TRANSPOWER

TPM DETERMINATION:

Assumptions book

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Version history

Version	Published	Key amendments compared to previous version
1.0	15 September 2022	n/a
1.1	16 March 2023	Benefit factors added (Chapter 5), minor updates and errors corrected (Chapters 2 and 3). Version history added.
1.2	14 February 2024	Amendments made to give effect to the Authority's June 2023 amendments to the TPM. Minor technical updates made. Appendices outside this document referenced.
2.0	25 November 2024	Amendments to the input assumptions in Chapter 2, including updates to the standard method rate, the HVDC capacity, the generation stack, the trajectory of future costs of generation, fuel prices and carbon costs, and our future generation expansion scenarios, as well as other refinements to reflect update information. Minor changes, including adding a new Appendix F (a spreadsheet that contains tabulated model input assumptions).
3.0	30 June 2026	Amendments to the input assumptions in chapter 2 and clarifications and minor amendments to the processes and methodologies in chapter 3. Chapter 2 changes include updates to the currency year, market scenario formation, HVDC upgrades, embedded generation, existing generation, thermal decommissioning, fuel assumptions, emissions, deficit costs and new generation. Chapter 3 changes relate to the regional scope of customer groups and a refined customer group merging approach.

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Appendix F **SDDP and OptGen Inputs for BBI Modelling**

Appendices B to F can be found at the following link: https://www.transpower.co.nz/our-work/industry/grid-pricing/transmission-pricing-methodology/assumptions-book.

Chapter 1
Introduction

1.1 Background and purpose

1. The Transmission Pricing Methodology (**TPM**) published by the Electricity Authority (**Authority**) in April 2022 (and as subsequently updated) contains the structural and fundamental aspects of the transmission pricing regime.[1] The TPM includes a role for secondary documentation.[2] Under the TPM's requirements for benefit-based charges (**BBC**s), Transpower must consult on and publish a BBC assumptions book (**assumptions book**).

2. This assumptions book contains the assumptions and detailed methodologies Transpower intends to apply for allocating and adjusting BBCs (calculating starting BBI customer allocations for post-2019 BBIs and adjusting BBCs).[3]

3. This assumptions book covers both of the standard methods (price-quantity method and resiliency method) and the simple method for calculating starting BBI customer allocations for post-2019 BBIs and following a BBC adjustment event.[4] The TPM does not specify what material it must contain. This assumptions book takes a relatively detailed approach, intended to provide greater (up-front) certainty about how BBCs will be allocated and adjusted under the TPM.

4. The assumptions book is not intended to replicate, and cannot change, the fundamental and structural requirements for allocating or adjusting BBCs, which are specified in the TPM itself.

5. All clause references are to clauses in the TPM, unless stated otherwise.

6. Appendices A to F (as amended from time to time) are incorporated into, and form part of, the assumptions book by reference.

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1 The Authority's decision paper and the TPM are available on the Authority's website.

2 Secondary documentation must include the assumptions book (that relates to BBC and is the subject of this consultation) and the Prudent Discount Practice Manual and may include a Reassignment Practice Manual.

3 A post-2019 BBI is a BBI commissioned after 23 July 2019. There are also some pre-2019 BBIs (**Appendix A BBIs**), the starting BBI customer allocations for which are specified in Appendix A of the TPM and therefore do not need to be calculated. However, the assumptions book will be relevant to how the BBCs for the Appendix A BBIs are adjusted.

4 The standard methods are used for high-value (> $30m) post-2019 BBIs. The simple method is used for low-value (≤ $30m) post-2019 BBIs.

1.2 Status of this assumptions book

7. The assumptions book is non-binding, except as otherwise stated in the TPM.
8. However, where Transpower makes a material departure from the assumptions book we must provide information about the departure and consult on it when we consult on our application of the relevant BBC allocation or adjustment methodology.
9. The assumptions and methodologies set out in the assumptions book must be consistent with the Code, including the TPM.

1.3 This assumptions book is a living document

10. The assumptions book is a living document that will be updated from time to time. For example, updates may be appropriate if MBIE updates its electricity demand and generation scenarios (**EDGS**), as Transpower and stakeholders gain experience with the allocation and adjustment of BBCs,[5] and if there are changes to generation nameplate capacities or new generation. Chapter 4 of the assumptions book will be updated for each subsequent simple method period.

11. We note that stakeholders can write to us at any time with information relevant to the content of the assumptions book.

12. We note also that for every high-value post-2019 BBI Transpower will consult on proposed starting customer allocations for the BBC. The proposed starting allocations will reflect future applications of the assumptions book. There may be feedback received and decisions made that flow back to an update to the assumptions book itself.

13. Under the TPM, Transpower must consult with customers on any proposed update to the assumptions book, subject to limited exceptions that mirror those that apply to the Authority's consultation on Code amendments under section 39(3) of the Electricity Industry Act 2010.

14. This means Transpower is not required to consult on an update to this assumptions book if we determine:

    a. the update is technical and non-controversial, or

    b. there is widespread support for the update among customers, or

    c. there has been adequate prior consultation on the update so that all relevant views of customers have been considered.

15. As noted above, Transpower must also consult specifically on any material departures from the assumptions book.

16. Transpower must review the contents of the assumptions book at least every seven years and consider whether any content of the assumptions book is appropriate for incorporation in the TPM. This is to ensure that any assumption or methodology in the assumptions book that proves resilient over time can be assessed for inclusion as a binding requirement for BBC allocation or adjustment.

17. When consulting on amendments to the assumptions book – or on applications of the assumptions book to a BBI – we intend to allow time for both submissions and cross-submissions.

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5 For every high-value post-2019 BBI Transpower will consult on the proposed starting BBI customer allocations for the benefit-based charge. There may be feedback received and decisions made that flow back to an update to the assumptions book.

18. When we update the assumptions book, we update version numbers as follows:

a. by one decimal place (e.g. update from v1.0 to v1.1) where the update is considered to be minor. An example of a minor update would be:

   - an update that has not been consulted on in the circumstances mentioned above, or
   - where consultation has occurred via another channel (e.g. via consultation on proposed starting BBI customer allocations for a particular high-value BBI)

b. by a full version number (e.g. update from v1.1 to v2.0) when a major update has been made. For example, when substantive changes have been made as the result of consultation on the contents of the assumptions book itself.

1.4 Glossary

19. The table below presents the acronyms and terms used throughout this assumptions book. Terms defined in the TPM have the same meanings in the assumptions book.

Term	Meaning
AC	Alternating current
ATB	Annual Technology Baseline
Authority	Electricity Authority
BBI consultation documents	The documents produced to support the consultation on the proposed starting benefit-based investment (BBI) allocations for each high-value post-2019 BBI
BBC	Benefit-based charges
BESS	Battery Energy Storage Systems
Capex	Capital expenditure
Capex IM	Transpower Capital Expenditure Input Methodology Determination [2012] NZCC 2. The latest version at the date of assumptions book v3.0 is here.
CCC	Climate Change Commission
CCGT	Combined-cycle gas turbine
Code	Electricity Industry Participation Code 2010
Constraint	A local limitation in the transmission capacity of the grid required to maintain grid security or power quality
Contingency	An unplanned event in the power system, including loss of a transmission asset
COR	Composite outage rates
CPI	Consumers Price Index
EDGS	Electricity demand and generation scenarios

Term	Meaning
EG	Embedded generator/generation
EIA	Energy Information Administration
EMI	Electricity Market Information
EPNPB	Expected positive net private benefits
FTR	Financial transmission rights, a mechanism to manage locational price risk
GSEE	Global solar energy estimator
GXP	Grid exit point
HVDC link	High voltage direct current inter-island link, the transmission link between the North Island and South Island
IEA NZE	International Energy Agency Net Zero Emissions by 2050 Scenario (NZE)
IRENA	International Renewable Energy Agency
Investment test	The investment approval test under section III of Part F of the Electricity Governance Rules 2003 (now revoked) or the Transpower Capex IM
kVAr	KiloVolt Ampere reactive (reactive power)
kWh	KiloWatt hour (energy)
LRMC	Long-run marginal cost
MBIE	Ministry for Business, Innovation & Employment
MERRA	Modern Era-Retrospective Analysis for Research and Analysis
MWA	Minimum weekly amount
MWh	MegaWatt hour (energy)
NASA	National Aeronautics and Space Administration
NREL	National Renewable Energy Laboratory

Term	Meaning
NZGP	Net Zero Grid Pathways
OCC	Official conservation campaign
OCGT	Open-cycle gas turbine
Opex	Operating expenditure
OptGen	The generation expansion tool used by Transpower. See Software « PSR (psr-inc.com)
PV	Power voltage
Pre-contingent load management	Load management that results from the application of a pre-contingent market constraint.
Pre-contingent market constraint	A security constraint applied by the system operator in the wholesale electricity market, usually limiting transmission flow over one or more circuits, affecting the dispatch and prices.
RAB	Regulatory asset base
RN	Renewables.ninja
RNPB	Regional net private benefit
SDDP	Stochastic Dual Dynamic Programming: The market model used by Transpower. See Software « PSR (psr-inc.com)
SPD	The scheduling, pricing, and dispatch tool used by the system operator for dispatching generators, creating prices, and forecasting dispatch and prices
SPS	Special protection scheme
System condition	The load and generation patterns Transpower uses to highlight transmission issues we can reasonably expect to occur with currently available information and trends. See Transmission Planning | Transpower
TOV	Transient over voltage
TPM	Transmission pricing methodology
TPR	Transmission Planning Report

Term	Meaning
Transpower IMs	Transpower Input Methodologies Determination [2012] NZCC 17. The latest version at the date of assumptions book v3.0 is here, as subsequently amended by this determination.
Transpower IPP	Individual price-quality path economic regulation that applies to Transpower
Transpower Capex IM	The capital expenditure input methodologies (Capex IM) sets out the rules for Transpower proposing, and the Commerce Commission assessing, Transpower's capital expenditure proposals. See Transpower-Input-Methodologies-Determination
TWAP	Time weighted average price
TWh	TeraWatt hour (energy)
VoLG	Value of lost generation
VoLL	Value of lost load
VWF	Virtual wind farm

Chapter 2
Input assumptions for the price-quantity method

2.1 Introduction to this chapter

20. The purpose of this chapter is to specify the numerical input assumptions we will use when applying the price-quantity method (one of the standard methods for calculating starting BBI customer allocations for high-value post-2019 benefit-based investments (**BBIs**)).

21. This chapter is structured in two parts:

    - Section 2.2 contains the assumptions for standard economic parameters for all BBIs under the price-quantity method
    - Section 2.3 contains detailed modelling assumptions, primarily used to calculate market regional net private benefit (**RNPB**) for market BBIs under the price-quantity method. Some assumptions in section 2.3 may also be used to calculate ancillary service and reliability RNPB for ancillary service and reliability BBIs respectively.

22. This chapter does not include assumptions that will change frequently or on an investment-by-investment basis (e.g. BBI-specific changes to the transmission network, demand, and new generation scenarios), which we will present when consulting on the starting BBI customer allocations for individual BBIs.

23. Throughout this chapter we have included background information to help stakeholders understand the assumption and its relevance.

24. Unless otherwise stated, in this chapter "from year x" and "to year y (and similar forms of language) mean from the start of year x and to the end of year y, respectively.

2.2 Assumptions for economic parameters

2.2.1 Discount rate

Assumption

25. We will use a default discount rate (**standard method rate**) of 5% p.a. (pre-tax, real).

Background

26. The TPM requires RNPBs to be discounted to a present value using the standard method rate, reflecting that benefits at the end of the standard method calculation period should be given less weight than those at the beginning due to the time-value of money. The TPM requires the standard method rate be the discount rate used in the investment test (if a tested investment), otherwise:

    a. the rate specified in this assumptions book, or

    b. if there is no applicable rate in the assumptions book, the rate in clause D6(3)(a) of the Transpower Capex IM.

27. The 5% p.a. rate is chosen for consistency with clause D6(3)(a) of the Transpower Capex IM, which prescribes a default discount rate of 5% to be used in the investment test when undertaking a cost-benefit analysis for different investment options.

28. We use a 7% discount rate as an input to OptGen (see section 2.3), which influences the timing of new generation.

29. As generation build decisions are made by generators, and generators typically have higher required rates of return, we have retained our original assumption of a 7% discount rate for the purposes of generation expansion modelling.

2.2.2 Assumptions around cash flows

2.2.2.1 Inflation and escalation

Assumption

30. RNPB is specified in real terms, which means that inflation is not applied to future RNPB and is calculated according to the prices of inputs in the year the analysis is prepared.

Background

31. Inflation and escalation are often confused. Inflation is defined as an increase in general prices throughout the full economy. Escalation refers to an increase in the cost of inputs relevant to an activity. The rate of escalation can be different to the inflation rate, and the rate of escalation may differ between inputs. It may therefore be appropriate to include escalation in the analysis where this is clearly forecast.

32. No adjustments to the standard method rate are made to account for future inflation or escalation, as the standard method rate is a real discount rate. In other words, our modelling is done in real terms.

2.2.2.2 Currency year

33. All costs and prices in this assumptions book are specified in 2025 dollar amounts unless otherwise stated. We undertake modelling using inputs specified in 2025 dollar amounts.

34. When necessary, we use June quarter consumers price indices (all groups) (CPI) to transform dollar amounts between years. Table 1 lists conversion factors (rounded to 3 d.p.) to transform 2025 dollar amounts to other years based on the Stats NZ September 2025 release[6].

Table 1. Currency Year Conversion Factors

To transform 2025 dollar values to	Multiply by (3 dp)
2021	0.828
2022	0.889
2023	0.943
2024	0.974
2025	1.000

Background

35. The generation and fuel costs used as model inputs were updated in 2025 and are specified in 2025-dollar amounts. However, some of the inputs are based on an older evidence base. For these older costs we convert values to 2025 dollars using the unrounded conversion factors specified in Table 1.

2.2.2.3 Taxes

Assumption

36. We assess RNPB as pre-tax.

Background

37. We assess RNPB as pre-tax for consistency with the investment test and the standard method rate.[7]

6 Consumers price index: September 2025 quarter | Stats NZ (2025)

7 While the Capex IM does not explicitly specify the discount rate as pre-tax, real, it was in the original grid investment test (the predecessor to the investment test), and it has been our standard practice to interpret the discount rate as pre-tax, real since then.

2.2.3 Standard method calculation period

38. This section describes how we determine when the standard method calculation period (the analysis period for calculating RNPB) for a BBI begins, its duration, and the year the RNPB is discounted to (time zero).

Assumption

39. The TPM requires the duration of the standard method calculation period to be the lesser of 20 years or the end of the useful life of the BBI. To determine the useful life of the BBI, we use the physical asset lives used to calculate depreciation and revenue under the Transpower IMs.[8] The standard physical asset lives from the Transpower IMs are listed in Table 2.

Table 2. Standard Physical Asset Lives from Transpower IMs

Asset	Useful life
Substations	55
Transformers	55
Oil Containment	45
Switchgear	45
220/110/66 kV Two Zone Bus Protection	15
22/11 kV Neutral Earthing Resistor	45
Transmission Lines	55

Background

40. The TPM requires the standard method calculation period to begin on the first of January after the effective full commissioning date of the BBI, and the year to which the RNPB is discounted (**time zero**) to be the year in which the effective full commissioning date occurs (i.e. always one year before the start of the standard method calculation period).

41. The effective full commissioning date is the date by which we expect the BBI will be in a commissioning state sufficient to release all of the BBI's principal benefits. This date will be on or after the BBI's expected commissioning date (the date the first asset or transmission alternative comprised in the BBI is commissioned) and may be before the BBI's expected full commissioning date (the date the last asset or transmission alternative comprised in the BBI is commissioned).

42. The standard method calculation period for a BBI is depicted in Figure 1.

[8] Schedule A, Transpower IMs.

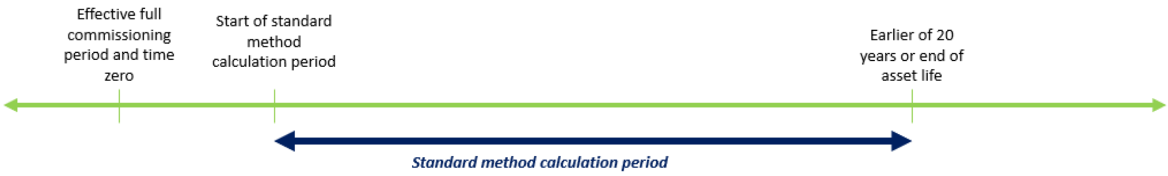

Figure 1. Standard Method Calculation Period for BBI

2.3 Modelling assumptions

43. We use SDDP (developed by PSR[9]) as our wholesale market model. SDDP simulates the wholesale electricity market by calculating a least cost optimal dispatch over the required time horizon (i.e. the standard method calculation period). The costs being optimised by SDDP include the variable and fixed system operating costs (e.g. generation fuel costs) plus penalties for the violation of constraints (e.g. hydro spill penalties).

44. We also use PSR's OptGen model[10] to determine the location, timing, and technology of new generation, which is an important input to the wholesale market model. We have included some of the key assumptions used by OptGen in section 2.3.8.

45. Detailed model input assumptions are provided in Appendix F – SDDP and OptGen Inputs for BBI Modelling with the rationale and data sources explained in this document.

2.3.1 Market scenario formation

Assumption

46. We use market scenarios that are variants of MBIE's 2024 EDGS[11]. Most of the modelling assumptions described in this chapter relate to electricity supply and are largely consistent between market scenarios. However, we have taken steps to promote diversity in terms of the type of generation developed through our variation of EDGS. The market scenarios vary according to:

    a. the cost declines applied to potential new generation stations (section 2.3.8.10),

    b. the extent of reinjection of emissions at new geothermal fields (section 2.3.6.1)

    c. BESS uptake (section 2.3.8.8)

    d. future emission trading scheme carbon (NZU) prices (section 2.3.6.2)

    e. the cost and availability of fuels used for thermal plant (section 2.3.5)

    f. the retirement schedule for existing thermal plant (section 2.3.4.9)

    g. the availability of demand response (section 2.3.7)

47. Demand growth also varies with each market scenario variant. This assumption book does not include demand assumptions for each market scenario as these will be developed and consulted on for each BBI. For illustrative purposes, we have included results from MBIE's 2024 EDGS demand forecast (gross electricity demand) in the first row of Table 3.[12]

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9 Software « PSR (psr-inc.com).

10 Software « PSR (psr-inc.com).

11 Electricity Demand and Generation Scenarios: Results summary | MBIE (2024)

12 Because we update the demand forecast each year, we have not included specific values in the assumptions book.

Table 3. Key market scenario assumptions

	Reference	Growth	Constraint	Environmental	Innovation
Electricity demand in 2050 (MBIE's 2024 EDGS)	62.1 TWh	71.7 TWh	53.6 TWh	68.6 TWh	72.1 TWh
New generation cost	'Base' cost scenario for all generation	'Low' cost scenario for geothermal and 'Base' cost scenario for other generation	'High' cost scenario for all generation	'Base' cost scenario for all generation	'Low' cost scenario for all generation
Geothermal generation	Low rates of reinjection	Medium rates of reinjection	Low rates of reinjection	High rates of reinjection	Medium rates of reinjection
BESS development	Medium	Medium	Medium	High	High
Carbon prices	Use "low" carbon price scenario	Use "medium" carbon price scenario	Use "low" carbon price scenario	Use "high" carbon price scenario	Use "medium" carbon price scenario
Domestic gas supply forecast	Low	High	Low	Low	High
Non-power generation gas consumption	High	High	High	Low	Low
LNG availability	Available from the start of 2028	Available from the start of 2028	Not available	Not available	Not available
Coal and diesel availability	Both available	Both available	Both available	Both available through to the end of 2039	Both available
Biomass pellet availability	Not available	Not available	Not available	Available	Available
Biofuel availability	Not available	Not available	Not available	Biodiesel available and Biogas available from	Not available

	Reference	Growth	Constraint	Environmental	Innovation
				the start of 2040	
Thermal plant retirements	Later decommissioning of Huntly unit 5, earlier decommissioning of Rankine units		Earlier decommissioning of Huntly unit 5, later decommissioning of Rankine units		
Demand response availability	Medium	Medium	Medium	Medium	High

Background

48. We are required to use market scenarios when calculating RNPB. The market scenarios in this assumptions book are based on MBIE's 2024 EDGS. These have been further varied to incorporate updated information on current market conditions and outlooks. We have also made efforts to increase generation diversity across our supply assumptions to promote varied, but plausible, generation outcomes.

49. The market scenarios are consistent with the overall theme of MBIE's 2024 EDGS shown below:

    a. Reference: Current trends continue

    b. Growth: Accelerated economic growth

    c. Constraint: Slower economic growth

    d. Environmental: Sustainable transition

    e. Innovation: Improved technologies are developed.

50. As described in Section 3.3.2 we may change (including adding or removing) market scenarios for any given BBI. Any changes or additions to the market scenarios will be disclosed when we consult on the starting BBI customer allocations for the BBI.

2.3.2 Transmission network

2.3.2.1 Existing network

Assumption

51. Transmission network properties, including the bus voltage, line resistance and reactance, and the line limits are from Transpower's asset capability information system, which is the same system that the grid owner uses to provide network information to the system operator.

Background

52. The asset capability information system is the best representation of the transmission network.

2.3.2.2 Changes to the network

Assumption

53. We assume an HVDC capacity of 1071 MW for north flow, and 762 MW for south flow.

54. From June 2028, we assume limits of 1200 MW north and 950 MW south.

55. From January 2032, we assume limits of 1400 MW north and 950 MW south.

Background

56. The current HVDC capacity is 1200 MW for north flow and 850 MW for south flow. However, there are constraints on the HVDC to ensure system security that can limit transfer to below these limits due to the configuration of the network and the availability of HVDC ancillary equipment. The HVDC limits we have used to determine this assumption are based on Transient Over Voltage (**TOV**) and Power Voltage (**PV**) limits (as described in Transpower's Bipole Operating Policy) applied to the forward looking and final pricing schedules in the market system (on average between December 2015 and November 2021 (inclusive)). The TOV and PV limits result in reductions of HVDC capability due to outages of DC and AC equipment that provide reactive support. Because there are several components affecting the limits and because HVDC transfer could frequently be high in the future, due to increased penetration of intermittent renewables, it is unlikely that outages can be re-scheduled to prevent these limits from binding with the current reactive components that make up the HVDC system.

57. We model the first HVDC upgrade in June 2028, with the limits increasing to 1200 MW for north flow, 950 MW for south flow. With our proposed investment in a new STATCOM at Haywards as part of our Net Zero Grid Pathways (**NZGP**) 1.1 Major Capex Proposal there will be additional reactive support, enhancing the transport of electricity across the HVDC, such that it is possible to reach the HVDC's current capacity of 1200 MW for north flows and increasing the south flow capacity to 950 MW.

58. We model the addition of a fourth Cook Strait cable in January 2032 that increases the HVDC north flow limit to 1400 MW.

59. The timings of the HVDC upgrades are based on information in our HVDC Link Upgrade Programme Major Capex Proposal[13], and as reflected in our consultation on BBC starting allocations for the HVDC Reactive Support BBI. [14]

2.3.2.3 HVDC transmission losses

Assumption

60. We approximate the loss curve for HVDC transfers in tranches with linear losses. We use the incremental (i.e. marginal) losses in each tranche. The losses for the existing and future states of the HVDC are shown in the "HVDC losses", "HVDC losses 1200MW" and "HVDC losses 1400MW" tabs of Appendix F.

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13 HVDC link Upgrade Programme Major Capex Proposal | Transpower (Sep 2025). Refer to Attachment 6: Benefits modelling, Section 2.1. The 1400 MW capacity upgrade installation date has been specified as January 2032 to account for the commissioning of the replacement control system as noted in footnote 11 of this attachment.

14 NZGP1.1 – Updated CNI & HVDC Reactive Support proposed starting BBI customer allocations, Consultation paper | Transpower (Feb 2026).

Background

61. HVDC loss curves are calculated from a simple DC circuit model which includes Pole 2, Pole 3 and an earth return. We assume balanced loading of the poles up to the nominal operating limit of Pole 2, and beyond this unbalanced loading.

62. We assume the circuit parameters listed in Table 4 for the existing HVDC and 1200 MW configuration. The circuit resistances are midpoint estimates across a cold/hot operating range.

Table 4. HVDC Circuit Parameters

	Resistance (ohms)	Voltage for north transfers (kV)	Voltage for south transfers (kV)
Pole 2	11.3255	350	342
Pole 3	11.0755	350	350
Earth return	1.1	NA	NA

63. We assume that following the upgrade of the HVDC to 1400MW the resistance of both poles is equal to the existing resistance of Pole 3 (for the existing HVDC the cable configuration is the cause of resistance variance between poles).

2.3.2.4 AC transmission losses

Assumption

64. Transmission losses on the AC network are included in our demand forecast rather than as an endogenous variable in SDDP. To account for the additional generation required due to AC losses, we add an additional 2.85% on to North Island demand and 3.85% on to South Island demand.

Background

65. We typically model AC transmission losses as an increase in demand rather than as a function of transmission flow because:

    a. modelling AC transmission losses as a function of transmission line flow significantly increases SDDP's run time, and

    b. increasing demand instead makes assessing and reviewing the outputs of SDDP more straightforward (and therefore less prone to error), because prices are the same across the grid without losses, other than for transmission constraints.

66. In general, we do not expect this assumption to materially affect RNPB unless loss benefits form a large proportion of the efficiency benefits of a BBI and we are using clause 52 of the TPM. Where this is the case, we will reassess the materiality of this assumption, and the practicality of alternative assumptions.

2.3.3 Demand

Assumption

67. We have not included demand forecasts in the assumptions book as they are updated annually based on new information from customers and consumers. We will use demand forecasts for calculating RNPB that are consistent with those used for the application of the investment test to the BBI.

Background

68. We will provide information about the demand forecasts on a project by project basis.

69. At a high level, we produce forecasts at a half hourly level that we aggregate into hourly blocks, and may aggregate further depending on the requirements of a specific investigation.

70. We use a two-stage process to produce forecasts. In the first stage we forecast underlying demand growth. This relates to "business-as-usual" growth and considers feedback from electricity lines businesses. In the second stage we forecast the effect that drivers such as electric vehicles, residential solar photovoltaic panels, residential battery storage, and electrification of industrial processes may have on future half-hourly demand. Stage 2 of the method is assumption driven, in that the model forecasts the effect that various uptake rates of these new drivers will have on demand. National electric vehicles, residential solar, process heat, and battery storage uptake forecasts are from (or reasonable variations of) the EDGS.

2.3.3.1 Embedded generation

Assumption

71. We model the following embedded generation (**EG**),[15] which means we model the loads at these GXPs as gross load and later calculate the net benefit/disbenefit to the gross load and embedded generation (see chapter 3, paragraphs 408 to 412 for more detail on this process). We only model EG that meet the definition of "large plant" in the TPM (Table 5).

Table 5. Large Embedded Generators

Transmission node	Associated EG	Source	Transmission customer
ASB066	Highbank	Section 4.2.2 of EA Networks AMP 2021	EA Networks
ASB066	Lauriston	Section 4.2.1 of EA Networks AMP 2025-2035	EA Networks

15 In this context, embedded generators are any generator >10 MW not connected to the transmission grid – i.e. generators connected to distribution networks or behind the meter of a major consumer. Commercial and residential-scale generators are modelled as part of our demand forecast.

Transmission node	Associated EG	Source	Transmission customer
BPE220	TaraW1	Table 15.41 of Powerco AMP 2021	Powerco
EDG110	RangitaikiLS	Section 2.4.1 of Horizon AMP 2025-2035	Horizon
EDG220	Edgcmb (Bay Milk)	Section 2.4 of Horizon AMP 2024-2034	Horizon
GLN220	Glenbrk[16]	Transpower operational data	NZ Steel
HLY220	S_Taiohi	Section 2.4 of WEL Networks AMP 2025	WEL Networks
HLY220	Rotohiko	Section 2.4 of WEL Networks AMP 2025	WEL Networks
HWA110	Hawera (Whareroa)	Transpower operational data	Whareroa Cogeneration Limited
HWB220	Waipori1A and a unit of Waipori2A (unit 1)[17]	Table 3.6 of Aurora AMP 2024 and information from Manawa Energy	Aurora (for Waipori at HWB)
HWB220	Mahiner_s1	Table 3.6 of Aurora AMP 2024	Aurora
KAW110	Kawerau_TAM, Onepu_TA2, Onepu_TA3, Onepu_TOPP1, and Onepu_KA24	Section 2.4 of Horizon AMP 2024-2034 and Transpower operational data	Horizon (Kawerau_TAM) and Norske Skog
KOE110	Kaitaia Solar Farm (Kohirā)	Section 2.5.2.1 of Top Energy AMP 2024	Top Energy
KOE110	S_TwinRivers	Section 2.5.1 of Top Energy AMP 2025	Top Energy

16 Note, this generating station is partially embedded but is modelled as a single generating station in SDDP.

17 See paragraph 111 for a full description of how we model the Waipori scheme.

Transmission node	Associated EG	Source	Transmission customer
KOE110	S_Pukenui	Section 2.5.1 of Top Energy AMP 2025	Top Energy
KOE110	Ngawha and Ngawha3	Section 2.5.2.2 of Top Energy AMP 2024	Top Energy
KPI110	Kapuni[18]	Transpower operational data	Nova Energy
KPU066	S_Whitianga	Transpower operational data	Powerco
LTN220	TaraW2	Table 15.41 of Powerco AMP 2021	Powerco
MAT110	Aniwhenua	Section 2.4 of Horizon AMP 2024-2034	Horizon
MHO110	Mangahao	Section 3.4.4 of Electra AMP 2024	Electra
MTO110	TePunaMauri	Transpower operational data	NorthPower
MTO110	S_GoldenStai	Transpower operational data	NorthPower
NMA220	White Hill	Electricity Authority's list of existing generation plants	Powernet
ROT110	Wheao	Transpower operational data	Unison
STK066	Cobb	Section 3.2 of Network Tasman AMP 2024	Network Tasman
TGA110	Kaimai	Table 15.41 of Powerco AMP 2021	Powerco

18 We model Kapuni cogeneration at KPI, but the load at KPA. KPI is connected to KPA by a single spur line so this is electrically equivalent. We map Kapuni cogeneration to KPA when calculating market benefits and disbenefits – see section 3.3.6.

Transmission node	Associated EG	Source	Transmission customer
TWH220	Te Uku	Table 1.2.4 of WEL AMP 2021	WEL Networks
WIL220	Mill Creek	Section 3.4.4 of WE AMP 2022	Wellington Electricity
WKM220	Mokai[19]	Table 6.19 of TLC AMP 2023	Mercury
WRK220	Rotokawa and Tauha1	Section 4.1.3 of Unison AMP 2024	Unison

Background

72. At most GXPs we model net demand – i.e. demand as measured at the grid exit point. However, at the above GXPs we model embedded generation (**EG**) to reflect possible changes to the operation of EG in response to the different system conditions modelled in SDDP, which is likely to result in more accurate RNPB than modelling net demand. We do not attempt to model all EG because smaller EG are represented as reductions to net demand as measured at the GXP.

73. In the first stage of this process, the base gross GXP demand is obtained from the shape of normalised recent load profiles. Corrections are made for weather induced or unplanned outages and industrial curtailments. These profiles only inform the initial shape of the load profiles that are subsequently scaled and altered through our demand forecasting process to align with top-down base peak and energy forecasts and subsequently changed to account for changes that will occur due to the uptake of products such as electric vehicles, solar photovoltaic panels, and batteries. As such, the profiles are updated and changed through the demand forecasting process.

74. Once the total gross profile has been determined by modelling other components, the net profile is determined by netting off the EG (i.e. subtracting an EG profile from the gross profile).

2.3.4 Existing Generators

75. This section describes our assumptions for existing generators. At the date of this version of the assumptions book, existing generators are those existing and commissioned at 1 Jan 2025.

19 Note, Mokai is not embedded but supplies some load to The Lines Company. The transmission charges for both Mokai generation and The Lines Company load at Whakamaru are recovered from Mercury; therefore, the transmission customer for this generator is Mercury.

2.3.4.1 Generation outages

Assumption

76. We model generation outages as a fixed constant deduction from plant capacity, such that the capacity represents the average available capacity over time after accounting for planned and forced outages. Exceptions to this are:

    a. thermal peaking stations are de-rated for forced outages only, as we generally expect scheduled outages to occur outside peak periods

    b. wind and solar are not de-rated, as capacity factors for intermittent plant is usually inclusive of outages

    c. batteries are not de-rated as SDDP does not currently have the ability to de-rate batteries.

77. Our generation outage assumptions for each existing station are presented in the following sections.

Background

78. Outage rates are implemented in SDDP for each station using composite outage rates (**COR**). The assumed COR values are listed in the tables in Appendix F. SDDP multiplies each station's maximum capacity by (1-COR/100).

79. It would be more precise to model the variation of plant capacity throughout the year that we expect to occur due to planned generation outages. However, this would require determining a maintenance schedule which would add complexity to the modelling, a degree of false precision, and make interpretation of results more difficult. In particular, we would need to consider how generation outages would be optimally scheduled, which would ideally need to consider market conditions at the time of the outage (which is not possible in SDDP).

2.3.4.2 Generation capacities

Background

80. There is not a consolidated and regularly updated public summary of information, including generation capacities, for existing generation units. For most plants, we have used the System Operator's 2025 Security of Supply Annual Assessment (SOSA)[20] and em6 data[21] to specify the capacity of the existing generators that we model. For a small number of geothermal stations, SOSA and em6 report aggregated capacities that do not align with

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20 2025 Security of Supply Annual Assessment | Transpower (2025). Refer to "2025 SOSA – Final Supplementary Data – Final Version.xlsx"

21 https://app.em6.co.nz/Generation

individual generator units; therefore, supplementary sources were used to disaggregate these totals.[22] [23]

81. Our assumptions for each existing station are presented in the following sections and Appendix F.

2.3.4.3 Thermal

Assumption

82. The thermal generators are detailed in the "Existing thermal" tab of Appendix F.

83. Weekly generation for cogeneration plants is given in the "Cogeneration" tab of Appendix F.

84. The following plants are modelled as unit commitment, which means that a plant must either generate for the entire stage or not generate at all for that stage (a stage is either one week or one month depending on the execution options within the model). The following plants have a unit commitment and a minimum generation constraint, which is based on historical data and given in the "Existing thermal" tab of Appendix F:

   a. Taranaki Combined Cycle

   b. Huntly Unit 5 (E3p)

   c. Huntly Unit 1

   d. Huntly Unit 2

   e. Huntly Unit 4 – we have also added a start-up cost of $10M to this unit, treated as a "soft constraint" to disincentivise operation, but not included as a cost in the calculation of producer benefits (see section 3.3.6.10).

85. All thermal plants are modelled as being able to use a primary fuel. Some existing thermal plants are also modelled as being able to use alternative fuels where these are lower cost than the primary fuel, or the primary fuel is unavailable. Table 6 outlines fuel options for existing thermal plant.

