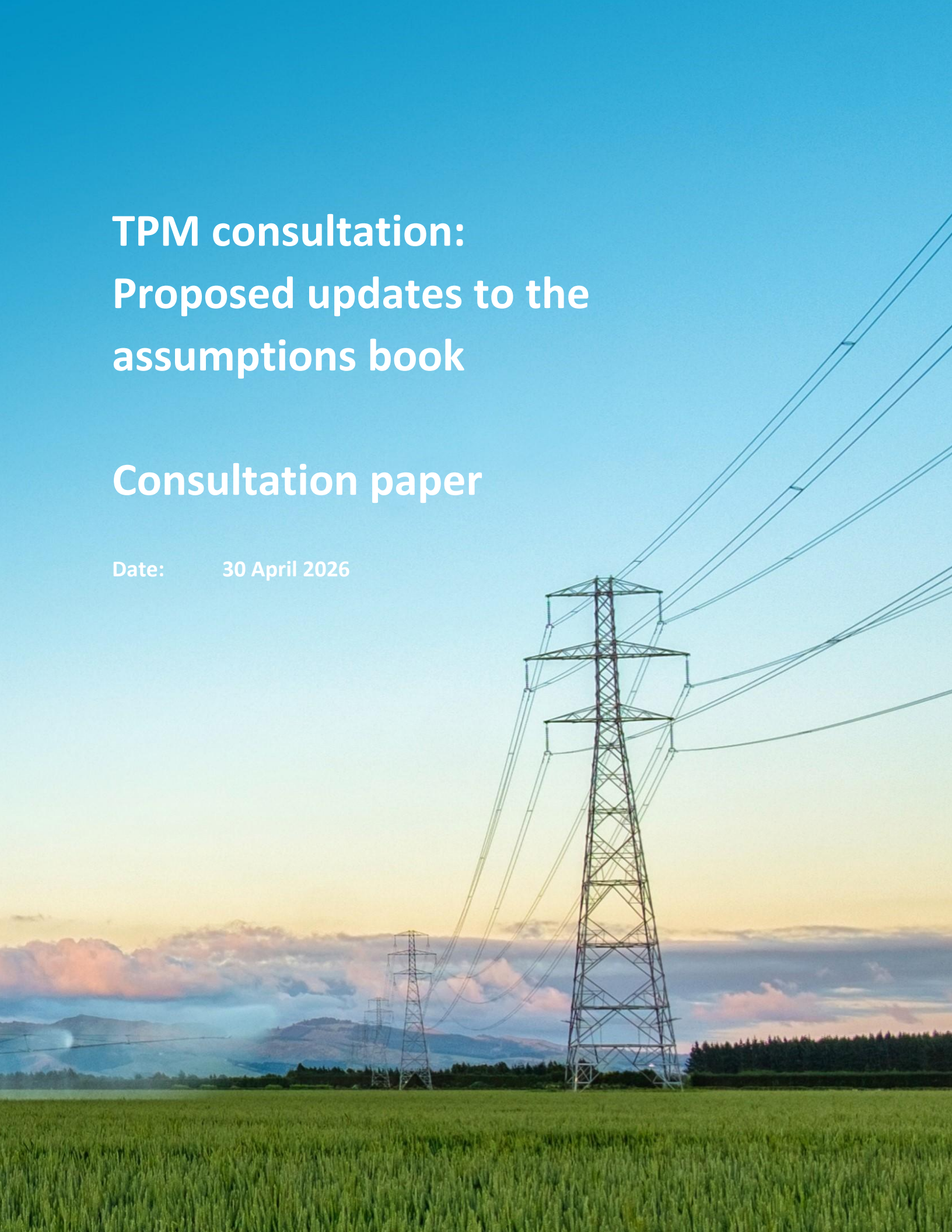
TPM consultation: Proposed updates to the assumptions book

Consultation paper

Date: 30 April 2026



Contents

1 Purpose

1. The purpose of this consultation is to seek feedback on an update to the benefit-based charge (**BBC**) assumptions book (**assumptions book**) under the transmission pricing methodology (**TPM**).[1]

2. The assumptions book contains assumptions and detailed methodologies relating to the allocation and adjustment of BBCs under the TPM. We published the current version of the assumptions book (assumptions book v2.0) in November 2024.[2]

