COMMERCE COMMISSION
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Transpower's Net Zero Grid Pathways stage one major capex proposal

Final decision and reasons paper

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Executive summary

Our final decision to approve a major capex proposal from Transpower

X1 This paper sets out our decision to approve the first staging project of a staged major capex project proposed by Transpower New Zealand Limited (**Transpower**).

X2 The paper:

X2.1 summarises stage one of the Net-Zero Grid Pathways 1 major capex proposal (**MCP**), as submitted to us by Transpower on 25 September 2023[1] (**NZGP1 stage one**); and

X2.2 sets out our evaluation of, and decision to approve, NZGP1 stage one, together with the reasons supporting our decision.

X3 We must evaluate a staging project Transpower submits to us against the criteria and requirements in the Transpower Capital Expenditure Input Methodology Determination [2012] NZCC 22 (**Capex IM**) and decide on whether to approve or decline it.[2] Transpower may only recover capital expenditure relating to a major capex project if we have first approved it.

X4 For the investment test, we are evaluating all the staging projects included in NZGP1 MCP. Based on the outcome of this evaluation, we then consider whether to approve or decline NZGP1 stage one. When Transpower identifies the need date for NZGP1 stage two, it must notify us and, among other things, consult on the investment options and investment tests.[3] Transpower, after taking into consideration submissions from the consultation, will then submit its preferred investment proposal for NZGP1 stage two to us for evaluation.

X5 Before making a decision on a staging project, we must consult and take account of interested parties' views on our draft decision.[4]

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1 Transpower "Net Zero Grid Pathways 1 Major Capex Project (Staged) updated – major capex proposal" (25 September 2023) available at https://comcom.govt.nz/__data/assets/pdf_file/0011/330014/Transpower2C-NZGP1.1-Updated-Proposal-main-document-25-September-2023.pdf.

2 The Capex IM is available at https://comcom.govt.nz/__data/assets/pdf_file/0026/88280/Transpower-capital-expenditure-input-methodology-determination-consolidated-29-January-2020.pdf. Clauses 3.3.5(1) and (4) set out the approve/decline decision that we must undertake if we do not reject the MCP under clause 3.3.4 of the Capex IM.

3 Capex IM, above n 2, clauses 3.3.1(1), 3.3.1(2)(b), and clause I6.

4 ibid, clause 3.3.5(5)(a).

X6 Our approval regime under the Capex IM aims to strike the right balance between allowing stakeholders to scrutinise individual major capex projects, providing scope for other parties to provide alternative solutions, and enabling Transpower to undertake investment that promotes the long-term benefit of its consumers.[5]

Transpower is seeking approval to enhance the grid to support the transition to net zero carbon

X7 Government policy on climate change has evolved, with a legislated target and supporting policies now in place for 10% less carbon emissions by 2030 than those set in 2017, and transition to net zero emissions by 2050.[6]

X8 Over the coming years we expect a transition from fossil fuel use, an increase in electrification, more intermittent renewable generation, less thermal generation, and a more distributed energy system.

X9 As Aotearoa New Zealand transitions to net zero emissions, Transpower is seeing a considerable increase in the number of new electricity generation connection enquiries and increasing electrification demand. Transpower's NZGP1 stage one seeks our approval to recover the cost of increasing the capacity of parts of the main transmission grid backbone "to enable the efficient dispatch of forecast new generation and a reliable supply for future demand growth over the interconnected grid".[7]

X10 NZGP1 stage one contains three investment packages:

X10.1 installing reactive plant, filter banks and associated equipment to upgrade inter-island HVDC link north transfer availability from 1071 MW to closer to 1200 MW (**HVDC upgrade**);

X10.2 increasing transfer capacity north from Bunnythorpe by between 60% to 90% by installing variable line rating and tactical thermal upgrade of Tokaanu-Whakamaru lines and to Bunnythorpe-Tokaanu circuits; duplexing Tokaanu-Whakamaru circuits with Goat conductor; upgrading protection on Huntly-Stratford circuit; replacing the special protection scheme at Tokaanu; and splitting the Bunnythorpe-Ongarue circuit (**Central North Island upgrade**); and

5 Commerce Commission, Transpower Capital Expenditure Input Methodology Reasons Paper (31 January 2012) (**2012 Capex IM reasons paper**), paras 2.5.12 to 2.5.13.

6 The New Zealand Government has set a target for net zero greenhouse gas emissions by 2050 (other than for biogenic methane). https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/emissions-reduction-plan/.

7 Transpower, Proposal, above n 1, p. 8.

X10.3 increasing transmission capacity by 25% (300 MW) under typical operating conditions by installing tactical thermal upgrading on both circuits of Wairakei-Whakamaru C line and the Edgecumbe-Kawerau 3 circuit on the Ohakuri-Edgecumbe A and Kawerau-Deviation lines; and splitting the Edgecumbe-Kawerau circuit (**Wairakei ring upgrade**).

X11 As part of stage one, Transpower is also seeking funding to carry out the investigation and design of a number of possible stage two projects (**Preparedness projects**).

X12 This is the first stage of a staged major capex project, and Transpower is seeking our approval to invest $392.9 million on this stage.

X13 While NZGP1 stage one could be viewed as three investment packages, we are considering it as a single MCP (staged) because those packages are to an extent interdependent. The interdependency is due to power flow across the three investment areas to meet power demand in Waikato and upper North Island. The generation developments driving NZGP1 stage one affect the core grid asset power flows identified in the proposal. Our analysis of NZGP1 stage one has looked at the proposal as a whole, and where appropriate, has focused on component aspects of the investments.

X14 However, while we have accepted the consolidated economic analysis approach in this proposal, we consider that future proposals should link discrete investment drivers more explicitly to individual investment proposals.

Our regulatory approval process to date

X15 Transpower first submitted its NZGP stage one proposal to us for our approval on 2 December 2022 (**original proposal**). On 13 June 2023, Transpower submitted an addendum (**Addendum**) amending its original proposal.

X16 On 27 July 2023, Transpower notified us that it identified a material error in the investment test supporting its proposal. After reviewing the corrected results, Transpower preferred a different option to the one it first preferred in its June 2022 short list consultation and included in its original proposal, and to the option it subsequently preferred in its June 2023 addendum.

X17 Following a further consultation with stakeholders, Transpower submitted an updated proposal to us on 25 September 2023.

X18 On 16 November 2023 we published our evaluation and draft decision in response to the 25 September 2023 proposal.[8] Submissions closed on 14 December 2023 and cross submissions on 25 January 2024.[9]

X19 We have reviewed those submissions and have incorporated the feedback we received about our draft decision into this final decision.

Our decision is to approve Transpower's proposal

X20 Having completed our evaluation of Transpower's NZGP1 stage one proposal, our decision is to approve NZGP1 stage one. On balance, we are satisfied with the information, assumptions, and supporting analysis provided by Transpower.

Our assessment of the electricity market costs and benefits

X21 This is the first generation connection driven MCP that Transpower has proposed since the HVDC Pole 3, Wairakei ring line and Lower South Island renewables upgrades in the late 2000s approved by the Electricity Commission.[10] Any proposed transmission upgrade to allow that generation capacity to meet demand must provide a net market benefit.

X22 Our decision to approve the investment of $392.9 million is only for stage one, which we have reached after evaluating the investment test for all the projects and stages of the MCP. Transpower will need to submit an MCP when it wants to seek approval for stage two.[11]

X23 Since Transpower's proposed investment option (Option 14) does not have the highest expected quantified net electricity market benefit, Transpower has carried out a qualitative assessment of the unquantified electricity market benefits of Option 14. We have considered Transpower's qualitative assessment of the unquantified benefits in making our final decision.

X24 Following our review, we are satisfied that Transpower has identified electricity market benefits of the investment option that outweigh the costs of that investment option, and in aggregate, Transpower's NZGP1 satisfies the investment test.

X25 However, the proposed investment involves three separate transmission upgrade packages, in three different parts of the transmission grid, under the umbrella of a consolidated set of market benefits and a consolidated investment need.

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8 Commerce Commission "Transpower's Net Zero Grid Pathways stage one major capex proposal - Draft decision and reasons paper" (16 November 2023) (**Draft decision reasons paper**).

9 Submissions and cross submissions on the Commission's draft decision are available on the Commission's website here.

10 Since 2010, the approval of MCPs has been administered by the Commission.

11 Capex IM, above n 2, clause C1(2).

X26 To satisfy ourselves that each of these transmission upgrade packages would pass the investment test on their own merits, we undertook further analysis of the Central North Island and Wairakei ring upgrades and HVDC upgrade packages that make up NZGP1 stage one.

The benefits for the Central North Island and Wairakei ring upgrades

X27 Our analysis indicates that the Central North Island and Wairakei ring upgrades will pass the investment test and appear good value for money when compared with new transmission capacity. We consider that there are likely generation developments that will need to access this increased capacity in the near future.

X28 We considered the Central North Island and the Wairakei ring upgrades together. The power flows in this part of the transmission grid are very interdependent because they both facilitate north transfer of power from Bunnythorpe. Any north transfer of power from Bunnythorpe will flow through both the Bunnythorpe-Tokaanu-Whakamaru network (**Central North Island**) and the Bunnythorpe-Wairakei-Whakamaru network (**Wairakei ring**).

X29 The proposed Central North Island and Wairakei ring upgrades will increase the power transfer capacity on the transmission circuits there by approximately 430 MW and 380 MW respectively. These capacity increases are very cost effective when compared with the cost of new transmission.

X30 We tested the robustness of Transpower's application of the investment test by carrying out our own assessment of potential displacement of thermal generation as a counterfactual case. We estimated the expected net benefits of fuel cost displacement and consider that these benefits are likely to justify the proposed Central North Island and Wairakei ring upgrades.

The benefits of the HVDC upgrade

X31 We carried out an in-depth analysis regarding the HVDC upgrade component of NZGP1. We did so because it was not clear if the assumptions Transpower had made about the Tiwai smelter exit date were still valid, and we were not sure that Transpower had identified sufficient benefits to justify the HVDC upgrade component of NZGP1 stage one.

X32 The Tiwai smelter exit would be equivalent to introducing 574 MW (about 5 TWh of energy) of surplus generation annually, which could be exported to the North Island. This generation would likely displace North Island thermal generation plant.

X33 We carried out two analyses to test the economic impact of the Tiwai smelter exiting in 2024 as assumed by Transpower:

X33.1 In the first analysis we used historical HVDC power transfer data to ascertain if constraining the HVDC to its existing capacity would impose significant wholesale market costs. We concluded that there may be a cost associated with this, but those costs may not be sufficient to justify the HVDC upgrade.

X33.2 In the second analysis we investigated whether the proposed HVDC upgrade would alleviate South Island hydro spill costs. We concluded that the benefit of avoided South Island hydro spill, due to increased HVDC capacity, appeared to be minimal and insufficient to justify the HVDC upgrade.

X34 When analysing Transpower's original proposal,[12] we were not fully satisfied that the HVDC upgrade component of NZGP1 stage one provided a positive net market benefit on a standalone basis. As a result, we asked Transpower how it will mitigate the risk of over-investment associated with the HVDC stage one investment.[13]

X35 In the Addendum, Transpower updated its proposal in this way:[14]

> …Transpower propose to make the HVDC Stage 1 works a 'contingent' project output. This means we will not commence the procurement, design, and build of the HVDC Stage 1 investment until we can quantitatively demonstrate, to the Commission, positive net benefits associated with the investment. The trigger for this could be confirmation of Tiwai's departure date, modelling to show the additional redundancy benefits from the STATCOM, or more certainty in the generation mix or load forecasts.
>
> …
>
> In order to progress the approval of this MCP, Transpower propose to make this project output contingent on us demonstrating to the Commission that there are clear net benefits to consumers.
>
> (footnote omitted)

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12 Transpower, Net Zero Grid Pathways 1 (staged) – major capex proposal (2 December 2022) (**original proposal**) available at https://comcom.govt.nz/__data/assets/pdf_file/0019/312391/TranspowerE28099s-Net-Zero-Grid-Pathways-1-Major-Capex-Proposal-Staged-2-December-2022.pdf.

13 Available at https://comcom.govt.nz/__data/assets/pdf_file/0022/320629/Letter-to-Transpower-seeking-additional-information-on-NZGP1-stage-one-29-May-2023.pdf.

14 Transpower, Net Zero Grid Pathways 1 – Major Capex Proposal (Staged) Addendum – Amending our proposal (13 June 2023) (**Addendum)** at pp. 4, 8. Available at https://comcom.govt.nz/__data/assets/pdf_file/0021/320628/Transpower-NZGP1-stage-one-Addendum-to-Proposal-13-June-2023.pdf.

X36 We will refer to this aspect of NZGP1 stage one together with the additional detail around triggers (ie, investment drivers), expectations, and process set out in the following paragraphs, as the "**HVDC assurance**". We consider that progressing the HVDC upgrade should be contingent on Transpower being able to quantitatively demonstrate to interested persons a net electricity market benefit for the HVDC upgrade investment

X37 Transpower, in its Addendum information, set out what it considered the possible triggers for the contingency may be, namely:

X37.1 confirmation of Tiwai's departure date;

X37.2 modelling to show the additional redundancy benefits from the STATCOM; or

X37.3 more certainty in the generation mix, or load forecasts.

X38 In our draft decision, we specified that progressing the HVDC upgrade should be dependent on one or more of the above triggers occurring (referred to as the "HVDC assurance trigger"). However, having considered submissions, we note that there may be other triggers that could justify the decision to upgrade the HVDC, and that Transpower should not be limited by those it identified in its Addendum given the real focus is on the effect of the trigger.

X39 For any other triggers to be sufficient, they would need to have the same effect as was proposed for the three specified triggers, which is the effect of Transpower being able to quantitatively demonstrate to interested persons a net market benefit for the HVDC upgrade investment. Nonetheless, we expect Transpower to identify the trigger, or driver of the HVDC investment, as part of its HVDC assurance so that interested persons can understand the rationale and analysis. We expect that the investment driver will also identify the appropriate timing of the investment.

X40 We expect Transpower to do the following prior to proceeding with the HVDC upgrade component of NZGP1 stage one:

X40.1 identify the investment driver of the HVDC upgrade;

X40.2 update its generation scenarios and investment test modelling;

X40.3 identify the costs and benefits and quantitatively demonstrate that the HVDC upgrade has a positive net market benefit; and

X40.4 provide sufficient information to enable interested persons to carry out an independent review of Transpower's analysis.

X41 In terms of process, we expect Transpower to seek feedback from interested persons as it progresses the HVDC upgrade and demonstrate how it has acted on that feedback. More specifically, we expect Transpower to do at a minimum what it specified in its own cross-submission, which is:

X41.1 publish all updated analysis and materials on its website for review by interested parties (and we would expect Transpower to bring these updated matters to the attention of at least the parties who provided submissions and cross-submissions on our draft decision);

X41.2 share the results at a webinar/workshop;

X41.3 invite feedback from interested parties, which Transpower will consider in its decision-making, allowing a reasonable time period for that feedback to be provided; and

X41.4 inform interested parties about its decision to proceed or not and how any input received influenced Transpower's decision. We would expect this information to be made available in the same ways as the updated analysis and materials.

X42 While we remain less certain regarding the benefits of the NZGP1 stage one HVDC upgrade relative to the other components of what we are assessing, our final decision is to approve the proposal, taking into account the HVDC assurance and the process outlined above.

X43 Transpower has assured us that it will quantitatively demonstrate the positive net market benefit following one or more of the HVDC assurance triggers, and our final decision is to not make the commencement of the HVDC upgrade dependent on a further decision or analysis by the Commission. It instead takes into account the HVDC assurance given by Transpower.

X44 In reaching our final decision, we have considered the possible uncertainties that underpin the HVDC upgrade component of NZGP1, namely that there may be longer delivery timeframes associated with HVDC cable equipment, and the importance of the HVDC link to Aotearoa New Zealand's electricity system. Given these uncertainties and the key risks that Transpower has to manage, we consider that approving NZGP1 stage one with the HVDC assurance will enable Transpower to manage the HVDC risks appropriately in accordance with the purpose of Part 4 of the Commerce Act 1986 (the **Act**).[15]

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[15] As specified in clause 6.1.1(2)(b) of the Capex IM, one of the criteria for evaluating an MCP is to consider the extent to which what is proposed will promote the purpose of Part 4 of the Act.

The components of our decision

X45 In reaching a decision to approve Transpower's proposal, the Capex IM requires us to determine the:[16]

X45.1 major capex allowance (**MCA**);[17]

X45.2 exempt major capex;[18] and

X45.3 major capex incentive rate.[19]

X46 We set out our decisions on these matters below.

Major capex allowance

X47 As part of our decision approving NZGP1 stage one, our decision is to set an MCA of $392.9 million for NZGP1 stage one.

X48 Our MCA decision, as described in Chapter 4 for NZGP1 stage one, is based on the base project cost estimate plus the 50th percentile of project cost uncertainties, being $32 million.

X49 Our MCA decision is summarised in Table X1.

Table X1 Major capex allowance for NZGP1 stage one ($ million)

Base estimate in 2022	P50 estimate in 2022	Inflation factors	Financing costs	MCA 2028 prices
294.8	326.8	40.7	25.4	392.9

Major capex incentive rate

X50 The major capex incentive rate we set under clause 3.3.5(7)(b) of the Capex IM determines the reward (or penalty) that Transpower receives (or bears) depending on how the actual cost of delivering a major capex project compares to the project's MCA.

16 Capex IM, clause 3.3.5(7) and Schedule C.
17 Under clause 1.1.5(2) of the Capex IM, 'major capex allowance' means the amount of major capex we approve in relation to an approved staging project.
18 Under clause 1.1.5(2) of the Capex IM, 'exempt major capex' means those portions of the MCA amount to which the major capex incentive rate does not apply, which may be expressed by reference to a category of expenditure within a major capex project or staging project, as we determine under clause 3.3.5(7) of the Capex IM.
19 Under clause 1.1.5(2) of the Capex IM, 'major capex incentive rate' means 15% or an alternative rate we specify in respect of an approved staging project.

X51 Under clause 1.1.5(2) of the Capex IM, the major capex incentive rate is 15% – the default rate – or an alternative rate we specify after considering a request from Transpower. In its proposal, Transpower proposed that the default MCP incentive rate of 15% apply to NZGP1 stage one.

X52 We are satisfied that the default incentive rate of 15% will incentivise Transpower to seek efficiencies in delivering NZGP1 stage one. We would only consider an alternative incentive rate for projects where the forecast cost is high, the forecast cost is uncertain, or the potential for efficiency gains is high. We do not consider any of these circumstances apply to NZGP1 stage one.

X53 Our decision, as set out in Chapter 4, is to set the major capex incentive rate for NZGP1 stage one at 15%.

Exempt major capex

X54 Exempt major capex is those portions of the MCA amount to which the major capex incentive rate does not apply and is typically set for portions of the MCA that reflect uncertainties.

X55 In its proposal Transpower did not propose any exempt major capex.[20] However, we have decided that exempt major capex should apply to the risk adjustment (contingency) identified by Transpower in its proposal.

X56 Our decision, under clause 3.3.5(7)(c) of the Capex IM, is to treat the risk adjustment component of the MCA as exempt major capex, equal to $38.4 million in 2028 prices. This means that $38.4 million of the MCA will not be subject to the incentive mechanism.

X57 Accordingly, in setting the exempt major capex and the major capex incentive rate, the incentive scheme under clause B3(1) of Schedule B of the Capex IM will work as follows. If the actual cost of delivering NZGP1 stage one is:

X57.1 less than the MCA minus exempt major capex, then applying the major capex incentive rate, Transpower will be entitled to a reward;

X57.2 between the MCA and the MCA minus exempt major capex, then there is no reward or penalty; and

X57.3 more than the MCA, then applying the major capex incentive rate, Transpower will be penalised.

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[20] Transpower, Proposal, above n. 1, p.13.

Chapter 1 Introduction

Purpose of this paper

1.1 The purpose of this paper is to:

1.1.1 explain our decision to approve Transpower's NZGP1 stage one proposal, including a contingency proposed by Transpower relating to part of it; and

1.1.2 summarise submissions from interested parties on our draft decision, which informed our final decision on whether to approve or decline the application.

Structure of the remainder of this paper

1.2 The body of this paper sets out:

1.2.1 the background to Transpower's NZGP1 stage one proposal;

1.2.2 our decision to approve Transpower's NZGP1 stage one proposal;

1.2.3 an overview of our decision-making framework under the Capex IM; and

1.2.4 a summary of submissions on our draft decision and our response to those submissions.

1.3 Attachments A-D set out the analysis, reasons, and Capex IM criteria underpinning our decision. Specifically:

1.3.1 Attachment A sets out our evaluation criteria under the Capex IM which comprise the general criteria,[21] specific criteria,[22] and the investment test;[23]

1.3.2 Attachment B provides our evaluation of the MCP against the general criteria;

1.3.3 Attachment C provides our evaluation of the MCP against the specific criteria;

1.3.4 Attachment D provides our evaluation of Transpower's application of the investment test; and

1.3.5 Attachment E summarises Transpower's NZGP1 revised short-list options.

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21 Capex IM, Part 6.
22 Capex IM, Schedule C.
23 Capex IM, Schedule D.

1.4 Attachment F lists the acronyms, abbreviations and terms used in this paper.

Regulatory approval process to date

1.5 A summary of our regulatory approval process for NZGP1 stage one prior to this decision is as follows:

1.5.1 On 23 July 2021, Transpower notified us under clause 3.3.1(1) of the Capex IM of its plan to develop an MCP (staged).

1.5.2 From August to October 2021, Transpower consulted with stakeholders on its long-list of options to meet the investment need (**long-list consultation**) and invited information on non-transmission solutions (**NTSs**) from interested parties as required by Schedule I of the Capex IM. [24, 25]

1.5.3 From 30 June to 15 August 2022, Transpower consulted on its short-list of investment options (**short-list consultation**) as required by Schedule I3 of the Capex IM.[26]

1.5.4 On 2 December 2022, Transpower submitted the original proposal (staged) to us for our approval of the first stage.[27]

1.5.5 On 13 June 2023, Transpower submitted the Addendum amending its original proposal.[28]

1.5.6 On 27 July 2023, Transpower notified us that it had identified a material error in how the costs of the counterfactual were included in the Investment Test. After reviewing the corrected results, Transpower preferred a different option to the one it first preferred in its June 2022 short list consultation and included in its original proposal, and also to the option it subsequently preferred in its June 2023 Addendum.

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24 Under clause 1.1.5(2) of the Capex IM, 'investment option' means a technically feasible solution, including an NTS, designed to facilitate or meet a specific investment need, other than an option fully funded under a new investment contract.

25 Transpower, Net Zero Grid Pathways 1 – major capex project (staged) investigation. Long-list consultation and non-transmission solution request for information (21 August 2021) (**long-list consultation document**) available at: https://www.transpower.co.nz/nzgp-phase-one-longlist-consultation.

26 Transpower, Net Zero Grid Pathways 1 – major capex project (staged) investigation- shortlist consultation (30 June 2022) (**short-list consultation document**) available at: https://www.transpower.co.nz/nzgp-phase-one-shortlist-consultation.

27 Transpower, NZGP1 stage one original proposal (2 December 2022) available at: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpower-capital-investment-proposals/transpower-major-capital-proposal/transpowers-net-zero-grid-pathways?target=documents&root=308476.

28 Transpower, Addendum, above n 7.

1.5.7 From August to September 2023, Transpower consulted with stakeholders on its updated preferred investment option.[29]

1.5.8 On 25 September 2023, Transpower submitted its updated NZGP1 stage one proposal to us for our approval.[30]

1.6 As explained further below under the heading "Background to the NZGP1 stage one major capex proposal", the 25 September 2023 version is what we evaluated.

1.7 Before making our final decision, we sought the views of interested persons on our draft decision, which we then considered as part of our decision-making process.

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29 Under clause 1.1.5(2) of the Capex IM, a 'proposed investment' is the investment option Transpower submits as an MCP to us for approval of a major capex project or, where it is a staged major capex project (as is the case in this MCP), approval of a staging project.

30 Transpower, Proposal, above n 1.

Chapter 2 Overview and background to this major capex proposal

Purpose of this chapter

2.1 The purpose of this chapter is to provide background on Transpower's NZGP1 stage one proposal. The chapter outlines:

2.1.1 what major capex projects are under the Capex IM; and

2.1.2 the content of and background to the NZGP1 stage one major capex proposal.

Major capex projects under the Capex IM

Major capex projects

2.2 A 'major capex project' is defined in the Capex IM to mean a project of major capex undertaken to address or enable a specific investment need to be met, which may be either or both, a transmission investment or a non-transmission solution (**NTS**).[31] A 'major capex project (staged)' is defined to mean "a major capex project consisting of two or more projects".[32]

2.3 Major capex covers capital expenditure for large individual transmission grid enhancement projects that, given their nature and magnitude, warrant our individual scrutiny and public consultation.[33] Specifically, under clause 1.1.5(2) of the Capex IM, 'major capex' means expenditure that is:

2.3.1 incurred to meet the grid reliability standards (**GRS**) or provide a 'net electricity market benefit';[34]

2.3.2 forecast to have an aggregate capital cost exceeding the base capex threshold of $20 million; and

2.3.3 not incurred in relation to asset replacement, asset refurbishment, business support or information system and technology assets.

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[31] Capex IM, above n 2, clause 1.1.5(2).

[32] ibid clause 1.1.5(2).

[33] Commerce Commission, *Transpower capex input methodology review – Decisions and reasons* (29 March 2018) (**2017/18 Capex IM review reasons paper**) para 54, available at: https://comcom.govt.nz/__data/assets/pdf_file/0033/79926/Transpower-capex-IM-review-Decisions-and-reasons-29-March-2018.PDF.

[34] Under clause 1.1.5(2) of the Capex IM, the GRS as defined under Schedule 12.2 under the Electricity Industry Participation Code 2010 (**Code**). NZGP1 stage one is proposed to provide positive net market benefits and is not required to meet the GRS.

2.4 Clause 3.3.3 of the Capex IM requires Transpower to submit a major capex proposal to us when it seeks approval for a major capex project or, if the proposal relates to a major capex project (staged), one or more staging projects.

2.5 If Transpower seeks approval for one or more staging projects, the aggregate forecast capital expenditure and forecast maximum recoverable costs for all the staging projects that comprise the staged major capex project must exceed the base capex threshold. The threshold that applies to NZGP1 stage one is $20 million.[35]

2.6 The Capex IM also sets out the information that Transpower needs to provide in the MCP and the associated certification of the information it provides.[36] The CEO of Transpower must certify that the information provided accurately represents Transpower's operations. The CEO certification must also state that the proposed investment was approved according to Transpower's director and management approval policies.[37]

2.7 Transpower may submit an MCP to us at any time during a regulatory period.[38]

What happens if we approve NZGP1 stage one as a staging project

2.8 Under clause 2.2.3(2)(f) of the Transpower Input Methodologies (**Transpower IMs**),[39] if we approve NZGP1 stage one as a staging project, Transpower may, after commissioning the relevant assets, include the actual costs of the assets in its regulatory asset base. Transpower may then recover those costs under its individual price-quality path (**IPP**) as transmission charges allocated to Transpower customers according to the transmission pricing methodology (**TPM**).[40, 41]

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35 Capex IM, clause 3.3.3(2) and the definitions of 'major capex' and 'base capex threshold' under clause 1.1.5(2). Note that in the 2023 IM Review we amended the base capex threshold to $30 million.

36 Capex IM, above n 2, at clause 7.4.1 and Schedule G.

37 ibid, clause 9.2.1.

38 ibid, clause 3.3.3(3).

39 Transpower Input Methodologies Determination 2010 [2012] NZCC 17.

40 Commerce Commission, IPP Determination clause 8, available at https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpowers-price-quality-path/setting-transpowers-price-quality-path-from-2020. We note that:

a) under clause 8.3.2 of the IPP, major capex we approve becomes part of the maximum allowable revenue that Transpower may recover for electricity transmission services in a pricing year by the Commission reconsidering the IPP under clause 3.7.4(4)(a) of the Transpower IMs; and

b) any incentive amounts arising from NZGP1 stage one will be determined as part of calculating the major capex expenditure and output adjustment under clause B3(1) of Schedule B of the Capex IM. Under clause 31.1.3(h) of the IPP, the incentive amounts will enter Transpower's EV account and roll over to affect Transpower's maximum allowable revenue at the next regulatory control period.

41 The TPM is the methodology by which Transpower prices its transmission services developed in accordance with subpart 4 of Part 12 of the Code and specified in Schedule 12.4 of the Code.

2.9 Under clause 7.5.1(1)(c) of the Capex IM, Transpower has provided an estimate based on the TPM of the increases in transmission charges from the expenditure relating to NZGP1 stage one.[42]

2.10 Transpower completed their consultation with stakeholders on the starting benefit-based investments (**BBIs**) customer allocations for NZGP1 stage one in September 2023.[43]

Background to the NZGP1 stage one major capex proposal

2.11 Transpower describes the Net Zero Grid Pathways as being a multi-year programme to develop plans for evolving the transmission grid as Aotearoa New Zealand pursues a goal of achieving net zero carbon emissions by 2050.[44]

2.12 Transpower explains that the proposed investment in the backbone of Aotearoa New Zealand's electricity transmission grid aims to ensure that the grid backbone has enough capacity to accommodate new renewable generation and maintain a secure and reliable supply of electricity.[45]

2.13 NZGP1 focuses on what Transpower describes as the first 'phase' of its NZGP programme. Transpower states that the first phase is focused on identifying and reducing potential constraints on the grid backbone to enable the efficient dispatch of forecast new generation and reliable supply of future demand growth over the interconnected grid, for the period out to 2035.[46]

2.14 The project is staged and Transpower has identified two stages to NZGP1.[47] Transpower is seeking approval for NZGP phase one, stage one, which is what we are referring to as 'NZGP1 stage one'.

Timeline to submission of NZGP1 stage one

2.15 Transpower submitted its Notice of Intention to plan the NZGP1 major capex project staged on 23 July 2021.[48]

2.16 Transpower submitted the original Net Zero Pathways 1 major capex proposal (staged) on 2 December 2022.[49]

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42 Transpower, Proposal, above n 1, Attachment G – Indicative charges for proposal.

43 Transpower did not receive any submissions. See https://www.transpower.co.nz/our-work/industry/grid-pricing/transmission-pricing-methodology/tpm-current-consultations.

44 Transpower, Proposal, above n 1, p 6.

45 ibid, p 7.

46 ibid, p 22.

47 ibid, p. 8.

48 Transpower, Notice of Intention to plan NZGP1 major capex project staged (23 July 2021) available at https://comcom.govt.nz/__data/assets/pdf_file/0018/308511/Transpower-Notice-of-intention-to-plan-Net-Zero-Grid-Pathways-Stage-1-23-July-2021.pdf.

