Transmission Pricing Methodology

Cost benefit analysis (CBA) of proposed TPM

CBA information session, 2 November 2021

Steps in CBA

Standard steps followed in assessing costs and benefits.

This presentation focusses on three of these steps.

- Define problem
- Select options for addressing the problem
- **Specify the baseline against which changes in costs and benefits are assessed**
- **Identify the effects of the proposed options**
- Evaluate against decision criteria
- **Test sensitivity results**

Process for this CBA

This CBA does not start from scratch but reconsiders the impacts of changing the TPM in light of new market data, expectations for the demand growth and details in the proposed TPM

- Starting point is CBA conducted for TPM Guidelines
- Revisits baseline assumptions and data
  - Generation costs
  - Demand growth
- Integrates details in proposed TPM, principally
  - allocations of interconnection charges
  - possible variations in TPM design parameters
- Scenarios
  - NZAS closed/NZAS open
  - Overhead opex recovered in (i) residual (ii) benefit-based charges
  - Generation customer shares base capex charges, approximately, (i) 50% (ii) 25%
  - Central is
    - NZAS closed
    - Overhead opex recovered in benefit-based charges
    - Default generation customer shares of base capex charges ~50%

Modelling approach

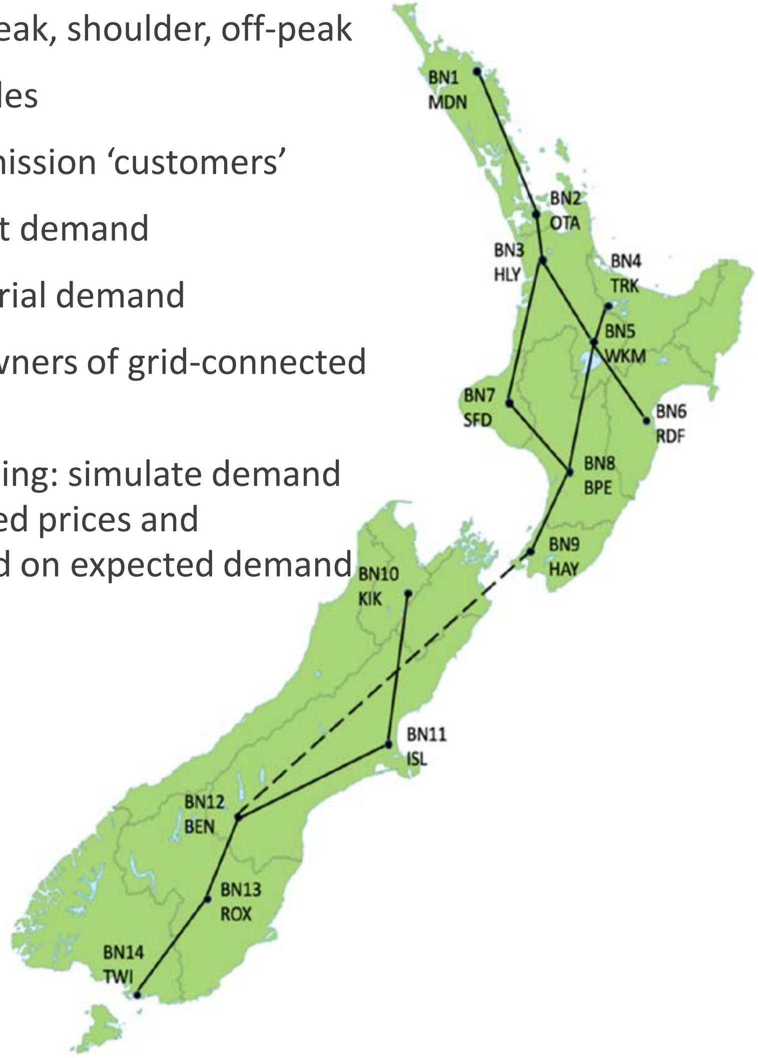
3 times of use: peak, shoulder, off-peak

14 backbone nodes

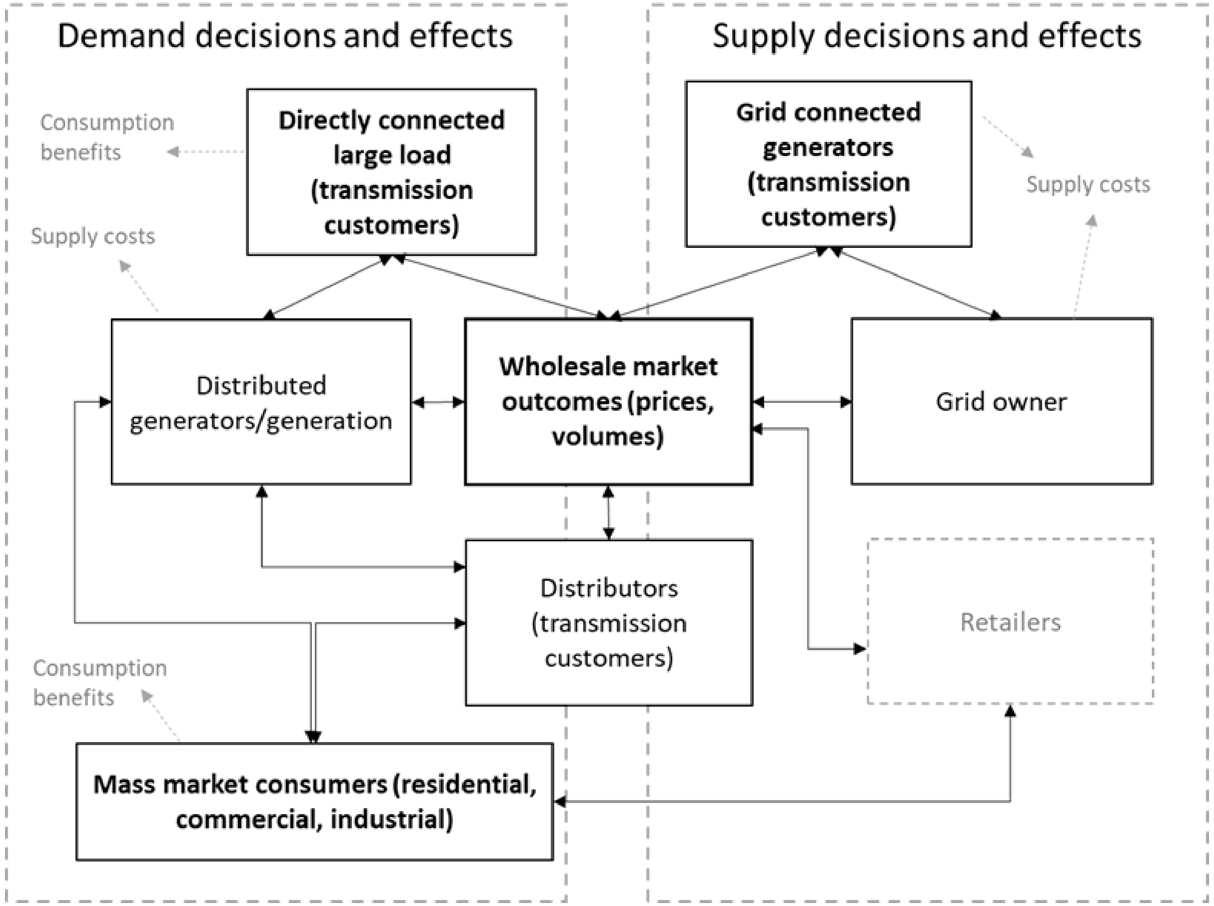
3 types of transmission ‘customers’