Table 6 Thermal generation fuel options

Generation type	Primary fuel	Alternative fuels
CCGT	Natural gas	N/A

22 At Onepu, SOSA reports a single 60 MW Kawerau Onepu unit, while em6 reports only the aggregated 'KAW110 ONU' value that represents (in our stack) Onepu_KA24, Onepu_TA2, Onepu_TA3 and Onepu_TOPP1. Additional generation breakdown sourced from Kaimai Hydro-Electric Power Scheme, Fast-Track Approvals Act Application for Resource Consent | Manawa Energy (2025)

23 At Wairakei, SOSA reports a combined 'Wairakei Net' capacity of 137 MW for Wairakei A, B and the binary plant, while em6 aggregates these as WRK2201 WRK0 whose maximum generation is approximately 140 MW. Plant information sourced from Contact invests to redevelop Wairakei | Contact Energy (Nov 2024).

Generation type	Primary fuel	Alternative fuels
OCGT (excluding Whirinaki)	Natural gas	Diesel, Biofuel[24]
Whirinaki OCGT	Diesel	N/A
Rankine	Coal	Biomass pellets

Background

86. Thermal plant characteristics are based on MBIE's thermal generation stack[25] with the modifications and exceptions noted below.

87. The variable operating and maintenance costs provided in MBIE's thermal generation stack have been inflation adjusted to 2025 dollar amounts.

88. Composite outage rates are based on plant availability factors in MBIE's thermal generation stack with the following exceptions:

    a. composite outage rate for peaker units (P40 (Huntly Unit 6), Whirinaki, SFDOCGT (Stratford Peakers), McKee, Junction Road, and Bream Bay). These are set to 3% to align with the Authority's Security Standards Assumptions Document[26]

    b. composite outage rate for the Glenbrook cogeneration plant. Outage rates are set so that annual production match recent historical operation

    c. composite outage rate for other cogeneration plant (Kapuni, Hawera, and Edgecumbe). These are set to zero as these plants have an assumed weekly generation profile based on recent historical operation.

89. Cogeneration plants often have dispatch patterns that do not align with expected (ordinary) behaviour. This is because they are heavily influenced by circumstances external to the electricity market. We use two approaches for dealing with cogeneration:

    a. Glenbrook is modelled with a pseudo fuel type called "process heat" which has zero cost and zero emissions. Plants with this fuel type are de-rated (using a composite outage rate) such that they produce an annual energy output consistent with historical production of the plant. The profile of these plants is flat throughout the year

    b. Kapuni, Hawera (Whareroa), and Edgecumbe are modelled with the actual fuel type retained (natural gas) but the plant is given an assumed weekly generation pattern derived by taking an average of historical data for recent years (See the "Cogeneration" tab in Appendix F).

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24 Biofuel for OCGTs is only available for the Environmental market scenario.
25 2020 Thermal Generation Stack Update Report | WSP (Oct 2020). Commissioned by MBIE.
26 Security Standards Assumptions document | Electricity Authority (2012).

90. The start-up cost for the third Huntly Rankine unit has been included to reflect that a third Rankine unit typically only operates when the system is in an extended period of shortage (e.g. during a dry year).

91. Alternative fuels represent the technical possibility for thermal generation plant to consume a range of fuels. We include options to burn:

    a. diesel and biofuel in place of natural gas in open-cycle-gas-turbine generators (except Whirinaki)

    b. biomass pellets in place of coal in the Huntly Rankine units[27].

92. In the SDDP model, thermal generation plants consume the lowest cost fuel subject to availability constraints. The uptake of alternative fuels is determined by market scenario assumptions around fuel costs, availability and carbon costs.

93. Upgrade costs to allow existing OCGTs to use alternative fuels have been ignored in our models. We would expect these costs to be significantly less than alternative options, such as procuring OCGT with multi-fuel capabilities.

2.3.4.4 Hydro

Assumption

Plant Characteristics

94. Hydro plant characteristics, including capacity, mean production coefficient, maximum turbining outflow, composite outage rate and modulation factor are provided in the "Existing hydro" tab of Appendix F.

Inflows

95. Incremental inflow data for each gauging station are obtained from the EMI,[28] with the specific inflow series used for each station described below. We use the full set of available historical inflows available from EMI, and update these data annually.

Minimum outflow constraints

96. Minimum outflow constraints for hydro systems where they apply are given in the "Min. outflow" tab of Appendix F.

Waikato

97. The Waikato hydro network is modelled as shown in the diagram below, consistent with the description of the network in the hydrological modelling dataset.[29] There is a split bus at the Arapuni plant, so water from Lake Arapuni can be diverted into either Arapuni 1-5 or Arapuni 6-8, as shown in Figure 2.[30] Note, Karapiro has a minimum outflow constraint of 148 cumecs.

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27 Biomass pellets have already been trailed for use in the existing Huntly Rankines. Huntly biomass trial a success | Energy News (Feb 2023).

28 Hydrological modelling dataset | Electricity Authority.

29 Hydrological modelling dataset | Electricity Authority, Hydro Power Scheme Background and Descriptions (Report 4), Section 2.1.

30 Note, where a hydro station injects into electrical busses that are connected to different transmission circuits (e.g. Arapuni, Roxburgh) we have created two hydro generating stations in SDDP and have added a dummy station upstream without the ability to produce electricity. This dummy station can

98. Lake Taupo is modelled with an available storage capacity of 764 hm.[30]

99. Incremental inflow data for each gauging station is obtained from the EMI files listed in Table 7. The scale factors are used to estimate the proportion of the total tributary flow observed at Arapuni that occurs at each project down the Waikato River. Total Arapuni tributary flows are determined by deducting Taupo outflows from total flows at Arapuni. We originally obtained total flows for sites along the Waikato from the original Power Archive,[31] although the original data set is no longer publicly available.

Table 7. Waikato Hydro Network Incremental Inflows

Plant Name	Inflow Scale (incremental)	EMI filename[32]
Aratiatia	0.064	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Ohakuri	0.162	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Atiamuri	0.018	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Whakamaru	0.236	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Maraetai	0.321	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Waipapa	0.034	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Karapiro	0.178	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv
Lake Taupo	1	NI_TPO_Actual_LakeTaupoInfrastructure_Inflow_72790(1).csv
Lake Arapuni	0.165	NI_ARI_Actual_WaikatoAtArapuni_Tribflow_92724(1).csv

Waikaremoana

100. The Waikaremoana hydro network is modelled as shown in Figure 3, consistent with the description in the hydrological modelling database:[33]

send water to either or both of the two downstream generating stations, therefore replicating the ability of the operator to direct water into the units connected to one or both of the transmission circuits based on the conditions on the grid at the time (e.g. it may be optimal to send all available water downstream of a transmission constraint rather than sharing it equally between all units at the station).

31 Hydrological modelling dataset | Electricity Authority, Flow Series Description and Methodology, Section 1.2.

32 Hydrological modelling dataset | Electricity Authority.

33 Hydrological modelling dataset | Electricity Authority, Hydro Scheme Background and Descriptions, Section 2.3.

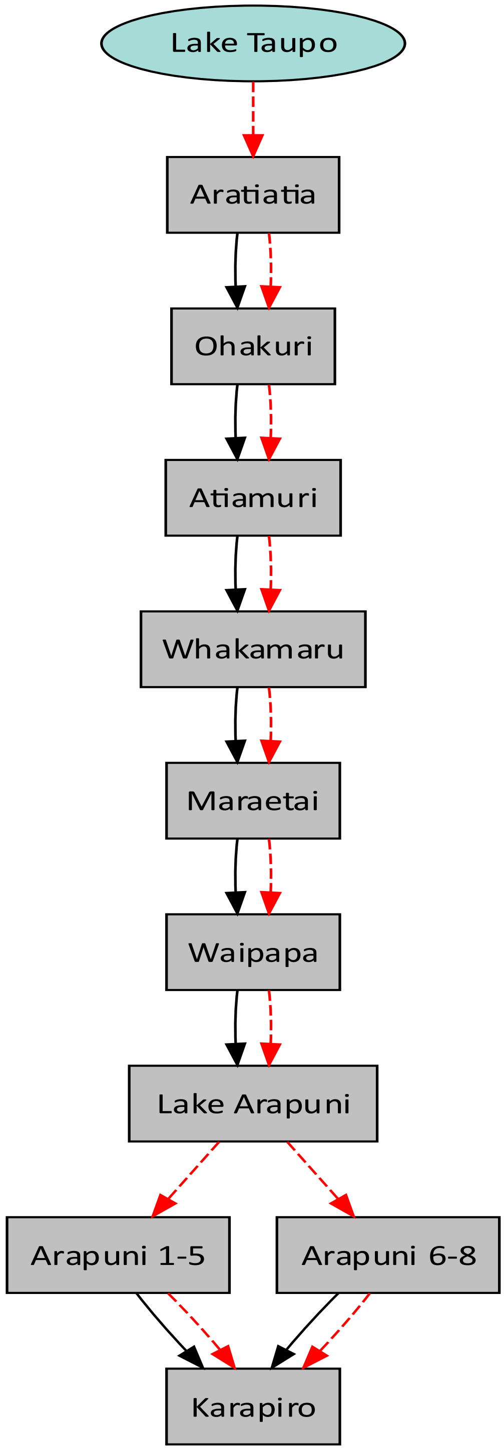

Figure 2. Waikato Modelled Topology

101. Lake Waikaremoana is modelled with an available storage capacity of 161 hm^3 and inflow based on “NI_WKA_Natural_LakeWaikaremoana_Inflow_3650(1).csv” file from EMI.[34]

[34] Hydrological modelling dataset | Electricity Authority.

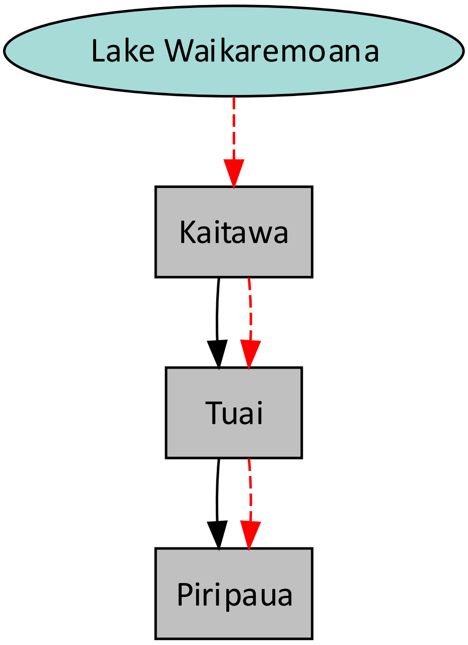

Figure 3. Waikaremoana Modelled Topology

102. Inflows for other North Island plants are modelled at the stations listed in Table 7.

Table 8. Other North Island Plants Inflows

Plant Name	Inflow Scale	EMI filename[35]
Rangipo	1	NI_RPO_Actual_RangipoStationNonLinear_Inflow_92790(2).csv
Tokaanu	1	NI_TKU_Actual_TokaanuStationNonLinear_Inflow_92790(3).csv
Aniwhenua	1	NI_MAT_Actual_LakeMatahina_Inflow_93254(1).csv
Mangahao	1	NI_MHO_Actual_MangahaoStation_Inflow_97502(1).csv
Kaimai	1	NI_RHI_Actual_RuahihiStation_Outflow_14130(1).csv
Wheao	1	NI_WHE_Actual_WheaoStation_Outflow_15462(1).csv
Patea	1	NI_RTG_Actual_PateaStation_Outflow_34300(1).csv

35 Hydrological modelling dataset | Electricity Authority.

Waitaki

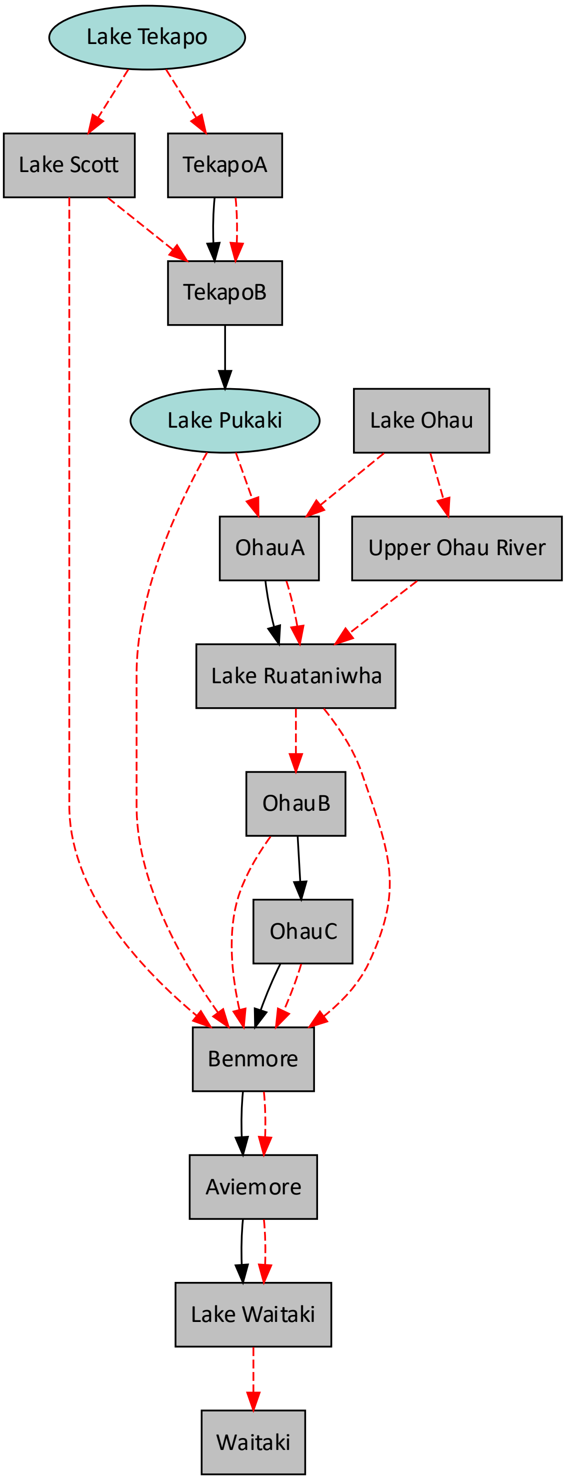

Figure 4. Waitaki Modelled Topology

103. The Waitaki hydro network is modelled as shown in Figure 4, consistent with the description in the hydrological modelling database.[36]

104. As seen in the "Min. outflow" tab of Appendix F, Upper Ohau River has a minimum outflow constraint of 8 cumecs from Week 18 to Week 43 and 12 cumecs for the rest of the year. Lake Waitaki values are based on the minimum flow defined in the HMD, except from October to March, when the minimum outflow can regularly be lowered for irrigation purposes.

105. The lakes included in the Waitaki model are listed in Table 9.

Table 9. Lakes in Waitaki Hydro Network Model

Name	Min storage level (hm^3)	Max storage level (hm^3)
Lake Tekapo	23.9	699.8
Lake Pukaki	0	2,425 (30.9 alert storage)[37]

106. Incremental inflow data is obtained from the EMI files in Table 10. The tributary flows at Aviemore and Waitaki are a scaled version of the tributary flow at Benmore. The scaling factor is obtained using total flow data from the original Power Archive, although the original data set is no longer publicly available. The Ohau outflows are deducted from the Benmore inflows, since Ohau inflows are modelled directly in our SDDP model.

Table 10. Waitaki Chain Incremental Inflows

Plant Name	Inflow Scale	EMI filename[38]
LakeTekapo	1	SI_TEK_Natural_LakeTekapo_Inflow_98770(2).csv
LakePukaki	1	SI_PKI_Natural_LakePukaki_Inflow_98770(1).csv
LakeOhau	1	SI_OHU_Natural_LakeOhau_Inflow_98614(3).csv
Benmore	-1	SI_OHU_Natural_LakeOhau_Inflow_98614(3).csv

36 Hydrological modelling dataset | Electricity Authority, Hydro Scheme Background and Descriptions, Section 3.1.

37 Alert storage refers to stored water that is only used by SDDP as a last resort before shedding load (by penalising it at a cost of 1.1 times the most expensive thermal plant). In this instance, the alert storage represents the bottom 0.2m of Lake Pukaki's range which cannot be used as efficiently due to operational limitations at Ohau A when the lake is at that level (so would rarely be used).

38 Hydrological modelling dataset | Electricity Authority.

Plant Name	Inflow Scale	EMI filename[38]
Benmore	1	SI_BEN_Actual_LakeBenmoreCombined_Tribflow_98615(2).csv
Aviemore	-0.4	SI_OHU_Natural_LakeOhau_Inflow_98614(3).csv
Aviemore	0.4	SI_BEN_Actual_LakeBenmoreCombined_Tribflow_98615(2).csv
Waitaki	-0.217	SI_OHU_Natural_LakeOhau_Inflow_98614(3).csv
Waitaki	0.217	SI_BEN_Actual_LakeBenmoreCombined_Tribflow_98615(2).csv

Clutha

107. The Clutha hydro network is modelled as shown in Figure 5, consistent with the description in the hydrological modelling database.[39] Like Arapuni in the Waikato scheme, there is a split bus at the Roxburgh station, so water at Lake Roxburgh can be diverted into either plant Roxburgh 1-5 or Roxburgh 6-8. Note, Lake Roxburgh has a minimum outflow constraint of 250 cumecs.

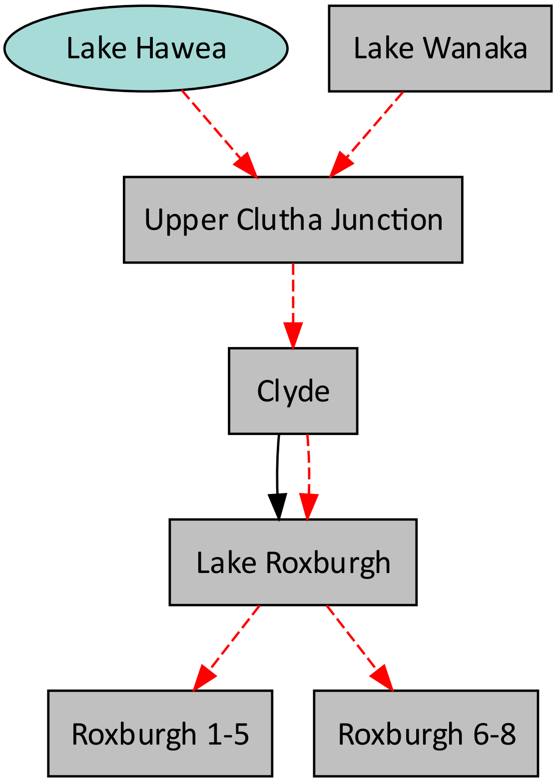

Figure 5. Clutha Modelled Topology

[39] Hydrological modelling dataset | Electricity Authority, Hydro Scheme Background and Descriptions, Section 3.4.

108. Lake Hawea is modelled with an available storage capacity of 1,142 hm^3.

109. Incremental inflow data listed in Table 11 is obtained from EMI:

Table 11. Clutha Hydro Network Inflows

Gauging Station	Inflow Scale	EMI_filename[40]
Lake Hawea	1	SI_HWE_Natural_LakeHawea_Inflow_9170(1).csv
Clyde	0.967	SI_ROX_Actual_LakeRoxburgh_Tribflow_99110(1).csv
Clyde	-0.967	SI_WAN_Natural_LakeWanaka_Outflow_9154(1).csv
Lake Wanaka	1	SI_WAN_Natural_LakeWanaka_Outflow_9154(1).csv
Lake Roxburgh	0.033	SI_ROX_Actual_LakeRoxburgh_Tribflow_99110(1).csv
Lake Roxburgh	-0.033	SI_WAN_Natural_LakeWanaka_Outflow_9154(1).csv

110. As shown in the diagram, Lake Hawea is modelled as being a controlled reservoir. However, any water released at Hawea does not directly generate any energy (as indicated by the red dashed line). At the same time, Lake Wanaka is modelled as a plant with no storage ability or related energy production. Both Lake Hawea and Lake Wanaka release water into the Upper Clutha Junction, which directs water into the Clyde plant. The incremental tributary flows at Clyde and Lake Roxburgh are calculated as proportions of the total tributary flow at Lake Roxburgh (again, based on the Power Archive). Note that the Lake Wanaka flow series has to be subtracted from the Clyde and Lake Roxburgh series in order to avoid double counting of inflows.

Waipori

111. The Waipori scheme is modelled as shown in Figure 6, consistent with the description of the scheme in the hydrological modelling database.[41]

112. Lake Mahinerangi is modelled with an available storage capacity of 140.56 hm,^{3} with 34.60 hm^3 modelled as alert storage. The inflows to Lake Mahinerangi (mean of 7.5 cumecs) were provided to Transpower by Manawa Energy.

113. We model Waipori2A as three separate units with one connecting to HWB220 and two connecting to BWK110. Waipori1A also connects to HWB220 and Waipori3 and Waipori4 connect to BWK110.

[40] Hydrological modelling dataset | Electricity Authority.

[41] Hydrological modelling dataset | Electricity Authority, Hydro Scheme Background and Descriptions, Section 3.8.

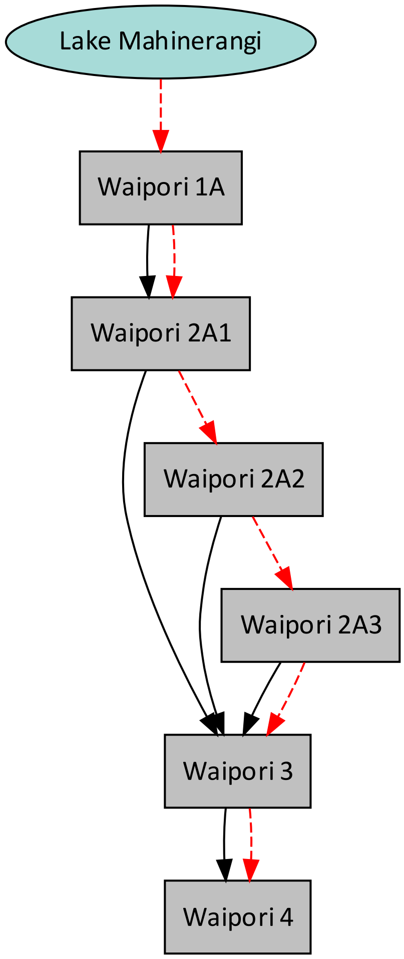

Figure 6. Waipori Modelled Topology

Other SI Hydro

114. The remaining South Island storage lakes included in our modelling are listed in Table 12:

Table 12. Other Hydro Plants in South Island

Name	Min storage level (hm^3)	Max storage level (hm^3)
Cobb	0	24.0
Coleridge	0	137.6
Manapouri	0	1029.1 (356.3 alert storage)[42]

[42] Lakes Manapouri and Te Anau both have upper and lower ranges which have restrictions on the length of time storage can be in that range and the frequency with which those ranges can be used. These constraints cannot be modelled in detail by SDDP. To capture the approximate value of this

115. Inflow data and reference files are listed in Table 13.

Table 13. Other South Island Hydro Plants Inflows

Gauging Station	Inflow Scale	EMI_filename[43]
Cobb	1	SI_COB_Natural_LakeCobb_Inflow_97904(2).csv
Coleridge	1	SI_COL_Actual_LakeColeridge_Inflow_97904(1).csv
Manapouri	1	SI_MAN_Actual_LakeManapouri(WithMararoaSpillAndMinFlowRegime)_Inflow_99552(1).csv
Waipori	1	SI_WPI_Actual_WaiporiStation_Outflow_174395(1).csv
Highbank	1	SI_HBK_Actual_HighbankStation_Outflow_7968(1).csv
Argyle & Branch River	1	SI_BRR_Natural_WairauRiverAtDipFlat_Flow_160114(1).csv

Background

116. SDDP operates via a two-step process:

a. establish the hydro operating policy through the calculation of water storage values. This step is referred to as the "policy step"

b. using the policy from the first step, simulate the operation/dispatch of the power system for a given (fixed) sequence of hydro inflows and renewable resource availability. This step is referred to as the "simulation step".

117. Within the policy step, we use synthetic inflow sequences that are derived from the actual inflows. The synthetic inflows reduce the level of fluctuations, help the model converge, and reduce computational run-time. We typically use up to 50 synthetic inflow sequences[44] to determine the operating policy, which is a practical trade-off between precision and run-time. The synthetic inflows are produced by SDDP by analysing the relationship between an inflow sequence and time of year as well as the interdependence among inflows to different hydro plants.

storage, the upper range has been ignored, and the lower ranges have been modelled as "alert" storage.

43 Hydrological modelling dataset | Electricity Authority.

44 To be more precise, we use 50 and 15 synthetic inflow sequences for the 'backward' and 'forward' phase of the SDDP algorithm.

118. Within the simulation step, we also typically use 50 synthetic inflow sequences. Our dispatch simulations are typically run on an hourly resolution, and this tends to restrict in practice the number of inflow sequences that can be simulated.

119. The above subsections list the hydro networks that we model in SDDP, along with properties of each plant and reservoir. Many of the hydrological properties we use are based on historical data sets internal to Transpower that are not publicly available (e.g. modulation factors, inflow scaling factors, min and max outflows). As part of this consultation, we welcome feedback from hydro asset owners on our assumptions.

120. We assume 2% composite outage rates for hydro stations based on the Authority's security standards.[45]

121. We model major hydro reservoirs as controlled storage (e.g. Lake Pukaki). The ability for run-of-river stations and stations downstream of a major reservoir to shift inflows across time is represented in one of two ways depending on the modelling task:

    a. When using load blocks (e.g. determining future cost functions), by a modulation factor (or regulation factor) – i.e. the ability to use its reservoir storage to transfer power generation across a stage. "1" indicates no storage capacity (flat production), "0" indicates that the plant is capable of full modulation (able to generate more during peak period at each stage).

    b. When using an hourly representation (e.g. final simulations), by considering the minimum and maximum reservoir volume as given in the Existing and Future hydro sheets in Appendix F.

122. To keep the modelling practical, we have decided to model a storage reservoir as controlled if the reservoir can store more than two weeks of its average inflow. The two-week limit was chosen because it is twice as large as the weekly time step that we use, and therefore water can be meaningfully stored in one time step for use in a later one.

123. All hydro topology diagrams are to be interpreted as illustrated in Figure 7.

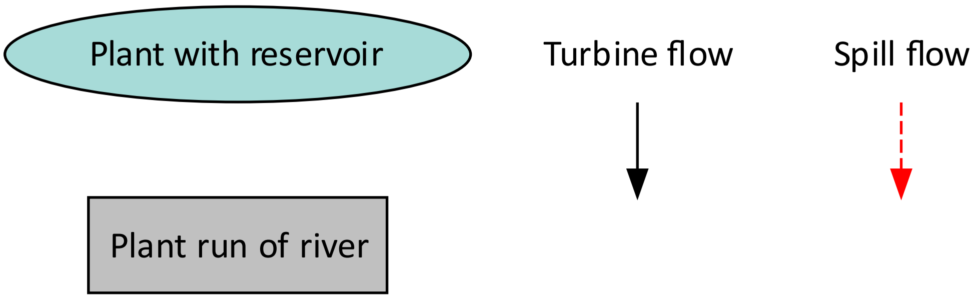

Figure 7. Key for Interpreting Hydro Topology Diagrams

A plant with a reservoir can store water for extended periods of time, while a run of the river plant only has limited storage capacity (see above comment on modulation factor). Plant outflow that passes through a turbine (hence injecting energy into the grid) is shown with a black arc, while outflow that bypasses turbines is shown with a red dashed arc. Red dashed lines represent water arcs in a scheme that do not directly

45 Security Standards Assumptions document | Electricity Authority (Nov 2012).

create energy (spill flow). In some schemes, like the Waitaki, these diversions can be used by an operator to inject energy into different parts of the grid.

124. Note that all red dashed arcs represent flows of water that do not produce energy (i.e. energy that is spilled around a station or released from a reservoir that has no generation units).

125. In this section, we describe the inflow at a station as it is loaded into SDDP. For a station at the top of a scheme, we obtain the total flow of water and for downstream stations, we obtain tributary or incremental flow. The tributary flow is defined as the flow entering the river between the station and any stations immediately upstream. For example (in Figure 2), the tributary flow at Ohakuri is from water entering the Waikato downstream of the Aratiatia station (excluding outflow from Aratiatia), but upstream of the Ohakuri station.

2.3.4.5 Geothermal

Assumption

126. Geothermal plant characteristics, including capacity and composite outage rate, are shown in the "Existing geothermal" tab of Appendix F.

127. We assume the retirement of the existing generation at Wairākei by 2031, and the partial replacement of this capacity by Te Mihi Stage 2, and an optional uplift of capacity with Te Mihi Stage 3.

Background

128. Composite outage rates are assumed to be 10%, which is consistent with capacity factor assumption in MBIE's geothermal stack, except for Mokai, Rotokawa and Poihipi which are set consistent with the capacity factors from recent historical operations.

129. The existing Wairākei generation is comprised of the Wairākei A&B stations and a bottom binary plant. The net generation from these is represented in SDDP with the plant 'WairakiNet'.

130. Contact Energy have a resource consent to operate the Wairākei A&B stations until June 2031.[46] We understand that Contact is planning a phased replacement of the plants with Te Mihi Stage 2 and Te Mihi Stage 3. These projects will reuse the existing Wairākei steam field.

131. We model the first stage of this phased replacement as committed build in Optgen with timing based on the developer's target date of 2027.[47] The existing generation at the site is reduced by approximately a half, at this point[48].

132. In 2031 the residual generation from the existing plant is assumed to cease and Te Mihi Stage 3 becomes available as a candidate project that the model can develop based on economic merit.

46 Ti Mihi Stage 2 project description | Contact Energy.
47 Ibid.
48 Ibid

2.3.4.6 Wind

Assumption

133. Wind farm characteristics, including their installed capacity, and wind region are shown in the "Existing wind" tab of Appendix F.

134. We also assume repowering dates for several existing wind farms as shown in Figure 8 (and also in the "Wind repowering" tab of Appendix F). The total increase in capacity due to repowering is approximately 468 MW.

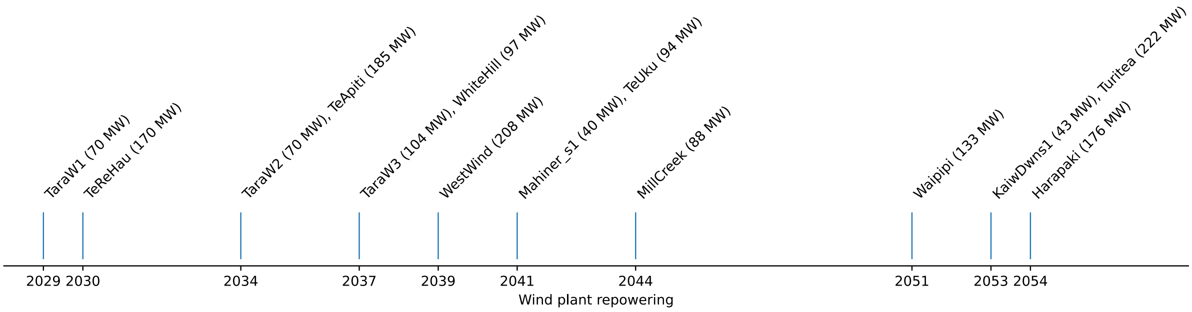

Figure 8. Modelled Wind Repowering Timeline

135. Capacity factors for wind farms located in each of the regions vary throughout the day and year based on profiles from Time Series Lab (**TSL**) developed by PSR. TSL adjusts these profiles to give agreement with the mean capacity factors given for each region in the 2020 MBIE Wind Generation Stack Update[49]. These target mean capacity factors are given in the "Wind mean cap. fac." tab of Appendix F.

Background

136. The wind repowering assumptions have been developed by Transpower based on the following assumptions:

    a. For Te Rere Hau we assume staged commissioning beginning in 2029. This is consistent with the developer's stated intentions, however we note that the repowering project has not yet reached financial close and we have based our repowering assumptions on the developer's stated intentions.'[50]

    b. For Tararua stage 1 & 2 we assume repowering after 30 years of operation

    c. for existing wind farms commissioned before 2020, we assume these are repowered after 30 years of operation with 4.2 MW turbines. We assume that there will be a 20% reduction in the number of turbines.

    d. for existing wind farms commissioned on or after 2020, we assume these are repowered after 30 years of operation, with the same quantity and capacity of the current turbines.

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49 Wind Generation Stack Update | Roaring 40s Wind Power (2020). Commissioned by MBIE.

50 Te Rere Hau Wind | Meridian Energy.

137. We assume Siemens SWT-4.0-130 as the turbine model with a hub height of 90m for all existing and future wind farms.

138. We have used TSL to generate our wind scenarios. TSL uses Kernel density estimation, Bayesian networks, and hourly historical data to generate synthetic hourly wind and solar scenarios.

139. TSL was used to generate historical hourly wind generation profiles by region. TSL reads weather data from National Aeronautics and Space Administration (**NASA**)'s Modern Era-Retrospective Analysis for Research and Analysis (**MERRA-2**) reanalysis model. We use all available data from 1980 to 2017 for our historical records.

140. Using MERRA-2, TSL calculates wind production through a model based on the Virtual Wind Farm (VWF), developed by Renewables Ninja. This generates capacity profiles for each region, scaled according to the target mean capacity factors in the "Wind mean cap. fac." tab of Appendix F , while preserving the seasonal and hourly variations in the underlying dataset.

141. We specify the target mean capacity factors using the mid-point of the high and low estimates of net generation from Table 4 of the 2020 MBIE Wind Generation Stack Update. This approach retains value from the high-resolution wind modelling done in that work, while utilizing the lower resolution MERRA-2 derived data to provide temporal variation.

2.3.4.7 Solar

Assumption

142. The "Existing solar" tab of Appendix F shows the modelled solar plants that presently exist within the network.

Background

143. We model 18 solar regions across the country; six in the South Island and 12 in the North Island. The regions have been determined based on geographic location.

144. Each region's capacity profile is an average of the individual profiles of all existing and potential future solar farms within the region.

145. Like wind, we have used TSL to generate our solar scenarios and the associated hourly historical generation profiles. This uses weather data from NASA's MERRA-2 reanalysis model, converted into solar power output using Renewables Ninja's Global Solar Energy Estimator (**GSEE**) model.

146. We assume 1 axis tracking, a 180° azimuth for all solar farms, panel oversizing of 30% and conversion losses of 10%. This results in mean capacity factors (across scenarios) ranging from 20% to 24% in the South Island and 22% to 25% in the North Island.

2.3.4.8 Batteries

Assumption

147. Modelled Battery Energy Storage Systems (**BESS**) which presently exist within the network are specified in the "Existing batteries" tab of Appendix F. All BESS new and existing are assumed to have a minimum charge of 0 MWh, an initial charge of 0.5 p.u. and charge and discharge efficiencies of 0.92 p.u.

Background

148. We identified the existing batteries from publicly available information.

2.3.4.9 Decommissioning

Assumption

149. The dates for the retirement of specific thermal units are shown in Figure 9 and in the “Retiring thermal” tab of Appendix F. All dates are for the start of the given year.

