Appendix B: Modelling methodology and results

Contents

1.   Purpose

1.1.   This appendix sets out the methodology used for our modelling and presents the entire set of results from this modelling.

1.2.   We use empirical modelling analysis to inform:

(a)   Whether different risk management alternatives can be considered as substitutes, assuming they are priced competitively

(b)   What risk management options are best used as part of a portfolio

(c)   What impact various scenarios have on the options/portfolios available for risk management:

(i)   With more intermittent generation in the market

(ii)   Higher spot price volatility

(iii)   Higher spot prices at super-peak times

(d)   What impact estimated risk premia have on the relative attractiveness of the different risk management options/portfolios

1.3.   We start our modelling with risk-neutral and perfectly competitive prices, assuming unlimited availability of each contract type. This is in keeping with a SSNIP test approach, which uses the competitive price rather than the prevailing price as the starting point and considers the impact of price increases.

1.4.   We do not use historical contract prices in our modelling because we have constructed market states where the expected return of each contract is different to what was observed in any particular year. Additionally, using just one year of data to determine if a contract's expected return is positive or negative would not give an accurate picture.

1.5.   We also add a premium to contract prices starting from the 'Seasonal risk premium' scenario, based on historical ASX data. This helps us understand how these premiums affect the performance of each portfolio.

2.   Methodology

2.1.   Retailers balance their objectives of maximising their expected profit and minimising the risk of large losses. One extreme is for the retailer to only be concerned with their expected profit and (based on the prices of risk management tools) they may remain completely unhedged. The other extreme would be for the retailer to only be concerned with their worst-case profit, likely offloading all their risk by entering a FPVV contract or charging their customers based on wholesale prices. However, this would likely lead to the lowest expected profit as the risk premium of offloading all risk would be very high.

2.2.   To assess both objectives, we model their profit under different possible outcomes in the market – we call these "market states". That is, our modelling attempts to replicate the risk management decision faced at any point in time by a non-integrated retailer, with uncertainty about what will happen to spot prices and its customer load. Over the modelled market states, we can compare the different risk management options and portfolios to see which ones result in the best risk

reduction, and the type of market states each option or portfolio improves. We also compare strategies to see which ones perform better in extreme market stress situations.[1]

2.3. With many different market states modelled and with each risk management strategy impacting each one of them uniquely, we need to pick a risk measure which transforms the profits and losses across all the market states to a single number. The purpose of the risk measure is to allow us to directly compare different risk management strategies' effectiveness at reducing the downside risk. Potential risk measures include: The 'Expectation' risk measure (a risk neutral risk measure), the 'Worst Case' risk measure (the market state with the lowest profit or largest loss), the 'Good Deal' risk measure[2], Value at Risk[3] (VaR) risk measure, and the Conditional Value at Risk[4] (CVaR) risk measure.

2.4. We illustrate both VaR and CVaR in Figure 1. Assuming a risk level of 20%, $VaR_{20\%}$ represents the smallest value where there is a 20% chance of profit being below this value. $CVaR_{20\%}$ is the expected profit when only looking at the outcomes with a profit lower than $VaR_{20\%}$.

2.5. VaR has traditionally been used more often in risk management regulation.[5] However, it has the undesirable property (especially in the context of comparing and optimising portfolios) of not following the principle of sub-additivity. This means that a diversified portfolio could end up with a higher VaR than the individual assets that make it up.

2.6. CVaR is a valuable alternative to VaR. It gives us a lower bound to VaR and follows the principal of sub-additivity, making it more reliable as a risk measure when comparing and optimising portfolios. Rockafellar et al (2000)[6] introduce a formula that allows us to apply CVaR in mathematical models.

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[1] Based on Stress tests | Electricity Authority (ea.govt.nz). Our capacity stress test uses the 16 highest demand trading periods and sets their price to $10,000/MWh (our model is a little more conservative as we don't model it as occurring in a single day). Our energy shortage stress test adds $300/MWh to all energy prices in a quarter (which is the difference between the test case and base case in Table 1).

[2] Druenne, Eric, Andreas Ehrenmann, Gauthier de Maere d'Aertrycke, and Yves Smeers. "Good-deal investment valuation in stochastic generation capacity expansion problems." In *2011 44th Hawaii International Conference on System Sciences*, pp. 1-9. IEEE, 2011.

[3] Duffie, Darrell, and Jun Pan. "An overview of value at risk." *Journal of derivatives* 4, no. 3 (1997): 7-49.

[4] Artzner, Philippe, Freddy Delbaen, Jean-Marc Eber, and David Heath. "Coherent measures of risk." *Mathematical finance* 9, no. 3 (1999): 203-228.

[5] Hull, John. *Risk management and financial institutions,+ Web Site*. Vol. 733. John Wiley & Sons, 2012.

[6] Rockafellar, R. Tyrrell, and Stanislav Uryasev. "Optimization of conditional value-at-risk." *Journal of risk* 2 (2000): 21-42.

Figure 1: Illustration of Value at Risk (VaR) and Conditional Value at Risk (CVaR)
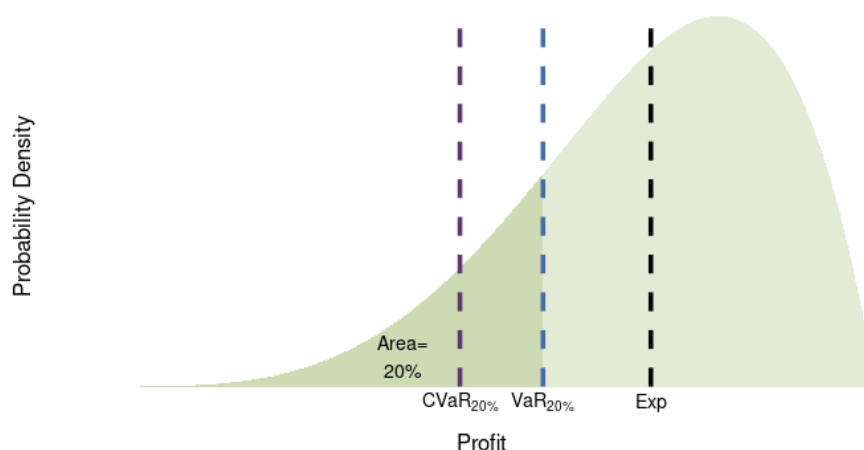
2.7.   For most of our modelling we use a 50% weight on the expected profit, and a 50% weight on the CVaR (at a 20% risk level) risk measure which we call E-CVaR.

Scenarios

2.8.   We run our modelling under seven different scenarios. Our baseline scenario is designed to inform our substitutability analysis. From this baseline scenario we then add different assumptions about pricing of the risk management options or expectations of market states, which allows us to isolate the impact of each assumption.

2.9.   The baseline scenario assumes a simple volume matching strategy for each contract. We also price each risk management option risk-neutrally. That is, the mean payoff over all the market states for each risk management option is zero. No risk premia are added to any risk management price. While this does not replicate a real-world scenario, it allows us to:

     (a)   Avoid falsely ruling in or out a substitute due to our construction of competitive risk management prices. This may be important since the calculation of our risk premia in our competitive risk management prices are based on historical data.

     (b)   Avoid falsely ruling in or out a substitute due to non-competitive current risk management prices.

2.10.   Our second scenario, still assuming contracts are priced risk-neutrally, is designed to allow for a portfolio approach to risk management. It selects the volume of each risk management option which maximises the risk adjusted profit. It allows us to see the relative risk reduction of different portfolios and compares this to the risk reduction of each risk management option in the baseline scenario.

2.11.   Using the portfolio optimisation approach, our third scenario adds risk premia to historical spot prices to construct contract prices.

2.12.   Our fourth scenario changes our risk measure to the worst-case risk measure, allowing us to see whether our conclusions about each portfolio remain consistent with a much more conservative risk measure.

2.13.   Using the E-CVaR risk measure with the added risk premia, the remaining three scenarios are designed to look at the impact of different assumptions about the future — more intermittent generation in the market, more volatile spot prices, and higher prices at super-peak times.

Table 1: Modelling scenarios

| Scenario	Assumptions			What the modelling will show us
	Product prices	**Spot prices**	**Risk management volume purchasing strategy**	
Baseline	Contract prices are priced risk neutrally (so the mean payoff of all contracts is zero). No risk premia added. Battery costs assumed to be offset by reserve market in expectation. The cost of Demand Response is assumed to exactly cover the expected savings from the lower wholesale costs. Revenue calculated to have zero mean profit across the market states	Equal weight given to 40 market states. Demand varies both overall and for peak demand. There are market states where both the average spot price and spot price volatility are changed, as well as states which volatility is targeted to the morning and evening peaks	Contract volumes equal to demand in the default market state	Used for our substitutability analysis. Shows the effectiveness of each hedging strategy (where contract volume matched to expected demand)
Maximising risk adjusted profit	^	^	Contract volumes = the volume which maximises the sum of the E-CVaR of their profit. We calculate the E-CVaR of each island, each quarter, and for business days and non-business days.	Shows the additional benefit of optimising the contract volume over a simple volume matching strategy (allows for more portfolio approach)

Competitive risk management prices	Contract prices based on our estimates of "reasonable" contract prices – starting with our estimated risk-neutral prices and adding seasonal premia	^	^	What impact does this have on the relative attractiveness of the different risk management options?
Worst-case risk measure	^	^	Contract volumes = the volume which maximises the sum of the Worst-case profit. We calculate the Worst-case profit of each island, each quarter, and for business days and non-business days.	Are our results still consistent when we use a more conservative risk measure.
More intermittent generation	^	Assume more solar and wind in the market, making spot prices lower when solar and wind generation is high.	Contract volumes = the volume which maximises the sum of the E-CVaR of their profit. We calculate the E-CVaR of each island, each quarter, and for business days and non-business days.	What impact a future market state may have on risk management practices
Higher volatility	^	Make spot prices in all market states more volatile.	^	What impact higher spot price volatility may have on risk management options
Higher prices at super-peak times	^	Make prices during super-peak periods in all market states higher.	^	Does this increase the attractiveness of shaped contracts?

Assumptions

Load profile

2.14.   For the load profile of our hypothetical non-integrated retailer, we sum the load profiles of Electric Kiwi, Todd Energy, Pulse Energy, and Flick Electric in 2023. Figure 2 shows that the load profile changes significantly throughout the year, and by island. We also see that business days tend to have a much larger and earlier morning peak and slightly higher evening peak compared to non-business days.