1) Mass-market demand
2) Large industrial demand
3) Investors/owners of grid-connected generation

Recursive modelling: simulate demand based on expected prices and investment based on expected demand and prices.



Primary component is a grid use model, modelling effects of changes in transmission charges on costs of demand and supply in the wholesale market and behaviour of transmission customers.



Amendments to grid-use modelling methods

Amendments made to accommodate policy scenarios and new demand and supply cost scenarios

- **Focus on levels**
  - demand response to prices changes depends on level of price relative to historical averages
  - to incorporate effects of significant demand and supply shocks e.g. persistent positive effect on demand of price decline if NZAS closes.
- Add **hybrid wind and solar farms** with batteries
  - shift output by time of use
  - reduce technical efficiency
  - raise capital cost of plant

- **Interrogate fixed vs variable charges**
  - fixed component of charges does not enter prices but rather impacts total demand via an income effect
  - demand responds to the prospect of new benefit based charges, by treating new benefit-based charges as $/MWh charges
  - demand responds to residual charges based on the lagged effect of incremental consumption on residual charges
  - fixed charges on generation impact on investment decisions but not operational decisions.

Costs

Categories of costs same as in 2020 CBA

Key changes are

- increase in development and implementation costs, based on Transpower experience and estimates
- much higher demand growth, sees an increase in costs of bringing grid investment forward due to rising peak demand

Quantified costs ($m)	Central
TPM development / approval	$9 ($4 - $13)
TPM implementation costs	$20 ($10 - $29)
TPM operational costs	$9 ($5 - $14)
Grid investment costs brought forward	$281 ($186 - $333)
Load not locating in regions with recent grid investment	$3 ($0 - $11)
Efficiency costs of price cap	$1
Total quantified costs	**$322 ($206 - $401)**

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Benefits

Benefit estimates similar in magnitude to guidelines CBA

- largest benefits come from reduced distortion to consumption and investment decisions ('more efficient grid use')
- benefits brought forward with transmission investment is second largest benefit, though more than offset by costs brought forward
- improvements in investment efficiency expected from internalisation of transmission costs, leading to more efficient investment in generation and large load, and increased scrutiny of transmission investment proposals
- benefits from increased certainty lower than expected in the guidelines decision.

Quantified benefits ($m)	Central
More efficient grid use	$1,098 ($461 - $2,021)
More efficient investment in batteries	$55 ($53 - $57)
Grid investment benefits brought forward	$243 ($210 - $284)
More efficient investment in generation and large load	$106 ($30 - $611)
More efficient grid investment – scrutiny of investment proposals	$61 ($12 - $122)
Increased certainty for investors	$11 ($0 - $29)
Total quantified benefits	$1,575 ($766 - $3,124)

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Summary by scenario

Weighted mean ($m)	Central	With Tiwai	Simple method 75:25	OH not in BBC
Gross change in consumer welfare	2,303	2,545	3,009	2,521
Change in interconnection costs	-1,205	-1,144	-810	-1,131
Net change in consumer welfare	1,098	1,401	2,199	1,391
Inefficient battery investment	55	48	55	55
More efficient investment, scrutiny, certainty	179	179	179	179
Transmission benefits brought forward	243	154	242	247
Transmission cost brought forward	-281	-159	-257	-256
Other costs	-42	-42	-42	-42
Net benefit	**$1,253 ($365 - $2,918)**	**$1,580 ($685 - $3,228)**	**$2,377 ($713 - $3,465)**	**$1,574 ($447 - $2,901)**

Baseline assumptions

Key sources:

(1) Climate Change Commission (2021) demonstration pathway

(2) MBIE generation stack update

Key assumptions:

(1) Rate of demand growth

(2) Rate of growth in generation costs

Assumption	Sample values
Wind generation capital costs (LRMC)	
Range for $ per MWh in 2020 ($2018)	$66.9/MWh - $97.3/MWh
Range for $ per MWh in 2035 ($2018)	$61.8/MWh - $88.5/MWh
Average annual growth	-0.80%
Utility scale solar generation capital costs	
Range for $ per MWh in 2020 ($2018)	$87.2/MWh - $113.4/MWh
Range for $ per MWh in 2035 ($2018)	$59.8/MWh - $76.9/MWh
Average annual growth	-3.00%
Step changes in demand	
Tiwai departure	Close end 2024 -5,322 GWh
Gas prices, central scenario	
$/GJ in 2020 ($2018)	$8.50/GJ
$/GJ in 2041 ($2018)	$10.10/GJ
Average annual growth	0.9%
Emissions prices	
$ per tonne 2020 ($2018)	$28.8/t
$ per tonne 2035 ($2018)	$154.3/t
Average annual growth	11.8%
Exogenous demand growth, average % growth	
Total	2.00%
Population growth	0.74%
Income growth	0.14%
Electrification	1.13%
Exogenous changes to generation capacity	
Commissioned	643 MW, 2022-2025
Decommissioned	-500 MW end 2024

