Seed Advisory

Market Risks for Large Customers

AEMC: ERC0123 Final Report

10 January 2013

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1. Executive Summary

1.1. The structure of this report

This report is the response to the Australian Energy Market Commission's (AEMC) request for advice and assistance with an assessment of market risks and options available to large purchasers of electricity in the National Electricity Market (NEM). The AEMC was seeking a detailed discussion of the range of possible approaches to the management of market risks for a *large commercial and industrial* (C&I) customer engaging in the purchase of electricity, comparing the relative risks and rewards of the different purchasing strategies identified, including:

- advice on the range of possible approaches to risk management of electricity purchases for large commercial and industrial users;
- an assessment of the potential for effective application of these approaches with particular focus on the South Australian region; and
- a quantitative assessment of the financial impact of different risk management approaches on large commercial and industrial users.

Section 2 begins by discussing why large commercial and industrial users might choose to *hedge* the cost of part or all of their electricity consumption. We have restricted our discussion to the reasons why a customer might choose (some) price certainty over the alternative of *spot price exposure*. Section 2 ends by discussing why large commercial and industrial users might choose to hedge all of their electricity consumption with a retailer.

Section 3 identifies the spectrum of possible purchasing and contracting strategies, based on the level of price certainty required by the customer and the choice of intermediary. The strategies are compared with the default strategy – full spot price exposure – and we discuss the factors underpinning the wholesale price achieved by and the risks associated with the strategy, as well as identifying the other issues entailed by each strategy, such as, in the case of the default strategy, AEMO membership. The discussion draws on our knowledge of market participants, including large users, to provide a qualitative guide to those factors we consider more important to large users' choices and those we believe are likely to be less important.

Section 4 outlines our modeling approach, the results of which are discussed in Section 5 and provided in detail in Appendix D. Elements of our approach and its underpinnings in the academic literature on forward price formation are discussed in greater detail in Appendix C.

1.2. Conclusions

1.2.1. Why hedge?

Without being risk averse, commercial and industrial customers hedge their wholesale electricity price risk for a wide range of reasons, including:

- The inability to pass through variable electricity costs in the prices of its output
- A desire to avoid price spikes or price shocks
- Budgetary certainty
- Convenience

- Relative costs of hedging compared with the costs of managing an unhedged position.

Our results suggest that this reasoning by customers is sound. As Figure 1.1 and Figure 1.2 show, the differences in the expected (average) cost for its electricity consumption that an unhedged customer could experience in the Victorian or South Australian markets are so large that only customers able to pass through their full range of costs to their customers will choose pool price exposure over a hedge. The difference in a customer's costs between a low price, low volatility market, such as that experienced in the South Australian market in from the second quarter 2011 through to the end of the first quarter 2012, and a high price, high volatility market, such as that experienced in South Australia during 2009, can be as high as 81 per cent, depending on the customer's load profile[1]. The exception to this conclusion is that class of large customers who are able to reduce their consumption rapidly and costlessly in response to high prices. For this group of customers, then a combination of pool price exposure and demand reduction is consistently a superior choice to pool price exposure alone or a partial or full hedge.[2] However, we think the number of customers who meet the conditions required to achieve this outcome is small and unrepresentative of large commercial and industrial users as a whole.

Further, our findings suggest that, considered over a number of years, hedging is superior to not hedging and the more comprehensive the hedge, the better.[3]

The benefit of hedging is reinforced by our tests of a "worst case scenario", which, based on actual pool outcomes, results in the unhedged strategy being the most expensive of all the strategies.[4]

1.2.2. What hedge strategy is best?

We have modelled a range of hedge strategies for a commercial and industrial customer with annual consumption of 30 GWh in the Victorian and South Australian markets under three different load profiles: flat, summer peaking and winter peaking and four different combinations of spot price and volatility, that is the incidence of prices in excess of \$300/MWh. We have called the states LPLV (low price, low volatility), LPHV (low price, high volatility), HPLV (high price, low volatility) and HPHV (high price, high volatility) and our analysis looks at the results of the hedging strategies modelled under each of the market states, taking into account the effect of prior and current market conditions on the costs of hedging.

The strategies modelled are:

- Spot price exposure combined with \$300 caps
- Part hedge, part spot exposure
- Progressive hedge strategy
- Full load following hedge
- Load curtailment.

[1] Calculated using data rebased to take account of the effect on price of the introduction of a carbon tax, see Sections 4.2.3 and 5.1.
[2] See Section 5.3.1.
[3] See Section 5.4.1.
[4] See Section 5.4.2.

Figure 1.1 Expected pool costs by customer profile and market state, expected, 5th and 95th percentiles, Victoria, $/MWh

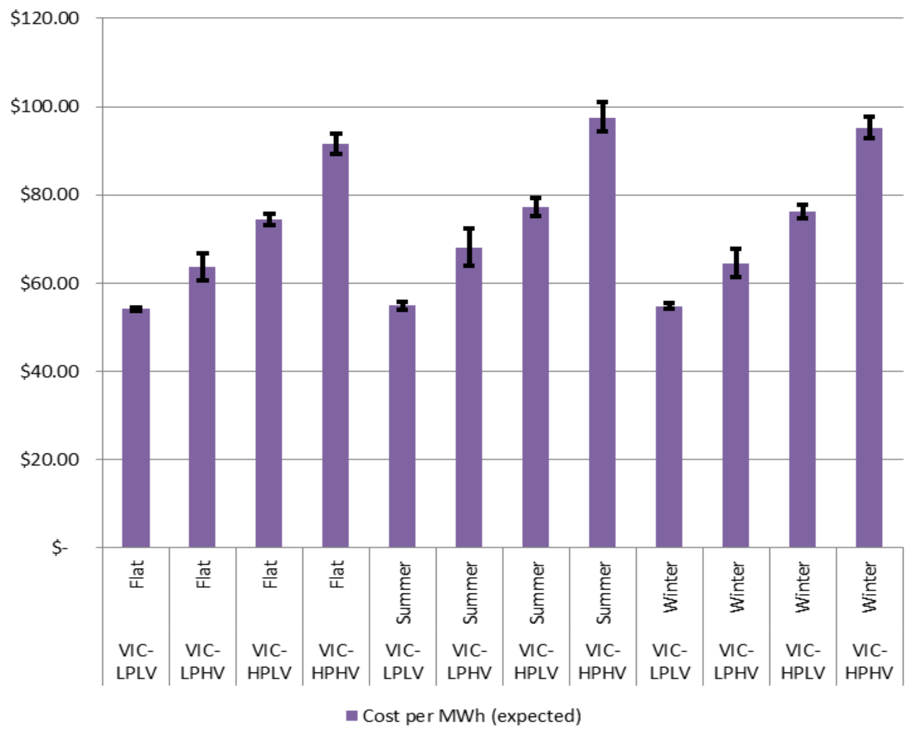
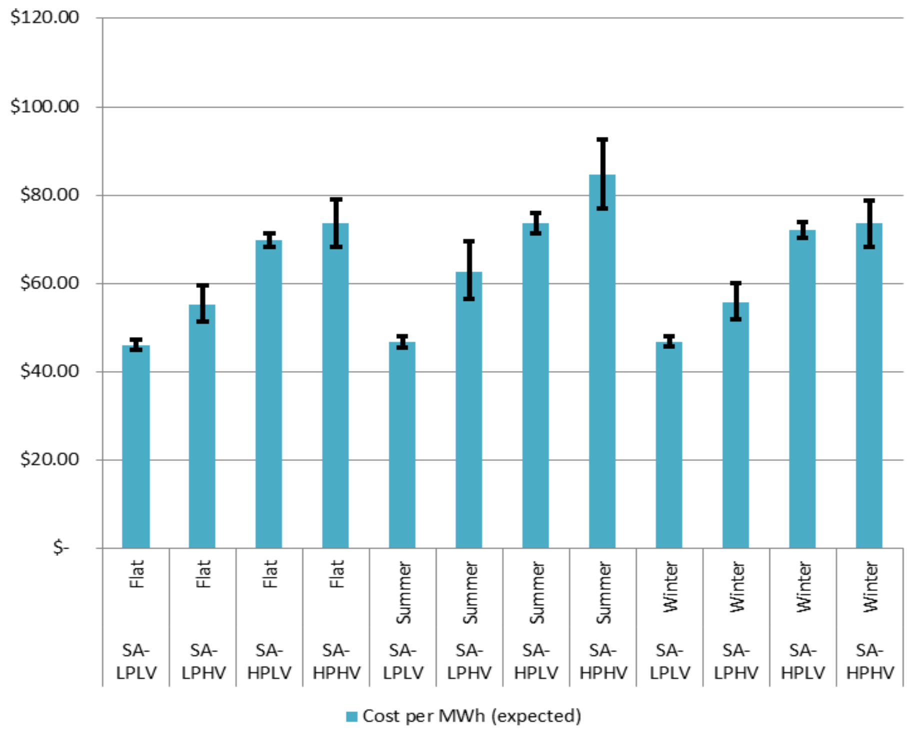


Figure 1.2 Expected pool costs by customer profile, market state with 5th and 95th percentiles, South Australia, $/MWh



In comparing the customer's costs under each of these strategies, we have referred to a strategy as either *superior* or *preferred.*

- A strategy is regarded as *superior* where for a similar cost it offers a materially higher lower level of risk for the customer.
- A strategy is regarded as *preferred* where, for a small additional cost, the customer can achieve a materially lower level of risk.

Table 1.1 summarises our findings for the Victorian and South Australian markets, looking at the performance of the strategies modelled under all the market states used. The strategies are ranked by total annual cost, calculated as a simple average of the cost of the hedging strategy to the customer under all market states modelled and taking into account the costs of the hedge instruments used and any residual spot price exposure, including the costs to the customer of being under or over hedged. Using a simple average of the 4 market states is designed to capture a customer's inability to forecast the market conditions that will prevail during the period of the hedge strategy chosen. In these circumstances, a simple average is the best representation of a customer's expected costs.

For a small number of cases we modelled, the standard contracting approach – the full load following contract – is the preferred strategy, although the progressive hedge, where the customer implements a rolling hedge program, may be marginally cheaper. The preference for the full load following contract reflects the significant reduction in possible outcomes relative to the progressive hedge.[5] In all other cases, with the exception of those customers for whom load curtailment is an achievable strategy, the progressive hedge is the preferred strategy, because it is less expensive than a load following contract.

Excluding load curtailment and pool exposure, the differences in the costs of the hedging strategies considered are, for customers with a flat load profile, narrow. For customers with peaky loads, a full load following hedge can be materially more expensive than the next best alternative, the progressive hedge, particularly in South Australia. For these customers, the progressive hedge is the superior strategy.

Implementing the strategies modelled in practice, however, can be difficult.