3. Under the TPM, we may publish updates to the assumptions book from time to time.[3] The TPM requires us to consult on updates to the assumptions book subject to certain exceptions.[4]

4. As well as some changes of a minor/tidy-up nature, we are proposing material changes to chapter 2 (Input assumptions for the price-quantity method) and chapter 3 (Processes and methodologies for the standard methods and simple method) of the assumptions book.[5]

5. A summary of material changes to chapter 2 follows:

    - **Costs rebased to current dollars**: All modelling costs and prices have been updated from 2021 to 2025 dollars to reflect more recent evidence and market data.
    - **More realistic market scenarios:** Market scenarios now better reflect future uncertainty, including differences in fuel availability, thermal plant retirements, battery uptake and demand response.
    - **Updates to existing generation:** Existing generation now includes plant commissioned up to 1 January 2025 and uses capacities from the System Operator's latest security of supply information.
    - **Updates to HVDC upgrade date:** The HVDC upgrade, which will increase capacity to 1200 MW north and 950 MW south, has an updated commissioning date of June 2028.
    - **Greater fuel flexibility for existing plant:** Existing gas turbines are assumed to be able to use natural gas, diesel and biofuels, while Rankine units can use coal or biomass pellets.
    - **Revised thermal retirement schedules:** Thermal plant retirement dates have been updated using recent market information and now vary across market scenarios.
    - **Improved renewable generation modelling:** Wind and solar generation profiles are now derived using PSR's Time Series Lab (TSL), improving consistency and future updatability of renewable resource inputs.
    - **Consistent treatment of wind repowering:** Repowering assumptions have been extended across wind farms to improve consistency and reflect current industry expectations.

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1 The TPM is in Part 12 of the Code, available at Electricity Industry Participation Code 2010 | Electricity Authority (ea.govt.nz).

2 Assumptions book | Transpower.

3 TPM clause 38(1).

4 TPM clauses 38(3) and 38(4).

5 Chapter 2 sets out the assumptions used to complete modelling as per the methods set out in chapter 3 of the assumptions book. We are not currently proposing any changes to chapter 4 or 5 of the assumptions book.

- **More detailed gas market modelling:** Domestic gas supply limits, LNG availability and gas storage are explicitly modelled to better reflect New Zealand market conditions.
- **Updated thermal fuel costs:** Thermal fuel costs have been updated throughout to reflect market conditions and to use up-to-date information from the IEA and other sources.
- **Updated biofuel assumptions:** For the Environmental scenario, biodiesel and biomethane are modelled separately, with distinct costs, availability limits and timing based on recent studies.
- **Updated geothermal generation emission rates:** Emission rates for existing geothermal plants are now based on more recent information from the New Zealand Geothermal Association. Emission rates for most future geothermal plants are now based on MBIE's 2020 geothermal generation stack and reinjection rates which vary by market scenario.
- **Updated geothermal generation carbon costs.** Carbon costs are now based on Treasury emission values in the long term and ASX NZU carbon price futures and other sources in the short term.
- **Revised shortage (deficit) cost settings:** Deficit tranche sizes and prices have been updated to reflect new evidence on demand response, diesel peaking costs and scarcity pricing.
- **Generation location modelling clarified:** How generation location is dealt with during generation expansion plan modelling is clarified.
- **More realistic project timelines:** A one-year development lag has been added for all new generation projects, and geothermal construction periods have been shortened, both based on experience.
- **Broader thermal build options:** New thermal generation candidates now include gas turbines, reciprocating engines and a Rankine option, with updated costs and performance data.
- **Updated technology cost assumptions:** Capital and operating costs for new generation and batteries have been refreshed using the Beca and Concept 2025 Generation Stack Report (**2025 Generation Stack Report**).
- **Updated generation cost decline assumption:** Future cost reductions are still assumed, but are now based on the low, base and high-cost trajectories from the 2025 Generation Stack Report, rather than older international sources, to better reflect New Zealand conditions.