49 Transpower, original proposal, above n 19.

2.17 In the original proposal, Transpower's preferred investment option was option 10, as set out in Table 2.1 below.

2.18 During our review of the original proposal, we identified issues with Transpower's preferred investment option. We requested that Transpower consider submitting NZGP1 with an addendum or amendment by other means, such as a redraft, that provided clarity on:

2.18.1 the investment need for the NZGP1 MCP;

2.18.2 the technically feasible investment options considered by Transpower to address the investment need; and

2.18.3 Transpower's proposed investment (ie, preferred investment option), particularly how that meets the investment need.

2.19 We also commented on Tiwai's departure date and suggested that an addendum would provide "an opportunity for Transpower to satisfy us and interested persons about how it will mitigate the risk of over-investment associated with the HVDC stage one investment in case Tiwai does not exit in 2024, as well as raising any timing considerations that are relevant to the test in the Capex IM".[50]

2.20 Transpower subsequently submitted an addendum to the original proposal on 13 June 2023. In the Addendum Transpower changed its preferred investment option to option 11.

2.21 During further review of the original proposal and the addendum, an error was discovered where Transpower had not included the ongoing maintenance cost in its investment test analysis.

2.22 Upon correcting the error, Transpower revised its preferred investment option to option 14. This led to additional consultation with stakeholders, which was undertaken during August and September 2023.

2.23 Transpower then submitted its updated proposal, NZGP1, with option 14 as the preferred investment option for NZGP1 stage one, dated 25 September 2023.[51] Unless expressly noted or the context requires otherwise, any reference to NZGP1 stage one or Transpower's proposal in this paper is a reference to the proposal as updated on 25 September 2023.

2.24 The draft decision and reasons paper set out our draft findings following our evaluation of NZGP1 stage one.[52] We sought stakeholder views on our evaluation and draft decision and have considered those views in our final decision.

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50 Commerce Commission, Letter to Transpower 'Request for Transpower to consider providing additional information to support Net-Zero Grid Pathways Major Capex Proposal (29 May 2023) available at https://comcom.govt.nz/__data/assets/pdf_file/0022/320629/Letter-to-Transpower-seeking-additional-information-on-NZGP1-stage-one-29-May-2023.pdf.

51 Transpower Proposal, above n 1.

52 Commerce Commission, Draft decision reasons paper, above n 8.

Table 2.1 Present value of net benefits of the investment options considered

Investment option	Project cost ($ million)	Net benefit ($ million)	HVDC Upgrade	Central North Island Upgrade	Wairakei ring Upgrade
Option 10	393	176	New HAY reactive support 4th HVDC cable to enable 1400 MW transfer capacity.	BPE-ONG split, HLY-SFD protection upgrade, BRK-SFD enhance, VLE, TTU and duplex TKU-WKM A&B lines, VLR and TTU BPE-TKU A&B lines and replace SPS at TKU	EDG-KAW split, TTU EDG-KAW, TTU WRK-WKM C line
Option 11	454	150		BPE-ONG split, HLY-SFD protection upgrade, BRK-SFD enhance, VLE, TTU and duplex TKU-WKM A&B lines, VLR and TTU BPE-TKU A&B lines and replace SPS at TKU.	TTU WRK-WKM C line, EDG-KAW split, TTU EDG-KAW, Replace WRK-WKM A line
Option 12	451	181		BPE-ONG split, HLY-SFD protection upgrade, BRK-SFD enhance, VLE, TTU and duplex TKU-WKM A&B lines, VLR and TTU BPE-TKU A&B lines and replace SPS at TKU.	EDG-KAW split, TTU EDG-KAW, Build new WRK-WKM D line, WRK substation equipment
Option 13	452	173		BPE-ONG split, HLY-SFD protection upgrade, BRK-SFD enhancement, TTU TKU-WKM, TTU BPE-WRK, Duplex TKU-WKM, Duplex BPE-TKU.	EDG-KAW split, TTU EDG-KAW, TTU WRK-WKM C line
Option 14	514	145		BPE-ONG split, HLY-SFD protection upgrade, BRK-SFD enhancement, TTU TKU-WKM, TTU BPE-WRK, Duplex TKU-WKM, Duplex BPE-TKU.	TTU WRK-WKM C line, EDG-KAW split, TTU EDG-KAW, Replace WRK-WKM A line
Option 15	510	175		BPE-ONG split, HLY-SFD protection upgrade, BRK-SFD enhancement, TTU TKU-WKM, TTU BPE-WRK, Duplex TKU-WKM, Duplex BPE-TKU.	EDG-KAW split, TTU EDG-KAW, Build new WRK-WKM D line, WRK substation equipment

The investment need, timing, and drivers

2.25 Transpower states that NZGP1 stage one is a result of its investigations into the inter-island HVDC Link (**HVDC Link**), Central North Island between Bunnythorpe and Whakamaru, and Wairakei ring parts of the grid backbone. Transpower states that these areas of the grid backbone are the most likely to constrain prior to 2035.

2.26 Looking at the three investment packages of the HVDC Link, Central North Island and the Wairakei ring, Transpower has stated that:[53]

2.26.1 investment is required to increase the average maximum transfer capacity of the existing HVDC Link, both northwards and southwards. The investment will also lift the availability of that capacity, especially during times when ancillary HVDC equipment are not available due to outages;

2.26.2 transmission flow across the Central North Island region is close to being constrained at times now and significant generation south of Bunnythorpe will lead to further constraints. Transpower has noted that the increase in available generation could be in the form of Tiwai smelter closure and/or further new wind generation in the Lower North Island region; and

2.26.3 during times of high available generation in the Wairakei Ring, Eastern Bay of Plenty or Hawke's Bay areas, transmission flow may be constrained. Also, high transmission flow on the Central North Island lines north to Whakamaru can exacerbate the Wairakei ring constraint but to a lesser extent. The investment would increase the capacities from Wairakei to Whakamaru lines for both the direct line and that via Ohakuri and Atiamuri. A new line or an enhanced existing Wairakei-Whakamaru A line, will be considered under NZGP1 stage two.[54]

2.27 Regarding the timing of the investment need, Transpower indicates in its proposal that:[55]

2.27.1 the HVDC Link and Central North Island constraints will bind frequently if the Tiwai smelter exits as early as 2024. Considering timing of the investment approval and project execution timelines, Transpower would complete Central North Island investment by 2028; and

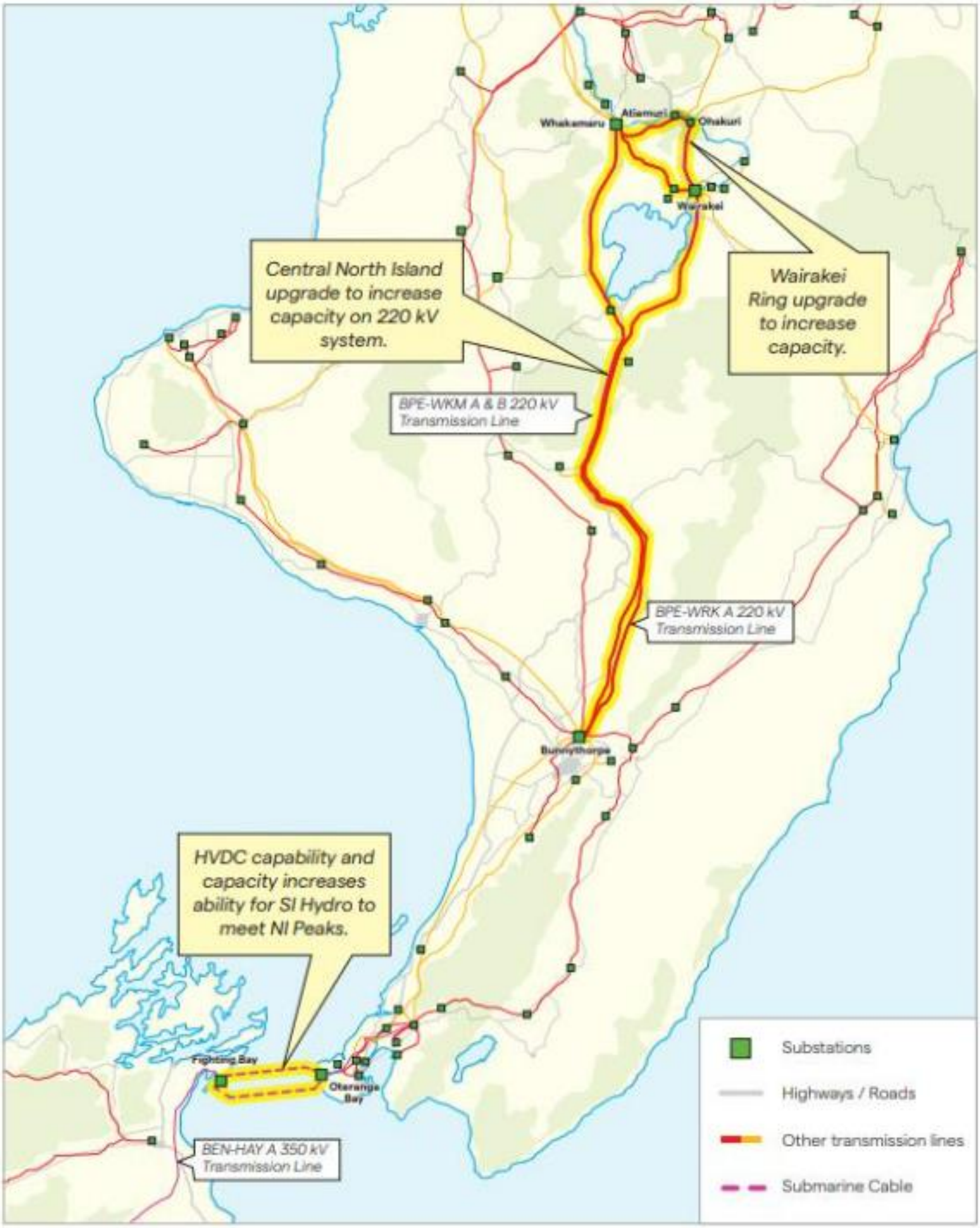
[53] Transpower, Proposal, above n 1, pp. 29-33.
[54] ibid, p. 37.
[55] ibid, pp. 37-38.

2.27.2 Wairakei ring constraints will bind frequently if the large volume of current enquiries for the connection of new renewable generation in the Wairakei region materialise into new generation projects. Transpower expects to commission the Wairakei ring works by 2025.

Overview of the transmission network

2.28 Figure 2.1 shows the areas of the grid backbone that are the focus of NZGP1.[56]

Figure 2.1 Geographical areas in NZGP1 proposal



56 Transpower, Proposal, above n 1, p. 33 – figure 12.

Chapter 3 Our decision-making framework

3.1 This chapter provides an overview of the decision-making framework we applied in reaching our decisions on Transpower's NZGP1 stage one proposal.

Our decision-making framework

Capex IM

3.2 Regulation under Part 4 of the Act (**Part 4**) seeks to promote the long-term benefit of consumers of regulated services.[57] These regulated services include electricity transmission services provided by Transpower.

3.3 The input methodologies under Part 4 are the upfront rules, processes, and requirements of Part 4 regulation. Their purpose is to promote certainty for suppliers and consumers in relation to the rules, requirements and processes applying to regulated services under Part 4.[58] The IMs apply to electricity transmission services provided by Transpower.

3.4 One of the IMs that apply to Transpower is the Capex IM.[59] The two major functions of the Capex IM are to provide for the scrutiny of Transpower's proposed and actual investments and to incentivise Transpower to deliver those investments efficiently.

Major capex projects

3.5 Under clause 3.3.2 of the Capex IM, Transpower may only recover its costs relating to a major capex project if we have first approved it.

3.6 Transpower submits an MCP to us.[60] If we do not reject the MCP,[61] we must either:[62]

3.6.1 approve the project (and in the case of a major capex project (staged), the approval or declinature is of one or more staging projects); [63] or

3.6.2 decline the project.

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57 Commerce Act, s 52A.

58 ibid, s 52R.

59 Along with the Capex IM, Transpower is subject to the Transpower IMs which set out Ims for: cost allocation, asset valuation, treatment of taxation, cost of capital, specification of price, the incremental rolling incentive scheme, and reconsideration of the price-quality path.

60 Capex IM, above n 2, at cl 3.3.3(1).

61 ibid, clause 3.3.4 states that we may reject an MCP if it does not comply with the requirements in clause 7.4.1, or if Transpower has not complied with the requirements specified in clause 3.3.1 of the Capex IM.

62 ibid, clauses 3.3.5(1)(a) and (b).

63 We will refer to "projects" to cover both staging projects and non-staged major capex projects.

3.7 If we approve an MCP, we must also determine the MCA,[64] major capex incentive rate,[65] and any exempt major capex.[66]

3.8 Before we can approve or decline an MCP, we must:

3.8.1 publish the MCP;[67]

3.8.2 evaluate the MCP in accordance with the evaluation criteria in the Capex IM, including any further information we have received in the evaluation process;[68] and

3.8.3 consult in the following ways:[69]

3.8.3.1 make and publish a draft decision or decisions on the MCP;

3.8.3.2 seek the written views of interested persons on anything published; and

3.8.3.3 seek the written views of interested persons on others' submissions.

3.9 We must evaluate an MCP against three sets of evaluation criteria in the Capex IM:

3.9.1 the general evaluation criteria for capital expenditure in Part 6;

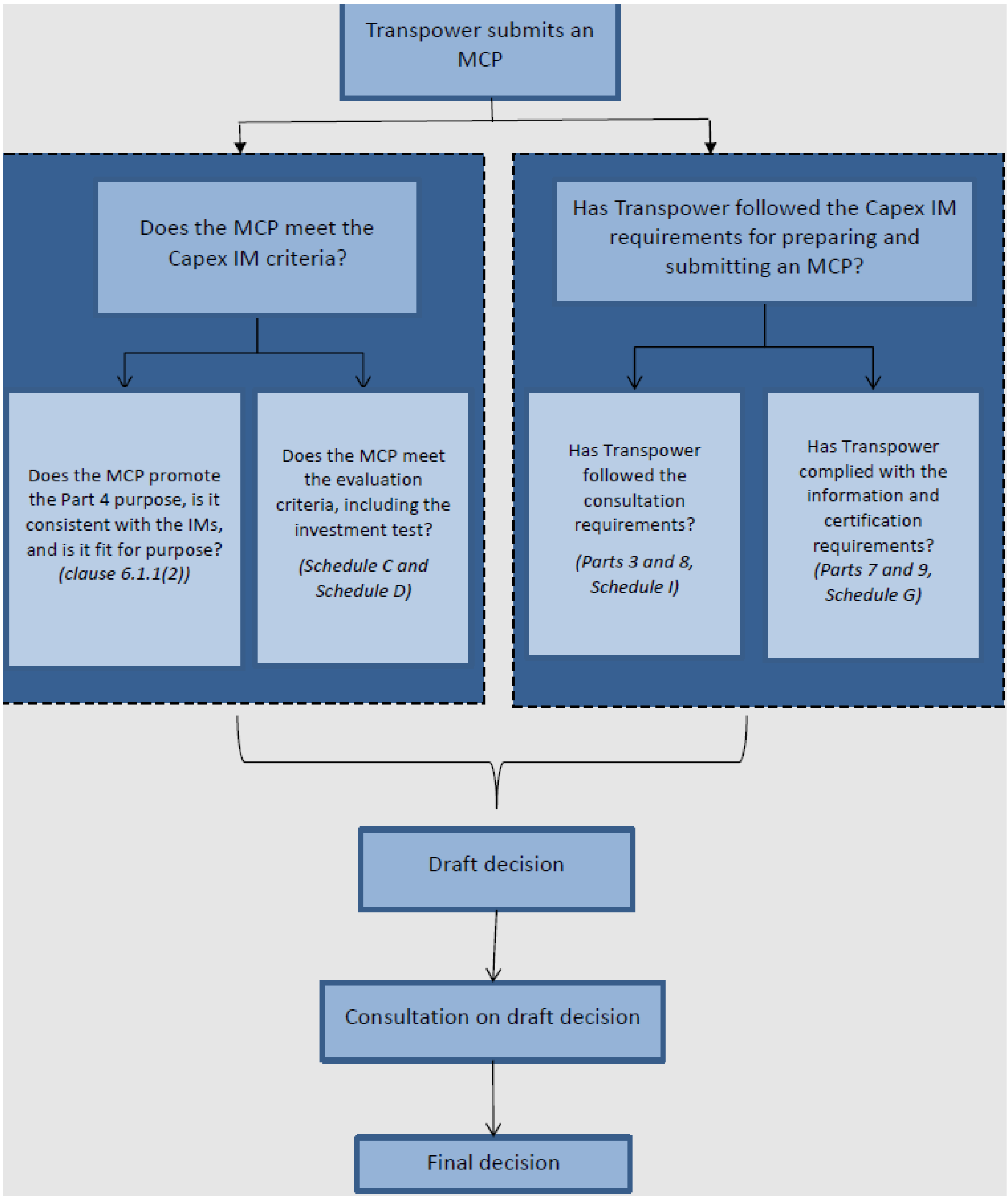
3.9.2 the specific evaluation criteria for MCPs in Schedule C;[70] and

3.9.3 the investment test in Schedule D, Division 1.[71]

3.10 Figure 2 below shows at a high level how our evaluation and decision fits into the Capex IM's regulatory approval process for major capex projects.

64 Capex IM, clause 3.3.5(7)(a).
65 Capex IM, clause 3.3.5(7)(b).
66 Capex IM, clause 3.3.5(7)(c).
67 Capex IM, clause 8.1.1(1)(a).
68 Capex IM, clause 3.3.5(5)(b)(i)-(ii).
69 Capex IM, clauses 3.3.5(5)(a) and 8.1.1(1)(a)(ii) to (iv).
70 Capex IM, clause 6.1.1(4), as part of that Part 6 criteria, we must also evaluate an MCP in accordance with the specific criteria for major capex proposals in Schedule C of the Capex IM.
71 Capex IM, clause C1(1) of Schedule C, we must evaluate whether the investment proposed in the MCP satisfies the investment test specified in Schedule D, Division 1 of the Capex IM.

Figure 3.1 Capex IM regulatory approval process for major capex projects



Chapter 4 Our decision is to approve Transpower's NZGP1 stage one proposal

4.1 This chapter sets out our decision to approve Transpower's NZGP1 stage one proposal. The approval is on the basis set out below, including the HVDC assurance.

4.2 In approving Transpower's proposal, we evaluated and determined the:[72]

4.2.1 MCA;

4.2.2 exempt major capex; and

4.2.3 major capex incentive rate.

4.3 We also evaluated the following components proposed by Transpower:[73]

4.3.1 the major capex project outputs;

4.3.2 the approval expiry date; and

4.3.3 the commissioning date assumption.

4.4 This section summarises our evaluation and determination of these components. The Capex IM criteria applicable to, and the reasons behind, our final decisions are set out in more detail in Attachments B to D.

We are satisfied that the project as a whole meets the evaluation criteria

4.5 Having completed our evaluation of Transpower's NZGP1 stage one proposal, and our review of draft decision submissions, our decision is to approve NZGP1 stage one. On balance, we are satisfied with the information, assumptions, and supporting analysis provided by Transpower.

4.6 Following our review, we are satisfied that Transpower has calculated net electricity market benefits of the investment options that outweigh the costs of those investment options, taking into account unquantified benefits.

4.7 In aggregate, Transpower's NZGP1 stage one passes the investment test.

4.8 However, the proposed investment involves three transmission upgrade packages, in three different parts of the transmission grid, under the umbrella of a consolidated set of market benefits and a consolidated investment need.

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[72] Capex IM, clause 3.3.5(7) and Schedule C.
[73] ibid, clause 3.3.5(6) and Schedule C.

4.9 To satisfy ourselves that each of these transmission upgrade packages would pass the investment test on their own merits, we carried out our own further analysis of the Central North Island and Wairakei ring upgrades and HVDC upgrade packages that make up NZGP1 stage one.

4.10 Our analysis indicates that the Central North Island and Wairakei ring upgrades will pass the investment test and appear good value for money when compared with new transmission capacity. We consider that there are likely generation developments that will need to access this increased capacity in the near future.

4.11 However, we are not fully satisfied that the HVDC upgrade component of NZGP1 stage one as provided in Transpower's proposal, provides a positive net electricity market benefit on a stand-alone basis at this time. It is on this issue that the HVDC assurance becomes particularly relevant.

HVDC assurance and Transpower's process

4.12 In our decision we have taken into account the HVDC assurance, ie, Transpower's proposal to make the HVDC stage one works a 'contingent project output'.[74] This means that Transpower will not commence the procurement, design, and build of HVDC stage one until it can quantitatively demonstrate to interested persons a net electricity market benefit associated with the investment.

4.13 Progressing the HVDC upgrade should be contingent on Transpower being able to quantitatively demonstrate to interested persons a net market benefit for the HVDC upgrade investment following one or more HVDC assurance trigger occurring.

4.14 Transpower, in its Addendum information, set out what it considered the possible triggers for the contingency may be, namely:[75]

4.14.1 confirmation of Tiwai's departure date;

4.14.2 modelling to show the additional redundancy benefits from the STATCOM; or

4.14.3 more certainty in the generation mix or load forecasts.

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[74] Transpower, Addendum, above n 7, p 4.
[75] Ibid, at pp. 4, 8.

4.15 In our draft decision, we specified that progressing the HVDC upgrade should be dependent on one or more of the above triggers occurring (referred to as the "HVDC assurance trigger"). However, having considered submissions, we note that there may be other triggers that could justify the decision to upgrade the HVDC, and that Transpower should not be limited by those it identified in its Addendum given the real focus is on the effect of the trigger.

4.16 For any other triggers to be sufficient, they would need to have the same effect as was proposed for the three specified triggers, which is the effect of Transpower being able to quantitatively demonstrate to interested persons a net market benefit for the HVDC upgrade investment. Nonetheless, we expect Transpower to identify the trigger, or driver of the HVDC investment, as part of its HVDC assurance so that interested persons can understand the rationale and analysis. We expect that the investment driver will also identify the appropriate timing of the investment.

4.17 We expect Transpower to do the following prior to proceeding with the HVDC upgrade component of NZGP1 stage one:

4.17.1 identify the investment driver of the HVDC upgrade;

4.17.2 update its generation scenarios and investment test modelling;

4.17.3 identify the costs and benefits and quantitatively demonstrate that the HVDC upgrade has a positive net market benefit; and

4.17.4 provide sufficient information to enable interested persons to carry out an independent review of Transpower's analysis..

4.18 In terms of process, we expect Transpower to seek feedback from interested persons as it progresses the HVDC upgrade and demonstrate how it has acted on that feedback. More specifically, we expect Transpower to do at a minimum what it specified in its own cross-submission, which is:

4.18.1 publish all updated analysis and materials on its website for review by interested parties (and we would expect Transpower to bring these updated matters to the attention of at least the parties who provided submissions and cross-submissions on our draft decision);

4.18.2 share the results at a webinar/workshop;

4.18.3 invite feedback from interested parties, which Transpower will consider in its decision-making, allowing a reasonable time period for that feedback to be provided; and

4.18.4 inform interested parties about its decision to proceed or not and how any input received influenced Transpower's decision. We would expect this information to be made available in the same way as the updated analysis and materials.

Our decision

4.19 While we remain less certain regarding the benefits of the NZGP1 stage one HVDC upgrade relative to the other components of what we are assessing, our final decision is to approve the proposal, including taking into account the HVDC assurance.

4.20 While Transpower has assured the Commission and submitters that it will quantitatively demonstrate the positive net market benefit following one or more of the HVDC assurance triggers, our final decision is to not make the commencement of the HVDC upgrade dependent on a further decision or analysis by the Commission. It instead takes into account Transpower's assurance that forms the HVDC assurance.

4.21 In reaching this view, we have considered the possible uncertainties that underpin the HVDC upgrade component of NZGP1, namely that there may be longer delivery timeframes associated with HVDC cable equipment, and the importance of the HVDC link to Aotearoa New Zealand's electricity system.

4.22 Given these uncertainties and the key risks that Transpower has to manage, we consider that Transpower is best placed to manage the HVDC risks appropriately in accordance with the purpose of Part 4 of the Act.

Major capex allowance

4.23 The MCA is the allowance for NZGP1 stage one and is based on the base estimate plus the 50th percentile of uncertainties. Our final decision is to set the MCA for the project shown in Table 4.1.

Table 4.1 Major Capex Allowance for NZGP1 stage one ($ million)

Base estimate in 2022	P50 estimate in 2022	Inflation factors	Financing costs	MCA 2028 prices
294.8	326.8	40.7	25.4	392.9

Incentive rate

4.24 The major capex incentive rate we set under clause 3.3.5(7)(b) of the Capex IM determines the reward (or penalty) that Transpower receives (or bears) depending on how the actual cost of delivering a major capex project compares to the project's MCA.

4.25 Under clause 1.1.5(2) of the Capex IM, the major capex incentive rate is 15% – the default rate – or an alternative rate we specify after considering a request from Transpower. In its proposal, Transpower proposed the default MCP incentive rate of 15% apply to NZGP1 stage one.

4.26 We are satisfied that the default incentive rate of 15% will incentivise Transpower to seek efficiencies in delivering NZGP1 stage one. We would only consider an alternative incentive rate for projects where the forecast cost is high, the forecast cost is uncertain, or the potential for efficiency gains is high. We do not consider any of these circumstances apply to NZGP1 stage one.

4.27 Our final decision is to set the major capex incentive rate for NZGP1 stage one at 15%.

Exempt major capex

4.28 Exempt major capex is those portions of the MCA amount which the major capex incentive rate does not apply and is typically set for portions of the MCA that reflect uncertainties beyond the control of Transpower.

4.29 In its proposal Transpower did not propose any exempt major capex.[76] However, we have decided that exempt major capex should apply to the risk adjustment (contingency) identified by Transpower in its proposal.[77] We consider that this approach appropriately balances incentives by ensuring that Transpower is not penalised if it incurs contingencies outside its control, while also not benefiting if it does not incur these contingencies.

4.30 Our final decision, under clause 3.3.5(7)(c) of the Capex IM, is to treat the risk adjustment component of the MCA as exempt major capex, equal to $38.4 million in 2028 prices. This means that $38.4 million of the MCA will not be subject to the incentive mechanism. In its draft decision submission, the Major Electricity Users' Group (**MEUG**) agreed with our approach.[78]

4.31 Accordingly, in setting the exempt major capex and the major capex incentive rate, the incentive scheme under clause B3(1) of Schedule B of the Capex IM will work as follows. If the actual cost of delivering NZGP1 stage one is:

4.31.1 less than the MCA minus exempt major capex, then applying the major capex incentive rate, Transpower will be entitled to a reward;

4.31.2 between the MCA and the MCA minus exempt major capex, then there is no reward or penalty; and

[76] Transpower, Proposal, above n 1, p.13.
[77] Transpower, Proposal, Attachment E: Costing Report p. 5.
[78] MEUG draft decision submission, above n 76, p. 3 para 13.

4.31.3 more than the MCA, then applying the major capex incentive rate, Transpower will be penalised.

Major capex project outputs for NZGP1 stage one

4.32 The major capex project outputs are the enhancement of specific sections of the transmission grid backbone under NZGP1 stage one.[79] These being:

4.32.1 HVDC upgrade – increasing transfer capacity from 1071 MW to closer to 1200 MW by installing:

4.32.1.1 reactive plant;

4.32.1.2 filter banks; and

4.32.1.3 associated equipment to upgrade the HVDC.

4.32.2 Central North Island upgrade - increasing transfer capacity north from Bunnythorpe by between 60% and 90% by:

4.32.2.1 installing variable line rating and tactical thermal upgrade of the Tokaanu-Whakamaru and the Bunnythorpe-Tokaanu circuits;

4.32.2.2 duplexing the Tokaanu-Whakamaru circuits with Goat conductor;

4.32.2.3 splitting the Bunnythorpe-Ongarue circuit;

4.32.2.4 upgrading protection on the Huntly-Stratford circuit; and

4.32.2.5 replacing special protection scheme at Tokaanu.

4.32.3 Wairakei ring upgrade - increasing transmission capacity by 25% (300 MW) under typical operating conditions by:[80]

4.32.3.1 tactical thermal upgrade of both circuits of the Wairakei-Whakamaru C line;

4.32.3.2 a tactical thermal upgrade of the Edgecumbe-Kawerau 3 circuit on the Ohakuri-Edgecumbe A and Kawerau-Deviation lines; and

4.32.3.3 splitting the Edgecumbe-Kawerau circuit.

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[79] Transpower, Response to RFI10, 18 October 2023.

[80] Transpower, Proposal, above n 1, p. 13.

4.32.4 NZGP1 stage two preparatory work to:

4.32.4.1 carry out a detailed design of duplex Bunnythorpe-Tokaanu A and B lines;

4.32.4.2 carry out a detailed design for tactical thermal upgrade of Bunnythorpe-Wairakei A line;

4.32.4.3 investigate route/high level design for new Bunnythorpe north 220Kv line;

4.32.4.4 investigate options for reconductoring one of the two 200 kV Brunswick-Stratford lines;

4.32.4.5 investigate route/high level design of either a new Wairakei-Whakamaru D line or replacement of Wairakei-Whakamaru A line;

4.32.4.6 develop quantifying resilience methodology;

4.32.4.7 carry out a study on diversification of Bunnythorpe substation;

4.32.4.8 carry out a study on lower North Island voltage stability; and

4.32.4.9 carry out a study on lower North Island system stability.

Commissioning date assumption for NZGP1 stage one

4.33 The commissioning date assumption is the date by which Transpower assumes the last asset of NZGP1 stage one (if approved) will be commissioned.[81]

4.34 Transpower plans to deliver NZGP1 stage one as several work packages with different forecast commissioning dates.

4.35 Transpower has proposed a commissioning date for all assets by 30 June 2028. [82] We have evaluated the commissioning date assumption and, as part of our final decision on NZGP1 stage one, we accept the proposed commissioning date assumption.[83]

81 Definition of 'commissioning date assumption' under clause 1.1.5(2) of the Capex IM.
82 Transpower, Proposal, above n 1, p. 13.
83 Capex IM, above n 2, clause 3.3.5(6)(e) and C1(3)(h).

Approval expiry date for NZGP1 stage one

4.36 The approval expiry date is the date beyond which Transpower cannot recover the costs of any major capex project assets and outputs it has not commissioned by that date.[84] [85]

4.37 We have evaluated the 31 December 2035 approval expiry date proposed by Transpower. As part of our final decision on NZGP1 stage one, we accept the proposed approval expiry date.[86]

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84 Under clause 3.3.6(1)(d) of the Capex IM, Transpower may apply to us to amend the approved approval expiry date.

85 Transpower Capital Expenditure Input Methodology reasons paper (31 January 2012) paragraph 6.9.4, can be found at; https://comcom.govt.nz/__data/assets/pdf_file/0028/63883/Capex-IM-Final-Reasons-Paper-31-January-2012.pdf.