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Baseline demand

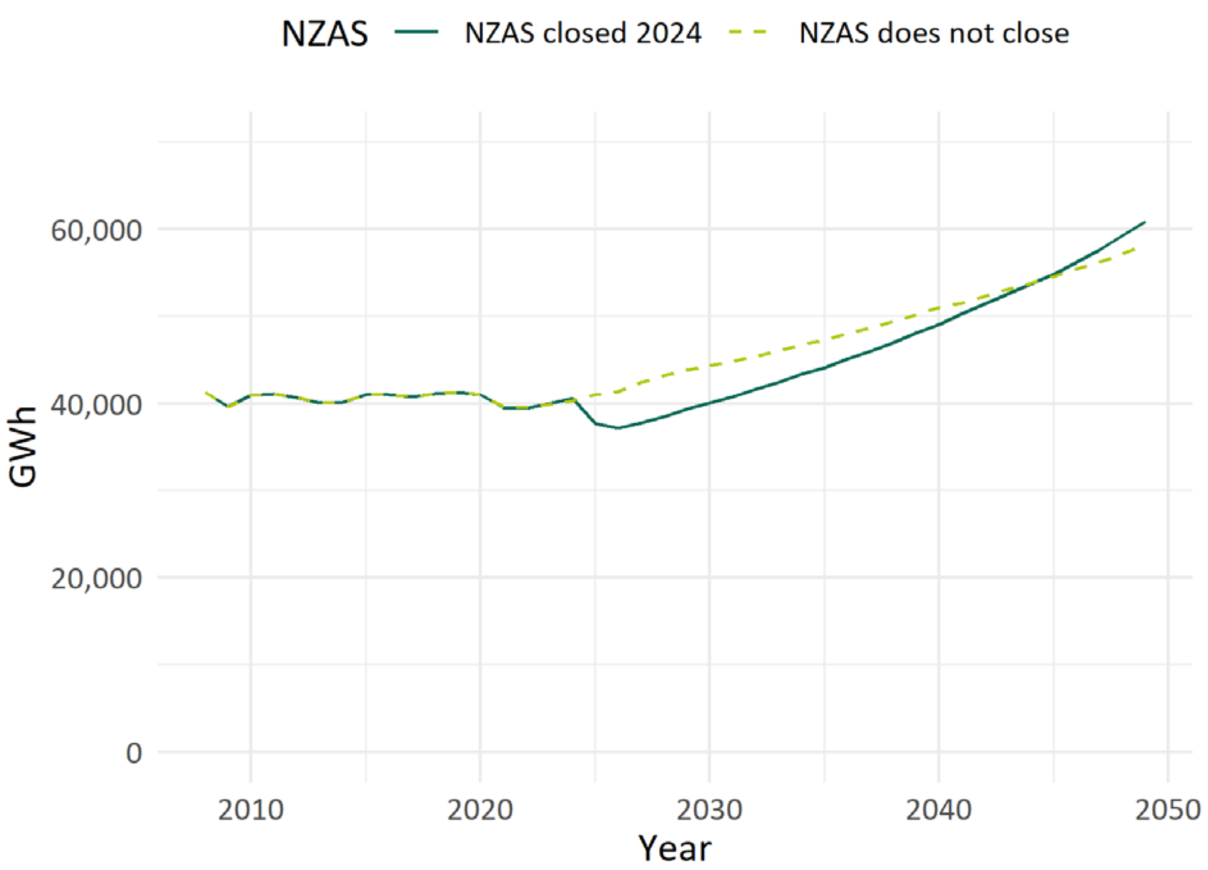
Assume constant average growth rate, after 2022, consistent with levels of demand reached in 2050 under the CCC demonstration pathway.

Higher growth rate under NZAS closure, requiring an average of e.g. 340MW of wind generation investment p.a. (~1.5 Turitea sized investments per year). As compared to 230MW p.a. if NZAS remains open.

If NZAS closes in 2024, demand returns to 2024 levels in 2029/30.

Projected volumes combine exogenous growth and price effects (lower prices boost demand, higher prices constrain demand).

Projected growth in energy consumption, average over demand and cost scenarios



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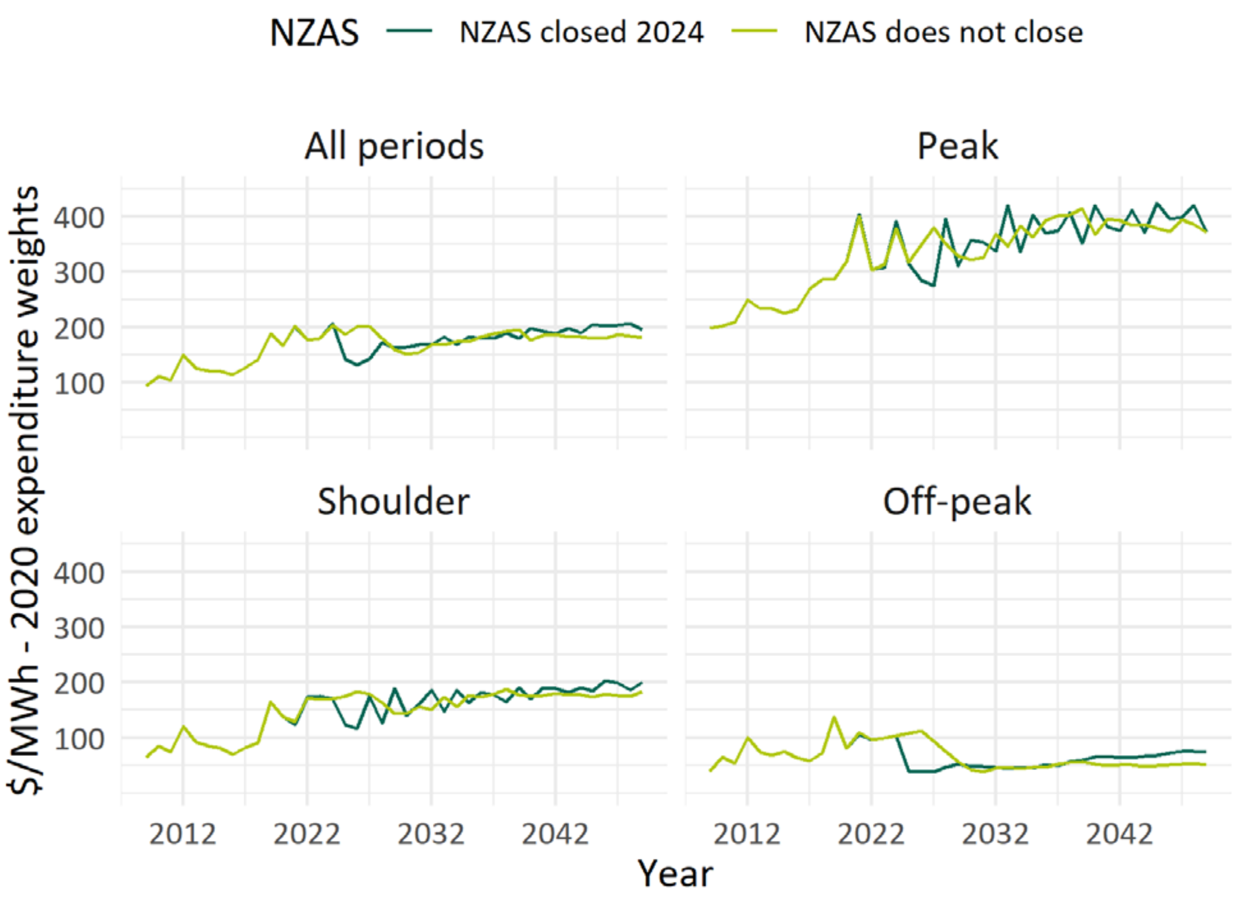
Baseline prices

Prices projected to fall off-peak and rise during peak and shoulder periods.