6. A summary of material changes to chapter 3 follows:

- **Regional scope of customer groups**: Potential regional customer groups are now only merged within the same modelled region, aligning the process with the purpose of modelled regions.
- **Refined merging approach**: Potential regional customer groups are merged based on similarity in NPB/IRA ratios using a revised method that avoids non-intuitive outcomes where less similar groups are merged ahead of more similar ones.

The impacts on these two changes on BBC starting allocations are expected to be minor.

7. The proposed changes are explained in more detail in section 3 below. We have published with this consultation draft assumptions book v3.0 showing the changes we propose to make. The proposed changes are tracked.

8. We have also published our technical assurance by Robinson Bowmaker and Paul and legal assurance by Simpson Grierson. The technical assurance is dated 22 April 2026 and does not cover a late change to the retirement date for Whirinaki.

9. Following our consideration of feedback from this consultation we will finalise and publish an updated assumptions book (assumptions book v3.0), likely in June 2026.

10. We consider some of the changes to the assumptions book we are proposing would constitute a material change to the current version of the assumptions book – hence the proposed update to v3.0 instead of v2.1.

11. Our proposed modelling assumptions are based on the 2024 version of the Ministry of Business, Innovation and Employment's (**MBIE's**) Electricity Demand and Generation Scenarios (**EDGS**). This was the latest version of the EDGS available at the time of preparing this consultation.

12. We have defined some terms in this consultation paper for convenience. Please also refer to the glossary in the assumptions book. Other terms used in this consultation paper have the meanings given to them in the TPM. All clause references are to clauses of the TPM, unless stated otherwise.

2 Consultation process and scope

2.1 Consultation process

13. The consultation period commences on 1 May 2026. Submissions are due by 5pm on 29 May 2026. This is followed by a period for cross-submissions. Cross-submissions are due by 5pm on 5 June 2026.

14. Please send submissions and cross-submissions to pricingteam@transpower.co.nz.

15. We will acknowledge receipt of all submissions and cross-submissions. Submissions and cross-submissions will be published on our website at https://www.transpower.co.nz/our-work/industry/pricing/transmission-pricing-methodology/tpm-current-consultations.

16. If your submission or cross-submission contains confidential material, please ensure this is clearly identified and provide a version of your submission or cross-submission that can be published. Transpower takes no responsibility for identifying confidential information.

17. Please note that all information provided to Transpower is subject to potential disclosure under the Official Information Act 1982.

18. If you have any questions about this consultation, please send them to pricingteam@transpower.co.nz. Your questions and our responses to them may be published on our website for reference by other submitters and stakeholders.

2.2 Feedback sought

19. Matters relating to the efficacy or merits of BBCs and the TPM generally are outside the scope of this consultation.

20. We welcome any feedback on the proposals in this consultation paper, including on the following questions:

> Q1. Do you agree with the proposed changes to chapter 2 of the assumptions book (section 3.2 below)? If not, why not?
>
> Q2. Do you agree with the proposed changes to chapter 3 of the assumptions book (section 3.3 below)? If not, why not?
>
> Q3. Are there updates to information about your assets or operations we should consider incorporating in the assumptions book?
>
> Q4. Are there any other changes to the assumptions book we should consider making now?

21. With all feedback, please include any relevant supporting evidence or examples.

3 Proposed changes to the assumptions book

3.1 Minor changes

22. We are proposing to make minor changes to the assumptions book including:

- being more specific about how we do some modelling steps
- updating cross references throughout.
- providing clearer descriptions of calculation steps and processes that do not represent material changes to modelling assumptions.
- removing Appendix A, which records material decisions and departures from Transpower's application of the TPM. Modelling assumptions changes (chapter 2)

23. Our proposed material changes to chapter 2 of the assumptions book and the rationale for each change are set out in the table below.