86 Capex IM, above n 2, clauses 3.3.5(6), C1(3)(e) and C4.

Chapter 5 Summary of submissions

Purpose of this chapter

5.1 The purpose of this chapter is to summarise the views provided by submitters through the draft decision consultation process and our response to those views. We have also commented on some of those views at other points in this paper.

Submissions and cross submissions from our consultation on our NZGP1 stage 1 draft decision

5.2 We received submissions on our draft decision from Nova Energy (**Nova**), MEUG, Meridian, Contact, and the Consumer Advocacy Council (**CAC)**.

5.3 We received cross-submissions on those submissions from Transpower, Vector, MEUG, the Independent Electricity Generators Association (**IEGA**) and Fonterra.

5.4 We have categorised the matters raised in submissions and cross-submissions as follows:

5.4.1 our draft decision to approve NZGP1 stage one;

5.4.2 the benefits of approving the HVDC upgrade now;

5.4.3 HVDC assurance and consultation;

5.4.4 analysis assumptions and alternatives considered; and

5.4.5 other matters raised in the draft decision consultation.

5.5 We summarise the submissions and cross-submissions below and discuss how we have had regard to them in making our final decision. The Attachments to this paper providing the analysis and reasons underpinning our final decision also refer to and draw on points from the submissions and cross-submissions where appropriate.

Our draft decision to approve NZGP1 stage one

5.6 In their submissions, Nova, MEUG, Meridian and Contact all supported our draft decision.

5.7 While Nova supported the draft decision, it submitted that Transpower had not included an upgrade at the Wairakei substation protection in its proposal.[87] We discuss this potential alternative investment and Transpower's cross-submission response to this, later in this chapter.

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[87] Nova Energy Limited, NZGP1 submission on draft decision (14 December 2023), p. 1.

5.8 MEUG supported the "overall objectives of the Net Zero Grid Pathways (NZGP) programme which it states aims to ensure that "the grid backbone has enough capacity to accommodate new renewable generation and maintain a secure and reliable supply of electricity"".[88]

5.9 MEUG's view is that an increase in renewables generation will:

5.9.1 increase competition and put "downward pressure on current wholesale prices, which have more than doubled in the last five years";[89] and

5.9.2 be essential to achieve the country's 2050 net zero target, and enable the greater electrification of our economy, including industrial process heat.[90]

5.10 However, MEUG notes that while the "proposal has been shown to be beneficial overall", and that it is "clear that the Central North Island Upgrade and the Wairakei ring upgrade are both beneficial, even as standalone projects" the HVDC upgrade is less clear.[91]

5.11 As an MCP process matter in general, MEUG considered that in future "it may be preferrable for Transpower to separate distinct investment projects and submit them as separate MCPs" and supported our approach to test the economics of the three projects separately.[92]

5.12 We agree with this view in general but note that, at the time we initially considered the scope of this MCP, it appeared to be a sensible approach to link the HVDC, CNI and Wairakei ring upgrades given that a Tiwai smelter exit in 2024 seemed likely and appeared to be driving the investment need of NZGP1 stage one.

5.13 Since Transpower consulted on its generation scenarios, the Tiwai smelter exit date has become less certain, and as we analysed the proposal, it highlighted that each of the HVDC, CNI and Wairakei ring upgrades now have distinct investment drivers.

5.14 Fonterra supported Transpower's proposal and recognised its importance "to maintaining security of supply across the grid and ensuring New Zealand's electricity network remains fit for purpose as decarbonisation accelerates".[93]

88 MEUG, submission on draft decision, above n 76, p. 1, para 4.
89 ibid, p. 2, para 5.
90 ibid, p. 2, para 4.
91 ibid, p. 2, paras 6 and 7.
92 ibid, p. 3, para 13.
93 Fonterra, cross submission on NZGP1 draft decision (25 January 2024), p. 1.

The benefits of approving the HVDC upgrade now

5.15 Meridian considers “there are significant net benefits associated with the HVDC upgrade now, regardless of whether the smelter continues to operate post-2024”.[94]

5.16 Meridian comments that the HVDC reactive support investment in NZGP1 stage one improves resilience by providing redundancy to existing HVDC reactive support assets (the synchronous condensers). It states that two synchronous condensers at Haywards have been out of service for an extended period, with an uncertain return to service date, and that this has reduced HVDC north flow capacity by more than 300MW.[95]

5.17 Meridian states that upgrading HVDC capacity now will also:[96]

5.17.1 enable a greater level of South Island hydro firming capability as the power system becomes more reliant on intermittent generation such as wind and solar, which provides long-term benefit to consumers; and

5.17.2 enable lower cost renewables to be developed in the South Island, with Transpower modelling suggesting over 4GW has been identified.

5.18 These potential HVDC upgrade benefits discussed by Meridian have been qualitatively identified by Transpower in its proposal information but have yet to be quantified. We expect that when Transpower applies the investment test to support its HVDC upgrade as part of the HVDC assurance, Transpower will quantify these.

5.19 Meridian notes that as a beneficiary of the HVDC, it expected it would pay a large percentage of any upgrade costs, noting that “by our estimate, the private benefits to Meridian will exceed Meridian’s share of the costs of the HVDC upgrade and we expect the same to be true for other beneficiaries of the HVDC upgrade.”[97]

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94 Meridian, submission on draft decision, above n 96, p.2.
95 Ibid, p. 2.
96 Ibid, p. 2, 3.
97 ibid, p. 3.

5.20 Both Meridian and Contact consider that NZGP1 stage one should be approved without the HVDC assurance,[98,99] while CAC suggested that Transpower's consultation requirements should be made more explicit in our final decision, regarding the steps Transpower should undertake prior to when it proposes to carry out the HVDC upgrade.[100]

5.21 Contact stated that the NZGP1 investments were cost effective, added network resilience, and "provide extra capacity in the network that allows for more distributed intermittent generation to access areas of high demand". Contact noted that with the impending retirement of thermal generation assets in Taranaki "the ability to shift load across North and South will become more important – particularly if an HVDC upgrade were to occur".[101]

5.22 Contact notes the importance of the HVDC link to "shift cheap, renewable electricity from the South to the North Island" and considers that the HVDC upgrade should commence as soon as possible because it "will add a material amount of zero-carbon peaking capacity in the North Island and will materially improve security of supply in the North Island during peak periods."[102]

5.23 Contact states that South Island hydro generation is the "lowest cost source of peaking capacity in the market" and that a higher capacity HVDC transfer capability will provide access to increased peaking capacity.[103] Further, having access to higher HVDC capacity will enable it to avoid potential hydro spill in the South Island, with modelling suggesting inflows may increase in future, and be more volatile due to climate change effects.[104]

5.24 Contact considers there are also additional benefits associated with the HVDC upgrade now, such as enabling more renewables generation investment in the South Island, noting that "about 450MW of wind has been consented (but not yet built), and an additional volume of over 700MW is in active development." [105]

98 Meridian, NZGP1 submission on draft decision (14 December 2023), p. 2.
99 Contact Energy, NZGP1 submission on draft decision (14 December 2023), p. 1.
100 CAC, submission on draft decision, above n 76, p. 2, para 6.
101 Contact, submission on draft decision, above n 97, p.2.
102 Ibid, p.1.
103 ibid, p. 1.
104 ibid, p. 2.
105 ibid, pp. 1, 2.

5.25 Contact suggests that, while the HVDC upgrade component of NZGP1 has been approved on a contingent basis, the benefits of the investment will be realised now, and that these benefits are not contingent on the Tiwai smelter decision,[106] although MEUG disagreed that the Tiwai smelter decision would have no effect on need and timing.[107]

5.26 Fonterra agreed "with submitters about the importance of this project and that it should proceed without delay" because the "HVDC link is a critical component in New Zealand's electricity grid and is likely to play an increasingly important role as the country continues to decarbonise."[108]

5.27 Fonterra qualified its support for the HVDC upgrade, stating that it would lower reserve costs which would likely outweigh the cost of additional transmission charges.

5.28 In its cross-submission MEUG reflected on the Meridian and Contact submissions regarding the benefits of the HVDC investment component of NZGP stage one and agreed with those benefits. MEUG's view is that the HVDC upgrade should not be dependent on decisions regarding the Tiwai smelter, and by enabling new generation investment, The HVDC upgrade "should put downward pressure on wholesale prices."[109]

5.29 In its cross-submission Vector commented on the view expressed by both Meridian and Contact, that the "HVDC upgrade would have the additional benefit of increasing firm peaking capacity in the North Island". It noted that the Electricity Authority is currently consulting on potential solutions for peaking capacity issues and it "would be beneficial if peak capacity – and the impact of the HVDC upgrade – could be considered more holistically by a single regulator rather than the fragmented approach under the current regulatory framework."[110]

5.30 Transpower's NZGP1 supporting analysis includes the effect of a Tiwai smelter exit in 2024 in all its scenarios, and renewables generation development in the South Island, which it consulted on. Transpower's analysis also captures the economic impact of South Island hydro spill which we discuss in Attachment D of this decision.

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106 Contact, submission on draft decision, above n 97, p.1.
107 MEUG, cross submission on NZGP1 stage one draft decision (25 January 2024), p. 2 para 4.
108 Fonterra, cross submission on draft decision, above n 100, p. 1.
109 MEUG, cross-submission on draft decision, above n 110, p. 2 para 4.
110 Vector, cross-submission on NZGP1 stage one draft decision, above n 76, p.2 paras 7-9.

5.31 During our analysis of the proposal, we investigated the effect of the most recent generation connection enquiries that were likely to progress, to test if these enquiries aligned with the scenarios that Transpower had used to identify the benefits of the proposal. We were satisfied this was the case for LNI and CNI generation, but it was less clear for South Island generation developments. We discuss our analysis more fully in Attachment D.

5.32 We expect that when Transpower considers its decision to upgrade the HVDC that it will update the scenarios to ensure it has the most up to date information in its supporting analysis. This includes new generation enquiries that may result if the Tiwai smelter decides to remain beyond 2024. It is possible that the Tiwai smelter remaining beyond 2024 will make South Island generation development more attractive to investors, particularly if developers consider that HVDC capacity will increase.

5.33 At the proposal stage, Transpower also considered the effect of synchronous condenser reliability and the impact increased HVDC capacity has on 'firming' intermittent North Island renewables but did not economically quantify these effects. In proposing to upgrade the HVDC we expect Transpower will carry out this supporting analysis to determine whether these have benefits.

5.34 While MEUG was not convinced the HVDC upgrade investment decision needed to be made now, it noted that "decisions will need to be made in adequate time to order equipment, particularly those items with long lead times." MEUG's view is that the future of the Tiwai smelter will "clearly impact the estimated benefits and needed timing for this investment, with decisions not expected until next year."[111]

5.35 In our decision we have approved the HVDC upgrade, including the HVDC assurance, to enable Transpower to manage delivery risk. Transpower has highlighted that there are considerable lead-time issues for HVDC components and limited manufacturers available to supply those components. The approval gives Transpower the ability to manage this risk and demonstrate to interested parties that the investment has a net market benefit.

HVDC assurance and consultation

5.36 In our draft decision, our view was that Transpower should not commence the procurement, design, and build of HVDC stage one until it was able to quantitatively demonstrate assurance to interested persons, that the HVDC investment provided a positive net electricity market benefit.

5.37 In their draft decision submissions both MEUG and CAC commented on our decision that the HVDC be approved taking into account the HVDC assurance.

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111 MEUG, submission on draft decision, above n 96, p.2 para. 7.

5.38 MEUG supported our decision to require HVDC assurance before Transpower proceed with the HVDC investment, noting that “decisions made about the future of the Tiwai smelter will clearly impact the estimated benefits” and “timing for this investment, with decisions not expected until next year”.[112]

5.39 MEUG encouraged us to require Transpower to make it’s HVDC upgrade decision public because “reassurance is necessary to ensure that consumers are confident that Transpower are investing in projects where there is a clearly defined need and a positive market benefit associated with the project”.[113]

5.40 In its submission CAC stated that “there must be an opportunity for adequate public scrutiny of Transpower’s future assessment of the net market benefit of the HVDC project” because this scrutiny is “essential to gauge the project’s expected benefits (and costs) to consumers”.[114]

5.41 CAC’s concern is that without independent scrutiny there may be errors in Transpower’s supporting analysis and “as the draft decision and reasons paper notes, there have been previous instances of Transpower errors”.[115]

5.42 CAC suggested that we consider including additional details in our final decision about “the consultation process that Transpower would be expected to undertake to ensure there is adequate public scrutiny”.[116]

5.43 In its cross-submission, MEUG expected to see the benefits of the HVDC upgrade “reflected in Transpower’s demonstration of the positive net market benefits from this project” and agreed with CAC that public scrutiny of this was important and there needed to be a clearly demonstrated benefit to consumers.

5.44 MEUG agreed with CAC that the final decision needed to include details regarding the process that Transpower should follow for providing the HVDC assurance information, and suggested that, in this final decision we include requirements that Transpower should:[117]

5.44.1 publish a summary of the decision to proceed with the HVDC upgrade;

5.44.2 provide an overview of the final cost-benefit analysis of the HVDC upgrade;

5.44.3 inform all interested parties, be it directly and/or via publication on Transpower’s website.

112 MEUG, submission on draft decision, above n 76, p. 2 para 7.
113 ibid, p. 2 para 8.
114 CAC, submission on draft decision, above n 76, p. 2 para 6.
115 ibid, p. 2 para 7.
116 ibid, p. 2 para 8.
117 MEUG, cross-submission on draft decision, above n 110, p. 2 para 5 and 6.

5.45 In its cross-submission Vector agreed with submissions "calling for more scrutiny from stakeholders around the HVDC assurance triggers" and that "further detail is needed on how these assurance triggers are met" noting that "in the absence of appropriate stakeholder scrutiny, it appears Transpower could have significant discretion as to whether an assurance trigger has occurred".[118]

5.46 In its cross-submission, Transpower noted the CAC and MEUG submissions on its HVDC investment assurance process, and stated it would do the following to support its decision to invest:[119]

> 1. Conduct updated Investment Test modelling – our initial modelling was undertaken in 2022 and since then there have been significant advancements in wind generation consenting in the lower South Island. As a result, we believe that this warrants a modelling refresh.
> 2. Share the results at a webinar/workshop – we will also publish the materials on our website.
> 3. Invite feedback from interested parties that we will consider in our decision-making.
> 4. Inform interested parties about our decision to proceed or not and how any input received influenced our decision.

5.47 Our view is that, before Transpower decides that the HVDC upgrade component of NZGP1 is required, it should, among the other steps specified, first demonstrate that the upgrade meets one or more of the HVDC assurance triggers occurring (referred to as the "HVDC assurance trigger"). Having considered submissions, we note that there may be other triggers that could justify the decision to upgrade the HVDC, and that Transpower should not be limited by those it identified in its Addendum given the real focus is on the effect of the trigger.

5.48 For any other triggers to be sufficient, they would need to have the same effect as was proposed for the three specified triggers, which is the effect of Transpower being able to quantitatively demonstrate to interested persons a net market benefit for the HVDC upgrade investment. Nonetheless, we expect Transpower to identify the trigger, or driver of the HVDC investment, as part of its HVDC assurance so that interested persons can understand the rationale and analysis. We expect that the investment driver will also identify the appropriate timing of the investment.

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[118] Vector, cross-submission on draft decision, above n 114, pp. 1-2 para 2-6.
[119] Transpower, cross-submission on NZGP1 stage one draft decision (25 January 2024), pp. 1-2.

Analysis assumptions and alternatives considered

5.49 Nova submitted that Transpower had not considered an additional investment in its proposal. Specifically, Nova suggested that Transpower was "remis in not including an upgrade of the Wairakei substation protection" (sic) because of:[120]

5.49.1 its locational criticality to the core grid;

5.49.2 the materiality of adjoining grid upgrades; and

5.49.3 the functionality remote-end grid protection plays in facilitating the efficient connection of new renewable generation.

5.50 Transpower cross-submitted on this point, stating that it plans to investigate this potential protection upgrade:[121]

> With an increasing number of generation connections on the existing lines into Wairakei, we are aware that different and more costly connection configurations will be required to ensure acceptable overall power system reliability and performance. One option is the upgrade of protection at Wairakei, however there is no immediate case for this, as duplicating the protection on this relatively large ring bus would be both complex and expensive. The current system of having line protection ensuring backup of bus zone protection is a reliable and proven system and duplicating the bus zone protection would have only a marginal improvement on grid resilience. We will incorporate this into our NZGP 1.2 investigation work on increasing transmission capacity into Wairakei.

5.51 In terms of the analysis Transpower has carried out and assumptions it has made in support of the proposal, MEUG submitted that it agreed with the EDGS updates Transpower used noting that the 2019 EDGS produced by MBIE needed to be updated, and that "Transpower is also likely to have to adjust the EDGS again, as part of stage 2 of the NZGP".[122]

5.52 In its cross-submission, the IEGA stated that Transpower had, in its NZGP1 process, "dismissed non-network solutions as an option or component for either of the three MCP projects" and that alternatives in the distribution networks more generally appeared not to have been taken into account.[123]

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[120] Nova, submission on draft decision, above n 90, p 1.
[121] Transpower, cross submission on draft decision, above n 122, p. 2.
[122] MEUG, submission on draft decision, above n 76, p. 3 para 13.
[123] IEGA, cross submission on NZGP1 draft decision (25 January 2024), p. 1.

5.53 The IEGA made a similar point in its response to Transpower's short-list consultation noting that while it supported the options considered, it was unclear whether Transpower's assumptions include new investment in distributed generation capacity (including battery storage capacity). In its Stakeholder Consultation Summary, Transpower responded to the IEGA stating that:[124]

> Our demand forecasts consider the impact of distributed generation (behind the GXP generation). Battery storage is an option available to the generation expansion model, as an alternative to peaking generation in particular. Our supply scenarios do reflect battery storage being built, but we acknowledge this is an area for further study in NZGP Stage 2.

5.54 This proposal is focussed on transmission upgrades to facilitate the connection of potential new generation. We consider that Transpower has consulted extensively on its generation scenarios over the course of NZGP1 development.

5.55 Following our review of the proposal we are satisfied that the Transpower needs analysis has incorporated the impact of known potential embedded generation when it carried out its energy forecasts for use in the NZGP1 scenario modelling.[125]

Other matters raised in the draft decision consultation

5.56 In our draft decision we decided that exempt major capex should apply to the risk adjustment (contingency) identified by Transpower. Our view was that Transpower should not be rewarded through incentives for saving cost contingency amounts. MEUG submitted that it agreed with this decision.[126]

5.57 MEUG questioned whether the Part 4 regulation via the Capex IM and Transpower IM "is sufficient to understand if proposals such as this are truly in the "long-term benefit of consumers".[127]

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124 Transpower Proposal, Attachment H, p. 21, available at https://comcom.govt.nz/__data/assets/pdf_file/0008/330011/Transpower2C-NZGP1.1-MCP-Attachment-H-Stakeholder-Consultation-Summary-September-2023.pdf

125 Transpower, Proposal, Attachment D - Scenario & Modelling Report p. 38. available at https://comcom.govt.nz/__data/assets/pdf_file/0013/330007/Transpower2C-NZGP1.1-MCP-Attachment-D-Scenario-26-Modelling-Report-September-2023.pdf

126 MEUG, submission on draft decision, above n 76, p. 3 para 13.

127 ibid, p. 2 para 9.

5.58 MEUG suggested that because the CNI and Wairakei Ring investment components of the NZGP1 investment were likely to be commissioned over the fourth regulatory control period for Transpower (2025-2030) (**RCP4**), to "correctly understand the price / affordability impact on consumers, you also need to look at the other components of price increases that consumers are likely to face during the 2025 – 2030 timeframe",[128] such as:

5.58.1 the forecast revenue increase of 39.5% in RCP4;

5.58.2 a likely increase in revenue charges due to the forthcoming electricity distribution businesses default price-quality path which may result in a forecast revenue increase of 30%; and

5.58.3 an expected increase in the wholesale electricity price, which has more than doubled in the last five years.

5.59 MEUG considers that "what is missing from the framework is consideration of the overall impact of electricity prices and whether the total level of investment into the electricity system results in affordable prices for both consumers and businesses" and recommends that this issue of coordinated sector affordability issue be addressed "as part of the Government's work on an Energy Strategy".[129]

5.60 Both Vector and the IEGA expressed support for this coordinated cost and network planning consideration of the long-term benefit of consumers in cross-submissions.[130, 131]

5.61 We appreciate that alongside our decision on NZGP1 stage one, there are other ongoing processes that will impact on the prices that consumers pay. The focus of this decision is applying the Capex IM test to understand whether Transpower's proposed investment provides a net benefit to consumers.

5.62 Having considered the costs and benefits identified by Transpower and its application of the investment test, our view is that that the NZGP1 stage one investment package will provide a net market benefit to consumers over the longer term.

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128 MEUG, submission on draft decision, above n 76, p. 2 para 10.
129 ibid, p. 3 para 12.
130 Vector, cross submission on draft decision, above n 114, pp. 2-3 paras 10-13.
131 IEGA, cross submission on draft decision, above n 126, p. 2.

5.63 MEUG in its cross-submission noted the limited consultation engagement, and that while this may be reflective of the robust consultation process carried out by Transpower, we may wish to explore ways to gain more feedback from stakeholders on major capital proposals going forward.[132]

5.64 We reviewed Transpower's consultation process as it developed this proposal, and its consultation approach to the NZGP programme. Transpower has consulted widely throughout the process including on the investment need, its variations to the demand and generation scenarios, and the investment options it considered. We consider that process to be robust and comprehensive.

5.65 In terms of stakeholder engagement in the MCP process, and MEUG's point that there has been limited engagement, we consider that, while the submitter numbers are relatively low, the feedback has been specific and detailed. The submissions we have received should provide Transpower with useful information about stakeholder expectations, and the extent of the analysis it needs to perform to support its HVDC upgrade.

[132] MEUG, cross submission on draft decision, above n 110, p. 2 para 7.

Attachment A Evaluation criteria

A1 This attachment sets out the evaluation criteria against which we evaluated NZGP1 stage one under the Capex IM.

A2 The Capex IM requires us to evaluate an MCP against three sets of criteria:

A2.1 the *general criteria* for evaluating all capex proposals in Part 6;

A2.2 the *specific criteria* for MCPs in Schedule C; and

A2.3 the *investment test* in Schedule D, Division 1.

General criteria for evaluating all capex proposals

A3 The general criteria for evaluating all capex proposals under the Capex IM are:

A3.1 whether what is proposed is consistent with the Capex IM and, where relevant, the Transpower IMs;[133]

A3.2 the extent to which what is proposed will promote the purpose of Part 4 of the Act;[134] and

A3.3 whether the data, analysis, and assumptions underpinning what is proposed are fit for the purpose of the Commission exercising its powers under Part 4 of the Act, including consideration as to the accuracy and reliability of data and the reasonableness of assumptions and other matters of judgement.[135]

Assessing whether what is proposed is consistent with the input methodologies

A4 The first general criterion is that an MCP must be consistent with the Capex IM and, where relevant, the Transpower IMs. We will discuss the Transpower IMs first.

A5 The Transpower IMs provide for recoverable costs associated with major capex projects and the revenue impact of such projects we have approved.[136,137] The Capex IM sets out the requirements that Transpower must follow when developing and proposing a staged major capex project, and that we must follow when evaluating an MCP for such a project.[138]

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133 Capex IM, above n 2, clause 6.1.1(2)(a).
134 ibid, clause 6.1.1(2)(b).
135 Ibid , clause 6.1.1(2)(c).
136 Transpower IM, above n 34, at clause 3.1.3(1)(d).
137 Capex IM, above n 2, clause 3.7.4(4).
138 ibid, Part 3.

A6 When assessing whether an MCP is consistent with the Capex IM, we evaluate the proposal's compliance with:

A6.1 the process requirements;[139]

A6.2 Transpower's consultation requirements;[140]

A6.3 the information requirements;[141] and

A6.4 the certification requirements.[142]

The process requirements

A7 The Capex IM requires Transpower to notify us of its intention to plan a major capex project or a staged major capex project.[143]

A8 Transpower must agree the following with us:

A8.1 a consultation programme;

A8.2 an approach to considering NTSs;

A8.3 an application date; and

A8.4 an approval timeframe.[144]

A9 Together with Transpower, we must publish the matters agreed on above and regularly review and update these matters.[145] We may (after considering Transpower's views) amend any of these matters to ensure they remain appropriate and reasonable.[146]

Transpower's consultation requirements

A10 The requirements for Transpower's consultation programme and its approach considering NTSs are set out in clause 8.1.3 of the Capex IM.

A11 Transpower must consult with interested parties on the following matters:[147]

A11.1 the investment need;

139 Capex IM, above n 2, clause 3.3.3.
140 ibid, clause 8.1.3.
141 ibid, Schedule G.
142 ibid, clause 9.2.1
143 Ibid, clause 3.3.1(1) and (2).
144 ibid, clause 3.3.1(3).
145 ibid, clause 3.3.1(6).
146 ibid, clause 3.3.1(7).
147 ibid, Schedule I, clause i1(1).

A11.2 each demand and generation scenario variation;

A11.3 key assumptions;

A11.4 long-list of options, including any potential NTSs (ie, the long-list consultation); and

A11.5 short-list of options including the results of the investment test (ie, the short-list consultation).

The information requirements in a major capex proposal

A12 In the MCP Transpower must provide to us the following:

A12.1 information on the investment need;[148]

A12.2 information on the relevant demand and generation scenarios;[149]

A12.3 information relating to each investment option;[150]

A12.4 information relating to the proposed investment;[151]

A12.5 major capex project outputs;[152]

A12.6 information on consultation;[153]

A12.7 information on NTSs;[154] and

A12.8 any additional supporting material Transpower reasonably considers is relevant to our decision on the major capex project.[155]

A13 The Capex IM also requires that:[156]

A13.1 the number of investment options in an MCP is appropriate given the magnitude of the estimated expenditure and the complexity of the investment need associated with the proposed investment; and

A13.2 the specificity of information and the rigour and comprehensiveness of the analysis for each investment option described in an MCP must be commensurate with the estimated expenditure and complexity of that option.

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148 Capex IM, above n 2, schedule G clause G2.
149 ibid, schedule G clause G3.
150 ibid, schedule G clause G4.
151 ibid, schedule G clause G5.
152 ibid, schedule G clause G6.
153 ibid, schedule G clause G7.
154 ibid, schedule G clause G8.
155 ibid, schedule G clause G9.
156 ibid, clause 7.4.1(2) and (3).

Certification requirements for MCPs

A14 Transpower's CEO must certify in respect of an MCP that:[157]

A14.1 the information provided by Transpower under Schedule G of the Capex IM was derived from and accurately represents, in all material respects, Transpower's operations;

A14.2 the proposed investment to which the information under Schedule G relates was approved in accordance with the applicable requirements of Transpower's director and management approval policies; and

A14.3 the MCP complies, in all material respects, with the information requirements set out in Schedule G.

A15 Our assessment of Transpower's compliance with the general criteria is set out in Attachment B.

Specific criteria for evaluating MCPs

A16 The specific criteria for evaluating an MCP are set out in Schedule C of the Capex IM, and are as follows:

A16.1 We must evaluate whether the proposed investment satisfies the investment test.[158]

A16.2 We must have regard to at least one of the following factors:

A16.2.1 whether the investment and investment options reflect GEIP, are technically feasible, can be implemented in terms of all the application statutory planning and regulatory requirements, and can be integrated in the network and market operations;[159]

A16.2.2 whether the estimated time for construction, commissioning date and completion date are reasonable;[160]

A16.2.3 whether key assumptions around outage planning are reasonable;[161]

A16.2.4 the extent that Transpower has had regard to views of interested parties in consultations;[162] and

A16.2.5 the impact of sensitivity analysis on the electricity market benefit of the proposed investment and investment options.[163]

157 Capex IM, above n 2, clause 9.2.1.
158 ibid, clause C1(1).
159 ibid, clause C2(a).
160 ibid, clause C2(b).
161 ibid, clause C2(c).
162 ibid, clause C2(d).
163 ibid, clause C2(e).

A16.3 We must also evaluate Transpower's proposed:

A16.3.1 MCA;[164]

A16.3.2 major capex project outputs;[165]

A16.3.3 approval expiry date;[166]

A16.3.4 major capex incentive rate;[167]

A16.3.5 exempt major capex;[168] and

A16.3.6 commissioning date assumptions.[169]

A17 The Capex IM lists evaluation techniques and approaches we may use in the specific evaluation but enable us to use any other technique of approach we consider appropriate in the circumstances.[170] We can also consider any additional information that we judge is relevant.[171]

A18 We discuss our assessment of the MCP against specific criteria in Attachment C and our evaluation of the MCP under the investment test in Attachment D.

Our decision on an MCP

A19 After evaluating an MCP, we can decide to either:

A19.1 approve the project as proposed by Transpower;[172] or

A19.2 decline the project.[173]

164 Capex IM, above n 2, clause C1(3)(a).
165 ibid, clause C1(3)(d).
166 ibid, clause C1(3)(e).
167 ibid, clause C1(3)(f).
168 ibid, clause C1(3)(g).
169 ibid, clause C1(3)(h).
170 ibid, clause C7.
171 ibid, clause C7(f).
172 ibid, clause 3.3.5(1)(a).
173 ibid, clause 3.3.5(1)(b).

Attachment B Evaluation against general criteria for capex proposals

Purpose of this attachment

B1 This attachment sets out our evaluation of:

B1.1 NZGP1 stage one against the general criteria for capex proposals set out in Part 6 of the Capex IM; and

B1.2 Transpower's consultation against the requirements of the Capex IM.

The general criteria in Part 6 of the Capex IM

B2 The general evaluation criteria set out in Part 6 of the Capex IM are:[174]

B2.1 whether what is proposed is consistent with the Capex IM and, where relevant, the Transpower IMs;

B2.2 the extent to which what is proposed will promote the purpose of Part 4 of the Act; and

B2.3 whether the data, analysis, and assumptions underpinning what is proposed are fit for the purpose of exercising our powers under Part 4 of the Act.

The Transpower IMs are not relevant to Transpower's NZGP1 stage one proposal

B3 As noted in Attachment A, the Transpower IMs provide for recoverable costs associated with major capex projects and the revenue impact of such projects we have approved.[175] Neither is relevant here because:

B3.1 recoverable costs are associated with Transpower recovering the operating costs of an NTS, and Transpower does not propose an NTS for NZGP1 stage one; and

B3.2 the revenue impact of staging projects is not a part of the regulatory approval process for a staging project.

B4 For those reasons, the Transpower IMs are not relevant to the consideration of the NZGP1 stage one proposal.

[174] Capex IM, above n 2, at cl 6.1.1(2).

[175] Transpower IMs, above n 34, at clauses 3.1.3(1)(d) and 3.7.4(4).

Transpower's proposal is consistent with the Capex IM

B5 To be consistent with the Capex IM, the proposed expenditure must be 'major capex' as defined in the Capex IM,[176] and Transpower must meet the notification, consultation, information, and certification requirements that apply.[177]

B6 We are satisfied that the proposed expenditure is major capex and that Transpower met the Capex IM requirements on notification, consultation, information, and certification. The details of our assessment of the individual requirements follow.