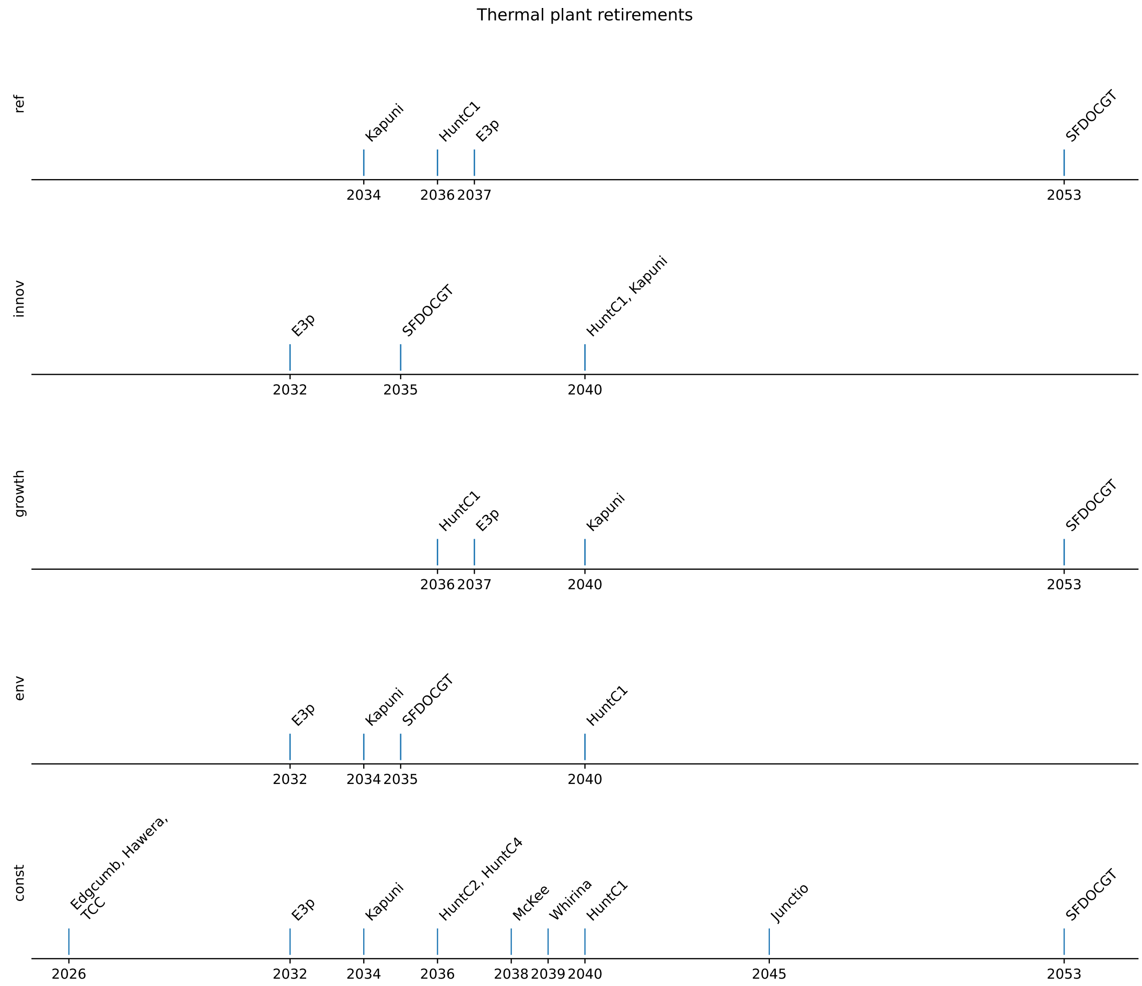

Figure 9: Retirement dates for thermal plants

150. The bottom panel in Figure 9 shows all thermal retirements for the Constraint scenario. The panels above show only the plant retirement dates for the remaining scenarios that vary from those in the Constraint scenario.

Background

151. Thermal generation decommissioning assumptions are derived as follows:

a) Huntly's decommissioning assumptions are based on recent market information[51] from Genesis Energy and to provide a degree of diversity in our market scenarios, reflective of the uncertainty as to when these plants may retire.

b) Decommissioning dates for Huntly Unit 5 (E3p) and the Stratford peakers (SFDOCGT) align with MBIE's 2024 EDGS scenario assumptions[52]. There is one exception; Huntly Unit 5 retires in 2032 for the Constraint scenario consistent with this scenario's gas cost and availability assumptions[53].

c) TCC retires in 2026, consistent with recent market information[54].

d) Decommissioning dates for Whirinaki, Mckee, and Junction Road have been sourced from MBIE's thermal generation stack[55]. We have added ten years to the MBIE thermal generation stack Whirinaki retirement date to reflect the low operating hours per year of this plant.

e) Hawera and Edgecumbe are modelled to retire in 2026, consistent with recent information provided by Fonterra[56].

f) Kapuni is modelled to retire in 2040 for the Growth and Innovation market scenarios. This is based on a 42-year project life, and 1998 commissioning date from MBIE's 2020 thermal generation stack report. Kapuni retires in 2034 for the Reference, Constraint and Environmental scenarios, consistent with these scenarios' domestic gas availability assumptions.

2.3.5 Fuel Assumptions

Assumption

152. We model fuel supply from natural gas, coal, diesel, biomass pellets and biofuel. Thermal plants are configured with the option to consume one of more of these fuels as described in 2.3.4.3 and 2.3.8.3.

153. For coal and diesel we assume unconstrained supply for all market scenarios except for Environmental. For this scenario we assume these fuels are available until the end of 2039.

154. For biomass pellets we assume unconstrained supply in the Innovation and Environmental scenario and no supply in the other market scenarios.

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51 Interim Report 2026| Genesis Energy (Feb 2026). See page 13.
52 Electricity Demand and Generation Scenarios: Results summary | MBIE (Jul 2024)
53 This scenario has low domestic gas supply availability and LNG costs are high.
54 Contact starts TCC decommissioning | Energy News (Jan 2026)
55 2020 Thermal Generation Stack Update Report | WSP (Oct 2020). Commissioned by MBIE.
56 Fonterra submission on Transpower HVDC Link Upgrade | Fonterra (Jun 2025)

155. The cost assumptions for coal, diesel and biomass pellets are shown in Figure 10 below and listed in the "Fuel price" tab of Appendix F.

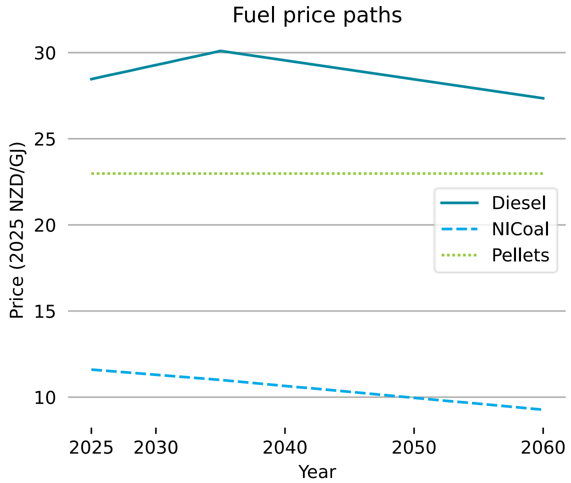

Figure 10: Price paths for Coal, Diesel, and Pellets

156. For natural gas we consider two tranches of supply with unique cost and availability assumptions:

a. Domestic natural gas available for power generation

b. Imported LNG for power generation for the Reference and Growth scenarios only.

The cost and availability of these tranches vary across scenarios consistent with the market scenario assumptions outlined in 2.3.1. Natural gas cost and availability assumptions are listed in the 'Gas cont. price' and 'Gas cont. avail.' tabs of Appendix F, and in Figure 11 and Figure 12. We assume that domestic gas supply is constant over the weeks of the year.

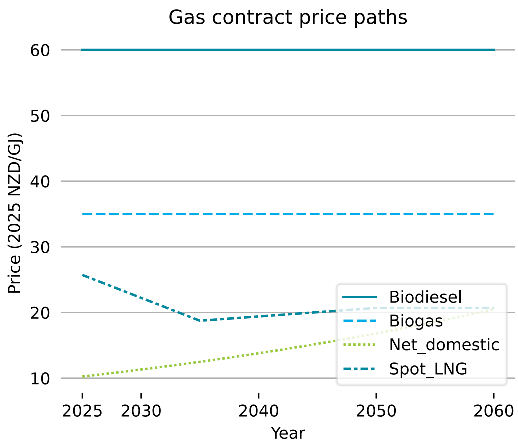

Figure 11: Gas and biofuel contract price paths

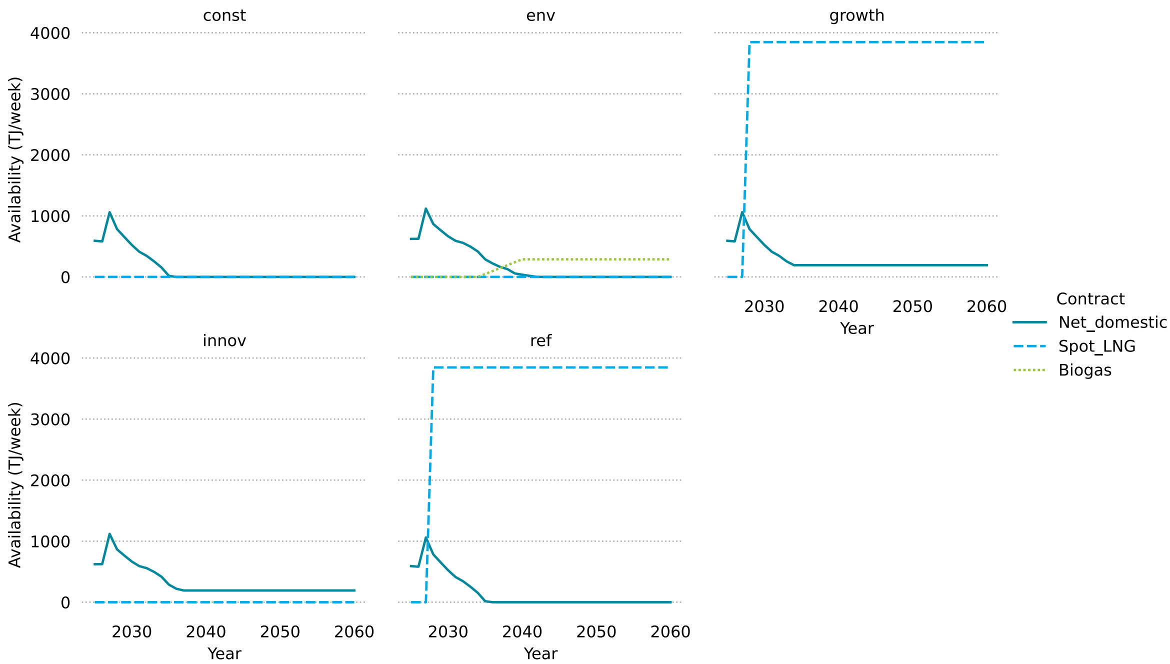

Figure 12: Gas and biofuel contract availability [57]

157. The cost and availability of LNG is uncertain. Our LNG assumptions will be updated for a BBI should new information arise indicating that significant adjustments to our approach are necessary.

158. A gas storage reservoir is also modelled to represent the Ahuroa Gas Storage Facility. This allows SDDP to move gas between stages (e.g. weeks). We assume a total capacity of 7 PJ for the reservoir and injection and withdrawal limits of 65 TJ/day. The domestic natural gas supply tranche can be injected into the reservoir, and the offtake can be consumed by all plants with natural gas as a fuel option.

159. Biofuel is available for the Environmental scenario only. For this market scenario we consider two biofuel supply options:

    a. Biodiesel, this is available without constraint and at a cost of $60/GJ.

    b. Biomethane, with cost and availability as shown in Figure 11 and Figure 12. Biomethane will be able to be used for electricity generation or stored for later use in the Ahuroa Gas Storage Facility (or similar storage infrastructure).

Background

160. For the Environmental scenario coal and diesel are assumed to be no longer available from the end of 2039 consistent with this scenario's high carbon costs and the assumed availability of low carbon alternatives.

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57 In the Environmental scenario Biodiesel is available without limit and has been omitted from this figure.

161. The potential for a domestic biomass pellet supply chain to be established has been signalled by Genesis Energy and other firms[58]. Genesis is targeting commercial contracts which would supply biomass by 2028 to Huntly. Although the targeted supply of 300 kt p.a. may be insufficient to fuel the Rankine units in dry hydrological conditions, to avoid complex modelling of fuel supply and stockpiling, we assume unrestricted availability of biomass in the Environmental and Innovation scenario. Biomass pellets are unavailable in other market scenarios. We view establishing a biomass pellets supply chain as a greater uncertainty than fuel shortages in dry years, so our scenarios focus on this issue.

162. We have estimated delivered fuel costs for biomass pellets to Huntly from indicative Rankine short run marginal costs published by Genesis[59]. The uptake of biomass in SDDP is determined by the relative cost of the fuel and emissions compared with coal. The scenario carbon cost assumptions result in a conversion to biomass before 2030 in the Innovation and Environmental scenario.

163. We benchmark our diesel price forecast to the IEA's 2025 Annual Energy Outlook Stated Policies (STEPS) scenario oil prices[60]. We calculate diesel price forecasts using a derived historical correlation between crude oil prices and MBIE landed diesel costs[61].

164. Similarly for coal, we anchor our fuel cost assumptions to the STEPS scenario coal prices for Japan and include an additional fixed cost component.

    a. This commodity price forecast is transformed into a fuel cost for Huntly by adjusting for inflation, foreign currency, and accounting for the lower calorific value of the fuel combusted in Rankine units compared with the benchmark steam coal.

    b. We assume an additional fixed component of $4.52/GJ to account for freight, logistics and any premiums applied. The fixed component has been calibrated to ensure alignment with actual reported fuel cost reported by Genesis of NZ$11.60/GJ in Q1 FY26.

    The modelled coal cost is then calculated using the equation:

$$coal\ price\ (NZD/GJ) = \frac{commodity\ price\ (USD/tonne) \times 0.72}{0.63\ \times 18.07} + 4.52$$

    where

    - 0.63 is the assumed NZD to USD ratio,

    - 0.72 accounts for the lower calorific value of the coal consumed in Huntly (4320 kcal/kg) compared with a Newcastle coal benchmark (6000 kcal/kg),

    - 18.07 is the net calorific value applied to transform metric tonnes to GJ

165. Although future oil and coal prices are uncertain and are likely to vary, we consider the STEPS scenario price forecast to be a credible central estimate of future prices and apply this to all market scenarios. We do not benchmark against more extreme high or low oil or

58 Investor Day 2025, Biomass Update | Genesis Energy (2025)
59 Ibid
60 World Energy Outlook 2025 | IEA (2025)
61 Weekly fuel price monitoring | MBIE

coal price forecasts to avoid these driving market scenario outcomes that may be inconsistent with the global conditions underpinning the external IEA scenario.

166. The injection and withdrawal limits and capacity for the modelled gas reservoir align with operational characteristics reported by the field owner and operator of Ahuroa.[62] The modelling of gas storage allows SDDP to consider the opportunity cost of consuming gas immediately, compared with storing it to displace more expensive fuels in the future. This approach enables price discovery within SDDP with prices above the underlying fuel cost during periods of gas scarcity.

167. The modelled fuel cost for the domestic natural gas available for power generation tranche represents the underlying long-run-marginal cost of domestic supply. Although gas prices have been elevated above these levels in recent years, we consider that this has been driven by scarcity rather than increases in the underlying production costs. As this scarcity effect is being evaluated within SDDP, it is not included in the input fuel costs.

168. The assumed 2025 fuel cost for domestic natural gas is the simple average of wholesale natural gas prices from 2021-2024 in real $/GJ reported by MBIE.[63] We assume natural gas production costs increase as the scale of the gas market reduces as some production costs will be fixed. We assume a 2% annual increase in domestic natural gas costs in real terms year on year to account for this.[64]

169. We model LNG as being available in the Reference and Growth market scenarios from the start of 2028. LNG is not available in the other market scenarios for these reasons:

    a. In the Constraint scenario, LNG imports are not consistent with this scenario's low economic growth and low demand growth.

    b. In the Environmental scenario, thermal generators have access to low carbon alternatives.

    c. In the Innovation scenario there are comparatively lower cost alternative generation and storage technologies.

170. LNG fuel costs are based on the 2025 IEA STEPS scenario[65] for all market scenarios except the Constraint scenario. For the Constraint scenario, LNG fuel costs align with the 2025 IEA Current Policies Scenario (CPS). This results in higher costs, consistent with the Constraint scenario's lower economic growth. This provides the commodity price which is transformed to a landed fuel costs using the equation:

$$LNG\ fuel\ cost\ (NZD/GJ) = \frac{commodity\ price\ (USD/MMBTU)}{0.63\ \times 1.055x} + \frac{1}{0.63} + 2.52$$

where:

- 0.65 is the assumed NZD/USD ratio,

62 Ahuroa Gas Storage facility update | NZX Announcement (Dec 2022)

63 NZ Energy Quarterly and Energy in NZ, September 2025 Quarter | MBIE (2025)

64 MBIE assume an annual fuel price increase of 2% in four of the 2025 EDGS scenarios which we assume accounts for this

65 With reference to the IEA's 2025 Annual Energy Outlook, Table 2.3, Japan's natural gas prices represent LNG for both the IEA's STEPS and CPS scenarios. IEA provide point year prices for 2024, 2035 and 2050, which we linearly interpolate between to give a continuous annual fuel price forecast.

- 1.055 is a conversion factor from MMTBU to GJ,
- 1 USD/GJ is the assumed shipping and irregular supply premium[66],
- 2.52 NZD/GJ is the average of the range of variable operating costs assuming regasification at Port Taranaki[67]

We assume that the fixed costs of an LNG import facility are not recovered through the fuel price.

171. Weekly availability constraints for domestic natural gas supply are applied for all market scenarios. We have estimated annual gas availability for power generation as the difference between forecast gas supply forecast and forecast non-power generation gas consumption for each scenario[68].

   a. Non-power generation gas consumption forecasts have been estimated for the market scenarios using our NZ Energy System model developed using the Low Emissions Analysis Platform (LEAP)[69]. We have recreated the MBIE's 2024 EDGS scenarios in this model by applying the published market scenario assumptions including the fuel switching assumptions[70] with some adjustments to align with short term market expectations[71]. The model outputs natural gas consumption at a sector level which is grossed up to give non-power generation consumption. The gas consumption forecasts fall into 2 distinct bands which we aggregate to produce 2 distinct scenarios for non-power generation consumption.

      i. High non-power generation gas consumption is based on the Reference scenario assumptions and applied to the Growth and Constraint scenarios also.

      ii. Low non-power generation gas consumption is consistent with the Innovation and Environmental scenario.

   b. We assume MBIE's published Gas Production Profile[72] as a low domestic gas supply forecast. This is based on producers' expectations, however it assumes no development of contingent resources.

   c. For our high domestic gas supply forecast, we assume the development of contingent resources prevent a supply short fall. We assume that gas supply maintains a margin of 10 PJ p.a. for power generation, net of other consumption.

   d. We assume that LNG supply –- for the Reference and Growth scenarios - is available on demand for electricity generation, and set a very high fuel availability to proxy an unrestricted supply

172. We assume biofuels are available in the Environmental scenario as these technologies are likely to be more viable where carbon costs are higher. Biodiesel is based on the mid-price

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66 NZ Battery Project - Biofuel and LNG cost | Hale and Twomey (2023). Commissioned by MBIE.

67 LNG Import and Options to Increase Indigenous Gas Market Capacity and Flexibility in New Zealand | Enerlytica (2023). Commissioned for MBIE.

68 Effectively this assumes that power generation gets the left-over gas once other consumers are served

69 LEAP

70 Electricity Demand and Generation Scenarios: Results Summary | MBIE (Jul 2024) and supplementary data

71 We have assumed an earlier closure of Methanex in 2027 and the closure of Ballance in 2026.

72 Petroleum reserves as at 1 January 2025 [XLSX] | MBIE (2025). See "Gas LPG Production Profile" tab.

scenario in analysis for the NZ Battery project[73]. Biomethane, is a processed form of biogas, indistinguishable from natural gas and able to be injected into existing gas networks. While this technology has an international track record, it is new to New Zealand, consistent with only being available from the mid 2030s onwards. Cost and availability have been chosen to align with the EECA report "Biogas and Biomethane in New Zealand"[74].

173. We assume thermal plants that are fuelled by 'process heat' (see section 2.3.4.3) have no fuel costs (or carbon emissions) under the assumption that the fuel cost is primarily attributable to the energy supplied to the industrial process.

2.3.6 Emissions

2.3.6.1 Emission rates

Assumption

174. We assume the emissions factors for each thermal fuel as listed in Table 14:

Table 14. Fuel Emission Factors

Fuel	Emissions factor
Coal	0.09 tCO_2/GJ[75]
Natural gas	0.05 tCO_2/GJ
Diesel	0.07 tCO_2/GJ[76]
Process heat	0
Biomass pellets	0
Biofuel	0

175. For geothermal plants, we assume the emissions rates shown in the "Geo. emission (low reinj.)", "Geo. emission (med. reinj.)" and "Geo. emission (high reinj.)" tabs of Appendix F.

73 NZ Battery Project - Biofuel and LNG cost | Hale and Twomey (2023). Commissioned by MBIE
74 Biogas and Biomethane in New Zealand | EECA (2021)
75 Based on a coal calorific value of 21.64 MJ/kg. Refer to the Ministry for the Environment's (MfE) Measuring Emissions guidance, Appendix F.
76 Based on a diesel calorific value of 38.49 MJ/litre. Refer to MfE's Measuring Emissions guidance, Appendix F

176. The geothermal emissions for generic generation plants vary across market scenarios as shown in Table 15.

Table 15 Geothermal generation emission scenarios

Geothermal emissions scenario	Scenario	Additional emissions reinjection
Low reinjection	Reference, Constraint	0%
Medium reinjection	Growth, Innovation	25%
High reinjection	Environmental	50%

Background

177. Emission factors for diesel, coal, and natural gas are derived from a guide from the Ministry for the Environment[77].

178. Biomass pellets and biofuel are assumed to have an emissions factor of zero. This follows IPCC and GHG Protocol conventions under which biogenic CO_2 emissions are treated as carbon-neutral at the point of combustion.

179. For geothermal generation, to account for the variability of GHG emissions across the different fields and technologies, we apply an emission rate specific to each plant. The emission rates are based on Mclean and Richardson (2019),[78] however we have updated emission rates to include the most recent reports from operators.[79]

180. We also assume reinjection of non-condensing-gases (**NCGs**) where it has been reported at existing geothermal plants and for plants under development where the developer states that it will operate in this way. We assume 100% reinjection at the Ngawha and Kawerau2 plants, and 80% reinjection at Ngā Tamariki.[80]

181. For candidate geothermal plants we also assume NCG reinjection when it has been realised at other plants operating at the same location. We assume 100% NCG reinjection at all Ngawha candidate projects.

182. The Te Mihi 2 and Te Mihi 3 plants are replacements for the existing Wairākei plant[81] and because it uses the same steam fields is assigned the same low emissions rate.

183. For all other candidate geothermal plants, we define emission rates based on the "GHG emissions category" classification for each project as provided in MBIE's 2020 geothermal

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77 Measuring emissions: A guide for organisations: 2024 detailed guide | Ministry for the Environment (2024)

78 See the Future Geothermal Generation Stack | Lawless Geo-Consulting (2020), and the NZ geothermal website (Greenhouse Gas Emissions from New Zealand Geothermal Power Generation in Context) for further details.

79 NZGA Pre-Seminar Presentation: New Zealand's Geothermal Carbon Capture and Reinjection | New Zealand Geothermal Association (2025)

80 Ibid.

81 Wairakei geothermal investments | Contact Energy (2024). Refer to downloads section for report.

generation stack[82]. We assume the midpoint rate in gCO2/kWh of the given range for each emission category as a base assumption. For the Growth, Innovation and Environmental scenarios, we scale these emission rates by the factors given in Table 15 to reflect the potential for emissions reduction through NCG reinjection.

184. We consider these assumed emission rates and injection rates are plausible given the performance of recent projects[83]. Our observation is that NCG reinjection is being achieved at binary geothermal plants and that the implementation with this technology type is simpler than for other geothermal generation types (e.g condensing steam turbines)[84].

185. We note that there is some uncertainty around the permanence of carbon dioxide sequestration for reinjected NCGs as the gases are not expected to form minerals with reservoir rock.[85] We intend to monitor technology development and operational reports in this space for any developments.

2.3.6.2 Carbon prices

Assumption

186. We assume three long-term carbon price projections as shown in Figure 13 and also in the "Carbon price" tab of Appendix F. The carbon price is held constant at these values within each year.

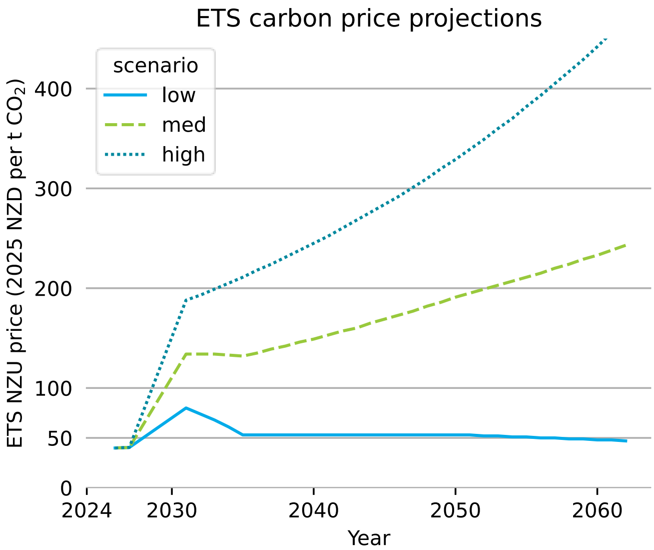

Figure 13: Future carbon price scenarios

187. These three carbon price projections are applied to the five market scenarios as described in Table 16.

Table 16: Relationship between market scenarios and carbon price projection scenarios

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82 Future Geothermal Generation Stack | Lawless Geo-Consulting (2020)

83 NZGA Pre-Seminar Presentation: New Zealand's Geothermal Carbon Capture and Reinjection | New Zealand Geothermal Association (2025)

84 2022 Annual Aotearoa New Zealand Geothermal Review | Montague et. el. (2023)

85 Carbon Capture and Storage in Geothermal Reservoirs | University of Auckland (2022). Memo to MBIE from Associate Professor Zarrouk, University of Auckland.

Market scenario	Carbon price projection scenario
Reference	Low
Growth	Medium
Constraint	Low
Innovation	Medium
Environmental	High

Background

188. Our carbon price projections are based on the following:

   a. For 2025, the carbon price is a simple average of year-to-date Carbon News NZU index prices.[86]

   b. For 2026 – 2027, carbon prices are based on ASX NZU carbon price futures[87].

   c. From January 2030, carbon prices are set to the emission values published by Treasury. Treasury provide low, central and high emission values which are for use in cost benefit analysis undertaken by central government agencies[88]. These cost scenarios are applied for our Low, Medium and High carbon price projection scenarios respectively.

   d. For 2028 – 2029, prices are assumed to transition from the 2026 ASX NZU carbon price to one of Treasury's emission value projections.

189. Future carbon prices are uncertain and depend on domestic climate policy. To reflect this uncertainty, we ensure our market scenarios explore a wide range of potential carbon prices. We ensure the carbon prices are compatible with current market conditions by basing our initial carbon prices on ASX trading and then constructing a gradual transition to the Treasury emission values.

86 GitHub - theecanmole/nzu: NZU mean monthly prices from actual prices.
87 NZU Futures | ASX. Future prices are based on settlement dated 08/12/2025.
88 Assessing climate change and environmental impacts in the CBAx tool | New Zealand Treasury

2.3.7 Deficit costs

Assumption

190. For Optgen and SDDP we assume the deficit cost tranches defined in Table 17.

Table 17. Deficit Cost Tranches

Deficit as a proportion of Island hourly demand		Cost (2025$/MWh
Constraint, Growth, Reference and Environmental market scenarios	**Innovation market scenarios**	
First 2.25% of demand	First 2.75% of demand	700
Between 2.25% and 4.5% of demand	Between 2.75% and 5.5% of demand	950
Between 4.5% and 9.5% of demand	Between 5.5% and 10.5% of demand	4000
Greater than 9.5% of demand	Greater than 10.5% of demand	21,000

191. In some situations, we may use alternative deficit cost tranches depending on the nature of the investment. If most of the deficit is from dry years or North Island capacity constraints, events which occur infrequently, then the deficit cost tranches described in Table 17 are likely to be appropriate. If most of the deficit is related to long term capacity constraints then self-supply is more realistic, with a cost approximately in line with our first deficit cost tranche. Therefore, in this case, we would increase the size of the first $700/MWh tranche so that it covers a larger proportion of demand.

192. When using clause 52 of the TPM, we will adjust prices in post-processing during periods of deficit to the lowest cost deficit tranche.

Background

193. An important input to OptGen and SDDP is the cost of energy that cannot be supplied, referred to as the deficit cost. The deficit cost influences how stored water is used in SDDP, with higher deficit costs resulting in higher water values, and therefore a tendency for water to be held back in reserve for dry periods. Similarly, the deficit cost influences the generation being built by OptGen, with a higher deficit cost resulting in generation being built sooner as the consequence of running out of generation is greater, as well as to cover very unlikely situations of deficit (e.g. during a very rare dry inflow sequence).

194. We typically see deficit in two situations: during peak periods where there is not enough transmission and generation to meet peak demand, and during dry inflow periods where there is not enough energy to meet demand.

195. To account for these characteristics, we assume that the cost of deficit is defined by four incrementally increasing 'tranches' as described in Table 17. Each tranche is for a given amount of deficit, expressed as a percentage of Island demand.

196. The first two tranches, ranging from $700/MWh to $950/MWh represent a range of voluntary, short term, 'demand response' measures. Such measures might include retailers

controlling hot water cylinder demand or an industrial consumer shedding load in response to high wholesale prices. The cost of these deficit tranches has been aligned to the LRMC of diesel peaking generation[89]. This cost should limit the number of times these deficit tranches are called upon in our dispatch simulations. Tranche size, as a percentage of demand, has been aligned to recent research investigating potential demand response capability[90]. For the Innovation scenario, tranche sizes are slightly bigger, as we assume technological innovation will increase the uptake of demand response by consumers.

197. The third tranche, $4000/MWh, represents voluntary, sustained demand response as would occur during dry inflow periods and would be typically provided by industrial or large commercial consumers. This type of demand response should be relatively costly as it would potentially be disruptive to these consumers' operations[91].

198. The last high value tranche, set at $21,000/MWh, is intended to represent forced curtailment of load (i.e. not supplying electricity), as could occur in a grid emergency. This is sourced from the default scarcity pricing blocks that are used as part of real-time pricing.[92] Rather than using all three blocks, we are proposing to use the first (lowest) block only because, in general, we expect 5% of load shedding[93] will be enough to mitigate most capacity shortages. A $21,000/MWh value is higher than what we would expect to persist in the long term. However, it is a realistic reflection of the high value consumers place on electricity during peak periods (if these shortages do not occur frequently).

199. With regard the application of clause 52 of the TPM, clause 49(4) of the TPM specifies that the maximum price that consumers will pay is their estimated cost of self-supply for electricity or alternative energy. More specifically, we assume the maximum long run average price received by consumers will be equal to the cost for an end-consumer to supply the electricity that is not supplied by the grid. In other words, the LRMC of a consumer installing behind-the-meter generation specifically to supply the load not supplied by the grid.

200. We assume diesel generation is the technology used for self-supply, and that its LRMC is approximated by the lowest cost deficit tranche provided in Table 17 (which is aligned to the LRMC of diesel generation – see above).

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89 Specifically, we calculated the LRMC of reciprocating diesel generation in 2040 - approximately the mid point of our modelling horizon- averaged across all market scenarios with different capacity factors. The first and second deficit tranche costs approximate an LRMC with a 5% and 3% capacity factor respectively. These capacity factors are intended to align with a diesel peaker, infrequently operating, in response to periods of system stress.

90 Sense Partners (in 2025, commissioned by the Electricity Authority) assessed current industrial demand response capability in New Zealand. They estimated that up to 2% of typical winter peak demand could be provided as short duration, intra-day demand response. The Electricity Authority (in 2024) conducted a demand side flexibility survey. This survey suggests that 'large scale consumers' would provide roughly half of all demand response. From this we estimate that current demand response capability is 4% (across our first two deficit tranches). We have used slightly higher values to reflect technological innovation.

91 Refer to Figure 14 and accompanying discussion in the above-mentioned Sense Partners report.

92 Update to scarcity pricing settings | Electricity Authority (2025).

93 Also forced curtailment will occur after demand response, which we assume is between 9.5 – 11.5 % of demand.

2.3.8 New generators

201. Transpower uses OptGen as its generation expansion model to determine new additions and retirements. This section covers some key assumptions used in OptGen.

2.3.8.1 Location of new generation

Assumption

202. We will disclose our assumptions of the location of new generation plants outside the assumptions book for each BBI.

Background

203. The EDGS do not specify the location of new generation; they provide only national forecasts over time. Our general approach to determining the location of new, uncommitted generation is outlined below.

204. Our generation expansion modelling will include HVDC capacity constraints and energy losses. This allows us to correctly account for the balance of generation investment between the two Islands, which is an important driver of future power flows across the HVDC link and the core grid.

205. Regarding the location of generation within each Island, where a BBI is likely to materially influence the location of new generation, we will consider modelling AC transmission constraints in our generation expansion modelling[94]. Including intra-Island AC transmission constraints can be computationally expensive; therefore, we include only those AC constraints that are relevant to the BBI under consideration. Where there are advantages to doing so, we may impose AC transmission constraints by manually adjusting a generation expansion plan with no modelled constraints (as a post processing step). Where this is done, care will be taken to ensure that the resulting expansion plan remains revenue adequate.

206. Where a BBI is unlikely to materially influence the location of new generation, generation investment decisions will be made without considering (or modelling) potential intra-Island transmission constraints.

207. In some cases, we may restrict generation investment in regions with transmission capacity constraints that are outside the scope of the BBI. This may occur if new generation build in a transmission-constrained region downstream of the BBI may need to be limited to the available transmission capacity of this region. Without this cap, an excess of new generation may be built which could potentially (and inappropriately) underestimate the benefits of the BBI.

208. Generation scenarios produced using this approach are not intended by us to be precise forecasts of the location of new generation. Rather, they are used to help us understand the extent to which a BBI is likely to benefit the electricity market.

2.3.8.2 Committed projects and earliest commissioning date

Assumption

209. Where we consider a project to be committed, we include it manually in the generation expansion plan for all scenarios. A list of committed plants as at April 2026 is shown in the

[94] For the counterfactual (without the BBI) and factual (with the BBI) cases. See Section 3.3.2.8.

"Committed projects" tab of Appendix F[95], and in Figure 14. For projects other than thermal peakers and BESS , we initially restrict build to those projects that are in Transpower's generation connection pipeline as at April 2026 – with timing shown in the OptGen Build Timing Restriction diagram as presented in Figure 15.

210. Updates to committed generation and Transpower generation connection queue may be made for each BBI. Updates will be restricted to changes that in our view are likely to have a material impact on the BBI's benefits.