Table 1: Summary of proposed material changes to chapter 2 of the assumptions book and rationale

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
Section 2.2 – Assumptions for economic parameters			
2.2.2.2	Costs and prices based on 2021 dollar amounts (referred to as "$2021" in this document).	Costs and prices based on 2025 dollar amounts (referred to as "$2025" in this document).	Much of the evidence base underpinning our model inputs have been updated to 2025 dollars.
Section 2.3 – Modelling assumptions			
2.3.1	Market scenario formation varies by: • cost decline assumptions for potential new generation • the extent of reinjection of emissions at new and existing geothermal fields • future emissions trading scheme carbon (NZU) prices • the use of zero emission fuel in gas fired generators • the extent to which utility scale batteries are installed alongside new solar farms	Market scenario formation varies by: • cost decline assumptions for potential new generation • the extent of reinjection of emissions at new and existing geothermal fields • future emissions trading scheme carbon (NZU) prices • *the costs and availability of fuels used for thermal plant* • *BESS uptake* • *the retirement schedule for existing thermal plant* • *the availability of demand response*	We have altered our market scenario formation to account for MBIE's 2024 EDGS and changes to our approach to modelling thermal fuels, BESS and demand response. The overall objective of our market scenario formation remains, in that market scenarios should reflect future uncertainty in generation build and provide diversity in terms of the types of generation developed.
2.3.2.2	The HVDC link is upgraded to a capacity of 1200 MW north and 950 MW south in May 2027.	This upgrade is now assumed to happen in June 2028.	To reflect the latest information on this project.
2.3.3.1	Large embedded generators are listed in the Assumptions Book.	The list of large embedded generators has been updated.	The list of large embedded generators has been updated to reflect recently commissioned embedded generation of at least 10 MW.
2.3.4	Existing generators are those existing and commissioned at 1 Jan 2023.	Existing generators are those existing and commissioned at 1 Jan 2025.	To update our generation stack with generators that have been commissioned since 2023.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.4.2	Existing generation capacities are based on MBIE's 2020 generation stack reports supplemented with other sources.	Existing generation capacities are based on the System Operator's 2025 Security of Supply Annual Assessment supplemented with other sources. The BRBPkr (less than 10 MW in capacity) and Te Rapa (retired) are no longer in our generation stack.	The System Operator's Security of Supply Annual Assessment is regarded as a more reliable source of information as it is regularly updated, and its contents are consulted with industry.
2.3.4.3	Existing OCGTs can run on natural gas only. Existing Rankines can run on biofuel only.	Existing OCGTs (except Whirinaki) can run on natural gas, diesel and biofuel. Existing Rankines can run on coal and biomass pellets.	It is technically possible to run an OCGT on natural gas, diesel and biofuel (either biomethane or biodiesel). Most existing OCGTs currently run on natural gas only. We assume that if lower cost fuels become available existing plant will be upgraded to operate with these fuels. Genesis Energy have successfully trialled using biomass pellets in the Rankine units at Huntly.
2.3.4.5	The Te Mihi 2 (100 MW) and Te Mihi 3 (100 MW) geothermal plants replace the Wairakei geothermal plant. The Wairakei geothermal plant is retired in phases. In the first phase this plant capacity is reduced to 38 MW in 2027, and its capacity is further reduced to 0 MW in 2031.	Te Mihi 2 and Te Mihi 3 each have a capacity of 101 MW (Appendix F). In the first phase, the Wairakei geothermal plant is reduced to 67 MW in 2027.	Capacities updated to reflect more recent information on these projects.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.4.6	Regional wind generation hourly capacity factors are based on renewables.ninga (RN). RN profiles are scaled up or down so that their average capacity factor aligns with MBIE's wind generation stack. This scaling follows the formula provided in the Assumptions Book.	Regional wind generation capacity factors are based on PSR's Time Series Lab (TSL) software package. TSL profiles are scaled so that their average capacity factor aligns with MBIE's wind generation stack. The TSL software package performs this scaling.	We derive our wind generation profiles using TSL as it will be more efficient to update this information in the future.
2.3.4.6	Existing wind farm repowering dates and capacities are as detailed in Appendix F.	Repowering dates and capacities are now also provided for the Harapaki, Kaiwera Downs I, Turitea and Waipipi wind farms. For these wind farms, which are all commissioned after 2020, we assume they are repowered after 30 years, with no change in wind farm capacity. We model repowering of Te Rere Hau as one stage, commissioned in 2030.	For consistency, repowering dates and capacities are provided for all wind farms. Regarding repowering for wind farms commissioned after 2030, this change was made for consistency, so all existing wind farms have a repowering date consistent with expected turbine lifespans. Repowering for these plants occurs towards the end of our normal model horizon where we cannot confidently predict replacement capacities. Even if the capacity changes are large, their impact on our modelling is minor, so we take the simplest assumption: the plant capacities remain unchanged. Te Rere Hau is now considered as one stage as this is more consistent with recent market information.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.4.7	Hourly solar profiles are modelled for each grid substation location. Profiles are generated using weather data from RN and then converted to solar power output using the Global Solar Energy Estimator.	Hourly solar generation profiles are generated for 18 regions using the TSL software package.	We derive our solar generation profiles using TSL as it will be more efficient to update this information in the future.