This reflects increasing penetration of renewables and diminishing thermal peaking capacity.

Prices at peak expected to be volatile.

Modelled average baseline prices, average over cost and demand scenarios/sensitivities. Prices include interconnection charges at peak.



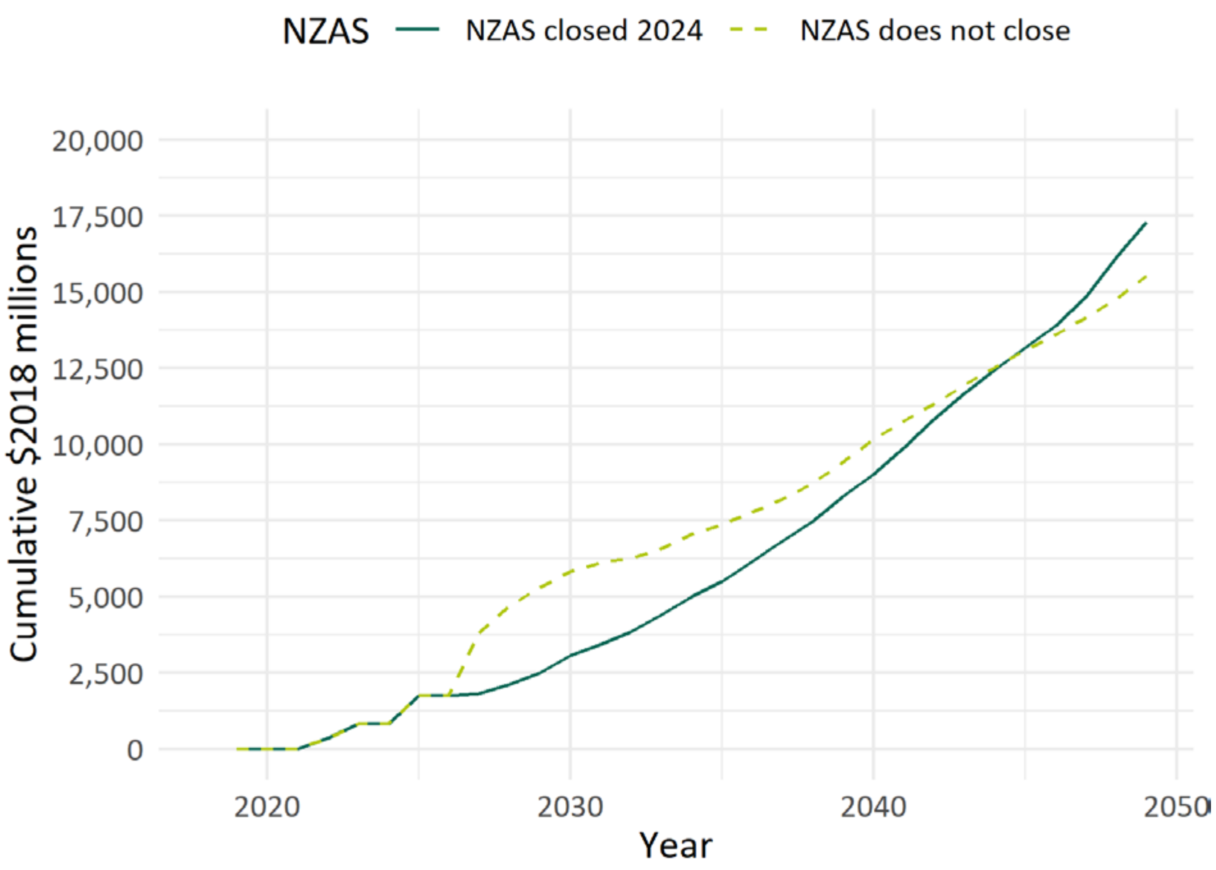
Baseline investment

Rapid investment required to meet rapidly growing demand.

Rate of investment is highest when Tiwai closes This is because of the assumed high fixed exogenous demand growth rate.

Technology	MW	% of total
Geothermal	152	2%
Hydro	367	4%
Solar	2,520	27%
Wind	6,455	68%
Other	0	0%
Total	9,494	100%
Batteries	4,747	50%

Modelled investment, average over cost and demand sensitivities



Transmission charges

Projected transmission investment and opex converted into revenue equivalents

In the baseline, DC interconnection charges recovered from south island generators based on SIMI and AC interconnection charge recovered from load customers based on existing RCPD parameters.

Key sources and assumptions:

(1) Transpower expenditure ITP (2020)

(2) Base capex held constant from 2035

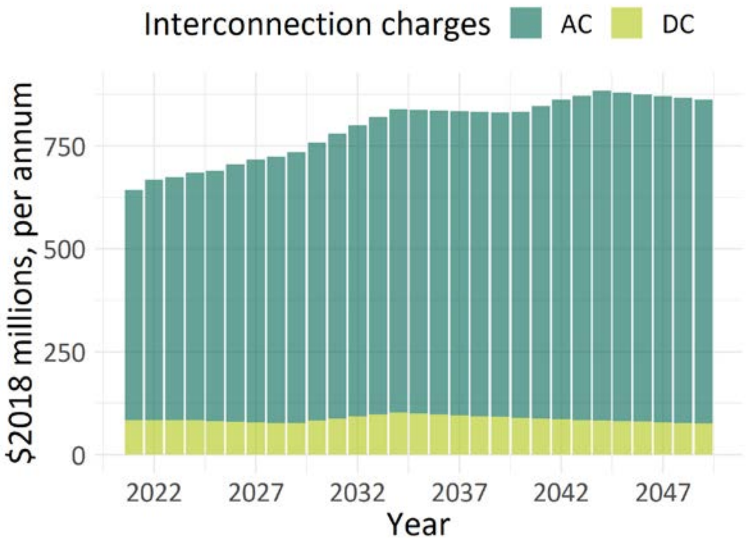
(3) High demand growth brings forward major capex from late 2030s to early 2030s