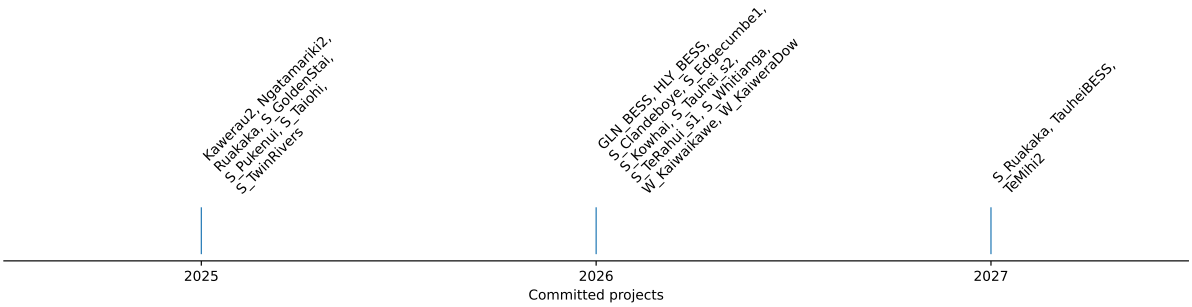

Figure 14: Modelled committed projects timeline

211. For BESS we assume the generic projects detailed in Section 2.3.8.8 have an earliest commissioning date of 2027.

212. We assume that a consented thermal peaker project can be developed in 2-years' time.

[95] This specifies the committed build from 1 Jan 2025 and includes projects which have now been commissioned. We normally begin our modelling on 1 Jan 2025 to give a period for the model to set up a representative hydro storage. The cost and installed capacity of the committed build is specified in the Future wind, Future Solar, Future Geothermal and Future Battery sheets of Appendix F.

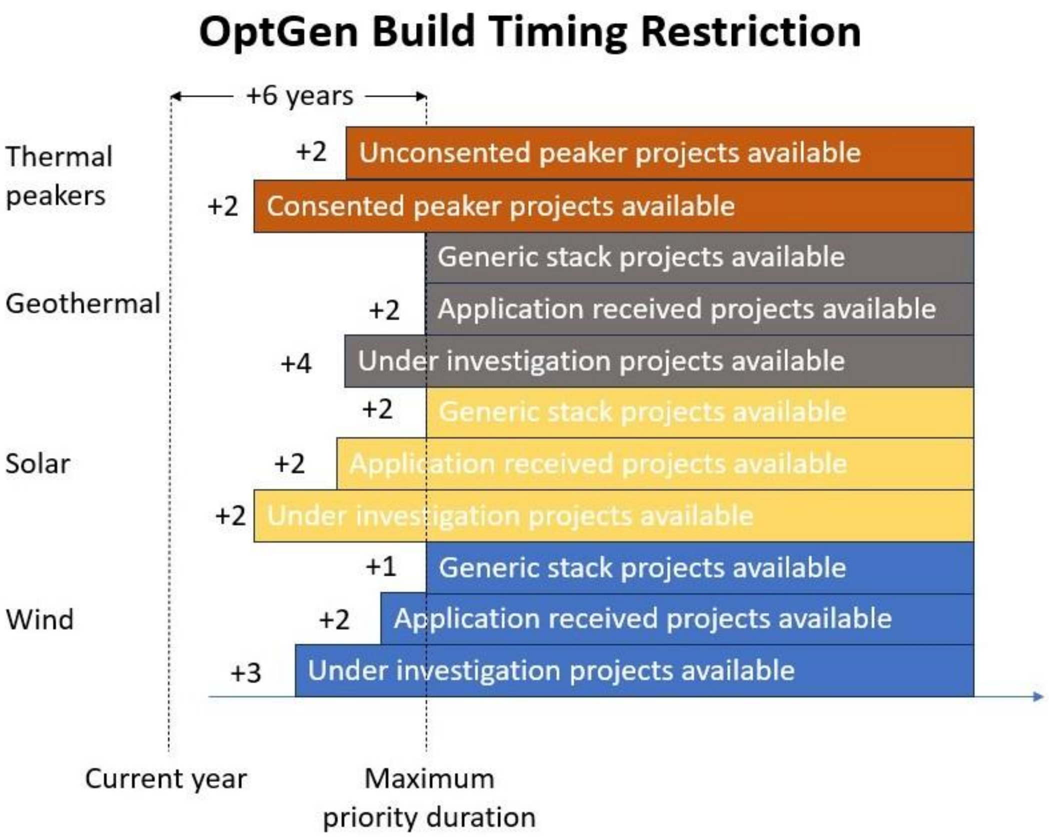

Figure 15. OptGen Build Timing Restriction, relative to current year

Background

213. Information on committed projects is sourced from Transpower's internal operations, supplemented by publicly available market information.

214. Information on other future generation projects is based on MBIE's generation stack updates, Beca and Concept's 2025 Generation Stack Report[96] and information from Transpower's generation connection pipeline.[97] The connection pipeline provides a rich source of information on potential generation which augments the 2025 generation stack. The connection pipeline is our best view of what the market intends to build in the short-term and is a real queue which developers cannot circumvent.

215. We apply the following process to set the earliest build date of wind, solar, geothermal and hydro projects in the connection pipeline:

    a. The connection pipeline classification of projects includes whether the generation connection status is in "Delivery", "Under investigation" by Transpower, or "Application Received".

    b. Projects in Transpower's connection pipeline with the status of "Under investigation" have the earliest commissioning dates defined below.

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96 [2025 Generation Stack Report | Beca and Concept (2025)](). Commissioned by Transpower.

97 [Connection enquiry information | Transpower]()

c. An additional two years is applied to these earliest commissioning dates for those projects with the status of "Application Received"

d. Other stack projects (e.g. those not in Transpower's connection queue) can be commissioned a further two years after this, or after six years from the current year if this occurs first.

216. The earliest commissioning date for BESS is assumed to be 2027. This reflects one year for planning and a one-year construction and consenting period[98], after which BESS build commences to support the gradual capacity build outlined in section 2.3.8.8.

217. The approach for thermal peaker plants is different to other generation and is based only on whether the project is consented or not. We assume that a consented thermal peaker project can be commissioned in two-years' time (e.g the earliest commissioning date for a thermal peaker project outlined below), and unconsented projects in four years' time.

218. Our earliest commissioning date assumptions, for "Investigation projects" are based on estimates of construction time and we add an additional one-year delay to account for the time required for developers to finalise an investment decision.

a. Wind: we assume a two-year construction period for wind stations based on recent projects – e.g. Waipipi,[99, 100] and Turitea (North)[101, 102]

b. Solar: we assume solar plants will take one year less than wind given the relative ease of construction (particularly less onerous civil/structural requirements)

c. Geothermal: we assume a three-year construction period. This is based on Contact's targeted timeline relating to the construction of Te Mihi Stage 2[103].

d. Thermal peaker: we assume a construction period of two years based on recent projects – e.g. Junction Road,[104, 105] and McKee[106, 107]

e. Hydro: we assume no hydro is built before 2037 because of the recent absence of major proposed and committed hydro projects, which may be due to the difficulty of consentinghydro projects of this nature. There are some signs in the market that this may be changing, and we will continue to monitor interest levels in hydro generation in New Zealand[108].

98 Recent BESS projects are expected to be commissioned over a 18 – 24 month period (e.g. the Ruakaka BESS project commenced in March 2023 and was completed in early 2025).
99 Construction at Waipipi to start soon – Tilt | Energy News (2019).
100 Waipipi fully commissioned – Tilt | Energy News (2021).
101 New wind farm a further step to low carbon future | NZX Announcements (2019).
102 Quarterly Operational Update | NZX Announcements (2021).
103 Contact Invests to Redevelop Wairakei | NZX Announcements (2024)
104 Todd moves ahead with Junction Road peaker | Energy News (2018).
105 Todd commissioning Junction Road gas peaker | Energy News (2020).
106 Todd to build $100m gas-fired peaker at McKee | Energy News (2010).
107 Todd starts commissioning $100m McKee peakers | Energy News (2012).
108 Meridian Energy are considering a number of hydro development concepts, the Clutha Pumped Hydro Consortium are pursuing pumped hydro at Lake Onslow and Westpower are pursuing the 23 MW Waitaha Hydro Scheme:
Meridian eyes 'multi-metre' Pūkaki raise in 1 TW hydro plan | Energy News (2025)

2.3.8.3 Thermal

Assumption

219. A list of possible future plants from the generation stack and related costs are shown in the "Future thermal" tab of Appendix F.

220. Future OCGT and Rankine thermal plants are configured with primary and alternative fuels as described in Table 6.

221. Future reciprocating engines are configured for diesel as the primary fuel. Alternative fuels for this technology are:

    a. Biofuel for all locations, for the Environmental scenario only.

    b. Natural gas for reciprocating engines at Huntly only.

222. For our generation expansion planning we may decide to only model primary fuels to reduce complexity and materially reduce computational effort.

Background

223. We include the following thermal generation technologies in our generation stack:

    a. OCGTs, located at either Stratford, Huntly and Otorohanga (connecting into the Taumarunui substation).

    b. Reciprocating engines, located at Bream Bay and Huntly.

    c. Rankines, located at Huntly.

224. Plant locations are based on current market indications as much as possible[109]. Plant capacities, as provided in Appendix F, are maximums. Our generation expansion modelling will only build as much thermal generation capacity as is required to ensure an economically optimal expansion plan.

225. We do not include CCGT type plants in our stack as we expect flexible peaking generation, such as OCGTs or reciprocating engines, to be more complementary to the high amounts of intermittent renewables that feature in our future scenarios. We expect that the operational capabilities of these types of peakers means that they can provide this firming service more economically than CCGTs.

226. Future thermal generation project costs, variable operating and maintenance costs and heat rates are based on information from the 2025 Generation Stack Report. We assume a

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Onslow to slash power costs, boost investment | Energy News (2026)
Waitaha Hydro gets draft consent, cuts term to 49 years | Energy News (2026)

109 With regard to OCGTs: Nova have consents to build OCGTs at Otorohanga. We also assume that OCGTs could be further developed at Huntly and Stratford, given the availability of existing infrastructure.
With regard to reciprocating engines: As reported in Energy News, Genesis Energy are considering options to install mobile reciprocating engines at Huntly and Channel Infrastructure are considering a diesel peaker project at Marsden Point using "containerised diesel gensets".
With regard to Rankines: As reported in Energy News, Genesis Energy considers that "Installing a new Rankine at Huntly is possible, however building a commercial standalone business case for one is likely challenged under current market settings."

COR of 3% for all new thermal generation plant, to align with the Authority's Security Standards Assumptions Document.

2.3.8.4 Hydro

Assumption

227. Possible future hydro plants, together with assumed specifications are listed in the "Future hydro" tab of Appendix F.

228. We also assume:

   a. a 'base' 2025 capital cost of $9,195/kW

   b. a 'base' 2025 fixed operating and maintenance costs (**FOM**) of $89/kW-yr

   c. variable operating and maintenance costs (**VOM**) at $0/MWh

   d. COR of 2%.

Background

229. Our list of potential new hydro plant is from MBIE's 2020 hydro generation stack.[110] Costs have been updated based on the 2025 Generation Stack Report.

2.3.8.5 Geothermal

Assumption

230. Potential future geothermal plants are listed in the "Future geothermal" tab of Appendix F.

231. Geothermal capital costs depend on technology and field enthalpy:

   a. flash geothermal plants have a 'base' 2025 capital cost of 5,600 $/kW

   b. binary geothermal plants have a 'base' 2025 capital cost of 6,700 $/kW

   c. a capital cost multiplier of 1.2 is applied to geothermal plant situated on low enthalpy geothermal fields.

232. We assume all new geothermal projects less than 50 MW will be binary, and all other new geothermal projects will be flash. The low enthalpy capital cost multiplier is applied to:

   a. Ngawha3-6.

   b. Mokai4

   c. Rotoma1

233. We also assume:

   a. a 'base' 2025 FOM at $162/kW-yr

   b. VOM at $0/MWh

   c. COR of 10%.

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[110] Hydro generation stack update for large-scale plant | Roaring 40s Wind Power (2020). Commissioned by MBIE.

Background

234. Our geothermal generation stack is based on MBIE's 2020 geothermal generation stack[111], from which we also take the specification of field enthalpy. Costs have been updated based on the 2025 Generation Stack Report.

235. The 50MW cut-off for binary plant is a simplification based on existing geothermal developments.

2.3.8.6 Wind

Assumption

236. Potential future wind generation plants, capacities and the renewable regions are listed in the "Future wind" tab of Appendix F.

237. We also assume:

    a. a 'base' 2025 FOM of $43/kW-yr

    b. VOM at $0/MWh.

Background

238. Transpower's wind generation stack is based on the 2025 Generation Stack Report. Project-specific details were provided to Transpower by Beca and Concept Consulting with no modification except to map projects to an appropriate GXP/GIP. The stack includes potential wind generation projects with 'base', 2025 capital costs ranging from $3,102/kW to $3,777/kW.

239. We have updated the wind generation plants to include additional projects that are in Transpower's generation connection pipeline[112] (as of August 2025). For these projects, we apply technology level cost assumptions, if they are not already covered by the 2025 Generation Stack Report.

240. We use the same regional capacity factors for new wind generation as the existing wind generation (see section 2.3.4.6).

2.3.8.7 Solar

Assumption

241. Potential future solar generation plants, capacities and the renewable regions are listed in the "Future solar" tab of Appendix F.

242. We also assume:

    a. a 'base' 2025 FOM of $27/kW-yr

    b. VOM at $0/MWh

Background

243. Transpower's solar generation stack is based on the 2025 Generation Stack Report. Project-specific details were provided to Transpower by Beca and Concept Consulting with

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111 Future Geothermal Generation Stack | Lawless Geo-Consulting (2020)

112 Connection enquiry information | Transpower

no modification except to map projects to an appropriate GXP/GIP. The stack includes potential solar generation projects with ‘base’ 2025 capital costs of $1,825/kW to $1,975/kW.

244. We have updated the future solar generation plants to include several plants from Transpower’s generation connection pipeline (as of August 2025). For these projects we apply technology level cost assumptions, if they are not already covered by the 2025 Generation Stack Report.

2.3.8.8 Batteries

Assumption

245. Potential future BESS and their respective maximum potential capacities, corresponding storage (MWh) and locations are presented in the “Future battery” tab of Appendix F.

246. We also assume:

a. a ‘base’ 2025 FOM of $25/kW-year

b. VOM is $0/MWh.

247. The round-trip efficiency of the batteries is 85%, split equally between charge and discharge efficiency.

248. We assume candidate BESS projects exist in eight locations in the North Island and six locations in South Island. These locations are selected such that there is at least one BESS project available in each Transpower grid zone.

249. All candidate BESS projects are two-hour batteries.

250. BESS build for each Island is linked to wind and solar build using the following constraint equation:

$$BESS \geq (Solar + Wind)x$$

Where:

- *BESS*, *Solar* and *Wind* are the installed capacity of each technology as built in a given year
- x is defined in Table 18.

The above constraint equation is applied from the start of 2027 onwards.

Table 18: Parameter x for each market scenario

Market scenario	MBIE’s 2024 EDGS new BESS installed capacity (MW)	Parameter *x*: The ratio of new BESS to New Wind and Solar
Reference	733	5%
Growth	733	3%
Constraint	733	9%

Market scenario	MBIE's 2024 EDGS new BESS installed capacity (MW)	Parameter *x*: The ratio of new BESS to New Wind and Solar
Innovation	1700	12%
Environmental	1700	11%

Background

251. We obtain BESS capital costs from the 2025 Generation Stack Report.

252. Round-trip efficiencies are based on NREL's Cost Projections for Utility-Scale Battery Storage.[113]

253. Limiting the potential locations where BESS can be built is a necessary modelling simplification. In Optgen, there is little to differentiate one BESS location from another unless potential grid constraints are considered, which would most likely be computationally expensive.

254. The constraint equations used to model BESS are intended to align BESS build outcomes with MBIE's 2024 EDGS. While MBIE defined absolute BESS build targets, they also noted that the economic incentives for BESS investment are closely linked to price volatility, which they expect to increase with higher penetrations of intermittent generation such as wind and solar. Consistent with this approach, we apply MBIE's ratio of BESS to intermittent generation (the x term in the constraint equation)[114]. This allows BESS build to scale with wind and solar development, catering for different levels of intermittent generation across market scenarios relative to MBIE's 2024 EDGS.

255. This approach has been adopted because, without explicit reserve requirements or other mechanisms that better reflect how prices are set in the wholesale market, Optgen tends to under-build BESS. This outcome reflects inherent differences between simulated prices and observed market prices, along with the value BESS provides through services not fully represented in the model. While alternative approaches to modelling BESS exist, they are currently either computationally expensive or add an undesirable level of complexity.

2.3.8.9 Transpower's generation connection pipeline cost assumptions

256. For projects sourced from Transpower's generation connection pipeline we assume that project costs are equal to the cost for typical plants from the 2025 Generation Stack.

113 Cost Projections for Utility-Scale Battery Storage: 2023 Update | NREL (2023). The analysis in this NREL report is based on a round-trip efficiency of 85%. SDDP is configured using a charge efficiency and discharge efficiency. We assume that these are both 92.2%, which taken together is approximately equal to a discharge efficiency of 85%.

114 The parameter x is calculated, for each market scenario, as

$$x = \frac{MBIE\ assumed\ BESS\ installed\ capacity - committed\ and\ existing\ BESS\ installed\ capacity}{(MBIE\ wind + solar\ installed\ capacity)_{year=2050} - (MBIE\ wind + solar\ installed\ capacity)_{year=2023}}$$

This accounts for committed BESS built before 2027.

Background

257. We do not have cost information on projects sourced from Transpower's generation connection pipeline. We use generic project costs sourced from the 2025 Generation Stack Report as this is an easily derived and reasonable assumption. This assumption is more relevant to geothermal, solar and wind projects whose values vary by project across the stack.

2.3.8.10 Chronological cost assumptions

Assumption

258. We apply different capital cost scenarios in each market scenario to all generation types:

   a. Reference: 'base' cost scenario

   b. Growth: 'low' cost scenario for geothermal, and 'base' cost scenario for other generation

   c. Constraint: 'high' cost scenario

   d. Environmental: 'base' cost scenario

   e. Innovation: 'low' cost scenario.

259. Capital costs are provided at a project level in the "Chron. cap. costs", tabs of Appendix F.

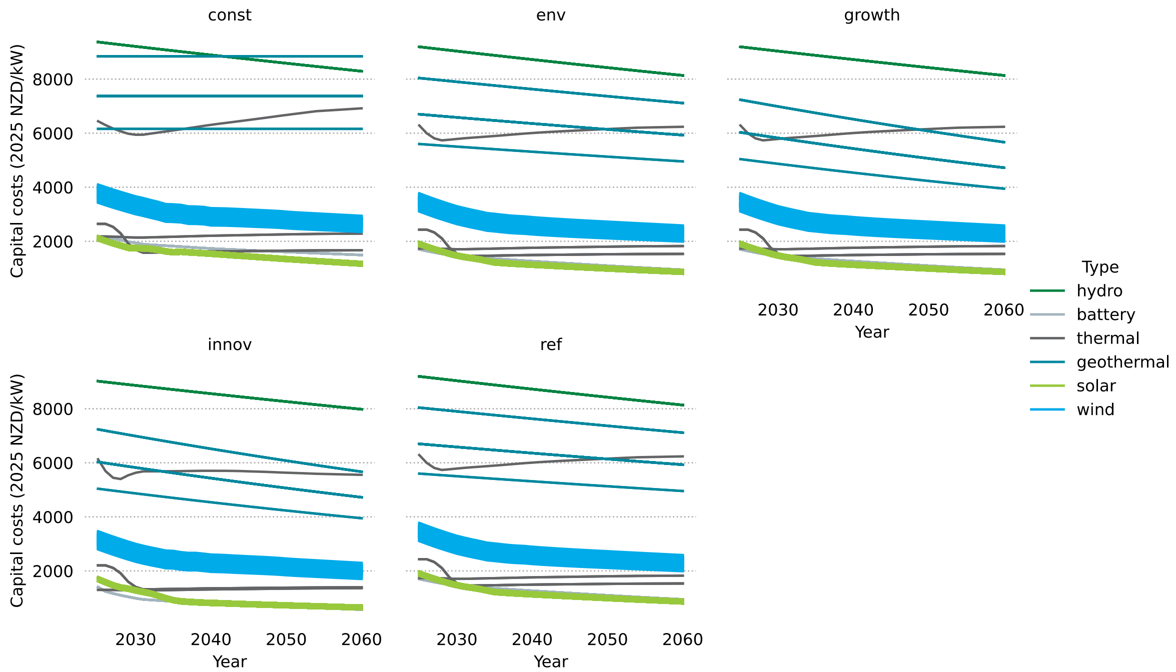

Figure 16 shows how the capital costs for the various technologies and market scenarios change with time. Figure 17 shows how the capital costs for the various technologies change with time relative to their capital cost were they to be built in 2025. Thermal projects have three trajectories: one each for OCGT, reciprocating, and Rankine plants.

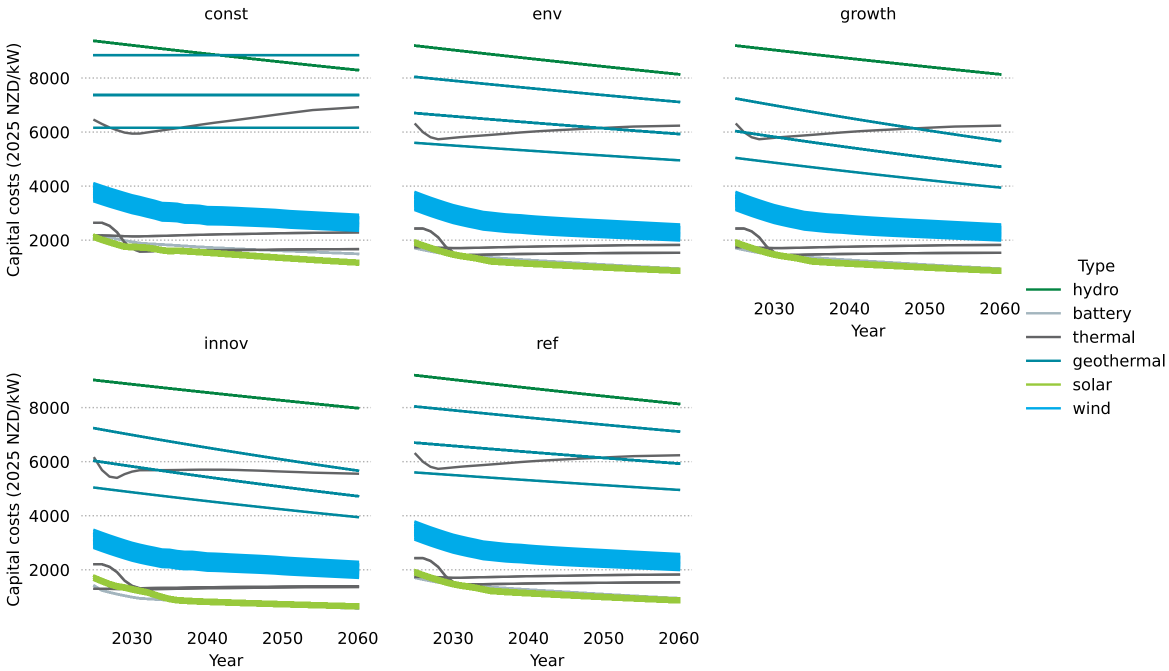

Figure 16: Chronological capital costs by technology and market scenario

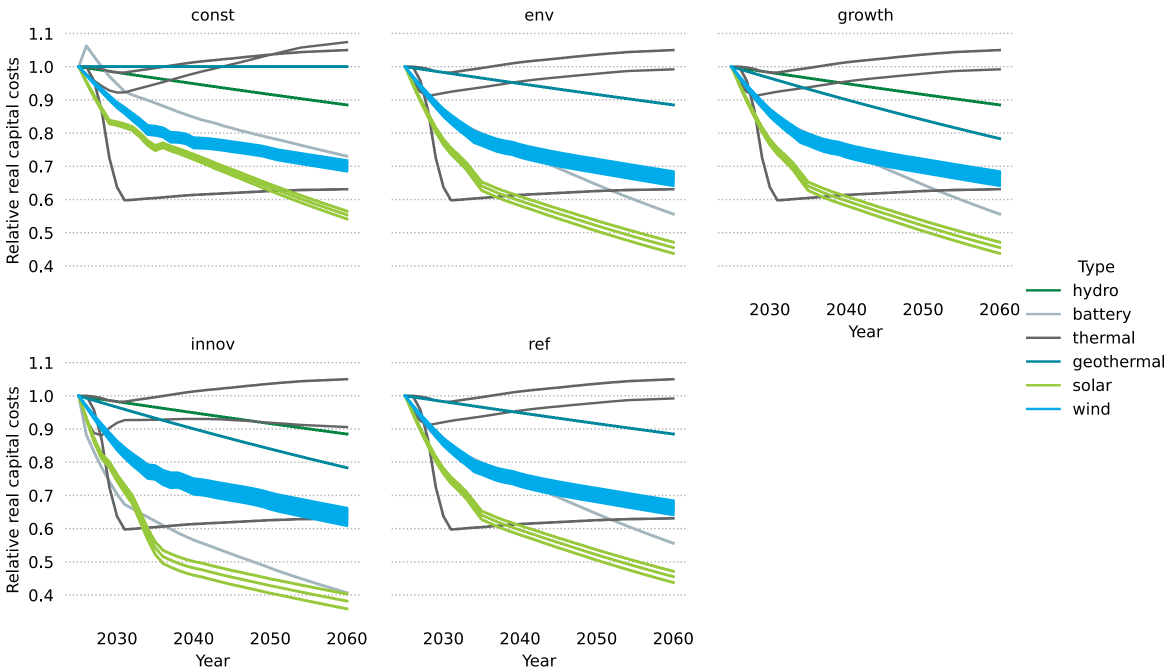

Figure 17: Chronological capital costs by technology divided by the cost of building the plant in 2025.

260. An annual reduction in FOM costs is also applied for all generation types. These are shown in Figure 18 and are provided in the "Chron. FOM costs" tabs in Appendix F.

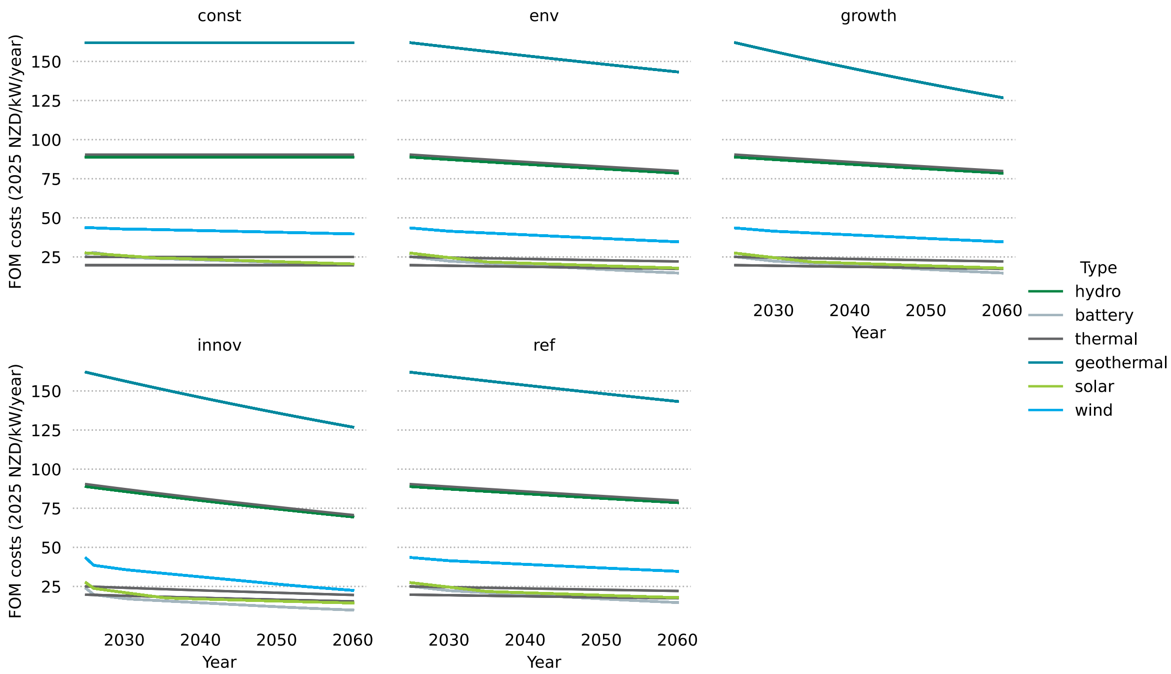

Figure 18: Chronological fixed operating and maintenance costs

Background

261. A generation project's capital and operating costs can change over time (in real terms). This is particularly relevant in the case of non-traditional generation such as wind, solar, and batteries, and to a lesser extent, geothermal. These technologies have seen dramatic price reductions over recent decades. This is expected to continue as research and manufacturing processes further develop and mature. Hydro and thermal generation costs are expected to vary less over time because they are mature technologies that are not generally viewed as having an expanding role in overseas markets (and therefore are not expected to benefit from economies of scale and new innovations).

262. We use the cost scenarios from the 2025 Generation Stack Report . This resource provides an estimate of project level costs for wind and solar generation and technology level cost for other generation types. All costs have been benchmarked consistently, and although international forecasts have been applied, the costs of NZ deployment are considered.

263. These 'low', 'base' and 'high' cost scenarios correspond to the classifications provided in the 2025 Generation Stack Report . All costs generally decline in real terms, and the cost scenarios reflect the extent to which costs fall. The 'low' scenario gives the minimum generation costs, 'high' gives the highest costs, and 'base' gives a midpoint estimate.

264. The generation capital cost scenarios applied are consistent with the market scenario themes. For example, in the Constraint scenario we assume higher technology costs to reflect international supply chain factors, whereas for the Innovation scenario we assume lower generation costs driven by high global technological uptake and manufacturing efficiencies. The Growth scenario applies a lower cost scenario exclusively to geothermal generation – we apply this to reflect the potential for NZ-led innovation in geothermal generation which is consistent with the domestic economic growth in the Growth scenario.

This setting also helps to promote some diversity in generation outcomes in our expansion plans.

265. The 2025 Generation Stack Report specifies FOM and VOM only at the technology level and only a single cost scenario is provided. For this reason, these costs are not varied across scenarios.

2.3.8.11 Placeholder generators

Assumption

266. 0.1 MW capacity diesel (representing thermal generation), wind, solar, and battery generators may be added to the factual and counterfactual to allow for future regional customer groups to be created.

Background

267. When new, large generating plant is connected to the grid it will receive charges for existing BBIs based on Part F of the TPM, which requires that, for a given BBI, new customers or new large plant are assigned to the regional customer group that the new customer is expected to be a member of. The regional customer group may be a future regional customer group which has no members when allocations are first set but are created because the benefits or disbenefits of the group are expected to be materially different to existing customers in the same modelled region.

268. Modelling placeholder generators allows us to create these future regional customer groups where:

    a. the benefits or disbenefits to a generation technology that doesn't currently exist in a modelled region may be materially different to existing generators in that modelled region; and

    b. OptGen has not commissioned all the possible generation technologies in a given modelled region.

269. The placeholder generators will have a 0.1 MW capacity such that they don't materially impact the modelled dispatch and prices.

270. We will not implement placeholder hydro generators because we consider the existing hydro generation is sufficiently dispersed that there will be a group for any new hydro generation to join. Similarly, we will not implement placeholder geothermal generation because any new generation is likely to connect in the regions where existing geothermal generators are located and so will have a group to join.

Chapter 3
Processes and methodologies for the standard methods and simple method

3.1 Introduction to this chapter

3.1.1 Purpose

271. This chapter provides an explanation of the processes and methodologies Transpower applies to calculate starting BBI customer allocations for post-2019 BBIs.

3.1.2 Background

272. The costs of new and certain historic interconnection investments (BBIs) are allocated to benefitting customers through BBCs. BBIs include investments in new interconnection assets and the replacement or refurbishment of existing ones.

273. The cost recovered through the BBCs for a BBI is referred to as the BBI's covered cost and includes the BBI's capital components (return of and on capital expenditure) and an allocation of Transpower's total operating costs (including overheads). See clauses 39 and 40 of the TPM for more detail on the calculation of covered cost.

274. A BBI's covered cost is allocated between customers so that the allocation is broadly proportionate to the expected positive net private benefit (**EPNPB**) each customer derives from the BBI.[115] That is, the BBC paid by a customer must reflect that customer's EPNPB from the BBI (if any) relative to all other customers' EPNPB.

3.1.3 Starting BBI customer allocations for new (post-2019) BBIs – standard and simple methods

275. The TPM includes three methods for calculating EPNPB, and therefore starting BBI customer allocations, for post-2019 BBIs. There are two standard methods (the resiliency and price-quantity methods) and one simple method.

276. The two standard methods are used to calculate EPNPB and starting BBI customer allocations for post-2019 BBIs expected to be valued over $30m when fully commissioned (high-value BBIs). The simple method is used to calculate EPNPB and starting BBI customer allocations for post-2019 BBIs valued up to $30m (low-value BBIs). This aligns with the $30m base capex threshold set by the Commerce Commission (**Commission**), below which Transpower does not need to seek separate Commission approval for grid investments.

277. The following diagram illustrates how Transpower determines which method to apply to a post-2019 BBI.

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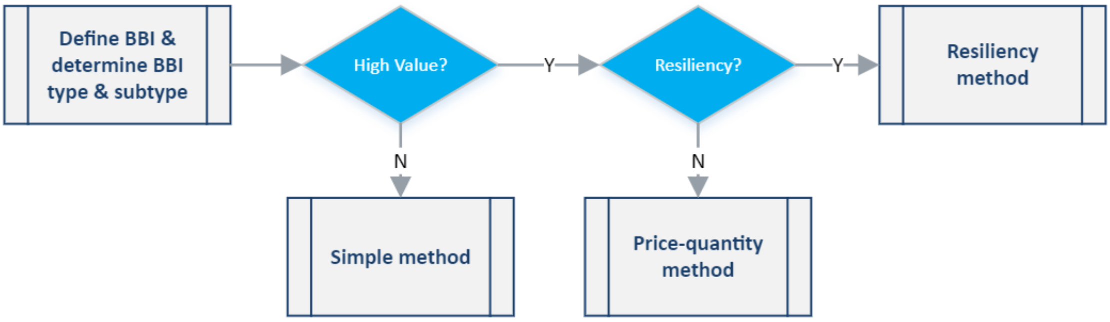
115 Where we refer to expected positive NPB, this is consistent with the TPM, which defines NPB as the sum of quantified benefits (positive values) and disbenefits (negative values) the regional customer group or customer is expected to receive from the relevant BBI. We use the term "expected" in this paper to signal that when we set customer allocations we do so based on customers' expected positive NPB at the time of setting. Unless there is an adjustment event (Part F of the TPM), customer allocations are not updated for a customer's actual NPB (or their expected NPB) in later periods even if these change.



Determine method for post-2019 BBI

3.1.4 The standard methods – price-quantity method and resiliency method

278. The price-quantity method must be used for all high-value post-2019 BBIs that are not resiliency BBIs. The price-quantity method calculates EPNPB based on price and quantity changes (with and without the BBI) in the wholesale markets for electricity and ancillary services and changes in reliability (unserved or unsupplied energy). Subject to certain limits, under the price-quantity method Transpower may also take into account other costs and benefits that arise outside electricity markets, such as aesthetic or safety improvements. Section 3.3 of this chapter relates to the price-quantity method.