2.3.4.9	Thermal retirements are as detailed in Appendix F.	Updated thermal retirements include: • The Edgcumbe and Hawera cogeneration plants retire in 2026. • TCC now retires in 2026. • The Kapuni cogeneration plant retires in 2034 in low domestic gas supply scenarios. • E3p, the Huntly Rankine units and the Stratford peakers have retirement dates that vary by market scenario. • Whirinaki now retires in 2039.	Changes to retirement dates reflect recent market information, to align with MBIE's 2024 EDGS and to provide market scenario diversity.
2.3.5 - Coal	Coal costs are based on historic market information from Genesis Energy and Enerlytica. Long term coal costs are assumed to remain stable. Coal is available in all market scenarios.	Coal costs are based on the IEA's 2025 Annual Energy Outlook STEPS scenario with adjustments for calorific value and other factors. For the Environmental scenario coal is available up until the end of 2039.	We use the IEA's STEPS scenario as this reflects current expected global trends in energy consumption. Coal availability is restricted in the Environmental scenario to align with this scenario's narrative and to provide market scenario diversity.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.5 - Diesel	Diesel costs are based on long term crude oil price forecasts from the IEA's 2023 Annual Energy Outlook, coupled with a historical correlation between commercial diesel and crude oil. Diesel is available in all market scenarios.	Diesel costs are based on the IEA's STEPS scenario, coupled with a historical correlation between landed diesel and crude oil. For the Environmental scenario diesel is available up until the end of 2039.	We use the IEA's STEPS scenario as this reflects current expected global trends in energy consumption. Diesel availability is restricted in the Environmental scenario to align with this scenario's narrative and to provide market scenario diversity.
2.3.5 – Biomass pellets	Biomass pellets are not modelled.	Biomass pellets are available for use in Rankine units for the Environmental and Innovation scenarios. Biomass costs are based on information from Genesis Energy.	To incorporate biomass pellets in our modelling.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.5 – Natural gas	For all market scenarios, except for the Environmental scenario, natural gas costs increase until 2032. From then onwards they are set to the price of imported LNG, as stated in EY's Gas Supply and Demand Report. For the Environmental scenario natural gas costs are set to ensure that by 2040 the cost of natural gas and carbon exceeds the assumed cost of biofuel. The available quantity of natural gas is unconstrained, and gas storage is not modelled.	We assume two natural gas tranches of supply: • Domestic natural gas • LNG The cost of domestic natural gas is assumed to increase at a rate of 2% year on year. Costs in 2025 are set to average historic prices from 2021 – 2024, as published by MBIE. The quantity of domestic natural gas is restricted and varies across market scenarios. Availability depends on assumed forecasts of domestic natural gas production and non-power generation uses of natural gas. These forecasts are based on information from MBIE. For all market scenarios the Ahuroa Gas Storage facility is modelled. LNG is available for the Reference and Growth scenario from 2028. The cost of LNG is based on the IEA's STEPS scenario.	To better model current settings in the New Zealand natural gas sector.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.5 - Biofuel	Biodiesel and biomethane are assumed to have the same cost, which is based on reports published by Scion and Beca. These fuels are available in unconstrained amounts for the Environmental scenario only.	In the Environmental scenario biofuels are available in the form of biodiesel and biomethane. Biodiesel costs are based on a report from Haley and Twomey. There are no constraints on biodiesel availability. Biomethane costs are based on a report from EECA. Biomethane is available from 2036, although in restricted quantities. Biomethane is assumed to be able to be stored in the Ahuroa Gas Storage facility. The cost and availability of biomethane is taken at the low end and high end of the range of values provided in the EECA report.	To update our approach to modelling biofuels with more recently published information on this fuel. We have taken an optimistic view on the cost and availability of biomethane in the Environmental scenario to align with the Environmental scenario narratives.
2.3.6.1	Biomass pellets are not modelled	Biomass pellets are assumed to have a zero emissions factor.	To incorporate biomass pellets in our modelling.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.6.1	Geothermal generation emission rates are derived from the 2024 New Zealand Geothermal Week Conference. Te Huka is assumed to have 100% reinjection. Geothermal emissions for the Growth Scenario are assumed to be reduced by 50%.	Geothermal generation emission rates, including for Te Huka, are derived from the 2025 NZGA presentation on geothermal carbon emissions. Geothermal emissions for candidate plants (except where reinjection is likely, based on similarly located existing plants) are based on MBIE's 2020 geothermal generation stack and are scaled by the re-injection factors provided in Table 16. These re-injection factors vary by scenario.	To update our geothermal emissions with more recently published information. Geothermal emissions for candidate plants have been refined to cater for uncertainty around the uptake of reinjection technologies and to allow diversity across market scenarios.
2.3.6.2	The low carbon price scenario is based on the 2024 EDGS reference scenario. The medium carbon price scenario is based on the Climate Change Commission's Demonstration Path. The high carbon price scenario is based on the IEA's NZE scenario. For the medium and high carbon price scenarios, carbon prices are interpolated between: • 2023 prices based on the Carbon News NZU index • 2032 prices sourced from the relevant long term price projection.	Carbon prices for the low, medium and high scenarios are based on emission values published by Treasury from the start of 2030. Prior to 2030: • 2025 prices are based on the Carbon News NZU index • 2026 - 2027 prices are based on the ASX NZU carbon price futures • 2028 -2029 prices are assumed to transition to Treasury's emission values.	To update emissions prices based on more recently published information