The proposed expenditure is major capex

B7 The Capex IM defines 'major capex' as expenditure that is:[178]

B7.1 incurred to meet the GRS or provide a net electricity market benefit;

B7.2 forecast to have an aggregate capital cost exceeding $20 million; and

B7.3 not asset replacement, asset refurbishment, business support, or information system and technology assets.

B8 The proposed expenditure for Transpower's NZGP1 stage one proposal is consistent with the Capex IM definition because:

B8.1 the proposed investment provides a quantified net electricity market benefit of $145 million;

B8.2 the MCA for NZGP1 stage one is $392.9 million or P50 of $326.8 million; and

B8.3 it is not incurred in relation to asset replacement, asset refurbishment, business support or information system and technology assets. Rather, it will enhance existing assets as well as add new assets to the grid backbone to increase:

B8.3.1 the HVDC Link north transfer capacity by about 130 MW;

B8.3.2 the transfer capacity of the Central North Island grid backbone to 1200 MW; and

B8.3.3 the Wairakei ring transfer capacity by 300 MW.[179]

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176 Capex IM, above n 2, clause 1.1.5(2).

177 ibid, clause 3.3.1, clause 7.4.1, Schedule I, Schedule G, and clause 9.2.1, respectively.

178 ibid, clause 1.1.5(2).

179 Therefore, it is not asset replacement, asset refurbishment, business support, or information system and technology assets.

Transpower has met the notification requirements under the Capex IM

B9 We are satisfied that Transpower's notification of 23 July 2021 complied with clause 3.3.1(1) of the Capex IM.[180] This is because the notification advised us of Transpower's intention to plan NZGP1 stage one.

B10 Transpower's notification also proposed the matters required under clause 3.3.1(2) of the Capex IM. On 24 August 2021 Transpower agreed with us a consultation programme, including the long-list and short-list consultations, and an approach for Transpower to seek proposals on NTSs.[181]

B11 Under clause 3.3.1(7), the Commission and Transpower must regularly review whether the consultation programme remains appropriate and reasonable. We may amend the consultation programme to achieve that outcome.

B12 On 30 August 2023, we agreed to Transpower undertaking a short-list consultation on its updated preferred option.[182] Consultation on the long-list of options was deemed not necessary as those options had not changed.

Transpower has satisfied the consultation requirements

B13 The Capex IM requires Transpower to consult with interested parties on the following matters when preparing an MCP:[183]

B13.1 its investment need;

B13.2 each demand and generation scenario variation;

B13.3 key assumptions;

B13.4 a long-list of options to meet each investment need; and

B13.5 a short-list of investment options to meet each investment need.

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180 Transpower, Letter of Notification under clause 3.3.1(1), 23 July 2021 is available at: https://comcom.govt.nz/__data/assets/pdf_file/0020/308513/TranspowerE28099s-Net-Zero-Grid-Pathways-Response-to-Transpower-on-preliminary-matters-and-timeframes-13-August-2021.pdf.

181 Commerce Commission, letter to Transpower agreeing matters under clause 3.3.1(2) of the Capex IM, 13 August 2021 is available at: https://comcom.govt.nz/__data/assets/pdf_file/0020/308513/TranspowerE28099s-Net-Zero-Grid-Pathways-Response-to-Transpower-on-preliminary-matters-and-timeframes-13-August-2021.pdf.

182 Commerce Commission, letter to Transpower "Matters relating to Second short list consultation to support Net-Zero Grid Pathways Phase 1 Major Capex Proposal (Stage 1)" (30 August 2023) available at: https://comcom.govt.nz/__data/assets/pdf_file/0024/327345/NZGP-Letter-to-Transpower-regarding-timeframes-August-2023.pdf.

183 Capex IM, above n 2, Schedule I, clause I1.

B14 Transpower's long-list consultation must:[184]

B14.1 describe the relevant investment need and its links to other relevant documents, such as the integrated transmission plan;

B14.2 set out the relevant demand and generation scenarios;

B14.3 specify any non-standard values or amounts of the calculation period or value of expected unserved energy for the investment test;

B14.4 specify any non-standard discount rate that it may use for the purpose of the investment test; and

B14.5 for each option, specify whether the option is a transmission investment or an NTS, and describe its features.

B15 Transpower's short-list consultation must:[185]

B15.1 describe the relevant demand and generation scenarios to be used for the investment test;

B15.2 provide information on the relevant key assumptions;

B15.3 describe each investment option, including its features, submissions on the option from the long-list consultation, and likely electricity market benefit or cost elements and project costs; and

B15.4 describe Transpower's preliminary application of the investment test.

B16 Transpower carried out its long-list consultation from August 2021 to October 2021 and its short-list consultation between July 2022 and August 2022, and again between August 2023 and September 2023 in a manner consistent with the above Capex IM requirements.

B17 Transpower consulted on its short-list of options in line with clause I3 of Schedule I, on the matters included in detail in the consultation documents. Transpower's short-list consultation included the following matters:

B17.1 seeking further information on the investment need;

B17.2 discussion of approach to derive the short-list of options;

B17.3 seeking comments on the economic assumptions Transpower used in the investment test;

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[184] Capex IM, above n 2, Schedule I, clause I2.

[185] ibid, Schedule I, clause I3.

B17.4 seeking comments on Transpower's analysis of and quantification of the costs and benefits of NZGP1 stage one;

B17.5 seeking comments on Transpower's assessment of unquantified benefits of the NZGP1 stage one; and

B17.6 seeking agreement on the intended approach to determine the preferred option.

Our evaluation of Transpower's consultation

B18 Transpower received seven submissions in response to its long-list consultation between August 2021 and October 2021 and 17 submissions in response to its short-list consultation between July 2022 and August 2022.[186] Transpower received three further submissions in response to its short-list consultation between August and September 2023.[187]

B19 As part of its consultation on the original proposal, Transpower asked 17 specific questions in its long-list consultation and 11 in its short-list consultation that were commented upon. Submitters were generally supportive of the process Transpower had used to refine its long-list to the short-list, and the criteria it used to do so.

B20 In response to the August-September 2023 consultation, Contact Energy Limited and Nova Energy Limited supported Transpower's choice of the proposed investment. [188, 189]

B21 Vector Limited accepted that in an uncertain environment, maintaining flexibility and investment options will ensure the most efficient solutions are ultimately adopted. In addition, Vector also voiced concern about:[190]

B21.1 Transpower ruling out non-transmission solutions since this market is developing and could be relevant for future Transpower's investments; and

186 See https://www.transpower.co.nz/about-us/our-strategy/net-zero-grid-pathways/nzgp-phase-one .

187 https://www.transpower.co.nz/nzgp-phase-one-updated-preferred-option-consultation.

188 Contact Energy Limited, 'Consultation: NZGP 1 Updated Preferred Option Consultation: 6 September 2023'. Available at https://static.transpower.co.nz/public/uncontrolled_docs/NZGP1%20updated%20preferred%20option%20consultation%20%20Contact%20submission.pdf?VersionId=5rw3hmzhxJ_qVxioYrK7HfPh9pQCuu02.

189 Nova Energy, 'Re: NZGP1 – Major capex proposal – updated preferred option, 4 September 2023. Available at https://static.transpower.co.nz/public/uncontrolled_docs/NZGP1%20updated%20preferred%20option%20consultation%20-%20Nova%20submission.pdf?VersionId=6xH_.3Ss7kooFI.lNO4BmRVgrM.AHGPh.

190 Vector Limited, 'Net Zero Grid Pathways 1: Major Capex Project (Staged) Updated Preferred Option Consultation: 6 September 2023'. Available at https://static.transpower.co.nz/public/uncontrolled_docs/NZGP1%20updated%20preferred%20option%20consultation%20-%20Vector%20submission.pdf?VersionId=2ZPpkOBY76VZ5fvvUzxBNqfikrvcexUQ

B21.2 Transpower not carrying out a sensitivity analysis for Tiwai not leaving rather than just sensitivities of a Tiwai exit in 2024 and 2030.

B22 We assessed whether the consultations complied with the Capex IM consultation requirements under Schedule I of the Capex IM. We are satisfied that Transpower met those requirements.

Delivering NZGP1 stage one as proposed will promote the purpose of Part 4 of the Act

B23 Under the general evaluation criteria, we must consider "the extent to which what is proposed will promote the purpose of Part 4 of the Act".[191]

The purpose of Part 4 of the Act

B24 The purpose of Part 4 of the Act is to promote the long-term benefit of consumers in markets where there is little or no competition and little or no likelihood of a substantial increase in competition.[192] 'Competition' means 'workable or effective competition'.[193]

B25 To promote workable or effective competition that is to the long-term benefit of consumers, we must promote outcomes in regulated markets that are consistent with outcomes produced in workably competitive markets. Section 52A(1) of the Act specifies the following four outcomes produced in such markets that we must promote so that regulated suppliers, including Transpower:

B25.1 have incentives to innovate and invest;

B25.2 have incentives to improve efficiency and provide services at a quality that reflects consumer demands;

B25.3 share the benefits of efficiency gains with consumers, including through lower prices; and

B25.4 are limited in their ability to extract excessive profits.

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191 2012 Capex IM reasons paper, above n 3, at para 1.3.7.

192 Commerce Act 1986, s 52A(1).

193 ibid, s 3(1).

The Capex IM and the purpose of Part 4

B26 The Capex IM was enacted under section 54S of the Act as part of the umbrella of requirements set by Part 4 of the Act. The Capex IM has been designed, reviewed, and refined, to promote the purpose of Part 4 under section 52A of the Act.[194, 195, 196]

B27 Clause 6.1.1(2)(b) of the Capex IM requires us to evaluate the extent to which what the MCP proposes will promote the purpose of Part 4.

NZGP1 stage one will promote the purpose in section 52A(1)(a) of the Act

B28 Transpower delivering the project outputs according to NZGP1 stage one and the HVDC assurance, will promote the purpose of Part 4, particularly as set out in section 52A(1)(a) of the Act. This is because doing so will provide Transpower with incentives to invest in enhancing the grid to enable new renewable generation to connect for the long-term benefit of consumers.

NZGP1 stage one will promote the purpose in section 52A(1)(b) of the Act

B29 Consistent with section 52A(1)(b) of the Act, delivering NZGP1 stage one to enhance transmission to facilitate new generation, will ensure there is sufficient supply to meet future demand growth, for the long-term benefit of consumers.

B30 The scenario updates Transpower has used have been developed since the NZGP1 stage one inception late in 2020.[197] Since then, in a fast-moving decarbonisation environment, many of the generation plants Transpower has modelled in its scenarios, located in the Lower North Island and Central North Island regions, and those that would connect to the Wairakei ring, are similar in location and capacity to actual generation projects that appear likely to proceed.

B31 While these 'likely to proceed generation projects' are different in their exact location, capacity, and timing to those that were modelled by Transpower, we are satisfied that these are likely to have a similar economic impact as those modelled in the proposal analysis, and similarly provide a positive net market benefit. This is explained in more detail in Attachment D.

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194 2012 Capex IM reasons paper, above n 3, at para 1.3.7.

195 2017/18 Capex IM review reasons paper, above n 3, at para X13.1.

196 Commerce Commission, Transpower Capital Expenditure Input Methodology Amendments Determination 2018 [2018] NZCC 8, available at: https://comcom.govt.nz/__data/assets/pdf_file/0033/88278/2018-NZCC-8-Transpower-capitalexpenditure-input-methodology-amendments-determination-2018-25-May-2018.PDF.

197 https://www.transpower.co.nz/consultation-edgs-2019-variations-develop-generation-scenarios.

B32 We are not fully satisfied that the HVDC upgrade component of NZGP1 stage one, as provided in Transpower's proposal, provides a positive net market benefit at this time. However, as noted elsewhere, we have taken into account the HVDC assurance.

B33 In reaching this view, we have considered the possible uncertainties that underpin the HVDC upgrade component of NZGP1, namely that there may be longer delivery timeframes associated with HVDC cable equipment, and the importance of the HVDC link to Aotearoa New Zealand's electricity system.

B34 Given these uncertainties and the key risks that Transpower has to manage, we consider that the HVDC assurance will enable Transpower to manage the HVDC risks appropriately in accordance with the purpose of Part 4 of the Act, as set out in section 52A.

B35 A number of draft decision consultation submitters discussed the HVDC assurance.[198] We have summarised these submissions in Chapter 5, including Transpower's cross submission response, where it gave an undertaking about the process it would carry out prior to its HVDC upgrade.[199]

NZGP1 stage one will promote the purpose of Part 4 by providing for Transpower to deliver the right investment at the right time

B36 The purpose of Part 4 of the Act, particularly as set out in section 52A(1)(a) and (b), will be promoted by delivering the right investment at the right time.

B37 In selecting the proposed investments, Transpower considered and consulted on a wide range of investment components including NTSs. The investment components included battery storage, load shedding, generation re-dispatch, variable line rating, dynamic line rating, transmission line upgrades and building new transmission lines.[200]

B38 Transpower then prepared a short-list of components using the following criteria:[201]

B38.1 fit for purpose;

B38.2 technical feasibility;

B38.3 practical to implement;

198 CAC, submission on draft decision, above n 114, p. 2 paras 7-8, above n 76; MEUG cross submission on draft decision, p. 2 paras 5, 6, above n 110; Vector, cross submission on draft decision, pp. 1-2 paras 2-6.
199 Transpower, cross submission on draft decision, above n 122, pp. 1-2.
200 Transpower, Long-list consultation document pp 15-28.
201 Transpower, Short-list consultation document pp 49-50.

B38.4 good electricity industry practice (**GEIP**);[202]

B38.5 system security; and

B38.6 indicative cost.

B39 Having reviewed Transpower's process to identify transmission and non-transmission solutions, and the criteria used to refine these, we are satisfied that Transpower has met its consultation obligations for those issues.

B40 Using the short-listed components as building blocks, Transpower prepared a list of investment options for its application of the investment test. The two HVDC upgrade options, three Central North Island upgrade options and three Wairakei ring upgrade options are listed in Table 12 of the Transpower NZGP1 stage one proposal.[203]

B41 We are satisfied that the shorted-listed options provide a reasonable and appropriate number of investment options for further analysis and testing under the investment test, given the magnitude of the estimated expenditure and the complexity of the associated investment need.[204] This is because the investment options:

B41.1 cover a range of potential solutions, including implementing options to increase capacity of existing assets such as variable line rating to defer upgrading those assets; and

B41.2 would meet the current and future needs of enhancing transmission capacity to facilitate the connection of potential new generation.

B42 The Capex IM requires Transpower to apply the investment test to select the investment option with the highest expected net electricity market benefit as the proposed investment.[205] This can include a qualitative assessment to take account of associated unquantified benefits or cost elements in certain circumstances.[206]

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202 Under clause 1.1.5(2) of the Capex IM, the definition of 'good electricity industry practice' is that specified in clause 1.1(1) of the Code, which is: "the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would reasonably be expected from a skilled and experienced asset owner engaged in the management of a transmission network under conditions comparable to those applicable to the grid consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission network and the applicable law."

203 Transpower, Proposal, above n 1, p.53.

204 Capex IM, clause 7.4.1(2).

205 ibid, clause D1.

206 ibid, clause D1(1)(c).

B43 The investment test under Schedule D of the Capex IM is a net benefit test that uses a range of future scenarios of the electricity market to identify the investment option with the highest expected net electricity market benefit. The test is designed to identify the most efficient investment option becomes the proposed investment put forward to us in an MCP.

B44 We consider the investment test enables the selection of the right investment based on the available information and corresponding assumptions about the future composition of the power system. Based on our evaluation in Attachments C and D, we are satisfied that Transpower has proposed the right transmission investments to meet the investment need, giving recognition to unquantifiable benefits and the HVDC assurance.

Delivering NZGP1 stage one provides the highest net market benefit

B45 Consistent with section 52A(1)(b) of the Act and the Capex IM, a proposed investment that is not necessary to meet the grid reliability standards, such as transmission to facilitate new generation, must provide the highest positive net market benefit, when all quantified cost or benefit elements are taken into account.[207, 208]

B46 When determining which investment option has the highest net electricity market benefits, only quantified net electricity market benefits or cost elements may be taken into account unless the circumstances specified in clause D1(c)(ii) and (2) apply. The Capex IM allows us to take into account unquantified net electricity market benefits or cost elements if there is an investment option with similar expected net electricity market benefits, which means that the difference in quantum is 10% or less of the aggregate project costs of the investment option to which the proposed investment is compared.[209]

B47 To satisfy the investment test where unquantified benefits or cost elements are included, the proposed investment must have the highest expected net electricity market benefit including a qualitative assessment to take into account the contribution of the associated unquantified electricity market benefits or cost elements.[210]

207 Capex IM, above n 2, clause D1(1)(b).
208 ibid, clause D1(1)(c)(i).
209 ibid, Schedule D, clause D1(1)(c)(ii) and (2). Under clause D1(3), we may, at our discretion, adopt an alternative percentage to 10% as proposed by Transpower.
210 ibid, cl D1(1)(c)(ii).

B48 An electricity market benefit or cost element may be treated as unquantified where:

B48.1 the cost of calculating its quantum, in accordance with clause D6(4), is likely to be disproportionately large relative to the quantum; or

B48.2 its expected value cannot be calculated in accordance with clause D6(4) with an appropriate level of certainty due to the extent of uncertainties in underlying assumptions or calculation approaches.

B49 Although Option 12 has the highest net market benefit without factoring in unquantified benefits, Transpower has selected Option 14 as its preferred option, on the basis of unquantified benefits.[211]

B50 We have assessed the unquantified benefits set out by Transpower and are satisfied with their use in selection of option 14 as Transpower's preferred investment option. The unquantified benefits and investment test are discussed in more detail in Attachment D.

B51 The NZGP1 stage one project, as a whole, seeks to facilitate the connection of new renewables generation to meet electrification demand growth. This is predicted to occur due to fossil fuel use being displaced by electricity in transport and in industrial process heating applications.

B52 To quantify the net electricity market benefits of each investment option and identify the proposed investment, Transpower must use a range of scenarios produced by MBIE, called EDGS, to calculate the net electricity market benefits. The most recent MBIE EDGS was produced in July 2019 and Transpower has, in its proposal, updated these, and has used the updated scenarios in its economic analysis.[212]

B53 We consider that Transpower's updates of the MBIE scenarios are prudent and appear to reflect the effect of the most up to date enquiries for generation connections in the Lower and Central North Island regions, and near Wairakei. Given the significant changes occurring in the sector we consider Transpower is likely to need to update these scenarios when it seeks approval for stage two of the NZGP1 project.

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211 Transpower, Proposal, above n 1, p.61.
212 Ibid, Attachment C – Options Report.

B54 In its draft decision submission MEUG agreed with the EDGS updates Transpower used noting that the 2019 EDGS produced by MBIE needed to be updated, and that "Transpower is also likely to have to adjust the EDGS again, as part of stage 2 of the NZGP".[213]

B55 Transpower in its cross submission, stated that when it came time to upgrade the HVDC component of NZGP1, it would revise its modelling because since 2022, when its most recent scenarios were developed, there have been significant advancements in wind generation consenting in the lower South Island.[214]

B56 Transpower has also used counterfactual generation cases to define the economic benefit of forecast new renewables generation. We are satisfied that this is a prudent economic analysis approach.

B57 Transpower has assumed that the Tiwai smelter exits in 2024, based on its consultation with industry since 2020.[215] This is a major uncertainty for industry and its generation project planning, and for Transpower in planning to facilitate those projects with grid upgrades.

B58 In its most recent Transmission Planning Report published in 2023, Transpower has assumed that the Tiwai smelter remains until 2034.[216] While the 2034 date is an assumption, it does highlight the analysis uncertainty Transpower faces as it assesses a need date for, and economic justification of, the HVDC component of NZGP1.

B59 By approving the HVDC component of NZGP1 stage one with the HVDC assurance, Transpower will have the ability to manage its delivery risk if or when those contingencies arise.

B60 We are satisfied that Transpower has carried out analysis demonstrating that, overall, its NZGP1 stage one proposal provides the highest net market benefit when compared to a range of investment options.

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213 MEUG, submission on draft decision, above n 76, p. 3 para 13.

214 Transpower, cross submission on draft decision, above n 122, p. 1.

215 Transpower, Consultation on EDGS variations, available at https://www.transpower.co.nz/consultation-edgs-2019-variations-develop-generation-scenarios.

216 The Transpower TPR is an assessment of transmission network upgrade needs over a 10-year forecast period. The 2023 TPR is available here and the Tiwai smelter assumption is discussed in section 19.2.1 on p. 363.

The data, analysis, and assumptions underpinning what is proposed are fit for purpose

B61 Schedule G of the Capex IM sets out the information that Transpower needs to provide in an MCP.

B62 Transpower's NZGP1 stage one proposal contains the following documents:[217]

B62.1 Main proposal – the main proposal document provides a consolidated summary of the analysis Transpower has performed to support its application and the conclusions it has reached;[218]

B62.2 Attachment A (Compliance Requirements) – summarises where in the proposal Transpower has addressed the Capex IM requirements;[219]

B62.3 Attachment B (Power system planning and HVDC assets condition report) – describes the power systems analysis performed to identify transmission investment constraints, potential transmission upgrades, and how upgrades were evaluated to determine the short-list investment options. It also describes the HVDC asset strategy and plan;[220]

B62.4 Attachment C (Options report) – describes how Transpower has refined its long-list and short-list options, and a summary of the cost benefit analysis it has applied to the short-list options to identify its proposed investment;[221]

B62.5 Attachment D (Scenario and modelling report) – describes and summarises the analysis Transpower has performed to identify the economic benefits of connecting new generation that justifies the transmission investments in the proposal;[222]

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[217] See https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpower-capital-investment-proposals/transpower-major-capital-proposal/transpowers-net-zero-grid-pathways.

[218] Transpower Proposal, above n 1.

[219] Transpower Proposal, Attachment A available at https://comcom.govt.nz/__data/assets/pdf_file/0010/330004/Transpower2C-NZGP1.1-MCP-Attachment-A-Compliance-Requirements-September-2023.pdf.

[220] Transpower Proposal, Attachment B available at https://comcom.govt.nz/__data/assets/pdf_file/0011/330005/Transpower2C-NZGP1.1-MCP-Attachment-B-Power-System-Planning-26-HDVC-Assets-Condition-Report-September-2023.pdf.

[221] Transpower Proposal, Attachment C available at https:// https://comcom.govt.nz/__data/assets/pdf_file/0012/330006/Transpower2C-NZGP1.1-MCP-Attachment-C-Options-Report-September-2023.pdf.

[222] Transpower Proposal, Attachment D available at https:// https://comcom.govt.nz/__data/assets/pdf_file/0013/330007/Transpower2C-NZGP1.1-MCP-Attachment-D-Scenario-26-Modelling-Report-September-2023.pdf.

B62.6 Attachment E (Costing report) – explains how Transpower has assessed the capital costs and revenue impact of the preferred option, and the costs associated with each investment option;[223]

B62.7 Attachment F (Indicative covered costs and starting BBI customer allocations report) – provides information about the estimated increase in transmission charges associated with the proposal consistent with the new Transmission Pricing Methodology requirements;[224]

B62.8 Attachment G (Indicative charges worksheet) – provides indicative charges for the NZGP1 proposal, consistent with the requirements of 7.5.1(1)I of the Capex IM;[225]

B62.9 Attachment H (Stakeholder Consultation Summary) - provides an overview of feedback from Transpower's stakeholder consultations on the Net Zero Grid Pathways Project Investigation and the response to that feedback.[226]

B62.10 Attachment I (Summary of RFIs) – collates our nine Requests for Information (RFIs) and Transpower's responses exchanged between the original proposal and submission of the upgraded proposal;[227]

B62.11 Attachment J (CEO Certification) – certification from Transpower's Chief Executive Officer that the information complies with the relevant provisions of the Capex IMs;[228]

B62.12 NZGP1 MCA Final version – Spreadsheet pertaining to the MCA for NZGP1 stage one;[229]

B62.13 Letter from TSA Advisory "Major Capex Proposal Investment Test Assurance Review (15 September 2023) – letter to Transpower following

[223] Transpower Proposal, Attachment E available at https:// https://comcom.govt.nz/__data/assets/pdf_file/0014/330008/Transpower2C-NZGP1.1-MCP-Attachment-E-Costing-Report-September-2023.pdf.

[224] Transpower Proposal, Attachment F available at https:// https://comcom.govt.nz/__data/asets/pdf_file/0015/330009/Transpower2C-NZGP1.1-MCP-Attachment-F-Expected-impact-on-transmission-charges-September-2023.pdf.

[225] Transpower Proposal, Attachment G, available athttps://comcom.govt.nz/__data/assets/excel_doc/0007/330010/Transpower2C-NZGP1.1-MCP-Attachment-G-Indicative-Charges-September-2023.xlsx.

[226] Transpower Proposal, Attachment H, available at https://comcom.govt.nz/__data/assets/pdf_file/0008/330011/Transpower2C-NZGP1.1-MCP-Attachment-H-Stakeholder-Consultation-Summary-September-2023.pdf.

[227] Transpower, Attachment I available athttps://comcom.govt.nz/__data/assets/pdf_file/0009/330012/Transpower2C-NZGP1.1-MCP-Attachment-I-Summary-of-RFIs-September-2023.pdf.

[228] Transpower, Attachment J available at https://comcom.govt.nz/__data/assets/pdf_file/0010/330013/Transpower2C-NZGP1.1-MCP-Attachment-J-CEO-Certification-September-2023.pdf.

[229] Transpower, NZGP1.1 MCA- final version available at https://comcom.govt.nz/__data/assets/excel_doc/0009/330003/a102d3d8b95fbc71713df81723bd28a1a500b8e9.xlsm.

TSA Advisory's review of the figures contained in the updated NZGP1 stage one proposal;[230] and

B62.14 Simpson Grierson's review of the updated NZGP1 MCP for compliance with the MCP requirements in the Capex IM.[231]

B63 When assessing an MCP, we must be satisfied that that data, analysis, and assumptions underpinning what is proposed are sufficient to make our decision. As we evaluated NZGP1 stage one, we sought from Transpower further explanations and clarifications on aspects of the proposal.

B64 In accordance with clause 3.3.5(4) of the Capex IM, we sought further information to assist our evaluation of the investment test, project costs and calculations of the MCA, assessment of the benefits of the HVDC investments (including the sensitivity of Tiwai smelter departure date), and to understand the technical benefits delivered by the Central North Island and Wairakei ring investments.

B65 Table B1 lists information that Transpower provided to assist our analysis.

230 TSA Advisory, Investment Test Assurance Review (15 September 2023) available at https://comcom.govt.nz/__data/assets/pdf_file/0012/330015/TSA-Management2C-NZGP1.1-Investment-Test-Assurance-Review-15-September-2023.pdf.

231 Simpson Grierson, Legal sign-off for NZGP1 major capex proposal (20 September 2023) available at https://comcom.govt.nz/__data/assets/pdf_file/0007/330001/Simpson-Grierson2C-NZGP1.1-MCP-Legal-sign-off-20-September-2023.pdf.

Table B1: Information provided by Transpower

Document short name	Subject
Original Proposal	Proposal document with Attachments A to H, submitted on 2 December 2022.
RFI01	Data on HVDC Transfer in 2022
RFI02	Factual versus counter factual generation differences
RFI03	Use of HVDC runback schemes to in the NZGP1 investment mix
RFI04	Reason for including quantifying resilience benefits, voltage stability studies and diversifying the Bunnythorpe substation in NZGP1 stage one
RFI05	Generation expansion plan – spreadsheet
RFI06	Further information on power system studies report
RFI07	Clarification on calculations of benefits
RFI08	South Island demand and expected spill
RFI09	Electricity market costs used in the investment test
Addendum	"Net Zero Grid Pathways 1 Major Capex Proposal (Staged) – Addendum – Amending our proposal" submitted on 23 June 2023. Addendum – supplementary information to address matters that were not adequately covered in the original proposal; such as potential future staging projects and the inclusion of model projects in the cost benefit analysis.
Updated Proposal	An updated Proposal along with all the Attachments, addressing the errors in the investment test. This included collated information on RFI01 to RFI09 in Attachment I submitted on 25 September 2023.
RFI10	Clarification on quantifying the investment need, investment options, unquantified benefits and proposed investment.

B66 Having reviewed the material that Transpower has provided to us, we are satisfied that the data, analysis, and assumptions, underpinning what is proposed, are sufficient for us to make our final decision on NZGP1 stage one, including the HVDC assurance.

B67 Transpower provided us with a number of qualitative reasons supporting this upgrade, and while it has not quantified these, it submitted that, when it plans to upgrade the HVDC component of NZGP1 stage one, it will carry out revised investment test analysis and publish that revised analysis to enable feedback from interested persons.[232]

[232] Transpower, cross submission on draft decision, above n 122, pp. 1-2.

Attachment C Evaluation against specific criteria

Purpose of this attachment

C1 This attachment sets out our evaluation of Transpower's NZGP1 stage one proposal against the specific criteria set out in Schedule C of the Capex IM, as required under clause 6.1.1(4) of the Capex IM.

Our approach to evaluating the specific components of the NZGP1 stage one major capex proposal

C2 There are three parts to our evaluation under Schedule C:

C2.1 evaluating NZGP1 stage one against specific criteria in clause C1(1) and C1(3);[233]

C2.2 having regard to one or more of the general factors under clause C2, and the specific factors relating to individual NZGP1 stage one components under clause C3 to C6, in evaluating NZGP1 stage one; and

C2.3 employing an evaluation technique under clause C7 in evaluating NZGP1 stage one.

C3 We describe the three parts to our evaluation under Schedule C in greater detail under the relevant subheadings below.

The specific criteria for evaluating a major capex proposal

C4 Our specific criteria for evaluating an MCP under Schedule C of the Capex IM can be broken down as follows:

C4.1 *investment test*: clause C1(1) requires us to evaluate whether the MCP's proposed investment satisfies the investment test in Schedule D of the Capex IM. Under clause C1(2), if the MCP relates to a staged major capex project, as is the case here, then the investment test must be satisfied for each staging project;[234] and

C4.2 *specific components*: clause C1(3) requires us to evaluate, to the extent applicable to the proposed investment, specific components of the proposed investment.

C5 Under clause C1(3) of Schedule C, the specific components of a proposed investment that we must evaluate depend on whether it includes an NTS.[235]

233 Capex IM, clause C1(2) sets out the criteria for the assessment in clause C1(1).
234 The results of the investment test are discussed in Attachment D.
235 Capex IM, above n 2, at cl C1(3) of Schedule C exhaustively sets out the components that we must evaluate to the extent applicable to the transmission investment of NTS.

C6 NZGP1 stage one's proposed investment is a transmission investment and does not include an NTS. Accordingly, the relevant MCP components we must evaluate are:[236]

C6.1 MCA (clause C3);

C6.2 approval expiry date and commissioning date assumptions (clause C4);

C6.3 major capex project outputs (clause C5); and

C6.4 major capex incentive rate (clause C6).