279. The resiliency method must be used where the primary purpose of a high-value post-2019 BBI is to mitigate a risk of cascade failure or a high impact, low probability (**HILP**) event resulting in unserved energy (referred to as a resiliency BBI). Section 3.4 of this chapter relates to the resiliency method.

280. Both standard methods involve determining regional customer groups of beneficiary customers (and, under the price-quantity method, the regional net private benefit (NPB) for each regional customer group) and then calculating individual NPBs for the customers in those groups with positive regional NPB based on historical grid use, mostly grid offtake or injection. The individual NPBs are then used to calculate the starting BBI customer allocations for the relevant BBI.

3.1.5 The simple method

281. The simple method uses a regional allocation model with regional allocation factors for generation and load to calculate regional NPB for each regional customer group. The regions and regional allocation factors are static – they apply to all low-value BBIs commissioned during a (usually) five-year simple method period, after which the regions and regional allocation factors are reset for low-value BBIs commissioned in the next simple method period (the BBI customer allocations for previously commissioned low-value BBIs do not change). The regions and regional allocation factors are calculated based on historical power flows before the start of the simple method period.

282. Under the simple method, as under the standard methods, individual NPBs for the customers in the regional customer groups with positive regional NPB are calculated based on historical grid use (grid offtake or injection), and the individual NPBs are then used to calculate the starting BBI customer allocations for the relevant BBI. Section 3.5 of this chapter relates to the simple method.

3.2 Define BBI and determine BBI type and sub-type

283. Internally, we often group expenditure together into a project or programme for administrative purposes (e.g. a tower painting programme made up of many small projects). However, under the TPM, we need to determine if a project or programme is a single BBI or several BBIs.

284. The Transpower Capex Input Methodology (**Transpower Capex IM**) includes definitions of project and programme for the purpose of determining if expenditure exceeds the base capex threshold:[116]

> ***project*** *means temporary endeavour requiring concerted effort, which is undertaken to create defined outcomes*
>
> ***programme*** *means-*
>
> *(a) two or more projects; or*
>
> *(b) two or more projects and expenditure activities,*
>
> *within the same category of capital expenditure that are grouped together on the basis of having a common purpose.*

285. Based on these definitions, we typically consider expenditure to be a single project or programme if it meets a common investment need.

286. For example, under the Transpower Capex IM, capital expenditure incurred to maintain the HVDC link is typically grouped together because all of the expenditure works together to ensure the HVDC link continues to operate. However, a tower painting programme consisting of many towers throughout the country would typically not be grouped together because the lines are in different geographic areas of the network.

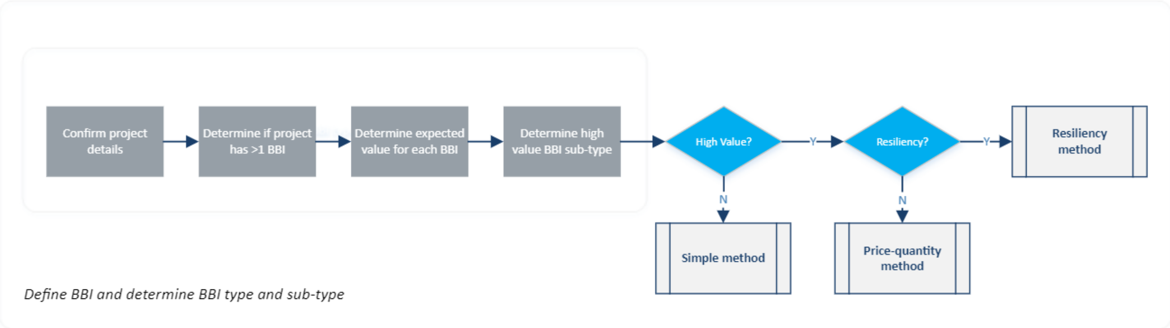
287. While this principle (or similar) is sufficient for the purpose of applying the Transpower Capex IM, it is not necessarily sufficient when determining if expenditure should be grouped together into a BBI under the TPM.

288. Defining the BBI is a pre-requisite to determining the method used to allocate BBCs for the BBI. We need to know:

    a. the type of the BBI, i.e. whether it is high value or low value (see paragraphs 293 to 296)

    b. if the BBI is a high value, the sub-type, i.e. whether it is a resiliency BBI or not (see paragraphs 297 to 299).

[116] Transpower-capital-expenditure-input-methodology-determination-consolidated-29-January-2020.pdf (comcom.govt.nz).



289. Paragraphs 290 to 301 provide a description of each process.

3.2.1 Confirm project details

290. When we propose a project (or programme) to the Commission (or as part of Transpower's internal business case approval process if not a tested investment[117]), the following will be confirmed:

   a. the expected capital expenditure and, if the project includes a transmission alternative, operating expenditure of the project

   b. the benefit types (i.e. market, reliability, ancillary service, resiliency and/or other benefits) that are expected to result from the project

   c. the expected commissioning date of the project, including where different stages (that is, specific grid outputs) of the project will be commissioned at different dates.

3.2.2 Determine if project has >1 BBI

291. It may be necessary for us to break a project (or programme) into more than one BBI in order to produce starting BBI customer allocations that are broadly proportionate to EPNPB. These are some situations where we may split a project into multiple BBIs:

   a. programmes of asset replacement or refurbishment relating to assets in very different parts of the network (e.g. a tower painting programme)

   b. when project components are committed at significantly different times. For example, the Lower South Island (**LSI**) Renewables project was originally approved in 2010 but was committed and has been delivered as two distinct projects – the first stage was completed in 2015/16 and the second was substantially completed in 2022

   c. where a project consists of distinct groups of grid outputs that address different investment needs.

292. This step also confirms the final grid state that will be delivered via the BBI and, as such, used as the factual under a standard method if the BBI is high value.

117 We refer here to the investment test applied to a tested investment under section III of Part F of the old Electricity Governance Rules or the Transpower Capex IM.

3.2.3 Determine expected value for each BBI

293. Once the project (or programme) has been assigned to one or more BBIs, the expected asset value and transmission alternative operating expenditure for the fully commissioned BBI can be confirmed.[118]

294. Where the expected value for a fully commissioned BBI is ≤$30m (that is, the BBI is a low value BBI), the TPM requires us to use the simple method in order to calculate a customer's individual NPB for that BBI. Similarly, if a project or programme is comprised of multiple BBIs whose individual value is <$30m but combined value is >$30m, the simple method will be applied.[119]

295. All high-value BBIs (those with an expected value when fully commissioned that exceeds $30m) will use either the resiliency or price-quantity method to calculate a customer's individual NPB.

296. The fully commissioned value of a BBI will be assessed based on the Commission-approved major capex allowance and/or maximum recoverable costs for the BBI, where available.

3.2.4 Determine high-value BBI sub-type

297. We will determine if a high-value post-2019 BBI is under the price-quantity or resiliency method based on the primary investment need being met by the BBI.

298. The resiliency method will be used when we determine that the primary investment need being met by the BBI relates to mitigating the risk of a HILP event or cascade failure. In all other instances we will use the price-quantity method.

299. For the purposes of the TPM, we consider a HILP event to be an event (or group of events) with the following characteristics:

    a. the probability of its occurrence is less than or equal to a one in 30-year event, and

    b. the impact of the event would be unserved energy greater than 2 GWh (but is not cascade failure).

3.2.5 Expenditure on existing BBIs

300. The discussion above is about expenditure that is comprised in a new BBI.

301. Under clause 37 of the TPM we may decide to treat refurbishment and replacement investments as part of an existing BBI, subject to certain limits. If we do that the investment will increase the covered cost of the existing BBI and we will not need to determine whether to treat the investment as one or more new BBIs.

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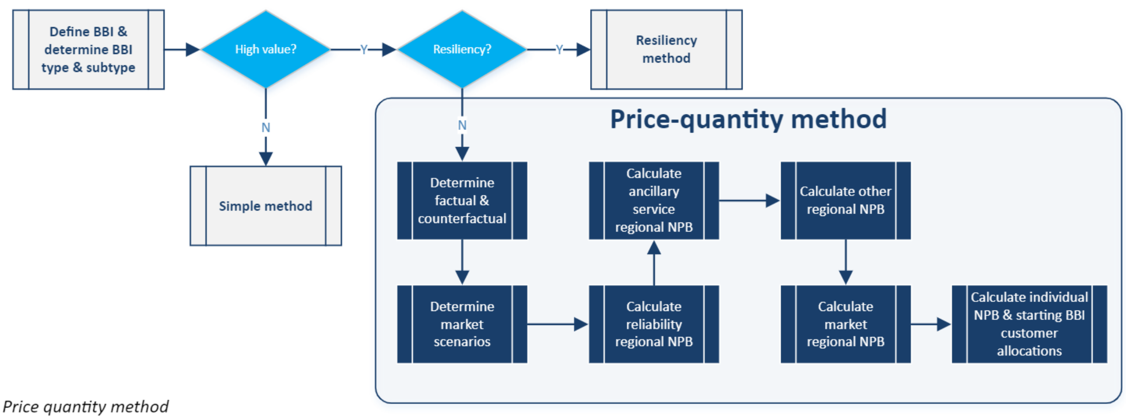
118 Like the test against the base capex threshold in the Capex IM, the high-value/low-value test in the TPM is on the expectation (forecast) of the project's cost, not the actual cost after commissioning. If a BBI's expected value when fully commissioned is less than the base capex threshold, it will be under the simple method regardless of its actual value after full commissioning.

119 The high-value/low-value test in the TPM will increase to $30m from 1 April 2025.

3.3 The price-quantity method (standard method)

302. The price-quantity method is used to calculate EPNPB when we determine that a high-value post-2019 BBI has not met the criteria of a resiliency BBI.

303. The price-quantity method requires a series of processes to be performed, as illustrated in the diagram below.



Price quantity method

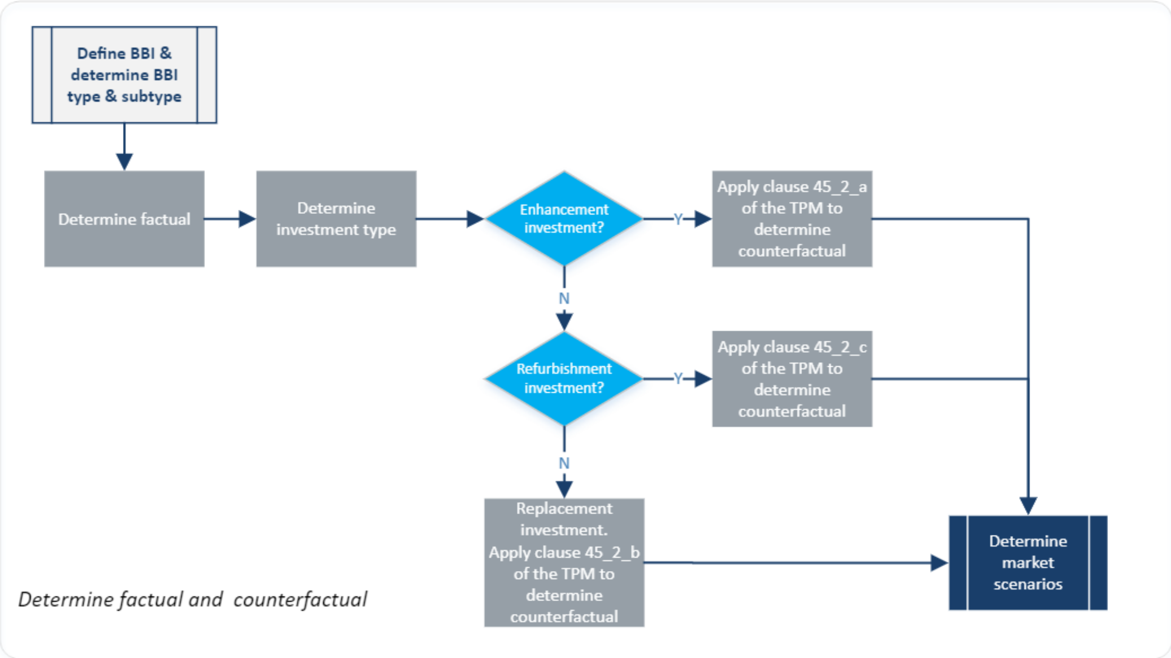
304. The following subsections provide a description of each process.

3.3.1 Determine factual and counterfactual

3.3.1.1 Introduction

305. The price-quantity method requires us to determine the factual and counterfactual (the future state of the grid with and without the BBI). This section provides a summary of the process undertaken to reach this determination and why it is necessary.

3.3.1.2 Overview diagram



3.3.1.3 Determine factual

306. The factual is the expected future grid state that will result from the completion of the BBI (i.e. the BBI is fully commissioned).

3.3.1.4 Determine investment type (and counterfactual)

307. The counterfactual is the expected future grid state that would result should no part of the BBI be completed (i.e. the BBI is not commissioned). In order to determine the counterfactual, we must determine the type of investment(s) being completed. Investments can be one of the following three types, and may also be a compliance investment:[120]

    a. replacement

    b. refurbishment

    c. enhancement.

308. The definitions of each investment type are specified in the TPM and are based on definitions in the Transpower Capex IM. Clause 45 states the principles we must use for determining the counterfactual depending on the investment type.

309. Occasionally, a BBI may be a combination of these investment types, e.g. an investment that increases the capability of the grid today (an enhancement) and also an investment to replace an asset nearing the end of its life (a replacement). In such situations, we will combine the clause 45 principles when determining the counterfactual in order to ensure the counterfactual represents a reasonably likely future grid state.

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120 A compliance investment is an investment made to ensure the grid can be operated within accordance with good electricity industry practice. A compliance investment may also be an enhancement, refurbishment or replacement investment.

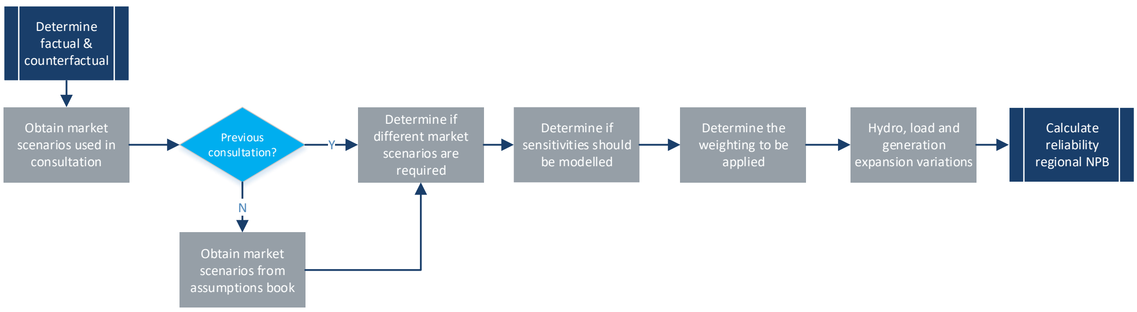
3.3.2 Determine market scenarios

3.3.2.1 Introduction

310. The price-quantity method requires us to determine market scenarios.[121] This section provides a summary of the process undertaken to reach this determination.

311. Clause 43(5) requires the input assumptions (including market scenarios) used to apply the standard method to be as consistent as reasonably practicable with those used to apply the investment test, except where we determine they would not produce allocations that are broadly proportionate to EPNPB (and as otherwise stated in the TPM). Therefore, the philosophy of this step is to use the same market scenarios as used for the investment decision. However, due to the different requirements of the TPM and the Transpower Capex IM, the market scenarios used for calculating EPNPB may need to be different, as outlined in this section.

3.3.2.2 Overview diagram



Determine market scenarios

3.3.2.3 Obtain market scenarios used in consultation

312. We may have consulted on the market scenarios for the BBI as part of investment test consultation under the Transpower Capex IM (or under the old Electricity Governance Rules). Our starting position is that we will use the same market scenarios for the price-quantity method.

313. However, the TPM does not require that this be the case where we determine that the application of the investment test market scenarios will not produce starting BBI customer allocations that are broadly proportionate to EPNPB. This may occur because:

    a. the investment test assesses efficiency net benefit, not private benefits, or

    b. the investment test is a decision-making tool, not a precise forecast of net benefits, whereas the price-quantity method requires us to calculate individual NPB for each beneficiary customer.

314. In these instances, we will change, add, or remove market scenarios (see section 3.3.2.5).

121 "Scenarios" in the TPM also includes outage scenarios, which are used for calculating regional reliability NPB. Section 3.3.3.4 details the process we use to determine an outage scenario.

3.3.2.4 Obtain market scenarios from the assumption book

315. When we have not previously consulted on the market scenarios for the BBI for the purpose of complying with the Transpower Capex IM (or old Electricity Governance Rules), our starting position is that we will use the market scenarios in chapter 2 of this assumptions book.

316. However, we may depart from the market scenarios in this assumptions book for the same reason we may depart from investment test market scenarios, i.e. we determine it is necessary to do so to calculate starting BBI customer allocations that are broadly proportionate to EPNPB (see section 3.3.2.5).

3.3.2.5 Determine if different market scenarios are required

317. We may apply different market scenarios to those used to comply with the Transpower Capex IM (or old Electricity Governance Rules) or those in chapter 2 of this assumptions book.

318. Examples of situations that may lead to a change in market scenarios are:

    a. to incorporate new information since the investment test was applied or the assumptions book was published

    b. to better reflect expected (i.e. probability-weighted) private benefits. For example:

        - if MBIE has included the decommissioning of a large plant in some EDGS[122] scenarios, but we consider it should be given an equal weighting under the price-quantity method for a given BBI, we will model an equal number of market scenarios with and without the decommissioning

        - if a market scenario is a sensitivity rather than one of the base scenarios in the EDGS or the investment test, we may include it as a market scenario under the price-quantity method to better reflect probability-weighted private benefits (subject to section 3.3.2.6)

    c. to exclude unlikely market scenarios that were included in the investment test to test the robustness of an investment to uncertainty but are considered unlikely to occur

    d. to remove market scenarios where they do not affect starting BBI customer allocations. This may occur where EPNPB varies across market scenarios, but the proportion of EPNPB received by beneficiary customers does not materially change.

3.3.2.6 Determine if sensitivities should be modelled

319. We will consider if a discrete change in our modelling assumptions that can occur independently of other assumptions should be included in our analysis (e.g. a decommissioning of a large plant). We refer to these discrete changes as sensitivities. Where we decide to include a sensitivity, we will do so by adding at least one market scenario with the sensitivity in place but with all other assumptions the same.

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122 Electricity demand and generation scenarios: Scenario and results summary (mbie.govt.nz).

320. There are likely to be several possible discrete changes in modelling assumptions that may affect EPNPB if we included them in a market scenario. However, we do not propose to model variations in all possible assumptions because:

  a. it is not practicable to model all the possible discrete changes that may occur over a 20-year standard method calculation period

  b. even if we modelled every plausible change, we would need to either implicitly or explicitly assign a probability to the change.

321. We will consider the inclusion of a sensitivity to model discrete changes in modelling assumptions if it meets the following criteria:

  a. the change is likely to materially affect the starting BBI customer allocations

  b. we have sufficient information about the change to model it accurately (e.g. size, location, and operating characteristics)

  c. the change has been discussed in the latest EDGS, in disclosure information provided to financial markets, or in other publicly available documents from reputable sources

  d. the effect of the change is not already approximated in other market scenarios.

3.3.2.7 Determine the weighting to be applied

322. The market scenario weightings will be:

  a. adopted from the relevant weightings used in the investment test for the BBI

  b. if there is no relevant investment test weighting or the relevant investment test weighting would not produce starting BBI customer allocations broadly proportionate to EPNPB, sourced from chapter 2 of this assumptions book, or

  c. if there is no relevant chapter 2 weighting or the relevant chapter 2 weighting would not produce starting BBI customer allocations broadly proportionate to EPNPB, determined by Transpower.

3.3.2.8 Hydro, load, and generation expansion variations

323. Clause 46(1) requires the market scenarios for a market BBI to include variations in load growth, generation expansion, and hydrology. Chapter 2 of this assumptions book details how we will meet this requirement for load growth and hydrology variations.

324. We will use Transpower's generation expansion tool to model how the national generation mix will change over the standard method calculation period in each market scenario.[123] If we consider that a market BBI will materially influence generation development and we believe that doing so will result in starting BBI customer allocations that better reflect positive NPB, we may use different generation scenarios in the factual and counterfactual as permitted by clause 46(2).

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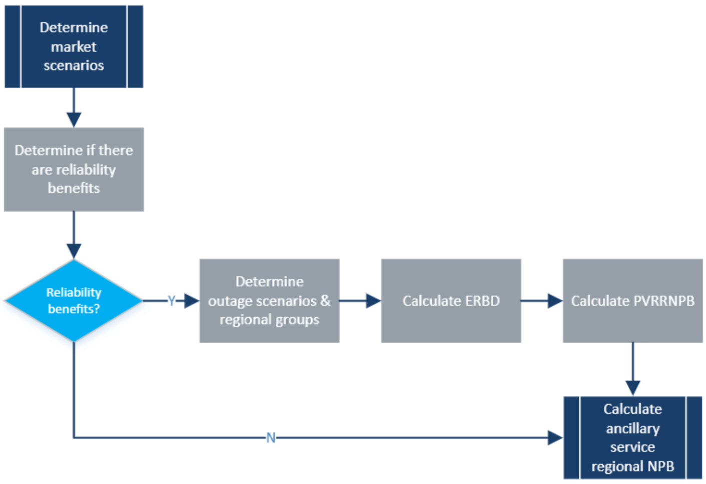
123 A generation expansion tool produces forecasts of new generation over an analysis period based on inputs such as the transmission grid, demand, and the operating characteristics, capital, and operating costs of possible new generating stations. We currently use PSR's OptGen as our generation expansion tool.

3.3.3 Calculate reliability regional NPB

3.3.3.1 Introduction

325. The purpose of this section is to provide a summary of the process undertaken to calculate reliability regional NPB for a high-value post-2019 BBI.

3.3.3.2 Overview diagram



Calculate reliability regional NPB

3.3.3.3 Determine if there are reliability benefits

326. Reliability regional NPB may be calculated when we determine the BBI will result in a material reduction in curtailed energy (either of demand or supply) due to an outage or other event or group of events affecting access to transmission services. In this case the BBI is referred to as a reliability BBI.

327. Where a BBI affects security constraints that are managed by the system operator as pre-contingent market constraints, we will assess the BBI as a market BBI only, even if the investment is undertaken under the grid reliability standards. The calculation of reliability regional NPB is limited to situations where supply to and from the grid is interrupted due to a fault or outage.

328. A high-value post-2019 BBI has reliability benefits if it:

   a. increases the redundancy of supply to customers no more than n-2 (e.g. a new line into a region where there was previously only one),[124] or

   b. reduces the extent or duration of an interruption to supply to customers (e.g. a special protection scheme that trips some load but prevents a more widespread interruption).

[124] N-2 refers to two levels of redundancy i.e. supply can continue after two separate components fail. We do not consider there will be material reliability benefits from a BBI that increases redundancy beyond n-2.

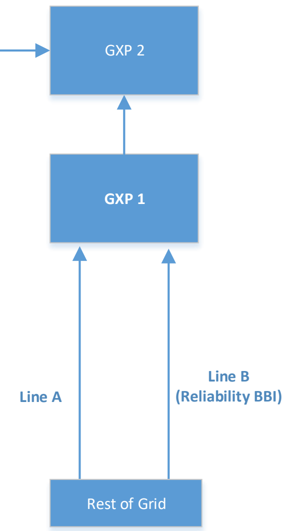
329. The exception to this is where we determine that the BBI mitigates the risk of a HILP event or cascade failure (see paragraph 298). In these instances, we will use the resiliency method to calculate EPNPB and starting BBI customer allocations (see section 3.4).

3.3.3.4 Determine outage scenarios and regional customer groups

330. To calculate the reliability regional NPB for the BBI, we need to determine the customers that will be affected by the outages or other events (the outage scenarios) the BBI is mitigating the curtailed energy risk of, and assign those customers to either a regional demand group or a regional supply group.

331. For BBIs that increase the redundancy of supply, the outage scenario will be the loss of the transmission components supplying the same GXPs/GIPs as the BBI. These will be the GXPs/GIPs where the change in expected curtailed energy is in the same direction (a reduction in expected curtailed energy). Therefore, the regional demand group will be the GXPs supplied by the BBI, and the regional supply group will be the GIPs connected to the grid via the BBI,[125] as represented in the diagram below where line B is the BBI.

	Counterfactual	Factual
Outage Scenario	**Loss of A**	**Loss of A *and* B**
Regional Demand Group	**GXP 1 & 2**	
Regional Supply Group	**GIP 1**	

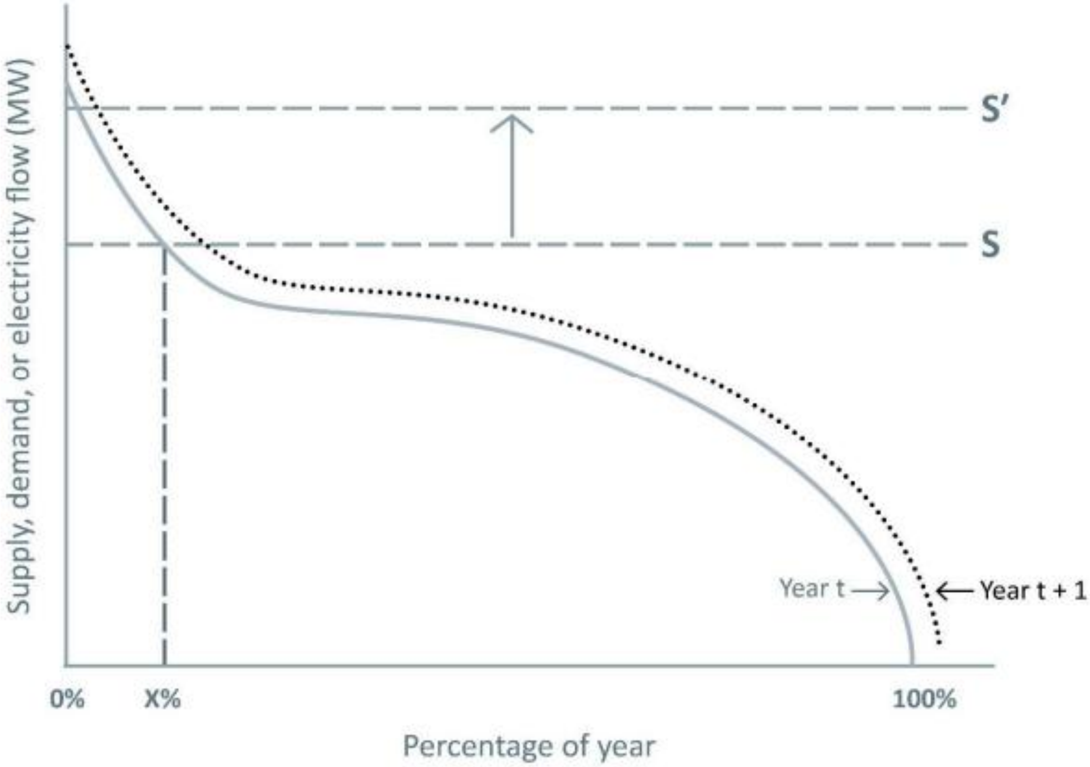


332. For reliability BBIs that reduce the duration or extent of an outage, we will determine the outage scenarios and regional customer groups on a case-by-case basis.

3.3.3.5 Calculate ERBD

333. The diagram below illustrates how we will quantify the expected reliability benefits and disbenefits (**ERBD**).

125 This example assumes the GIP cannot operate islanded from the rest of the grid, and therefore benefits from the more reliable connection to the grid.



334. The capability of the transmission system before and after investment is represented by system limits (s and s’ in the diagram above). These limits represent the point above which the system is at risk of interruption following an outage scenario. System limits are produced by detailed engineering modelling of the capability of the power system.

335. The probability of being above a system limit is represented by a supply, demand, or transmission flow duration curve (depending on the nature of the outage scenario being mitigated), which is the supply, demand, or transmission flow throughout the year ordered from its highest level (i.e. the peak) to the lowest (i.e. the trough).

336. The magnitude of curtailed energy is calculated by the probability of being above the limit multiplied by the probability of the outage scenario occurring multiplied by the amount of load or generation expected to be disconnected following the outage scenario.

337. ERBD is equal to the change magnitude of curtailed energy (MWh) multiplied by the value of lost load (**VoLL**) or value of lost generation (**VoLG**) ($/MWh), where the ERBD is the magnitude of curtailed energy in the counterfactual minus the magnitude of curtailed energy in the factual (clause 54(6)).

3.3.3.6 Calculate PVRRNPB

338. There are three steps required to calculate the present value of reliability regional NPB (**PVRRNPB**), detailed in the following sections.

Remove ERBD for customers or large plant that do not currently exist

339. Before finalising ERBD for a regional customer group and outage scenario, we remove ERBD attributable to customers or large plant (≥ 10 MW) that do not currently exist.[126] We do this in proportion to the size of the load relative to the size of the node. For example, if a regional customer group's ERBD is $100m, the regional customer group's annual demand is 500 GWh, and the size of the new customer or large plant is 50 GWh, the regional customer group's ERBD will be $90m. By removing these benefits or disbenefits, we allow individual NPB to be calculated correctly under clause 83 when the new customer or large plant connects to the grid.

Calculate PVRRNPB

340. PVRRNPB is calculated as the weighted average value of ERBD for each regional customer group and market scenario (clause 54(7)). We also apply the discount rate (the BBI's standard method rate) to the RRNPB at this step.

$$PVRRNPB = \frac{1}{\sum W_s} \sum_s \sum_t \frac{ERBD_{t,s}}{(1+discount\ rate)^t} \times W_s$$

where W_s is the probability weighting for the market scenario.

341. In accordance with clause 46(3), if a market scenario for a BBI includes a customer ceasing to be a customer, the market scenario will not be applied in the BBIs factual or counterfactual in respect of that customer (i.e. will have a weighting of zero).

Remove regional customer groups with a negative PVRRNPB

342. Clause 47 requires that a customer's individual NPB only be calculated in respect of their regional customer groups with positive present values of regional NPB. As a consequence, regional customer groups with negative present values of reliability regional NPB are excluded from the calculations of individual NPB and starting BBI customer allocations.

3.3.4 Calculate ancillary service regional NPB

3.3.4.1 Introduction

343. The purpose of this section is to provide a summary of the process undertaken to calculate ancillary service regional NPB for a high-value post-2019 BBI.

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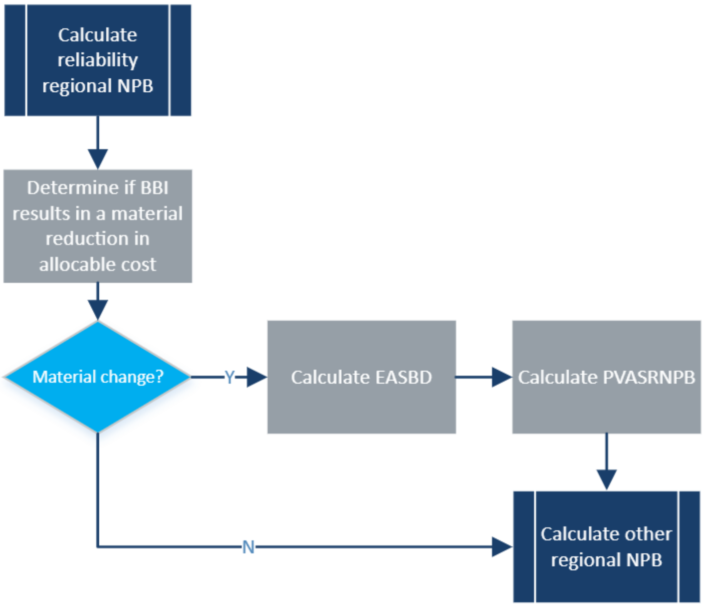
126 Except if the group is a future regional customer group, in which case we need to retain the regional NPB for that group in order to calculate the individual NPB for customers entering the group when they connect to the grid.

3.3.4.2 Overview diagram



Calculate ancillary service regional NPB

3.3.4.3 Determine if BBI results in a material reduction in allocable cost

344. We may calculate ancillary service regional NPB where we determine the BBI will result in a material decrease in the allocable cost of any of three specified ancillary services – instantaneous reserve, frequency keeping and/or voltage support. In this case the BBI is referred to as an ancillary service BBI.

345. Under the TPM, only direct allocations of allocable cost to customers are relevant. Allocations to Transpower are ignored. This is why no EPNPB is calculated for over frequency reserve or back start, all of the allocable cost of which go directly to Transpower. Transpower's allocation of the allocable cost for instantaneous reserve is also ignored.

346. The allocable cost of instantaneous reserve (absent event charges) is paid by owners of generating units greater than 60 MW capacity and the HVDC owner (Transpower). We may calculate ancillary service regional NPB in respect of instantaneous reserve where we expect this allocable cost to materially decrease as the result of the BBI.

347. The allocable cost of frequency keeping is paid by purchasers of electricity in proportion to their share of grid offtake. We may calculate ancillary service regional NPB in respect of frequency keeping where we expect this allocable cost to decrease materially as the result of the BBI.

348. The allocable cost of voltage support is paid by distributors in the relevant zone requiring the service.[127] Distributors must pay a nominated peak kVAr charge and a monthly peak penalty charge and may make or receive an annual residual payment so that the allocable cost is not under or over-recovered. We may calculate ancillary service regional NPB in

[127] As defined in Part 1 of the Code.

respect of voltage support where we expect this allocable cost to decrease materially as the result of the BBI.

3.3.4.4 Calculate EASBD

349. We have not developed detailed processes or methodologies for calculating expected ancillary service benefits and disbenefits (**EASBD**) at this time. We expect to develop such processes and methodologies when we first calculate ancillary service regional NPB for an ancillary service BBI.

3.3.4.5 Calculate PVASRNPB

350. There are three steps required to calculate the present value of ancillary service regional NPB (**PVASRNPB**), detailed in the following sections.

Remove EASBD for customers or large plant that do not currently exist

351. Before finalising EASBD for a regional customer group and market scenario, we remove EASBD attributable to customers or large plant (≥ 10 MW) that do not currently exist.[128] We do this in proportion to the size of the load relative to the size of the node. For example, if a regional customer group's EASBD is $100m, the regional customer group's annual demand is 500 GWh, and the size of the new customer or large plant is 50 GWh, the regional customer group's EASBD will be $90m. By removing these benefits or disbenefits, we allow individual NPB to be calculated correctly under clause 83 when the new customer or large plant connects to the grid.

Calculate PVASRNPB

352. PVASRNPB is calculated as the weighted average value of EASBD for each regional customer group and market scenario (clause 53(6)). We also apply the discount rate (the BBI's standard method rate) to the ASRNPB at this step:

$$PVASRNPB = \frac{1}{\sum W_s} \sum_s \sum_t \frac{EASBD_{t,s}}{(1+discount\ rate)^t} \times W_s$$

where Ws is the probability weighting for the market scenario.

353. In accordance with clause 46(3), if a market scenario for a BBI includes a customer ceasing to be a customer, the market scenario will not be applied in the BBIs factual or counterfactual in respect of that customer (i.e. will have a weighting of zero).