- Both the size of the customer's load and the market the customer's operations are located in affect the customer's ability to implement a number of the strategies modeled.
  - In modeling a 30 GWh customer, we have modeled a large customer that could implement a progressive hedge in the exchange traded market, by hedging 50 per cent of its load annually using two year forward contracts. Smaller customers – for example a 10 GWh/year customer – would not be able to replicate this position.
  - Our estimate of the customer's costs includes the costs of the over-hedged position, but an *under-hedged* customer's costs would have been higher.
  - Not all regional markets can support even a two year rolling hedge program. For the purposes of the modeling, we have assumed this is possible in the South Australian market, although this assumption is inconsistent with published market information.

[5] See Section 5.3.2.

Table 1.1 Hedging strategies from highest to lowest cost, by customer profile and region, total expected (average) annual cost, $

Customer Profile	Hedging Strategy	Average cost, $	Hedging Strategy	Average cost, $
	Victoria		South Australia	
Flat	**Progressive**	$2,220,587	**Load Following Contract**	$1,922,814
	Load Following Contract	$2,212,932	**Progressive**	$1,914,271
	Part hedge	$2,200,042	Part hedge	$1,906,630
	Pool + Caps	$2,165,658	Pool + Caps	$1,844,090
	Pool	$2,128,153	Pool	$1,836,841
	Load Curtailment	$1,992,296	**Load Curtailment**	$1,632,094
Summer Peaking	**Load Following Contract**	$2,638,389	**Load Following Contract**	$2,598,323
	Progressive	$2,356,450	**Progressive**	$2,118,776
	Pool + Caps	$2,339,027	Part hedge	$2,111,135
	Part hedge	$2,335,905	Pool + Caps	$2,055,844
	Pool	$2,264,016	Pool	$2,041,346
	Load Curtailment	$2,089,672	**Load Curtailment**	$1,765,055
Winter Peaking	**Load Following Contract**	$2,332,913	**Load Following Contract**	$2,116,889
	Progressive	$2,298,887	**Progressive**	$1,936,612
	Part hedge	$2,249,876	Part hedge	$1,928,970
	Pool + Caps	$2,215,493	Pool + Caps	$1,866,431
	Pool	$2,177,988	Pool	$1,859,181
	Load Curtailment	$2,028,316	**Load Curtailment**	$1,654,626

- Regardless of the results of the modeling, the benefits of the standard contracting approach – the load following hedge – are reinforced by the characteristics of Australian electricity derivative markets and the regulatory and other requirements a customer directly participating in the market must meet reinforce.
  - By using a retail intermediary, customers benefit from economies of scale, specialisation and able to access standard contracts – the load following hedge – that for smaller commercial and industrial customers or customers with peaky or unpredictable load can be a superior product to that available using a combination of direct wholesale market participation and standard traded contracts.

- To the extent that retailers offer longer term contracts than are achievable in traded markets, then retailers offer a valuable market making service.

1.2.3. Customers' challenges in managing their electricity price risk

In managing electricity price risk directly, standard traded contract sizes are too large to provide an effective hedge for many customers. In the exchange traded market, the standard contract size is 1 MW. For a commercial and industrial customer at the low end of the large customer category – that is, a customer consuming 10 GWh a year – a single standard base load contract represents a hedge of around 86 per cent of the customer's annual electricity consumption, but it is an effective hedge only to the extent that the customer's load is flat, invariant between peak and off peak periods and not weather related. If the customer's load is peaky or displays a strong work day pattern, the effectiveness of the hedge is lower; that is, the level of protection against adverse spot price movements is lower.

Standard contract sizes in the *over-the-counter* (OTC) market are even larger, at 5 MW, but, for an additional price, a large customer may be able to contract for a hedge contract(s) with the desired load shape and other characteristics.

Whatever electricity derivative market the customer contracts in, the market will be incomplete; only a small number of the possible types of electricity derivatives are available and even the most actively traded – forward or swap contracts – are only available for one to two years into the future. Liquidity is low even for the most actively traded contracts. Reported traded volumes in the OTC market have been falling for a number of years and the term to maturity of the reported traded contracts has also been falling. Contract quantities traded in the exchange traded market appear to have peaked in 2010/11, falling in 2011/12 and continuing to fall in 2012/13, measured by daily trades relative to daily trades in the previous period. Incomplete markets and low liquidity reduce the scope for and flexibility of the approaches that customers might use to hedge their electricity price risk.

Relative to the NSW or even Victorian markets, liquidity in the South Australian market is low and restricted to the balance of the current quarter and the four quarterly contracts making up the following (2013) calendar year. Strategies that could, potentially, be implemented in NSW or, with less certainty, in Victoria cannot be implemented in South Australia in the exchange traded market.

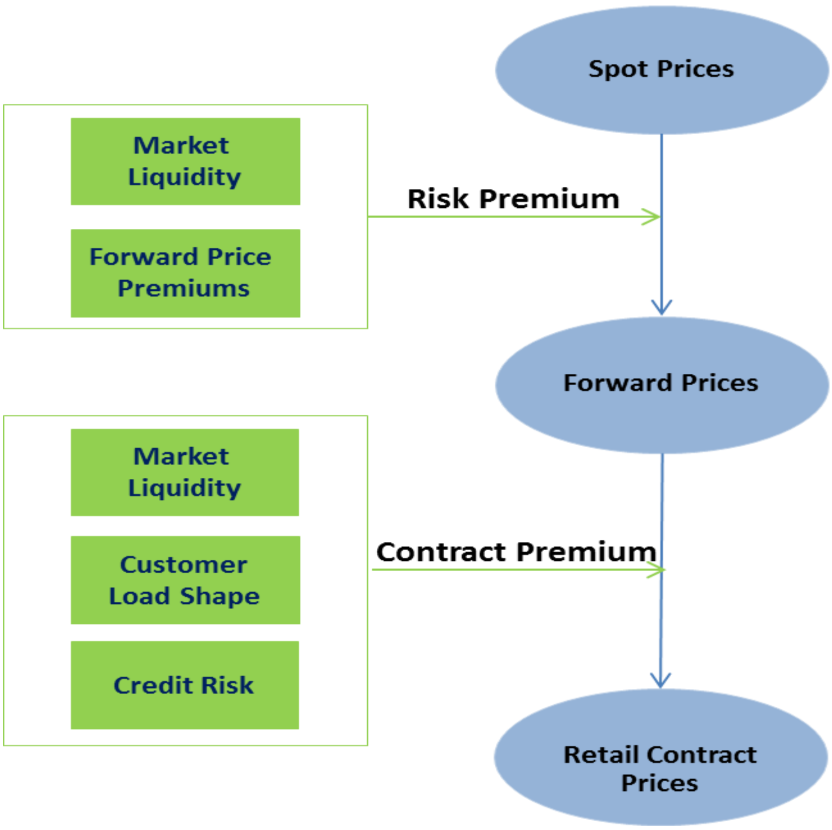
2. Large customers and the risk of electricity spot prices

In this section, we discuss why large commercial and industrial users might choose to hedge the cost of the wholesale electricity component of their electricity consumption.[6] In this section, “hedge” means any of a range of possible strategies that have the effect of substituting a more certain price for wholesale electricity for the alternative of paying the wholesale regional spot price (spot price exposure). We have not discussed the level of price certainty achieved (the level of price risk transferred), but restricted our discussion to the reasons why a customer might choose (some) price certainty over spot price exposure. Finally, in Section 2.3, we discuss the characteristics of retailers’ typical offering, the load following hedge and the characteristics a customer’s load would need to demonstrate to allow the customer to replicate this offering outside the OTC market.

2.1. The costs of hedging

At a conceptual level, there are two distinct categories of costs incurred by a large customer that chooses to hedge its wholesale electricity purchases, as shown in **Figure 2.1** below.

Figure 2.1 The costs of hedging: high level schematic



[6] Large customer contracts typically pass through network charges, the direct cost of regulatory imposts and large new tax and market events, such as the GST and the introduction of a carbon price.

The two categories of costs are:

- The *risk premium* required by a market participant or intermediary to offer a fixed price for some future period (a forward, swap or *contract for difference*) in exchange for spot market exposure. In the absence of a risk premium, at the time the transaction is entered into, the market price for the *forward contract* would be equal to the expected spot price over the term of the agreed contract leaving the parties to the transaction indifferent to the choice of the spot or fixed price. The generally used explanation for the difference between the expected spot price and the forward price is that the party offering a fixed price requires compensation for the risk it is assuming in accepting the spot price. The risk premium is also expected to be impacted by other factors including market liquidity. In a less liquid market the risk premium is expected to be higher[7].

  In addition to the risk premium in moving from spot price exposure to a forward price, a large customer looking to hedge its own load would pay an explicit fee (*premium*) for any other derivative products used. For example, in entering into a *cap* contract, the purchaser pays a premium to the cap provider.

- Where the customer chooses a retail intermediary, the *contract premium* required over and above the wholesale market price to provide for the risks associated with offering a forward contract with significant volume uncertainty to a customer. Retailers' contract premiums differ according to the shape of the customer's load – peakier customers' loads incur higher contract premiums because of the observed relationship between high electricity load and high prices – and may vary also with other factors such as the term of the contract, the liquidity of the market for which the contract is required, the creditworthiness of the customer and other factors, such as the retailer's portfolio considered as a whole.

In taking a decision to hedge and reduce its risks, typically a customer is taking two decisions, both of which involve some element of cost: in agreeing to a forward price, a customer chooses to incur costs in excess of the current expected spot price outcome – that is, pays a risk premium. Then, in using a retail intermediary, the customer incurs additional costs in the form of the retailer's contract premium. Quoted prices for forwards and the current premium for other electricity derivatives – cap prices, for example – are available, but the *risk premium* is not separately identified or easily quantified.[8] Similarly, if contract prices were observable, the contract premium would not be readily identifiable, depending on the retailer's assessment of the customer's risk as well as the retailer's costs and margin and underlying wholesale position. While both risk and contract premiums could be regarded as being set in competitive markets, the customer is not necessarily well equipped to assess the level of each cost in relation to potential spot market costs.

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[7] See, for example, the discussion in Redl and Bunn, (2011) relating to the formation of forward premiums.

[8] The literature that discusses the size of the spot/forward *risk premium* in electricity and other commodity markets uses the ex post *risk premium* as a proxy for the unobservable *ex ante risk premium*. The ex post risk premium and, based on industry knowledge, the contract premium can vary considerably from period to period, depending on spot price market outcomes over the life of the contract, choices made by the retail intermediary in hedging the customer's load and the skill of the retailer.

Despite the difficulties of assessing whether the cost of hedging and the additional cost of intermediation represent fair value compared with potential spot price outcomes and the other costs of managing its unhedged load, a large customer may choose to hedge its wholesale electricity spot price risk for a range of reasons. Further, given the specific characteristics of Australian electricity derivative markets, a large customer that chooses to hedge may choose a retailer to access otherwise inaccessible hedge markets and for a superior product.

