TRANSPOWER

Lower South Island: Major Capex Proposal Longlist Consultation

Attachment 1: Need and Longlist of Options

November 2026



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1 Need

1.1 Regional context

The Lower South Island includes the provincial cities of Dunedin and Invercargill, alongside important tourism and rural service centres such as Queenstown, Wānaka and Cromwell. The region has a diverse and growing economy, supported by its productive land and natural resources. Key industries include agriculture, manufacturing, tourism, forestry, mining and fishing, which contribute significantly to both the regional economy and New Zealand's export sector.

Continued economic development, alongside emerging industrial and electrification opportunities, is expected to contribute to growing electricity demand across the region. The Lower South Island is also a major electricity generation region, with some of New Zealand's largest hydro generation schemes and significant potential for further generation development, particularly wind, as well as hydro, battery energy storage systems (BESS), and solar.

1.2 Investigation area

To help describe transmission system issues in the Lower South Island (LSI) region, we define the investigation area as including both:

- the Clutha Upper Waitaki area, which encompasses the transmission system between the Clutha area (Clyde and Roxburgh) and the Upper Waitaki area (Twizel to Livingstone)
- the Otago-Southland area, which encompasses the Clutha area and everything south of it. We refer to the area south of Roxburgh and west of Three Mile Hill as the Southland area

The scope of this investigation is limited to the 220 kV circuits in the Lower South Island; 110 kV circuits are outside the scope. Figure 1 shows the single line diagram of the existing 220 kV transmission network of the Lower South Island.

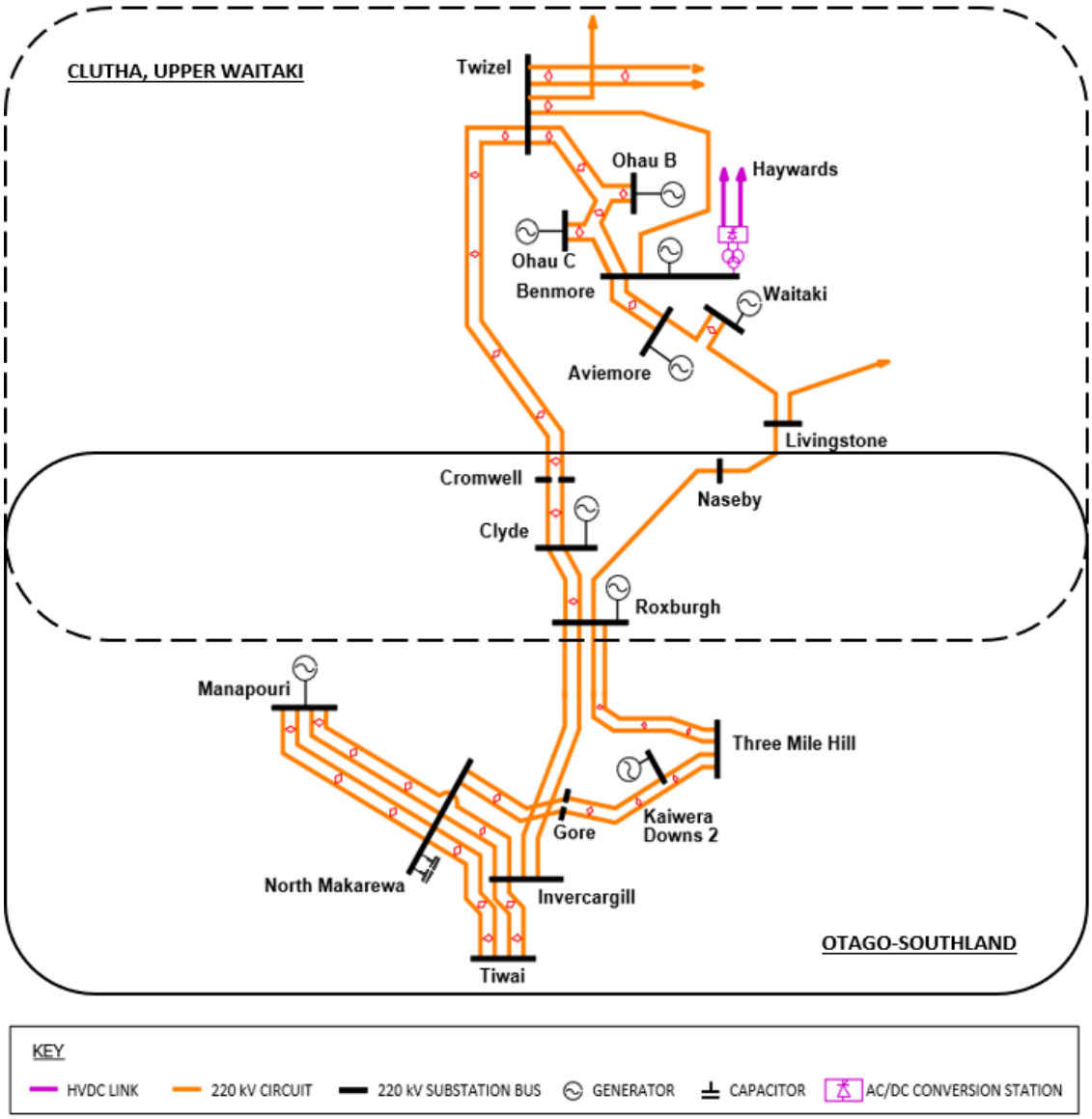

Figure 1: Lower South Island 220 kV network

The Lower South Island grid backbone comprises the following 220 kV circuits:

- nine circuits between Twizel and Livingstone, which connect six large Waitaki Valley hydro generation stations and the HVDC link at Benmore
- three circuits from Roxburgh to Twizel and Livingstone
- four circuits from Roxburgh to Invercargill and North Makarewa (two of which run via Three Mile Hill)
- two double-circuit lines between Manapouri and Tiwai via North Makarewa and Invercargill.

Only three transmission circuits connect Otago-Southland to the Waitaki Valley: Roxburgh-Cromwell-Twizel 1 and 2, and Roxburgh-Naseby-Livingstone 1. The region also hosts the South Island termination point for the inter-island HVDC link, which enables electricity to be transferred between the North and South Islands.