Remove regional customer groups with a negative PVASRNPB

354. Clause 47 requires that a customer's individual NPB only be calculated in respect of their regional customer groups with positive present values of regional NPB. As a consequence, regional customer groups with negative present values of ancillary service regional NPB are excluded from the calculations of individual NPB and starting BBI customer allocations.

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128 Except if the group is a future regional customer group, in which case we need to retain the regional NPB for that group in order to calculate the individual NPB for customers entering the group when they connect to the grid.

3.3.5 Calculate other regional NPB

355. In most cases, the regional NPB derived from a high-value post-2019 BBI will be one or more of market, ancillary service or reliability regional NPB. If we identify quantifiable regional NPB that is not one of these, we may calculate and apply it as other regional NPB.

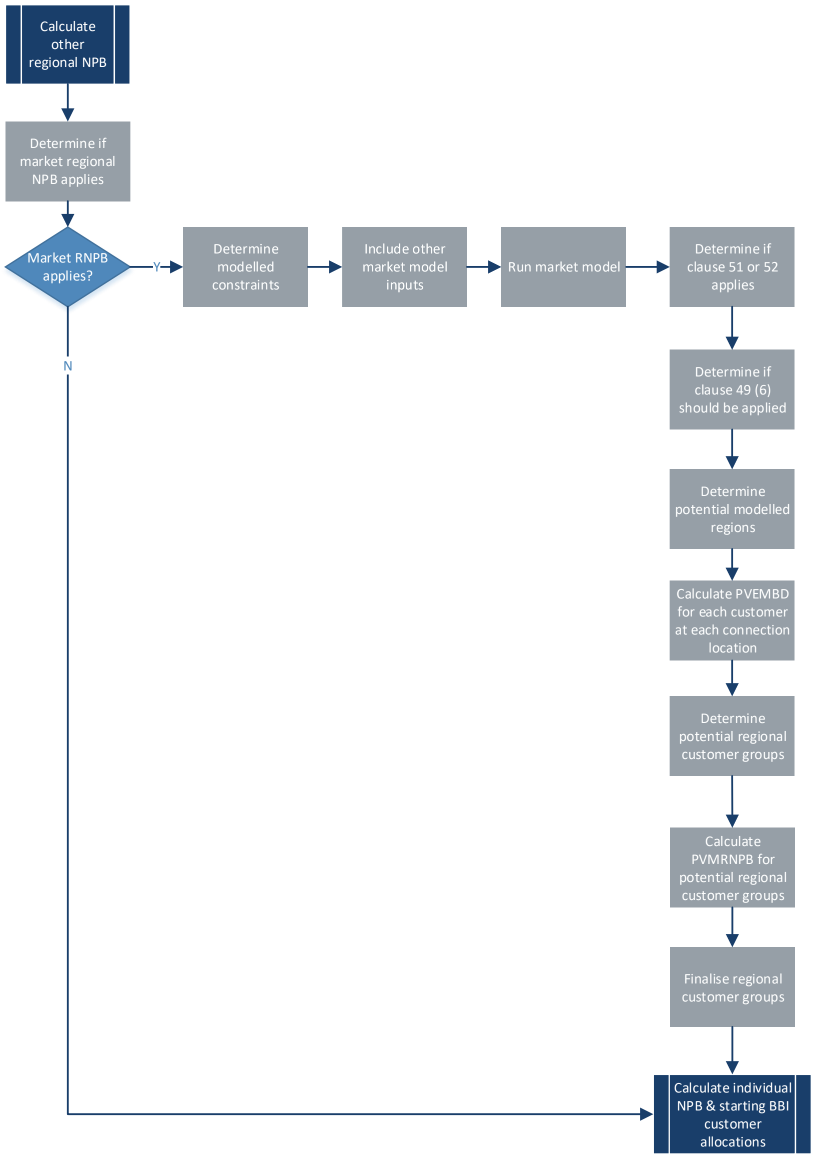
356. To be eligible for calculation, other regional NPB must meet the conditions of clause 55(2).

3.3.6 Calculate market regional NPB

3.3.6.1 Introduction

357. The purpose of this section is to provide a summary of the process undertaken to calculate market regional NPB for a high-value post-2019 BBI.

3.3.6.2 Overview diagram



Calculate market regional NPB

3.3.6.3 Determine if market regional NPB applies

358. We calculate market regional NPB when we determine that the BBI is expected to have a material impact on prices or quantities in the wholesale market for electricity, relative to its counterfactual. In this case the BBI is referred to as a market BBI.

3.3.6.4 Determine modelled constraints

359. In order to calculate market regional NPB for the BBI, we must determine the transmission constraints to be used in the market model. This is part of determining the investment grids (clause 49(2)). The transmission constraints used in the market model are the constraints on the HVDC link and the modelled constraints.

360. The TPM defines a modelled constraint as:

    a. a constraint affecting a new grid asset comprised in the BBI, or

    b. a constraint that would be alleviated materially if the BBI were fully commissioned, as determined by Transpower.

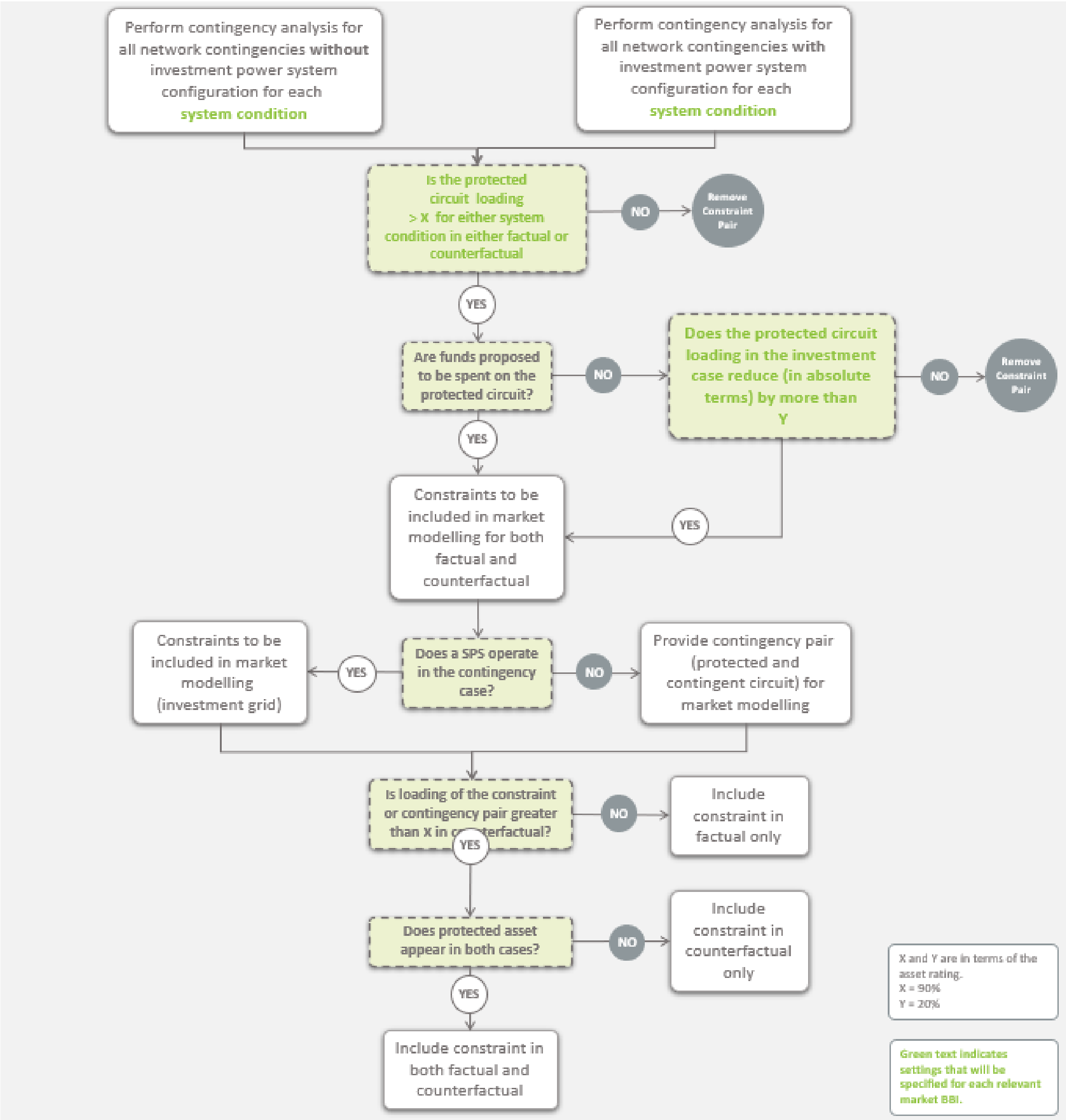
361. In order to model a point of constraint, the market model requires us to input either:

    a. the contingency at the point of constraint (comprised of a contingent branch and selected protected branches), or

    b. the constraint equation that can be used to include the effect of a special protection scheme (**SPS**) or a group constraint such as a voltage stability constraint.

362. We only include constraints in the market model that would be managed by the system operator as pre-contingent market constraints. These are derived using the process illustrated in the diagram below.[129]

[129] In the diagram, "system conditions" means load and generation patterns that we use to highlight transmission issues we can reasonably expect to occur with currently available information and trends.



3.3.6.5 Include other market model inputs

363. In addition to the factual, counterfactual, market scenarios and modelled constraints that have been previously discussed, there are several other quantitative input assumptions required for the market model (e.g. the cost of self-supply).

364. These additional assumptions will be:

a. adopted from the relevant assumptions used in the investment test for the BBI

b. if there is no relevant investment test assumption or the relevant investment test assumption would not produce starting BBI customer allocations broadly proportionate to EPNPB, sourced from chapter 2 of this assumptions book, or

c. if there is no relevant chapter 2 assumption or the relevant chapter 2 assumption would not produce starting BBI customer allocations broadly proportionate to EPNPB, determined by Transpower.

3.3.6.6 Run market model

365. SDDP is the market model used by Transpower.[130] We use SDDP as the market model because:

    a. SDDP meets all of the requirements of the definition of wholesale market model in the TPM,

    b. we currently use SDDP when undertaking the investment test where market benefits are being analysed, noting that the TPM generally requires alignment with the investment test under clause 43(5), and

    c. SDDP can adjust the scheduling of hydro generation depending on inflows and reservoir storage levels, thereby accounting for different hydrological scenarios as required by clause 46(1).

3.3.6.7 Determine if clause 51 or 52 applies

366. The TPM has two methods for calculating market regional NPB, in clauses 51 and 52. Clause 51 results in market regional NPB in quantity (GWh) terms. Clause 52 results in market regional NPB in dollar terms.

367. In general, clause 51 determines allocations based on the quantities of energy consumed during periods of benefit determined by Transpower. We determine these periods of benefit based on the price changes resulting from the BBI.

368. Clause 52 relies more than clause 51 on the pricing produced by the market model, which means the risks related to false precision must be considered when determining if one method should be preferred over the other. In this context, by false precision we mean allocations that vary between customers due to factors that are highly sensitive to uncertain input assumptions, or due to an artefact of the modelling framework that does not reflect reality (for example, one generator always being dispatched over another due to a slightly lower operational cost).

369. The TPM specifies circumstances in which we must apply either clause 51 or clause 52.

Clause 51

370. Clause 51(1)(a) requires us to use clause 51 where most of the supply benefits relate to new large generating plant. We apply this clause by:

    a. estimating, based on clause 52, the change in the present value of regional NPB for new large generating plant with EPNPB throughout the standard method calculation period (value A)[131]

    b. estimating, based on clause 52, the change in the present value of regional NPB for all generating stations with EPNPB throughout the standard method calculation period (value B)

130 Software « PSR (psr-inc.com).

131 A new large generating plant is defined as a large generating plant (> 10 MW capacity) for which the final decision to proceed with investment has not been made by the proponent at the time we make this calculation.

c. if value A is greater than 50% of value B (as weighted averages across market scenarios), we determine that clause 51(1)(a) applies.

Clause 52

371. Clause 52(1)(b)(i) requires us to use clause 52 where most of the benefits relate to consumers avoiding high prices due to a lack of transmission and generation capacity during peak periods. We apply this clause by:

   a. estimating, based on clause 52, the change in the present value of regional NPB during times when there is a supply shortage (deficit) in the counterfactual for regional demand groups with EPNPB during these times (value A)

   b. estimating, based on clause 52, the change in the present value of regional NPB for regional demand and supply groups with EPNPB during these times (value B)

   c. if value A is greater than 50% of value B (as weighted averages across market scenarios), we determine that clause 52(1)(b)(i) applies.

When neither circumstance applies

372. When neither of the above circumstances applies, we will use clause 51 unless we consider it will not produce starting BBI customer allocations that are broadly proportionate to EPNPB (clauses 51(1)(b) and 52(1)(b)(ii)).

373. In general, clause 51 will produce starting BBI customer allocations that are consistent with an assumption that the magnitude of price changes due to a BBI are the same for supply and demand customers, and is the same over time and between market scenarios. Clause 51 will not be appropriate for BBIs where:

   a. we expect the change in price between the factual and counterfactual to be of a significantly greater magnitude for one group of beneficiaries compared to another

   b. this expectation is not sensitive to uncertain input assumptions across a reasonable range.

374. Clause 52(1)(b)(i) describes one situation where using clause 51 would not result in starting BBI customer allocations that are broadly proportionate to EPNPB (when the BBI is mitigating high prices due to a lack of generation and transmission capacity in the counterfactual).

375. Another situation in which we consider clause 51 will not produce starting BBI customer allocations that are broadly proportionate to EPNPB includes if a market BBI connects a much smaller region to the wider grid – e.g. at the 220 kV:110 or 66 kV interface. In this situation, we expect the absence of the BBI at this interface would have a greater impact on the price in the smaller region than the rest of the grid because the surplus or deficit is proportionally greater in the smaller region. In an extreme case, a market BBI may have no discernible impact on price in the wider market as the volume of generation or load being constrained is so much smaller than the market as a whole.

3.3.6.8 Determine if clause 49(6) should be applied

376. The TPM allows us to change the prices from our market model where we determine that using the raw prices will not produce starting BBI customer allocations that are broadly proportionate to EPNPB. This will usually be to moderate the sensitivity of modelled prices and changes to prices to modelling assumptions and other inputs.

377. Examples of when we may determine that this is necessary are:

a. to reflect the long-run cost of self-supply (see section 2.3.7)

b. when the efficiency benefits of the BBI primarily result from lower capital costs to new generators (e.g. a transmission investment that enables low-cost generation), and where these lower costs are not adequately reflected in the prices from the market model.

3.3.6.9 Determine potential modelled regions

378. To determine the modelled regions for the BBI, we must identify the grid points of connection where customers are expected to experience the same or similar benefit (in proportion to their size). As a result, regions are determined based on the GXPs/GIPs that are expected to have the same or similar decrease/increase in price or quantity (clause 50(1)).

379. These differences will occur as the result of transmission constraints as, in general, a transmission constraint will result in increased prices downstream of it and decreased prices upstream of it. As a result, modelled regions are determined using the points of modelled constraint determined for a BBI in the AC network (see section 3.3.6.4) and the HVDC link constraints.

380. A potential modelled region for a BBI in the AC network is comprised of either:

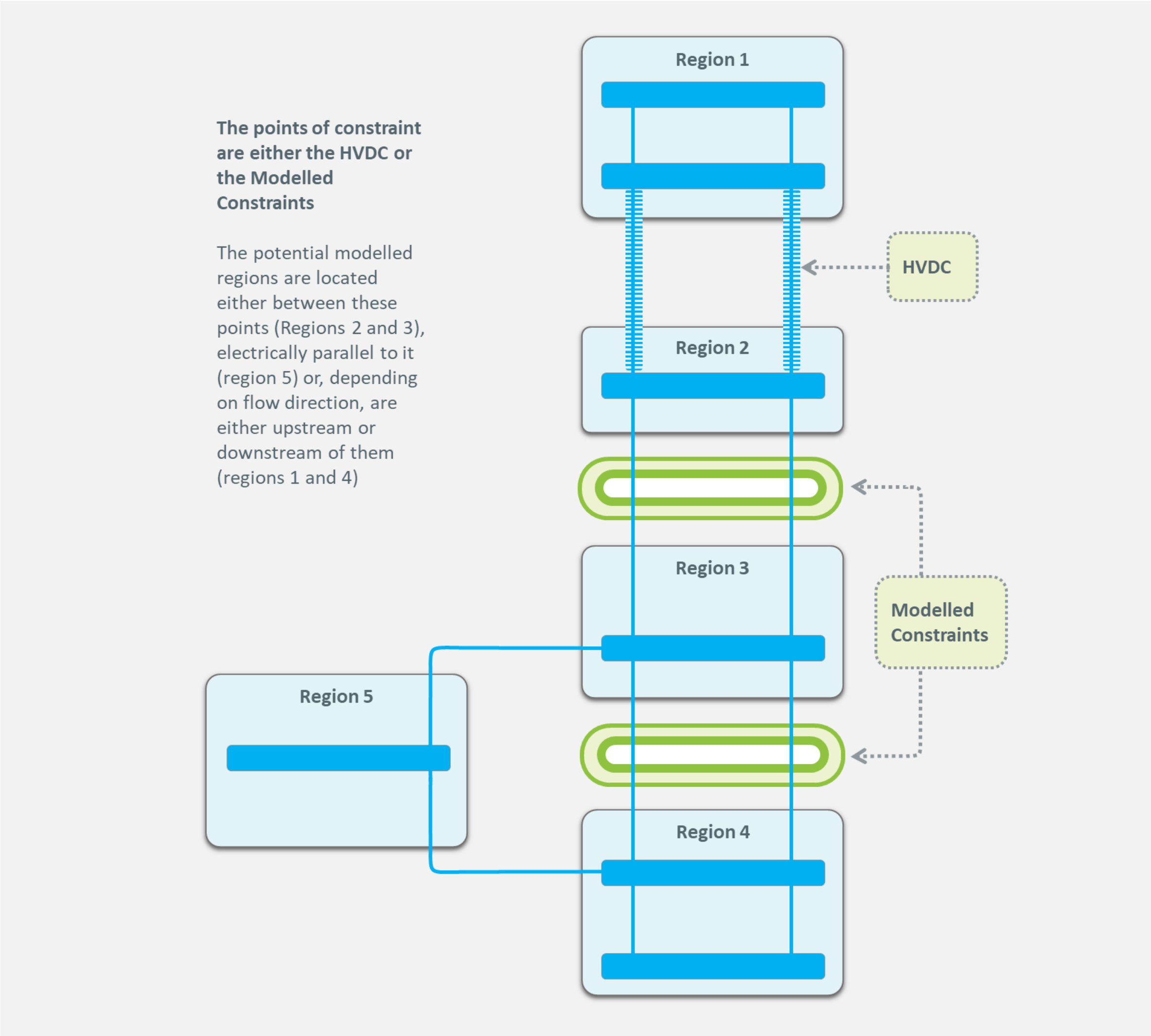
a. the GXPs/GIPs that exist between the points of modelled constraint or the HVDC link

b. the GXPs/GIPs that are downstream of the last point of modelled constraint or the HVDC link

c. the GXPs/GIPs that are upstream of the first point of constraint, or

d. the GXPs/GIPs that are electrically parallel to the modelled constraint.

381. An example is provided in the diagram below:



382. A BBI in the DC network will have two potential modelled regions – the North Island and the South Island.

383. An algorithm is used to determinate potential modelled regions. Prices at each bus from an hourly SDDP simulation of the counterfactual are filtered to times when a modelled constraint is binding. The correlation coefficient, *r*, between prices at one bus and the next is calculated. If *r* is greater than a given threshold (0.98 is the default) then the next bus joins a group with the previous bus. Modelled regions (sets of buses) determined by this algorithm may be modified by amalgamating very small sets of buses into larger regions taking into account the location of the buses in relation to the modelled constraints.

3.3.6.10 Calculate PVEMBD for each customer at each connection location

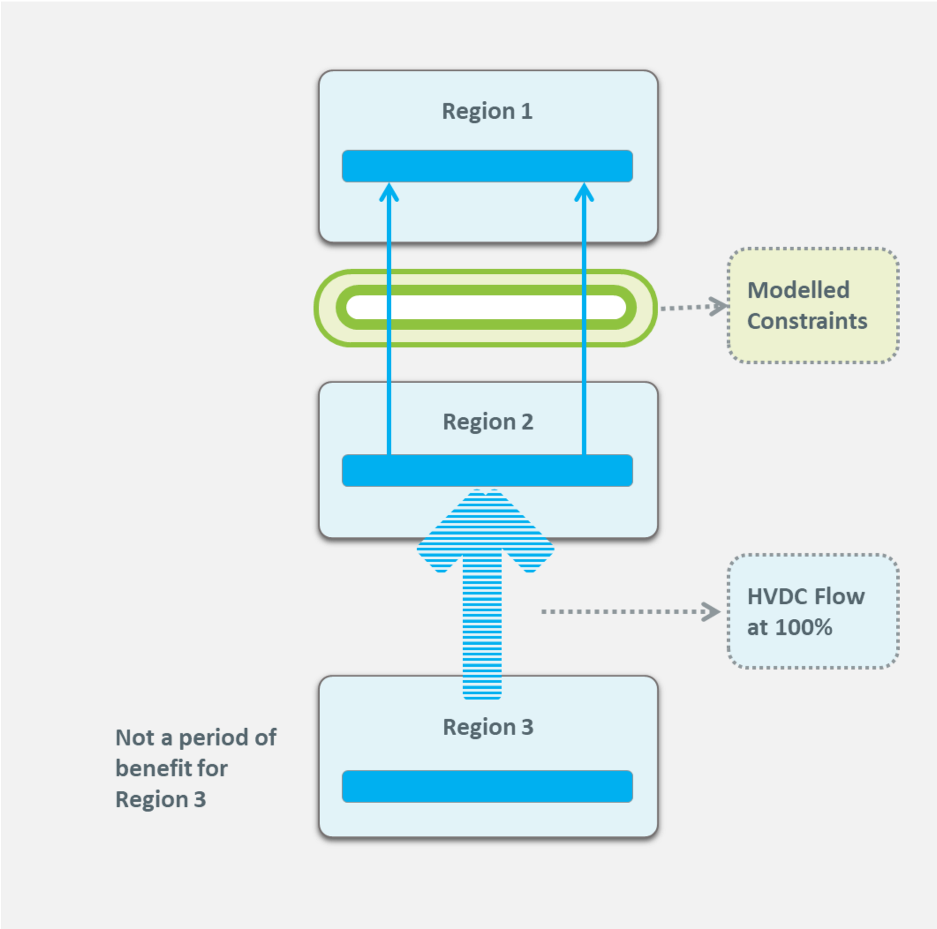
384. The calculation of expected market benefits and disbenefits (EMBD) will differ depending upon if we are applying clause 51 or clause 52. The following sections describe the calculation under each clause.

Calculate EMBD for each market scenario – clause 51

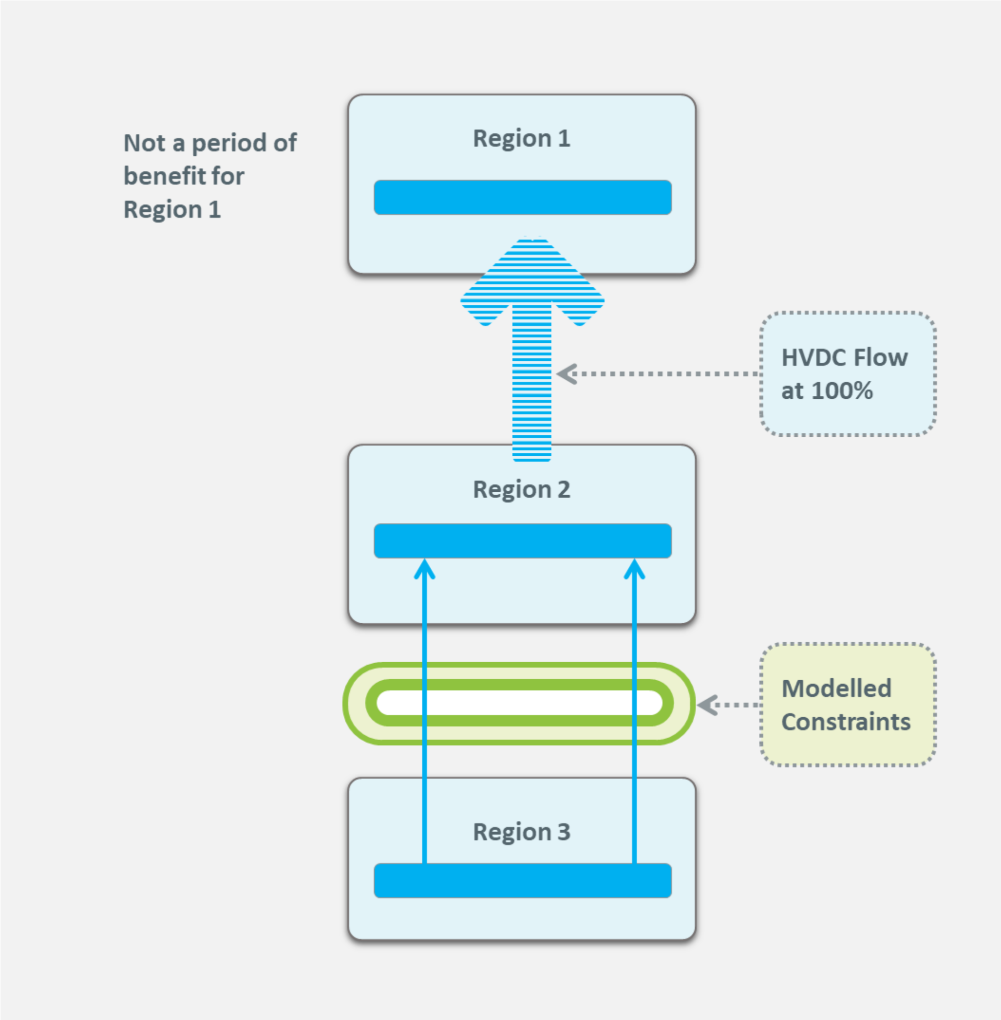
385. Clause 51(3)(b) requires us to determine the periods of benefit, being the periods during which the BBI is modelled to generate its primary market benefits.

386. We determine the periods of benefit as the periods in which an AC constraint or DC constraint is binding in the counterfactual for all regional customer groups, with the following exception.

387. As shown in the diagram below, if a modelled constraint is electrically downstream of the HVDC link in a given load block, the periods of benefit for regions upstream of the HVDC link (Region 3) in that load block do not include periods in which the HVDC link is binding and power is flowing across the HVDC link in the same direction as the modelled constraint.



388. Similarly, as shown in the diagram below, if a modelled constraint is electrically upstream of the HVDC link in a given load block, the periods of benefit for regions downstream of the HVDC link (Region 1) in that load block do not include periods in which the HVDC link is binding and power is flowing across the HVDC link in the same direction as the modelled constraint.



389. In accordance with clause 51(3), we calculate EMBD as follows.

390. EMBD for a customer at a connection location is calculated using generation and load outputs from the market model. Because some customers have both load and generation at a connection location, we calculate EMBD for load and generation separately.

391. The generation portion of EMBD for a customer at a connection location by the BBI is calculated using the following formula:

$$EMBD_{Gen_{cust,loc}} = Gen_{cust,loc,CF,e} - Gen_{cust,loc,CF,a} + GenDelta_{cust,loc}$$

where

$EMBD_{Gen_{cust,loc}}$ is the generation portion of EMBD for the customer ($cust$) at the connection location (loc).

$Gen_{cust,loc,CF,a}$ is the generation for the customer ($cust$) at the connection location (loc) in the counterfactual (CF), during the periods of benefit when prices are alleviated due to the BBI.

$Gen_{cust,loc,CF,e}$ is the generation for the customer ($cust$) at the connection location (loc) in the counterfactual (CF), during the periods of benefit when prices are exacerbated due to the BBI.

$GenDelta_{cust,loc}$ is the generation delta between the factual and counterfactual for the customer ($cust$) at a location (loc), i.e. factual generation minus counterfactual generation.

392. The load portion of EMBD for a customer at a connection location is calculated using the following formula:

$$EMBD_{Load\,cust,loc} = Load_{cust,loc,CF,a} - Load_{cust,loc,CF,e} + LoadDelta_{cust,loc}$$

where

$EMBD_{Load\,cust,loc}$ is the load portion of EMBD for the customer ($cust$) at the connection location (loc)

$Load_{cust,loc,CF,a}$ is the load for the customer ($cust$) at the connection location (loc) in the counterfactual (CF), during the periods of benefit when prices are alleviated due to the BBI.

$Load_{cust,loc,CF,e}$ is the load for the customer ($cust$) at the connection location (loc) in the counterfactual (CF), during the periods of benefit when prices are exacerbated due to the BBI.

$LoadDelta_{cust,loc}$ is the load delta between the factual and counterfactual for the customer ($cust$) at the connection location (loc), i.e. factual load minus counterfactual load.

393. Conceptually, these formulae use the periods in which a modelled constraint is binding in the counterfactual, i.e. when prices are suppressed upstream and elevated downstream of the constraint. We therefore count quantities exposed to those abnormal prices and apply positive or negative values to those quantities based on whether the customer benefits or disbenefits from the removal of those abnormal prices. We then add any changes in quantity between the factual and the counterfactual.

394. This captures, for example, the additional generation released by alleviating a constraint, but reflect that due to different storage levels in the factual compared to the counterfactual these could occur at different points in time. This also captures changes in volume for other reasons, for example if new generation can enter the market due to the BBI.

Calculate EMBD for each market scenario – clause 52

395. If using clause 52, EMBD is calculated in accordance with clauses 52(3) to (7) as follows:

$$market\ benefit\ for\ regional\ demand\ group\ (\$) = \left[\left(deficit\ cost\ (\$/MWh) - price_F\ (\$/MWh)\right) \times load\ supplied_F(MWh)\right] - \left[\left(deficit\ cost\ (\$/MWh) - price_{CF}\ (\$/MWh)\right) \times load\ supplied_{CF}(MWh)\right] + \Delta LCE$$

$$market\ benefit\ for\ regional\ supply\ group\ (\$) = [price_F\ (\$/MWh) \times generation_F(MWh) - fuel\ cost_F(\$) - carbon\ emissions\ cost_F] - [price_{CF}\ (\$/MWh) \times generation_{CF}(MWh) - fuel\ cost_{CF}(\$) - carbon\ emissions\ cost_{CF}] + \Delta LCE$$

where F and CF refer to the factual and counterfactual respectively, and the deficit cost is equal to the cost of self-supply (see section 2.3.7).

396. Note, battery storage both produces and consumes electricity. When consuming electricity its generation will be negative in the formula above, which is the same as treating its consumption of electricity from the grid as a production cost in accordance with clause 52(5).

397. Clauses 52(3)(b) and 52(4)(b) require us to include the modelled change in loss and constraint excess (**LCE**) (now known as settlement residue) allocations in the calculation of EMBD (outside the FTR market and unless we have applied clause 49(6)). Conceptually, LCE for a constrained transmission line is the excess revenue received by the clearing manager due to consumers paying more for the electricity at the downstream node of the line than generators are paid for the electricity entering the line at the upstream node.

398. We only consider the change in LCE over the lines involved in the modelled constraint. For example, for an investment in the HVDC link we only consider LCE due to the HVDC link, but for a more complex constraint, e.g. a voltage stability constraint, we will include all of the lines included in the constraint equation used to model the voltage constraint.

399. The LCE generated by transmission circuit *i* that separates nodes *A* and *B*, is the amount paid by consumers for electricity exiting the line ($F_{iB}P_B$) minus the amount generators are paid for electricity entering the line ($F_{iA}P_A$):

$$\mathrm{LCE_i} = \mathrm{F_{iB}P_B} - \mathrm{F_{iA}P_A}$$

where F_{iB} is the flow on line *i* in the *A*→*B* direction[132] as measured at node *B* and P_B is the price at *B*.

400. For example, the LCE generated by the HVDC link is given by:

$$LCE_{HVDC} = (F_{\mathrm{HAY}Pole2} + F_{HAYPole3})P_{HAY220} - (F_{BENPole2} + F_{BENPole3})P_{BEN220}$$

where P are prices at HAY220 and BEN220 and F are flows on poles 2 and 3 of the HVDC link at Haywards and Benmore. Unless we specifically model losses, as we do for the HVDC link, $F_{iA} = F_{iB}$, and we are only considering the change in LCE due the allevation of the modelled constraint.

401. Before LCE is distributed to customers, LCE is used to settle financial transmission rights and Transpower's costs of operating the Settlement Residue Allocation Methodology[133] are recovered. We assume that these processes are not changed by the BBI and therefore the change in the total amount distributed to customers is given by the change in LCE as calculated using the equation above.

402. The LCE payments are distributed to customers using current simple method allocators for the investment region containing the constrained transmission line, *i*. The change in LCE payments to a customer at a given location is then:

$$\Delta LCE_{cust,loc} = \sum_i SMA_{i,cust,loc}(LCE_F - LCE_{CF})_i$$

where $SMA_{i,cust,loc}$ is the Simple Method Allocator for the investment region containing the transmission line, for the customer and location, which are given in Appendix C.

132 If the flow on line *i* is from *B* to *A* then F_{iB} and F_{iA} are negative.

133 [Settlement Residue Allocation Methodology | Transpower]

Common steps for clauses 51 and 52

403. There are several steps to calculate PVEMBD that are common to clauses 51 and 52.

Calculate present value EMBD

404. We calculate a market scenario-weighted EMBD by multiplying EMBD by the weighting for each market scenario and calculate EMBD as a present value in this step:

$$PVEMBD = \frac{1}{\sum W_s} \sum_s \sum_t \frac{EMBD_{t,s}}{(1 + discount\ rate)^t} \times W_s$$

where W_s is the probability weighting for the market scenario.

Remove PVEMBD for customers or large plant that do not currently exist

405. With the exception of potential future regional supply groups, before finalising EMBD for a regional customer group and market scenario, we remove EMBD attributable to customers or large plant (≥ 10 MW) that do not currently exist.[134] We do this in proportion to the size of the load relative to the size of the node. For example, if a regional customer group's EMBD is $100m, the regional customer group's annual demand is 500 GWh, and the size of the new customer or large plant is 50 GWh, the regional customer group's EMBD will be $90m. By removing these benefits or disbenefits, we allow individual NPB to be calculated correctly under clause 83 when the new customer or large plant connects to the grid.

Split loads with more than one customer at a connection location

406. We typically model loads at each connection location as a single load, even if there is more than one load customer at that connection location. Where this is the case, we will attribute the load portion of PVEMBD to each customer based on their offtake intra-regional allocator (**IRA**) as a proportion of the total of all customers' offtake IRAs at that connection location. Where one customer is a non-distribution customer and one customer is an electricity distribution business, we assume that the load growth at that connection location is wholly attributable to distributor customers, consistent with our demand forecasts for non-distributor customers which generally assume no load growth.

3.3.6.11 Determine potential regional customer groups

407. Market regional NPB is calculated for a regional customer group. A proportion of the market regional NPB is then allocated to each customer within that group (see paragraphs 429 to 441).

408. A regional customer group is comprised of:

    a. a region of the grid, and

    b. the GXPs or GIPs located within that region of the grid (a modelled region), and

    c. the customers connected at those GXPs or GIPs.