C7 Our evaluation of these MCP components and how we tested NZGP1 stage one against the requirements of Schedule C are outlined below in the order listed above.

Factors we must have regard to in evaluating a major capex proposal

C8 In evaluating the specific criteria, Schedule C specifies factors we must have regard to and techniques we may use:

C8.1 *General factors to have regards to*: clause C2 requires us to have regard to at least one of the general factors listed in clause C2(a) to (e) when evaluating an MCP. These factors are:

C8.1.1 whether the proposed investment and investment options:

a) reflect good electricity industry practice (**GEIP**);

b) are technically feasible;

c) can be implemented in terms of statutory process and regulatory consents; and

d) can be integrated into the system and market operations;

C8.1.2 whether the estimated time to deliver the project is reasonable compared to the proposed commissioning date;

C8.1.3 whether key assumptions around outages are reasonable;

C8.1.4 the extent to which, in complying with the consultation programme or approach to considering NTSs, Transpower has had regard the views of interested parties; and

[236] Capex IM, above n 2, Schedule C, clause C1(3).

C8.1.5 the impact of the sensitivity analysis on electricity market benefit or cost element of the proposed investment and investment options.

C8.2 *Factors to have regards to when evaluating the components of an MCP*: clauses C3 to C6 each specify a list of factors; we must choose at least one factor from each list to have regard to evaluating the specified components of NZGP1 stage one. The relevant components under these provisions are, respectively, the MCA; the proposed approval expiry date; the proposed major capex project outputs; and the proposed major capex incentive rate.

C9 We set out the respective factors we had regard to under clause C3 to C6 in our evaluation below of each of the NZGP1 stage one components.

The evaluation techniques we may use in evaluating NZGP1 stage one under Schedule C

C10 Under clause C7 of Schedule C, in evaluating NZGP1 stage one, we may employ one of more of the following evaluation technique:

C10.1 powerflow analysis and dynamics in the grid (clause C7(a));

C10.2 detailed critiques of conceptual designs to the extent necessary to derive credible estimate cost and time estimates (clause C7(b));

C10.3 analysis and review of costs and benefits associated with the MCP's proposed investment and investment options (clause C7(c));

C10.4 critiques of market development scenarios used in the MCP (clause C7(d));

C10.5 unit rate benchmarking (clause C7(e)); and

C10.6 any other technique or approach we consider appropriate in the circumstances (clause C7(f)).

C11 We used different techniques when assessing the factors set out in Schedule C. We mention the specific technique we used for each factor in the relevant sections below.

Clause C1(1)- evaluation of whether NZGP1 stage one satisfies the investment test

C12 In this section we outline:

C12.1 the criteria for satisfying the investment test; and

C12.2 our observations on the investment test.

C13 We set out our evaluation of the investment test in Attachment D.

Criteria for satisfying the investment test

C14 The investment test set out in Schedule D of the Capex IM uses a cost-benefit analysis using discounting of all associated costs and benefits in the electricity market over a defined calculation period to identify the most economic investment option as the proposed investment. The test is applied using hypothetical scenarios that predict the development of the electricity market over the calculation period.[237]

C15 Under clause D1(1) of Schedule D, a proposed investment satisfies the investment test if it has the highest expected net electricity market benefit and is sufficiently robust to sensitivity analysis.

C16 The net electricity market benefits:[238]

C16.1 do not need to be positive for the proposed investment to meet the N-1 criterion of the GRS; but

C16.2 need to be positive for any other proposed investment.

C17 Since the purpose of NZGP1 stage one is to facilitate the connection of new generation, as opposed to falling under the first limb above, the net electricity market benefits must be positive.

C18 When determining which investment option has the highest net electricity market benefits, only quantified net electricity market benefits or cost elements may be taken into account unless the circumstances specified in clause D1(c)(ii) and (2) apply. The Capex IM allows us to take into account unquantified net electricity market benefits or cost elements if there is an investment option with similar expected net electricity market benefits, which means that the difference in quantum is 10% or less of the aggregate project costs of the investment option to which the proposed investment is compared. [239]

C19 To satisfy the investment test, the proposed investment has the highest expected net electricity market benefit including a qualitative assessment to take into account the contribution of the associated unquantified electricity market benefits or cost elements.[240]

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237 2012 Capex IM reasons paper, above n 4, at para 7.2.1. We note that in our 2017/18 Capex IM review, we decided to retain the investment test criteria and approach in the 2012 Capex IM. See 2017/18 Capex IM review reasons paper, above n 65, at para 194.

238 Capex IM, Schedule D clause D1(1)(b).

239 ibid, Schedule D, clause D1(1)(c)(ii) and (2). Under clause D1(3), we may, at our discretion, adopt an alternative percentage to 10% as proposed by Transpower.

240 ibid, cl D1(1)(c)(ii).

Our assessment of Transpower's application of the investment test

C20 In reviewing Transpower's application of the investment test, we carried out our own analysis. We took a two-step approach.

C20.1 Firstly, we looked at whether Transpower's inputs and assumptions were reasonable and met the requirements of Capex IM and whether the preferred investment passed the investment test.

C20.2 Secondly, we cross-checked Transpower's investment test application to satisfy ourselves that components of the proposal would deliver net electricity market benefits.

C21 In reviewing the economic analysis results in Transpower's proposal we consider that Transpower has taken a robust approach in applying the investment test and that the costs and benefits have been reasonably calculated, noting the uncertainty in long term generation development.

C22 Following our review, we are satisfied that Transpower has calculated net electricity market benefits of the investment options that outweigh the costs of those investment options, and in aggregate, Transpower's NZGP1 stage one passes the investment test.

C23 In summary, we are satisfied that the proposed investment meets the investment test under Schedule D of the Capex IM. Specifically, we are satisfied:

C23.1 with the values Transpower has used for the parameters of the investment test;

C23.2 that the proposed investment has the highest positive net benefit when considering both the quantified and unquantified benefits;

C23.3 that the expected net market benefit is positive under various sensitivity criteria except under +30% increase in capital cost and under 10% discount rate; and

C23.4 that the robustness of the proposed investment to sensitivity analysis is acceptable. The results of the quantitative sensitivity analysis across all the short list options, do not show a consistent best option. However, we are satisfied that Transpower's staged approach is appropriate to manage the uncertainty.

C24 Our evaluation of Transpower's application of the investment test is outlined in Attachment D.

Clause C2 – General evaluation of the major capex proposal

C25 As mentioned above, the Capex IM requires that we must have regard to at least one of the following factors when evaluating a major capex proposal:[241]

C25.1 whether the proposed investment and investment options:

C25.1.1 reflect GEIP;

C25.1.2 are technically feasible;

C25.1.3 can be implemented in terms of the statutory planning process and regulatory consents;

C25.1.4 can be integrated into system and market operations;

C25.2 whether the estimated time required for construction and commissioning is reasonable;

C25.3 whether the key assumptions around outage planning are reasonable;

C25.4 the extent that Transpower has had regard to the views of interested persons when considering NTSs; and

C25.5 the impact of the sensitivity analysis on electricity market benefit or cost elements of the proposed investment and investment options.

C26 We have had regard to:

C26.1 the impact of sensitivity analysis on electricity market benefit or cost elements of the proposed investment and investment options; and

C26.2 whether the proposed investment and investment options the proposed investment and investment options can be integrated into the transmission system and the market operations.

The impact of sensitivity analysis on electricity market benefit or cost elements of the proposed investment and investment options

C27 Transpower has noted that, typically, the sensitivity analysis for an MCP "overwhelmingly" supports Transpower's proposed investment. However, for NZGP1 the sensitivity analysis suggests there is no clear best investment option as shown in Table C1 below.[242]

[241] Capex IM, above n 2, clause C2(a-e).
[242] Transpower, Proposal, Attachment C, p. 51.

Table C1 Transpower's core sensitivity analysis results ($ million)

Investment option	Investment test	-30% capital cost	+30% capital cost	-30% ongoing costs	+30% ongoing costs	4% discount rate	5% discount rate	10% discount rate
10	176	290	62	180	172	545	390	1
11	150	283	16	153	147	533	372	-29
12	181	312	51	186	177	583	415	-8
13	173	327	20	*156*	*191*	609	425	-30
14	145	318	-28	*126*	*164*	594	404	-62
15	175	345	5	*158*	*192*	641	445	-41

C28 The net electricity market benefits across the investment options are sensitive to capital costs and discount rates changes suggesting that the current uncertainty is affecting the most economic investment option. In particular, we note that the:

C28.1 impact of stage two investments, particularly those options with Bunnythorpe-Tokaanu duplexing (capital cost of $190 million) results in a $350 million swing in the net market benefit when considering +/-30% capital sensitivity analysis; and

C28.2 4% and 5% discount rates suggest that the benefits of renewable generation developments being dispatched will be realised in the longer term.

C29 Depending on the scenario, Options 10, 12 and 15 have the highest net electricity market benefit. We consider that there are capital cost uncertainty issues that are specific to some of the stage two investments analysed by Transpower and distinguish between the options. For example:

C29.1 While Option 14's net quantified electricity market benefit is lower than Options 10, 11, 12, 13 and 15, the Bunnythorpe-Tokaanu duplexing cost estimate (stage two) is $190 million in Options 13, 14 and 15. Transpower states that the cost estimate for this project is for analysis purposes. Based on the level of uncertainty in forecasting the future cost of the project, this cost could vary significantly. This cost variation will then reflect on the net electricity market benefits of Options 14, 15 and 16.

C29.2 Option 14 at stage two involves refurbishing the Wairakei-Whakamaru A line and provides new line between Wairakei, Ohakuri and increases transmission capacity by duplexing between Ohakuri and Whakamaru. Options 12, and 15 involve a new Wairakei-Whakamaru D line. Both are estimated to cost $90 million in Transpower's proposal. However, future cost estimates may be different given the new line cost is likely to involve easement purchase and property process issues, while replacing the existing Wairakei-Whakamaru A line has more certainty in terms of the line route. This could favour Options 11 and 14. Capital costs for both these projects are high level estimates based on past projects.[243]

C30 Given the uncertainty regarding future capital costs and renewable generation benefits, the results of the sensitivity analysis suggest that project staging is an appropriate approach because stage two outputs may change depending on how the generation developments progress. As noted previously, Transpower will need to submit an MCP when it wants to seek approval for stage two.

Whether the proposed investment and investment options can be integrated into the transmission system and the market operations

C31 In this section we discuss whether the proposed investment and investment options can be integrated into the transmission system and the market operations. We consider that this would be the case if these investments provide sufficient transmission capacity, and do not incur transmission uneconomic constraints, to allow efficient dispatch of forecast generation under normal operating conditions.

C32 The proposed investment and investment options delivering sufficient transmission capacity is directly linked with the investment need of NZGP1 stage one. Transpower states the investment need as:[244]

> The investment need of NZGP1.1 is to enable the efficient dispatch of new generation and a reliable supply for future demand growth over the interconnected grid.
> To meet this investment need, this proposal seeks funding approval for
> (1) shorter term initiatives; and
> (2) further investigations into longer-term planning issues and larger investments.

C33 Transpower's power flow analysis (Attachment B – Power system analysis report of its Proposal) sets out the transmission capacity the investment options and the proposed investment will deliver. [245]

243 Transpower, Proposal Attachment C, p. 33.
244 Transpower, Proposal, above n 1, p.12.
245 Transpower, Proposal, Attachment B: Power system analysis report.

C34 We assessed Transpower's power flow analysis in the context of the proposed investment, investment options and modelled projects. The power flow analysis sets out the effect of each investment option on transmission capacity.

C35 Transpower presented the results of its load flow studies in Attachment B of the proposal and provided further information in response to RFI07. Table C2 summarises the transmission capacity increases associated with each of the proposed transmission investments from Transpower's studies.

Table C2 Summary of increased capacity due to major capex project outputs

Major capex outputs	Capacity (MW)
HVDC upgrade	
+/- 60 Mvar Statcom plus 49 Mvar filter bank	1180
Central North Island capacity upgrade	
Current capacity @ 70% hydro[246]	740
Split 110 kV Bunnythorpe-Ongarue A circuit – Bunnythorpe – Tokaanu constrains.	910
Thermal upgrade (TTU) of Tokaanu -Whakamaru A&B circuits (95 deg) – Huntly Stratford cct 1 protection constraint	910
Apply variable line rating (VLR) and TTU Bunnythorpe- Tokaanu A&B circuits	990
Duplex Tokaanu-Whakamaru A&B circuits (Goat 120 deg)	1170
Duplex Bunnythorpe- Tokaanu A&B circuits (future stage)	*1360*
TTU Bunnythorpe-Wairakei circuit (future stage)	*130*
Wairakei ring capacity upgrade – Capacity depends on demand in the Bay of Plenty. Numbers are for a net demand of 100 MW.	
Current capacity at 100 MW of net Bay of Plenty demand	1160
TTU Wairakei-Whakamaru C circuits to 100 deg[247]	1160
TTU Edgecumbe-Kawerau 3 circuit to 90 deg	1540
Upgrade Wairakei-Whakamaru A line (future stage)	2800
New Wairakei-Whakamaru D line (future stage)	3200

246 Upstream generation affects the transfer limit. In this table the transfer limits correspond to 70% hydro generation dispatch.

247 Without TTU Wairakei-Whakamaru C, TTU Edgecumbe-Kawerau 3 increases the capacity to 1280 MW.

C36 The NZGP1 stage one proposed investment will deliver about 760 MW of additional north transfer capacity for the Central North Island circuits and an additional 300 MW for the Wairakei ring.

Clause C3 – evaluation of the major capex allowance

C37 Transpower has requested an MCA of $392.9 million, in 2028 prices. Table C3 summarises the components of the MCA.

Table C3 Summary of the components of the MCA

MCA component	Amount ($ million in 2028 dollars)
Inter-island HVDC Link	76
Central North Island	187
Wairakei Ring	19
Preparedness & supporting projects	13
Base estimate	295
Uncertainties	32
P50 estimate of cost (real) (P50 estimate)	327
Consumer Price Index (CPI)	41
Interest During Construction (IDC)	25
MCA	393

The major capex allowance appears reasonable

C38 We are satisfied that the underlying calculations, cost estimates and reports provided by Transpower during our review verify Transpower's calculation of the MCA.

C39 We consider that the NZGP1 stage one project cost estimates are reasonable subject to, the commissioning date of 30 June 2028 and the HVDC assurance.

C40 In coming to this conclusion, we are mindful that estimating the capital costs of projects as outlined in NZGP1 stage one is a complex engineering process that requires:

C40.1 producing conceptual designs;

C40.2 conducting site investigations;

C40.3 scoping the projects and then prepare the scope of work packages; and

C40.4 estimating the quantity of work for each work package.[248]

C41 In reviewing the estimated costs, we sought to form a view on whether Transpower had:

C41.1 adequately scoped the works;

C41.2 estimated the quantities;

C41.3 applied the unit costs where applicable;

C41.4 allowed for preparation costs for turnkey portions of the projects; and

C41.5 derived uncertainties in a reasonable manner.

C42 We outline our approach to assessing the MCA and the analysis we carried out in the following paragraphs.

Our approach to evaluating the MCA

C43 Under clause C3 of Schedule C, we must consider at least one of the following factors when evaluating the MCA:

C43.1 how Transpower used the major capex project outputs, key drivers, key assumptions, and cost modelling to determine the P50 and MCA cost (clause C3(a));[249]

C43.2 the capital costing methodology and formulation, including unit rate sources, the method used to test the efficiency of unit rates and the level of contingencies included (clause C3(b));

C43.3 the impact of forecast costs on other costs of Transpower, including the relationship with operating expenditure (clause C3(c));

C43.4 mechanisms for controlling actual capital expenditure with respect to the MCA (clause C3(d)); and

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248 Examples of work packages include site excavation, fencing, installing security lights, constructing the foundation for the equipment, freighting equipment onto sites and installing the MCPO's primary assets.

249 The MCA is the allowance for the project and is based on the base cost estimate plus the fiftieth percentile of uncertainties, or P50 cost estimate. Under clause 1.1.5(2) of the Capex IM, 'P50' means the estimated aggregate project costs where the probability of the actual aggregate project costs being lower than that estimated is 50%.

C43.5 the efficiency of the proposed approach to procurement of goods and services (clause C3(e)).

C44 We consider the factors under clause C3(a) and (b) because they best enable us to form a view on whether Transpower's estimate cost of the project and the subsequent derivation of the MCA are reasonable.

C45 Our assessment discussed below covers clause C3(a) and (b) together to avoid repetition.

How Transpower used the major capex project outputs to determine the MCA

C46 Transpower derived the MCA according to the components shown in Table C2, using the following general approach:

C46.1 determine the base estimate and uncertainties;

C46.2 use triangular distribution to derive the P50 costs in 2022 prices;[250]

C46.3 forecast exchange rates and forecast inflation from 2022 to 2025; and

C46.4 forecast financing costs.

C47 Transpower's base estimate is the summation of the cost to deliver the three major capex project outputs of this project plus the support and preparedness projects.

C48 Transpower engaged engineering consultants to prepare two Solution Study Reports (**SSRs**) for the:

C48.1 transmission lines and auxiliary substation works for the proposed works associated with Central North Island investment; and

C48.2 transmission line works in regard to the Wairakei Ring investment.[251]

C49 The SSRs determine:

C49.1 in consultation with Transpower, the scope of works required to deliver the project, grouped, and itemised into various work packages (work packages); and

C49.2 quantities of various line components associated with the work packages (quantities).[252]

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250 Triangular distribution is a representation of the probability distribution when using data for maximum, minimum and most likely values.

251 For the Wairakei lines and site works, Transpower revised these estimates based on its prior site visits and in consultation with the consultants.

252 An example of a work package is to reinforcement of tower foundations and strengthening of the tower lattice members to enable duplex lines installation.

C50 The SSRs detail the works that needed to be carried out on the existing transmission lines and substations in terms of tactical thermal upgrade and duplexing works.[253]

C51 The SSRs contain sufficient detail for both contractors and Transpower to carry out the required works and to meet the objectives of increasing the capacities of the specified sections of the transmission grid.

C52 The work packages outlined in the SSRs appear to have sufficient detail and are based on information provided by Transpower, site visits and ground conditions.[254] Certain existing transmission line routes in the proposed Wairakei ring upgrade could not be surveyed due to inaccessibility. In this case the consultant relied on information provided by Transpower and ground conditions in the vicinity of these transmission line routes to formulate the work packages. We are satisfied that these assumptions are reasonable.

C53 Based on the SSRs for proposed investments in Wairakei ring and Central North Island we are satisfied with the approach taken by Transpower to estimate the base values of the major capex project outputs for these areas. In the case of the HVDC, Transpower has used its Transpower Enterprise Estimation System (**TEES**) pricing model and indicative prices provided by potential suppliers. There is a clear link between the cost estimate and each major capex project output.

The capital costing methodology

C54 We evaluated the base estimate of the project cost using the technique of the capital costing methodology and formulation as outlined under clause C3(b) of Schedule C.[255]

C55 The main inputs into the base estimate are the results of SSRs, TEES and overheads.[256]

C56 The SSRs do not allow for any overheads or uncertainties costs in its estimates for each work packages for the relevant transmission line or substation.

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253 Duplexing a transmission line describes the replacement of a single conductor with two conductors on each circuit.

254 Transpower provided its estimates based on the value in its in-house TEES model whereby estimated unit costs for various components of the works base estimate can be derived.

255 The base estimate is the cost of each element (for example labour cost, and list of material) used to provide the overall project estimate.

256 Overheads includes Transpower's and the consultant's administrations, engineering support during project delivery, managements and commissioning, customer and landowner liaison costs, consenting and other indirect costs of the contractors', etc.

C57 Transpower estimated the cost of overheads by using its TEES model estimates from similar past projects and a multiplier[257] to allow for cost variations in 2022 pricing.

C58 Transpower has included the following uncertainties in the MCA:

C58.1 uncertainties in the work packages or quantities (scope risks) because SSRs are produced prior to the detailed design stage so the quantities are best estimates at the SSR stage of the project; and

C58.2 risks in delivering a project (project risk), such as delays due to weather, procurements and delivery, constructability issues, environment, and property risks.

C59 Transpower used work packages, quantities, unit costs, overheads, and an allowance for risk, to derive the P50 cost estimate by:

C59.1 using the material quantity of components identified in the SSRs of various transmission line sections under each work package to derive two other sets of quantities for each work package – the 'lower' and 'upper' quantities, which reflect the range of variation in quantities Transpower has observed for such projects;

C59.2 using TEES, as the source of unit costs for the work packages, and quantities derived above, Transpower estimated the lower cost estimates based on SSR quantities (SSR estimate) and upper cost estimates for each work package (work estimates);

C59.3 deriving lower, mid, and upper cost estimates for overhead and project risks (overhead estimates);

C59.4 summing the overhead estimates and works estimates to derive three sets of cost estimates for calculating the P50 estimate of cost. We refer to the SSR estimate plus the mid overhead estimate as the 'base estimate'; and

C59.5 applying triangular distribution to the three sets of estimates to derive the P50 estimate.

C60 We are satisfied that the above methodology provides an MCA based on the P50 estimate for project costs as required by the Capex IM.[258]

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[257] Transpower has derived the appropriate multiplier through outcomes of Transpower's risk workshops and using the appropriate CPI and labour index.

[258] Capex IM, above n 2, at clause G5(2)(c).

C61 We are satisfied that the triangular probability distribution approach used by Transpower to derive the P50 cost estimate. We are also satisfied with the lower and upper cost estimates derived based on the estimate of material and labour unit quantities that Transpower has used. The variation between these and the base quantities are in the range expected of such estimates at this phase of a project's life cycle.

Unit rate sources and the method used to test the efficiency of unit rates

C62 TEES includes a database of assembly costs which is the source of the unit costs Transpower use in its costing methodology. The Capex IM requires us to evaluate the unit rates and the method used to test the efficiency of the unit rates.[259, 260] We assessed how Transpower derives and updates its unit rates as follows:

C62.1 as part of evaluating NZGP1 stage one, we evaluated TEES and assessed how Transpower ensures unit costs in TEES are current. The same process is used to update the unit costs in assemblies.[261] We are satisfied that Transpower has a sound process to ensure the unit costs are current. For example, Transpower updates external labour and material rates based on actual costs from completed project and through internal panel review; and

C62.2 as part of evaluating Transpower's unit costs and assembly costs that have been factored into the TEES unit costs, we asked Transpower to verify the values of previous similar projects as well as the multipliers used to update the TEES estimates to 2022 prices. Based on our random sampling of certain material items and evaluating its estimate, we are satisfied that:

C62.2.1 the current unit costs in TEES are reflected in Transpower's cost estimation; and

C62.2.2 the assemblies are sufficiently granular for the purpose of estimating the cost of the MCP.

259 Capex IM, Schedule C - clause C7(e) refers to unit rate benchmarking. Here we considered how Transpower keeps its unit rates current.

260 Capex IM, Schedule C clause C3(b).

261 An assembly is a package of work with one or more cost items underneath it. Transpower considers that assemblies can provide the level of more granular and site-specific costs required to estimate the cost of the project.

The level of contingencies included in the base estimate

C63 The two types of risks contributing to uncertainties are:

C63.1 scope risk, which arises from uncertainties, at this early stage, in estimating the quantities for the work packages; and

C63.2 project risks, which arise from variations in prices, stakeholder liaison, environmental considerations, and project commencement timing and project duration due to external events such as weather.

C64 Allowing for the above uncertainties recognises that not all works can be identified at this early phase, because contractor prices can vary, project delivery can be affected due to availability of equipment outages, and there can be project delays due to external events such as weather.

C65 We consider these risks have a reasonable possibility of materialising and have therefore accepted them in the MCA. This allows Transpower to recover these costs should they materialise.

C66 We are satisfied that the value of the uncertainties, proposed by Transpower, is reasonable and consistent with clause G5(2)(c) of Schedule G of the Capex IM, which requires that the proposed MCA be a P50 estimate of the capital cost and the estimated probability distribution of the P50.

C67 The level of contingencies Transpower included in the base estimate is $32 million (in 2022 prices), being 11% of the base estimate, which we consider is appropriate for NZGP1 stage one and that percentage is at the lower end of the recent MCPs we have reviewed.[262]

Exchange rate and inflation assumptions

C68 The exchange rate and inflation assumptions of the MCA are subject to the wash-up mechanism, which means these assumptions do not impact the incentive calculation or the final revenue amount Transpower can recover.[263]

C69 Transpower's exchange rates and inflation assumptions are shown below in Tables C4 and C5 below.[264]

262 In the case of the Waikato Upper North Island voltage management stage 1 MCP the contingency was 25.9% of the base estimate, while for Bombay Otahuhu reinforcement MCP the contingency was 11.4%.

263 Capex IM, Schedule B, above n 2, clause B3(1).

264 Transpower, Proposal - Although a range of rates are given from 1 July 2016 to 1 July 2025, the exchange rates given above are as at 1 July 2022 except for IDR, KRW, MYR the rate is as at 1 July 2021.

Table C4 Exchange rates used to calculate the MCA

Currency	Exchange rate
AUD	0.9331
CAD	0.8750
CNY	4.8490
EUR	0.5554
GBP	0.5140
HKD	4.5060
IDR	10030.0600
JPY	69.2100
KRW	777.7440
MYR	2.8697
SEK	5.904
SGD	0.9518
THB	22.832
TWD	21.1855
USD	0.6412

Table C5 Forecast inflation rate used to calculate the MCA[265]

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rate	6.7%	5.2%	3.6%	2.7%	2.2%	2.1%	2.0%	2.0%	2.0%

Financing costs assumptions

C70 Transpower has estimated its financing costs based on the assumption that:

C70.1 the financing rate is set at Transpower's current weighted average cost of capital (**WACC**);[266]

C70.2 expenditure occurs at the end of each month: and

C70.3 the same principles used in its base capex proposal still apply.[267]

265 Transpower, Proposal – The actual Annual CPI to June 2022 was 7.30%.

266 We set the WACC in our cost of capital determination: Commerce Commission, Cost of capital determination for electricity distribution businesses' 2020-2025 default price-quality paths and Transpower New Zealand Limited's 2020-2025 individual price-quality path (2019) NZCC 12 (25 September 2019), available at: https://comcom.govt.nz/_data/assets/pdf_file/0022/177034/2019-NZCC-12-Cost-of-capitaldetermination-EBDs-and-Transpower-25-September-2019.PDF.

267 Under clause 1.1.5(2) of the Capex IM, the 'base capex proposal' is the information Transpower submits to enable us to determine the components of the IPP under clause 2.2.2 of the Capex IM.

C71 The capital expenditure profile of NZGP1 stage one is the 'S' curve typical of such projects.[268] Most expenditure in the case of the line works will occur throughout the project's duration with an increase in expenditure at the start of the project, allowing for project mobilisation and start-up.

C72 Site preparation works, that are carried out in the early stages of the construction phase are where variations in scope or delays, and corresponding increased costs, are most likely. Due to the comparatively lower costs of site preparation works for NZGP1 stage one, the effect of variations to capital expenditure profile on the financing costs is not high.

Clause C4 – evaluation of the proposed approval expiry date

C73 Transpower proposes an approval expiry date of 31 December 2035 for NZGP1 stage one.

C74 The effect of an approval expiry date is that Transpower cannot recover the costs of any assets commissioned after this date. This incentivises Transpower to deliver the project within the approval expiry date or apply for an amendment to that date under clause 3.3.6(1)(d) of the Capex IM.

C75 In evaluating Transpower's proposed approval expiry date under clause C4 of Schedule C, we must have regard to at least one of the six factors listed in that provision.

C76 We tested Transpower's proposed approval expiry date against the factors set out in clause C4(c): the effect of the proposed approval expiry date and the commissioning date assumption in NZGP1 stage one.

C77 We agree that Transpower's revised approval expiry date is reasonable since it provides Transpower with sufficient time to deliver on NZGP1 stage one while managing the short-term uncertainty regarding HVDC investment. Our final decision is that the clause 3.3.6(1)(d) requirements have been met.

Clause C5 – evaluation of the major capex project outputs

C78 We evaluated Transpower's proposed major capex project outputs against the factors set out in clause C5(a): the extent to which the major capex project outputs reflect the nature, quantum, and functional capability of the transmission investment assets to be commissioned.

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268 Project S curve is a graphical representation of the cumulative expenditure of the project, and this normally takes the shape of "S".

C79 The major capex project outputs and the quantum of these outputs are mentioned above under paragraph 4.23.

C80 The nature and functional capability of the proposed transmission investment assets are to improve the reliability and enhance the transfer capacity of the transmission assets by alleviating potential transmission constraints and facilitate the flow of electricity from generation areas, such as the Lower and Central North Island, Wairakei ring area and South Island, to the higher demand areas of Waikato and Upper North Island.

C81 We are satisfied that the NZGP1 stage one outputs reflect the nature, quantum, and functional capability of the transmission investment assets to be commissioned. Our final decision is that the requirements of clause C5(a) have been met.

Clause C6 – evaluation of the major capex incentive rate and exempt major capex

C82 The major capex incentive rate we set under clause 3.3.5(7)(b) of the Capex IM determines the reward (or penalty) that Transpower receives (or bears) depending on how the actual cost of delivering a major capex project compares to the project's MCA.[269] Exempt major capex is those portions of the MCA amount to which the major capex incentive rate does not apply to.[270]

C83 Transpower has proposed:[271]

C83.1 a major capex incentive rate of 15%; and

C83.2 that we do not set any exempt major capex.

Major capex incentive rate

C84 Under clause 1.1.5(2) of the Capex IM, the major capex incentive rate is 15%, the default rate, or an alternative rate we specify after considering a request from Transpower. In its NZGP1 stage one proposal, Transpower proposed the default MCP incentive rate of 15% apply.

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269 Clause B3(1) of Schedule B of the Capex IM determines how the major capex incentive rate applies to an approved major capex project.

270 Capex IM, clause 1.1.5(2) above n 2.

271 Transpower, Proposal, p. 13.

C85 We are satisfied that the incentive rate of 15%, which is the default rate under the Capex IM, will incentivise Transpower to seek efficiencies in delivering NZGP1 stage one. We would only typically consider moving from the default incentive rate for projects where the forecast cost is high, the forecast cost is uncertain, or the potential for efficiency gains is high. We do not consider the circumstances of NZGP1 stage one to be appropriate for us to set an alternative incentive rate.

Exempt major capex

C86 Exempt major capex is the part of the MCA to which the major capex incentive rate does not apply. It is typically set for portions of the MCA that reflect uncertainties that are outside the control of Transpower. Transpower has proposed that there not be any exempt major capex.

C87 Transpower has characterised the project cost estimate contingency as a risk adjustment to "account for cost uncertainty not represented in our lower and upper bound estimates".[272]

C88 The effect of applying exempt major capex to identified cost contingencies is that Transpower would not suffer a loss from spending the contingency if the risks eventuate. Similarly, the consumers would not have to pay for any reward if the contingency allowance is not spent. This approach is consistent with how we treat uncertainties relating to foreign exchange and inflation forecast error as mentioned under 'Exchange rate and inflation assumptions' in paragraphs C64 and C65.