1.3 Overview of need

The Lower South Island contains approximately 60% of the country's hydro generation capacity, much of which is typically exported through the Lower South Island transmission network and across the HVDC link. However, electricity can also be imported into the region, particularly during dry periods to conserve hydro storage when inflows are low.

High import conditions generally occur when generation at Manapouri, Roxburgh and Clyde is low, wind generation is low, and regional demand is high. This may occur during a dry year, for example. Conversely, high export conditions can occur when hydro and wind generation are high[1] and regional demand is low.

During periods of high import or export, electricity transfers can be limited by thermal, voltage and angular stability constraints under intact network conditions. In particular, these constraints can affect the ability to transfer electricity between Otago-Southland and the Waitaki Valley, with only three transmission circuits connecting the two regions. Constraints can also arise on other transmission circuits within the region, depending on system conditions.

These constraints are expected to become more significant as demand and generation increase across the Lower South Island. New generation could increase the amount of electricity seeking to be exported from the region, while electrification and potential large step-load connections, including mining operations, data centres and processing facilities, could substantially increase import requirements. As a result, existing constraints may bind more frequently and have a greater impact on the efficient dispatch of generation and supply of load. Figure 2 shows where thermal import and export constraints occur across the region and identifies those driven by prospective generation.

In particular, we are concerned about import constraints on the Invercargill-Roxburgh circuits and Southland's voltage stability limit following the connection of large loads. In the short term, we are investigating a range of measures to help relieve these constraints, including replacing the North Makarewa capacitors with higher-rated units, using variable line ratings, and implementing special protection schemes. We are also working directly with individual customers to explore connection approaches that minimise their impact on the grid. Together, these measures may help manage constraints in the short term while longer-term solutions are investigated through this MCP.

The Lower South Island MCP therefore needs to address existing transmission constraints while ensuring the network is prepared for significant growth in generation and load. We are therefore taking a broad approach to investigating investment options, with the aim of developing the network in a coordinated way rather than responding incrementally as individual connections emerge.

[1] Maximum generation conditions assume that all hydro units are generating, and that wind generation is exporting at 100% of installed capacity.

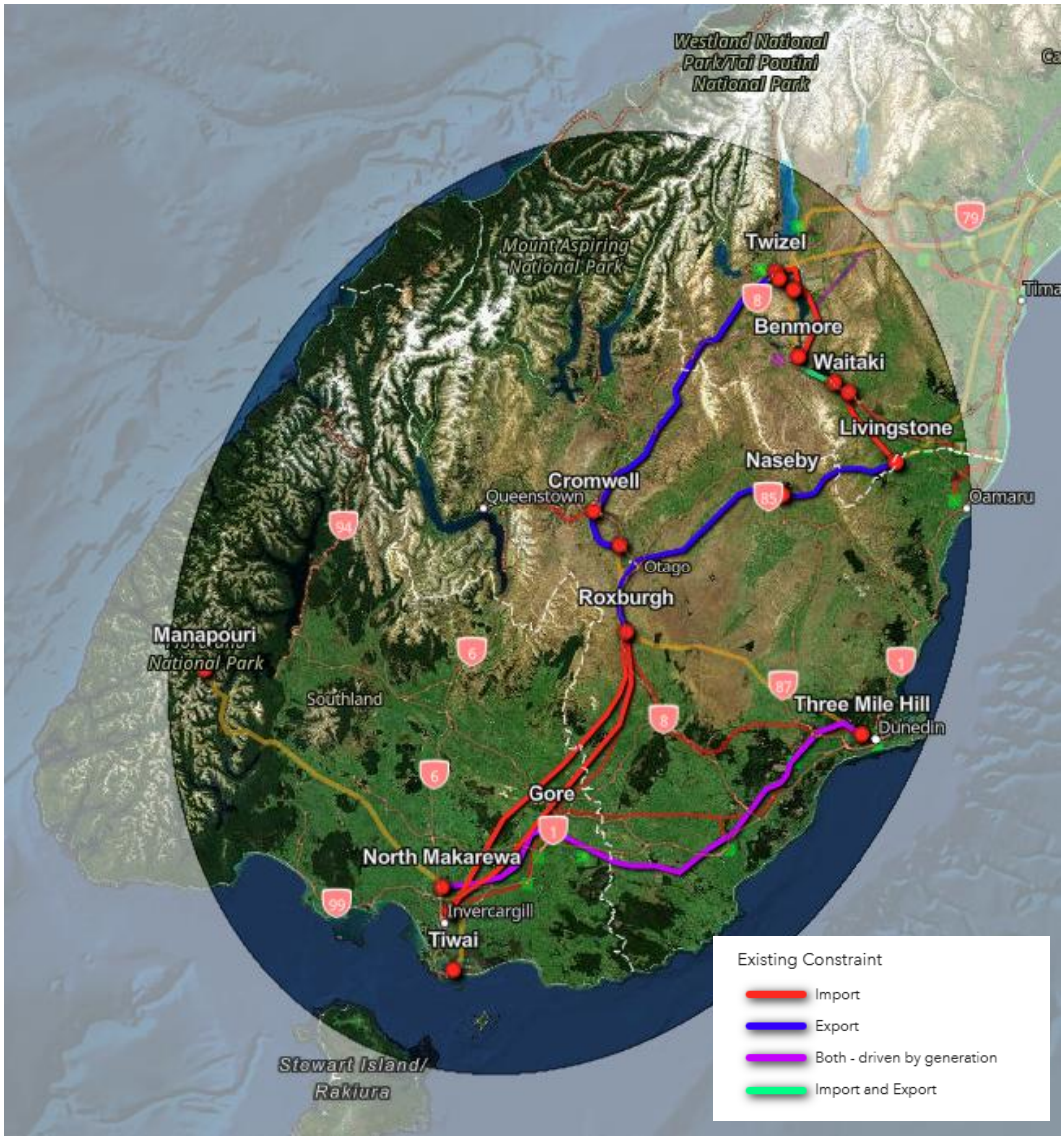

Figure 2: Geographic map of Lower South Island MCP thermal constraints

1.4 Transmission constraints

System studies indicate there is potential for thermal, voltage and angular stability constraints across the Lower South Island network. These may occur under both high import and high export conditions. These constraints are identified in Transpower's Transmission Planning Report[2] and are illustrated separately in Figure 3 and Figure 4 below.