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.7	Four deficit tranches are defined ($2021): • First 5% at $600/MWh • 5–10% at $800/MWh • 10–15% at $2,000/MWh • 15% at $10,000/MWh	Deficit tranches have been updated. For all market scenarios, except for the Innovation scenario (see below), they are now ($2025): • First 2.25% at $700/MWh • 2.25–4.5% at $950/MWh • 4.5–9.5% at $4,000/MWh • 9.5% at $21,000/MWh	The size for the first two tranches has been aligned to recent research on the potential for demand response in New Zealand. The cost for the first two tranches has been aligned to the LRMC of diesel peaking generation. The size of the third tranche remains the same at 5%. The size of the fourth tranche has increased to accommodate the reduction in size of the first two tranches. The cost for the fourth tranche aligns with recent changes to scarcity pricing in the spot market. The cost of the third tranche was doubled to align with changes to the fourth tranche.
2.3.7	Deficit tranche structure is applied uniformly across all market scenarios.	Larger tranche thresholds, for the first two tranches, are applied for the Innovation scenario: • First 2.75% at $700/MWh • 2.75–5.5% at $950/MWh	Larger tranche sizes have been used to for the Innovation scenario consistent with higher levels of technological innovation for this scenario.
2.3.7	When using Clause 52 of the TPM, prices are capped at the lower of deficit cost or the LRMC of self-supply. The latter is calculated using diesel generation cost assumptions.	When using Clause 52 of the TPM, prices are capped at the lowest cost deficit tranche ($700/MWh). This tranche is calibrated to reflect self-supply costs using diesel generation.	To simplify the application of Clause 52 of the TPM by removing the need for a separate self-supply LRMC calculation. The two approaches are consistent in that the lowest deficit cost tranche is aligned to the LRMC of diesel.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.8.1	The location of new generation is typically determined by modelling grid constraints in OptGen.	Generation expansion modelling will include HVDC capacity constraints and energy losses to account for the balance of North Island and South Island new generation build. To guide the location of generation within each Island, AC transmission constraints, relevant to the investment under consideration, will be considered if that investment might materially influence where new generation is built. If needed, generation in a region may be capped to reflect transmission limits and avoid underestimating an investment's benefits.	More detail has been added to reflect current modelling practice.
2.3.8.2	Information on new projects is from MBIE's generation stack updates and the Transpower connection queue. Geothermal projects assume a four-year construction period. Other construction periods are defined for other technologies. For all technologies no additional delay for investment decisions is specified.	Additional sources of information on new projects include Transpower's internal operations, publicly available information and the 2025 Generation Stack Report. Geothermal projects assume a three-year construction period. An explicit one-year development lag is now added to all project timelines. BESS in the connection queue, other than where committed, is not modelled. The generic BESS projects defined in Section 2.3.8.8 have an earliest commissioning date of 2027.	A shorter construction period for geothermal projects reflects updated project experience A one-year delay across all generation types has been introduced to better represent typical lags between a project securing consents and reaching a final investment decision. We use generic BESS projects rather than connection queue projects as part of our overall simplified approach to modelling BESS as defined in Section 2.3.8.8.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.8.3	Only OCGTs are considered as potential thermal generation candidates. OCGTs are assumed to be capable of using natural gas and biofuel. Eight candidate OCGTs are considered with a total potential capacity of 2960 MW. Costs are sourced from the National Renewable Energy Laboratory.	Potential thermal generation candidates include OCGTs, reciprocating engines and a Rankine candidate. Fuel capabilities for new thermal generation are: • OCGTs can use natural gas, diesel and biogas. • Reciprocating engines can use biofuels and natural gas if located at Huntly. • The Rankine candidate can use coal or biomass pellets. If modelling alternative fuels becomes too computationally complex, only primary fuels may be modelled in expansion planning. Six candidate thermal plants are considered with a total capacity of 3860 MW Costs and heat rates are sourced from the 2025 Generation Stack Report.	An expanded scope of potential thermal generation technologies and fuels corresponds to recent developments within the electricity industry. It also allows our modelling to consider potentially lower cost means of meeting the demand that these thermal generators serve. The potential capacity of candidate thermal generation has been increased to ensure that our thermal generation build is not artificially constrained in our generation expansion models. Costs and heat rates are now based on more up to date information.