Figure 2: Load profile of non-integrated retailer's over 2023. North Island load accumulated at Ōtāhuhu, South Island load accumulated at Benmore.
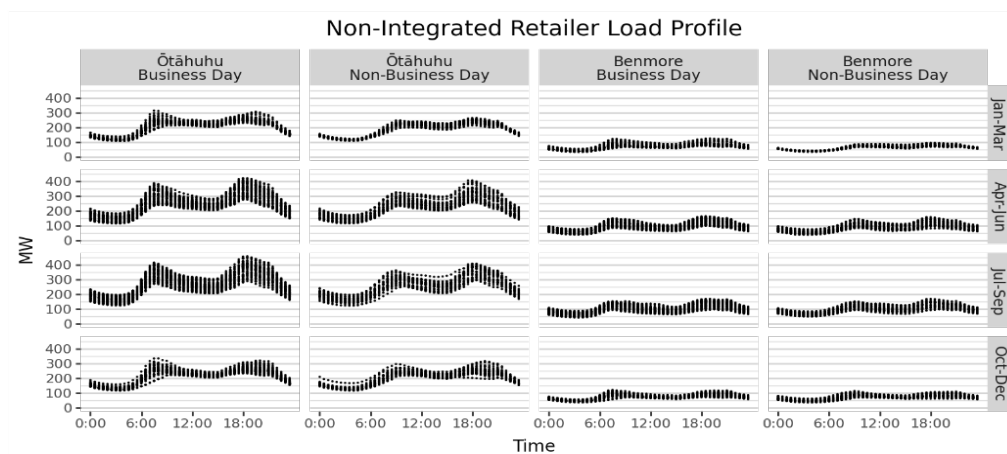
Market states

2.15.   There are 40 market states, created by varying the spot price and/or the non-integrated retailers' demand. These 40 market states are constructed as the combination of:

(a)   Eight different spot price market states:

(i)   Default: Uses 2023 wholesale prices (CPI adjusted to 1 January 2024)

(ii)   Low Price - Low Volatility: Multiply all prices by 0.5

(iii)   Low Price - High Volatility: Multiply all prices by 1.5 and subtract $155/MWh (setting a floor price of $0/MWh)

(iv)   High Price - Low Volatility: Multiply all prices by 0.5 and add $124/MWh

(v)   High Price - High Volatility: Multiply all prices by 1.5

(vi)   High Morning Peak Price: Multiply all morning peak prices (7am-10am) by 3

(vii)   High Evening Peak Price: Multiply all evening peak prices (5pm-8pm) by 3

(viii)   High Morning and Evening Peak Price: Multiple both morning peak and evening peak prices by 2

(b)   Five different demand market states:

(i)   Default: Uses 2023 reconciled offtake of the modelled hypothetical non-integrated retailer

(ii) Overall Demand Higher 5% - Peak Higher 2%: **Increase** demand at every point of connection by 5%, then **increase** demand during the morning and evening peak periods by a further 2%

(iii) Overall Demand Higher 5% - Peak Lower 2%: **Increase** demand at every point of connection by 5%, then **decrease** demand during the morning and evening peak periods by 2%

(iv) Overall Demand Lower 5% - Peak Higher 2%: **Decrease** demand at every point of connection by 5%, then **increase** demand during the morning and evening peak periods by 2%

(v) Overall Demand Lower 5% - Peak Lower 2%: **Decrease** demand at every point of connection by 5%, then **decrease** demand during the morning and evening peak periods by a further 2%

Which risk management options and portfolios we look at

2.16.   We compare many different risk management options, each with individual characteristics. Table 2 summarises each contract in terms of:

(a)   The contract length (i.e. whether each contract is only for a single quarter or for the entire year).

(b)   The time the contract covers. For example, the modelled OTC morning peak contract covers 7am to 10am.

(c)   Whether there is a separate product for business days and non-business days.

(d)   Additional information about the model, how the contract works, or some caveats about the contract.

Table 2: Summary of each type of risk management option modelled.

Risk management option	Contract Length	Time Covered	Separate Business Day and Non-Business Day Volumes	Description / Caveats
ASX baseload hedges	Quarterly	All trading Periods	Yes	Existing ASX baseload contracts do not have a separate product for Business Days and Non-Business Days.
ASX peak hedges	Quarterly	7am to 10pm	Yes	Existing ASX peak contracts do not cover Non-Business Days.
OTC Morning Peak	Quarterly	7am to 10am	Yes	Morning peak contracts cover a range of different times. However, we tend to see that many of them would at least cover 7am to 9am. We extended this to match length of the evening peak contract.

OTC Evening Peak	Quarterly	5pm to 8pm	Yes	Evening peak contracts cover a range of different times. However, we tend to see that many would at least cover 5pm to 8pm.
OTC C300	Quarterly	All trading Periods	Yes	Caps prices to $300/MWh. Each MWh purchased is distributed evenly throughout the contract duration. For each trading period, return per MWh is the maximum of $0/MWh and the spot price minus $300/MWh.
Battery	Annual	All trading Periods	No	Assumed knowledge of 1 hour ahead PRSS prices to create a bid and offer strategy that is realised in the real time market. Earnings in the reserve market are assumed to be the same across all market states.
Flattened Demand Profile (Demand Response)	Annual	All trading Periods	No	Modelled by completely flattening their daily load profile. The retail price is re-calculated as the new LWAP.
Solar PPA	Annual	All trading Periods	No	Generation profile is based on Kaitaia Solar Farm in 2024.
Wind PPA	Annual	All trading Periods	No	Generation profile is based on Tararua Wind Farm in 2023.
Geothermal PPA	Annual	All trading Periods	No	Generation profile is based on Ngā Awa Pūrua Power Station in 2023.

2.17.   For a battery to be profitable in the wholesale market in the short run, it requires there to be sufficient volatility in wholesale prices so that it can cover the cost of degradation due to cycling the battery. Thus, the specific parameters of the battery impact its effectiveness as a risk management tool. The assumed parameters for the battery in our model are:

(a)   Roundtrip efficiency = 0.8 MWh/MWh

(b)   Battery cost = $1,000,000/MW

(c)   Ratio of storage capacity = 2 MWh/MW = 2 Hours

(d)   Self-discharge rate = 2% per month

(e)   Number of cycles = 8000

2.18.   The additional degradation of using a battery is assumed to cost = (1 / Ratio of storage capacity) * (1 / Number of cycles) * Battery Cost = $62.50/MWh of

discharge (ignoring any degradation that occurs due self-discharging). This additional degradation cost needs to be covered on top of the efficiency losses for it to be profitable to use a battery in the wholesale market. Our model assumes that the battery is risk neutrally priced, assuming earnings on the reserve market don't change across scenarios and are sufficient to recover the capital costs so that the profit of using the battery as a risk management vehicle is 0 in expectation.

2.19. In an attempt to model a good but not perfect use of the battery, the process of simulating the battery first assumes we have perfect knowledge of the 1 hour ahead PRSS (Price-Responsive Schedule Short) prices at the Ōtāhuhu and Benmore nodes (assumed to be the possible locations of the battery). We then solve an optimisation model which runs the battery optimally using these PRSS prices. We then use the results of the optimisation model to create input offers and bids in the real time market which we simulate to calculate the profitability of the battery in each scenario.

2.20. We attempt to cover a range of risk management portfolios in both our Baseline scenario and the following scenarios which use portfolio optimisation. The portfolios considered are summarised in Table 3 and whether they apply to the Baseline scenario (or the scenarios with portfolio optimisation). Some portfolios can't be included in the baseline scenario because there are several risk management options for all trading periods. As a result, it's not clear how to choose the volume for each option.

Table 3: Combination of contracts considered in each modelled portfolio.

Portfolio Name	Risk management options included	Baseline Scenario
Unhedged	None	Yes
Battery	Battery	Yes
C300	OTC C300	Yes
Demand Response	Flattened Demand Profile	Yes
Baseload	ASX baseload hedge	Yes
Peak	ASX peak hedge	Yes
Super-Peak	OTC Morning Peak, OTC Evening Peak	Yes
Baseload & Peak	ASX baseload hedge, ASX peak hedge	Yes
Baseload & Super-Peak	ASX baseload hedge, OTC Morning Peak, OTC Evening Peak	Yes
Baseload, Peak, & Super-Peak	ASX baseload hedge, ASX peak hedge, OTC Morning Peak, OTC Evening Peak	Yes
Baseload, Peak, Super-Peak, Battery, & C300	ASX baseload hedge, ASX peak hedge, OTC Morning Peak, OTC Evening Peak, Battery, OTC C300	No

Baseload, Wind, & Solar	ASX baseload hedge, Wind PPA, Solar PPA	No
Baseload & Battery	ASX baseload hedge & Battery	No
Baseload & C300	ASX baseload hedge & OTC C300	No
Demand Response & Baseload	Flattened Demand Profile, ASX baseload hedge	Yes
Solar	Solar PPA	Yes
Wind	Wind PPA	Yes
Geothermal	Geothermal PPA	Yes

Prices of risk management options

2.21.   We calculate a risk neutral price for each quarter and day type for all contracts so that we can directly compare things like the PPA and batteries, which are annual contracts that do not depend directly on quarter and day type, to the ASX and OTC contracts.

2.22.   The volume of the PPA and batteries purchased are assumed to have a fixed relationship across quarters and day types based on the number of trading periods.

2.23.   The process of getting the risk neutral prices for baseload, peak and super-peak contracts at each location (Ōtāhuhu and Benmore) is:

   (a)   Find which trading dates are relevant based on:

       (i)   The quarter (January to March, April to June, July to September, or October to December)

       (ii)   The day type (Business Day or Non-Business Day)

   (b)   Within these trading dates, find which trading periods are relevant for the contract, for example:

       (i)   Peak = 7am to 10pm.

       (ii)   Morning peak = 7am to 10am.

       (iii) Evening peak = 5pm to 8pm.

       (iv)   Baseload = all trading periods.

   (c)   Calculate the return of the contract (assuming the hypothetical retailer buys 1MWh spread evenly across the contract duration) in each trading period for the contract.

       (i)   The volume of the contract in that trading period = 1 / number of hours.

       (ii)   The return from the contract is equal to the volume in that trading period multiplied by the spot price.

   (d)   Sum up the return in each trading period to get total quarterly returns.

   (e)   Repeat (c) and (d) for each different market state.

(f)   Calculate the mean total return across all the different market states (i.e. the expected revenue from the contract).

(g)   This mean total return for 1MWh is the risk neutral price of the contract.

2.24.   The process for getting the risk neutral price for the C300 contract at each location (Ōtāhuhu and Benmore) is:

(a)   Find which trading dates are relevant based on:

(i)   The quarter (January to March, April to June, July to September, or October to December)

(ii)   The day type (Business Day or Non-Business Day)

(b)   As we assume that it is a Baseload contract, within these trading dates, all trading periods are relevant for the contract.

(c)   Calculate the return of the contract (assuming the hypothetical retailer buys 1MWh spread evenly across the contract duration) in each trading period for the contract.

(i)   The volume of the contract in that trading period = 1 / number of hours.

(d)   The return from the contract is equal to the volume in that trading period multiplied by max (spot price – 300, 0).

(e)   Sum up the return in each trading period to get total quarterly returns.

(f)   Repeat (c) and (d) for each market state.

(g)   Calculate the mean total return across all the different market states (i.e. the expected revenue from the contract).

(h)   This mean total return for 1MWh is the risk neutral price of the contract.

2.25.   We are modelling each PPAs ability to reduce risk nationally. With most new wind, solar, and geothermal investments being in the North Island, we model PPAs as being in Ōtāhuhu. The process for getting the risk neutral price for each PPA is:

(a)   Query the generation of the unit used to model the PPA (mentioned in Table 2) over the entire year.

(b)   Find which trading dates are relevant based on:

(i)   The quarter (January to March, April to June, July to September, or October to December).

(ii)   The day type (Business Day or Non-Business Day).

(c)   Scale the output of the generator by dividing the output in each trading period by the total energy output over that quarter and day type.

(d)   Calculate the revenue of the scaled generator by multiplying the scaled output by the wholesale price.

(e)   Sum the revenue earned by the generator over all the relevant trading periods to get the quarterly returns.

(f)   Repeat (d) and (e) for each market state.

(g)   Calculate the mean total return across all the different market states (i.e. the expected revenue from the contract).

(h)   This mean total return for 1MWh is the risk neutral price of the contract.

2.26.   The process for getting the risk neutral price for the battery is similar to the PPA, except the revenue is based on our simulated operation of the battery, and the battery in our model can be located at both Ōtāhuhu and Benmore.