Under high import conditions, both thermal and voltage stability constraints can arise. Which constraint binds first, and when, depends on system conditions and modelling assumptions. The Lower South Island import limits we have identified range from approximately 800 MW to 1,500 MW. The corresponding timing of these constraints is discussed in more detail later in this chapter.

2 FINAL 2026 Transmission Planning Report_0.pdf

Under high export conditions, both thermal and voltage stability constraints may also arise, although which constraint is limiting is less clear and will depend on system conditions. The need for investment to support higher exports will be assessed economically rather than defining a specific export limit at which investment would be triggered.

Presently, these constraints are managed by the System Operator with generation dispatch. As generation and load increase, these constraints are expected to bind more frequently. Import constraints are expected to be the more significant driver of transmission investment, particularly as large new loads connect in the region. The following sections describe the constraints and the conditions under which they arise in more detail.

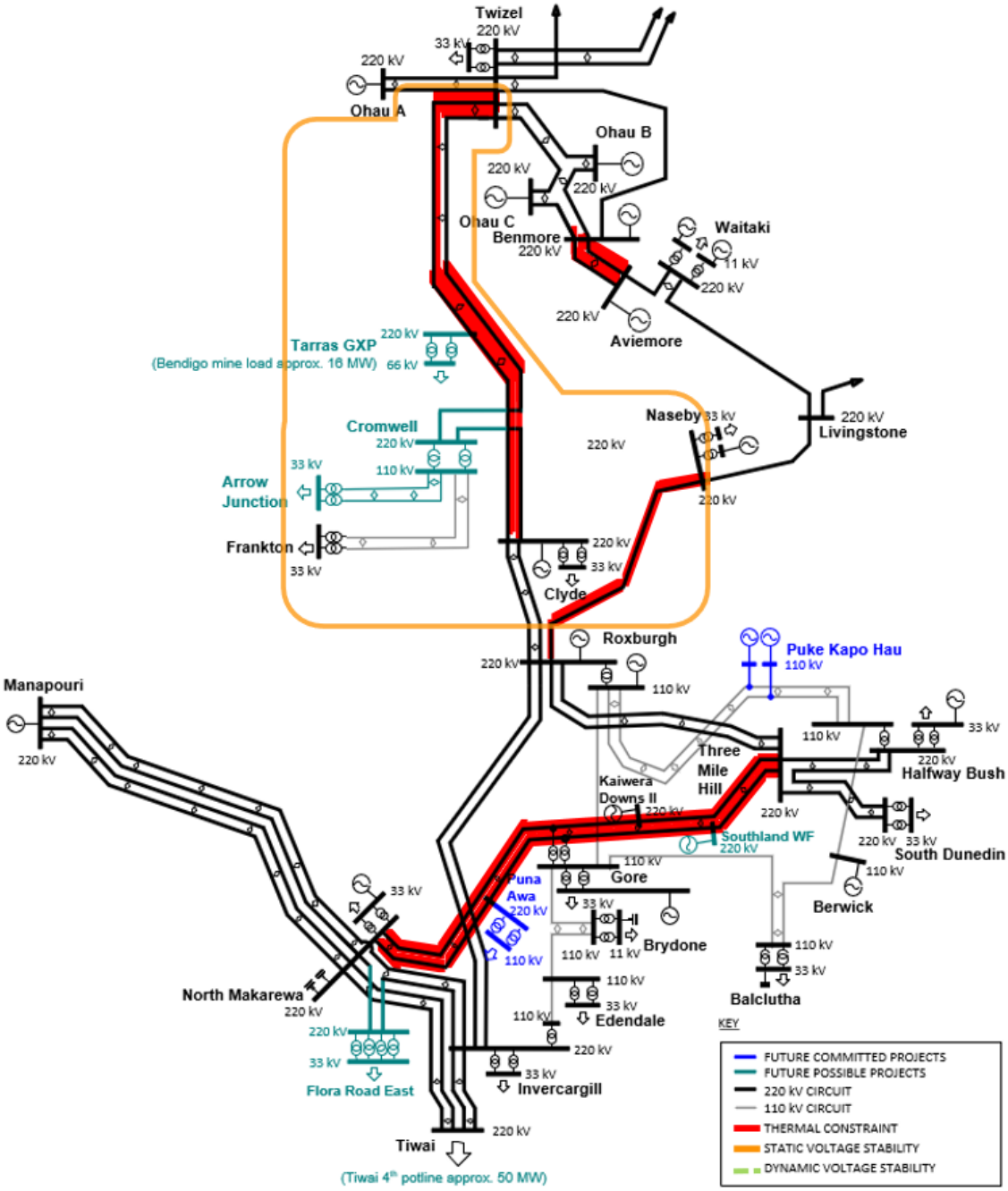

Figure 3: Existing Lower South Island export constraints

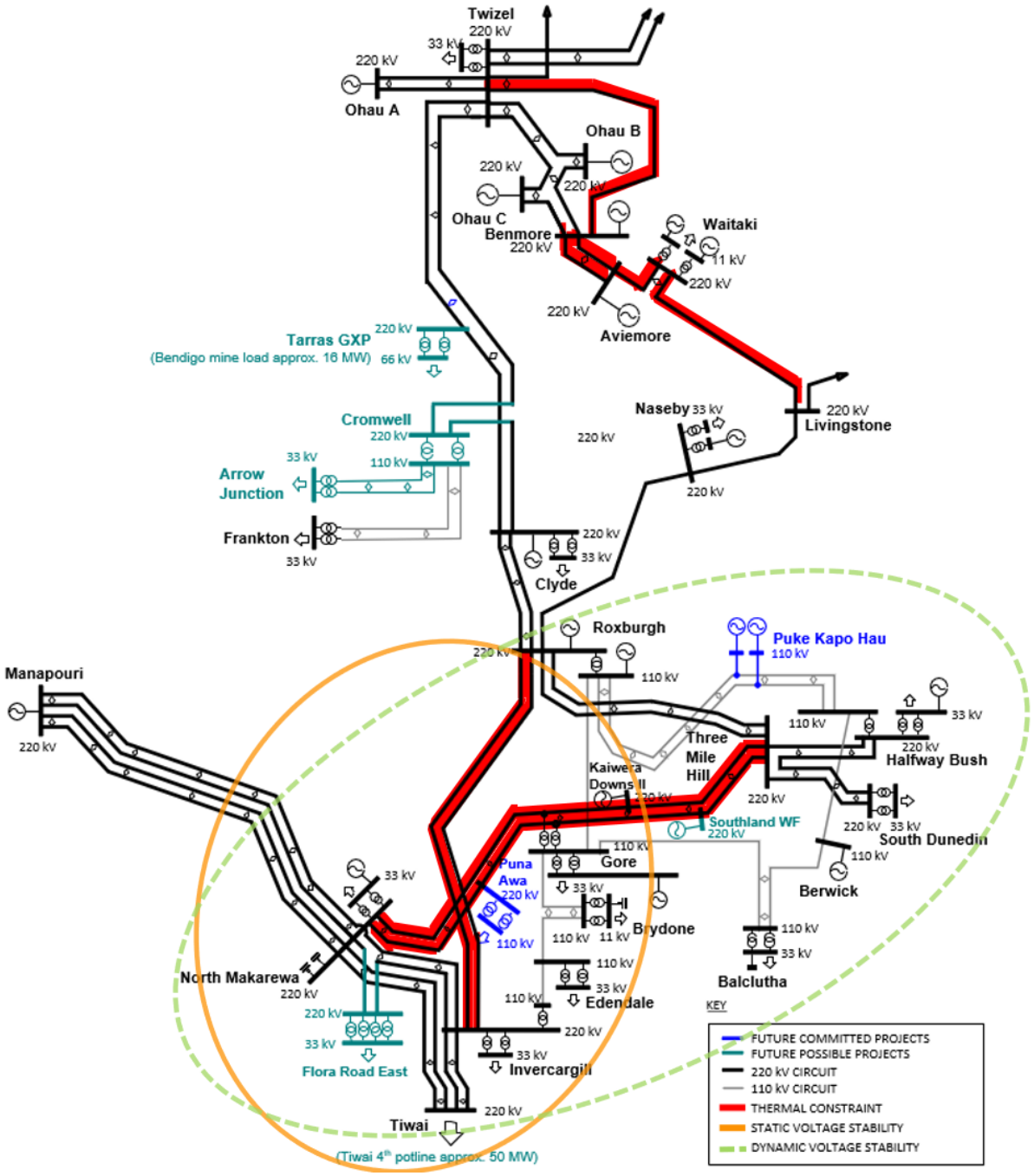

Figure 4: Existing Lower South Island import constraints

1.4.1 Thermal Constraints

Thermal constraints refer to constraints on the amount of power that can be transmitted so that the conductors (and other equipment) do not overheat.

Thermal capacity limits or constraints can be addressed either by constructing new transmission lines or enhancing the capacity of existing ones. Capacity upgrades can be achieved through targeted thermal up-rates, which allow the lines to operate at higher temperatures, thereby increasing their ability to carry more power. Another option is replacing existing conductors with higher-capacity alternatives to alleviate constraints.

Installing new overhead lines offers the most significant increase in thermal capacity. However, this approach comes at a higher cost and requires early planning due to lengthy consenting and construction timelines.

High Southland import system conditions

Studies have assessed the impact of low generation in Otago-Southland during peak demand periods (i.e., high import). Under these conditions, transmission constraints requiring management by the System Operator already exist when supplying the Otago-Southland region from the Waitaki Valley and via the HVDC link. Table 1 summarises these binding thermal issues under high import conditions.