2.2. Why manage the risk of electricity spot prices

There are a wide range of reasons why a large customer would choose to hedge its wholesale electricity spot price risk, including:

- The inability to pass through variable electricity costs in the prices of its output
- A desire to avoid price spikes or price shocks
- Budgetary certainty
- Convenience
- Relative costs of hedging compared with the costs of managing an unhedged position.

2.2.1. The inability to pass through variable electricity costs in the customer's output prices

A large customer may not be able to pass through variable electricity costs to its customers where in doing so it incurs a disadvantage relative to its competitors. For example:

- If a large customer's competitors have entered into multi-year fixed price contracts for their wholesale electricity costs, then a customer who has not hedged its wholesale electricity costs may be unable to recover variable electricity costs by altering its prices. This is the case whether the price variation is the result of a large short term price increase or a smaller, trend increase in spot prices that results in an increase in spot prices relative to contract prices over a given period. On the other hand, if a large customer achieves a relative price benefit from deciding not to hedge its load, in a competitive market that benefit is likely only to be transitory, as its competitors could be expected to adopt a similar approach to the management of their electricity purchases.
- If the customer sells into a competitive market, the customer may have no ability to pass on prices that differ even for a short period from those of its competitors.

In the first of these cases – the customer's hedging strategy differs from that of its competitors and, as a result, the customer's wholesale electricity costs are higher than its competitors – where electricity derivative markets are efficient and hedge and contract prices adjust to reflect higher spot prices, the (dis)advantage is likely to be less significant over the medium to long term.

For a NEM region where the cost of electricity is higher than in other regions, if the customer's markets and its competitors are all confined to a single region, then:

- Provided the forward market is efficient and competitive, timing differences in the beginning and end of a customer's hedge would not be expected to present a persistent source of (dis)advantage.
- If spot and hedge prices have a predictable and stable relationship then the choice of spot price exposure or a hedge for that exposure is unlikely to persistently benefit

one group of industry participants over another, although, from time to time, either the spot exposed or the hedged group may have a temporary advantage.

- However, if spot and hedge prices do not have a predictable and stable relationship then the choice of spot wholesale electricity price exposure or a hedge for that exposure may benefit one group of industry participants over another.
  - However, repeated intervals where spot prices outcomes are very high relative to hedge prices could be expected to increase the risk premium required in the market for a forward contract, and may cause the number of parties willing to offer forward prices to fall, reducing liquidity in the wholesale market. Depending on the number of parties initially willing to offer forward prices, a reduction in the number of parties that continue to be willing to offer forward prices may result in an illiquid retail market, increasing contract premiums or decreasing the availability of contracts.

Once the NEM regional boundary no longer defines the customer's market, then the customer's ability to pass through variable costs is constrained, as the competitive market price will reflect the costs of competitors from regions with lower wholesale electricity prices. Again, it is unclear where the balance of advantage lies (whether spot exposed or hedged), although any characteristics of the regional market that result in higher electricity costs are likely to disadvantage the customer relative to its competitors in other regions.

2.2.2. A desire to avoid price spikes or price shocks

Electricity spot markets are widely acknowledged to be the most volatile of any commodity market, when volatility is measured by looking at potential and actual price changes over very short periods of time. In addition to the high level of spot price volatility, electricity spot markets, including the National Electricity Market (NEM), display *fat tailed distributions*. The distribution of spot price outcomes in a fat tailed distribution, compared with a normal distribution, typically has more (and larger) outliers in the tail of the distribution – that is, over a given period of time there are on average more short term high price intervals than are demonstrated by the price behaviour of other traded commodities.

Measured over longer periods of time, wholesale electricity price volatility declines markedly. However, while electricity spot price volatility falls when considered over the longer term – say, monthly, quarterly or annually – the costs of high short term price movements can be very significant, considered either as the cost of the short term price movement and its cash flow consequences or as the impact on achieved quarterly or annual prices.

Finally, spot price behaviour in the NEM demonstrates expected – and, to some extent, predictable – relationships between low capacity and high prices, such as the effects of a sustained heat wave on regional spot prices. However, high spot prices are also associated with random and unpredictable events, including generator and equipment failures, interruptions to fuel supply, human error and generator bidding patterns, making it difficult to anticipate and plan for the effects of high spot prices on achieved electricity spot prices.

Given these characteristics – very high short term price volatility, more frequent very large high price events and the lack of predictability of at least some sources of short term price volatility – a rational large customer could choose, acting rationally, to hedge its wholesale electricity price risk, without being regarded, in economic terms, as risk averse.[9] The customer's decision may be reinforced by a number of other factors, such as the relative costs of the alternatives (hedging or taking spot price exposure) and the customer's ability to manage its spot price exposures through timely changes, which are addressed below.

2.2.3. Budgetary certainty

Hedging offers a large customer a level of budgetary certainty for the wholesale cost of energy relative to the alternative of spot price exposure.

Large customers may look for price certainty even if wholesale electricity costs do not represent a significant element of the costs of production for a variety of reasons, including:

- Narrow profit margins.
  The narrower the profit margin, the more likely (all other things being equal) that a customer will prefer certainty over uncertainty in its wholesale electricity costs, even where that certainty is achieved at some cost relative to the expected spot price outcome.
- The frictional and other costs of changing the price of the customer's output.
  Large orders spread over more than a year, long term supply arrangements and end user preferences for more stable rather than more frequently varied prices, as well as the administrative costs of changing prices provide a reason for preferring more to less stable prices.
- Prioritising management focus.
  A large customer may incur significant wholesale electricity costs without wholesale electricity costs representing the largest or most significant of the costs incurred in a manufacturing process. A large customer may prefer to direct management time to towards other elements of the production process that are more significant to it. In the case of wholesale electricity purchases, this preference may be compounded by the specialist nature of the skills required to manage the customer's spot market exposure and its regulatory and other obligations.

For very large users of electricity where electricity is a significant production cost – for example, the mineral processing or the computer chip production industries – the value of price certainty is so high that customers typically look to achieve long term price certainty by building their own generation or through very long term contracts for wholesale energy, network charges and other regulatory costs. [10] Prior to the construction of an electricity intensive production facility, the owner will seek to ensure the long term viability of the capital investment by agreeing the future electricity costs. In the absence of a long term agreement on the cost of wholesale electricity, the risk of the long term, capital intensive, immobile investment in the facility would materially increase. The characteristics of investments of this type – the electricity intensity, the long term nature and capital intensity, as well as the immobility – and the

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[9] The term "risk averse" in economic literature refers to an economic actor who chooses to avoid a risk by taking a decision that results in a known lower payback/incurs a higher known cost than the payoff/cost of the uncertain alternative on the balance of probability.

[10] The most recent contracts to provide wholesale electricity to the Portland smelter in Victoria, for example, had terms of 22 and 20 years respectively, see http://www.alcoa.com/australia/en/news/releases/20100301_VO_new_PC.asp.

competitiveness of the market in which the customer sells its output, make achieving a very high level of wholesale electricity price certainty a significant factor in the decision to commit to the investment.

2.2.4. Convenience

Prior to the introduction of the NEM, all large customers' contracts could be regarded as hedged, in that term contracts for the customer's entire electricity costs were entered into and, depending on the nature of the indexation in the relevant customer contract, the customer's price was predictable over the term of that contract. The potential to choose wholesale electricity spot price exposure postdates the introduction of the NEM and is, in consequence, a choice that's only been available for a relatively short period of time. For many customers, not only is the choice of a hedge consistent with their previous experience, it is also preferable, taking into account the skills and experience available to the customer.[11]

In choosing to hedge its wholesale electricity costs, a large customer may prefer the convenience of a hedged term contract over spot price exposure where, for example:

- A hedged position requires a lower investment in the acquisition of new skills by the large customer compared with the alternative.
  Depending on whether, in choosing spot market exposure, the customer uses an intermediary with a retail license to manage its market participation and other obligations, these new skills extend past "the way it's always been done" to participation in AEMO's prudential and settlement systems and negotiation of transmission and distribution Use of System agreements, for example. These requirements are discussed at greater length in Section 3.
- The alternative, spot price exposure, requires more oversight in estimating the customer's economic position from time to time.
  The customer's achieved electricity spot price will vary both with its usage and the performance of the relevant regional spot market over the billing period.

2.2.5. Relative costs of hedging compared with the costs of managing an unhedged position

Retailers' offerings to large customers in effect present a bundle of services that includes:

- Expertise in the physical and financial markets
- Cash flow smoothing
- Credit risk intermediation[12]
- Management of the metering and settlement interfaces with the relevant markets, both physical and financial

[11] The skills and experience available to the customer are likely to differ both across firms and across regions. Smaller firms, even in the large customer category, and firms in regional areas are likely to have (or perceive they have) access to a lower level of skills and experience than those available to very large firms or firms in metropolitan areas.

[12] In particular, in relation to the customer, the retailer assumes counterparty credit risk for wholesale market transactions, absorbing the costs, in incurred of a counterparty's failure to perform on a derivative transaction. The extent of the credit risk assumed depends on the market in question. The spot market prudentials are designed to protect Market Participants from all but a low very level of credit exposure, as are the ASX margining requirements. OTC markets, however, can be subject to very high levels of counterparty credit risk and OTC transactions are generally subject to margining only as a result of specific agreement by the contracting parties.

- Management of the customer's day-to-day interface with the transmission and distribution networks, including providing where required, credit support for the retailer's obligations to network businesses
- Management of a range of regulatory and other obligations that accompany participation in derivative markets, including Australian Financial Services Licenses and margin requirements.

Depending on whether, in taking on spot market exposure, the customer uses an intermediary with the necessary licenses and expertise, some or all of these obligations will fall to the customer, along with the associated costs. Of the associated costs, some require annual fees (AEMO membership, for example); some represent an opportunity cost (higher levels of working capital associated with less predictable cash flows); some represent a cost in management time and expertise, (for example, the execution and management of Transmission Use of Service (TUoS) and Distribution Use of Service (DUoS) agreements); and some represent a cost in management time (other regulatory obligations).

2.3. Why a customer would choose to hedge with a retailer

There are a number of reasons why a large customer would choose to hedge its wholesale electricity spot price risk with a retailer, including:

- Retailers aggregate individual customers' loads into a portfolio containing amounts consistent with the minimum required parcel for traded electricity derivatives (bulk purchasing) and, in addition, in managing multiple customers' electricity consumption, achieve some diversification benefits where customers' load shapes differ. A customer that hedges its own risks may be subject to significant risks from under- or over-hedging, depending on the size of its load and its load shape relative to the standardised characteristics of exchange traded and typical OTC contracts and, to the extent that its facilities display similar load shapes, receives no diversification benefit.
- Some retailers offer forward prices for a contract terms that may exceed the term of available forward prices in the publicly traded electricity derivative markets. Retailers offering 3 year contracts outside the NSW and Victorian regional electricity markets, for example, are "making a market", that is, they are offering a product that the customer would be unable to duplicate in the publicly quoted traded markets.
- The typical retail contract offers a load following hedge that for all large customers without very specific characteristics, offers a superior risk transfer than the alternative hedge products available, because it covers the customer in the event of load and load shape variations.