2.27.   By setting the contract price (i.e. the cost of the contract) equal to the expected revenue of the contract, the expected profit from buying the contract is zero.

2.28.   Table 4 summarises how we calculate prices of each option in each scenario.

2.29.   Appendix A discusses in more detail how the risk premia are calculated.

Table 4: Pricing the risk management options in each scenario

Risk management option	Scenario						
	Base-line	Portfolio optim-isation	Seasonal risk premium	Worst case risk measure	More intermittent generation	Higher volatility	Higher prices at super-peaks
ASX hedges	Risk neutrally	Risk neutrally plus quarterly premium					
Battery	Risk neutrally						
C300	Risk neutrally						
Demand response	Risk neutrally						
OTC hedges	Risk neutrally	Risk neutrally plus quarterly premium					
Solar PPA	Risk neutrally						
Wind PPA	Risk neutrally						
Geothermal PPA	Risk neutrally						

Volume of risk management options purchased

2.30.   In the baseline scenario the process of getting the volumes of each contract at each location is as follows:

(a)   Battery: The size of the battery purchased (in MW) on each island is the average demand over the entire year in the default demand market state.

(b)   C300: The amount of the C300 purchased is the total MWh of demand in that quarter, island, and day type in the default demand market state.

(c)   Demand Response: There is no contract purchased, the daily load profile is just assumed to be flat.

(d) Baseload: The amount of the Baseload ASX contract purchased is the total MWh of demand in that island, quarter, and day type in the default demand market state.

(e) Peak: The amount of Peak ASX contract purchased is the total MWh of demand from 7am to 10pm in that island, quarter, and day type in the default demand market state.

(f) Super-Peak:

(i) The amount of OTC Morning Peak contract purchased is the total MWh of demand from 7am to 10am. In that island, quarter, and day type in the default demand market state.

(ii) The amount of OTC Evening Peak contract purchased is the total MWh of demand from 5pm to 8pm. In that island, quarter, and day type in the default demand market state.

(g) Baseload & Peak: When buying baseload and peak contracts together, the volume of the peak contract purchased is calculated as an extra volume on top of the baseload volume. The baseload volume purchased is set to the amount needed to cover the retailers load overnight (i.e., the average demand between the hours of 10pm and 7am). The peak volume is therefore the extra demand on top of this baseload demand during the peak hours (7am to 10pm). Thus, the baseload and peak volumes are calculated as:

(i) $\text{ASX Baseload Volume} = \text{mean}(\text{Demand}_{10pm-7am}) \cdot \text{Hours}_{All}$

(ii) $\text{ASX Peak Volume} = (\text{mean}(\text{Demand}_{7am-10pm}) - \text{mean}(\text{Demand}_{10pm-7am})) \cdot \text{Hours}_{7am-10pm}$

(h) Baseload & Super-Peak: Similarly, when buying baseload and super-peak contracts together, the volume of the super-peak volume is calculated as an extra volume on top of the baseload volume. The baseload, morning peak, and evening peak volumes are calculated as:

(i) $\text{ASX Baseload Volume} = \text{mean}(\text{Demand}_{10am-5pm,8pm-7am}) \cdot \text{Hours}_{All}$

(ii) $\text{OTC Morning Peak Volume} = (\text{mean}(\text{Demand}_{7am-10am}) - \text{mean}(\text{Demand}_{10pm-7am})) \cdot \text{Hours}_{7am-10am}$

(iii) $\text{OTC Evening Peak Volume} = (\text{mean}(\text{Demand}_{5pm-8pm}) - \text{mean}(\text{Demand}_{10pm-7am})) \cdot \text{Hours}_{5pm-8pm}$

(i) Baseload, Peak, & Super-Peak: Again, when buying baseload, peak, and super-peak contracts together, the volume of the super peak volume is calculated as an extra volume on top of the baseload and peak volume. The baseload, peak, morning peak, and evening peak volumes are calculated as:

(i) $\text{ASX Baseload Volume} = \text{mean}(\text{Demand}_{10pm-7am}) \cdot \text{Hours}_{All}$

(ii) $\text{ASX Peak Volume} = (\text{mean}(\text{Demand}_{10am-5pm,8pm-10pm}) - \text{mean}(\text{Demand}_{10pm-7am})) \cdot \text{Hours}_{7am-10pm}$

(iii) $\text{OTC Morning Peak Volume} = \big(\text{mean}(\text{Demand}_{7am-10am}) -$
$\text{mean}(\text{Demand}_{10am-5pm,8pm-10pm})\big) \cdot \text{Hours}_{7am-10am}$

(iv) $\text{OTC Evening Peak Volume} = \big(\text{mean}(\text{Demand}_{5pm-8pm}) -$
$\text{mean}(\text{Demand}_{10am-5pm,8pm-10pm})\big) \cdot \text{Hours}_{5pm-8pm}$

(j) Demand Response & Baseload: The daily load profile is assumed to be flat, and the volume of the baseload contract purchased is the total MWh of demand in that island, quarter, and day type.

(k) Solar: The total MWh of Solar PPA purchased over the entire year is equal to the total MWh of demand.

(l) Wind: The total MWh of Wind PPA purchased over the entire year is equal to the total MWh of demand.

(m) Geothermal: The total MWh of Geothermal PPA purchased over the entire year is equal to the total MWh of demand.

2.31. All the subsequent scenarios are based on the results of a portfolio optimisation model that minimises the sum of the E-CVaR across the islands, quarters and day types.

3.   Results

Baseline scenario

3.1. A contract position that closely matches the load profile is expected to improve risk-adjusted welfare under risk-neutral pricing.

3.2. Figure 3 shows that the Baseload contract over-hedges the non-integrated retailer overnight and under-hedges during morning and evening peak times.

3.3. In Figure 4, adding the ASX peak contract (plus one for non-business days) helps the non-integrated retailer better match the load profile, reducing overnight over-hedging.

3.4. Figure 5 shows that including OTC morning and evening peak contracts further improves the portfolio's ability to match the load profile, especially during peak times.

3.5. In contrast, Figure 6 shows that the Solar PPA is much worse at matching the load profile than the Baseload contract due to its generation volatility and poor alignment with the load profile.

Figure 3: Volume matching method: Baseload - Contract position and load profile in each island, quarter, and day type.
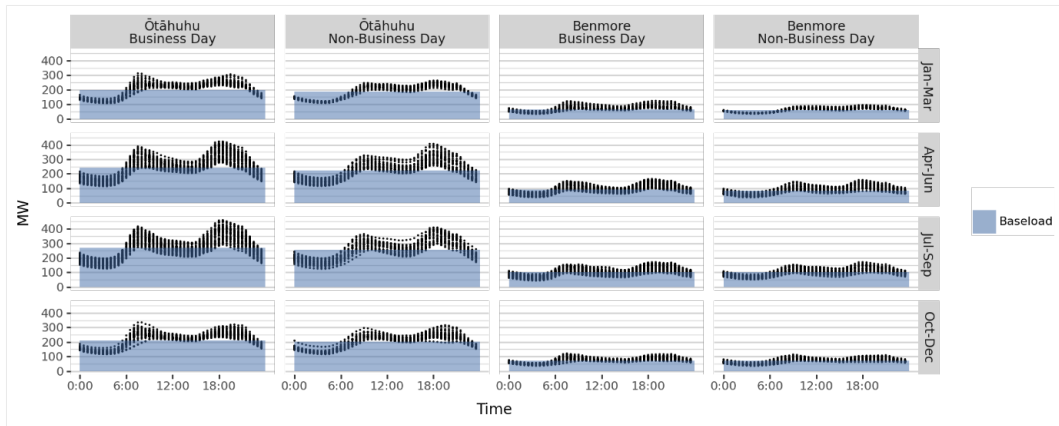

Figure 4: Volume matching method: Baseload and Peak - Contract position and load profile in each island, quarter, and day type.
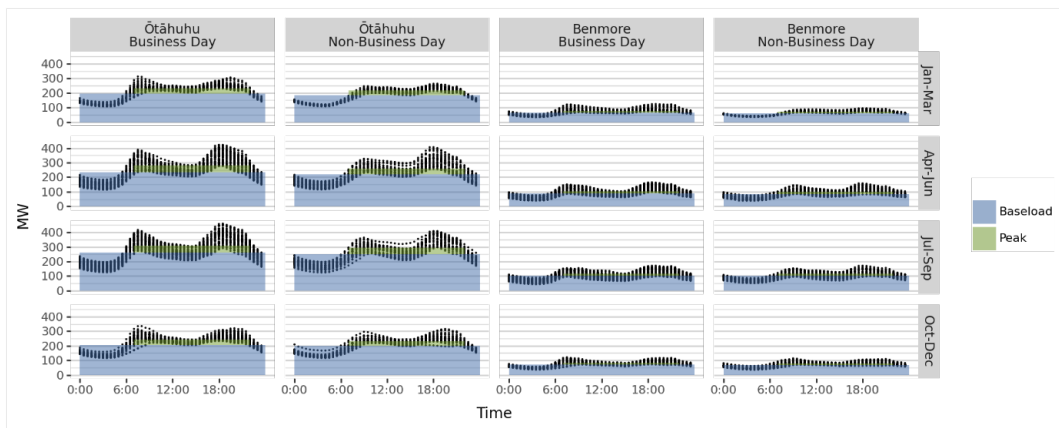
Figure 5: Volume matching method: Baseload, Peak, and Super-Peak - Contract position and load profile in each island, quarter, and day type.
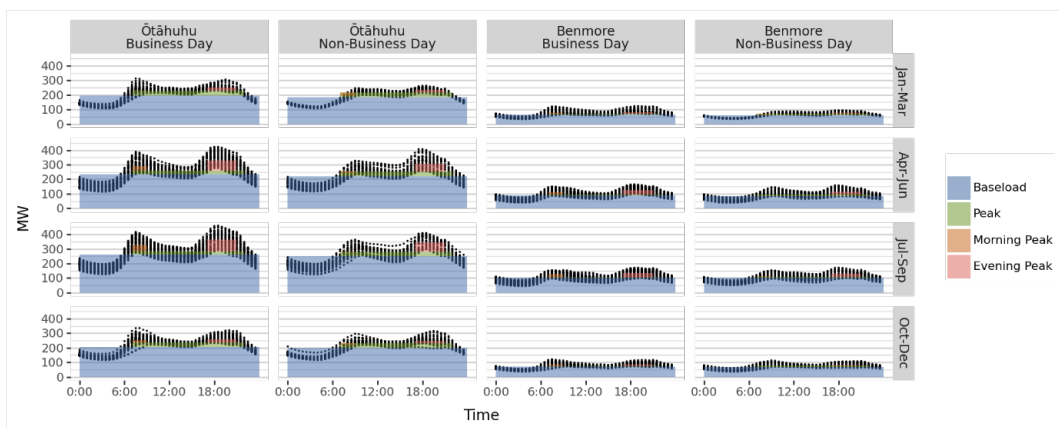
Figure 6: Volume matching method: Solar PPA - Mean contract position (alongside 10th and 90th percentiles) in each island, quarter, and day type.
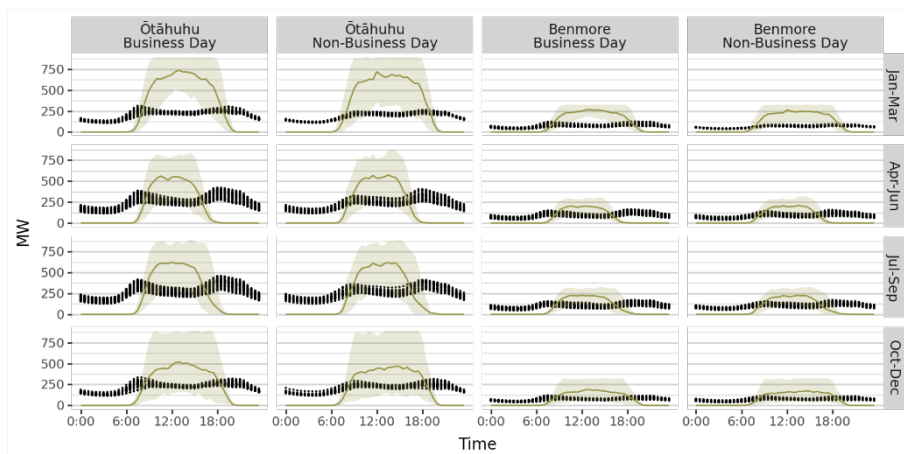

3.6. Figure 7 compares the E-CVaR of Profit given each portfolio. Throughout our modelling, this value is always negative because we assume both retail and contract prices are set risk-neutrally, meaning they will not make a profit on average. Additionally, since we model the non-integrated retailer as risk-averse, they put additional weight on market states with high losses. In theory, this could change in the scenarios with a negative premium on some contracts, but that does not occur in our analysis.