C89 The proposal's project cost contingency is estimated by Transpower to be $31.9 million, which is 9.8% of the total project cost estimate of $326.8 million. This translates to a contingency of $38.4 million for the forecast MCA of $393 million (in 2028 prices).[273]

C90 In our review of Transpower's detailed costing data, we ascertained that there was no risk adjustment or inflationary index associated with $10.2 million of preparatory costs. On this basis we consider that the contingency amount of $38.4 million, relates to the MCA of $393 million (in 2028 prices).

C91 We consider that project cost risks have a reasonable possibility of materialising and have therefore included them in the MCA. This allows Transpower to recover these costs should the risks materialise.

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[272] Transpower, Proposal, Attachment E: Costing Report p. 5.
[273] Ibid, p. 5.

C92 However, we have decided that exempt major capex should apply to the risk adjustment (contingency) identified by Transpower. Our view is that Transpower should not be rewarded through incentives for saving cost contingency amounts. In its draft decision submission MEUG agreed with this approach.[274]

C93 Our final decision, under clause 3.3.5(7)(c) of the Capex IM, is to treat the risk adjustment component of the MCA as exempt major capex, equal to $38.4 million in 2028 prices. This means that the cost of uncertainties up to this amount will not be subject to the incentive mechanism.

C94 Accordingly, in setting the exempt major capex and the major capex incentive rate, the incentive scheme under clause B3(1) of Schedule B of the Capex IM will work as follows. If the actual cost of delivering NZGP1 stage one is:

C94.1 less than the MCA minus exempt major capex, then applying the major capex incentive rate, Transpower will be entitled to a reward;

C94.2 between the MCA and the MCA minus exempt major capex, then there is no reward or penalty; and

C94.3 more than the MCA, then applying the major capex incentive rate, Transpower will be penalised.

274 MEUG, submission on draft decision, above n 76, p. 3 para 13.

Attachment D Evaluation of the investment test

Purpose of this attachment

D1 This attachment sets out our review of Transpower's application of the investment test. We discuss:

D1.1 Transpower's selection of the proposed investment;

D1.2 our evaluation of the parameters Transpower used in the investment test application;

D1.3 the expected net electricity market benefits Transpower found;

D1.4 the results of Transpower's sensitivity analysis; and

D1.5 our assessment of Transpower's investment test application.

Transpower's selection of the proposed investment

D2 The Capex IM defines an investment option as a technically feasible solution designed to facilitate or meet a specific investment need.[275]

D3 In its original proposal, Transpower selected Option 10 as the proposed investment. Following our initial review, we indicated to Transpower that it should reconsider whether Option 10 met the investment need because:

D3.1 the outputs of Central North Island in Option 10 would not provide sufficient transfer capacity to efficiently dispatch the forecast generation; and

D3.2 the proposed Wairakei ring investment did not show all the NZGP1 stage one outputs and future staging projects, such as a new line.

D4 We requested that Transpower consider an addendum to NZGP1 stage one with further information to allow us to assess NZGP1 stage one against the test set out in the Capex IM. The addendum was also requested to provide clarity on:

D4.1 the investment need for NZGP1 stage one;

D4.2 the technically feasible investment options considered by Transpower that will address the investment need; and

D4.3 how it will mitigate the risk of over-investment associated with the NZGP1 stage one HVDC investment in case the Tiwai smelter does not leave in 2024, or that the demand in that location is replaced.

[275] Capex IM, above n 2, clause 1.1.5(2).

D5 We requested that Transpower demonstrate and confirm that all investment options meet the definition in the Capex IM for an investment option by removing any non-complying options from the current list.

D6 Transpower provided the Addendum, which included additional information and made key changes to its proposal. Transpower revised its proposed investment to Option 11.

D7 During our review of the Addendum, Transpower discovered errors in its application of the investment test and decided to revise its proposal following a consultation with stakeholders. Following its consultation and revised application of the investment test, we sought further clarity on some issues.

D8 Table D1 sets out stage one and stage two of NZGP1, as set out in Transpower's response to our RFI10.[276]

Table D1 Transpower's updated NZGP1 proposed investment (stage two investments in red)

Investment option	Net benefit ($ million)	HVDC upgrade	Central North Island upgrade	Wairakei ring upgrade
Option 14	145	New HAY reactive support and filters.	Split Bunnythorpe Ongarue line, upgrade Huntly-Stratford protection, replace SPS at Tokaanu, TTU and duplex Tokaanu-Whakamaru A&B lines, TTU Bunnythorpe-Tokaanu A&B lines.	TTU Wairakei-Whakamaru C line, split Edgecumbe-Kawerau 110 kV line, and TTU Edgecumbe-Kawerau 220 kV line.
		4th HVDC cable to enable 1400 MW transfer capacity	Duplex Bunnythorpe-Tokaanu line, TTU Bunnythorpe-Wairakei line. Reconductor Brunswick-Stratford line.	Upgrade Wairakei-Whakamaru A line

[276] Transpower, RFI10, p. 8.

NZGP1 proposed investment must provide a positive net market benefit

D9 The investment test set out in Schedule D of the Capex IM uses a cost-benefit analysis using discounting of relevant costs and benefits in the electricity market over a defined calculation period to identify the most economic investment option as the proposed investment.[277]

D10 Under clause C1(2), for the purposes of deciding whether a staged proposed investment satisfies the investment test, we must evaluate whether the investment test is satisfied for all proposed staging projects.

D11 Under clause D1(1) of Schedule D, a proposed investment satisfies the investment test if it has the highest expected net electricity market benefit and is robust to sensitivity analysis compared with other investment options.

D12 The expected net electricity market benefit:[278]

D12.1 does not need to be positive for the proposed investment to meet the N-1 criterion of the GRS; but

D12.2 needs to be positive for any other proposed investment.

D13 The proposed investment in NZGP1 stage one:

D13.1 is not required to meet the N-1 criterion of the GRS and must therefore provide a positive net market benefit; and

D13.2 must provide the highest net market benefit either on a quantified basis or under certain conditions including unquantified costs and benefits.

D14 When determining which investment option has the highest net electricity market benefits, only quantified net electricity market benefits or cost elements may be taken into account unless the circumstances specified in clause D1(c)(ii) and (2) apply. The Capex IM allows us to take into account unquantified net electricity market benefits or cost elements if there is an investment option with similar expected net electricity market benefits, which means that the difference in quantum is 10% or less of the aggregate project costs of the investment option to which the proposed investment is compared. [279]

[277] 2012 Capex IM reasons paper, above n 4, at para 7.2.1. We note that in our 2017/18 Capex IM review, we decided to retain the investment test criteria and approach in the 2012 Capex IM. See 2017/18 Capex IM review reasons paper, above n 65, at para 194.

[278] Capex IM, above n 2, Schedule D clause D1(1)(b).

[279] ibid, Schedule D, clause D1(1)(c)(ii) and (2). Under clause D1(3), we may, at our discretion, adopt an alternative percentage to 10% as proposed by Transpower.

D15 To satisfy the investment test, the proposed investment has the highest expected net electricity market benefit including a qualitative assessment to take into account the contribution of the associated unquantified electricity market benefits or cost elements.[280]

D16 An electricity market benefit or cost element may be treated as unquantified where:

D16.1 the cost of calculating its quantum is likely to be disproportionately large relative to the quantum; or

D16.2 its expected value cannot be calculated with an appropriate level of certainty due to the extent of uncertainties in underlying assumptions or calculation approaches.

How the investment test is applied

D17 In carrying out the investment test, Transpower must:[281]

D17.1 estimate the electricity market benefits or cost elements and project costs for each investment option under each relevant generation and demand scenario;[282]

D17.2 calculate the net electricity market benefits for each investment option under each relevant generation and demand scenario (net electricity market benefit is the sum of the electricity market benefits less the sum of the electricity market costs including the project cost); and

D17.3 calculate the expected net electricity market benefit, including any unquantified benefits, which is the weighted average of the net electricity market benefit under each relevant demand and generation scenario.

D18 As part of carrying out the investment test, Transpower must also test whether its proposed investment is sufficiently robust under sensitivity analysis, which verifies whether the proposed investment is robust to changes in some of the key assumptions.[283]

280 Capex IM, above n 2, clause D1(1)(c)(ii).
281 ibid, Schedule D, clause D2.
282 The terms ‘electricity market benefit or cost element’, ‘project cost’, and ‘relevant generation and demand scenarios’ are defined in Schedule D clause D4(1), (2), and clause D3(4).
283 Capex IM, above n 2, Schedule D, clause D1(1)(a).

How we evaluated Transpower's application of the investment test

D19 Under the Capex IM, we reviewed Transpower's application of the investment test by considering whether:

D19.1 the parameters of the investment test are appropriate and whether Transpower consulted on the parameters it applied;

D19.2 Transpower reasonably estimated the expected net electricity market benefit of each investment option;

D19.3 the proposed investment is the investment option with the highest net electricity market benefit, including unquantified benefits; and

D19.4 the proposed investment is robust to sensitivity analysis.

D20 We present a summary of our evaluation in this attachment.

Our evaluation of the parameters of the investment test

D21 The Capex IM allows Transpower some discretion to select the analysis parameters of inputs into the investment test. Transpower is required to consult on the values of the parameters it uses and other key investment test analysis considerations.[284] These parameters and inputs include:

D21.1 the demand and generation scenarios (comprising demand forecasts and generation scenarios);[285]

D21.2 the qualitative assessment used to take into account the contribution of associated unquantified electricity market benefit or cost elements;[286]

D21.3 the value of expected unserved energy used to calculate the cost of involuntary demand curtailment borne by end users of electricity;[287]

D21.4 discount rate used;[288]

D21.5 calculation period used;[289]

D21.6 cost of demand side management (we discuss Transpower's modelling of demand side management when we assess the application of the investment test);[290] and

[284] Capex IM, above n 2, clause I4.
[285] ibid, clause G3(1) of Schedule G.
[286] ibid, clause G3(1) of Schedule G.
[287] ibid, clause G4(5)(c) of Schedule G.
[288] ibid, clause G4(5) of Schedule G.
[289] ibid, clause G4(5)(b) of Schedule G.
[290] ibid, clause D4(1)(c) of Schedule G.

D21.7 investment options considered.[291]

D22 The demand and generation scenario assumptions for NZGP1 underpin the economic justification of the proposed investment. We incorporated our consideration of how Transpower has developed and consulted on its scenarios when we evaluated Transpower's application of the investment test.

D23 For the reasons we outline below, we are satisfied that Transpower has reasonably selected the investment test parameters.

Whether Transpower's demand and generation scenarios are reasonable variations of EDGS

D24 The Capex IM requires Transpower to use the relevant demand and generation scenarios when it calculates the expected net electricity market benefit in the investment test.[292]

D25 The relevant scenarios are either the demand and generation forecasts published by the Ministry of Business and Innovation and Employment (**MBIE**) or Transpower's development of a reasonable variation of those scenarios (**scenario variations**), having had regard to the views of interested persons on the variation.[293]

D26 The most recent scenarios published by MBIE are the 2019 EDGS. EDGS has five hypothetical future scenarios – Reference, Growth, Global, Environmental and Disruptive.[294]

D27 In its NZGP1 stage one proposal, Transpower developed scenario variations based on MBIE's 2019 EDGSs.[295] Transpower explain in its proposal that scenario variations are necessary because:[296]

> In order to model possible economic benefits from our investments, we require plausible scenarios of Aotearoa New Zealand's future electricity supply and demand. These scenarios must be consistent with Aotearoa New Zealand achieving net zero carbon by 2050. While we started from MBIE's 2019 Electricity Demand and Generation Scenarios (EDGS), we identified an unusually large number of possible futures.

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291 Capex IM, above n 2, clause 7.4.1(2).
292 ibid, clause D2.
293 ibid, Schedule D clauses D3(1) and (2). Under clause I1(1)(b) of Schedule I of the Capex IM, Transpower must consult on each demand and generation scenario variation.
294 MBIE, Electricity demand and generation scenarios report, 2019. Available at https://www.mbie.govt.nz/dmsdocument/5977-electricity-demand-and-generation-scenarios-report-2019-pdf.
295 Capex IM, above n 2, clause D3(3).
296 Transpower, Proposal, above n 1, p. 33 section 2.4.1.

The demand and generation scenario variations must be feasible and reasonable

D28 The Capex IM requires that demand and generation scenario variations proposed by Transpower must be reasonable variations of EDGS to be considered as relevant scenarios for application in the investment test.[297]

D29 Clause D3(3) of the Capex IM sets out a non-exhaustive list of the factors that Transpower must have regard to in order for a scenario variation to be a "feasible and reasonable" variation of EDGS. Those factors are:

D29.1 existing and forecast demand;

D29.2 the grid reliability standards;

D29.3 the value of expected unserved energy;

D29.4 transfer capacities and capabilities of the grid;

D29.5 the cost of supplying sufficient ancillary services;

D29.6 the cost of losses necessarily incurred in efficiently meeting demand;

D29.7 operating expenditure incurred in efficiently meeting demand by means of existing assets, committed projects, decommissioned assets, and modelled projects;

D29.8 the capital cost of efficiently meeting demand by means of modelled projects;

D29.9 the timing of decommissioning an asset or removing or re-rating a decommissioned asset; and

D29.10 likely range of investment options to which the investment test relates.

D30 Some of these requirements are more relevant to the demand scenarios and some are more relevant to the generation scenarios. Transpower has considered the clause D3(3) requirements across the suite of analysis it has carried out to support NZGP1 stage one. For example:

D30.1 Transpower has, in its power systems analysis, considered the grid reliability standards and transfer capacities and capabilities of the grid, to identify transmission circuits overload for N-1 core grid outages. This analysis not only identifies existing network constraints for use in the market dispatch analysis tool to calculate the benefits of new generation, but also the impact and feasibility of transmission upgrades.

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297 Capex IM, above n 2, clause D3(3).

D30.2 When Transpower carries out its market dispatch analysis in PSR Inc's SDDP software (**SDDP**) it also models transmission constraints, consistent with the grid reliability standards, transfer capacities and capabilities of the grid, the forecast demand, the cost of supplying sufficient ancillary services, and the cost of losses incurred to meet demand.

D30.3 The operating costs for existing assets, committed projects, decommissioned assets, and modelled projects, and the capital costs for efficiently meeting demand using the modelled projects, have all been incorporated into the consideration of the power systems analysis and market dispatch analysis Transpower has carried out. These factors influence the identification of transmission network issues, potential upgrade solutions and the economics of these solutions. These considerations are embedded within each of the investment options investigated.

D31 In the next sections we evaluate Transpower's demand and generation scenario variations. We are satisfied that Transpower has factored in the clause D3(3) requirements in its development of the scenario variations. Where we identified issues with the scenario variations, we discuss these with reference to the clause D3(3) requirements in the following sections.

Our evaluation of Transpower's demand scenario variations

D32 In its analysis, Transpower has modified the MBIE EDGS energy demand scenarios it updated in 2021 as the starting point for the NZGP1 analysis energy demand scenarios out to 2050.

D33 Transpower discusses its process for updating the scenarios in Attachment D of its proposal, stating that:[298]

> We consulted with the industry on reasonable variations to the EDGS 2019 demand forecasts, to ensure they were up to date and published these in December 2021. Since then, there have been other changes affecting our forward view of electricity demand, so we have made some minor adjustments.

D34 In its proposal, Transpower explains that it has made minor adjustments to its 2021 EDGS demand forecasts due to:[299]

D34.1 updated historical data that inform the base load demand forecast;

D34.2 an updated view of future demand at each Grid Exit Point (**GXP**) through discussion with customers;

D34.3 replacement of the Marsden Point oil refinery by a storage terminal; and

298 Transpower, Proposal, above n 1, Attachment D, pp. 9-13.
299 ibid, pp. 9-10.

D34.4 the retirement of Kawerau pulp and paper mill.

D35 Our view is that the process Transpower carried out to identify the demand and generation scenarios it used in its analysis, has been prudent, and is consistent with the Capex IM requirements.

D36 Transpower compared its NZGP1 stage one energy demand forecast with other energy demand forecasts using different hypothetical future scenarios. These forecasts were carried out by the Climate Change Commission (**CCC**) and to support Transpower's Whakamana i Te Mauri Hiko.[300]

D37 Our view is that Transpower's NZGP1 stage one energy demand forecasts cover a similar range of hypothetical futures and energy demand quantities as those produced by the CCC and in support of its Whakamana i Te Mauri Hiko. The exception is the Transpower's Whakamana i Te Mauri Hiko "Mobilise and Decarbonise" scenario which has a slightly higher energy demand forecast.

D38 Figure D1 shows that the resulting energy demand curves for the five NZGP1 energy demand scenarios are similar to the original MBIE 2019 energy demand curves. The demand adjustments have produced a small decrease in the energy demand forecast for all scenarios, resulting in, on average, a reduction of 6 TWh in each scenario by 2050.

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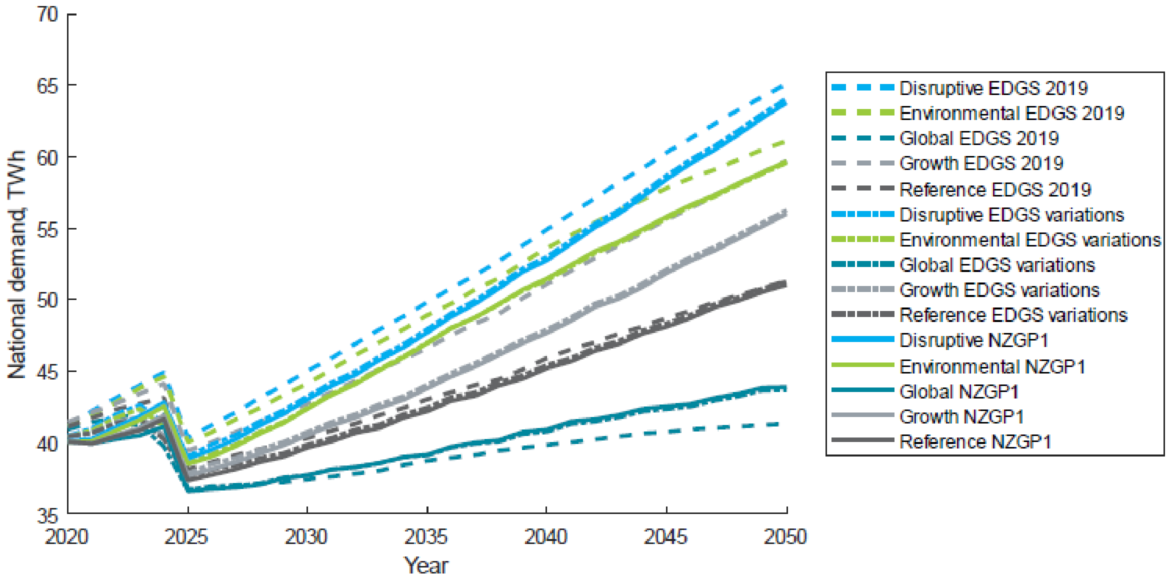
300 Transpower's Whakamana i Te Mauri Hiko is its long term view examining the potential future scenarios that may impact Aotearoa New Zealand's energy future and is available here https://www.transpower.co.nz/about-us/our-strategy/whakamana-i-te-mauri-hiko-empowering-our-energy-future

Figure D1 Comparison of EDGS 2019 energy demand forecasts, 2021 EDGS variations and proposed NZGP1 energy demand forecasts[301]



Peak demand forecasts

D39 EDGS does not forecast MW demand by region or GXP, but instead provides national level forecasts of energy demand. When Transpower carries out its power systems and economic analysis it must estimate peak demand forecasts by GXP by matching the national energy forecasts with known GXP demand levels and growth trends.

D40 Transpower's peak demand forecasts are based on econometric modelling and are usually carried out annually. In its 2022 Transmission Planning Report Transpower summarise the demand forecasting process as:[302]

> For national, island and regional peak forecasts, we use an ensemble of models (trend, econometric, etc.) to produce forecasts based on historical peak values. At a GXP level we used simpler techniques and have drawn on information, primarily from local distribution companies, to derive GXP forecasts.

D41 We are satisfied that Transpower has reasonably translated the national energy demand forecasts developed for NZGP1, to reasonable peak demand forecasts for each GXP when it carries out its power system analysis to identify transmission constraints and transmission upgrade solutions, and for use in the market dispatch analysis.

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301 Transpower, Proposal, Attachment D: Scenario & Modelling, p.11 - Figure 2.

302 Transpower 2022 Transmission Planning Report available at https://www.transpower.co.nz/our-work/industry/transmission-planning

D42 Transpower has taken this demand forecasting approach in previous MCPs, and in NZGP1 stage one, and we are satisfied that this process is robust, fit for purpose process, and complies with the Capex IM.

D43 In conclusion, we are satisfied that Transpower has met the Capex IM clause D3(2) requirements. We agree with the process that it uses to match the energy demand forecasts in its energy demand scenario variations to GXP demand, and that the demand scenario variations are reasonable variations of the 2019 EDGS.

D44 However, one key assumption that Transpower has made in all its NZGP1 stage one energy demand forecasts is that the Tiwai smelter closes by 2024, and this is a key uncertainty in this proposal.

D45 The 2024 Tiwai smelter exit assumption is common in each scenario Transpower has developed and was based on its consultation feedback at the time the scenarios were defined. This assumption creates a significant modelled generation surplus in the South Island and affects the economics of the NZGP1 proposal, particularly the economics of the HVDC upgrade component.

D46 In its most recent Transmission Planning Report published in 2023, Transpower has assumed that the Tiwai smelter remains until 2034.[303] While the 2034 date is an assumption it does highlight the analysis uncertainty Transpower faces as it assesses a need date for, and economic justification of, the HVDC upgrade component of NZGP1.

D47 In its submission to Transpower’s consultation on its updated preferred option, Vector suggested that Transpower carry out additional sensitivity analysis where “Tiwai does not close” because there was “ongoing uncertainty around Tiwai”.[304]

D48 We discuss the effect of this assumption and Transpower’s analysis of it when we evaluate Transpower’s calculation of the net electricity market benefits derived from the generation scenario variations in paragraph D128.

D49 A generation scenario is a hypothetical prediction of a set of generation developments within the electricity industry. In the analysis that supports the NZGP1 stage one proposal, the generation scenarios assist in defining a significant part of the economic benefit of connecting new generation into the wider grid.

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303 The Transpower TPR is an assessment of transmission network upgrade needs over a 10-year forecast period. The 2023 TPR is available here and the Tiwai smelter assumption is discussed in section 19.2.1 on page 363.

304 Vector submission on Transpower’s Preferred Option 6 Sep 2023, available at https://www.transpower.co.nz/nzgp-phase-one-updated-preferred-option-consultation

D50 This benefit is used as an input in the investment test to determine if transmission investment to facilitate that new generation is efficient, and which investment option provides the highest expected net electricity market benefit.[305]

D51 Similar to its energy demand forecasts, the MBIE EDGS provide energy generation forecasts at a national energy level and by generation source type. EDGS does not provide information on the location of each potential generation project, and this must be estimated by Transpower.

D52 To finalise its generation expansion plans for each scenario, Transpower used Optgen software, which determines "the lowest cost combination of capital costs (due to investments in new generation) and operating costs (due to operating existing and new generation plant) for each year in the modelling horizon."[306]

D53 Transpower summarised its use of Optgen by stating that:

> We first find the lowest cost combination of generation projects that must be built to meet forecast demand over the modelling horizon (from 2022 through to 2055). This is our generation forecast or 'generation expansion plan' and is developed using PSR Inc's Optgen software.[307]

D54 To support its approach in finalising its generation scenario variations Transpower consulted with industry on its generation energy forecast and, on the location, capacity, and timing of potential future generation projects (generation expansion plan). It also used the information from generation connection enquiries to inform this forecast.[308]

D55 The consultation also included seeking further specific information from potential generation project developers. The feedback suggested that there was considerable uncertainty in the sector due to several major decisions, such as the Tiwai smelter closure leading to a generation capacity surplus, Project Onslow, and investor interest in grid scale batteries.[309]

D56 We reviewed Transpower's generation scenario variations with this uncertainty in mind and understand that Transpower has been facing an unprecedented volume of new connection enquiries over the last two to three years. There is difficulty in judging which of these projects is more likely to proceed.

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305 Capex IM, clause D1(1)(c).
306 Transpower, above n 25, Proposal Attachment D.
307 Transpower, Proposal Attachment D.
308 Transpower, NZGP1 Scenarios Update, Executive summary.
309 Transpower, NZGP1 Scenarios Update p. 7.

D57 With reference to Transpower's new connections dashboard on 13 June 2023, there are 213 active new grid connection generation enquiries being processed by Transpower. There are 60 potential connections in the Lower North Island and Central North Island regions, and 38 potential connections spread across the Taranaki and Bay of Plenty regions, many of which would be investment drivers for the proposed NZGP1 upgrades.[310]

We reviewed the generation projects that would be investment drivers of NZGP1 stage one

D58 We also sought further information from Transpower about how more advanced generation connection enquiries compared with the generation projects it had modelled in its power systems and market dispatch analysis.

D59 We were interested in whether the projects Transpower had assumed as likely to be committed were not likely to proceed and if this was affecting the economics of the proposal.

D60 We asked Transpower:

D60.1 if it had information regarding whether the Central Wind and Puketoi projects are progressing past their present consented status, noting that the NZWEA website does not suggest that these projects are, or are planned to be, constructed in the near future; and

D60.2 for information supporting the generation assumptions in Transpower's Generation Expansion Model for Regions 2, 3 and 4.[311]

D61 Transpower responded that the version of its generation expansion plan provided in the NZGP1 stage one proposal was not the most up to date plan and had been superseded.

D62 Transpower noted that, in its updated generation expansion plan, neither the Central Wind nor Puketoi projects are built pre-2025 in any scenario, and that it did not hold any information on the advancement of these projects beyond their present consented status.

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310 See Transpower's connection enquiries at https://experience.arcgis.com/experience/97d4604079b545448280423f9269b9ea/page/Dashboard/.

311 Regions 2,3 and 4 refer to the South Island (Region 4), Lower and Central North Island (Region 3) and Bay of Plenty, Hawkes Bay, and East Coast (Region 2). Transpower's regional allocations are set out in p.31 section 3.2.2 Proposal Attachment D – Scenario and Modelling report.

D63 The updated generation expansion plan assumed the following committed generation that could be considered as economic drivers of the proposal:

D63.1 Turitea wind in 2022 (221 MW);

D63.2 Tauhara geothermal 2023 (168 MW);

D63.3 Harapaki wind in 2024 (176 MW);

D63.4 Ruakaka battery in 2024 (100 MW); and

D63.5 Te Huka geothermal in 2025 (52 MW).

D64 Following our review of the proposal and our investigation of how more recent generation connection enquiries affected the NZGP1 stage one economic analysis, we consider that Transpower's short term generation scenario variations are reasonable variations of the MBIE EDGS and that they have incorporated the views of interested persons.

D65 However, while we accept that Transpower's generation scenarios are reasonable, and that these have been widely consulted on, we do have the following concerns with the longer-term generation expansion plan that Transpower is likely to need to consider when it reviews the generation scenarios for NZGP1 stage two:

D65.1 a very high percentage of forecast new generation is from wind and about half of the wind generation is forecast to be in the Lower North Island. Our analysis of Transpower's generation scenarios shows that wind farms located in the Lower North Island and Taranaki regions would likely be in the same wind corridor. This will increase market vulnerability to the power output from wind farms;

D65.2 there is little difference in generation technology under some scenarios. This could be because of the nature of the EDGS and Transpower has referred to this in its submission on the 2023 update of EDGS; and

D65.3 in the longer term, less than the forecast wind generation might develop in the Lower North Island region, particularly if offshore wind farms develop in the Taranaki and Waikato regions.

Relevant demand and generation scenarios

D66 Given the volume of enquiries in the regions that would drive the NZGP1 stage one upgrades, and the uncertainty surrounding their timing, we are satisfied that the generation scenario variations Transpower has used in its analysis are reasonable variations on EDGS for NZGP1 stage one of the investment options. We are satisfied that they are relevant generation scenarios under clause D3(4) of the Capex IM.

D67 Transpower will need to review its generation and demand forecasts for a future stage of NZGP1.

Discount rate

D68 The Capex IM sets the standard discount rate of 7% but also allows another rate that may be appropriate for a specific circumstance. Transpower may use an alternative rate subject to consultation under clause I3 of the Capex IM.[312]

D69 Transpower has used 7% as the standard rate and 4% and 10% in its sensitivity analysis in line with clause D7(3)(b) and (c) of Schedule D of the Capex IM, respectively.

D70 Transpower notes, in its proposal, that it did "receive feedback during consultation that a 7% discount rate seems high and that a lower rate, say 4%, may be more reasonable".[313] A lower discount rate would more heavily weight the longer-term decarbonisation benefits in the Capex IM economic analysis.

D71 We are satisfied that the 7% discount rate is reasonable given the sensitivity analysis undertaken.

Calculation period

D72 The Capex IM defines the cost benefit analysis calculation period as a minimum 20-year period commencing on the commissioning date of the last asset to be delivered by the proposed investment, except where significant electricity market benefit or cost elements and project costs are expected to arise or be incurred thereafter.[314]

D73 Transpower has used a cost benefit analysis calculation period that extends to 2050 on the basis that benefits will continue to accrue after a 20-year calculation period has ended.[315]

D74 We are satisfied with Transpower using a calculation period out to 2050, since the last asset in its proposal is forecast to be commissioned in June 2028.[316]

D75 We note that due to high uncertainties in generation forecasts after 2035, we used a shorter calculation period in our evaluation of the economics of the proposed investments for NZGP1 stage one.

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312 Capex IM, above n 2, clause D6.
313 Transpower, Proposal, above n 1, p.58.
314 Capex IM, above n 2, clause 1.1.5.
315 Transpower, Proposal, above n1, Attachment D, p.32.
316 Transpower, Proposal, above n 1, p.13.

Investment options that Transpower considered

D76 The Capex IM requires that:

D76.1 the number of investment options must be appropriate given the magnitude of the estimated expenditure and the complexity of the investment need associated with the proposed investment;[317] and

D76.2 with respect to each investment option the specificity of information and rigour and comprehensiveness of the analysis must be commensurate with the estimated expenditure and complexity of the option.[318]

D77 In its revised proposal, and following consultation, Transpower considered six options (Options 10 to 15) in its short-list application of the investment test. In all six options the HVDC upgrade components are common investments, while each option contains variations of different investments in the Central North Island region and Wairakei ring. The different options Transpower considered are summarised in Attachment E.

Whether the number of investment options is appropriate given the magnitude of the estimated expenditure and the complexity of the investment need

D78 The Capex IM defines an investment option as a technically feasible solution designed to facilitate or meet a specific investment need.