In addition to these benefits, a retailer provides the bundle of services described in Section 2.2.5 as part of the retail offering.

2.3.1. The important customer characteristics in replicating a load following hedge

If a customer is seeking to achieve an effective hedge in the traded markets – that is, one that provides similar cover to a load following hedge without material spot price exposure as a result of differences between the customer's load profile and traded market offerings (unders and overs) – then the customer needs to be:

- Sufficiently large that exchange traded contract minimum sizes represent a good match for the customer's annual load.
  - The available exchange traded contracts are standardised at 1 MW and not available in fractional sizes. An annual forward contract is equivalent to an annual throughput of 8,760 MWh. A 10 GWh commercial and industrial customer – that is, a customer at the low end of the common definition for a large customer – would achieve around 86 per cent hedge cover of its annual electricity consumption with a single contract: two contracts mean the customer would be over 70 per cent *over hedged* for its annual consumption. Depending on the customer's load shape, neither of these outcomes is necessarily consistent with being well hedged: a customer could retain significant peak exposure (under hedged), while being materially over-hedged during off-peak periods, if its load displays a typical working day/weekend pattern. A 35 GWh customer with a flat load (see below) could achieve a good match between the exchange traded contract and its hedged requirements, using 4 annual contracts.
  - Given the differences between regional spot and forward markets, if the customer has facilities in different regions, then each of the customer's facilities needs to reach the minimum contract size, as there is no ability to aggregate load across regions, without incurring significant additional risks from the differences in regional market behaviour.
- Predictable in its electricity consumption, with a predictable peak/off peak pattern, no relationship with weather and a very high level of predictability from day to day, allowing standard forward contracts to be used with little or no requirement for further hedging (no requirement for caps or weather hedges, for example) and very low, if any exposure to the cost of under- or over-hedging.
  - Customers displaying these characteristics – very large scale and flat and predictable load profiles – include a range of businesses with large scale energy intensive processes (smelting, metals manufacturers, some building materials, some food manufacturing processes and a number of water utilities).[13]
- If the customer's load shape is peaky – if, for example, the customer's usage is weather sensitive and increases with the temperature – then standard forward contracts will not capture the weather dependent nature of the customer's demand or the load/price relationship displayed by electricity spot markets. The customer may require a cap to reduce its exposure to high price events in the spot market, in

[13] Published material from the NGERS database provides some insight into those industries with very high total energy use and the relative size of different users. For example, the NGERS data demonstrates the very large difference between, say, Murray Goulbourn (food processing) at more than 10 times the total energy use of the National Australia Bank, see http://www.climatechange.gov.au/government/initiatives/national-greenhouse-energy-reporting/publication-of-data/~/media/government/initiatives/nger/data/NGER-Greenhouse-and-energy-information-2010-2011-3-PDF.pdf

addition to any forward contracts entered into. The minimum contract size for exchange traded caps is 1 MW and cap contracts are not available in fractional sizes.

- Customers displaying these characteristics – peaky or weather dependent load profiles – include a range of businesses with heavy usage during business hours or air conditioning driven requirements (banks, property portfolios, large retail chains), as well as food processors, and other manufacturers with variable manufacturing processes.

We believe the customers meeting these requirements for efficient, low cost management of their own hedging requirements – that is, very large users with flat and predictable load profiles – are relatively few in number and not necessarily typical of large commercial and industrial customers generally.

Alternatively, there are customers for which no financial hedge may be required. These customers' production processes are sufficiently flexible to allow the customer an active and rapid demand side response, allowing the customer to replicate a hedge position through the control of its production process. If the customer has a low cost to reducing or shutting down its production to reduce its electricity consumption *and* a rapid response time, then the customer can replicate the operation of a cap but at any *strike price* the customer chooses. We believe these customers represent a special case and are not typical of the majority of large customers.

The longer the lead time required to achieve a low cost reduction in electricity consumption, the less effective and the more expensive this strategy will be for the customer. Not all short term forecasts of high price intervals are followed by a high spot price and the longer the period between the forecast and the actual, the lower the accuracy of the forecast. A customer requiring significant warning to efficiently reduce its load – for example, because in rearranging its production mix, the optimal time for this to occur is the evening prior to the high price period – will incur the costs of changing its production mix on a large number of occasions relative to the number of high price events that occur. Further, the customer will be unlikely to be able to anticipate or respond in time to unexpected high price events following, for example, network failures.

2.3.2. Why you would choose one retailer only

Larger loads generally attract lower prices, so commercial and industrial customers with multiple sites or facilities within a region aggregate their facilities' electricity consumption and select a single retailer. In aggregating the customer's sites, the retailer hedges the total consumption in a given region in a single transaction, having taken account of diversification, if any exists, in the customer's load and between the customer's load and that of the retailer's other customers. It is common for customers with sites across multiple regions to contract each region with a separate retailer, as customers will not see any aggregation of their load across regions as a retailer is unable to hedge across regions with one price or approach.

The benefit of aggregation is highest for a large user with a large number of relatively small sites: a commercial and industrial customer with several large facilities may receive little or no additional benefit from aggregating the sites where each site is sufficiently large to attract lower prices and may benefit from some competitive tension in separately contracting its load for each site, rather than contracting the load in total.

At the site level, however, unless the site has multiple connections and the associated meters, splitting the load to introduce competitive tension is impractical in the absence of some agreed protocol about the basis for allocation of the load in a given period between the competing retailers.

2.3.3. Options available to commercial and industrial customers

In Section 3, we discuss the options available to any customer in either taking spot price exposure or hedging its load and the issues associated with each identified option, without restricting our discussion to customers with highly specific – and, we believe, uncommon – characteristics.

3. Available purchasing and contracting strategies to manage the risk of electricity spot prices

In this section we identify the spectrum of possible purchasing and contracting strategies, based on the level of price certainty required by the customer and the choice of intermediary. The strategies are compared with the default strategy – full spot price exposure – and we discuss the components of the wholesale electricity price achieved by and the risks associated with each strategy, as well as identifying the other issues entailed by each strategy, such as, in the case of the default strategy, AEMO membership. The discussion draws on our knowledge of market participants, including large users, to provide a qualitative guide to those factors we consider more important to large users' choices and those we believe are likely to be less important. Based on our knowledge of the market, we have also provided a qualitative assessment of the availability of each of the strategies by NEM Region.

3.1. The spectrum of possible approaches

Table 3.1 lists the spectrum of possible wholesale electricity purchasing approaches, from full spot price exposure to the construction or purchase of a generator, differentiating where appropriate, between strategies undertaken by the large customer itself (Strategies 1 to 6 and 13) and the same strategies, undertaken for the customer by a retailer.[14]

Choice involves trade-offs. In moving through Strategies 1 to 6, the customer achieves higher levels of *ex ante* price certainty, but pays a cost to reduce its spot price exposure and incurs additional costs – both direct and in management time and attention – in managing its hedge position and the regulatory requirements associated with membership of the pool and management of its financial derivatives. In Strategy 13, where the customer builds or buys a generator to provide its own needs, the customer can achieve long term price certainty,[15] although in doing so it also takes on the risks associated with an investment in a large long life capital intensive investment, in particular the risks of the capacity cycle and of technological change and replaces its electricity price risk with fuel price risk. Under certain circumstances, such as those currently prevailing in Eastern Australian gas markets, the customer may also face fuel contracting risk, that is the risk of being unable to contract or to contract for the desired term for the fuel required.

[14] Broadly defined, as in the glossary, to include any party with a retail license.

[15] Whether even a medium size large customer can do so at a competitive cost is a separate issue. Base and mid-load generation is subject to significant economies of scale, which mean that customers may have difficulty in accessing competitive costs where co-generation is not available or useful. Further, in regional areas, access to fuel may be an issue, as bottled gas and diesel are too expensive to allow for competitively priced electricity

Table 3.1 Possible wholesale electricity purchasing strategies: costs, risks and requirements, by management method

Strategy Description	Cost of electricity	Risks	Best suited to which customers? Additional costs/requirements
1. Full spot market exposure: **No retail intermediary/ customer registers with AEMO directly**	• Load weighted spot price for the relevant period. – The flatter the customer's load's behaviour, the closer the load weighted price to the time weighted price.	• *Effective cost* of wholesale electricity is unknown in advance. – However, depending on the predictability of usage and nature of manufacturing/process requirements, the customer may be able to manage its exposure and, in consequence, its price, by altering its consumption in advance of expected high prices/in response to actual market prices. • The price may not become more certain as time passes: high price spikes, even late in a year, can materially increase the total cost over the year.	Best suited to: • Customer able to pass through its electricity costs, ***or*** • Customer able to manage its exposure by altering its consumption in advance of expected high prices/in response to actual market prices. Additional costs/requirements: • AEMO registration costs • Additional working capital to meet AEMO Prudential requirements • Separate contracts, Transmission and Distribution, each potentially requiring additional prudential requirements • Customer appoints and pays for a meter data manager (MDM) • Some additional internal management requirements.
2. Spot market exposure, combined with $300 caps: **No retail intermediary/ customer registers with AEMO directly**	• Load weighted spot price for all trading intervals where price is below $300/MWh for the relevant period, *plus* • $300/MWh for all trading intervals covered by the cap where the price exceeds $300/MWh, *plus* • Cap premium, ($/MWh for every MW covered by the cap), usually payable in advance/at time of contracting.	• Effective cost of wholesale electricity is unknown in advance. • However, the maximum potential cost can be estimated with a higher degree of certainty, due to the removal of prices >$300/MWh. • There is still residual exposure to high spot prices: – where the level of caps purchased is insufficient to cover the customer's load at times of high demand. • The customer is exposed to the risk of the counterparty defaulting on the cap	Best suited to: • Very large commercial and industrial customers whose electricity consumption is above minimum exchange traded contract size. Desirably, the customer's consumption profile would not be weather sensitive, reducing the cost of cap(s) otherwise required. • All other customers may be required to use OTC market and pay a premium to contract at smaller than standard minimum quantities. Typical OTC contracts require **higher** minimum quantities than exchange traded contracts, although, unlike the exchange traded market, non-standard contracts

Strategy Description	Cost of electricity	Risks	Best suited to which customers? Additional costs/requirements
		payoff during periods of high prices. – The extent of this risk depends in part on the choice of market. The cost incurred in the event of a default is lower in the *exchange traded market*.	may be negotiated, at a cost. Additional costs/requirements • Where available, as for (1), above, ***plus*** – Australian Financial Services License (AFSL) required, with associated regulatory, capital and reporting obligations – Depending on the market in which the cap is purchased, additional working capital to meet margin costs or, possibly, prudential requirements to provide counterparty with confidence on credit exposure.
3. Spot market exposure, combined with *weather derivative* that pays off when temperature at defined location exceeds agreed level **No retail intermediary/ customer registers with AEMO directly**	• Load weighted spot price for all trading intervals for the relevant period, *plus* • Weather derivative premium ($/MWh), payable in advance/at time of contracting, *less* • Payout received from counterparty that has the effect of achieving the agreed strike price for all trading intervals where the weather derivative applies.	• Effective cost of wholesale electricity is unknown in advance. • However, the maximum potential cost in periods of extreme weather can be estimated with a higher degree of certainty. In this instance the customer is using a weather derivative as a substitute for a cap or other derivative product. The rationale for this is that spot prices are usually correlated with very high (or very low) temperatures, so a customer who purchases a weather derivative will purchase cover for very high or very low temperature days. • Weather derivative may not be available in the contract quantity required. • Customer remains exposed to high spot prices unrelated to extreme weather events, for example in the event of generator or transmission outages. • The temperature at the defined location (typically set for a given location in each	Best suited to: • Customers whose electricity consumption is highly weather correlated. Additional costs/requirements: • If available, then as for (1), above, ***plus*** – Spot price costs when high spot prices unrelated to extreme weather events – Spot price costs when the temperature at the defined location is not representative of temperatures across the region during a high price period. – If contract is a derivative, then Australian Financial Services License (AFSL) required, with associated regulatory, capital and reporting obligations – However, not required if weather contract entered into as an insurance contract.