3.7. A flat daily load profile with a Baseload contract is basically tied with the 'Baseload & Super-Peak' portfolio in terms of offering the greatest risk reduction. This is followed closely by the 'Baseload, Peak, & Super-Peak' and 'Baseload & Peak' portfolios. PPAs generally perform worse at reducing risk, with the Geothermal PPA being the best performer. On their own, purchasing demand response, the C300 contract and the battery each increased risk relative to being unhedged.

Figure 7: Volume matching method: Sum of E-CVaR in each island, quarter, and day type given each portfolio.
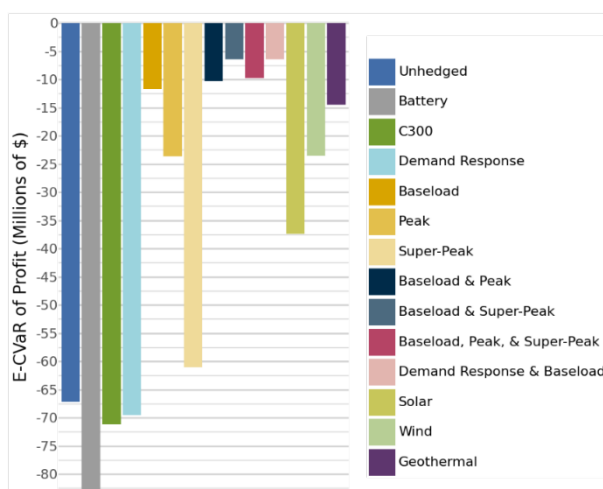
3.8.   Figure 8 and Figure 9, show the profits for each portfolio across different market states in the North Island during business days for the July to September quarter.

3.9.   When the non-integrated retailer is unhedged, there is a significant disparity between market states. In some states, large profits are made due to low spot prices, while in others, substantial losses occur. Although the Battery and C300 contracts provide some improvements to the high super-peak market states, they worsen the 'High Price and Low Volatility' and 'High Price and High Volatility' market states, ultimately increasing overall risk.

3.10.   Flattening the load profile improves outcomes in the high super-peak price market states by reducing consumption during those periods. However, this approach offers little improvement in market states where prices are consistently high because it also reduces retail revenue. As a result, it is worse than staying unhedged. However, when the load profile flattening is combined with the Baseload contract, it significantly reduces losses across all high-price market states (Figure 9).

3.11.   The Baseload contract alone is effective at improving outcomes in high-price market states with both low and high volatility, as these market states experience price increases throughout the day. However, compared to more shaped contracts, the Baseload contract is less effective in reducing losses in the high super-peak price market states.

3.12.   PPAs, while less effective overall, do improve outcomes in high-price market states. However, they struggle in high super-peak price states, with the Solar PPA performing particularly poorly during the high evening peak price market states.

3.13.   The 'Baseload & Super-Peak' and 'Baseload, Peak, & Super-Peak' portfolios experience their largest losses in the low price and low demand market states. In these states, the 'Baseload, & Super-Peak' portfolio has smaller losses, suggesting better performance in this quarter, during business days, and in the North Island. This outcome is unexpected, as all the contracts in the 'Baseload & Super-Peak' portfolio are also available in the 'Baseload, Peak, & Super-Peak' portfolio, so optimal volume selection should result in the Baseload, Peak, & Super-Peak' portfolio performing no worse than the 'Baseload & Super-Peak' portfolio. This implies that the volume matching method can create solutions that are far from optimal, leading to these surprising results.

Figure 8: Volume matching method: Profit in each market state in the North Island, in the July to September quarter, and during business days. Less effective portfolios.
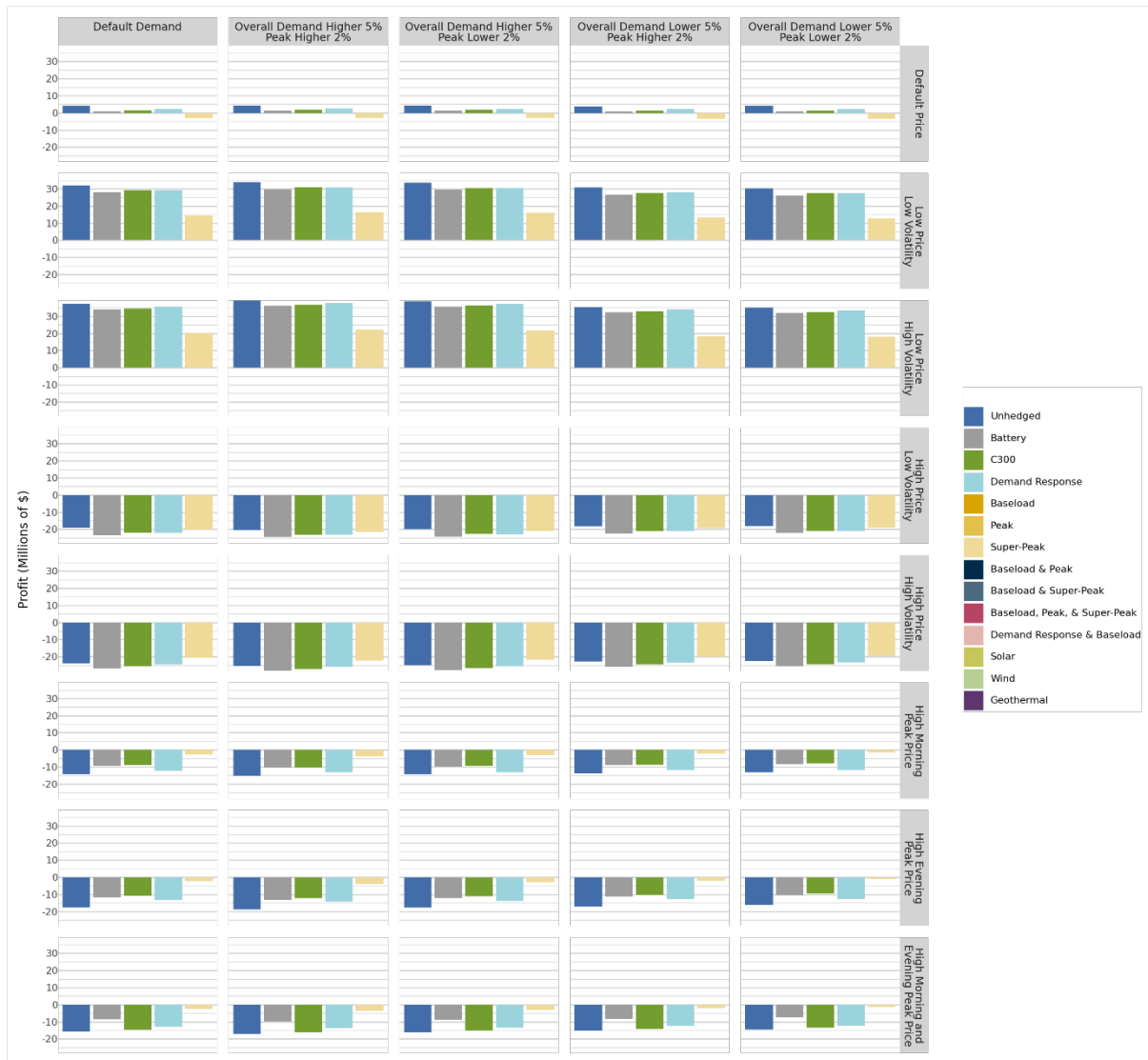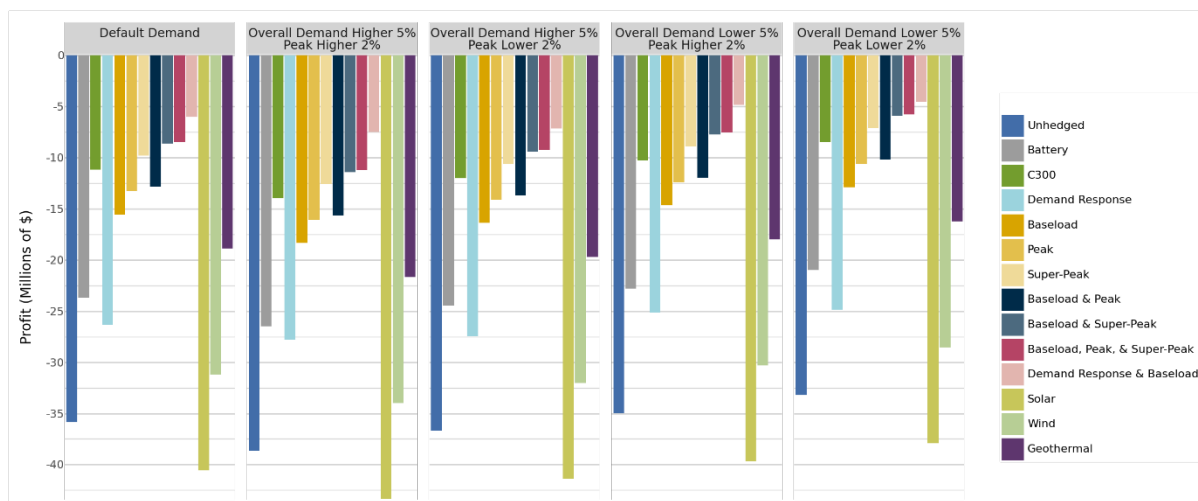
Figure 9: Volume matching method: Profit in each market state in the North Island, in the July to September quarter, and during business days. More effective portfolios.
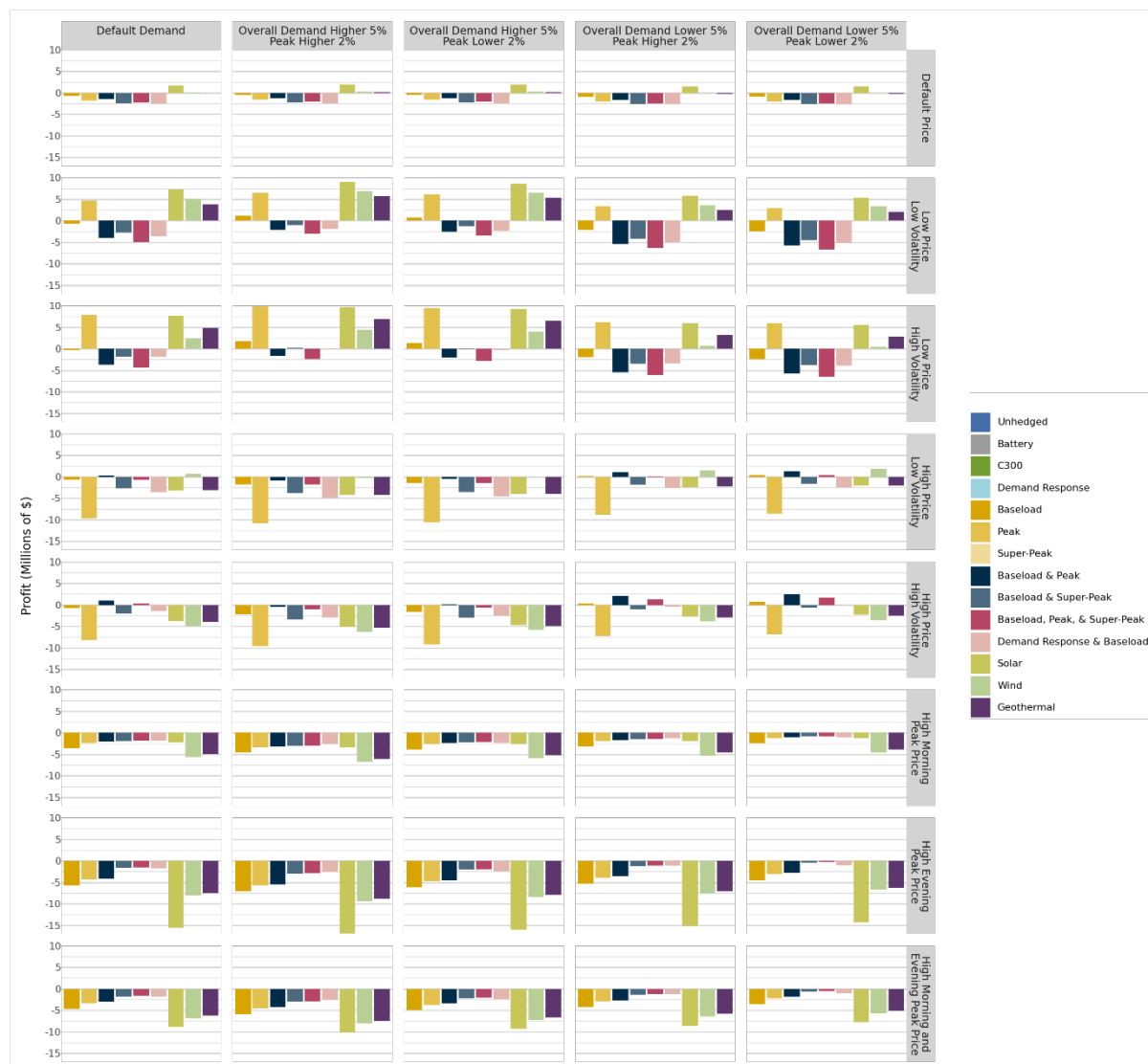