Table 1: Current binding thermal constraints under high Southland import system conditions

Constraint	Binding Contingency[3]	Comments
Aviemore-Benmore-1/2	Aviemore-Benmore-2/1[4]	First constraint to bind is dependent on the level of Waitaki Valley generation.
Benmore-Twizel-1	Ohau B-Twizel-3	Benmore-Twizel-1 circuit is expected to bind first under most generation scenarios. Aviemore-Benmore circuits are expected to bind first under low Waitaki generation scenarios. These circuits represent constraints on generation export from Benmore. The constraints are a function of HVDC south flow and Benmore generation, supplying South Island load. These constraints predominantly represent an economic rather than a reliability issue, as they could potentially be resolved by generation redispatch. Therefore, justification for investment will be determined by economic modelling.
Aviemore-Waitaki-1 or Aviemore-Benmore	Clyde-Cromwell-Twizel-1/2	The binding constraint varies with Waitaki Valley generation. The Aviemore-Waitaki-1 circuit is the binding constraint when approximately two or more machines are generating at Aviemore. For less than two machines generating at Aviemore, the Aviemore-Benmore circuits are the binding constraint.

[3] Only binding contingencies are shown in this table. While other contingencies can also cause overloads, those shown represent the worst-case conditions.

[4] This constraint is being managed by a circuit overload protection scheme. The scheme manages the overloading of both Aviemore-Benmore circuits by tripping the Aviemore-Waitaki circuit, following an Aviemore-Benmore outage.

Invercargill-Roxburgh-1/2	Invercargill-Roxburgh-2/1	When Southland import[5] exceeds approximately 800 MW. Refer to Figure 5 for when we might expect this constraint to bind.
North Makarewa-Gore-Three Mile Hill-2	Kaiwera Downs -Gore-Three Mile Hill-1	Under maximum wind conditions[6], North Makarewa-Gore-Three Mile Hill-2 circuit is more susceptible to overloads. This is because we assumed a larger single-circuit windfarm connection (300 MW) on North Makarewa-Gore-Three Mile Hill-2, compared to a smaller single-circuit windfarm connection (155MW) on North Makarewa-Three Mile Hill-1.

High Southland export system conditions

Initial studies have assessed the impact of high generation in Otago-Southland during light load periods. Under these conditions, transmission constraints exist when exporting power from the Otago-Southland region to the Waitaki Valley and via the HVDC. These constraints will bind more frequently as generation in the area increases. Table 2 summarises these binding thermal issues under high export conditions.