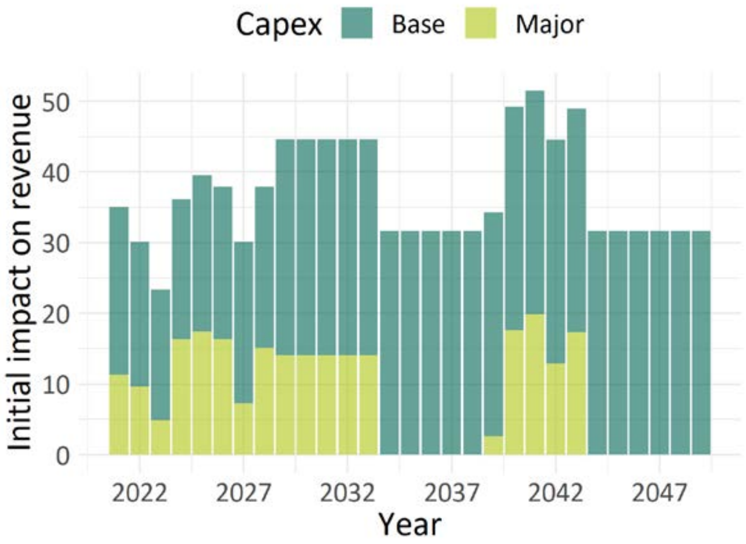
(4) Major capex after 2040 includes

  a) Bombay-Otahuhu capacity expansion

  b) Central and lower north island capacity expansion

  c) Upper South Island voltage stability





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Proposal – effects on interconnection charges

The simple method is expected to be used to allocate the majority of benefit-based charges (~80%).

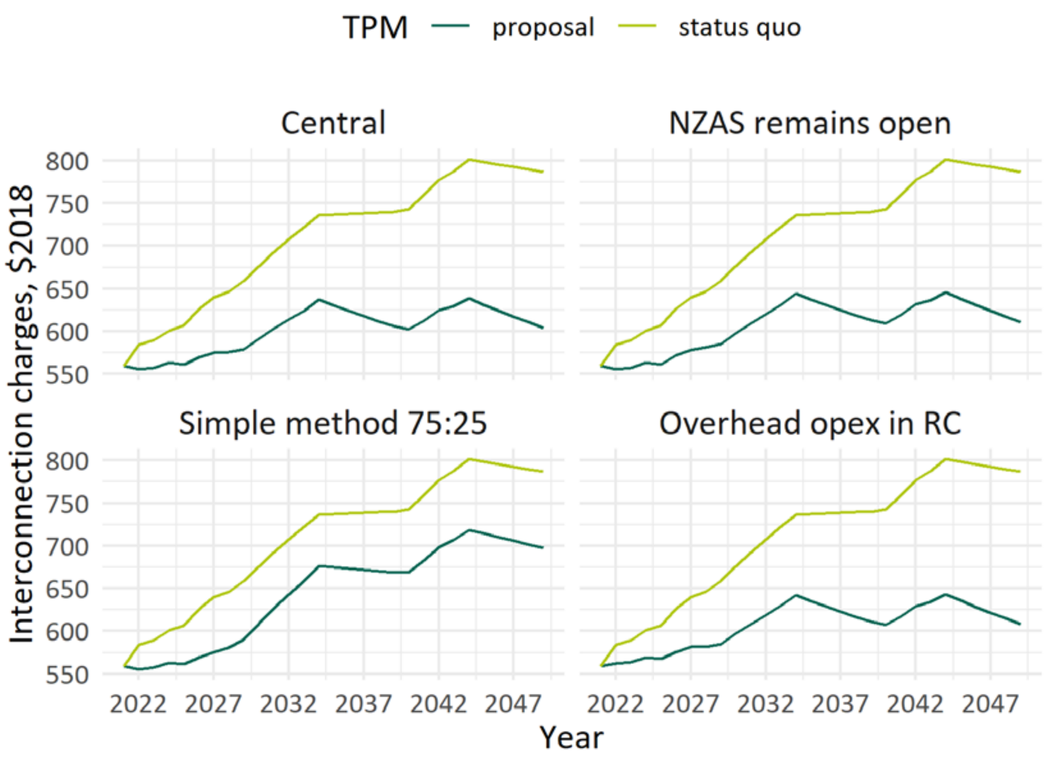
Thus, changing the default generator share of benefits (to 25%) under the simple method significantly increases load customer share of revenue.

Other scenarios have much smaller effects on the split of interconnection charge revenue as between load and generation.

Impacts of different allocations to load or generation will depend on relative size of distortions as between suppressing demand and suppressing investment.

- **Transmission charges allocated via**
  - Initial BBCs (Transpower June 2021)
  - Simple method BBCs
    - fixed flows/allocators
    - regional E&D investment (by HV zones)
    - regional R&R capex based on shares of counts of assets
  - Standard method BBCs
    - Fixed HVDC benefit shares
    - Case studies
    - Shares of AMD and shares of LCE as proxies for benefits from reliability and benefits from economic investments.