Strategy Description	Cost of electricity	Risks	Best suited to which customers? Additional costs/requirements
		NEM region) may not be representative of temperatures across the region during a high price period. In this event, the weather derivative will provide no protection. • The customer is exposed to the risk of the counterparty defaulting on the cap payoff during periods of high prices.	
4. Part spot market exposure/part hedged or contracted **No retail intermediary/ customer registers with AEMO directly**	• Load weighted spot price for all trading intervals for unhedged load, *plus* • Hedged price, including risk premium, for all hedged/contracted load. In this instance the hedge could be a mixture of CfDs, caps, forwards or futures.	• Effective cost of wholesale electricity is unknown in advance • However, the degree of uncertainty is reduced in proportion to the extent of the hedged position. • The customer is exposed to the risk of the counterparty defaulting on the payoff during periods of high prices. – The extent of this risk depends in part on the choice of market. The cost incurred in the event of a default is lower in the exchange traded market.	Best suited to: • Very large commercial and industrial customers whose electricity consumption is significantly above minimum exchange traded contract size, to allow for the use of exchange traded instruments in part hedging the load. • All other customers may be required to use OTC market and pay a premium to contract at smaller than standard minimum quantities. Typical OTC contracts require *higher* minimum quantities than exchange traded contracts, although, unlike the exchange traded market, non-standard contracts may be negotiated, at a cost. Additional costs/requirements: • Where available, as for (1), above, ***plus*** – Australian Financial Services License (AFSL) required, with associated regulatory, capital and reporting obligations – Depending on the market in which the hedge is implemented, additional working capital to meet margin costs or, possibly, additional prudential requirements to provide counterparty with confidence on credit exposure.

Strategy Description	Cost of electricity	Risks	Best suited to which customers? Additional costs/requirements
5. Rolling portfolio of hedge contracts **No retail intermediary/ customer registers with AEMO directly.** **Hedge is implemented in OTC market, or, as markets incomplete and illiquid, as series 1 year rolling contracts.**	• Rolling average hedged/contracted price, including risk premium, *plus* • Any unhedged spot market costs incurred as a result of any mismatch between the hedged load shape and the actual load shape. – The customer may be over-hedged, that is, obliged to make payments on hedge contracts unrelated to its load, or under-hedged, that is, exposed to the spot market for load in excess of its hedge position.	• Relative to competitors with longer term hedge positions or contracts, when prices are rising or falling, subject to more rapid price adjustment and hence more risk. • In this example, the customer purchases a portfolio of contracts that may include CfDs, futures, forwards, caps and options, creating a portfolio of hedge contracts in a similar way to that which a retailer would manage its portfolio. • Unless the customer's load shape can be replicated using standardised contracts, then the customer is exposed to the risks of under- or over- hedging. Under-hedging leaves the customer with a residue of spot price exposure; over hedging leaves the customer with wholesale market exposure.	• Incomplete financial markets – in particular, very illiquid markets exchange traded markets more than 12 months out for base load contacts and the absence of activity in peak contracts – result in this strategy being implemented in OTC markets and/or effectively as a set of rolling 1 year contracts. Best suited to: • As for (4) above. Additional costs/requirements: • Where available, as for (1) above, ***plus*** – Australian Financial Services License (AFSL) required, with associated regulatory and reporting obligations – Some potential for cash flow mismatch as a result of margin requirements for contracts entered into in advance of current quarter.

	Strategy Description	Cost of electricity	Risks	Best suited to which customers? Additional costs/requirements
6.	**Fully hedged:** **No retail intermediary/ customer registers with AEMO directly**	• As for (5) above – Effective contract term/hedge duration may be longer than achievable under (5)	• Not equivalent to a *load following hedge* (see 12 below), except under rare circumstances that the customer's load is large enough to be hedged through standardised contracts, subject to little or no load variation and consistent in shape with available standardised products. (See discussion in Section 2.3) – Where these conditions do not hold, the customer is subject to the risks of under- or over-hedging. • "Cliff edge" re-pricing risk at end of hedge. – However, to the extent this is consistent with competitors, may not result in competitive (dis)advantage.	Best suited to: • As for (4) above. Additional costs/requirements: • As for (1) above, ***plus*** – Australian Financial Services License (AFSL) required, with associated regulatory and reporting obligations – Some potential for cash flow mismatch as a result of margin requirements for contracts entered into in advance of current quarter.
7.	**Full spot market exposure:** **Retailer intermediation**	• As for (1), above, *plus* • Retailer fee.	• As for (1), above.	Best suited to: • As for (1) above. • The choice of going direct vs. retailer intermediation is a function of load size and organisational preferences and capabilities. Additional costs/requirements: • Costs borne by retailer (retailer fee), including the cost of credit risk, and retailer margin.
8.	**Spot market exposure, combined with $300 caps:** **Retailer intermediation**	• As for (2), above, *plus* • Retailer fee.	• As for (2), above, with the exception of credit risk. – The retailer assumes credit risk in relation to the customer, but in selling the customer caps, the customer is exposed to no new credit risk.	Best suited to: • As for (2) above. • The choice of going direct vs. retailer intermediation is a function of load size and organisational preferences and capabilities Additional costs/requirements: • Costs borne by retailer (retailer fee), including the

Strategy Description	Cost of electricity	Risks	Best suited to which customers? Additional costs/requirements
			cost of credit risk, and retailer margin.
9. Spot market exposure, combined with weather derivative that pays off when temperature at defined location exceeds agreed level **Retailer intermediation**	• As for (3), above, *plus* • Retailer fee.	• As for (3), above with the exception of credit risk. – The retailer assumes credit risk in relation to the customer, but in selling the customer a weather derivative, the customer is exposed to no new credit risk.	Best suited to: • As for (3) above. • The choice of going direct vs. retailer intermediation is a function of load size and organisational preferences and capabilities. Additional costs/requirements: • Costs borne by retailer (retailer fee), including the cost of credit risk, and retailer margin. • Extent of protection provided by weather derivative matter of contracted terms. However, would anticipate that failure of derivative would be passed through to customer.
10. Part spot market exposure/part hedged or contracted **Retailer intermediation**	• As for (4), above, *plus* • Retailer margin, including contract premium for hedged component.	• As for (4), above, with the exception of credit risk. – The retailer assumes credit risk in relation to the customer, but in selling the customer a weather derivative, the customer is exposed to no new credit risk.	Best suited to: • As for (4) above. • The choice of going direct vs. retailer intermediation is a function of load size and organisational preferences and capabilities Additional costs/requirements: • Costs borne by retailer (retailer fee), including the cost of credit risk, and retailer margin. • Contract premium to cover possible risks, in particular load shape exposure for part hedged element.

Strategy Description	Cost of electricity	Risks	Best suited to which customers? Additional costs/requirements
11. Rolling portfolio of hedge contracts: **Retailer intermediation**	• As for (5) above, plus • Retailer margin, including contract premium.	• As for (5) above, with the exception of credit risk. – The retailer assumes credit risk in relation to the customer, but in selling the customer a weather derivative, the customer is exposed to no new credit risk.	Best suited to: • As for (5) above. • The choice of going direct vs. retailer intermediation is a function of load size and organisational preferences and capabilities. • However, the use of a retailer can, for a price, assist the issue of minimum traded contract sizes and market liquidity. Additional costs/requirements: • Costs borne by retailer (retailer fee), including the cost of credit risk, and retailer margin. • Contract premium to cover possible risks, in particular load shape exposure. • Retailers' willingness to offer longer terms and smaller contract quantities than available in publicly traded markets may make this a more viable strategy implemented through an intermediary than on a self-managed basis. • However, for the duration of the retailer relationship, no competitive pressure on retailer margin, as metering requirements make use of multiple retailers impractical.
12. Fully contracted (load following hedge): **Retailer intermediation**	• As for (6) above, ***plus*** – Effective contract term/hedge duration may be longer than achievable under (5)	• "Cliff edge" re-pricing risk at end of hedge. – However, to the extent this is consistent with competitors, may not result in competitive (dis)advantage.	Best suited to: • As for (6) above • However, the use of a retailer can, for a price, assist the issue of minimum traded contract sizes. In addition using a retailer will be able to provide a 'full' load following hedge with no 'overs or unders' risk. Additional costs/requirements: • Costs borne by retailer (retailer fee), including the cost of credit risk, and retailer margin.

Strategy Description	Cost of electricity	Risks	Best suited to which customers? Additional costs/requirements
			• Contract premium to cover possible risks, in particular load shape exposure.
13. Buy/build own generation	• Long term, substantially fixed cost of electricity, based on cost of construction. – Achieved cost, although subject to movements in response to fuel input costs, will be dominated by capital costs (interest and depreciation).	• Mismatch between the amount generated and the amount consumed by the customer would be subject to spot price exposure. • While not subject to level of variation associated with NEM wholesale market, costs may be higher from time to time to achievable cost in the NEM, representing a competitive disadvantage. • Fuel price risk and, depending on required fuel, from time to time, fuel re-contracting risk.	Best suited to: • Very large customers with access to fuel. Cogeneration, for example, is only viable with access to reticulated gas; bottled gas or diesel – the alternatives in regional areas – are too expensive to make cogeneration viable. Additional costs/requirements: • May not represent best use of scarce capital resources. • Available generators for purchase may exceed maximum size required, resulting in a need to form a consortium or, alternatively, assume pool price risk. • If built and financed by external party, long term contractual commitments required may represent significant barrier to contracting. • Suitable sites may not be available in the location. • There are economies of scale to generation. – Sharing a generator may provide the basis for achieving some economies of scale. However, even in industrial parks, unless the sites are immediately contiguous to the generator, then retail license may be required.