2.3.8.4	New hydro generation costs are ($2021) • Capital costs: $5,100/kW • Fixed operating and maintenance costs: $47.5/kW-year Costs are sourced from MBIE's 2011 generation stack.	New hydro generation costs are ($2025) • Capital costs: $9,195/kW • Fixed operating and maintenance costs: $89/kW-year Costs are sourced from the 2025 Generation Stack Report.	Costs are now based on more up to date information.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.8.5	New geothermal generation costs are ($2021): • Capital costs: $4,930 – $9,767/kW • Fixed operating and maintenance costs: $190/kW-year A 20% capital cost reduction is applied to the Growth scenario. Costs are sourced from MBIE's 2020 geothermal generation stack	New geothermal generation capital costs vary by technology and field type ($2025): • $5,600/kW for flash geothermal plants • $6,700/kW for binary plants • A 1.2 cost multiplier is applied for projects on low-enthalpy fields. Fixed operating and maintenance costs are $162/kW-year ($2025). These costs apply across all market scenarios. Costs are sourced from the 2025 Generation Stack Report.	Costs are now based on more up to date information. The new approach acknowledges that smaller binary plants and lower-temperature fields are inherently more expensive. While the capital cost reduction for the Growth scenario has been removed, we encourage geothermal generation in this market scenario through high capital cost reductions (over time) and higher assumed NCG reinjection rates.
2.3.8.6	New wind generation costs are ($2021): • Capital costs: $1,867– $3,042/kW • Fixed operating and maintenance costs: $35 - $50/kW-year Cost information is sourced from a Roaring40s (2020) report.	New wind generation costs are ($2025): • Capital costs: $3,102/kW to $3,777/kW • Fixed operating and maintenance costs: $43/kW-year Costs are sourced from the 2025 Generation Stack Report.	Costs are now based on more up to date information.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.8.7	New solar generation costs are ($2021): • Capital costs: $1,200–$1,700/kW. Near-term solar builds were assumed at the low end of this range. • Fixed operating and maintenance costs: $20/kW-year Cost information is sourced from a study by Alan Miller (2020).	New solar generation costs are ($2025): • Capital costs: $1,825–$1,975/kW • Fixed operating and maintenance costs: $27/kW-year Costs are sourced from the 2025 Generation Stack Report.	Costs are now based on more up to date information.
2.3.8.8	BESS candidates have a charge duration of 2-hour, 4-hour and 8-hour duration. Corresponding capital costs ($2021) are $1451/kW, $2442/kW and $4424/kW. BESS projects exist throughout the core grid. Some BESS projects are associated with potential solar farms and Optgen needs to build both projects together. The extent of this association varies by market scenario. Costs are sourced from the National Renewable Energy Laboratory.	For simplicity, and to improve model convergence, only BESS projects with a 2-hour duration are considered. BESS capital costs are ($2025) $1700/kW. Candidate BESS projects are limited to 14 locations, with at least one BESS project located in each Transpower grid zone. BESS build is linked to wind and solar build. The proportion of BESS to wind and solar varies by market scenario. Costs are sourced from the 2025 Generation Stack Report.	Cost information is now based on more up to date information. Our approach to modelling BESS is intended to align with MBIE's 2024 EDGS and to avoid computationally intensive alternative approaches.
2.3.8.9	For projects sourced from Transpower's connection pipeline, we assume that project costs are equal to average costs across all projects in our generation stack that have the same technology.	For projects sourced from Transpower's connection pipeline, we assume that project costs are equal to the typical costs from the 2025 Generation Stack Report.	The 2025 Generation Stack Report provides typical (or generic) plant costs.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
2.3.8.10	Explicit chronological cost decline assumptions are applied by technology and market scenario (advanced / moderate / conservative). Both capital cost and fixed operating and maintenance costs are assumed to reduce over time. This assumption is based on information sourced from the National Renewable Energy Laboratory.	Chronological cost declines use the 'low', 'base' and 'high' cost scenarios from the 2025 Generation Stack Report.	Chronological cost declines are now based on more up to date information that better reflects New Zealand conditions.