Load customer interconnection charges



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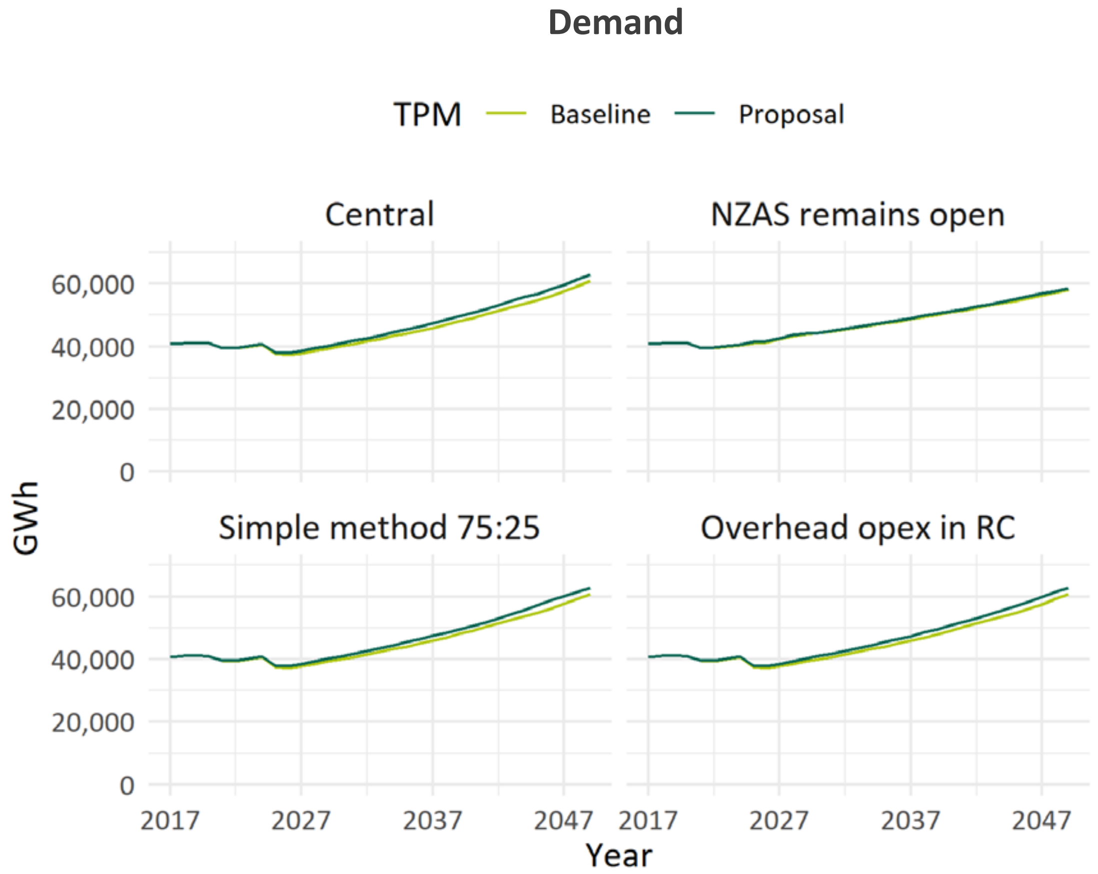
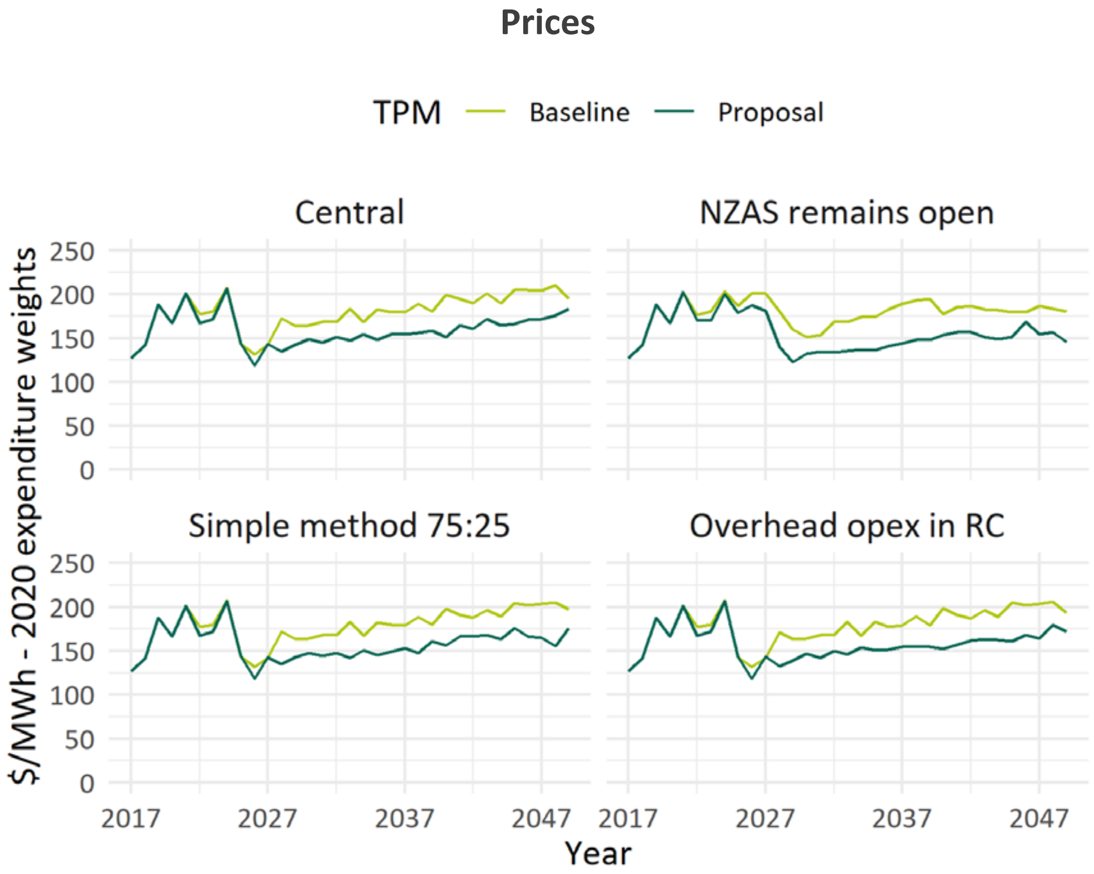
Proposal, impact on prices and demand

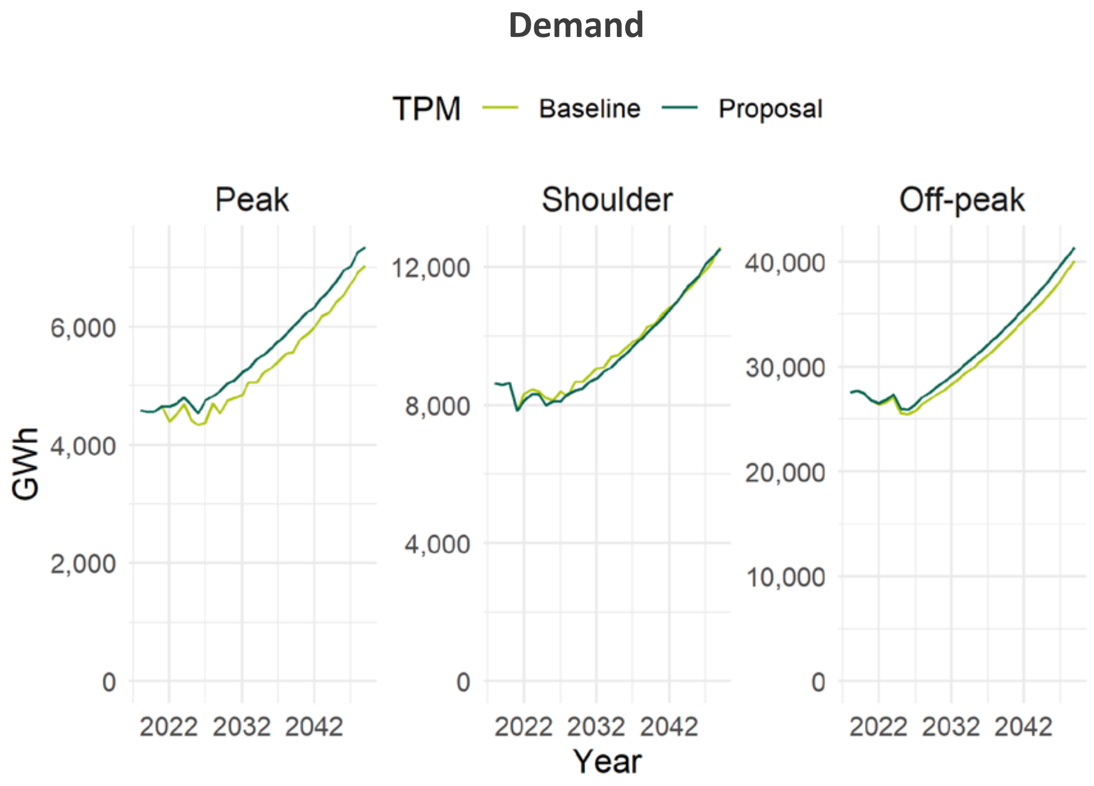
Average over all sensitivities. Prices include variable interconnection charges.