Alternatively, in theory at least, the customer could choose to implement one of Strategies 7 to 12 through a retailer. Depending on the extent of the risk transfer, the customer may pay:

- A fee indirectly related to the costs incurred by the retailer in managing the customer's position. Strategy 7, for example, involves no risk transfer and the services provided are primarily administrative, so we would anticipate the fee involved would be correspondingly low.
- A retail margin which, among other costs would include a contract premium related to the extent of the uncertainties associated with the risk transfer from customer to retailer. The less predictable the customer's load, the higher the contract premium could be expected to be.

Not all strategies are offered by all retailers and some strategies may not be offered in the precise form described. The rolling hedge strategy (Strategy 11), for example, where offered, is typically offered as a sequence of one year contracts rather than a bundle of overlapping multi-year contracts.[16] The offering is restricted to a small number of very large retailers and the customers that take up this offer are typically advised by an independent third party advisory firm providing energy market advice on the optimal timing of the future contracting decision.[17] Its equivalent, Strategy 5, may not be achievable as other than as a series of one year contracts outside NSW and (possibly) Victoria. Even in NSW, current exchange traded contracts for 2014 are showing very limited liquidity.[18] We are not aware of any customers that are implementing this strategy in the more liquid regional electricity derivative markets in NSW, Victoria or Queensland and we understand that the number of customers implementing this strategy through a retailer (Strategy 11) is very small.

Finally, the conditions that a customer's load requires to successfully and efficiently replicate a load following hedge without a retailer (Strategy 6) are so onerous as to exclude, in our view, most large commercial and industrial customers.

3.2. The limits to purchasing and contracting strategies in the NEM

In our judgement, there is a range of (overlapping) reasons why the full spectrum of strategies for large commercial and industrial electricity customers to manage their purchasing and contracting decisions may not be available. Key among the explanations are:

- High and unpredictable spot price outcomes
- Incomplete financial markets
- Low liquidity, available financial markets
- Market characteristics (standard contract size) designed for very large market participants

[16] In effect, in entering into a contract of this kind, the customer enters into a forward contract for the first period, and has a series of options relating to the time at which it enters into the further forward contracts required over the life of the contract.

[17] Retailers' AFSL typically do not allow the retailer to provide advice that could be construed as financial advice, such as on the optimal timing of the purchase of a forward contract or expected developments in the price of electricity derivatives.

[18] This may be a function of current political uncertainty relating to the future of a carbon price in its current form. On the other hand, liquidity in Australian electricity markets has shown a long term trend decline. See the discussion in Section 3.2.3.

- Limited number of intermediaries interested in dealing with customers' hedging requirements, particularly in smaller regional markets (South Australia and Tasmania)
- Significant regulatory and compliance burden for participants who proceed without an intermediary.

3.2.1. High and unpredictable spot price outcomes

As with other electricity spot markets, spot prices in the NEM are characterised by higher volatility than other commodity markets, and higher price events occur with a greater frequency than in other financial markets. Both of these characteristics are consistent with rational risk neutral customers, including sophisticated customers, taking insurance against the impact of high price events on their wholesale electricity costs. However, to the extent that these characteristics mean that market participants offering hedge contracts are effectively required to have a physical position in the relevant regional market to manage their own risks, then these characteristics are also inconsistent with the development of deep, liquid markets, which require the entry of third parties willing to take one or other side of a given contract, depending on their market view.

3.2.2. Incomplete traded financial markets

Not all of the product offerings a large customer requires to implement the strategies identified are available in traded electricity markets. For example, for a customer (or a retailer without its own generation portfolio) to implement a rolling hedge program, the customer would need to be able to enter into forward contracts for a proportion of its load on, say, a rolling three year basis. In the current exchange traded market, traded three year contracts are not available in any NEM region; in NSW and (possibly) Victoria, a customer might contract forward for 2013 and 2014; outside NSW and Victoria, a customer would have difficulty contacting for more than one year.

The incompleteness of the traded financial markets means that retailers offering customer contracts play an important role in making markets, that is, in offering a price for a contract term that might otherwise be unavailable.

3.2.3. Low liquidity, available financial markets

Even though traded volumes on the exchange traded market have increased significantly relative to the previous exchange traded market offerings, the bulk of the activity occurs in contracts relating to the current quarter (balance of the quarter) and, but to a lesser extent, in the quarters making up the next twelve months. The most frequently traded contract for any year is the Q1 (January to March) contract, which is also the period where spot prices are typically at their highest and most volatile.

The volume of reported OTC appears to be falling and, in addition, there has been a sharp reduction in the term of OTC contracts, with more than 80 per cent of reported contracts now having a term of less than 12 months.[19]

There may be specific reasons for the current absence of liquidity, relating to uncertainty about the future of the carbon price, given that exchange traded contracts include carbon in their prices. However, OTC contracts have been showing a long term decline in the proportion of contracts with a term of more than a year, which suggests that greater

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[19] Not all OTC contracts are reported. AFMA's annual survey captures reported trades by members, but excludes trades by non-members and unreported member trades.

certainty about the future of the carbon price may be insufficient to significantly increase liquidity in longer term contracts.

The most frequently traded region is NSW; the least traded is South Australia. No exchange traded contracts exist for Tasmania. One region's contract is not a perfect substitute for another and, depending on the extent of the price relationship between the two regions, may not even be a good substitute. For states where the spot price is correlated – Queensland/NSW or South Australia/Victoria – contracting in one state to manage price risk in another state presents a high level of inter-regional price risk (basis risk); particularly if prices in the two markets are likely to separate at times when high price events are likely to occur. Settlement Residue Auction revenues provide some limited hedge to basis risks between interconnected regions.

3.2.4. Market characteristics designed for very large market participants

A large customer may consume considerably more than 10 GWhs electricity a year, but a single exchange traded flat (peak and off peak hours) contract represents 8.7 GWh/year. The contract size is a function of the requirements of traditional wholesale market participants – retailers and generators – for whom larger contracts present economies in managing their hedging task. Any individual large customer using the exchange traded market will either face a mis-match (either under or over) between its load and its hedge position, effectively restricting the customer to the OTC market or the retail contract market. However, minimum contract sizes in the OTC market are now 5 MW, although, for a price, market participants may consider smaller volumes. Minimum contract sizes in the OTC market have increased over time; while standard exchange traded contract sizes represent the commercial judgment of the contract manager about the contract characteristics most valuable to its customers.

A customer that chooses to use the OTC or exchange traded markets also incurs a range of obligations relating to the valuation and reporting of the contracts it has entered into and may be covered by the recent ASIC proposals relating to the capital required by electricity derivative market participants.

3.2.5. Limited number of intermediaries interested in assuming risk, particularly in smaller regional markets

Providing a hedge to a large customer under the customary forward contract structure with volume flexibility transfers volume and price risk from the customer to the hedge provider. In a liquid market there are only likely to be a small number of parties willing to assume these risks; in smaller, less liquid markets, the number of willing participants may be very small. Finally, there may be no willing participants offering contracts at a price acceptable to large customers.

3.2.6. Significant regulatory and compliance burden for participants who proceed without an intermediary.

The requirements for participation in wholesale electricity markets and electricity derivative markets are significant and potentially onerous for an individual participant. There are a range of advisers who offer services including holding an AFSL license and undertaking the requirements of a Responsible Officer, as well as advisers who undertake regulatory and other compliance services. These services come at a cost and, over and above their direct cost, there are frictional costs to the management of a number of separate contractors and costs of co-ordination and supervision.

Further, over and above the number and extent of the requirements, the extent of the requirements has the potential to act as a barrier to entry, discouraging a large customer who might otherwise undertake its own electricity hedging from doing so.

The costs that a customer needs to incur in hedging its own load or paying an intermediary depend on the sophistication required and difficulty in managing the customer's load characteristics and required price certainty.

3.3. Assessing the availability of the different strategies

In Table 3.2 we have provided a qualitative overview of the availability of the strategies available by NEM region, considering:

- Availability (the existence of products across a range of product categories and periods) and market liquidity
- The characteristics of the customers required to successfully replicate retailer load following contracts
- The number and sophistication of the retail offerings available in the market.

We have assumed that:

- customers are unwilling to take on basis risk, that is, the risk of hedging in one NEM region for an exposure in another (less liquid) region
- customers who choose to take spot market exposure without any financial hedge and customers whose production processes are sufficiently flexible to allow the customer an active and rapid demand side response represent a special case and have been identified as such
- Similarly, customers whose load has the characteristics compatible with replicating a load following hedge in the financial market (large, weather insensitive and highly predictable) represent a special case and have been identified as such.

As Table 3.2 suggests, at a very high level the availability of the identified strategies differs from NEM region to NEM region and the customer best suited to particular strategies also differs from strategy to strategy. The smaller NEM regions offer customers relatively little flexibility in their choice of strategy, while the larger NEM regions can support a wider range of strategies, although for relatively short periods and, for the larger number of the identified strategies, not as standard customer options.

Table 3.2 Possible purchasing and contracting strategies: availability by NEM region and category of customer, schematic.

Strategy	NEM Region				
	NSW	Qld	SA	Tas	VIC
1.	For customers willing to take spot price exposure. May be able to manage exposure with changes to consumption				
2.	Available, but some customer characteristics better suited (willingness to take residual risks, scale)		Not available: low market liquidity		
3.					
4.					
5.					
6.	For customers with size, no weather sensitivity and predictability				
7.	Available, but not standard		Unlikely to be available		
8.					
9.					
10.					
11.					
12.	Available		Low availability/not all retailers offer		
13.	For customers willing to purchase a generator for whom this represents an economic use of capital				

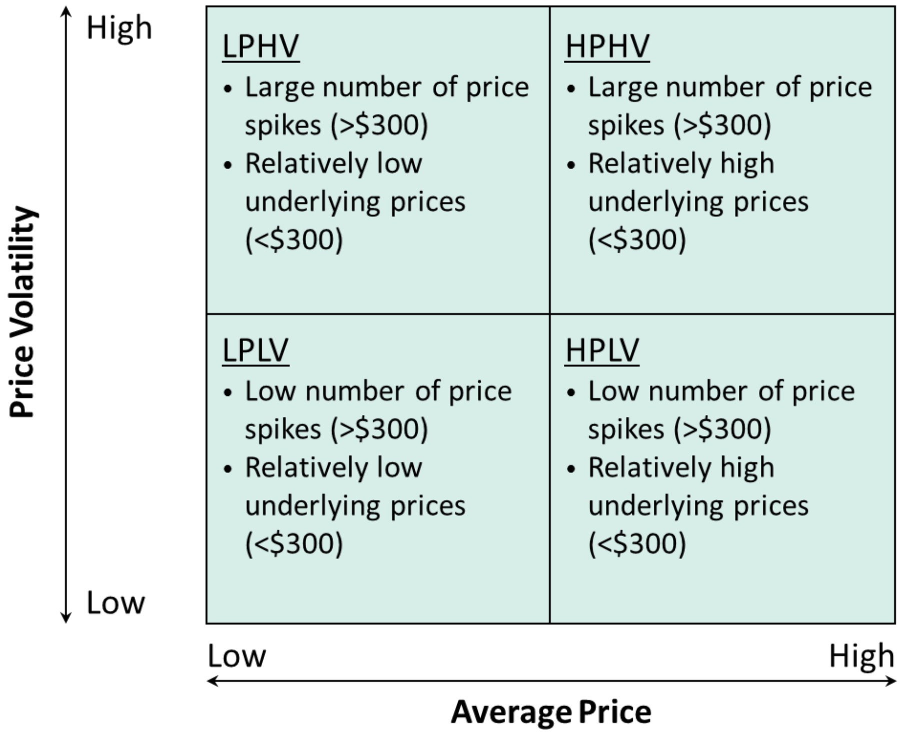
4. The Analytical Approach

In this Section, we detail our approach to the AEMC's requirements, our assumptions, the model used to produce the results and discuss the limitations of our approach in the application of our results to large commercial and industrial customers' experiences.