D79 This NZGP1 stage one major capex proposal has been proposed by Transpower to upgrade the transmission network to facilitate economic access to the wider transmission grid for:

D79.1 potential new generation developments in the Lower North Island and Central North Island regions, and

D79.2 any generation surplus in the South Island, due to either a Tiwai smelter exit or new generation developments there.

D80 NZGP1 stage one can be considered as three different investments to enhance the capacity in different parts of the transmission grid. Following its long-list consultation process, Transpower prepared a wide list of investment options for investment test application. The two HVDC upgrade options, three Central North Island upgrade options and three Wairakei ring upgrade options are listed in Table 12 of Transpower's NZGP1 stage one proposal.[319] The investment options Transpower investigated are a combination of these upgrades.

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317 Capex IM clause 7.4.1(2).
318 ibid, clause 7.4.1(3).
319 Transpower, Proposal, above n 1, p. 51.

D81 We are satisfied that the shorted-listed options set out in Transpower's original proposal provided a reasonable number of investment options for analysis and testing under the investment test. This is because the investment options:

D81.1 covered a range of potential solutions including implementing options to increase capacity of existing assets such as variable line rating to defer upgrading those assets; and

D81.2 would meet the investment need by enhancing transmission capacity to facilitate the connection of potential new generation or a generation surplus.

D82 Since the original proposal was lodged Transpower modified the short-list options project staging, and also how it will progress the HVDC upgrade component. These changes include:[320]

D82.1 that NZGP1 will now be a two-stage project, not a three-stage project;

D82.2 the addition of investigation studies for North Island voltage and system stabilities for all investment options; and

D82.3 the HVDC assurance.

D83 NZGP1 stage one investments have been characterised by Transpower as "shorter term initiatives and investigations on further longer-term issues", while the stage two investments are for "planning and carrying out larger investments".[321]

D84 We have reviewed the material provided in the original proposal, the revised proposal, and the project staging changes Transpower made. In its revised proposal material, Transpower has amended its proposal from a three-stage project to a two-stage project. We consider that these changes were not material because:

D84.1 there is no change to the range of options consulted on and what stakeholders have reviewed; and

D84.2 it does not change any of the material Stage 1 project outputs, or the Stage 2 project outputs, when compared with the three-stage option.

D85 We are satisfied that Transpower's changes to its proposal do not affect the number of investment options Transpower could have consulted on with stakeholders.

[320] Transpower, Proposal, above n 1, Table 1: NZGP1.1 at a glance.
[321] Transpower, Addendum, above n 14.

D86 Transpower has also expanded the short-list investment options it has considered in its revised proposal to capture the most economically robust combination of investments to meet the investment need.

Whether, for each investment option, the specificity of information and rigour and comprehensiveness of the analysis are adequate

D87 Transpower provided sufficient information and supporting analysis on the Central North Island and Wairakei ring upgrade as part of NZGP1 stage one, including in response to our RFIs, which we listed in Attachment B.

D88 We summarised Transpower's analysis of the impact of the investment options under the heading "Clause C2 – General evaluation of the major capex proposal" in Attachment C.

D89 As we carried out our review of the original proposal, we were not fully satisfied that Transpower provided sufficient quantitative information and analysis to conclusively support approval of the HVDC stage one investment.

D90 In its Addendum, Transpower provided us with a number of qualitative reasons supporting this upgrade and indicated it would quantify some of these during consultation on our draft decision. This was based on the timetable at that time and prior to the issues which were noticed in July, leading to a revised proposal.

D91 In its revised proposal, Transpower provided some quantitative analysis it stated supported the full approval of the HVDC stage one investment. We further discuss this analysis in our evaluation of the investment test below.

Our evaluation of the investment test application and sensitivity studies

D92 We outline the analysis that supports our findings and our assessment of Transpower's application of the investment test for NZGP1. We have analysed how Transpower calculated the net market costs and net electricity market benefits in its investment test application, and the sensitivity analysis it has carried out.

D93 Transpower's NZGP1 stage one investment need is driven by potential significant new generation in the Lower North Island and Central North Island regions, with generation connection enquiries increasing since the NZGP1 process began, and a possible generation surplus in the South Island. Therefore, Transpower's generation scenario assumptions underpin the proposal economics, and we describe how we reach our conclusions on the reasonableness of these.

D94 We also discuss how Transpower has calculated the positive net electricity market benefits of the proposal. This proposal is to upgrade the transmission network to facilitate new generation into the wider grid and requires a different analysis approach than that taken to upgrade the transmission network to meet demand. We review Transpower's process and approach to this.

Our evaluation of Transpower's calculation of electricity market cost and benefit elements

D95 In applying the investment test, Transpower must calculate the following for each investment option included in the MCP:

D95.1 the electricity market benefits under the relevant demand and generation scenario;

D95.2 the electricity market costs under the relevant demand and generation scenario;

D95.3 the net electricity market benefit for the relevant demand and generation scenario; and

D95.4 the expected net electricity market benefit.

D96 Under Schedule D of the Capex IM:

D96.1 'electricity market benefit or cost element' means any of the market benefits received or market costs incurred by consumers during the calculation period under the relevant demand and generation scenario that will affect net electricity market benefits;[322]

D96.2 the 'net electricity market benefit' is, in respect of an investment option applied to a demand and generation scenario, its aggregated quantum of each electricity market benefit or cost element less its aggregated quantum of each project cost; and

D96.3 the 'expected net electricity market benefit', in respect of an investment option, is the weighted average of the net electricity market benefit under each relevant demand and generation scenario.[323]

D97 In evaluating Transpower's application of the investment test, we assessed whether Transpower reasonably estimated, for each investment option in NZGP1 stage one:

D97.1 the electricity market benefits;

D97.2 the electricity market costs; and

[322] Capex IM, above n 2, clause D4(1).
[323] ibid, clause D2(1).

D97.3 the net electricity market benefit and the expected net electricity market benefit.

How Transpower estimated the costs and benefits of the proposal

D98 Clause D4 of the Capex IM sets out the electricity market cost or benefit elements that Transpower can consider in the investment test. Accordingly, Transpower considered the following categories of electricity market costs and benefits for the investment options it considered:[324]

D98.1 fuel costs, eg, the cost of dispatching electricity;

D98.2 cost of demand-side management;

D98.3 MCP project and modelled project capital costs, eg, including future assets that are likely to exist whose nature and timing is affected by an investment option, for instance new generation;

D98.4 operation and maintenance costs, eg, costs of existing assets, options, and modelled projects; and

D98.5 losses costs, including transmission and local distribution network losses.

D99 We evaluated Transpower's calculation of the electricity market costs and benefits under the following sub-headings:

D99.1 how Transpower estimated the costs and benefits of the proposal; and

D99.2 a summary of our findings on Transpower's calculation of the costs and benefits.

Fuel costs

D100 Transpower used the following approach to assess the relative electricity market fuel costs of the investment options and the proposed investment:[325]

D100.1 generation expansion plans were developed using Optgen for each generation scenario for two cases– a factual and counterfactual. The factual case includes the new generation connections and investment option transmission upgrades, while the counterfactual case assumes the transmission network is not upgraded to connect new generation. In the counterfactual case, demand growth is met by some other means;

324 Transpower, Proposal, above n 1, Attachment C, p.33.
325 Transpower, Proposal, above n 1, Attachment D, p. 23.

D100.2 for both the factual and counterfactual cases, generation fuel costs are assessed by optimising market dispatch solutions for each year in the modelling horizon. For this analysis, Transpower used SDDP software. This market dispatch analysis was performed for a range of historical hydro inflow sequences, demand levels and wind generation variability; and

D100.3 the counterfactual case was modelled as other out-of-merit order generation build plan and battery solutions across the grid to meet demand without alleviating any identified transmission constraints. The benefits accrue to the factual case by displacing the more costly out-of-merit order generation build plan in the counterfactual case.

D101 We reviewed the approach Transpower had taken to create the factual and counterfactual cases, and its analysis approach to calculating the benefits of upgrading the transmission network to facilitate new generation. We agree with this approach.

Cost of demand side management

D102 In its analysis Transpower modelled demand side management (**DSM**) as both a peaking and low hydro inflow year solution in its scenarios. Table D2 sets out the DSM costs Transpower has assumed in its analysis.[326]

Table D2 Transpower's investment test DSM costs

Proportion of hourly demand	Cost
First 5% of demand	$600/MWh
Between 5% and 10% of demand	$800/MWh
Between 10% and 15% of demand	$2,000/MWh
Greater than 15% of demand	$10,000/MWh

D103 In its original NZGP1 proposal Transpower did not specify the source for the DSM costs it has assumed, but they do reflect the likely cost of contracting demand side management that have been used in other projects.

D104 As a comparison, for the Waikato and Upper North Island Voltage Management (**WUNI**) major capex project Transpower used pre-fault DSM costs of $2,000/MWh.[327]

326 Transpower, Proposal, above n 1, Attachment D, p. 19.

327 Transpower "Waikato and Upper North Island Voltage Management Attachment C: Options and Costing Report (13 December 2019), p. 28.

D105 We note that it is not easy to assess the reasonableness of future demand side management costs since these can:

D105.1 vary with the type of demand involved, eg, commercial, or industrial;

D105.2 the duration of DSM use;

D105.3 when it is used; and

D105.4 whether it is pre- or post-fault demand side management.

D106 These costs are also likely to increase as demand side management capacity penetration levels rise, an effect Transpower has also modelled.

D107 However, while we cannot predict future costs, we are satisfied with the assumptions Transpower has made around its modelled demand side management based on its previous approach.

D108 We agree with Transpower that demand side management costs may increase as its quantum or duration increases, and so Transpower's proportionate pricing approach is appropriate.

MCP staging project and modelled project capital costs

D109 Transpower used its TEES cost estimation framework to estimate the NZGP1 stage one and modelled project capital costs. This is set out in its Costing Report as Attachment E of the NZGP1 proposal.[328]

D110 We have discussed Transpower's approach to project cost estimation in Attachment C and are satisfied that the process is robust and fit for purpose.

Operation and maintenance costs

D111 Transpower has assigned operating and maintenance costs (**O&M**) for each existing asset, the transmission investment options considered, and each modelled project in its economic analysis.[329] Present value O&M cost estimates associated with key transmission lines, before and after duplexing or reconductoring, have been provided.[330]

328 Transpower, Proposal, Attachment E – Costing report available at https://comcom.govt.nz/__data/assets/pdf_file/0014/330008/Transpower2C-NZGP1.1-MCP-Attachment-E-Costing-Report-September-2023.pdf

329 Transpower, Proposal, Attachment C - Options Report p. 33.

330 Transpower estimates that duplexing or reconductoring the BPE-WRK A line, BPE-WKM A line and BPE-WRK A line would reduce present value O&M costs by about $2 million in each line.

D112 Additionally, as part of its fuel cost analysis to ascertain the benefits of new generation, Transpower has modelled variable operating and maintenance costs associated with the different generation types.[331]

D113 While we did not evaluate Transpower's assessment of O&M costs in detail, because these do not have a material impact on the results of the investment test, we are satisfied that Transpower has reasonably modelled and accounted for O&M costs in the proposal.

Losses costs

D114 When comparing investment options that contain different transmission upgrade options in an investment test application, transmission loss cost differences between options may be significant.

D115 While Transpower's power system analysis options report talks about transmission losses in only general terms, the quantification of losses for each investment option is carried out following the analysis to ascertain the relative fuel costs in the generation dispatch analysis.

D116 Transpower notes that losses costs are estimated as a post processing step after the generation dispatch analysis has been carried out, and quantified "using known circuit resistance and circuit flow", derived from that analysis.[332]

D117 To reduce computational burden, Transpower has used the generation dispatch analysis and assessed losses for a variety of analysis solution resolutions over the assessment period. There are some snapshot analyses using an hourly resolution of load in the generation dispatch analysis, but most loss calculations Transpower has carried out use load block assumptions to model the effect of different forecast load levels over a year.[333]

D118 Transpower has then estimated the forecast wholesale market price during these load blocks, and the transmission line flows, to calculate losses costs over the year for each investment option factual scenario relative to losses calculated in the counterfactual scenario.

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331 Transpower, Proposal, Attachment D - Scenario & Modelling Report p. 38. available at https://comcom.govt.nz/__data/assets/pdf_file/0013/330007/Transpower2C-NZGP1.1-MCP-Attachment-D-Scenario-26-Modelling-Report-September-2023.pdf

332 Ibid, p. 39.

333 ibid, p. 26.

D119 We agree that this approach is reasonable and that the use of load blocks is an appropriate means to estimate losses over a year. Carrying out generation dispatch analysis, for every hour of every year of the calculation period, would be more accurate but would be too computationally burdensome.

D120 We are satisfied with Transpower's approach to modelling losses in its proposal.

Summary of our findings on Transpower's calculation of the costs and benefits

D121 Transpower calculated the benefits of NZGP1 holistically because of the interconnected nature of the transmission network. While the approach is consistent with the Capex IM, for NZGP1 stage one, this approach does not isolate the benefit of individual projects.

D122 The NZGP1 stage one proposal involves three separate investment packages for transmission upgrades of the HVDC, Central North Island and Wairakei ring, that form a single proposal.

D123 Transpower took this step because the generation projects that would be the investment drivers, and assumptions it has made about the Tiwai smelter, all affect the transmission constraints it identified in the affected regions.

D124 We have accepted this consolidated economic analysis approach in this proposal but consider that future proposals should link discrete investment drivers more explicitly to individual investment proposals.

D125 In its submission MEUG considered that in future "it may be preferrable for Transpower to separate distinct investment projects and submit them as separate MCPs" and supported our approach to test the economics of the three projects separately.[334]

D126 We agree with this view in general but note that, at the time we initially considered the scope of this MCP, it appeared to be a sensible approach to link the HVDC, CNI and Wairakei ring upgrades given that a Tiwai smelter exit in 2024 seemed likely and appeared to be driving the investment need of NZGP1 stage one.

D127 Since Transpower consulted on its generation scenarios, the Tiwai smelter exit date has become less certain, and as we analysed the proposal, it highlighted that each of the HVDC, CNI and Wairakei ring upgrades have distinct investment drivers. In these situations, as Transpower progresses the NZGP programme, it should consider separate MCPs and identify and quantify the net benefits of each.

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334 Transpower, Proposal, Attachment D - Scenario & Modelling Report, p. 3, para 13.

Our assessment of the electricity market costs and benefits

D128 This is the first generation connection driven MCP that Transpower has proposed since the HVDC Pole 3, Wairakei ring line and Lower South Island renewables upgrades in the late 2000s under the Electricity Commission.

D129 Under the Capex IM, any proposed transmission upgrade that is not required to meet the GRS, such as one undertaken to facilitate new generation access across the wider transmission grid (ie, to alleviate transmission constraints), must provide a positive net electricity market benefit.[335]

D130 We have already described the process Transpower has taken to identify the benefits of upgrading the transmission network using the generation scenarios and the benefits associated with displacing a counterfactual generation case. We agreed with this approach. Largely, the economic justification of the proposal is dependent on these benefits (nominally the fuel costs and reduction in transmission losses) being greater than the market costs (capital plus operating and maintenance costs) of the investment options considered in an NPV analysis.

D131 We will now discuss our observations of Transpower's application of the investment test.

Our observations of Transpower's investment test results

D132 We have already described that the proposed investment is essentially three separate transmission upgrade packages, in three different parts of the transmission grid, under the umbrella of a consolidated set of market benefits.

D133 In reviewing Transpower's investment test application, we carried out our own analysis. We took a two-step approach. Firstly, we looked at the proposal and whether this passed the investment test. Secondly, we cross-checked Transpower's investment test application to satisfy ourselves that individual components of the proposal would deliver net electricity market benefits.

D134 In reviewing the economic analysis results in Transpower's proposal we consider that Transpower has taken a robust approach in applying the investment test and that the costs and benefits have been reasonably calculated, noting the significant uncertainty.

[335] Capex IM, above n2, clause D1.

D135 We investigated how Transpower's generation scenarios reflected the likely demand growth, and the actual enquiries Transpower was progressing. We were satisfied that the more recent generation enquiries Transpower was progressing were sufficiently advanced and would likely have a similar effect as the generation modelled in Transpower's scenario analysis that was driving the net electricity market benefits.

D136 Table D3 sets out the investment test results for the six investment options Transpower considered in its revised proposal.[336]

Table D3 Present value of quantified expected costs and benefits of the investment options ($ million in 2022 prices)

Investment option	Net market benefit	PV costs	PV benefits
Option10	176	393	569
Option 11	150	454	604
Option 12	181	451	632
Option 13	173	452	625
Option 14	145	514	659
Option 15	175	510	685

D137 Table D3 illustrates that the quantified net electricity market benefits range from $145 million to $181 million for the six investment options considered and all these options pass the investment test.

D138 Transpower has proposed Option 14 as its preferred option and relied on the unquantified benefits that this option provides.[337]

[336] Transpower, Proposal Attachment C, pp. 45-46.
[337] Transpower, Proposal, above n 1, p. 24.

Table D4 Transpower's unquantified benefit application ($ million)

Investment option	Investment option net benefits	Δ net benefits vs Option 12	Net market project costs
Option 10	176	-5	393
Option 11	150	-31	454
Option 12	181	-	451
Option 13	173	-8	452
Option 14	145	-36	514
Option 15	175	-6	510

D139 Option 12 has the highest quantified net electricity market benefits at $181 million. The project cost elements of Option 12 are $451 million. The difference in the net market benefits between Option 12 and the other investment options is less than 10% of the project cost elements of Option 12 of $45.1 million.

D140 The closeness of the investment test results for Options 10 to 15 means that a more qualitative approach to selecting the preferred investment is a reasonable one to make.

D141 We conclude that Transpower has demonstrated that unquantified benefits may be considered in the application of this investment test.

Transpower's preference is Option 14

D142 Transpower's preference as its investment option is Option 14, despite other options having marginally higher quantified net electricity market benefits. The investment test results indicate that Options 10 to 15 all appear to be viable NPV positive options, with the quantified net electricity market benefits ranging from $145 million (Option 14) to $181 million (Option 12) – a range of $36 million.

D143 All these investment options meet the investment need and address future renewables generation on the grid to different degrees of timing and capacity, particularly for those investments in the Central North Island region and Wairakei Ring. The different transmission investments for Options 10 to 15 are summarised in Attachment E.

D144 We now discuss whether Transpower has sufficiently made the case for preferring Option 14 over Option 12, which provided the highest quantified net electricity market benefit.[338]

D145 We reviewed Transpower's view that Option 14 provided unquantified benefits over Option 12, noting that:

D145.1 there are significant generation enquiries in the Central North Island region. The Wairakei-Whakamaru C line TTU in Option 14 (stage one) provides additional Wairakei ring transmission capacity upwards of 250MW, and confidence that new generation can be developed and dispatched in the short term, that Options 12 does not;

D145.2 the Bunnythorpe-Wairakei TTU and Bunnythorpe-Tokaanu duplexing in Option 14 (stage two) means higher transmission capacity for Lower North Island and Central North Island renewables (investments that are not in Option 12). This will provide real option value and certainty to renewables developers investigating new generation in the Lower North Island and Central North Island regions. Our evaluation found there are a significant number of generation enquiries in these regions;

D145.3 maintaining N-1 security during maintenance for Option 14 seems to be minor and would only accrue as a reliability benefit if there was an outage during maintenance. However, over the much longer term (eg, 20-30 years) Option 14 would provide a greater capacity into the Bay of Plenty region to future-proof demand growth in the region; and

D145.4 replacing the Wairakei-Whakamaru A line with increased capacity rather than a new Wairakei-Whakamaru D line, along the route of C line, allows geographic route diversity which will have a route diversity resilience benefit in favour of the Wairakei-Whakamaru A line replacement option and favours Option 14.

D146 While Option 12 has higher quantified net electricity market benefits than Option 14, Transpower has identified a range of unquantified benefits that favour Option 14 over Option 12. We have concluded that these unquantified benefits are neither present in Option 12 nor outweighed by any unquantified benefits that accrue in Option 12. We agree with the Option 14 unquantified benefits identified by Transpower, and also note that:

D146.1 the stage one investments are essentially the same in Options 12 and 14, with the exception being the Wairakei-Whakamaru TTU. Our assessment of the proposal has satisfied us that the Option 14 stage one investments

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[338] Capex IM, above n 2, clause D1(2)(a).

appear to be good value in that they allow significant new generation, early access the transmission network at a low cost;

D146.2 the investment test results are highly sensitive to the stage two investment capital costs, particularly the Bunnythorpe-Tokaanu duplexing (Option 12), new Wairakei-Whakamaru D line (Option 14), and Wairakei-Whakamaru A line replacement (Option 14). Refining these costs with detailed study designs to reduce cost uncertainty has considerable option value; and

D146.3 approving the stage one investments now, which contains preparatory costs to carry out the requisite major stage two investment detailed study designs, will allow Transpower to quickly respond when better information about new likely generation connections in the Central North Island and Lower North Island regions become available.

D147 Given the capital cost uncertainties inherent in this proposal at stage two, the fact that the stage one investments are common in Option 12 and 14 (with the exception being that Option 12 does not contain the Wairakei-Whakamaru C line TTU), and the uncertainty surrounding generation development, there is considerable option value in:

D147.1 approving the relatively lower cost Option 14 stage one investments now to realise benefits early; and

D147.2 carrying out the detailed study designs for the stage two investments in stage one. Doing so allows Transpower to quickly respond when new generation connections in the Central North Island and Lower North Island regions become more certain.

D148 This aligns with Transpower's preference for Option 14 over Option 12.

D149 In summary and following our review of how Transpower has applied the investment test, we are satisfied that Transpower has adequately calculated the quantified net electricity market benefits of the investment options, and that these outweigh the costs.

D150 We consider that, on balance, Option 14 provides unquantified benefits that favour it over Option 12, when the range of uncertainties are considered, and aligns with Transpower's least regret investment approach.

D151 Finally, we also undertook a high-level economic benefit review of the Central North Island and Wairakei ring investments and HVDC investment to confirm whether these investments would pass the investment test if proposed separately.

D152 While we used a high-level economic analysis to test the Central North Island and Wairakei ring investments, our review of the proposed HVDC upgrade was more focussed due to the Tiwai smelter exit assumption made by Transpower.

Benefits for the Central North Island and Wairakei ring investments

D153 We considered the Central North Island and the Wairakei ring investments together because these networks facilitate north transfer of power from Bunnythorpe. Any north transfer of power from Bunnythorpe will flow through both the Bunnythorpe-Tokaanu-Whakamaru network (Central North Island) and the Bunnythorpe-Wairakei-Whakamaru network (Wairakei ring).

D154 The stage one Central North Island and Wairakei ring investments will significantly increase the power transfer capacity on the transmission circuits there, and will be very cost effective when compared with the cost of new transmission lines for the same purpose.

D155 We tested the robustness of Transpower's application of the investment test by carrying out our own assessment of potential fuel cost displacement based on likely generation locating in Regions 2 and 3 (denoted by Transpower in its scenario modelling analysis) and the displacement of thermal generation as a counterfactual case.[339]

D156 We assessed the stage one benefits of the Central North Island and Wairakei ring investments as follows:

D156.1 we assumed that if Transpower upgraded the Central North Island lines, the generation developers will be incentivised to build in Regions 2 and 3;

D156.2 we estimated the benefits of the geothermal generation by calculating the cost of fuel and emission of equivalent thermal generation that potential new generators in these regions would displace. We assumed that the equivalent thermal plant would have fuel and emission costs similar to the fuel and emission costs of fossil fuel generation;

D156.3 we assumed that repowering the wind farms will be cheaper than building new ones elsewhere and that sufficient transmission capacity will incentivise wind generators to repower the existing wind farms to a higher install capacity, as in Transpower's forecast;

D156.4 we restricted the evaluation period to 2035; and

339 Region 2 includes the Bay of Plenty, Taupo and Hawkes Bay regions, while Region 3 is the lower and central North Island region extending down from Wairakei to Wellington. Transpower, Proposal, above n1, Section 3.2.2 in Attachment D, at p. 31.

D156.5 based on Transpower's generation modelling we identified potential generation build as follows:

(a) 126 MW wind farm that is confirmed in Transpower's new generation forecast. Since these are being built to replace fossil fuel power stations, we assessed the potential fuel cost displacement based on the displacement of thermal generation as a counterfactual case;

(b) 302 MW of additional capacity from repowering existing wind farms. We assessed potential capital costs savings of repowering versus new builds; and

(c) 441 MW of geothermal generation on the Wairakei side of the Wairakei ring under the disruptive scenario. We assumed that given the base generation nature of geothermal power stations these will be built under all scenarios. We assessed the potential fuel cost displacement based on the displacement of thermal generation as a counterfactual case.

D157 Using the above assumptions, our economic analysis indicates that the NZGP1 stage one outputs of the Central North Island and Wairakei ring investments are likely to provide a positive net electricity market benefit.

D158 We estimate expected net electricity market benefits of fuel cost displacement and consider that these benefits are likely to justify the proposed Central North Island and Wairakei ring investments if they were an MCP without the HVDC upgrade.

The benefits of the HVDC upgrade NZGP1 stage one investment

D159 We carried out more in-depth analysis to test the HVDC upgrade component of NZGP1 stage one. We were unclear that the assumptions Transpower had made were still valid and that it had not identified sufficient benefits to justify it.

D160 The HVDC link's primary role is to allow the transfer of South Island hydro generation energy to the North Island. In NZGP1 Transpower proposes to enhance the HVDC link in the following two stages:

D160.1 in NZGP1 stage one – install a dynamic reactive device (DRD) and HVDC filter banks for an estimated major capex allowance of $103 million. These assets will enhance the transfer capability of the HVDC from 1071 MW to 1200 MW;[340] and

[340] The 1071 MW transfer capability is based on historical asset outage data at Haywards that limits power transfer of the installed design capability of 1200 MW. This is discussed in the Proposal p. 14.

D160.2 in NZGP1 stage two, install a new HVDC cable and upgrade the design capacity of the HVDC link to 1400 MW. Transpower plans to do this either around 2027 or when it replaces the existing HVDC cables in the early 2030s.

D161 In its proposal, Transpower identified two drivers that support enhancing the HVDC link transfer capability, namely:

D161.1 the Tiwai smelter exit which Transpower has assumed will occur by the end of 2024;[341] and

D161.2 forecast growth in new generation in the South Island.[342]

D162 Transpower concluded that the effect of the Tiwai smelter departure will result in HVDC and Central North Island constraints, stating that:[343]

> In December 2020, we undertook work to consider the effect on the transmission system of Rio Tinto's announcement to wind-down, and eventually close, the Tiwai Point aluminium smelter (Tiwai). That study identified the most restrictive transmission constraints as occurring on the High Voltage Direct Current (HVDC) link and the North Island 220 kV Alternating Current (AC) network between Bunnythorpe and Whakamaru (referred to as the Central North Island or CNI). Relieving these constraints would provide the highest benefit to consumers.

D163 The Tiwai smelter exit is equivalent to introducing 574 MW (about 5 TWh of energy) of surplus generation, which can be exported to the North Island. This generation would likely displace North Island thermal generation plant.

D164 If the Tiwai smelter does exit, we estimate that some South Island generation would be constrained during times of high north transfer on the HVDC. Transpower's rationale for enhancing the transfer capacity of the HVDC link, and eventually upgrading the link, is to reduce the amount of potential constrained generation.

Tiwai smelter exit date and South Island generation assumptions

D165 Transpower's NZGP1 stage one economic analysis has been significantly affected by the assumptions of Tiwai smelter's exit in 2024 and that a new HVDC cable is installed in 2027.[344]

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341 Transpower, Original Proposal, above n 13, p.10.

342 ibid, p.31.

343 Transpower, Proposal, above n 1, p.22.

344 Our view is that it is unlikely that the Tiwai smelter will now exit in 2024. At the time Transpower was developing its NZGP1 scenarios, the industry view, and following statements made by the owners of Tiwai, was that this exit was inevitable and that 2024 was the most likely date for this exit.

D166 As part of its proposal analysis Transpower carried out three sensitivity studies to test the robustness of this assumption, namely that:

D166.1 the Tiwai smelter closes at the end of 2024, and Transpower installs a fourth HVDC cable in 2027;

D166.2 the Tiwai smelter closes at the end of 2034, and Transpower installs a fourth HVDC cable in 2027; and

D166.3 the Tiwai smelter closes at the end of 2034, and Transpower installs a fourth HVDC cable in 2034.

D167 Transpower concluded that these sensitivities demonstrated its overall proposal had a positive net expected market benefit even if the Tiwai smelter exit is deferred until 2034, provided installation of the fourth HVDC cable is also deferred.

D168 Following our analysis, we are unclear where the benefit of the NZGP1 HVDC upgrade originates if the Tiwai smelter exit is delayed until 2034. Transpower notified us during our review of the original proposal that this benefit could be due to South Island generation developments. However, our review of Transpower's scenarios indicated that no significant new generation was forecast to occur until after 2037, slightly increasing post-2045.

D169 Given the HVDC link's primary role is to allow the transfer of South Island generation energy to the North Island, and not for reliability reasons, the absence of new South Island generation developments between 2024 and 2037 in the scenarios suggests that new generation is not contributing to the benefits of enhancing the HVDC link.

D170 We also note that the forecast increase in South Island demand exceeds the forecast increase in South Island generation from 2040. This indicates that less South Island generation will be available for export to the North Island, affecting the benefits of the HVDC upgrade.

How we assessed the HVDC upgrade benefits

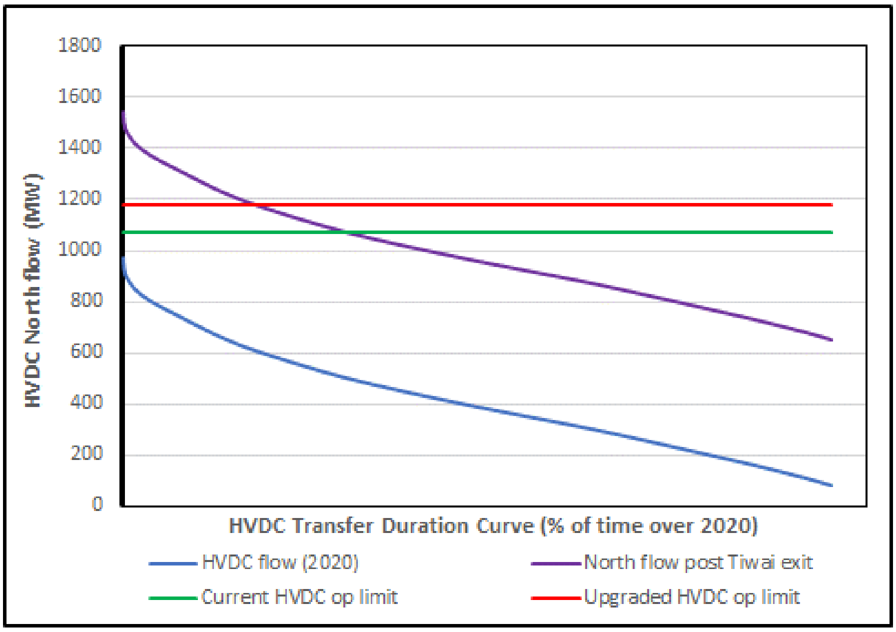
D171 We provide details on our analysis of the HVDC upgrade and Transpower's responses to our request for information in the following order:

D171.1 how we assessed the benefits of the HVDC upgrade; and

D171.2 other analysis we have carried to ascertain if the HVDC upgrade is necessary.