Impact on demand and prices by time of use

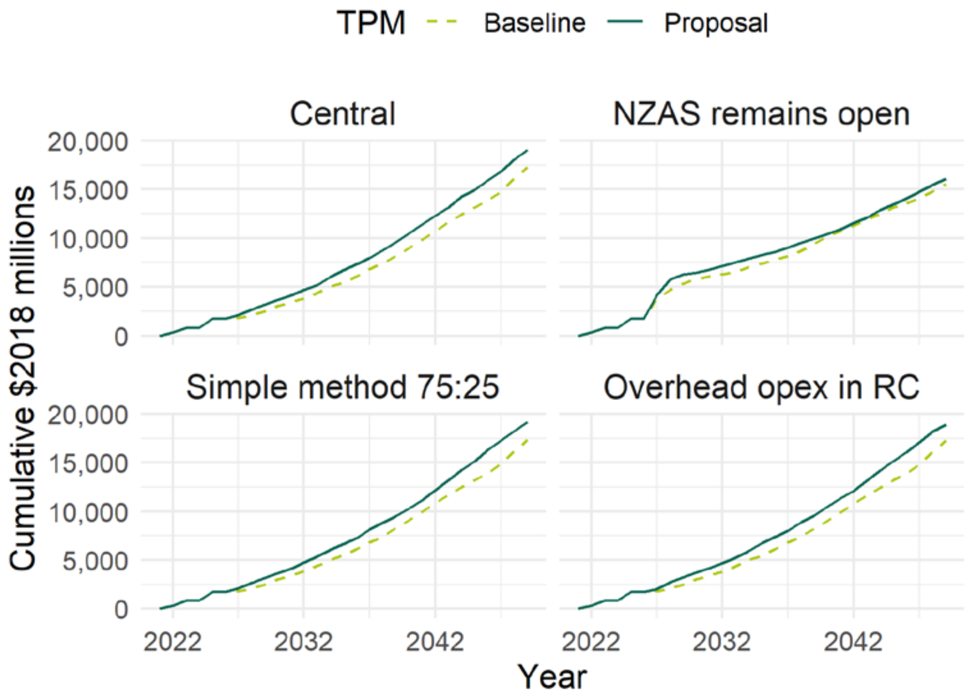
Average over all sensitivities and policy scenarios. Prices include variable interconnection charges.



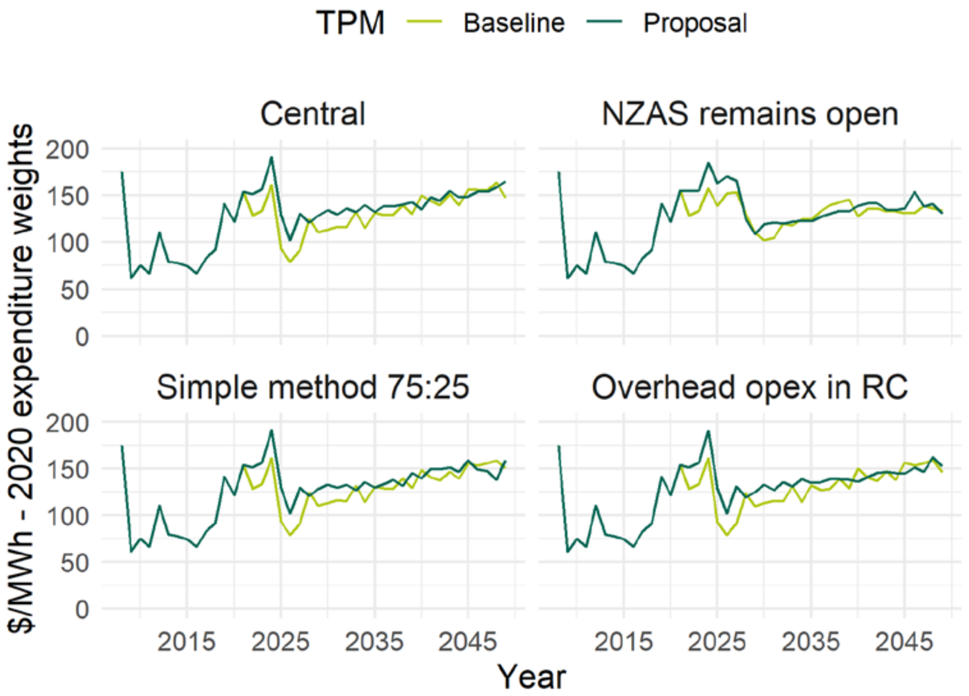
Impact on energy prices and investment

Average over all sensitivities.