3.14. Figure 10 shows how each portfolio performs during the capacity shortage stress test. The 'Demand Response & Baseload' portfolio performs the best, followed by the portfolios which include the super-peak contract.

3.15. In this quarter, demand is much higher compared to the rest of the year. So, the PPA portfolios will tend to be under-hedged as we are locked into a volume for the entire year. The Solar PPA performs worse than remaining unhedged because there is very little solar generation during the 16 highest demand trading periods, which all occur in the evening near sunset.

3.16. Figure 11 shows the effectiveness of each portfolio during the energy shortage stress test. Portfolios that include the 'ASX Baseload' contract perform very well in this test.

Figure 10: Volume matching method: Profit given the capacity shortage stress test in the July to September quarter. All spot prices are set to $10,000/MWh in the 16

highest demand trading periods. All other prices are from the default price market state.

Figure 11: Volume matching method: Profit given the energy shortage stress test in the July to September quarter. Compared to the default price market state, the price in every trading period is increased by $300/MWh.
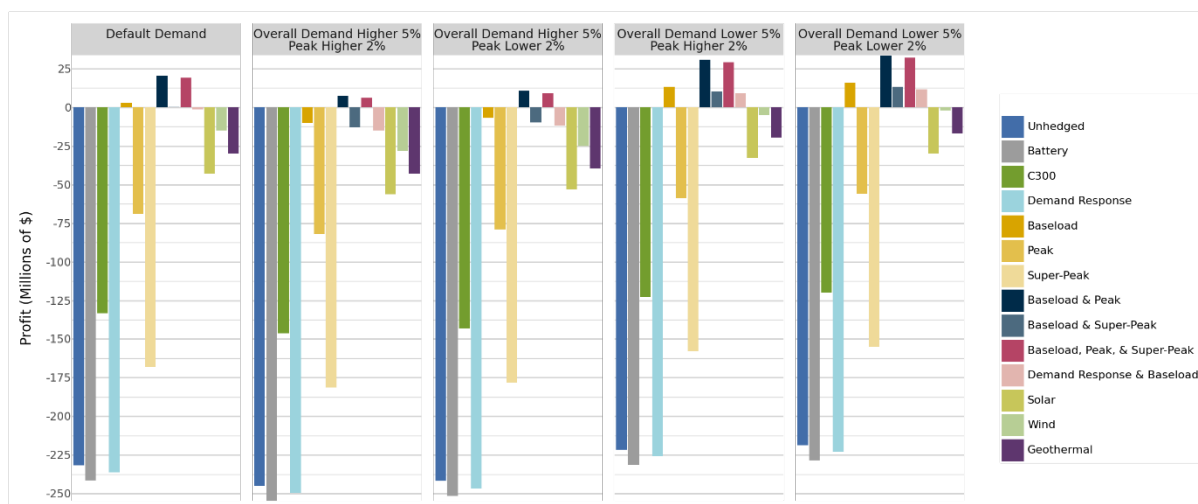

Maximising risk adjusted profit

3.17.   Comparing Figure 12 to Figure 3, we see that for the given market states, it's best to buy more than the 'Default' demand market state volume. Figure 13 and Figure 14 show that the optimal contract volume can differ significantly from those in the volume-matching method.

3.18.   Another advantage of choosing contract volumes through a portfolio optimisation is the ability to buy a mix of contract types as shown in Figure 15.

3.19.   The optimal C300 volume is significantly lower compared to the previous section, and the optimal battery capacity (when not combined with another contract) is zero. However, when combined with a baseload contract, both a battery and C300 contract helps to reduce risk.

3.20. Comparing Figure 17 to Figure 7, all portfolios have improved when compared to equivalent portfolios in the volume-matching method.
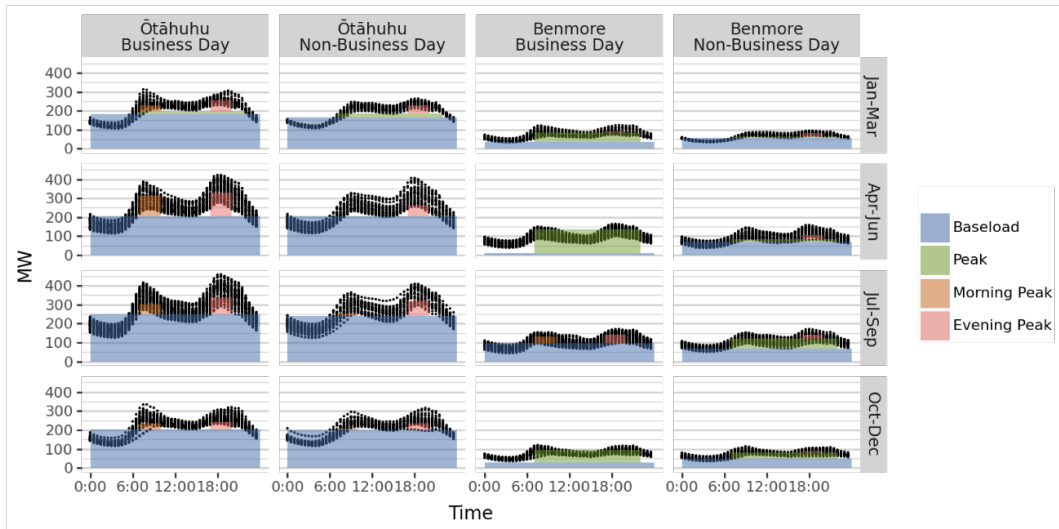
Figure 12: Portfolio optimisation: Baseload - Contract position and load profile in each island, quarter, and day type.
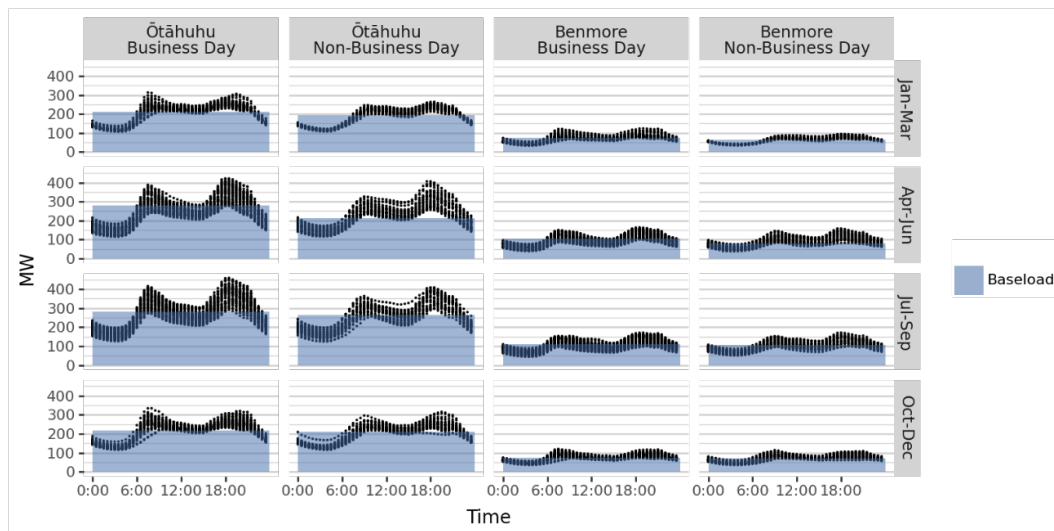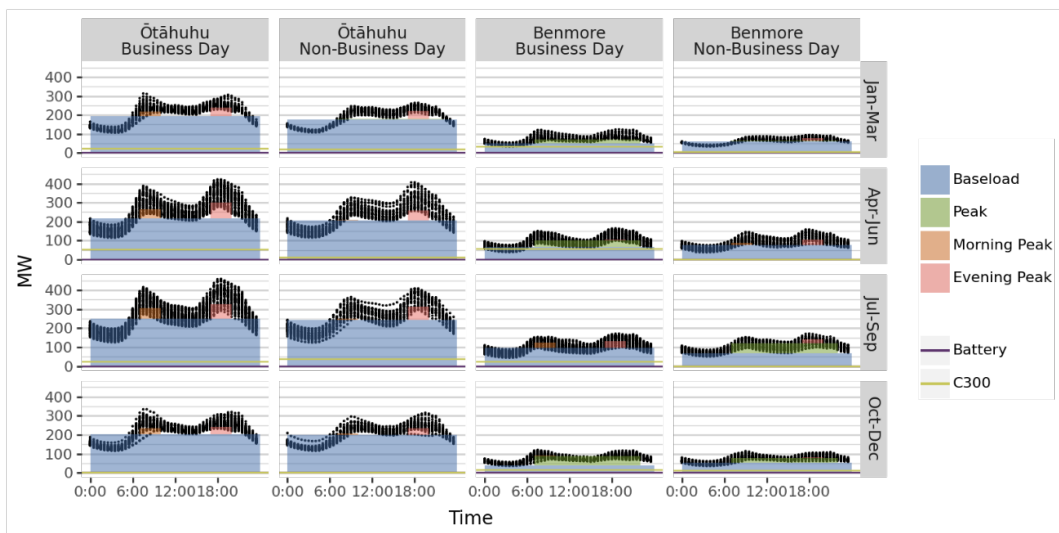

