vessel has a maximum joint carousel capacity of 17,000T, a maximum laying depth of 3,000m, cable handling and laying capacity of approximately 100T.

Further details can be found here
https://www.prysmiangroup.com/sites/default/files/atoms/files/Leonardo%20da%20Vinci_Datasheet_v4.pdf

The estimated in cable water weight of a suitable HVDC cable is 35kg/m and at an average water depth of 4,500m this is 157T, while the max depth of the Tasman Sea is 5,500m. The maximum cable length able to be installed before jointing is indicated at approximately 280-350km, necessitating 7 submarine joints per trans-Tasman cable.

Taken together, although theoretically possible to lay a cable across the Tasman Sea, practically:

- there is no DC link of such a scale in the world
- there is presently no vessel:
    - capable of physically laying and supporting such a cable connection, or
    - of sufficient capability to embark enough cable for a single run, or
    - having the capability to effect or make a repair joint in waters of the depth seen in the Tasman Sea

To achieve a Tasman crossing would require development of the associated cable, and cable laying systems and infrastructure, estimated at NZ$500-700M. Presently there is no vessel, ROV or marine plough capable of handling a suitable HVDC power cable at that depth due to the dimensions and mass involved. This presents as a high-risk project, currently exceeding the delivery capability of any cable supplier at present. It would rely on a long distance multi-jointed cable system to provide secure Dry Winter cover, while relying heavily on a third party to provide geopolitical energy security.

The major issue with laying power cables at depth involve the high laying tensions that may compromise the cable long term integrity through ovalisation of the cable insulation and sheath due to excessive strain on the conductor as it is paid from the ship to the seabed. The other limitation is strain levels within the cable conductor and insulation system at any joint locations and how that is managed during the jointing process and then subsequent laying onto the seafloor.

To perform its primary function of ensuring Dry Winter cover would require the link to have a high availability and high level of security and damage from third party activities such as anchor or propeller drops, bottom trawling etc. Practical means of achieving this include embedment into the sea floor and/or protection with rock blankets in shallower areas. Ongoing operations, maintenance and routine inspection and testing become more challenging as depth and distance increase. Managing such an important asset in international waters at depth and over long distances have not been considered.

Also not considered is the DC overland connection from the submarine cable to the Australian and New Zealand grids or the AC/DC convertor stations required at both ends. As there are more realistic and cost competitive local options for Dry Winter management this option is regarded as having low probability of proceeding.

M.2.3 Solution financial quantum and accuracy

Cost and time estimates assumed to be as per AACEI 69R-12 hydro and 96R-18 transmission estimate standards Class 5 (concept screening -20%+100%), at best Class 4 (Feasibility -15%+50%)

Evaluating cable procurement and installation costs from recently completed or under construction projects only and excluding costs associated with:

- AC/DC convertor stations
- Landside DC transmission connections between the submarine cable transition stations to the existing AC systems.
- The cost to provide any additional redundancy.
- Comparison to existing submarine links

Table 27: HVDC link across Tasman comparison with existing HVDC link costs

Item	Bass Strait	North Sea	Tasman Sea
Project Name	Basslink	Viking	TBA
Cable Project Cost	NZ$900M	EU$2B NZ$4B	Cable NZ$18-23B Terminals NZ$1B Land links (50km x 2) NZ$300M Vessels & technology NZ$700M Total NZ$20-25B

Assuming a bipole link of at least 1,000MW continuous (700MW per pole on overload) for a 700MW capable N-1 link then a minimum project budget of between $20-25B would be required.

M.3 Summary

Although technically possible, the present day practicality and capability of building a 2,500km submarine link of 1,000MW continuous capacity with overload capacity of 700MW per pole in water depths up to 5,000 meters is marginal at this time. If this capability existed, it would cost a minimum of $18-23B for the cable system alone. Additional costs such as system losses, AC/DC converter stations and AC connections and lines at either end would need further consideration.

Resilience and energy security issues associated with linking our energy market to Australia's and protecting the cable link from damage in international waters by third parties, or the ability to affect repairs, have not been considered.

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