D172 We analysed potential HVDC power transfer using historical DC transfer data supplied by Transpower. We used this analysis to consider the effect of additional HVDC power flow if the Tiwai smelter exits, or if there is more surplus South Island generation in the future.

Figure D2 HVDC transfer analysis with and without Tiwai smelter exit assumption



D173 Figure D2 is a power transfer duration curve analysis with the highest DC power transfer to the lowest, plotted over the year, in this case 2020. The light blue curve is the 2020 HVDC power transfer duration data supplied by Transpower. As an upper bound assumption, we added the generation surplus created by Tiwai smelter exit onto the 2020 HVDC power transfer data to create a post-Tiwai exit power transfer duration curve (the purple curve).

D174 Figure D2 shows the percentage of time HVDC north flow (the purple curve) could be greater than the current 1071 MW transfer level if the Tiwai smelter were to exit. We estimated that there could be surplus South Island generation available to transfer north about 25% of the time, above the present estimated capability of 1071 MW.

D175 However, this assumes that if the Tiwai smelter exits, the generation dispatch patterns will be same as in 2020, which will not be the case. What is more likely is that a South Island generation surplus created by a Tiwai smelter exit would increase HVDC energy transfer levels over the year. In other words, the HVDC power transfer duration curve would likely flatten.

D176 We can use the graph in Figure D2 to illustrate what a constrained HVDC is likely to cost as an upper bound. The potential constrained off energy is denoted by the area enclosed by the y-axis and the green and purple lines. The NZGP1 stage one investment would reduce the constrained off energy generation by the area enclosed by the green, red, and purple lines. This reduction provides what could be considered a likely upper bound benefit of enhancing the HVDC based on 2020 dispatch patterns.

D177 We estimated that the potential constrained off energy cost could be about $4.3 million per annum assuming an electricity price of $150/MWh. This is equivalent to a NPV of $46 million at 7% discount rate which on its own would not justify the HVDC upgrade capex.

D178 However, the constraints do not necessarily result in market costs unless there is hydro spill or South Island generation is lower cost than the North Island generation it would otherwise displace. We estimate the constrained generation to be less than 5% of South Island storage capacity.

D179 Under most conditions, the constrained generation will store water and generate later to replace North Island thermal generation. The exception will be when there is high water flow into the South Island lakes and if those lakes are full.

D180 Transpower studies also noted this effect, and in response to our review questions, Transpower stated that:[345]

> Load growth has been higher than assumed at the start of NZGP1.1. This, combined with low levels of new generation development and the completion of the CUWLP work, mean that the large amounts of hydro spill we have previously seen in our modelling, once Tiwai closes, are less likely. We would still expect significant hydro spill in wet hydrological years.

D181 Transpower noted that Aotearoa New Zealand is currently experiencing a wet hydro inflow year, but that outages on reactive equipment are restricting the HVDC transfer capacity to below 1200 MW.[346]

D182 Our review of Transpower's HVDC flow data and the Energy Link Limited HydroWatch report, highlighted that some South Island hydro spill could be due to HVDC transfer capability. [347, 348]

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345 Transpower, Request for information response RFI07.

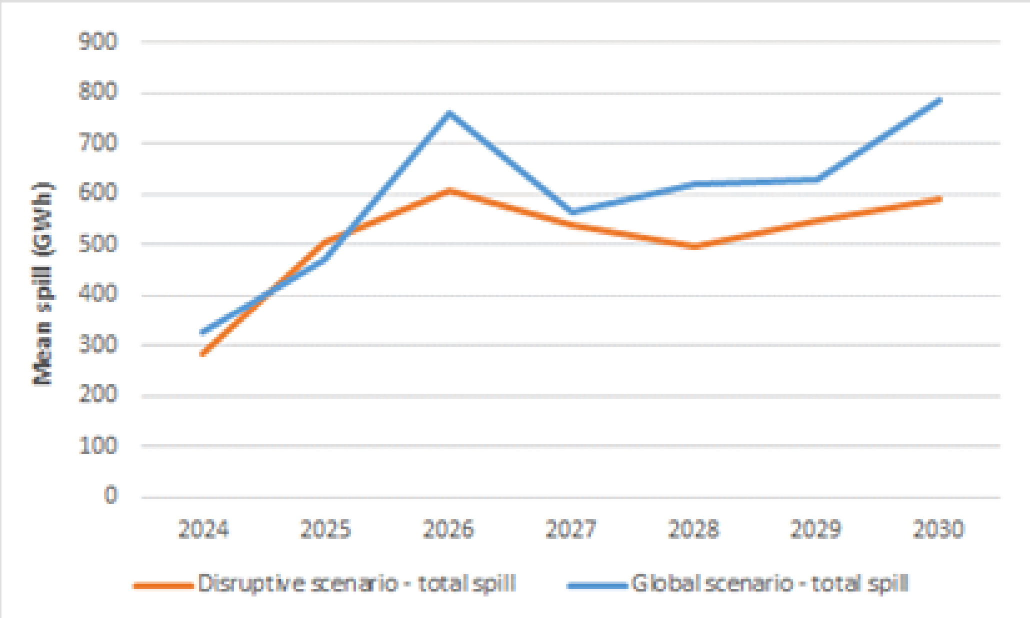
346 Transpower, Addendum, p. 7.

347 Transpower System Operator live data available at https://www.transpower.co.nz/system-operator/live-system-and-market-data/hvdc-transfer.

348 Energy Link Limited, HydroWatch. Available at https://www.energylink.co.nz/news/field_category/hydro-watch-153.

D183 In response to our questions, Transpower provided us with consolidated mean annual hydro spill estimates for the Clutha, Waitaki and Manapouri hydro catchments, for both the global and disruptive scenarios (see Figure D3).[349]

Figure D3 Hydro spill estimates for the Clutha, Waitaki and Manapouri hydro catchments



D184 Figure D3 illustrates that there is South Island hydro spill estimated in 2024, which is before the Tiwai smelter is modelled to depart in Transpower's scenarios. In our review, we were interested in the effect of the NZGP1 stage one HVDC upgrade on the hydro spill estimate and whether this upgrade makes spill any less likely.

D185 Figure D3 illustrates that, while the modelled hydro spill drops after 2025, between 2025 and 2030 it oscillates between 500 GWh and 800 GWh depending on the scenario. There appears to be no noticeable trend that clearly shows the NZGP1 stage one HVDC upgrade provides material savings in potential hydro spill. Transpower also made this observation in response to our questions.[350]

D186 In summary, following our analysis, we consider that a Tiwai smelter exit in 2024 may not create sufficient benefit on its own to justify upgrading the HVDC, and that the benefit of avoided South Island hydro spill due to increased HVDC capacity appears to be minimal.

349 Transpower, Request for information response RFI08.
350 ibid.

D187 However, Transpower has indicated that there are other benefits that may accrue to justify the HVDC investment component of NZGP1 stage one. We consider these possible benefits next.

Other HVDC upgrade investigations we carried out

D188 As we reviewed the NZGP1 stage one proposal we also considered whether the HVDC upgrade helps firm North Island generation. Transpower raised this additional factor in support of the NZGP1 stage one HVDC upgrade but did not quantify it.

D189 Transpower stated in its proposal that one reason for upgrading the HVDC is its future role in 'firming' North Island generation. However, in its proposal Transpower did not quantify the benefit of firming or how it could be quantified.

D190 HVDC firming is where the HVDC transfers South Island hydro generation to support North Island demand during periods of low North Island generation. Currently, both the HVDC and the thermal generation in the North Island perform this function.

D191 In a low carbon scenario, Transpower's view is that, over time, South Island generation will play a more significant role in 'firming' North Island intermittent generation, especially wind generation.

D192 The ability of South Island generation to 'firm' North Island demand depends on several factors including:

D192.1 if there is sufficient surplus generation in the South Island;

D192.2 if the South Island generation can compete with schedulable generation in the North Island. Schedulable generation is generation that can be brought into service when required and includes biogas thermals; and

D192.3 if the North Island power system is able to operate without support from significant North Island thermal generation. This is either due to voltage or transient stability constraint issues.

D193 We consider that the HVDC firming role will develop over time and may become more prominent when North Island thermal generation is decommissioned. This is expected to occur in the early 2030s. However, it is also possible that non-fossil fuel thermal generation will be built in the North Island, which could back up any shortfall in intermittent wind generation for example.

D194 In summary, while we agree with Transpower that the HVDC may help firm intermittent generation in the North Island, and that this may occur in the future, Transpower did not quantify the benefit of this.

Transpower's revised proposal HVDC analysis

The effect of Tiwai smelter exit and HVDC upgrade benefits

D195 In its revised proposal Transpower provided further analysis it suggested supports the approval of the HVDC component of NZGP1 stage one. In the updated analysis Transpower undertook sensitivity studies to assess the impact of Tiwai staying until 2034 on the benefits of NZGP1 and calculate the redundancy benefit of the proposed new STATCOM. Transpower tested the following sensitivities:[351]

D195.1 Tiwai closes in 2034 and HVDC stage one is installed by 2027, with the fourth HVDC cable (HVDC stage two) deferred until 2032; and

D195.2 Tiwai closes in 2034 and the HVDC investment (stages one and two) deferred until 2032 and 2034, respectively.

D196 Transpower concluded that:[352]

D196.1 the net electricity market benefits are maximised if Tiwai closes in 2024 and HVDC stage one and stage two are installed in 2027 and 2028 respectively;

D196.2 if Tiwai closure is deferred until 2034, then it is more economic to defer HVDC stage two until 2032 when the existing cables have to be replaced; and

D196.3 if Tiwai closure is deferred until 2034, it is still economic to undertake the HVDC stage one works as soon as possible. The reason for this is that, during RCP4, Transpower is planning to undertake life extension works (refurbishment) on the Haywards synchronous condensers and the presence of a new STATCOM will lift the overall transfer capability of the HVDC link during that time (**redundancy benefit**).

D197 Given our assumption that the Tiwai smelter closure is likely to be deferred beyond 2024, we tested Transpower's third point and discuss our findings below. Table D5 shows the results of Transpower's sensitivity studies on alternative Tiwai smelter closure dates.

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351 Transpower, Proposal, above n 1, p. 17.
352 Ibid, pp. 17-18.

Table D5 Transpower's updated HVDC analysis

	Install STATCOM and Fourth Cable now	Install STATCOM now Delay Fourth Cable	Delay STATCOM and Fourth Cable
STATCOM install date	May 2027	May 2027	Jan 2031
Fourth Cable install date (Stage 2)	May 2028	Jan 2032	Jan 2032
	Gross benefits - unweighted average across scenarios ($ million, NPV to 2022, 7% discount rate)		
Tiwai closes 2024	$668	$622	$540
Tiwai closes 2034	$523	$512	$484
	NPV of NZGP1 Net benefits of Option 14 ($ million)		
Tiwai leaves 2024	$145		
Tiwai leaves 2034		$66	
Tiwai leaves 2034			$65

D198 The benefits set out in Table D5 are those for the NZGP1 project in aggregate rather than the benefits realised by the HVDC investments. Transpower's sensitivity studies show that the highest benefits are realised when the HVDC investments are timed with Tiwai's closure.

D199 If the HVDC stage one is delivered before Tiwai closes, the results of Transpower studies show that although the net electricity market benefits are still positive:

D199.1 the aggregate net electricity market benefits reduce by about 45%; and

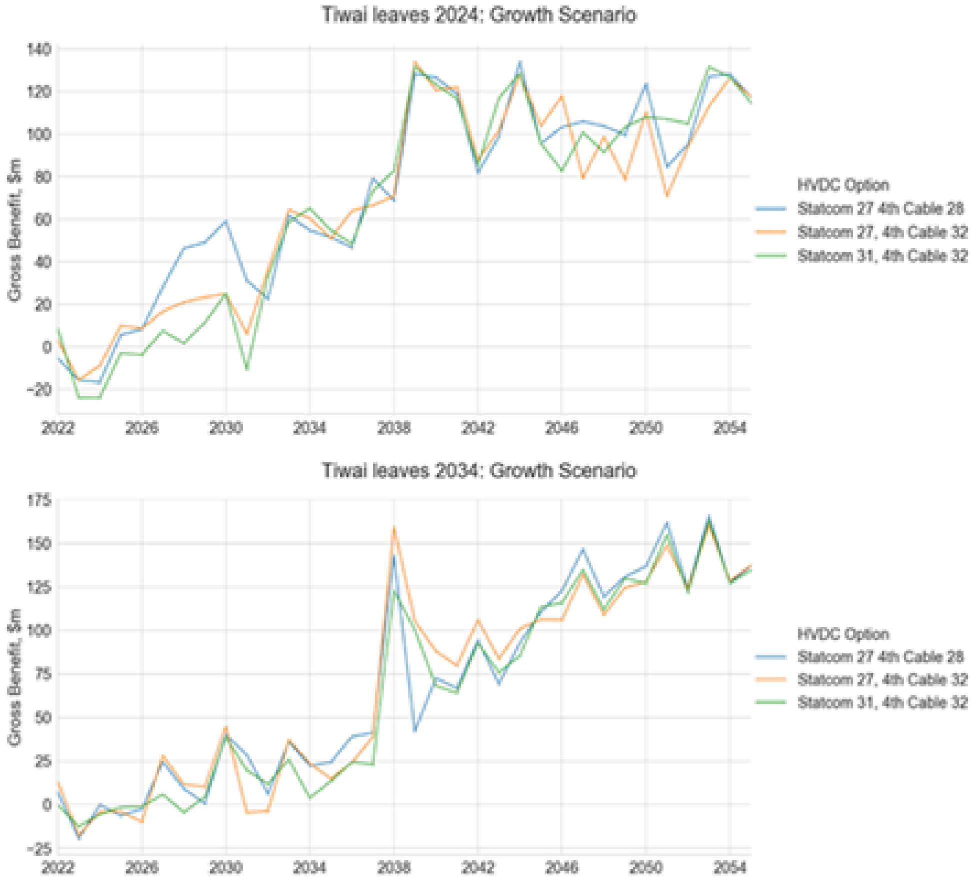
D199.2 the net electricity market benefits are the about the same whether the HVDC stage one investments are made now or deferred until 2034.

D200 Transpower also provided information on the time series of gross benefits associated with the above sensitivity studies for the growth scenario it used in its analysis. Transpower advises that similar trends are observed for other EDGS scenarios.

D201 Figure D4 shows the gross benefits as a time series for the Tiwai closure dates Transpower assessed.[353]

[353] Transpower, Proposal, above n 1, Appendix A in Attachment C, at pp. 57-58.

Figure D4 Undiscounted gross benefits by time for the growth scenario



D202 Transpower concluded that it is still economic to undertake the HVDC stage one works as soon as possible because of STATCOM redundancy benefits.

D203 With reference to Figure D4, the blue line denotes the gross benefits where the HVDC stage one and stage two are commissioned in 2027 and 2028 respectively. Under this investment scenario, the HVDC upgrade will provide STATCOM redundancy benefits when the synchronous condensers are out of service for maintenance.

D204 The redundancy benefit effect is depicted as the separation between the blue lines, and the orange and green lines, between 2027 and 2031 in the 'Tiwai leaves 2024' analysis.

D205 Based on our observations of the Transpower analysis, Figure D4 illustrates that:

D205.1 most of the redundancy benefits arise only if Tiwai closes in 2024 and HVDC stages one and two are delivered in time for the synchronous condenser refurbishment works to occur;

D205.2 if Tiwai does not close in 2024, the STATCOM redundancy benefits are for a shorter period, and their quantum is much lower; and

D205.3 after 2031, there does not appear to be any significant redundancy benefits in either of the two scenarios shown in Figure D4.

D206 Figure D4 also shows some separation between the green and the blue and orange lines for the case where Tiwai remains until 2034. However, the quantum of the separation is less and only for two years.

D207 Our qualitative analysis of Figure D4 does not give us confidence that it is beneficial for HVDC stage one to be installed as soon as possible, given that the Tiwai smelter closure by 2024 is uncertain, highlighted by Transpower's most recent Tiwai smelter exit assumption in its 2023 Transmission Planning Report.

D208 We consider that progressing the HVDC upgrade should be contingent on the HVDC assurance, which includes Transpower being able to quantitatively demonstrate to interested persons a net market benefit for the HVDC upgrade investment.

D209 We expect that for Transpower to progress the HVDC upgrade investment it must demonstrate that the upgrade meets one or more of the HVDC assurance triggers occurring. Following our consideration of draft decision submissions we note there may be other triggers that could justify the decision to upgrade the HVDC. Transpower should not be limited by those it identified in its Addendum given the real focus is on the effect of the trigger.

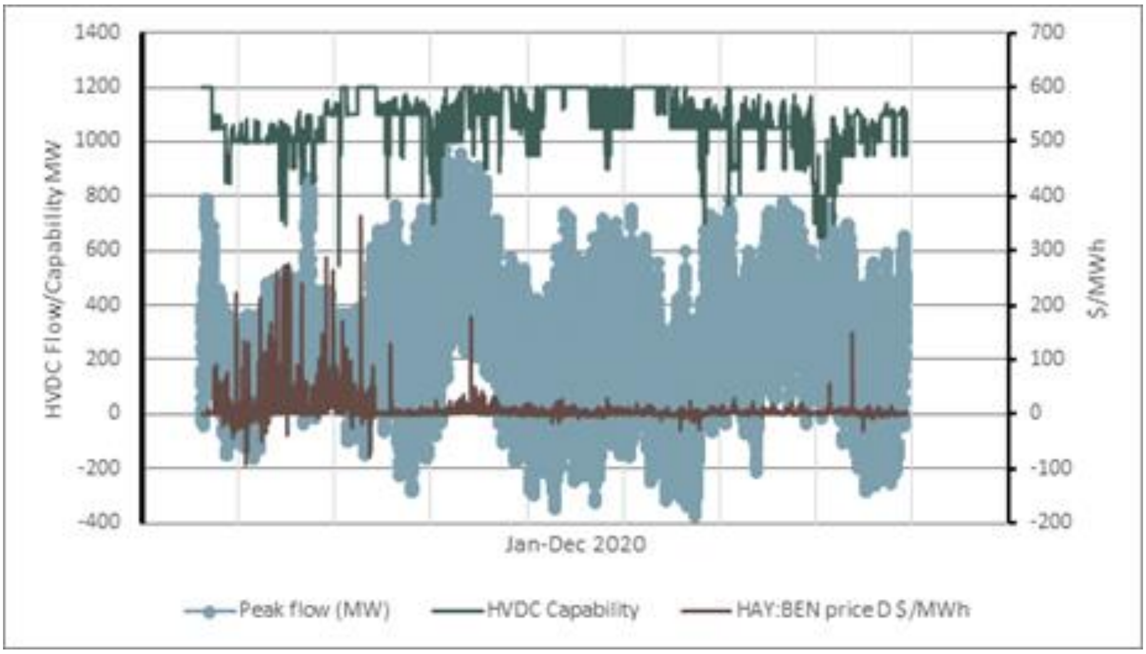
D210 As discussed in Attachment B, we consider that a project will promote the purpose of the Act if the right project is delivered at the right time.

Assessing Haywards synchronous condenser reliability benefits

D211 We carried out our own analysis to assess whether the STATCOM was likely to provide redundancy benefits at Haywards.

D212 For this purpose, we used reliability data for the Haywards synchronous condensers, 2020 HVDC flow data, HVDC operational capability, and nodal price differences between Benmore and Haywards available from the Electricity Authority's website. Our analysis is set out in Figure D5.

Figure D5 HVDC operational capability, HVDC flow and BEN-HAY price differences for 2020



D213 We assume that if the Benmore – Haywards price difference is material, HVDC north flow will be high and/or HVDC operational capability reduced, then the unavailability of the Haywards synchronous condensers could be constraining HVDC transfer levels and affecting the market price.

D214 Figure D5 indicates that:

D214.1 most of the time, the reduced HVDC operational capability may not be significantly affecting the market. This is because north flow is well below the HVDC operational capability limit; and

D214.2 there is a significant nodal price difference between Benmore and Haywards in the summer when compared to the rest of the year and a corresponding reduction in the HVDC operation capability. However, HVDC north flow is not low for most of this period indicating that the reduced HVDC operational capability may not be causing the nodal price difference.

D215 We conclude that the observations from the Figure D5 analysis support our interpretation of the analysis in Figure D4. This indicates that the redundancy benefits of the HVDC stage one investment may be marginal until the Tiwai smelter departs.

Summary – revised proposal HVDC analysis

D216 While we are satisfied that the HVDC investments in NZGP1 are reasonable projects, we are not fully satisfied with the timing of these investments. Given that the Tiwai smelter future will be known soon, we consider that approval of the HVDC stage one investments should be subject to the HVDC assurance triggers.

Summary of our assessment of the proposed investment benefits

D217 We have carried out our own analysis to assess whether the Central North Island, Wairakei ring and HVDC upgrade components of NZGP1 would pass the investment test under their own merits.

D218 We agree that the Central North Island and Wairakei ring investments will likely pass the investment test and appear very good value for money when compared with new transmission lines. We consider that there are likely generation developments that will need to access this increased capacity in the near future.

D219 We are not fully satisfied that Transpower has demonstrated that the HVDC upgrade component of NZGP1 stage one provides a positive net market benefit at this time.

D220 While Transpower provided us with several qualitative reasons, and some qualitative analysis in its updated proposal supporting this upgrade, this was inconclusive.

Our review of Transpower's sensitivity analysis

D221 The Capex IM requires Transpower to perform a sensitivity analysis to test whether the proposed investment is robust to some key assumptions.[354] The Capex IM also lists the parameters that must be varied to assess whether the results of the investment test are robust to variations.[355] These parameters reflect the key assumptions that can have a significant impact on the results of the investment test.

D222 There are two reasons sensitivity analysis is carried out. The first is to ensure that the proposed investment is robust to some of the key assumptions and passes the investment test, and the second is whether the results of the investment test are robust to the selection of the proposed investment when compared to the investment options.

354 Capex IM, above n 2, clause D7.
355 ibid, clause D7(1).

D223 Transpower considered several parameters in its core sensitivity analysis, including:[356]

D223.1 capital costs;

D223.2 ongoing operation and maintenance costs; and

D223.3 discount rate.

D224 Transpower also tested the sensitivity to the Tiwai smelter exit date and HVDC stage two investments, which we discussed from D158 to D169. Transpower also presented some sensitivities around scenario weightings.

Core sensitivity analysis

D225 Transpower presented the results of its sensitivity analysis in its Table 18, and we have reproduced these results in Table D6 for the six investment options considered.[357]

Table D6 Transpower's core sensitivity analysis results ($ million)

Investment option	Investment test	-30% capital cost	+30% capital cost	-30% ongoing costs	+30% ongoing costs	4% discount rate	10% discount rate
10	176	290	62	180	172	545	1
11	150	283	16	153	147	533	-29
12	181	312	51	186	177	583	-8
13	173	327	20	156	191	609	-30
14	145	318	-28	126	164	594	-62
15	175	345	5	158	192	641	-41

D226 Typically, MCP sensitivity analysis "overwhelmingly" supports Transpower's proposed investment. However, for NZGP1 stage one the sensitivity analysis suggests there is no clear best investment option.

356 Transpower, Proposal, above n 1, p.56.
357 ibid, p.57.

D227 These sensitivity analysis results are expected given the economic case for NZGP1 stage one is dominated by:

D227.1 the capital cost impact of the stage two investments, particularly those options with the BPE-TKU duplexing ($189 million) - there is a $346 million change in the net electricity market benefit when the +/-30% capital cost sensitivity is applied in Option 14; and

D227.2 the likely longer-term benefit impact of renewables (sensitivity analysis discount rates of 4%).

D228 Given there is a lot of uncertainty regarding future capital costs and renewables benefits, that uncertainty suggests that project staging is the correct approach in this case because stage two outputs may change depending on how generation developments progress and project capital cost estimates become more certain.

D229 The original intent of the project staging mechanism, introduced in the 2018 Capex IM Review, was to reduce the risks for projects with high levels of uncertainty, specifically uncertainties in project capital costs, and to better manage investment timing and need.[358] NZGP1 is one such project.

D230 We have accepted Transpower's preference for Option 14 over the other options after considering:

D230.1 the unquantified benefits;

D230.2 the potential issues surrounding the capital cost estimation uncertainty of Option 14 BPE-TKU duplexing costs, and

D230.3 the near-term benefit of increased transmission capacity in the Wairakei ring.

D231 We consider that Transpower's reason for its preference for Option 14 should carry weight given the close nature of the investment test results and the significant uncertainties involved.

D232 We conclude that, while the proposed investment is not robust to significant variations in capital costs, the stage two uncertainties are addressed by staging the project, and the project is therefore sufficiently robust to approve the stage one investments.

358 Transpower capex input methodology review Decisions and Reasons, 29 March 2018, para 244, p. 71.

Attachment E NZGP1 updated proposal short-list[359]

Components		Option 10	Option 11	Option 12	Option 13	Option 14	Option 15
HVDC	New HAY reactive support 1200MW	✓	✓	✓	✓	✓	✓
	4th Cook Strait cable 1400MW	✓	✓	✓	✓	✓	✓
CNI	TTU TKU-WKM	✓	✓	✓	✓	✓	✓
	TTU BPE-TKU	✓	✓	✓	✓	✓	✓
	Duplex TKU-WKM	✓	✓	✓	✓	✓	✓
	Duplex BPE-TKU				✓	✓	✓
	TTU BPE-WRK				✓	✓	✓
	BRK-SFD enhance	✓	✓	✓	✓	✓	✓
CNI Supporting	BPE-ONG split	✓	✓	✓	✓	✓	✓
	HLY-SFD protect upgrade	✓	✓	✓	✓	✓	✓
	Replace SPS at TKU	✓	✓	✓	✓	✓	✓
WRK	110 kV EDG-KAW split	✓	✓	✓	✓	✓	✓
	TTU 220 kV EDG-KAW	✓	✓	✓	✓	✓	✓
	TTU WRK-WKM C line	✓	✓		✓	✓	
	Replace WRK-WKM A line		✓			✓	
	New WRK-WKM D line			✓			✓
	WRK sub equip			✓			✓
Total benefit		569	604	632	625	659	685
Total cost		393	454	451	452	514	510
Net benefit		176	150	181	173	145	175

[359] Investments in red text are NZGP1 stage two projects.

Attachment F Acronyms, abbreviations, and terms

F1 This attachment lists the acronyms, abbreviations, and terms used in this paper in Table F1 below.

Table F1 Acronyms, abbreviations, and terms

Acronym	Definition
2012 Capex IM reasons paper	Commission's Transpower Capital Expenditure Input Methodology Reasons Paper, 31 January 2012
2017/18 Capex IM review reasons paper	Commission's Transpower capex input methodology review - Decisions and reasons paper, 29 March 2018
the Act	Commerce Act 1986
Benefits	Electricity market benefits
BBIs	Benefit-based investments
Capex IM	Commission's Transpower Capital Expenditure Input Methodology Determination
CCC	Climate Change Commission
CEO	Chief Executive Officer of Transpower
Code	Electricity Industry Participation Code 2010
Commission	Commerce Commission
CAC	Consumer Advocacy Council
DSM	Demand side management
EDGS	Electricity demand and generation scenarios as published by MBIE in July 2019 at https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-modelling/electricity-demand-and-generation-scenarios/
GEIP	Good Electricity Industry Practice
GRS	Grid reliability standards under Schedule 12.2 of the Code
GXP	Grid exit point

HVDC	High Voltage Direct Current
IEGA	Independent Electricity Generators Association
IMs	Input methodologies under Part 4 of the Act
IPP	Transpower’s Individualised Price-Quality Review Path Determination 2020 [2019] NCC19
Long-list consultation	Transpower’s consultation on its long list of options to meet the investment need of the major capex proposal
MCA	Major capex allowance means the amount of major capex approved by the Commission in relation to a major capex project
MCP	Major capex proposal
MEUG	Major Electricity Users Group
Mvar	Megavolt amps (Reactive)
MW	Megawatt, which is a measure of power
MWh	Megawatt hours, which is a measure of energy
N-1 criterion of GRS	The GRS standard at clause 2(2)(b) of Schedule 12.2 of the Code that provides that with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state following the tripping of one of the transmission assets in the core grid
Net benefits	Net electricity market benefits
Nova	Nova Energy
NPV	Net present value
NTS	Non-transmission solution
NZGP1 stage one	The first staging project to which this MCP relates under the Capex IM
NZGP1 stage two	The second staging project of the NZGP for which Transpower intends to submit an MCP when the investment is needed
PSO cost estimate	The 50th percentile cost, which means there is a 50% probability that Transpower will complete NZGP1 stage one within the P50 cost
Part 4	Part 4 of the Act

Project	Means the staged major capex project proposed by Transpower in the MCP, and for which Transpower intends to submit a further MCP for future stages when those investments are needed
Proposed investment	Means the investment option in the MCP for which Transpower seeks approval
Quantities	Term used by Transpower to describe "quantities of various line components associated with the work packages"
RCP4	the fourth regulatory control period for Transpower (2025-2030)
RFI	Request for information
Scenario variations	Transpower's reasonable variation of the demand and generation forecasts published by the Ministry for Business, Innovation and Employment.
Short-list consultation	Transpower's consultation on its shortlist of investment options for the MCP
SDDP	PSR Inc's SDDP software used by Transpower
SSRs	Solution Study Reports produced by Transpower
STATCOM	A static synchronous compensator is a type of electrical plant that provides or absorbs reactive power
TEES	Transpower's Enterprise Estimation System
Tiwai smelter	Tiwai Point Aluminium Smelter
TPM	Transmission Pricing Methodology is the methodology by which Transpower prices its transmission services developed in accordance with subpart 4 of Part 12 of the Code and specified in Schedule 12.4 of the Code
Transpower	Transpower New Zealand Limited
Transpower IMs	Transpower Input Methodologies Determination 2010 [2012] NZCC 17
TTU	Tactical thermal upgrade
TWh	Terawatt hours

WACC	The weighted average cost of capital we set for electricity distribution businesses and Transpower in our recent cost of capital determination: Cost of capital determination for electricity distribution businesses' 2020- 2025 default price-quality paths and Transpower New Zealand Limited's 2020-2025 individual price-quality path [2019] NZCC 12 (25 September 2019)
Work packages	Term used by Transpower to describe/classify "the scope of works required to deliver the project, grouped, and itemised into various work packages"
WUNI	Transpower's Waikato and Upper North Island Voltage Management major capex project