Figure 13: Portfolio optimisation: Baseload & Peak - Contract position and load profile in each island, quarter, and day type.
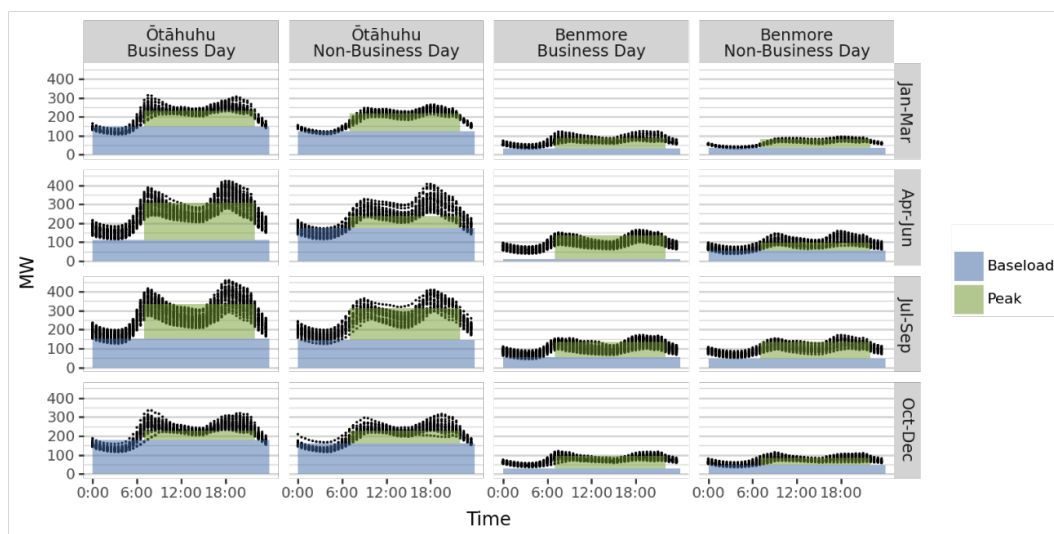
Figure 14: Portfolio optimisation: Baseload, Peak, and Super-Peak Contract position and load profile in each island, quarter, and day type.
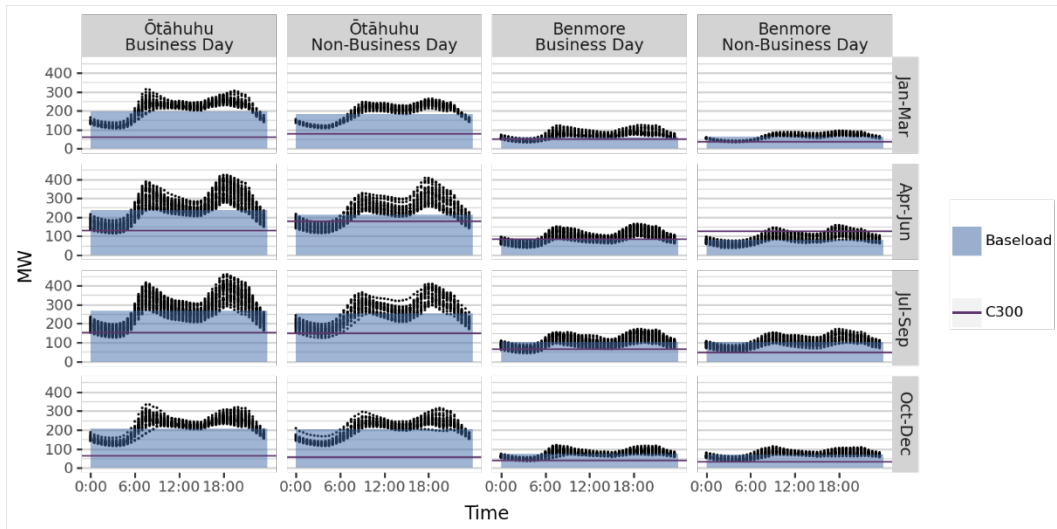

Figure 15: Portfolio optimisation: Baseload, Peak, Super-Peak, Battery, and C300 - Contract position and load profile in each island, quarter, and day type.
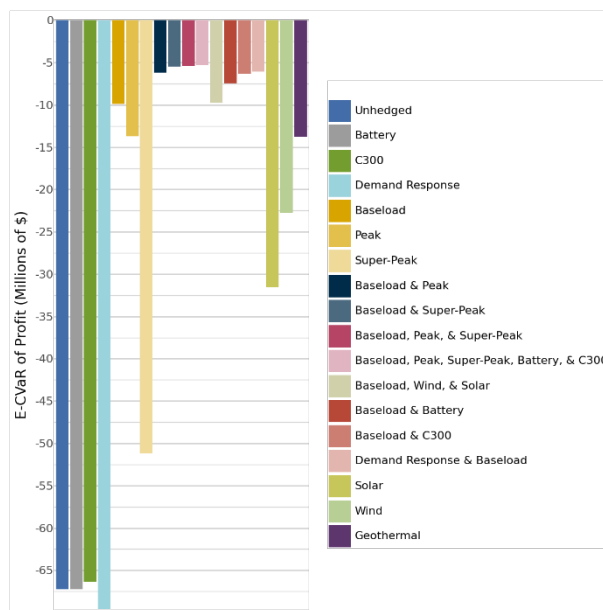
Figure 16: Portfolio optimisation: Baseload and C300 - Contract position and load profile in each island, quarter, and day type.

Figure 17: Portfolio optimisation: Sum of E-CVaR in each island, quarter, and day type given each portfolio.

3.21.　Comparing Figure 18 and Figure 19 to Figure 8 and Figure 9, we see that across all the Non-PPA portfolios, the portfolio optimisation method reduces large losses better than the volume-matching method.

3.22.　PPA volumes are chosen to minimise risk for the whole year, instead of focusing on any quarter. So, in this specific quarter (July to September), the volume-matching method works better in high-loss market states, even though portfolio optimisation reduces risk more effectively over the entire year.

Figure 18: Portfolio optimisation: Profit in each market state in the North Island, in the July to September quarter, and during business days. Less effective portfolios.
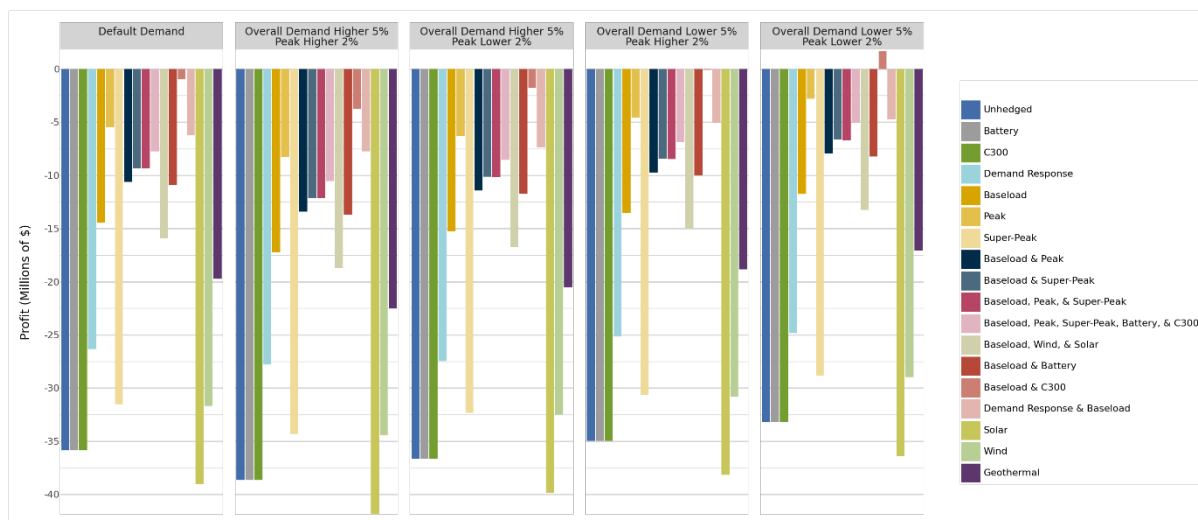
Figure 19: Portfolio optimisation: Profit in each market state in the North Island, in the July to September quarter, and during business days. More effective portfolios.


3.23. Since contract volumes are chosen to minimise risk over the 40 market states, there are mixed results when comparing their effectiveness to the volume-matching method during the stress tests.

3.24. Because the optimal solution avoids buying a battery or the C300 contracts for July to September, the non-integrated retailer remains unhedged with these portfolio choices.

3.25. We see that PPAs continue to perform worse than portfolios with ASX and OTC contracts during these stress tests.

3.26. We also see that adding more instruments tends to improve the non-integrated retailer's profit during these stress test scenarios. The notable exception is that the 'Baseload & C300' portfolio performs the best across both stress tests. Figure 16 shows that the best strategy for this portfolio is to buy more baseload than their expected demand, which helps in the energy stress test. The optimal solution is to also buy a combined baseload and C300 volume that nearly as high as their peak consumption, which helps in the capacity stress test.

Figure 20: Portfolio optimisation: Profit given the capacity shortage stress test in the July to September quarter. All spot prices are set to $10,000/MWh in the 16 highest demand trading periods. All other prices are from the default price market state.

Figure 21: Portfolio optimisation: Profit given the energy shortage stress test in the July to September quarter. Compared to the default price market state, the price in every trading period is increased by $300/MWh.
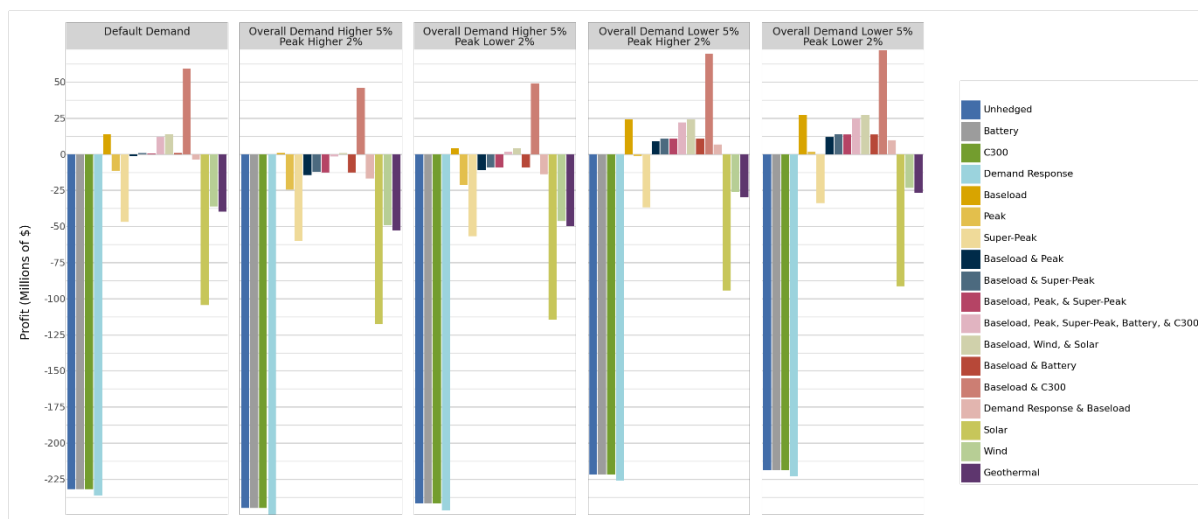
Adding premiums to risk management prices

3.27.   From 2011 to the end of 2023, we have observed that contracts on the ASX (for those traded more than a year ahead) tend to be priced above their final reference price during winter quarters and tend to be priced below their final reference price in summer quarters.