Table 2: Binding thermal constraints under high Southland export system conditions

Constraint	Contingency	Comments
Aviemore-Benmore-1 & Aviemore-Benmore-2	Livingstone-Orari-1 Livingstone-Naseby-1	The binding constraint varies with Waitaki Valley generation. The Clyde–Cromwell circuits are the binding constraint when the Aviemore and Waitaki combined generation is less than 200 MW. The Aviemore-Benmore circuits are the binding constraint when the Aviemore and Waitaki combined generation is above 200 MW.
Clyde-Cromwell-1 or 2	Clyde-Cromwell-Twizel-1 or 2, or Naseby-Roxburgh-1 or Livingstone-Naseby-1	

[5] Southland import boundary is defined as the power flow measured across the four 220 kV circuits (Invercargill–Roxburgh–1 and 2, and Roxburgh–Three Mile Hill–1 and 2) and the three 110 kV circuits (Halfway Bush–Roxburgh–1 and 2, and Gore–Roxburgh–1).

[6] Assumes existing wind generation and an additional 300 MW possible wind generator on NMA–GOR–TMH-2.

1.4.2 *Voltage Stability*

Voltage stability refers to the ability of the system to maintain acceptable voltage levels across all buses under normal conditions and following disturbances such as generator trips, circuit faults or outages. Voltage instability can result in a progressive and uncontrollable rise or decline in voltage. Voltage rise can damage transmission assets and connected equipment, while voltage collapse can result in widespread blackouts, requiring a 'black start' of the grid.

A power system requires both long-term (static) voltage stability, and short-term (dynamic) stability in the event of a fault on the system. Static reactive devices such as capacitor banks provide binary on/off response and are generally used to support static voltage stability. Dynamic reactive devices such as SVCs, STATCOMs and synchronous condensers provide fast continuous response and are generally used to support dynamic voltage stability.

The System Operator's real-time tools provide alerts to impending static voltage stability and thermal overload risks, and these can currently be managed using available tools. However, without investment to meet the need as generation and demand grow, the System Operator may resort to demand management in the LSI region – limiting electricity supply in the region to maintain voltage stability and manage thermal limits. Table 3 summarises binding static voltage stability constraints in the region.

Table 3: Binding static voltage stability constraints

System condition	Contingency	Comments
High Southland import	Invercargill-Roxburgh-1/2 or North Makarewa-Gore-Three Mile Hill-1/2	Static voltage stability limits transfer when load South of Roxburgh exceeds approximately 800-1,500 MW, depending predominantly on the number of hydro generators operating at Manapouri, wind generation and the availability of the North Makarewa capacitors.
High Southland export	Naseby-Roxburgh-1	Static voltage stability limits transfer when Southland export exceeds 900-1,100 MW. This is dependent on the number of hydro generators available at Clyde.

Initial dynamic voltage stability assessments indicate a risk of poor voltage recovery within the region following a three-phase fault, but a low risk following a single-phase-to-ground fault. For the purposes of identifying a dynamic voltage stability investment need, we propose assessing whether the required post-fault voltage performance criteria can be met following a single-phase-to-ground fault. This is consistent with the approach adopted for the Upper South Island MCP dynamic studies.[7] For single-phase-to-ground faults, the dynamic voltage stability limit doesn't bind before the thermal limits or PV limits.

1.4.3 *Transient Rotor Angle Stability*

Transient rotor angle stability (TRAS) is a synchronous machine's ability to remain synchronised under normal operating conditions and to maintain synchronism after a disturbance. TRAS is critical

[7] Upper South Island Upgrade Project – Power System Analysis Report

for the System Operator to ensure the stable operation of the grid. Loss of synchronism - sometimes referred to as “out of step” or “pole slipping” for synchronised machines - can lead to damage to the synchronous generators. Further, it could lead to power system instability, voltage fluctuation and loss of other generators.

There is a known transient rotor angle stability issue associated with high Manapouri generation export.[8] This can arise following a three-phase fault at Manapouri and is currently managed operationally by the System Operator through a generation export constraint under specified system conditions.[9]

Longer-term mitigation of this local stability issue is being investigated through a separate customer project. While the separate customer project is expected to address the existing local stability limitation, any increase in Manapouri generation beyond the current export constraint may still be constrained by limitations elsewhere on the transmission network. This MCP therefore acknowledges the existing local issue and the mitigation being progressed separately but will focus on testing the broader network impacts of increased Manapouri generation output. These impacts will be assessed through dedicated generation sensitivities.

For high import conditions, studies undertaken to date have not identified a material angular stability limitation. Further assessment will be undertaken as future generation and demand assumptions are refined.

A three-phase fault will be used to assess transient rotor angle stability, which is consistent with the System Operator’s approach to identifying the existing issue. However, any stability limits identified through this assessment would only drive grid investment through this MCP where investment is economically justified.

1.4.4 When are the import limits on transfer into Southland going to bind?

The Southland import constraints are highly dependent on the availability of local generation in Southland. Figure 5 shows an indicative range of import constraints into Southland for different Manapouri generation levels. It shows the summer constraints and load forecast, as summer constraints are marginally worse than winter constraints.

Using a conservative dispatch including two Manapouri units and no local wind contribution, constraints bind with Southland load of approximately 800 MW. To put that in context the 2025 summer peak load was around 900 MW. It is important to note that load in this region follows a relatively flat duration curve, meaning that peak loads in the area can occur for a considerable portion of the year.

Presently, these limits can be managed operationally with generation dispatch. However, they will begin to bind even with significant contribution from local generation, with the forecast sharp increase in load in Southland.

To develop our shortlist plans to meet the longer-term forecast load in the Southland region we propose to apply a lower-bound dispatch of local generation. We are proposing to assume two Manapouri units and no wind contribution.