Investment



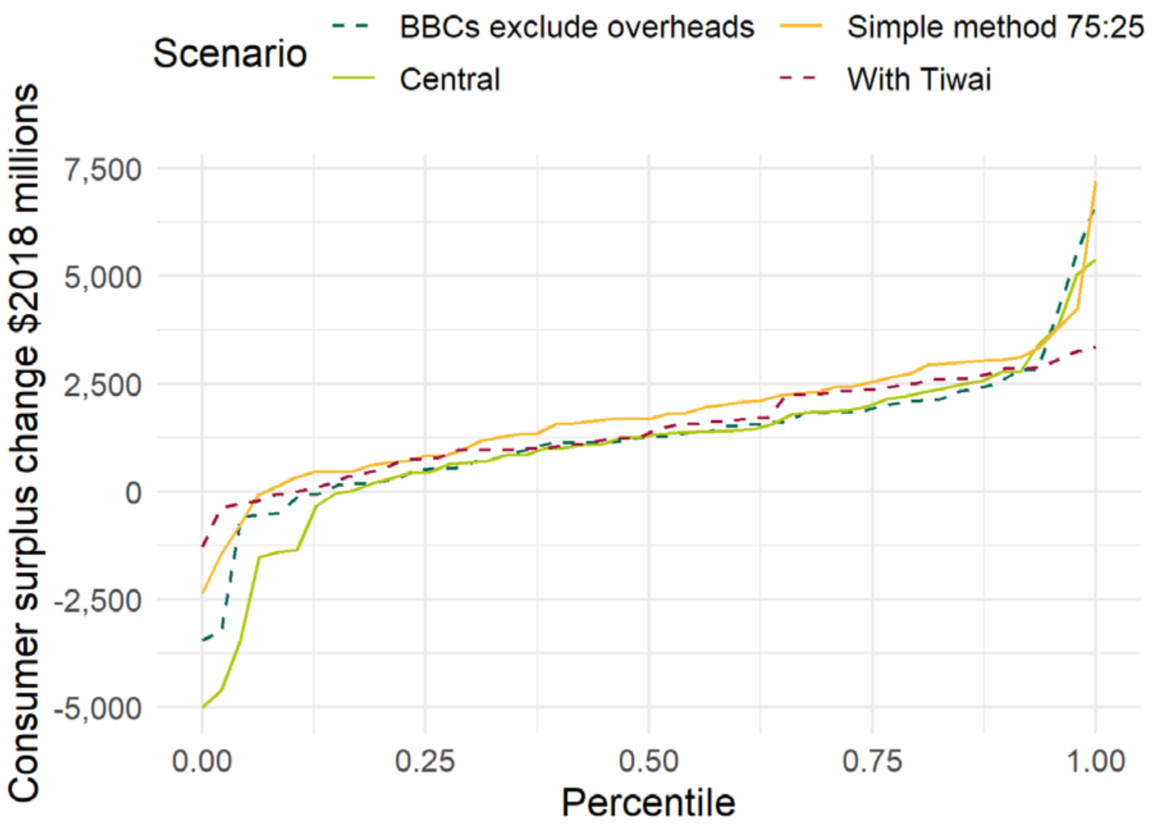
Energy prices



Consumer surplus impacts

Consumer surplus calculation based on estimate of consumer surplus change based on consumer surplus under the proposal and the baseline assuming consumer surplus zero if prices sufficiently high, relative to historical averages, that demand would be zero in the long run (using long run linear elasticity of demand of -0.74).

Change in consumer surplus, net of change in interconnection charge revenue



Sensitivities

400 simulations completed, with variable values for assumptions, to test the sensitivity of results to changes in external factors

Values varied in sensitivity analysis

- NZAS closure: 2024, never
- Rate of growth in generation SRMC, over central case: -1%, -0.5%, +0.5%, +1%
- Rate of growth in generation LRMC, over central case: -1%, -0.5%, +0.5%, +1%
- Rate of demand growth: -0.5%

Probabilities assigned to sensitivities

- NZAS closure treated as a scenario – no probability assigned
- Cost growth scenarios assigned probabilities based on:
  - projected difference in costs from trend in 2035
  - historical standard deviations from trend growth in the PPI for SRMC and the CGPI for LRMC
- Demand growth scenario assigned a probability based on standard deviations in the rate of growth in gross national income.

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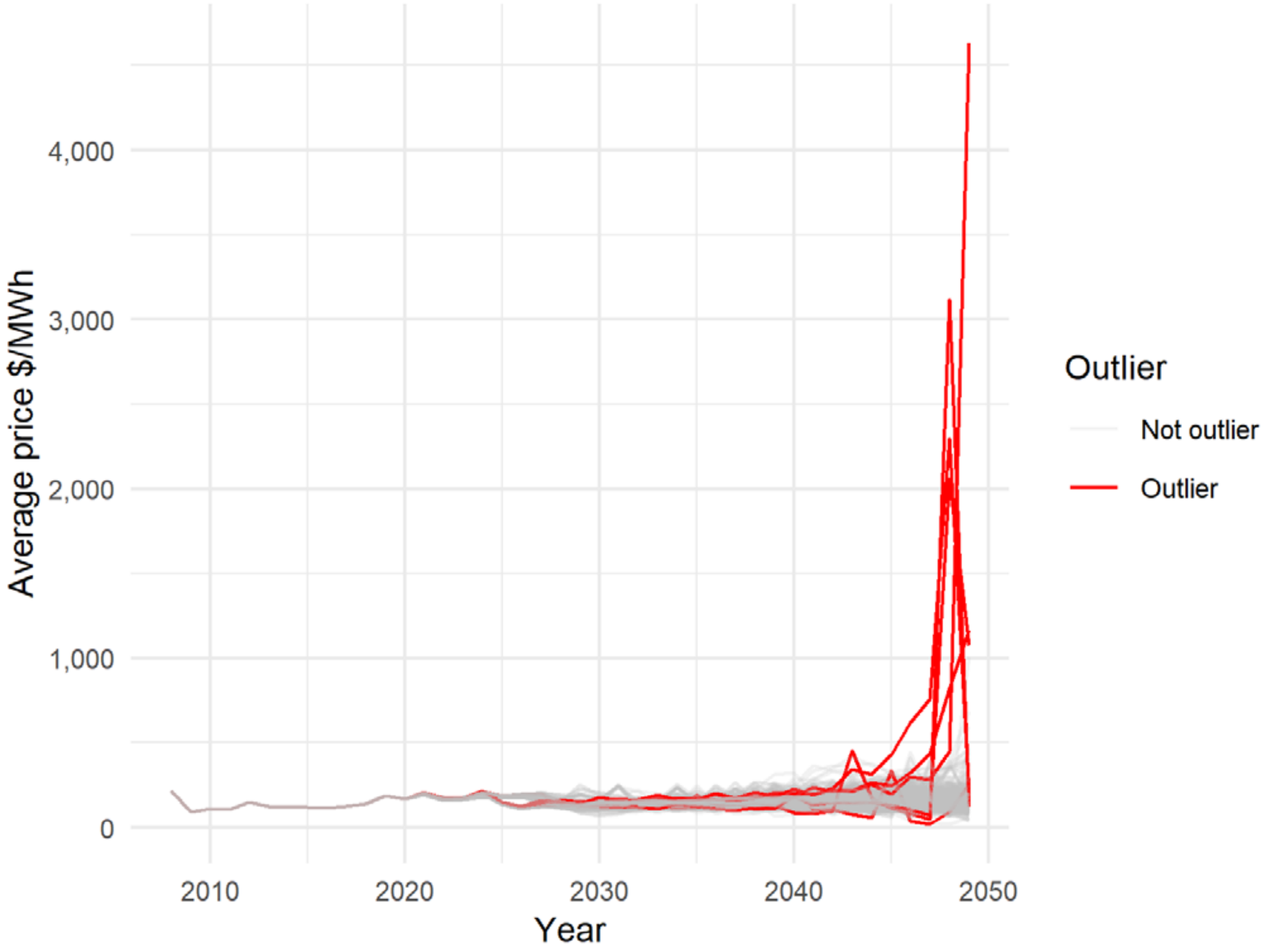
Outlier removal

Seven of the sensitivity simulations (out of 400 simulations) have been excluded from results because they produce implausibly high prices and massive swings in demand in the final years of the simulation.

These outlier events occur in high-cost sensitivity simulations and reflect the inability of the model, which is calibrated on contemporary market conditions, to adequately deal with extreme market conditions late in the simulation period



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