3.28.   Adding this seasonal premium to all quarterly contracts could affect how much of each contract it is optimal to buy. It may also make some of the other contracts worth including in the portfolio.

3.29.   Table 5 shows the premiums we add to the risk-neutral price of each ASX and OTC contract (excluding the C300 as only a small proportion of this premium would apply).

3.30.   There may also be additional premiums for peak and super-peak contracts due to scarcity and higher volatility (in addition to the scarcity and volatility premia present in the ASX premium). However, due to the complexity in calculating these premia, we have not attempted to add them here. This is discussed further in Appendix A.

3.31.   Our risk-neutral prices already include a shape premium for the peak and super-peak hedges.

Table 5: ASX Premium ($/MWh) by Quarter and Location

	Ōtāhuhu	Benmore
January – March	-21.0	-20.0
April – June	17.0	9.0
July – September	25.0	16.0
October – December	-9.0	-15.0

3.32.   Comparing Figure 22 to Figure 17, we see that adding these premia generally increase the overall risk for portfolios using ASX or OTC contracts.

3.33.   The exception is for the 'Super-Peak' portfolio where the optimal portfolio involves buying a relatively high number of contracts during the summer quarters in both scenarios. The negative premium during these quarters means that the overall impact of the premium is to make them much cheaper, leading to a lower risk than in the 'Portfolio optimisation' scenario.

3.34.   This premium has also made buying PPAs along with baseload contracts viable for the portfolio.

3.35.   In Figure 24, we see that the high-loss market states are much worse than in Figure 19 because of the large premium on ASX and OTC contracts in this quarter.

Figure 22: Including seasonal risk premium: Sum of E-CVaR in each island, quarter, and day type given each portfolio.
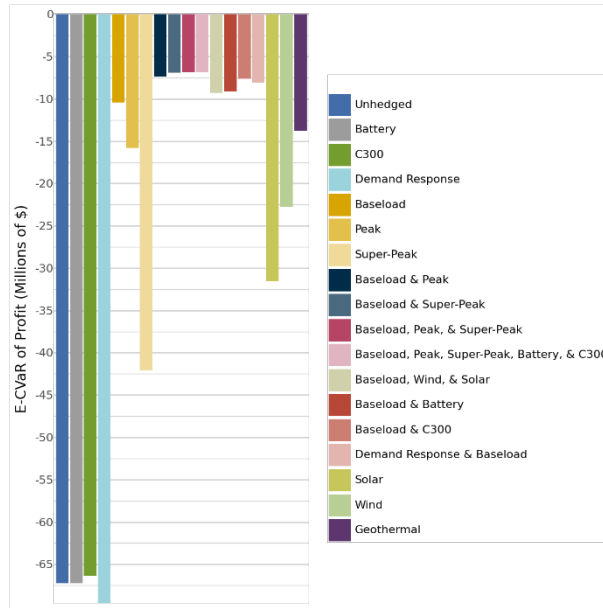
Figure 23: Including seasonal risk premium: Profit in each market state in the North Island, in the July to September quarter, and during business days. Less effective portfolios.

Figure 24: Including seasonal risk premium: Profit in each market state in the North Island, in the July to September quarter, and during business days. More effective portfolios.

Worst-Case Risk Measure

3.36.   We now compare how well each portfolio maximises worst-case profits for the given market states. Comparing Figure 25 to Figure 22, using a worst-case measure leads to there being a bigger benefit of using shaped contracts compared to the remaining portfolios. This difference is larger than when we used the E-CVaR risk measure, but the results still reach the same conclusion of having a variety of risk management tools being beneficial.

3.37.   In Figure 27, each portfolio has a higher worst-case profit compared to Figure 24, but this comes with higher costs in other market states and higher overall expected costs due to the added premiums.

Figure 25: Worst-case risk measure: Sum of worst-case profit in each island, quarter, and day type given each portfolio.

Figure 26: Worst-case risk measure: Profit in each market state in the North Island, in the July to September quarter, and during business days. Less effective portfolios.

Figure 27: Worst-case risk measure: Profit in each market state in the North Island, in the July to September quarter, and during business days. More effective portfolios.
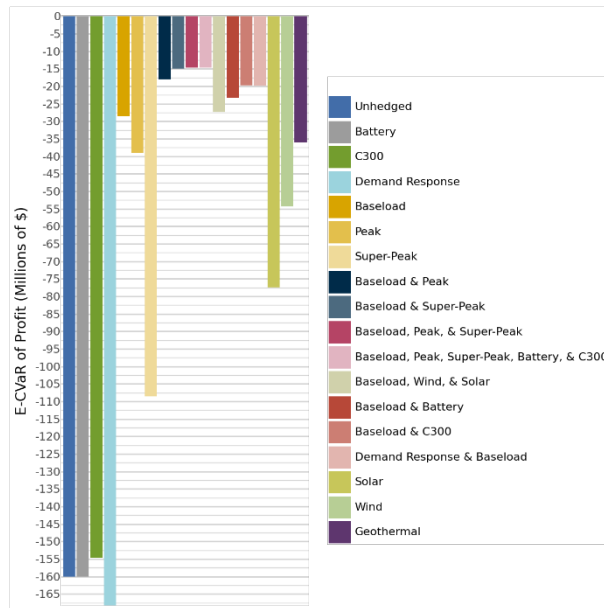

More intermittent generation

3.38.   As wind and solar make up a larger share of energy generation, the ratio of their Generation Weighted Average Price (GWAP) to the Time Weighted Average Price (TWAP) is expected to decrease. According to Concept's modelling[7], for every 10% (of total generation) increase in wind, the GWAP/TWAP ratio for wind drops by about 0.1, and for every 10% increase in solar, it drops by about 0.3.

3.39.   In this scenario, we adjust wholesale prices as a function of wind and solar output in each trading period so that both wind and solar have a GWAP/TWAP ratio of 0.7. This ratio corresponds to wind making up about 30% of generation and solar making up about 10%.

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7   MDAG: Price discovery with 100% renewable electricity supply. Concept Consulting and Energy Link (ea.govt.nz)

3.40.   Comparing Figure 28 to Figure 22, we see that wind and solar PPAs become less effective as risk management tools. Comparing Figure 30 to Figure 24 we see that one reason is their reduced ability to hedge against high evening peak prices.

Figure 28: More intermittent generation: Sum of E-CVaR in each island, quarter, and day type given each portfolio.

Figure 29: More intermittent generation: Profit in each market state in the North Island, in the July to September quarter, and during business days. Less effective portfolios.

Figure 30: More intermittent generation: Profit in each market state in the North Island, in the July to September quarter, and during business days. More effective portfolios.

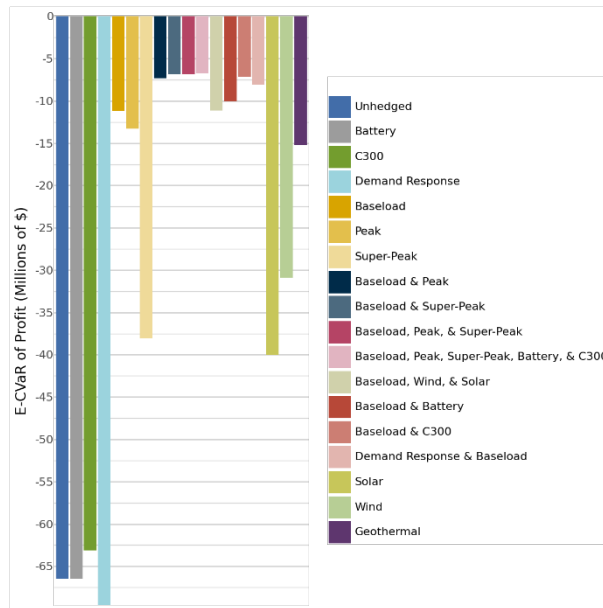## Higher spot price volatility

3.41.   In this scenario, we adjust wholesale prices relative to the baseline scenario (like we did for the Low Price – High Volatility market state) by increasing the spot price multiplier by 0.5 and subtracting $70/MWh ($82/MWh in the Low Price – High Volatility market state to ensure the mean wholesale price is similar to the Low Price – Low Volatility market state), setting a floor price of $0/MWh, so the average price across all market states stays about the same.

3.42.   Comparing Figure 31 to Figure 22, we see that options including a battery, C300, or demand response become more useful as a risk management tool, and can even reduce risk slightly on their own (i.e. without having to use with a baseload contract).

Figure 31: Higher spot-price volatility: Sum of E-CVaR in each island, quarter, and day type given each portfolio.

Figure 32: Higher spot-price volatility: Profit in each market state in the North Island, in the July to September quarter, and during business days. Less effective portfolios.
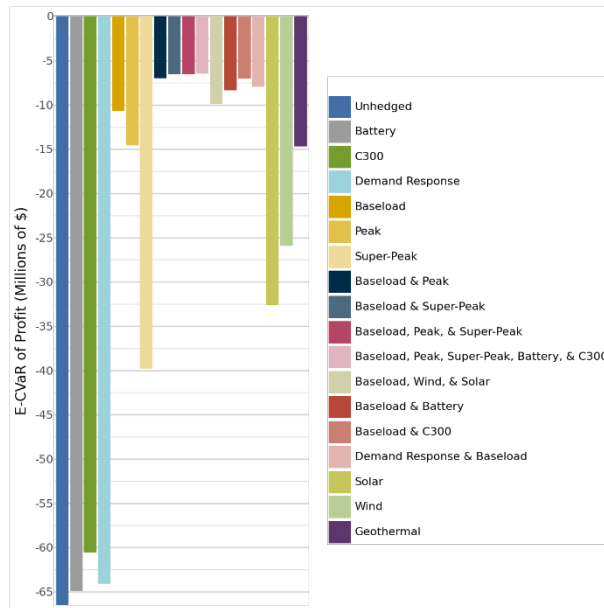
Figure 33: Higher spot-price volatility: Profit in each market state in the North Island, in the July to September quarter, and during business days. More effective portfolios.

Higher prices at super-peak times

3.43. For this scenario, relative to the baseline scenario we subtract $20/MWh ($30/MWh in the Low Price – High Volatility market state to ensure the mean wholesale price is similar to the Low Price – Low Volatility market state), setting a minimum price of zero, from all prices and increase super-peak (morning and evening peak) prices by 50%, so that average prices across market states remain similar.

3.44. In Figure 34, like in the 'Higher spot price volatility' scenario, the battery, C300 and demand response options become more effective at reducing risk. Solar PPAs become less effective at reducing risk, especially when compared to wind PPAs.

Figure 34: Higher super-peak prices: Sum of E-CVaR in each island, quarter, and day type given each portfolio.

Figure 35: Higher super-peak prices: Profit in each market state in the North Island, in the July to September quarter, and during business days. Less effective portfolios.

Figure 36: Higher super-peak prices: Profit in each market state in the North Island, in the July to September quarter, and during business days. More effective portfolios.