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8 MAN_TRAS_Management_Summary.pdf

9 CAN Manapouri Inter-trip Enabled Stability Constraint - Revision of Notice 8000000148 Sent 26-05-2026 800000383.pdf

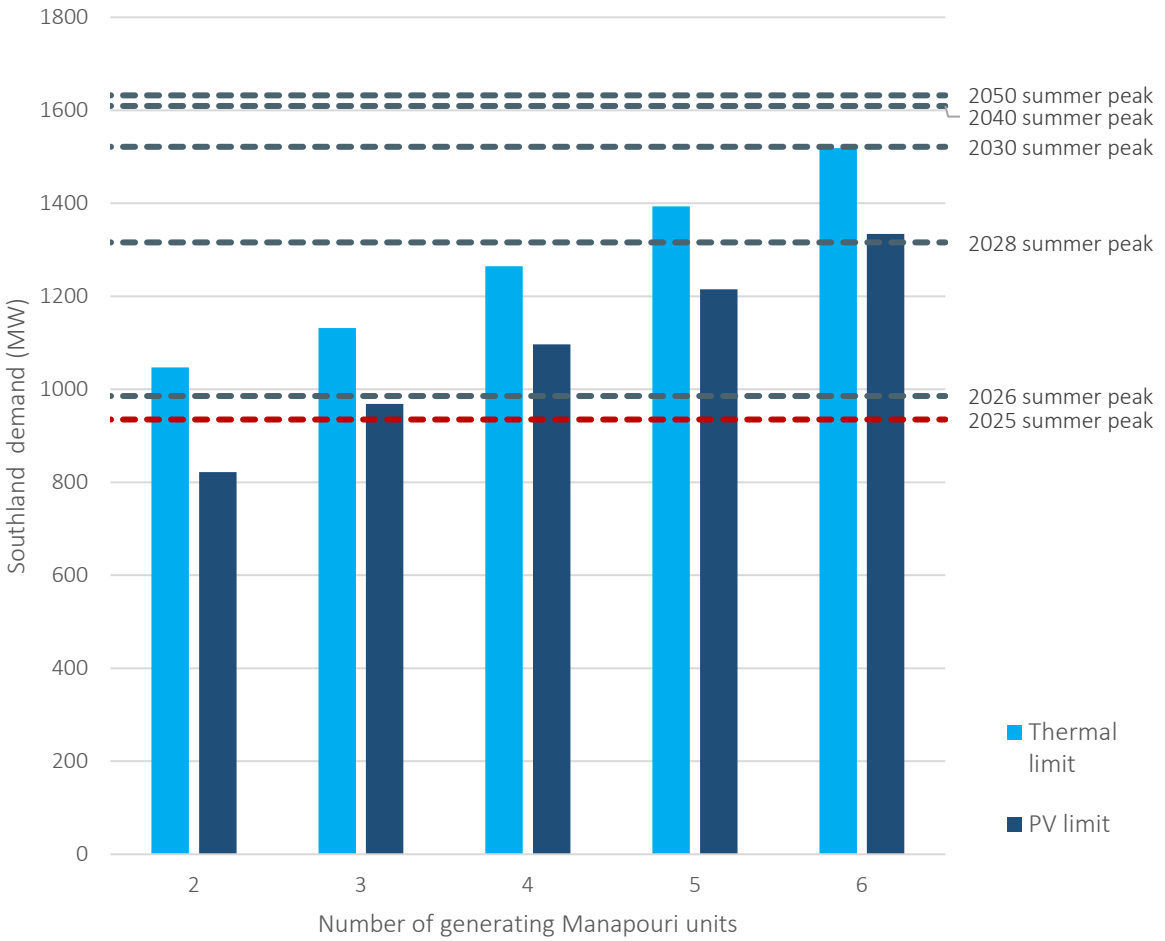

Figure 5: Southland import capacity limit versus Manapouri units available[10]

Q1. **Do you agree with our assessment of the investment need?**

Q2. **Do you consider our proposed lower-bound generation dispatch assumption (two Manapouri generation units and no local wind) reasonable for assessing investment need and timing?**

Q3. **Are there any other issues or considerations relating to the investment need that we should incorporate into the investigation?**

Q4. **Do you support our proposed approach of assessing rotor angle stability using three-phase faults and dynamic voltage stability using single-phase faults?**

[10] Forecast peaks are based on the most recent version of the 2024 EDGS environmental prudent peak forecast, refer to Attachment 2 for more detail.

2 Longlist of options

A longlist of options has been developed, setting out a wide range of possible ways to address the need and alleviate the constraints identified in Section 1. The longlist comprises individual investment components that could be combined in different ways – depending on the demand and generation scenarios considered – to form development plans.

Some of these options may be 'enabling' investments. These are investments that enable new generation to connect and export electricity to the grid where development might otherwise be constrained by the cost or scale of transmission investment required. As part of this MCP, we are exploring both traditional grid backbone investments and enabling investments, either or both of which could ultimately form part of the MCP.

We are taking a broad approach to identifying and evaluating potential solutions, including relevant non-transmission alternatives. The longlist comprises three broad categories:

- Non-transmission solutions, such as energy storage and demand-side services
- Transmission options that upgrade or enhance existing assets
- Transmission options that involve building new assets.

2.1 Longlist of investment components

Table 4 contains the longlist of investment components considered capable of contributing to the need identified in section 1.3.

Table 4: Longlist of investment components[11]

ID	Location	Type	Details	Duration of works	High-level cost estimate
1. Non-transmission solutions (NTS)					
A1	Lower South Island region	Demand-side NTS	Enter into a grid-support contract with demand-side services to defer or replace transmission investments		
A2	Lower South Island region	Energy storage NTS	Enter into a grid-support contract with energy storage providers to defer or replace transmission investments		
A3	Lower South Island region	Generation NTS	Enter into a grid-support contract with generators to defer or replace transmission investments		

[11] The options may be staged, and this may be considered for future development plans. This will be consulted on as part of the shortlist consultation.