409. The purpose of a regional customer group is to identify the customers who receive similar benefits to one another and so that we can allocate a proportion of the regional NPB for

134 Except if the group is a future regional customer group, in which case need to retain the regional NPB for that group in order to calculate the individual NPB for customers entering the group when they connect to the grid.

the regional customer group to each customer based upon their historical grid offtake or injection. We group GXPs and GIPs into potential regional customer groups and calculate regional NPB for each group. The regional customer groups may later be combined if they have similar benefits in proportion to their size (see section 3.3.6.13).

410. Having regional customer groups, rather than relying directly on the modelled benefits or disbenefits of each individual customer, allows us to limit the effect of false precision in our modelling. Potential regional supply groups are based on generating technology because we would expect plant with similar technology to have similar costs and to be dispatched similarly in the wholesale market, therefore gaining similar benefits from the BBI. The modelled dispatch, however, will be more sensitive to input assumptions compared to the wholesale market. Grouping these plants together removes the false precision associated with this sensitivity. For example, a $0.01 difference in operational costs between two marginal plants could lead to a significant difference in the modelled dispatch of one plant over the other.

411. In choosing regional customer groups it is also important to consider the effect of using historical IRAs. Regional demand groups are split into industrial and non-industrial offtake because non-industrial loads are likely to receive greater benefits in relation to their historical IRAs due to greater load growth compared to industrial loads. If industrial and non-industrial loads were grouped together, industrial loads would be paying for a portion of the benefits attributable to non-industrial loads in the relevant modelled region.

412. If a customer has both load and generation at the same connection location, we group them in either a supply or demand group based on their net private benefit, i.e. after offsetting generation disbenefits from load benefits (or vice versa). This is illustrated in the below table, in which all customers are at the same connection location and prices are decreasing due to the BBI. This results in a benefit for load customers and a disbenefit for generation customers. The disbenefit from generation is subtracted from the benefit from load for the customers with load and generation at the connection location (4 and 5).[135] Customers 1 and 4 would be allocated to the regional demand group and customers 2, 3, and 5 to the regional supply group.

Customer	Node	Average load	Average generation	Load benefit or disbenefit	Generation benefit or disbenefit	Net benefit or disbenefit
1	ABC220	300MW	0MW	$300m	$0m	$300m
2	ABC220	0MW	100MW	$0m	-$100m	-$100m
3	XYZ220	0MW	100MW	$0m	-$100m	-$100m
4	DEF220	100MW	50MW	$100m	-$50m	$50m
5	UVW220	50MW	100MW	$50m	-$100m	-$50m

135 The TPM does not allow for load and generation benefits and disbenefits to be combined across connection locations.

413. Other relevant information may be used to determine the customer group at a connection location, such as IRAs.

414. The potential load groups for each modelled region are:

    a. industrial offtake

    b. non-industrial offtake

    c. load customers with significantly different benefits (but with the same sign) as other load customers in the same modelled region due to them having embedded generation. These "Load with generation" groups are designated if the absolute value of their generation PVEMBD (treating the embedded generation as grid-connected) is between 50% and 100% of the absolute value of their load PVEMBD.

415. The potential generation groups for each modelled region are:

    a. wind generation

    b. solar generation

    c. geothermal generation

    d. controlled hydro generation (all stations in the following hydro networks: Manapouri, Waitaki, Clutha, Waikaremoana, Waikato, Cobb, and Coleridge)

    e. run-of-river hydro generation

    f. thermal commitment generation

    g. thermal peaker generation

    h. battery storage

    i. cogeneration

    j. generation customers with significantly different benefits (but with the same sign) as other generation customers in the same modelled region due to them having embedded load. These "Generation with load" groups are designated if the absolute value of their generation PVEMBD is between 100% and 150% of the absolute value of their load PVEMBD (treating the embedded load as grid-connected).

416. We will separate a regional customer group into new and existing customers if we consider the benefits of the BBI primarily accrue to new customers. For example, an investment that primarily enables new generation may not have material benefits to existing generators (because the new generators would not exist without the BBI and therefore prices for existing generators in the same modelled region would be the same as or lower in the factual.

417. Where we create a regional customer group consisting entirely of new customers (a future regional customer group), we will determine a notional IRA for the group for the purpose of assigning them to a final regional customer group (as described in section 3.3.6.13). For supply customers, these future customer groups correspond to the placeholder generators described in section 2.3.8.11, which have been included for this purpose. IRAs, which are usually historical mean injection for supply customers, are estimated from the

counterfactual modelled injection, averaged over the first 5 years of simulation and weighted over market scenarios, for these placeholder generators.

3.3.6.12 Calculate PVMRNPB for potential regional customer groups

418. There are three steps required to calculate the present value of market regional NPB (**PVMRNPB**) for potential regional customer groups, detailed in the following sections.

Calculate PVMRNPB

419. The PVMRNPB for a potential regional customer group is the sum of the PVEMBD of all customers of the relevant type at connection locations within the modelled region for the regional customer group.

Remove regional customer groups with a negative PVMRNPB

420. Clause 47 requires that a customer's individual NPB only be calculated in respect of their regional customer groups with positive present values of regional NPB. Consequently, the regional customer groups with negative present values of market regional NPB are excluded from the calculations of individual NPB and starting BBI customer allocations.

Convert quantity value of market regional NPB to dollars if required

421. Where we have calculated regional NPB for benefit classes other than market benefit and we have calculated market regional NPB under clause 51, we convert the quantity value of the market regional NPB for each regional customer group to dollars.

422. To do this we:

    a. sum the positive market regional NPB for all regional customer groups calculated under clause 51

    b. calculate the percentage of that total contributed by each regional customer group (X)

    c. for the same regional customer groups, sum positive market regional NPB calculated under clause 52 at the same generating stations and nodes (Y)

    d. multiply the dollar value of market regional NPB calculated at step 3 (Y) by each regional customer group's percentage contribution calculated at step 2 (X).

3.3.6.13 Finalise regional customer groups

423. We amalgamate potential regional customer groups to further reduce false precision where doing so will result in similar starting BBI customer allocations for the customers in those groups. This smooths out relatively insignificant variations between regional customer groups produced by the market model and helps ensure the starting BBI customer allocations are broadly proportional to EPNPB.

424. We apply two conditions when amalgamating potential regional customer groups:

    a. the groups must be in the same modelled region prior to the amalgamation, and

    b. we do not amalgamate regional supply groups with regional demand groups.

425. We compare each potential regional customer group's PVMRNPB to total IRA ratio. This tells us whether customers' individual NPBs would be similar if groups are amalgamated compared to if they are not. By amalgamating groups with a similar PVMRNPB to IRA ratio,

we group customers together that have similar benefits with respect to their offtake or injection.

426. For each modelled region, and for demand and supply separately, we sort the potential regional customer groups in descending order of PVMRNPB/IRA. We then find the potential regional customer group that has the largest PVMRNPB/IRA in proportion to the preceding (next highest PVMRNPB/IRA) group. If the proportion is greater than 80% then these potential regional customer groups are amalgamated and a PVMRNPB/IRA for the new group is calculated after summing the two groups' PVMRNPB and IRA. This process of amalgamating the two closest groups is repeated until there are no further PVMRNPB/IRA values that are more than 80% of their predecessor.

427. This process is illustrated in the example below for SI regional supply groups, noting that for illustrative purposes we have reduced the number of generation groups from those listed in section 3.3.6.11.

Generation group	PVMRNPB ($m or GWh)	IRA (GWh)	PVMRNPB /IRA ratio	Percentage of previous
wind gen	60	20	3.00	
storage hydro gen	100	40	2.50	83%
run of river hydro gen	220	100	2.20	88%
solar gen	35	20	1.75	73%
thermal gen	10	30	0.33	19%

Generation group	PVMRNPB ($m or GWh)	IRA (GWh)	PVMRNPB /IRA ratio	Percentage of previous
wind gen	60	20	3.00	
hydro gen	320	140	2.29	76%
solar gen	35	20	1.75	75%
thermal gen	10	30	0.33	19%

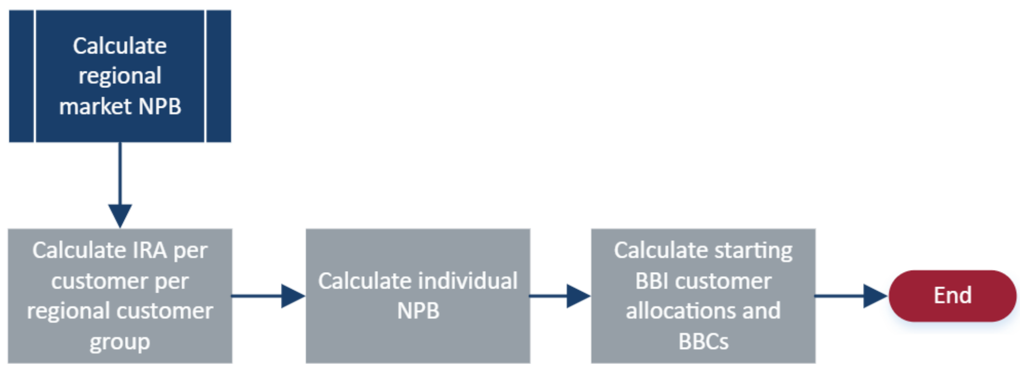
428. In this example, the storage and run of river hydro potential regional supply groups have the closest PVMRNPB/IRA ratios. The RoR ratio is 88% of the storage ratio, so we amalgamate these two groups to form a "hydro" group. In the second table we calculate the PVMRNPB/IRA for the amalgamated hydro group and recalculate the proportions

between consecutive groups. The highest proportion is now hydro/wind, which is less than 80%, so there is no further amalgamation. The final regional supply groups are wind, hydro, solar and thermal.

3.3.7 Calculate individual NPB and starting BBI allocations

3.3.7.1 Introduction

429. The final step in the price-quantity method is to allocate positive regional NPB calculated for each regional customer group between the customers in that group and then use those individual NPBs to calculate starting BBI customer allocations for the BBI. This requires us to complete a series of three calculations, as illustrated below. The following sections describe how each calculation is performed.



Calculate individual NPB and *starting BBI customer* allocations

3.3.7.2 Calculate IRA per customer per regional customer group

430. To calculate a customer's individual NPBs for the regional customer groups it is a member of, we must calculate their IRA for each regional customer group. Clauses 65 to 67 relate to the calculation of IRAs.

431. For market and reliability BBIs, the IRA for regional demand groups can be either mean historical annual offtake (for non-peak BBIs) or mean historical coincident peak offtake (for peak BBIs), both measured in kWh. The IRA for regional supply groups is always mean historical annual injection (clause 65(1)).

432. Clause 65(8) requires use of between 1 and 100 peak offtake trading periods per capacity year to calculate mean historical coincident peak offtake, with the number of peak offtake trading periods referred to as T. We use a T=100 for the following reasons:

    a. while peak BBIs may initially only provide benefits during a small number of trading periods, as demand grows over time we expect the number of trading periods in which the capacity is used to grow. Therefore, using a low T value risks sending a price signal that is too strong – incentivising economically inefficient peak avoidance

    b. using a low T value would risk customers receiving a higher or lower starting BBI customer allocation for a peak BBI due to chance. A higher T value will reduce the sensitivity of the calculation and be a more reliable measure of average offtake during peak periods.

433. Clause 65(2) specifies the IRAs for ancillary service regional customer groups.

Specified ancillary service	Type of ancillary service regional customer group	IRA
Instantaneous reserve	Regional supply group	Mean historical annual injection
Frequency keeping	Regional demand group	Mean historical annual offtake
Voltage support	Regional demand group	Mean peak kVar

434. IRAs are calculated based on injection or offtake (per trading period) or nominated peak kVar (per capacity year) for the five complete capacity years immediately preceding the final investment decision date for the BBI (CMP B) (clauses 65(5) to 65(9)).

435. New customers and recent customers (customers connected for less than two full capacity years during CMP B) have their IRAs estimated (but, for recent customers, taking into account any available information about their offtake, injection or mean peak kVar) (clauses 66 and 83(3)(a)).

436. Where a regional customer group consists entirely of customers who do not yet exist (referred to as a future regional customer group), we determine a notional IRA value for that group in accordance with clause 67. This is necessary so that the adjustment provisions in the TPM will work correctly when new customers join the group. For supply customers, these future regional customer groups are regional supply groups that are represented in SDDP by the placeholder generators described in Section 2.3.8.11. In the absence of historical injection for these generators, we estimate the IRAs as the scenario weighted mean injection for these placeholder generators over the first 5 years of the hourly SDDP simulation.

437. Under Part F of the TPM, if a pre-start adjustment event for a post-2019 BBI has occurred, it must be treated as a benefit-based charge adjustment event that occurred or will occur at the start of the post-2019 BBI's start pricing year (clause 75(4)).

3.3.7.3 Calculate individual NPB

438. A customer's individual NPB for the BBI is the sum of the present value of net private benefit (**PVRNPB**) for each regional customer group with positive PVRNPB of which the customer is a member, multiplied by the customer's IRA for the group as a proportion of the total of all customers' IRAs for the group (clause 47).

3.3.7.4 Calculate starting BBI customer allocations and BBCs

439. The starting BBI customer allocations for the BBI are calculated as each customer's individual NPB divided by the sum of all customers' individual NPBs (clause 43(1)).

440. Note that customer allocations are fixed over the lifetime of the BBI, except to the extent they are adjusted when specific adjustment events occur, such as a new customer or large plant entering or exiting.

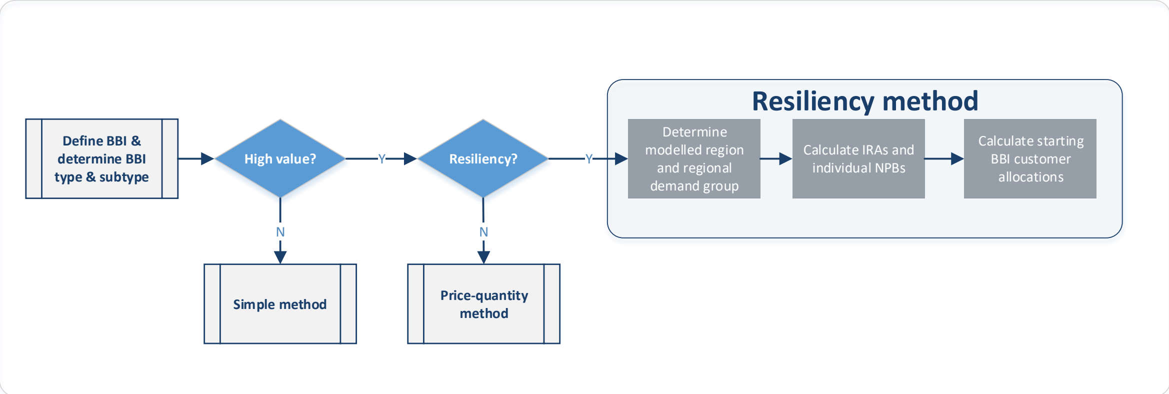
441. A customer's BBC for the BBI is calculated by multiplying the BBI's covered cost by the customer's BBI customer allocation (clause 35(2)).

3.4 The resiliency method (standard method)

3.4.1 Introduction

442. The resiliency method is used to calculate EPNPB when we determine that a high-value post-2019 BBI's primary investment need relates to mitigating the risk of a HILP event or cascade failure. The criteria applied in order to make this determination is discussed in section 3.2.4. In this case the BBI is referred to as a resiliency BBI.

443. The resiliency method requires three processes to be performed, as illustrated in the diagram below.



444. Sections 3.4.1.1 to 3.4.1.3 provide a description of each process.

3.4.1.1 Determine modelled region and regional demand group

445. Conceptually, resiliency BBIs are very similar to reliability BBIs (refer paragraphs 326 to 342). However, for resiliency BBIs there is only one modelled region and one regional customer group (clause 58).

446. The modelled region is the region that would be affected by the HILP event or cascade failure without the BBI. This region will be either:

   a. if mitigating a risk of cascade failure, the island in which the risk is mitigated; or

   b. the region in which the risk of the HILP event is mitigated.

447. Once the modelled region is determined, the regional customer group (a regional demand group) will be comprised of all offtake customers located within the modelled region, except grid-connected batteries.

448. As an example, take a region that is currently supplied by a single line, which is vulnerable to extended interruptions if a tower were to fail due to flooding. If a new line is built on a different route, supply into the region will be more resilient. Therefore, the regional demand group will be all loads supplied by the new line.

3.4.1.2 Calculate IRAs and individual NPBs

449. For resiliency BBIs, the individual NPB for each beneficiary customer is equal to each customer's IRA.

450. The IRA for the resiliency method is mean historical annual offtake (clause 65(3)). This IRA is calculated based on the customer's average historical annual offtake at all connection locations in the modelled region during the five complete capacity years before the final investment decision date for the BBI (CMP B) (clause 65(5)).

451. New customers and recent customers (customers connected for less than two full capacity years during CMP B) have their IRAs estimated (but, for recent customers, taking into account any available information about their offtake, injection or mean peak kVar) (clauses 66 and 83(3)(a)).

452. Under Part F of the TPM, if a pre-start adjustment event for a post-2019 BBI has occurred), it must be treated as a benefit-based charge adjustment event that occurred or will occur at the start of the post-2019 BBI's start pricing year (clause 75(4)).

3.4.1.3 Calculate starting BBI customer allocations and BBCs

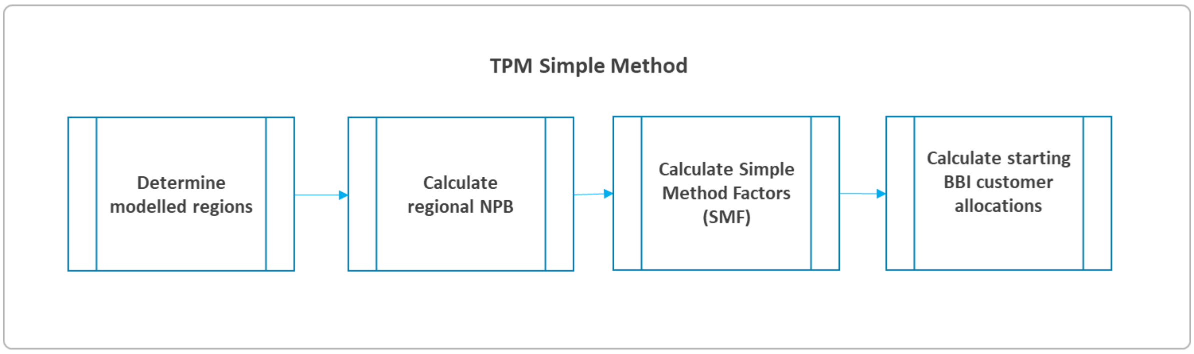
453. The starting BBI customer allocations for the BBI are calculated as each customer's individual NPB divided by the sum of all customer's individual NPBs (clause 43(1)).

454. A customer's BBC for the BBI is calculated by multiplying the BBI's covered cost by the customer's BBI customer allocation (clause 35(2)).

3.5 The simple method

455. The simple method is used to calculate EPNPB for a low value BBI.[136]

456. The simple method requires a series of five processes to be performed, as illustrated in the diagram below.



457. Clauses 59 to 67 contain the rules for these processes.

458. Unless there is an adjustment event (Part F), the simple method uses the same regional and individual customer allocators (NPBs) for the whole simple method period to which the allocators relate (i.e. the simple method allocators are not calculated per BBI but rather per simple method period). A simple method period is a period of, typically, five years (clause 60).

459. The simple method modelled regions and allocators for the first simple method period are published in chapter 4 of this assumptions book.

3.5.1 Determine modelled regions

460. The modelled regions for the simple method are connection regions and the HVDC link (clause 62(1)).

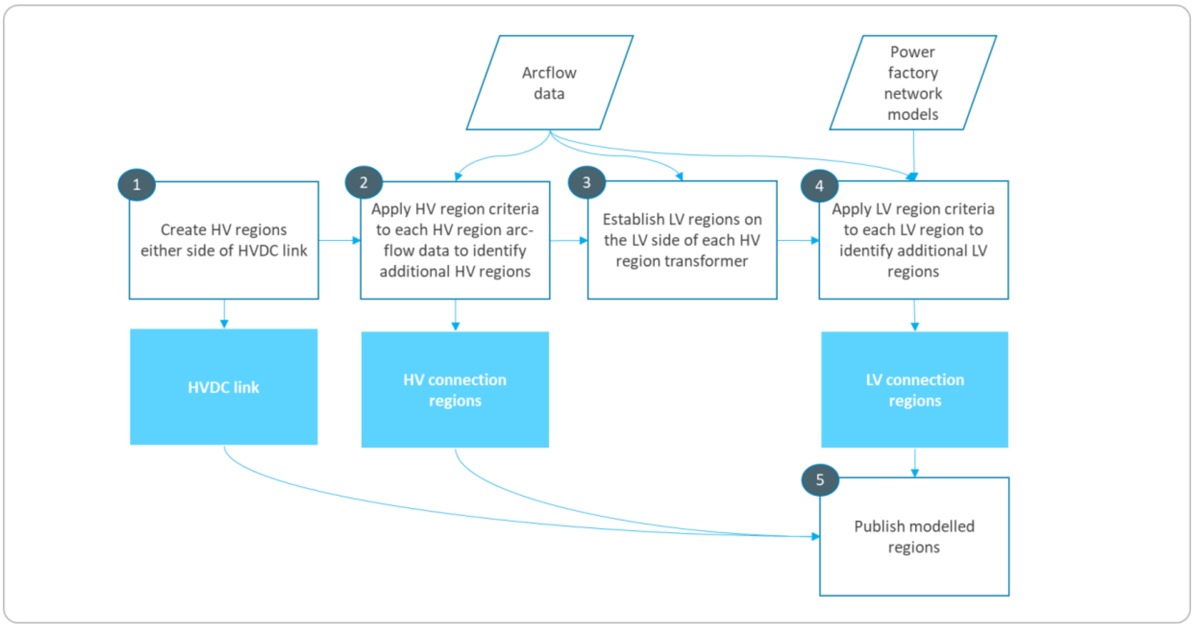
461. Connection regions are determined by analysing historical half hourly data used to set market prices (Arcflow data).[137] The connection regions for a simple method period are determined from the Arcflow data for a five capacity year period preceding the start of the simple method period (CMP C). CMP C for the first simple method period is 1 September 2016 to 31 August 2021.[138]

462. Clause 62(4) details how Transpower determines the connection regions. The process we use when doing so is represented in the diagram below.

136 The process used to determine that a BBI is low value is detailed in section 282.

137 The Arcflow data is the MW flow scheduled along an arc in the transmission network. Arcflow data is the MW flows calculated in the market clearing engine (SPD) and used in the determination of final wholesale electricity nodal prices.

138 The first simple method period started on 24 July 2019 so that all low value post-2019 BBIs are captured in it. This means CMP C for the first simple method period overlaps.



463. The connection regions that result from this process and the HVDC link are the modelled regions for the simple method period.

3.5.1.1 Determine high voltage connection regions (steps 1 and 2)

464. High voltage (**HV**) connection regions comprise grid assets greater than or equal to 220kV.

465. HV connection regions are defined on either side of the HVDC link by analysing Arcflow data.

466. Possible HV connection region boundaries are drawn across a set of interconnection branches (interfaces) that would electrically separate two parts of the grid at the HV level.[139]

467. A final HV connection region boundary is established where the electricity flow across an HV interface satisfies two criteria:

   a. first, there is a prevailing electricity flow across the interface. This criterion is satisfied if, for at least 95% of the trading periods over CMP C, the electricity flow for all branches in the interface is in the same direction as the total flow across the interface[140]

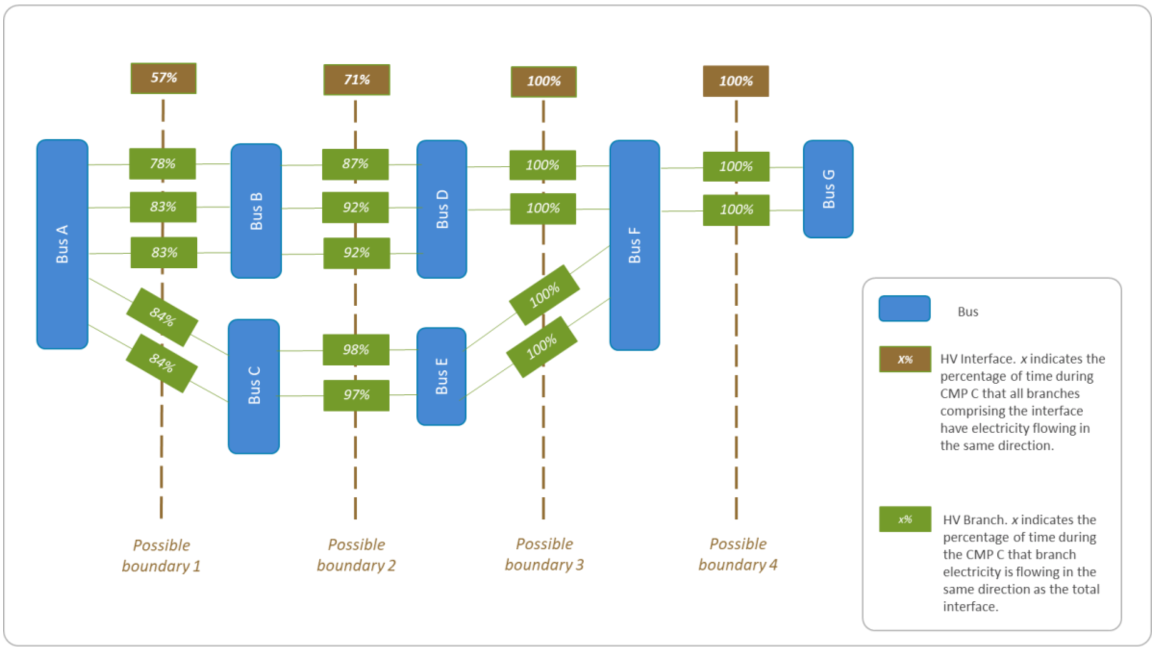
   b. second, once a prevailing directional flow has been established across the interface, we test to determine if the prevailing flow can be isolated. We conclude that it can be isolated if the directional flow of electricity on the “other side” of the boundary

139 An interface is a collection of branches. A branch is an electrical link between two market nodes. Branches in the context of the simple method only apply to interconnection branches. Interface branch assets that make up the HV connection region boundary are allocated to each HV connection region in proportion to the electricity flows across the interface.

140 We use a 95% threshold to determine a prevailing flow and allow for up to 5% of trading periods to be impacted by abnormal conditions such as maintenance outages while still capturing the prevailing flow concept.

bus(es) is variable.[141] The other side of the boundary bus refers to the HV branches that are connected to the boundary bus but are not part of the interface and do not directly connect the boundary buses (in the case with two boundary buses). Each branch is tested for variable directionality by analysing its Arcflow data. The upper and lower 5th percentiles of Arcflow data are removed.[142] If the remaining electrical flow across the branch is not all in the same direction, then that branch is considered variable. There must be at least one variable branch at each boundary bus to satisfy this criterion.

468. The first criterion above (prevailing flow of electricity across a possible boundary) is illustrated in the following simplified example.



469. In this example:

a. Possible boundary 1 is comprised of three HV branches between Bus A and Bus B and two HV branches between Bus A and Bus C. These five branches form the HV interface across the potential boundary. In this case, the five branches are all flowing in the same direction 57%[143] of the time during CMP C (as shown in the brown box). This does not meet the 95% criterion for a prevailing electricity flow across the interface and so possible boundary 1 is discarded.

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141 For a potential boundary interface, the boundary bus(es) for that interface are the electrical bus(es) that connect branch(es) that form part of that interface and connect branch(es) that do not form part of that interface.

142 The rationale for using the upper and lower 5th percentiles is the same as that explained in footnote 140 above.

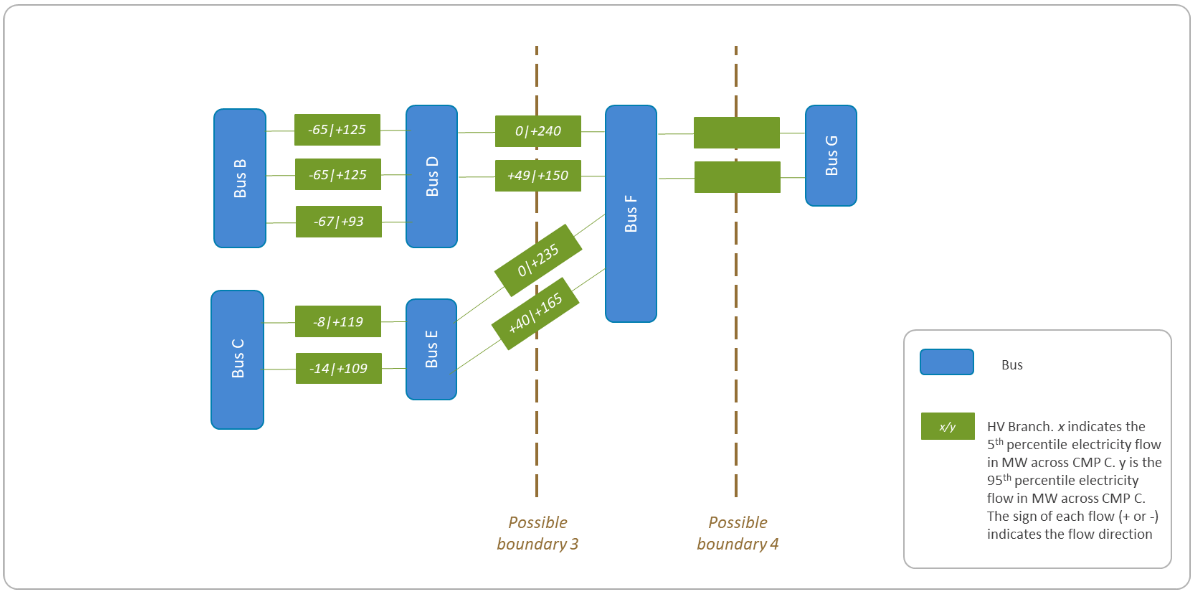
143 We calculate the percentage of time that all branches in an interface are flowing in the same direction by considering the state in each CMP C trading period. There are approximately 87,600 trading periods in CMP C. For possible boundary 1, the electricity flow across the five HV branches were all in the same direction as the HV interface flow (be they from left to right or right to left) in 49,932 (57% of 87,600) trading periods. The threshold for satisfying the prevailing electricity criteria is 83,220 (95% of 87,600) trading periods where all interface branches are moving electricity in the same direction as the interface.

b. Possible boundary 2 is also comprised of five HV branches, three between Bus B and Bus D and two between Bus C and Bus E. These five branches form the HV interface across the potential boundary. In this case, the five branches are all flowing in the same direction 71% of the time during CMP C (as shown in the brown box). This does not meet the 95% criterion for a prevailing electricity flow across the interface and so possible boundary 2 is discarded.

c. Possible boundary 3 is comprised of two HV branches between Bus D and Bus F and two HV branches between Bus E and Bus F. These four branches form the HV interface across the potential boundary. In this case, the four branches are all flowing in the same direction 100% of the time during CMP C (as shown in the brown box). This exceeds the 95% criterion for a prevailing electricity flow across the interface. Possible boundary 3 progresses to the second criterion to determine whether this prevailing flow can be isolated.

d. Possible boundary 4 is comprised of two HV branches between Bus F and Bus G. These two branches form the HV interface across the potential boundary. In this case, the two branches are flowing in the same direction 100% of the time during CMP C (as shown in the brown box). This exceeds the 95% criterion for a prevailing electricity flow across the interface. Possible boundary 4 progresses to the second criterion to determine whether this prevailing flow can be isolated.

470. The second criterion above tests the two possible boundaries that satisfy the first criterion (possible boundary 3 and possible boundary 4) to determine if the prevailing flows across the relevant HV interfaces can be isolated.



471. In this example:

a. For possible boundary 3, the boundary buses are Bus D and Bus E. We test the three HV branches between Bus D and Bus B and the two HV branches between Bus E and Bus C to see if both boundary buses (D and E) have at least one branch where the electricity flow is variable across CMP C. These five branches are "on the other side" of possible boundary 3 because they are connected to Buses D and E and are not interface branches. In this case, all the five branches have variable flow because the 5th percentile flow is negative and the 95th percentile flow is positive (in a directional sense) in all cases.[144] We conclude that the prevailing electricity flow across the HV interface can be isolated and an HV region is established on either side of boundary 3.

b. For possible boundary 4, the boundary bus is Bus F. The prevailing electricity flow across possible boundary 4 can be isolated if at least one of the two HV branches between Bus F and Bus D is variable and at least one of the two HV branches between Bus F and Bus E are variable. In this case, none of the four branches are variable as the 95th percentile is positive in each case and the 5th percentile is either zero or a positive value. We conclude that the prevailing electricity flow across the HV interface cannot be isolated from the prevailing electricity flow across the HV interface for boundary 3.

c. This results in the confirmation of a single HV to HV boundary at boundary 3 (where there is a prevailing electricity flow across the HV interface that can be isolated). An HV connection region is established on either side of boundary 3.

3.5.1.2 Determine low voltage connection regions (steps 3 and 4)

472. Low voltage (**LV**) connection regions comprise grid assets less than 220kV and include the LV nodes and branches from the interconnecting substation (including the interconnecting transformer).

473. LV connection regions are initially established on the LV side of each interconnecting transformer branch that connects part of the LV interconnected grid to an HV connection region (clause 62(4)(c)).

474. If an LV connection region is connected to more than one HV connection region then it is necessary to split the LV connection region at the branch where there is the lowest average electricity flow (the minimum transfer branch). We use Arcflow data to rank the LV branches within the LV connection region and create separate LV connection regions on either side of the minimum transfer branch. We repeat this exercise until all LV connection regions are connected to only one HV connection region (clause 62(4)(d)).

475. If after that process there is more than one HV to LV interconnection branch into an LV connection region, we need to evaluate if the LV connection region could be further split into separate LV connection regions. This could occur at the branch with the lowest average electricity flow in the LV connection region based on Arcflow data (the minimum transfer branch) (clause 62(4)(e)). This possible boundary would be confirmed if the electricity flow across the minimum transfer branch is low relative to total electricity flows between the interconnecting transformers within the LV connection region.