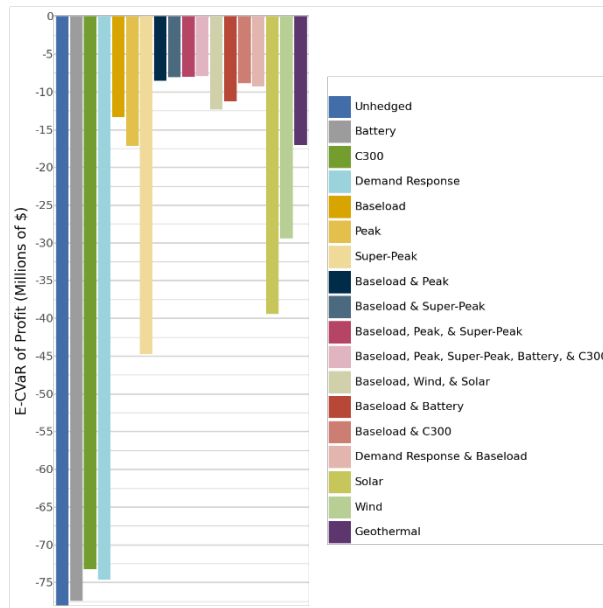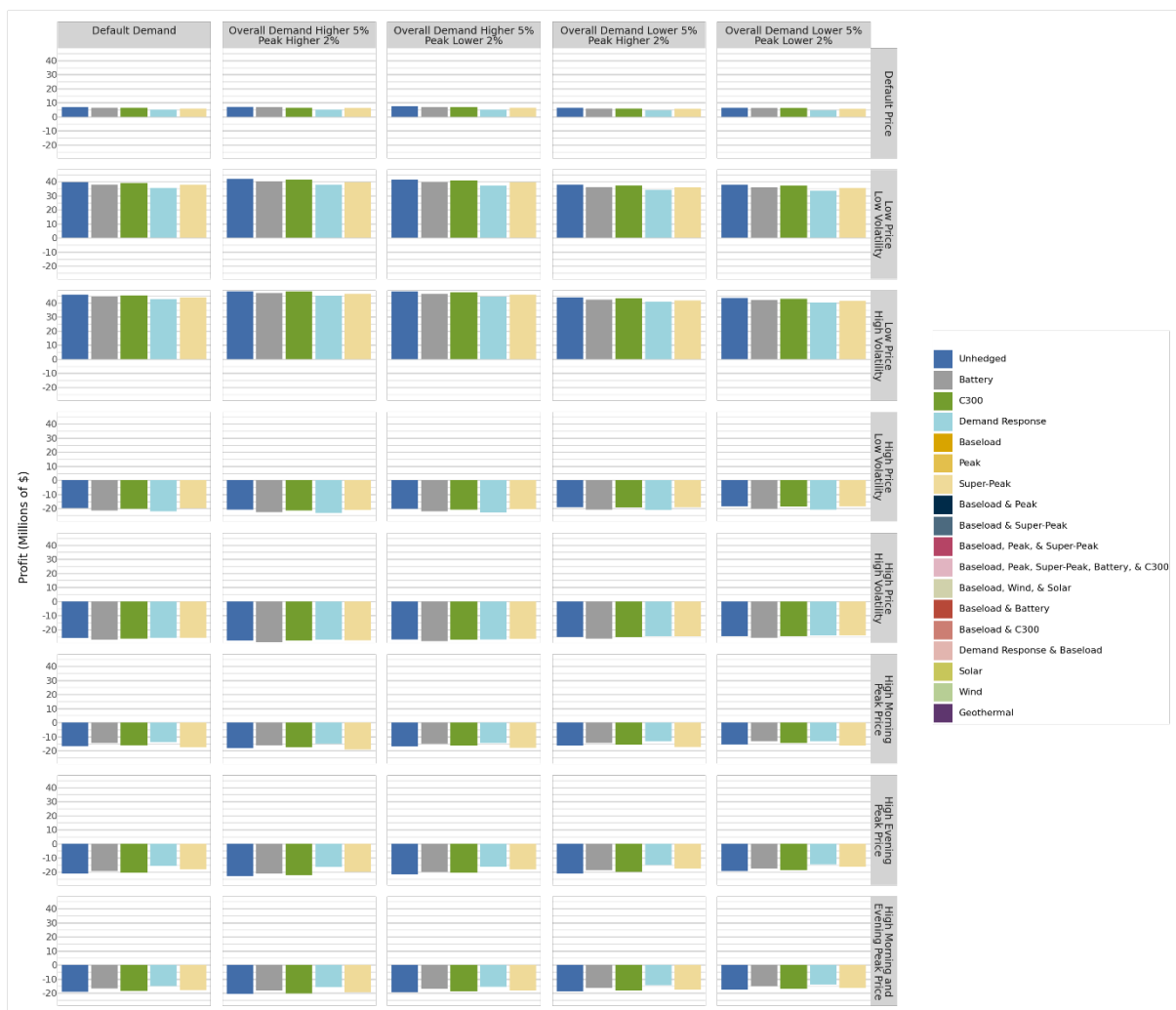## Comparing contract prices and risk adjusted profits across scenarios

3.45.   Table 6 summarises the risk-adjusted profit across all scenarios and portfolios.

3.46.   Table 7 to Table 10 summarise the contract prices across all scenarios. For brevity, each table is the simple average of the contract prices over Ōtāhuhu and Benmore as well as business days and non-business days.

3.47.   The battery price is the $/MW price divided by the number of hours in that quarter and day type.

3.48.   In the 'More Intermittent Generation' scenario, we see that the contract price for both wind and solar drop substantially across all quarters. Despite this reduction in contract price, the wind solar PPAs performed worse as risk management tools in this scenario (as shown by comparing Figure 28 to Figure 22).

3.49.   Conversely, the contract price for the battery and C300 contract increases significantly in the 'Increased Peak' scenario, where we saw it as a much more useful as a risk management tool (as shown by comparing Figure 34 to Figure 22).

Table 6: Risk-adjusted profit in all scenarios for all portfolios ($m pa).

Portfolio Name	Scenario						
	Baseline	Portfolio optimisation	Seasonal risk premium	Worst-case risk measure	More Intermittent Generation	Increased Volatility	Increased Peaks
Unhedged	-67.24	-67.24	-67.24	-160.11	-66.45	-66.51	-78.02
Battery	-82.90	-67.24	-67.24	-160.11	-66.45	-64.91	-77.45
C300	-71.14	-66.34	-66.34	-154.73	-63.12	-60.56	-73.21
Demand Response	-69.60	-69.60	-69.60	-168.30	-69.60	-64.08	-74.61
Baseload	-11.66	-9.91	-10.44	-28.58	-11.22	-10.72	-13.35
Peak	-23.69	-13.69	-15.79	-39.09	-13.28	-14.60	-17.19
Super-Peak	-61.11	-51.17	-42.06	-108.60	-38.05	-39.80	-44.76
Baseload & Peak	-10.33	-6.18	-7.36	-17.98	-7.30	-7.00	-8.56
Baseload & Super-Peak	-6.42	-5.49	-6.89	-14.98	-6.85	-6.55	-8.04
Baseload, Peak, & Super-Peak	-9.78	-5.40	-6.86	-14.74	-6.85	-6.51	-8.00
Baseload, Peak, Super-Peak, Battery, & C300	■	-5.32	-6.84	-14.73	-6.70	-6.50	-7.97
Baseload, Wind, & Solar	■	-9.79	-9.32	-27.38	-11.17	-9.88	-12.34
Baseload & Battery	■	-7.42	-9.10	-23.39	-10.08	-8.39	-11.28
Baseload & C300	■	-6.30	-7.63	-19.78	-7.13	-7.04	-8.89
Demand Response & Baseload	-6.42	-6.05	-8.12	-19.94	-8.12	-7.94	-9.28
Solar	-37.43	-31.56	-31.56	-77.46	-40.02	-32.63	-39.48
Wind	-23.54	-22.75	-22.75	-54.41	-30.92	-25.96	-29.43
Geothermal	-14.53	-13.77	-13.77	-35.99	-15.21	-14.70	-17.04

Table 7: Modelled contract prices in each scenario in the January to March quarter ($/MWh).

Scenario(s)	Contract Name

	Base-load	Peak	Morning Peak	Evening Peak	C300	Battery	Solar	Wind	Geo-thermal
Baseline & Portfolio Optimisation	140.61	159.49	182.87	205.82	9.84	4.51	161.86	123.48	148.38
Seasonal Risk Premium & Worst-Case Risk Measure	120.11	138.99	162.37	185.32	9.84	4.51	161.86	123.48	148.38
More Intermittent Generation	117.04	118.41	162.57	159.74	12.14	5.22	105.34	99.39	144.49
Increased Volatility	124.46	147.49	171.33	199.98	15.84	10.86	172.57	121.61	154.95
Increased Peaks	121.57	151.52	216.71	248.78	19.07	16.87	167.86	123.94	151.03

Table 8: Modelled contract prices in each scenario in the April to June quarter ($/MWh).

Scenario(s)	Contract Name								
	Base-load	Peak	Morning Peak	Evening Peak	C300	Battery	Solar	Wind	Geo-thermal
Baseline & Portfolio Optimisation	87.08	106.36	169.19	159.84	13.14	8.74	90.77	74.86	95.58
Seasonal Risk Premium & Worst-Case Risk Measure	100.08	119.36	182.19	172.84	13.14	8.74	90.77	74.86	95.58
More Intermittent Generation	110.29	128.77	208.83	209.14	19.98	10.17	72.94	68.08	107.39
Increased Volatility	88.69	112.25	192.29	175.09	19.75	25.37	77.66	59.34	87.49
Increased Peaks	102.18	130.40	234.30	217.72	22.09	26.47	85.02	72.90	99.36

Table 9: Modelled contract prices in each scenario in the July to September quarter ($/MWh).

Scenario(s)	Contract Name								
	Base-load	Peak	Morning Peak	Evening Peak	C300	Battery	Solar	Wind	Geo-thermal
Baseline & Portfolio Optimisation	132.11	144.70	168.08	189.62	4.57	6.71	139.40	126.35	140.26
Seasonal Risk Premium & Worst-Case Risk Measure	152.61	165.20	188.58	210.12	4.57	6.71	139.40	126.35	140.26
More Intermittent Generation	152.39	154.70	182.63	226.97	7.27	7.58	93.53	102.59	139.18

Scenario(s)	Base-load	Peak	Morning Peak	Evening Peak	C300	Battery	Solar	Wind	Geo-thermal
Increased Volatility	146.23	160.54	180.76	211.97	5.82	12.32	136.95	117.89	137.38
Increased Peaks	150.40	172.96	232.45	263.78	10.49	20.18	133.56	123.83	139.55

Table 10: Modelled contract prices in each scenario in the October to December quarter ($/MWh).

Scenario(s)	Contract Name								
	Base-load	Peak	Morning Peak	Evening Peak	C300	Battery	Solar	Wind	Geo-thermal
Baseline & Portfolio Optimisation	157.22	176.14	205.39	222.34	8.55	10.94	169.93	154.58	168.39
Seasonal Risk Premium & Worst-Case Risk Measure	145.22	164.14	193.39	210.34	8.55	10.94	169.93	154.58	168.39
More Intermittent Generation	142.48	148.27	193.15	188.25	12.99	12.00	119.20	122.84	163.79
Increased Volatility	150.56	173.56	202.40	226.66	13.55	13.47	178.20	159.56	178.97
Increased Peaks	146.63	177.87	254.50	279.17	17.85	25.56	176.82	156.34	171.84