4.1. The Modeling Approach

The AEMC's intention was to explore the merits of a range of possible hedging strategies under conditions of price volatility and uncertainty and without reference to the impacts on any actual participants or to actual market prices that have occurred. In order to explore the robustness of the possible hedging strategies identified under a range of alternative market states, we identified four (4) different market states that we believed would have materially different implications for the hedging strategies to be tested. **Figure 4.1** illustrates the different states we chose – low price, low volatility (LPLV); high price, low volatility (HPLV); low price, high volatility (LPHV); and, high price, high volatility (HPHV).

Figure 4.1 Market States combining different price levels and different levels of price volatility: schematic



In defining these states, it was not our objective to represent all possible market conditions in the NEM, but rather as representing elements of a stress test. As an approach to stress testing, the market states capture the characteristics a large commercial and industrial customer might consider in evaluating a proposed hedging strategy. In addition, in defining these states and modeling them in the way we have chosen (see Section 4.2.1, below), the framework allows us to look at the impact on a given hedging strategy of the transition from one state to another, for example, in the extreme case from LPLV to HPHV and to compare the effects of strategies of different lengths – for example, the effect of a customer adopting a typical retail contract, which is to say, a load following hedge with a strategy combining pool exposure and caps – by considering the combinations of possible transition paths.[20]

Figure 4.2 and **Figure 4.3** show the lower and upper paths in the series of possible outcomes considered in our analysis.

In **Figure 4.2**, forwards, risk premiums, cap premiums and contract premiums for the following year are priced based on the current market state. Consistent with current contracting practice, large commercial and industrial customers negotiate with retailers from around 3 months in advance of the commencement of a new retail contract. None of the participants – customers or retailers – know which of the four possible market states will eventuate in the next period. In **Figure 4.2**, initial prices and all following years' prices are set in a relatively benign LPLV market. If one LPLV year follows another, then the initial prices will have been consistent with market performance, but if, for example, an LPLV year is followed by its opposite, an HPHV year, strategies with a *higher* fixed component will outperform all other strategies in that year.

In **Figure 4.3**, in contrast, in each of the years shown the market state is HPHV. In our analysis, participants learn: a HPHV market today means participants expect HPHV prices next year. If one HPHV year is followed by another and market participants share this expectation, then forward, cap and retail contract prices for that year will be broadly consistent with spot market outcomes. However, if an HPHV year was to be followed by a LPLV year, then strategies with a *lower* fixed price component will outperform all others in that year.

No market participant knows which market state will prevail in the following year. From a customer's perspective, we have evaluated the strategies included in this analysis on the basis that each state defined has an equal chance of occurring – the naïve weighting strategy discussed in Section 4.2.5.4. The customer compares the expected outcome of the strategy, based on the current year's conditions and the prices available, against the alternatives and the expected cost of pool exposure, taking into account the states defined. In comparing a multi-year retail contract with the alternatives, which are typically of a shorter duration, the customer considers the fixed costs of the multi-year contract with the possible paths available to it in managing its electricity price risk.

In Section 5.1, in discussing our results, **Figure 4.2** and **Figure 4.3** are repeated, using our results to illustrate a large customer's possible range of costs when unhedged. Later in Section 5, similar representations of the costs of customer's possible hedge strategies are provided.

[20] In the NEM, the typical large commercial and industrial contract would have a term of 3 or more years. However, in relying on published exchange traded contract prices, we are unable to replicate a 3 year contract. The results of analysis in Section **5**G would be similar if three year contract prices were available to us.

Figure 4.2 Possible electricity spot market states: priced in a repeated LPLV environment, partial schematic

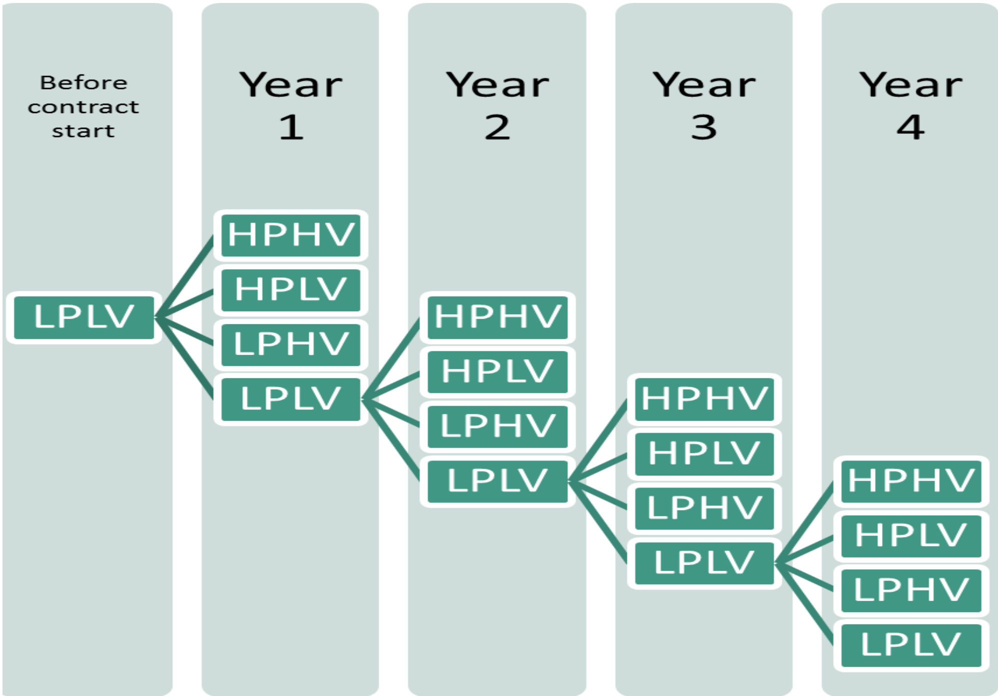
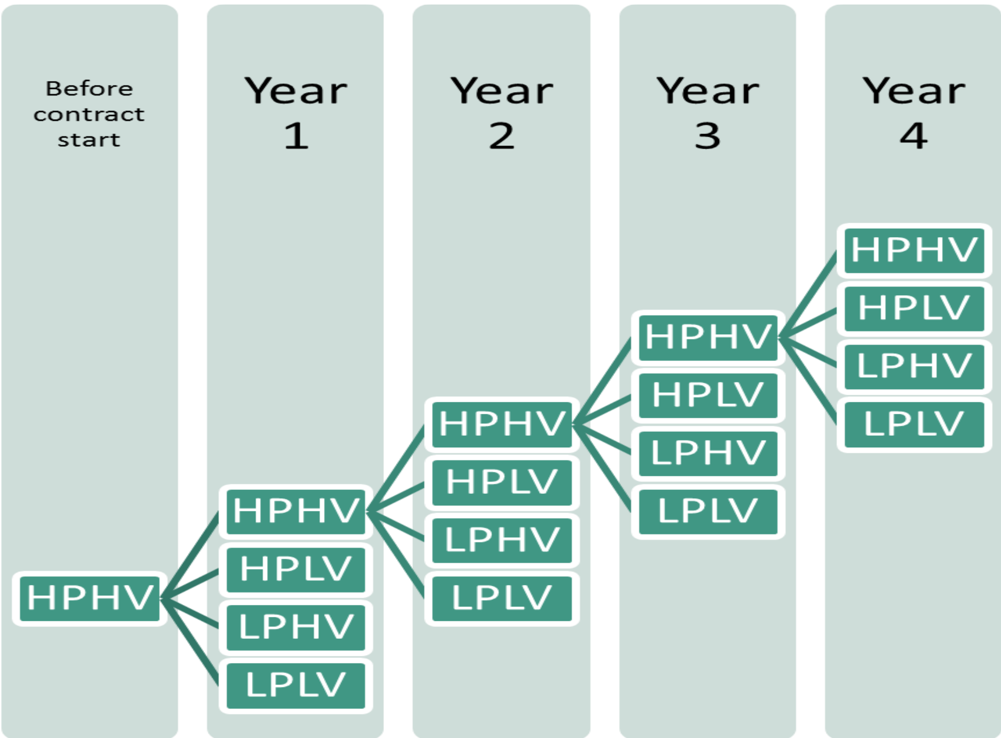


Figure 4.3 Possible electricity spot market states: priced in a repeated HPHV environment, partial schematic



To arrive at our results, we have:

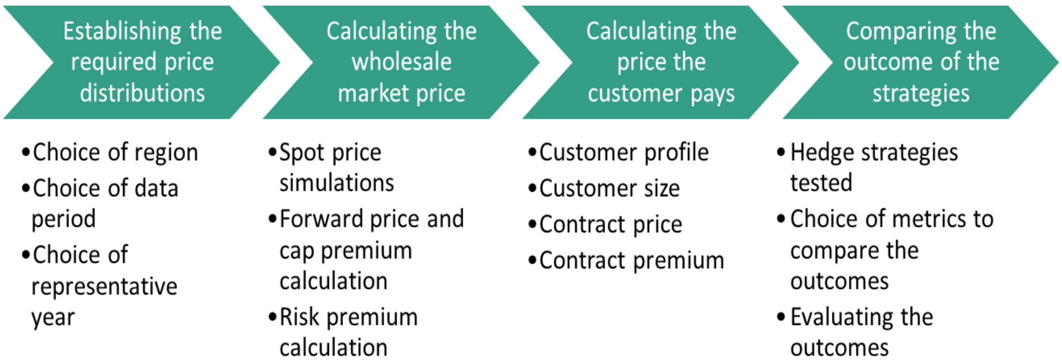
- derived the spot market characteristics for each of these spot market outcomes from twelve month periods in the South Australian and Victorian markets that represent the best fit for each case, considering the mean spot price and implied $300 cap prices (see Section 4.2.1.3).
- calculated the effective cost of the agreed strategies both as total costs and, where appropriate,[21] in $/MWh, taking account of both the expected and actual mean spot price and the potential cash flow at risk associated with the 95th percentile of the relevant spot price distribution. For those strategies that expose a consumer to very high spot prices in the event of a possible "worst case scenario", we have also considered the effect of a plausible "worst case scenario" effect on effective costs (see Section 5.4.2).