3.2 Standard method changes (chapter 3)

24. Our proposed material changes to chapter 3 of the assumptions book and the rationale for each change are set out in the table below.

Table 2: Summary of proposed material changes to chapter 3 of the assumptions book and rationale

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
3.3.6.13	The described method of finalising regional customer groups includes the possibility of amalgamating potential regional customer groups from different modelled regions.	Regional customer groups are only amalgamated within modelled regions.	Amalgamating regional customer groups across modelled regions complicates the process of finalising regional customer groups and risks producing groups that are non-intuitive and difficult to explain. The purpose of modelled regions is to separate customers into regions that experience similar market outcomes, which supports cost allocations that are broadly proportionate to positive NPB. Amalgamating customers across different modelled regions based on an NPB/IRA ratio is a relatively tenuous way to group beneficiaries compared with the consideration of electrical constraints and broad market impacts that determine modelled regions. In practice, this change will only rarely impact the formation of final regional customer groups, and even then, will only have a minor impact on allocations for the customer groups involved in amalgamation.

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
3.3.6.13	After sorting potential regional customer groups in descending order of NPB/IRA, a group is amalgamated with a previous (higher NPB/IRA) group if the NPB/IRA ratio is >80% of that of the previous group.	Instead of processing each potential regional customer group once in descending order of NPB/IRA, the percentage of NPB/IRA to that of the previous (next higher) group is calculated for all groups. The pair with the highest percentage (i.e. the most similar two groups) are amalgamated if the percentage is >80%. The NPB/IRA ratio is recalculated for the newly formed group after summing both NPB and IRA. The process is repeated until there are no more groups with a relative difference of 80% or more.	The current amalgamation method falls over in the obvious case where, for example, we have three groups with NPB/IRA ratios of 100, 81, and 79. The previous method would amalgamate the first two groups and leave the most similar groups separate. The proposed revised method amalgamates the most similar groups, which better supports the aim of producing allocations that are broadly proportionate to positive NPB.

3.3 Appendix changes

Assumptions book section	Assumptions book version 2.0	Proposed change in assumptions book version 3.0	Rationale for change
Appendix A	Appendix A records material decisions and departures from Transpower's application of the TPM.	Remove Appendix A.	Appendix A is prone to falling out of date and does not contain useful information not already disclosed when we publish our decision documents for starting BBI customer allocations on our website. The TPM does not require the Appendix A information to be in the assumptions book.

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