ID	Location	Type	Details	Duration of works	High-level cost estimate
2. Transmission options: Upgrade existing assets[12][13]					
B1	AVI-BEN-A	Line upgrade	Duplex 220 kV circuits	20 to 30 months	$23m - $93m
B2	BEN-ISL-A & TWZ-DEV-A	Line upgrade	TTU 220 kV circuits	10 to 14 months	$7m - $26m
B3	ROX-TWZ-A	Line upgrade	Duplex 220 kV circuits	55 to 75 months	$132m - $531m
B4	NMA-TMH-A	Line upgrade	Duplex 220 kV circuits	60 to 80 months	$81m - $324m
B5	INV-ROX-A	Line upgrade	Duplex 220 kV circuits	70 to 120 months	$150m - $600m
B6	INV-ROX-B	Line upgrade	Duplex 220 kV circuits	25 to 35 months	$58m - $233m
B7	BEN-TWZ-A	Line upgrade	Reconductor 220 kV circuits	6 to 9 months	$8m-32m
B8	AVI-LIV-A	Line upgrade	Reconductor 220 kV circuits	20 to 40 months	$174m - $323m
B9	Lower South Island region	Substation upgrade	Associated substation upgrades to match the line capacity. The detail of this option will be determined by thermal chain analysis.	20 to 54 months	$45m - $180m
3. Transmission options – New assets[14]					
C1	INV-ROX-C	New line	Build a new 220 kV line	70 to 120 months	$307m - $1,229m
C2	GOR-ROX-B	New line	Build new 220 kV line	60 to 100 months	$193m - $770m
C3	NMA-ROX-A	New line	Build a new 220 kV line	70 to 120 months	$292m - $1,168m

[12] Development pathways may support completing a tactical transmission upgrade (TTU) ahead of line reconductoring where this provides earlier benefits or enables investment to be efficiently staged.

[13] We are not aware of any further reconfiguration options that address the need.

[14] Note that for new assets, line routes, intermediate connection locations, asset configurations and other design details have not yet been determined. The options presented are intended to provide a high-level indication of the potential investment only.

ID	Location	Type	Details	Duration of works	High-level cost estimate
C4	AVI-LIV-ROX-A	New line	Build a new 220 kV line	80 to 150 months	$397m - $1,590m
C5	BEN-TWZ-ROX-A	New line	Build a new 220 kV line	80 to 150 months	$445m - $1,783m
C6	BEN-LIV-TMH-A	New line	Build a new 220 kV line	80 to 150 months	$427m - $1,707m
C7	BEN-ONSLOW, ONSLOW-NMA	New line and new GXP/GIP	Build a new 220 kV line and a new GXP (Onslow).	120 to 240 months	$603m - $2,414m
C8	BEN-ROX	New line	Build a new 220 kV line	80 to 150 months	$365m - $1,461m
C9	Lower South Island region	New line	Build a new 400 kV line in the region[15]	120 to 240 months	$777m - $3,107m
C10	MAN-ROX	New line	Build a new 220 kV line	80 to 150 months	$469m - $1,847m
C11	Lower South Island region	Impedance management	Series compensation on one line or more lines in the region	36 to 48 months	$160m - $638m per double circuit line
C12	BEN to Flora Road East	New line	Build a new 220 kV line	120 to 240 months	$731m - $2,925m
C13	Lower South Island region	New HVDC line	Extend the HVDC line south of Benmore	80 to 150 months	$2,300m - $4,200m
C14	Lower South Island region	Voltage support	Install a new STATCOM, E-STATCOM or synchronous condenser in the region	36 to 48 months	$45m - $180m
C15	Lower South Island region	SPS[16]	Install a special protection scheme (SPS) to maintain the power system following a contingency	24 to 48 months	$0.5m - $2m per SPS

[15] We remain open to considering other voltage levels for new lines where appropriate.
[16] Type of SPS to be determined at a later stage.

ID	Location	Type	Details	Duration of works	High-level cost estimate
C16	Lower South Island region	New switching station	Build new 220 kV switching station in the region	24 to 36 months	$23m - $90m
C17	Lower South Island region	Protection upgrades	Install new protection and circuit breakers to guarantee faster protection clearances	24 to 48 months	$3m - $9m
C18	Lower South Island region	Voltage support	Install new static capacitors in the region	14 to 20 months	$5m - $18m

We are not consulting on a preferred option at this stage. We are seeking input to refine the longlist and understand which components and locations are most relevant to customers and future load and generation developments in the region.

Q5. **Are there any other options we should add to our longlist?**

Q6. **If new or upgraded shared transmission capacity were developed, which connection areas or locations would be most beneficial to you and why, for example, proximity to your projects, lower curtailment risk or fewer consenting barriers?**

Q7. **Are there any constraints or limitations we might not be aware of regarding our options?**

2.2 Evaluating our longlist of options

We propose to evaluate our longlist of options using a set of high-level screening criteria, as set out below. The screening criteria will be used to eliminate options that are not appropriate for inclusion in the short-listed development plans to which we apply our options assessment, including the Investment Test.

We will consider the feedback we receive in this consultation both in terms of whether the criteria are appropriate, and in relation to developing and refining shortlist development plans.

Our shortlist options may be single options from the longlist (such as a new line) or more often, combinations of options presented as a development plan. This allows options that only deliver short term benefit to be compared with more extensive options that aim to meet the need over the longer term.

Broadly, we intend to use six criteria for screening:

Table 5: Short-listing screening criteria

Criteria	Details
Fit for purpose	• Extent to which the option addresses the need identified in section 1 • Extent to which the option maintains N-1 security as demand grows • Extent to which the option accommodates outages • Extent to which the option remains effective across a range of demand forecasts • Extent to which the option can be staged to reduce investment risk
Technically feasible	• Complexity of solution • Reliability, availability and maintainability of the solution • Future flexibility – fit with long-term strategy for the grid

Criteria	Details
Practical to implement	• Ability to implement the solution within the proposed investment timeframe • Implementation risks, including potential delays due to property and environmental issues
Good electricity industry practice	• Consistent with good international practice • Ensures safety and environmental protection • Accounts for relative size, duty, age and technological status • Technology risks
System security[17]	• Improved system security • System operator benefits (controllability) • Dynamic benefits (modulation features and improved system stability)
Indicative cost	• Whether an option will clearly be more expensive than another option with similar or greater benefits

Q8. Do you agree with our screening criteria? Is there anything you would change, remove or add?

2.3 Non-transmission solutions

Transpower is committed to considering viable non-transmission solutions (NTS) that could defer, reduce or avoid the need for transmission investment. NTS are alternatives to traditional transmission investment that can help manage a transmission need, for example by changing the level, location or timing of electricity generation or demand.

Our longlist includes three broad categories of NTS that could help address the need for investment in the Lower South Island. Through this consultation, we are particularly interested in hearing from parties that may be able to provide NTS, including information on their potential capability, location and timing.

We welcome feedback on the potential availability of NTS in the region and interest in providing them. Information provided through this consultation will not be commercially binding. We expect to seek more detailed information on potential NTS through a formal Request for Information (RFI) later in the MCP process.