476. To determine whether the electricity flow across the minimum transfer branch is low relative to total electricity flows between the interconnecting transformers within the LV connection region we apply an injection test to a pair of HV to LV interconnecting sites (substations where the HV to LV interconnecting transformers are located) using a PowerFactory model.[145] The test involves adding 10MW of generation at the HV node of one of the interconnecting sites then adding a 10MW load at the LV node at the other interconnecting site. We observe the change in electricity flow across the minimum

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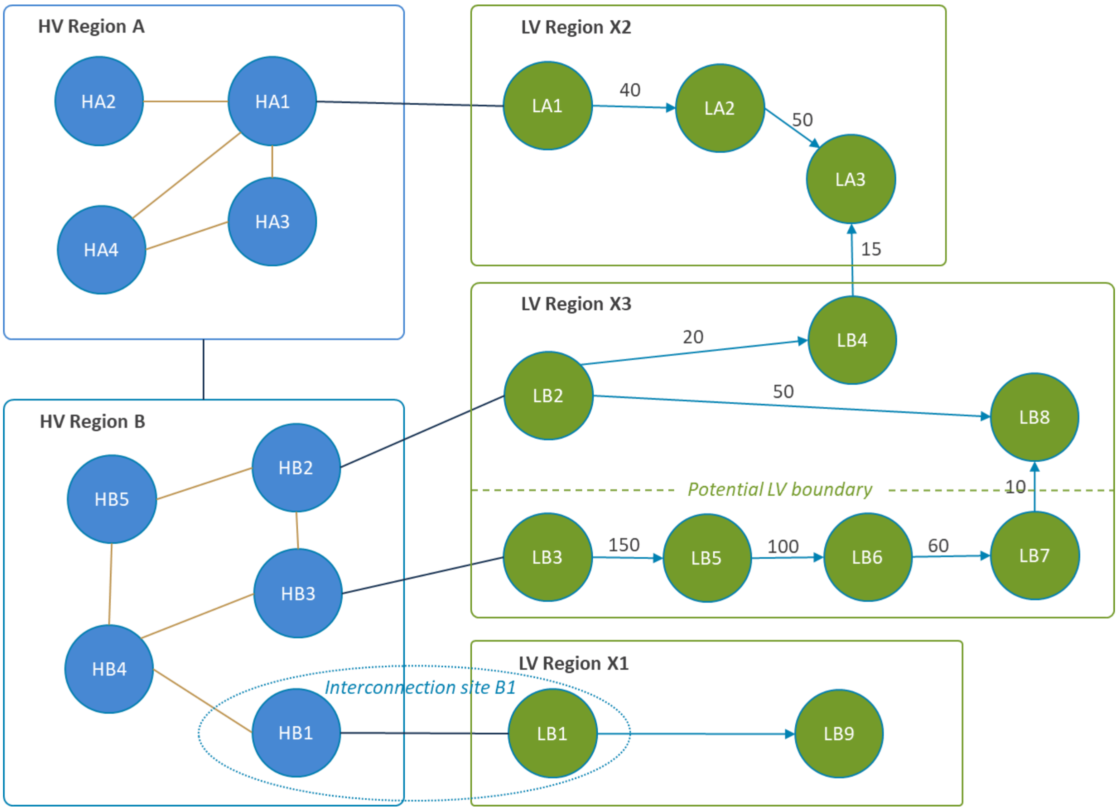
144 The interface branches for possible boundary 3 are the two branches between Bus D and Bus F and the two branches between Bus E and Bus F.

145 We use the most recently published Electricity Market Information (**EMI**) model at the time that we determine our connection regions for each simple method period.

transfer branch and conclude that the electricity flow is low if it changes by 1MW or less (i.e. 10% or less). We repeat the test in the opposite direction.

477. Below is a simplified example of how LV connection regions are determined.



a. LV Region X1 can be established as an LV connection region without further analysis of electricity flows as LV Region X1 is connected[146] to only one HV connection region (HV Region B) and is connected by only one HV to LV interconnection branch.

b. The interconnection branch transformers LA1 and LB2 are part of one LV interconnected grid that is connected to more than one HV connection region (HV Region A and HV Region B). Separate LV connection regions must be established either side of the minimum transfer branch so that each LV connection region is connected to only one HV connection region. The minimum transfer branch is between LA3 and LB4 where the average electricity flow magnitude is 15MW. Creating two LV connection regions, LV Region X2 and LV Region X3, either side of this branch ensures the two LV connection regions are each connected to only one HV connection region.

c. LV Region X3 includes two HV to LV interconnection sites (LB2 and LB3) so it is necessary to determine if LV Region X3 should be split into separate LV connection regions. Separate LV connection regions can be established on either side of the minimum transfer branch within LV Region X3 if electricity flow on that branch is low relative to total electricity flows between interconnecting sites in LV Region X3. The

146 "Connected" in the context of the simple method connotes an electrical connection. The electrical connection is based on the connection in the power flow case used in the PowerFactory model referenced in section 3.5.1.2.

minimum transfer branch within LV Region X3 is between LB7 and LB8 where the average electricity flow magnitude is 10MW.

d. Separate LV connection regions are established on either side of the minimum transfer branch (LB7_LB8) if average electricity flow magnitude on the branch is low relative to total electricity flows between interconnection sites B2 and B3. To assess this:

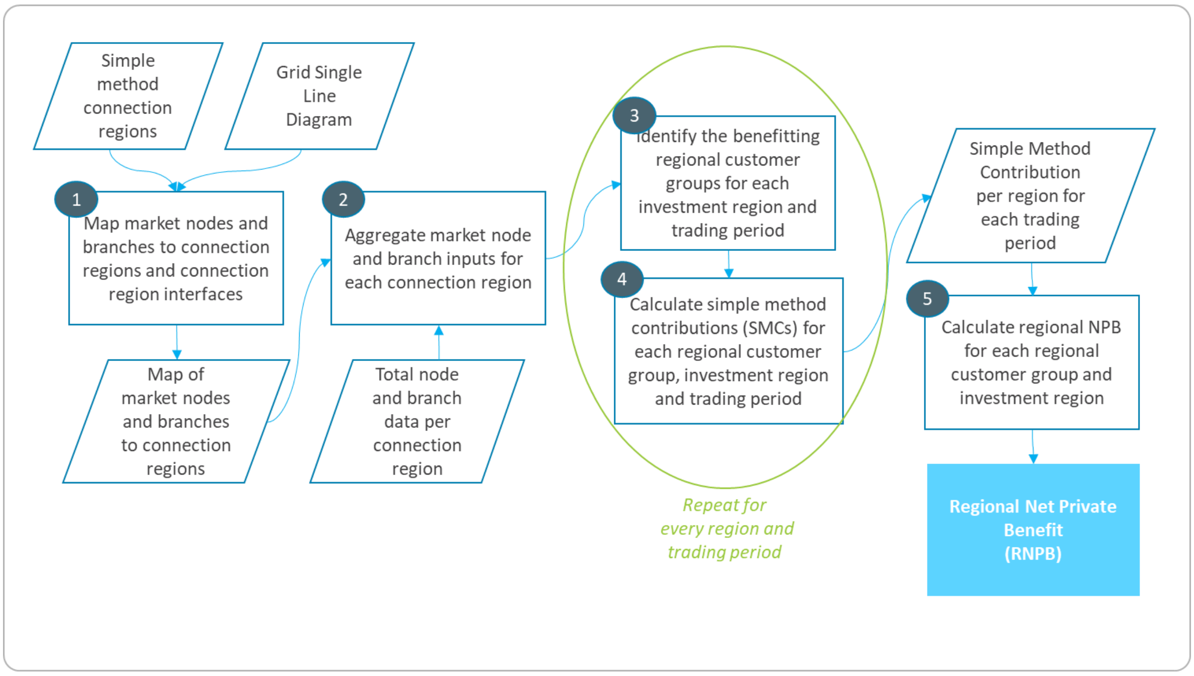
   - Injection test 1: Generation into LV Region X3 is increased at node HB2 by 10MW and offtake is increased at node LB3. If the flow of electricity across branch LB7_LB8 is impacted by less than 10% of the additional 10MW (i.e. falls to no less than 9 MW) then we conclude that the flow is low relative to total electricity flows between the nodes in the HB2_LB3 direction.
   - Injection test 2: The test is repeated in the opposite direction. Generation is increased by 10MW at node HB3 and load is increased by 10MW at node LB2. Electricity flow across branch LB7_LB8 is low relative to total electricity flows between the nodes in the HB3_LB2 direction if it increases to no more than 11MW.
   - If the average of both injection tests result in no more than a 1MW change in electricity flow across branch LB7_LB8 then separate LV connection regions are created on either side of this boundary.

3.5.2 Calculate regional NPB

478. Regional NPB is calculated for each regional customer group. Each connection region will have two regional customer groups– a regional demand group (the offtake customers located within that connection region) and the regional supply group (the injection customers located within that connection region) (clause 63).

479. A regional customer group will have a different regional NPB value for each different investment region (the modelled region in which the BBI is located). Regional NPB is a weighted average of the regional customer group’s simple method contribution (**SMC**) for an investment region over CMP C for the relevant simple method period.

480. The formulae used to calculate regional NPB are in clause 64. The process we follow when completing these calculations is depicted in the illustration below.



3.5.2.1 Map market nodes and branches to connection regions and connection region interfaces (step 1)

481. Using the SPD diagram that was current at the end of the CMP C for the simple method period and the connection region determination, we map:[147]

   a. each market node to the connection region in which it is located

   b. each branch to the connection region interface it pertains to.[148]

3.5.2.2 Aggregate market node and branch inputs for each connection region (step 2)

482. The raw offtake and injection data we use for this step are the wholesale market final pricing" nodal prices and volumes" datasets published on the Authority's website. We use the datasets published at the time we calculate regional NPB.

483. To calculate offtake and injection at market nodes, embedded generation cleared in the market is netted off against market load data at the same electrically equivalent market node(s) to produce net generation (injection) or net load (offtake) at that these market nodes.

484. We calculate regional demand group offtake for each trading period during CMP C by aggregating net market load data from all market nodes mapped to a connection region.[149]

485. We calculate regional supply group injection for each trading period during CMP C by aggregating net market generation data from all market nodes mapped to a connection region.

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147 The SPD diagram can be found at https://www.transpower.co.nz/system-operator/information-industry/electricity-market-operation/scheduling-and-dispatch.

148 A connection region interface is an interface that connects one connection region to another.

149 We will exclude any trading periods for which we consider we do not have reliable data.

486. We calculate regional interface electricity flows for each connection region and each trading period during CMP C by summing the market branch flow data for all interface branches mapped between connection regions.

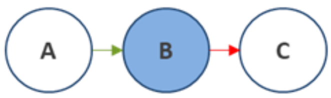
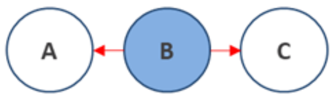
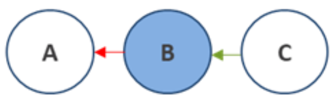
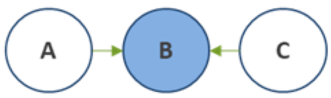
3.5.2.3 Identify the benefitting regional customer groups for each investment region and trading period (step 3)

487. For each investment region in each trading period during CMP C, we use the regional interface electricity flows to identify the benefitting regional customer groups, being:

a. regional demand groups that import electricity from the investment region either directly or indirectly

b. regional supply groups that export electricity to the investment region either directly or indirectly.

488. The benefitting regional customer groups for an investment region may change from trading period to trading period depending on the directional flow of electricity between connection regions. This is illustrated in the following example which is a variation of the simple three connection region illustration in clause 64:

Trading period	Flow pattern	Benefitting regional customer groups
1		Supply$_b$ Demand$_b$ Demand$_c$ Supply$_a$
2		Supply$_b$ Demand$_b$ Demand$_a$ Demand$_c$
3		Supply$_b$ Demand$_b$ Demand$_a$ Supply$_c$
4		Supply$_a$ Supply$_b$ Demand$_b$ Supply$_c$

3.5.2.4 Calculate simple method contributions (SMCs) for each regional customer group, investment region and trading period (step 4)

489. We use the inputs calculated in step 2 and the regional customer groups determined in step 3 to calculate the SMC for each regional customer group, investment region and trading period during CMP C. The SMC formulae are in clause 64(5) for the simple three connection region example in that clause.

490. For each regional customer group and investment region, we calculate the weighted average of SMC across all trading periods during CMP C. Each trading period can have a different weighting as determined by Transpower.[150] For the first simple method period we have weighted all trading periods equally.

491. The weighted average SMCs represents the generalised electricity flow state for all connection regions across the relevant simple method period.

3.5.2.5 Calculate regional NPB for each regional customer group and investment region (step 5)

492. The weighted average SMC calculated in step 4 for a regional supply group and investment region is the regional supply group's regional NPB for the investment region.

493. The weighted average SMC calculated in step 4 for a regional demand group and investment region multiplied by the demand factor is the regional demand group's regional NPB for the investment region. The demand factor scales up regional NPB for regional demand groups relative to regional NPB for regional supply groups.[151] The demand factor is, effectively, 1.67 (clause 64(4)).

3.5.3 Calculate simple method factors

494. A customer has a simple method factor (**SMF**) calculated for each regional customer group it is a member of (clause 61(2)).

495. The process we follow for these calculations is depicted in the illustration below and described in the following sections.

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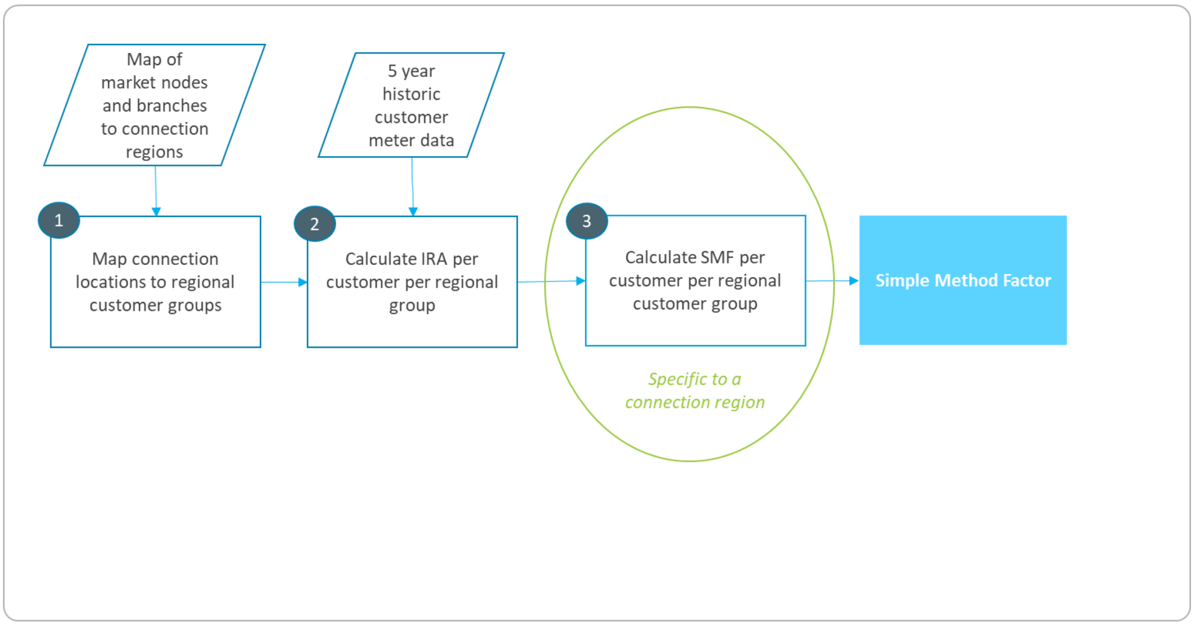
150 The ability to apply a different weighting to trading periods is included in the TPM to avoid the need to change the TPM in the event it is reasonable to apply different weightings in order to ensure BBI customer allocations are broadly proportionate to EPNPB (clause 64(4)). For example, if there are trading periods within CMP C that have no data available at the time of calculation, we can weight those trading periods as zero without a change to the TPM.

151 The Authority's rationale for the demand factor is in paragraphs 5.44 to 5.62 of its [Transmission Pricing Methodology 2022: Decision paper].



3.5.3.1 Map connection locations to regional customer groups (step 1)

496. We map each market node to a connection location.

497. We map each connection location to a connection region using the map of market nodes to connection regions (see paragraph 481).

3.5.3.2 Calculate IRA per customer per regional customer group (step 2)

498. To calculate a customer's SMFs for the regional customer groups it is a member of, we must calculate their IRA for each regional customer group. Clauses 65 to 67 relate to the calculation of IRAs.

499. For BBIs under the simple method, the IRA for regional demand groups is mean historical annual offtake. The IRA for regional supply groups is mean annual historical injection (clause 65(4)).

500. IRAs are calculated based on injection or offtake (per trading period) over CMP C (clauses 65(10) and 65(11)).

501. New customers and recent customers (customers connected for less than two full capacity years during CMP C) have their IRAs estimated (but, for recent customers, taking into account any available information about their offtake or injection) (clauses 66 and 83(3)(a)).

3.5.3.3 Calculate SMF per customer per regional customer group (step 3)

502. We calculate each customer's SMF for each regional customer group by dividing the customer's IRA for the regional customer group by the total of all customers' IRAs for the regional customer group.

3.5.4 Calculate individual NPB and starting BBI customer allocations

3.5.4.1 Calculate individual NPB

503. A customer's individual NPB for the BBI is the sum of the of the regional NPB (for the relevant investment region) for each regional customer group of which the customer is a member multiplied by the customer's SMF for the group (clause 61(1)).

3.5.4.2 Calculate starting BBI customer allocations and BBCs

504. The starting BBI customer allocations for the BBI are calculated as each customer's individual NPB divided by the sum of all customers' individual NPBs (clause 43(1)).

505. A customer's BBC for the BBI is calculated by multiplying the BBI's covered cost by the customer's BBI customer allocation (clause 35(2)).

3.5.4.3 Apportioning between investment regions

506. If the BBI is in more than one investment region, the above calculations are done separately for each investment region, with an appropriate apportionment of the BBI's covered cost between the investment regions.

507. For this purpose, the allocation of grid assets to connection regions is relevant. Under clause 62(4)(f):

    a. where a grid asset is part of an HV to HV branch, the grid asset is allocated between the HV connection regions in proportion to the total electricity flows during CMP C

    b. where a grid asset is part of an HV to LV branch, the grid asset is attributed to the LV connection region

    c. where a grid asset is part of an LV to LV branch, the grid asset is allocated 50% to each LV connection region.

Chapter 4
Regions and factors for the simple method

4.1 Introduction

508. This chapter of includes the simple method modelled regions and the simple method customer allocation model.

509. The model includes the SMFs, RNPB, demand adjustment factor (**F**) and BBI customer allocation (**CA**) values for the for the first simple method period.

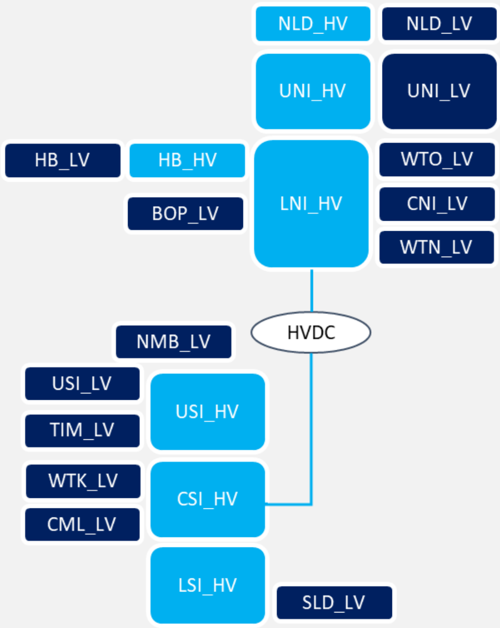
510. The assumptions book must contain the simple method modelled regions (clause 62(2)), the simple method factors for each regional customer group (clause 61(5)) and the regional NPB for each regional customer group with respect to each investment region (clause 64(1)).

511. This chapter will be updated with the simple method modelled regions and simple method customer allocation model for each subsequent simple method period prior to the commencement of that period.

4.2 Modelled regions

4.2.1 Table of regions

513. The table below contains the modelled regions for the first simple method period. These regions were determined using the process detailed in section 3.5.1 of chapter 3.



Region ID	Region Description
NLD_HV	Northland high voltage
UNI_HV	Upper North Island high voltage
LNI_HV	Lower North Island high voltage
HB_HV	Hawke's Bay high voltage
LSI_HV	Lower South Island high voltage
CSI_HV	Central South Island high voltage
USI_HV	Upper South Island high voltage
HVDC	HVDC link
NLD_LV	Northland low voltage
UNI_LV	Upper North Island low voltage
WTO_LV	Waikato low voltage
CNI_LV	Central North Island low voltage
WTN_LV	Wellington low voltage
HB_LV	Hawke's Bay low voltage
BOP_LV	Bay of Plenty low voltage
SLD_LV	Southland low voltage
CML_LV	Cromwell low voltage
WTK_LV	Waitaki low voltage
TIM_LV	Timaru low voltage
USI_LV	Upper South Island low voltage
NMB_LV	Nelson-Marlborough low voltage

4.2.2 HV connection regions

514. Transpower is not required to assess electricity flows over the entire high-voltage grid when determining connection regions (clause 62(5)(a)) and did not do so when we determined the initial boundaries to be assessed.

515. Instead, we considered the geographical and electrical similarity of the nodes in each region in order to determine the location we considered it possible a boundary could exist. We identified thirteen potential HV connection regions in the North Island and eleven potential HV connection regions in the South Island. We then tested these boundaries using the rules set out in section 3.5.1.1.

4.2.3 North Island HV connection regions test result

516. The following table summarises how the thirteen potential North Island HV connection regions were evaluated using the two tests described in 3.5.1.1 of chapter 3 and how that process resulted in the final four HV connection regions:

Name	Interface circuits	Branch Name	Prevailing flow test	Isolation test	Determined region
Northland	BRB-HPI	BRB_HPI1.1	Passes	Passes	Northland High Voltage (NLD_HV)
	HPI-MDN	HPI_MDN1.1			
North Shore	ALB-HEN-3	ALB_HEN3.1	Fails		Upper North Island High Voltage (UNI_HV)
	HEN-HPI	HEN_HPI1.1			
	HOB-WRD	HOB_WRD1.1			
North Isthmus	HEN-OTA	HEN_OTA.1	Passes	Fails	
	OTA-SWN	OTA_SWN.1			
	HOB-WRD	HOB_WRD1.1			
South Auckland	OTA-PEN 5&6	OTA_PEN5.1	Passes	Fails	
		OTA_PEN6.1			
	HEN-OTA	HEN_OTA.1			
	OTA-SWN	OTA_SWN.1			
	PAK-PEN-3	PAK_PEN3.1			
Upper North Island	BHL-WKM-1&2	PAK_WKM1.2	Passes	Passes	Lower North Island High Voltage (LNI_HV)
		PAK_WKM2.2			
	HLY-TAT-2	HLY_OTA2.1			
	DRY-HLY	DRY_HLY1.1			
	OHW-OTA 1&2	OHW_OTA1.1			
		OHW_OTA2.1			
	OTA-WKM 1&2	OTA_WKM1.1			

Name	Interface circuits	Branch Name	Prevailing flow test	Isolation test	Determined region
		OTA_WKM2.1			
WUNI	BHL-WKM-1&2	PAK_WKM1.2	Fails		
		PAK_WKM2.2			
	HLY-SFD	HLY_SFD.1			
	TMN-TWH	TMN_TWH1.1			
	OHW-WKM	OHW_WKM1.1			
	HAM-WKM	HAM_WKM.1			
	OTA-WKM 1&2	OTA_WKM1.1			
		OTA_WKM2.1			
Wairākei Ring North	HLY-SFD	HLY_SFD.1	Fails		
	TMN-TWH	TMN_TWH1.1			
	TKU-WKM 1&2	TKU_WKM1.1			
		TKU_WKM2.1			
	WRK-WKM	WKM_WRK1.1			
	THI-WKM	THI_WKM1.1			
	ATI-OHK	ATI_OHK.1			
	EDG-TRK 1 &2	EDG_TRK1.1			
		EDG_TRK2.1			
WRK Ring South	HLY-SFD	HLY_SFD.1	Fails		
	TMN-TWH	TMN_TWH1.1			
	TKU-WKM 1&2	TKU_WKM1.1			
		TKU_WKM2.1			

Name	Interface circuits	Branch Name	Prevailing flow test	Isolation test	Determined region
	WRK-WKM	WKM_WRK1.1			
	THI-WRK	THI_WRK1.1			
	OHK-WRK	OHK_WRK.1			
CNI	HLY-SFD	HLY_SFD.1	Fails		
	TMN-TWH	TMN_TWH1.1			
	TKU-WKM 1&2	TKU_WKM1.1			
		TKU_WKM2.1			
	RPO-WRK	RPO_WRK1.1			
Bunnythorpe	BPE-TKU 1&2	BPE_TKU1.1	Fails		
		BPE_TKU2.1			
	BPE-TNG	BPE_TNG1.1			
	BPE-BRK 1&2	BPE_BRK1.1			
		BPE_BRK2.1			
Wellington	BPE-PRT-1	BPE_PRM_HAY1.1	Fails		
	BPE-PRT-2	BPE_PRM_HAY2.1			
	BPE-TWT-1	BPE_TWC_LTN1.1			
	BPE-LTN-1	BPE_WIL1.1			
Hawkes Bay	RDF-WRK	RDF_WRK.1	Passes	Passes	Hawkes Bay High Voltage (HB_HV)
	WHI-WRK	WHI_WRK1.1			
Bay of Plenty	ATI-WKM	ATI_WKM.1	Fails		
	OHK-WRK	OHK_WRK.1			
Tarukenga	ATI-TRK 1&2	ATI_TRK1.1	Passes	Fails	

Name	Interface circuits	Branch Name	Prevailing flow test	Isolation test	Determined region
		ATI_TRK2.1			
	EDG-TRK 1&2	EDG_TRK1.1			
		EDG_TRK2.1			
Western Bay of Plenty	ATI-TRK 1&2	ATI_TRK1.1	Passes	Fails	
		ATI_TRK2.1			
	EDG-KAW-3	EDG_KAW3.1			

4.2.4 South Island HV connection regions test result

517. The following table summarises how the eleven potential South Island HV connection regions were evaluated using the two tests described in 3.5.1.1 of chapter 3 and how that process resulted in the final three HV connection regions:

Name	Interface circuits	Branch Name	Prevailing flow test	Isolation test	Determined region
Nelson	KIK-STK 1&2	KIK_STK1.1	Passes	Fails	Upper South Island HV (USI_HV)
		KIK_STK2.1			
North Canterbury	ISL-KIK	ISL_KIK1.1	Passes	Fails	
	CUT-WTT 2&3	ISL_KIK2.2			
		ISL_KIK3.2			
Top of South Island	ISL-KIK	ISL_KIK1.1	Passes	Fails	
	ISL-WTT 2&3	ISL_KIK1.2			
		ISL_KIK1.2			
Christchurch	ISL-TKB	ISL_TKB.1	Passes	Fails	
	ASB-ISL	ASB_ISL1.1			
	ASB-BRY	ASB_BRY.1			

Name	Interface circuits	Branch Name	Prevailing flow test	Isolation test	Determined region
	ISL-LIV	ISL_LIV.1			
Mid Canterbury	ISL-TKB	ISL_TKB.1	Passes	Fails	
	ASB-OPI 1&2	ASB_TIM_TWZ1.1			
	ISL-LIV	ASB_TIM_TWZ2.1			
		ISL_LIV.1			
USI	ISL-TKB	ISL_TKB.1	Passes	Passes	Central South Island High Voltage (CSI_HV)
	OPI-TWZ 1&2	ASB_TIM_TWZ1.3			
	ISL-LIV	ASB_TIM_TWZ2.3			
		ISL_LIV.1			
Upper Waitaki Valley	CML-TWZ 1&2	CYD_TWZ1.2	Fails		
	OHB-TWZ	CYD_TWZ2.2			
	OHC-TWZ	OHB_TWZ.1			
	BEN-TWZ	OHC_TWZ.1			
	ISL-LIV	BEN_TWZ.1			
		ISL_LIV.1			
Lower Waitaki Valley	CML-TWZ 1&2	CYD_TWZ1.2	Fails		
	LIV-WTK	CYD_TWZ2.2			
	ISL-LIV	LIV_WTK.1			
		ISL_LIV.1			
Lower South Island	CML-CYD 1&2	CYD_TWZ1.1	Passes	Passes	Lower South Island High Voltage (LSI_HV)
	NSY-ROX	CYD_TWZ2.1			
		NSY_ROX.1			

Name	Interface circuits	Branch Name	Prevailing flow test	Isolation test	Determined region
Central Otago	CYD-ROX 1&2	CYD_ROX1.1	Fails		
	NSY-ROX	CYD_ROX2.1			
Southland	INV-ROX 1&2	INV_ROX1.1	Fails		
	GOT-TMH 1&2	INV_ROX2.1			
		NMA_GOR_TMH1.2			
		NMA_GOR_TMH2.2			

4.2.5 LV connection regions

518. The following table summarises how the final thirteen LV connection regions were determined using the process described in 3.5.1.2 of chapter 3:

North Island LV connection regions				
LV Region	**Connected HV region**	**Interface**	**Interface branches**	**Test**
NLD_LV	NLD_HV	NLD_HV_NLD_LV	MDN_T5.T5, MDN_T6.T6	HV:LV no split required
		UNI_LV_NLD_LV	HEN_MPE1.3_HEN_MPE2.3	HV:LV split at minimum transfer branch
UNI_LV	UNI_HV	UNI_LV_NLD_LV	HEN_MPE1.3_HEN_MPE2.3	HV:LV split at minimum transfer branch
		UNI_HV_UNI_LV	OTA_T2.T2, OTA_T3.T3, OTA_T4.T4, OTA_T5.T5, PEN_T10.T10, PEN_T6.T6, HEN_T1.T1, HEN_T5.T5, HOB_T12.T12, ALB_T4.T4	HV:LV split at minimum transfer branch
		WTO_LV_UNI_LV	BOB_OTA2.1, BOB_OTA1.1	HV:LV split at minimum transfer branch
WTO_LV	LNI_HV	WTO_LV_UNI_LV	BOB_OTA2.1_BOB_OTA1.1	HV:LV split at minimum transfer branch
		LNI_HV_WTO_LV	HAM_T6.T6, HAM_T9.T9	HV:LV split at minimum transfer branch
		CNI_LV_WTO_LV	ARI_ONG.2	LV:LV split at minimum transfer branch

North Island LV connection regions				
CNI_LV	LNI_HV	CNI_LV_WTO_LV	ARI_ONG.2	LV:LV split at minimum transfer branch
		LNI_HV_CNI_LV	BPE_T1.T1, BPE_T2.T2, BPE_T3.T3, NPL_T8.T8, SFD_T10.T10, SFD_T9.T9	HV:LV split at minimum transfer branch
		WTN_LV_CNI_LV	MGM_MST1.1	LV:LV split at minimum transfer branch
WTN_LV	LNI_HV	WTN_LV_CNI_LV	MGM_MST1.1	LV:LV split at minimum transfer branch
		LNI_HV_WTN_LV	HAY_T5.T5, HAY_T2.T2, HAY_T1.T1, WIL_T8.T8	HV:LV split at minimum transfer branch
BOP_LV	LNI_HV	LNI_HV_BOP_LV	KAW_T12.T12, KAW_T13.T13, EDG_T4.T4, EDG_T5.T5, TRK_T2.T2, TRK_T3.T3, KMO_T2.T2, KMO_T4.T4	HV:LV no further valid split
HB_LV	HB_HV	HB_HV_HB_LV	RDF_T3.T3, RDF_T4.T4	HV:LV no split required

South Island LV connection regions				
LV Region	**Connected HV region**	**Interface**	**Interface branches**	**Test**
SLD_LV	LSI_HV	LSI_HV_SLD_LV	GOR_T11.T11, GOR_T12.T12, INV_T1.T1, ROX_T10.T10, HWB_T6.T6, HWB_T4.T4	HV:LV no further valid split
CML_HV	CSI_HV	CSI_HV_CML_LV	CML_T5A.M5A, CML_T5B.M5B, CML_T8.M8	HV:LV no further valid split

WTK_LV	CSI_HV	CSI_HV_WTK_LV	WTK_T23.T23WTK_T24.T24	HV:LV split at minimum transfer branch
		WTK_LV_TIM_LV	STU_TIM.1	HV:LV split at minimum transfer branch
TIM_LV	USI_HV	WTK_LV_TIM_LV	STU_TIM.1	HV:LV split at minimum transfer branch
		USI_HV_TIM_LV	TIM_T5.T5, TIM_T8A.T8A, TIM_T8B.T8B, TIM_T8.T8	HV:LV split at minimum transfer branch
USI_LV	USI_HV	USI_HV_NMB_LV	ISL_T3.T3, ISL_T6.T6, ISL_T7.T7, WPR_T12.T12, WPR_T13.T13	HV:LV split at minimum transfer branch
		NMB_LV_USI_LV	DOB_T11.M11, DOB_T12.M12	LV:LV split at minimum transfer branch
NMB_LV	USI_HV	NMB_LV_USI_LV	DOB_T11.M11, DOB_T12.M12	LV:LV split at minimum transfer branch
		USI_HV_NMB_LV	KIK_T1.T1, KIK_T2.T2, STK_T7.T7	HV:LV split at minimum transfer branch

Note 1 Each of the separate LV connection regions is connected to only 1 HV connection region (clause 62(4)(d))

Note 2 The 'Test' column indicates how each boundary has been established as outlined in the following table:

HV:LV no split required	Determined by cl 62(4)(c). Where there is an HV to LV interface through only one interconnection branch.
HV:LV no further valid split	Determined by cl 62(4)(c). And subsequent testing concluded cl 62(4)(e) did not apply
HV:LV split at minimum transfer branch	Determined by cl 62(4)(d) where LV:LV boundaries are defined at the minimum transfer branch to ensure each LV connection region connects to only one HV connection region.
LV:LV split at minimum transfer branch	Determined by cl 62(4)(c) or (d). And subsequent testing created a further LV:LV boundary under cl 62(4)(e).

4.3 Simple Method Customer Allocation

519. The Simple BBI customer and regional allocations model is published as Appendix B of this assumptions book.

520. From time to time some starting IRAs, SMFs and BBI customer allocations are corrected or updated through consultation with the relevant customers. The simple method starting IRAs, SMFs and Customer Allocations are published as Appendix C to this assumptions book.

Chapter 5
Adjustments to both low-value and high-value BBIs

5.1 Benefit factors

522. A new customer arriving is a BBC adjustment event.

523. Under clause 83(6), benefit factors are used to calculate new customers' starting BBI customer allocations for the Appendix A BBIs (the seven historical BBIs in Appendix A of the TPM).

524. Benefit factors are calculated for each Appendix A BBI, Appendix A customer and connection location at which the customer is (or was) connected. A customer's benefit factor for an Appendix A BBI and a connection location is the part of the customer's Appendix A allocation for the BBI attributable to the connection location per kWh of the customer's injection or offtake at the connection location over CMP D, or our estimate of what that injection or offtake would have been (clause 83(7)).

525. The relevant benefit factor(s) for comparator customer(s) (customers of the same type as the new customer) are used to calculate the new customer's starting BBI customer allocations for each of the Appendix A BBIs.

526. Because the benefit factors are based on the Appendix A allocations and are only calculated for the Appendix A customers, the benefit factors are static.

527. There are many benefit factors because each Appendix A customer has a separate benefit factor for each Appendix A BBI and each connection location at which the customer is connected. Accordingly, we have published the benefit factors with this assumptions book in a separate spreadsheet – see BBC Assumptions Book benefit factors.

5.2 Adjusted BBI Customer Allocations

528. BBI Customer Allocations are adjusted over time due to BBC adjustment events under Part F of the TPM. The current BBI Customer Allocations are published as Appendix D to this assumptions book.

5.3 BBI covered costs

529. Each BBI's covered cost is recalculated annually as part of setting prices for the next pricing year. The current BBI covered costs are published alongside this assumptions book as Appendix E. A customer's BBCs are calculated by multiplying its BBI allocation by the BBI's covered cost.

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