[17] Additional benefit resulting from an economic investment

Q9. **Are you aware of, or able to provide, any non-transmission solutions that could help defer, reduce or avoid transmission investment in the Lower South Island? If so, please provide high-level details on the type, location and size of the solution.**

3 Regulatory process for investment approval

If this MCP investigation identifies a preferred option that will enhance the service provision of the existing grid, we expect that the investment cost will exceed $30 million. In this case, we will submit an MCP to the Commerce Commission to recover the costs of the project from transmission customers. The Transmission Pricing Methodology (TPM) sets out how the cost of the project (the covered cost[18]) is recovered from customers who are expected to benefit from the investment. We may also consider alternative funding arrangements in addition to the MCP process.

3.1 Investigation process

The process we are using for this investigation is consistent with the requirements of the Transpower Capital Expenditure Input Methodology (Capex IM). The diagram in Figure 6 sets out the general process followed by this investigation. We are at the 'Option Identification' stage.

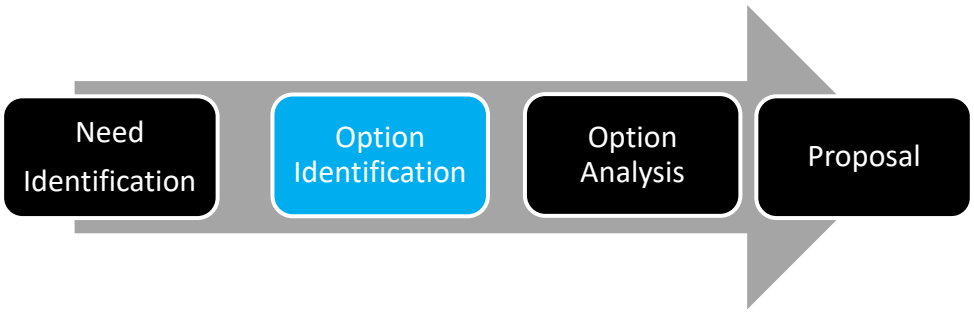

Figure 6: Options assessment approach

As we move through the process, we will undertake targeted engagement with key stakeholders, and two consultations. The first is a longlist consultation, which is the purpose of this document, and includes consultation on:

- Investment need (this Attachment, section 1)
- Longlist of options to be considered (this Attachment, section 2)
- Demand and generation scenarios we will use in our assessment (Attachment 2)
- Key assumptions we will use in our assessment (Attachment 3).

Our second consultation will be a shortlist consultation, outlining our refined shortlist of development plans, our options evaluation, application of the Investment Test, and other supplementary analysis, to identify which development plans are economic under what circumstances. This process will test what input assumptions would need to hold for the development plans to be economic.

In addition to quantifiable benefits, our assessment may consider a range of unquantified benefits and other net economic benefits where they are material to the decision. Sensitivity analysis will be

[18] The covered cost refers to the cost recovered through benefit-based charges for a benefit-based investment under the TPM. It includes capital components (return on and of investment) as well as an allocation of Transpower's operating costs, including overheads.

undertaken to test the robustness of the analysis, and the identified shortlisted development plans will form the basis of a shortlist consultation.

3.2 Relationship with the Transmission Pricing Methodology

The Electricity Authority's Transmission Pricing Methodology (TPM) has applied since 1 April 2023.[19] The TPM determines how Transpower's allowable revenue is recovered from its customers in each pricing year. To support the understanding of the TPM, we have released a TPM information sheet that explains the relationship between price-quality regulation and investment approval for transmission services, and price setting under the TPM.[20]

A key component of the TPM is the benefit-based charge (BBC), which recovers the costs of some historic interconnection investments, and all interconnection investments commissioned after 23 July 2019. BBCs recover the costs of these investments from those customers who are expected to benefit from the investment. For investments expected to have a capital cost greater than $30 million (high-value investments),[21] the modelled costs and benefits used to produce these allocations are aligned with electricity market benefits or cost elements under the Investment Test.

The Commerce Commission determines how much revenue Transpower, as the owner and operator of the National Grid, can recover from its customers according to its regulation of Transpower under Part 4 of the Commerce Act. The TPM determines the allowable revenue is recovered from (or allocated to) each of Transpower's customers in each pricing year.

Once Transpower's capital expenditure proposal has been approved by the Commerce Commission, whether as major capex or base capex, the covered cost[22] of the approved investment may be recovered under the TPM.

The TPM requires that allocations for high-value benefit-based investments (BBI) are based on customers' expected positive net private benefits. One or more of the solutions to meet the need of this project will be high-value. Therefore, the assumptions and scenarios that we use in the application of the Investment Test are likely to be used to determine allocations for one or more components of this project under the new TPM, unless we consider these will result in allocations that are not broadly proportional to expected positive net private benefit. As such we propose that the assumptions in this investigation are consistent with the TPM Assumptions Book v3.0[23], unless otherwise noted.

In our operational review of the TPM[24] we identified the potential problem where in regions likely to see future generation, transmission upgrades are sometimes needed ahead of new connections. We

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19 Electricity Industry Participation Code, Part 12-Transport, Schedule 12.4: Part 12—Transport | Electricity Authority

20 TPM Information Sheet- Relationship between transmission investment and pricing

21 The TPM defines a high-value investment by reference to the base capex threshold in the Capex IM, which is currently $30 million.

22 The cost recovered through the BBCs for a BBI is referred to in the TPM as the BBI's covered cost. The covered cost of a BBI includes capital components (return on and of investment) and an allocation of Transpower's operating costs (including overheads).

23 Assumptions book | Transpower

24 TPM Operational Review | Transpower

refer to these transmission upgrades as 'enabling investments'. This could be connection or interconnection investments (which might be the outcome of this MCP investigation). Under the current TPM, existing load customers mostly pay for these upgrades until the new generators connect, meaning the existing load customers fund benefits ultimately received by future generation customers (or, potentially, vice versa).[25] It has not yet been determined whether this issue will be addressed as part of the operational review or will be referred to the Authority for broader policy consideration.

[25] Transpower: TPM Operational Review 2026 Workstream 1 (section 10.2)



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