In undertaking this work, we have used SimEnergy (Appendix A) that uses the current consensus approach – Mean Reverting, Jump Diffusion or MRJD – to simulate spot market outcomes for each of the identified periods (Section 4.2.1.3) for the South Australian and Victorian regions (Section 4.2.1.1) and to calculate the effective cost of the strategies tested for each of the customer types considered (Section 4.2.4.1), taking into account any spot exposure, the costs of hedging strategies implemented and the pay-offs for each of the hedging instruments included.

4.2. Establishing the framework for the analysis

Figure 4.4 shows the organising framework we used in developing the components of our approach and arriving at our results. We have adopted the same organising approach in describing our assumptions and approach in the following material.

Figure 4.4 Schematic of analytical approach



4.2.1. Establishing the required price distributions

We have looked at spot market data for the South Australian and Victorian regions of the NEM for the period from Q1 2005 to Q2 2012 in choosing representative years and as the basis for our simulations of pool price outcomes for the regions chosen.

[21] We have not stated the results in $/MWh where, for example, we are discussing the average of a large number of cases and customer profiles, where electricity consumption differs by very small amounts between the different customer profiles. Similarly, we have provided information on the 95th percentile where considering an individual case or a limited number of cases for a single customer profile, but not when summarising a wide number of outcomes across profiles and strategies.

4.2.1.1. Choice of region

The AEMC was particularly interested in understanding the effects of the characteristics of the South Australian region on the results. Victoria was chosen based on the relationship with the South Australian region, in particular the shared weather patterns. Spot prices in the two regions demonstrate a high level of correlation. However, despite this strong relationship between the two regions, the behaviour of the two regional spot markets appears to differ markedly from period to period. (See Section 4.2.1.3, below.)

4.2.1.2. Choice of data period

Other work we have done suggests an increase in volatility around 2007 across the NEM, possibly now in the process of reversing. This observation was one reason why we adopted our analytical approach, compared with, for example, an approach that used simulated pool outcomes drawn from a longer time period. The period chosen corresponds to the period for which we have exchange traded contract data – important in the modeling of the risk premium included in forward prices – and omits Q3 2012, the first quarter of trading since the introduction of a carbon price, on the basis that we have no information at present that would allow us to understand the effects of the carbon price introduction's effects.

4.2.1.3. Choice of representative years

In **Table 4.1** the spot price performance for all rolling periods of 4 quarters in the period from the beginning of 2005 to the end of the June quarter 2012 have been ranked in order of Base Price – that is, the forward price consistent with spot prices under \$300/MWh for the period, assuming a zero risk premium – and then implied cap prices – that is, the break-even price for a \$300 cap implied by spot prices over \$300/MWh for the same period. The periods are described by the contract description for the exchange traded contract for the quarter beginning the rolling 4 quarters. In the table M2011, for example, refers to the four quarters commencing at the beginning of Q2, 2011 and ending at the end of Q1, 2012.

Representative years for each of the designated market states were then identified based on the price and implied cap price, representing volatility. In choosing the representative year for each of the defined states, we have tried to avoid extreme outcomes, particularly for HPHV and LPLV, where the results may have been skewed by a single, high priced event. In the South Australian region, where we identified competing periods for the choice of LPLV and HPHV, we have tested the pool price outcomes for the Test years to understand the possible sensitivity of our results to the choice of year.

The data was initially ranked on the South Australian region data; the Victorian data has been listed in the order determined by the South Australian rankings, although, contrary to our initial hypothesis, the consistency between the two sets of rankings is not high.

Table 4.1 Choice of representative years: rolling 4 quarter implied forward and cap prices, Victoria and South Australia regions, Q1 2005 to Q2 2012

Qtr	Base	$300 Cap	State	Qtr	Base	$300 Cap	State
	Victoria				South Australia		
U2011	27.29	0.00		U2011	30.26	1.34	
M2011	**26.70**	**0.09**	**LPLV**	**M2011**	**30.87**	**1.42**	**LPLV**
Z2011	35.33	0.65		Z2011	37.91	1.65	
H2005	26.26	1.28		H2005	33.58	2.71	Test LPLV
H2007	**63.49**	**8.33**	**HPHV**	**H2007**	**57.55**	**3.43**	**HPLV**
Z2006	60.11	7.78		Z2006	55.99	3.55	
U2006	54.95	8.49		U2006	51.71	4.09	
M2006	39.35	5.82		M2006	41.46	4.42	
H2006	34.16	5.31		H2006	38.71	4.75	
M2005	31.96	5.50		M2005	37.42	5.03	
U2005	32.52	5.79		U2005	37.79	5.53	
Z2005	34.59	6.49		Z2005	39.80	6.06	
U2010	27.15	1.94		U2010	32.68	7.02	
Z2010	28.03	1.94		Z2010	34.77	7.19	
M2010	30.89	5.59		M2010	32.94	7.24	
H2011	29.40	1.82		H2011	37.47	7.55	
H2010	34.56	9.51		**H2010**	**40.49**	**14.35**	**LPHV**
Z2008	37.87	7.03		Z2008	47.86	15.60	
M2008	45.03	7.62		M2008	53.91	15.97	
U2008	41.90	7.62		U2008	51.21	15.97	
M2009	33.53	5.84		M2009	55.88	26.56	
U2009	**36.38**	**9.58**	**LPHV**	U2009	55.40	26.86	
Z2009	36.69	9.58		Z2009	55.73	26.91	
H2008	40.26	2.15		H2008	66.55	28.39	
U2007	**46.77**	**2.19**	**HPLV**	U2007	73.64	28.57	Test HPHV
H2009	36.62	7.22		**H2009**	**60.62**	**28.74**	**HPHV**
M2007	58.15	5.16		M2007	81.61	28.83	
Z2007	42.47	2.75		Z2007	69.11	29.10	

Key: Exchange traded contracts are identified by a code identifying the expiry date. A contract identified by H ends at the end of Q1 in the nominated year; M, Q2; U, Q3 and Z, Q4. In the table above, M2011 refers to the four quarters commencing in Q2, 2011 and ending at the end of Q1, 2012.

The period nominated as LPLV is the same for both regions, but in all the other cases the 12 month period chosen as representative of a given market state differs between South Australia and Victoria. The period nominated as HPLV in the South Australian region was selected as HPHV in the Victorian region, while the HPLV period in Victoria is the Test HPHV period in South Australia.

The lack of the expected consistency, and, in particular, the differences in the period nominated as HPHV, between the two regions raises some interesting questions about market behaviour.

- The differences are inconsistent with a hypothesis that higher prices and/or higher volatility are driven by weather, as the two regions share a similar weather pattern.
- Similarly, the differences are inconsistent with a hypothesis that higher prices and/or higher volatility are a signal of an emerging capacity shortfall. If this were the case, you would expect to see the results cluster in date order, rather than the more random rank order displayed.

In Section 5.1, we look at the results, measured as customers' expected and 95th percentile spot market costs for the market states, regions and customer profiles used in the modeling. Section 5.4.3.1 looks at the difference that using the Test LPLV and HPHV representative years would have made to the results.

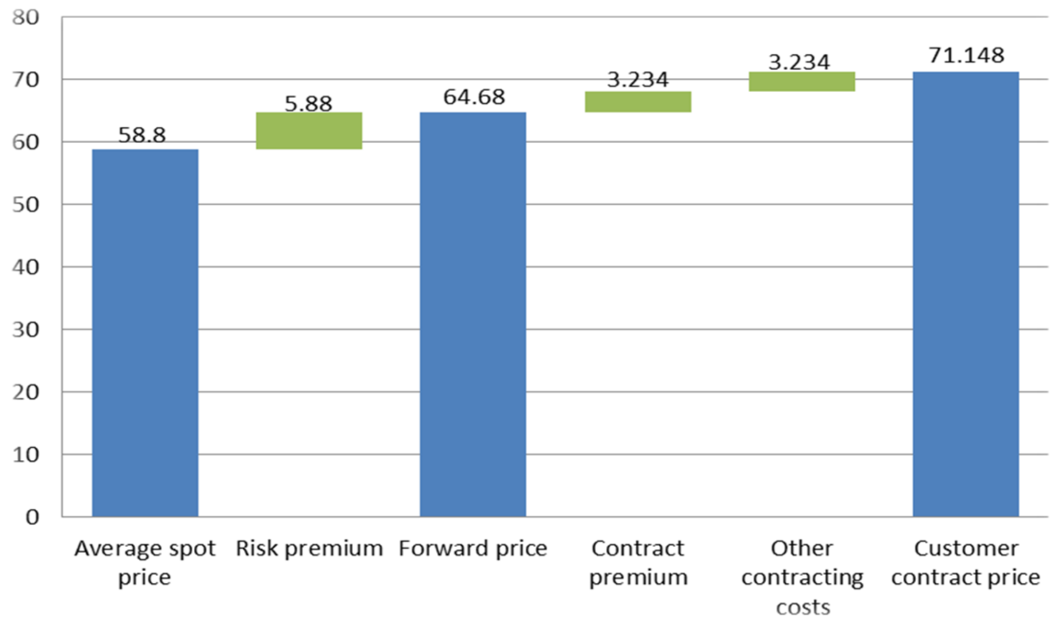
4.2.2. Calculating the wholesale market price

Figure 4.5 is a highly simplified version of the relationship between spot, forward and contract prices in the Australian electricity market. Appendix C discusses in more detail the current research findings in Australia and internationally about the direction of the relationship – whether from spot to forward or from forward to spot – the additional influences on the spot and forward prices and the research findings looking at the explanatory power of relationships between the two variables.

For this study, we have assumed that futures risk premiums for each of the identified states are mainly determined by the current level and volatility in the spot market as well as recent payoffs for futures and cap futures contracts (Section 4.2.2.2). A similar process was undertaken to calculate cap premiums. For the purposes of this analysis, contract premiums were calculated taking into account customers' load shapes; no allowance was made for other contracting costs in the full load following contract price.

We have reviewed the sensitivity of our results, reviewing the implied and calculated forward prices to check the consistency with our calculated prices and premiums, as well as reviewing the relative performance of the load following hedge – the only strategy to require contract premiums – to identify whether its relative performance was sensitive to the cost over and above the forward price.

Figure 4.5: Relationship between spot, forward and contract prices, schematic, $/MWh



4.2.2.1. *Spot price simulations*

We used SimEnergy that uses the current consensus approach – Mean Reverting and Jump Diffusion or MRJD – to simulate spot market outcomes for each of the identified states for the South Australian and Victorian regions, drawing on the spot price outcome in the representative year. A thousand simulations of the spot market price were performed for each strategy and customer profile.

SimEnergy was also used to calculate the effective cost of the strategies tested for each of the customer types considered, taking into account any spot exposure, the costs of hedging strategies implemented and the pay-offs for each of the hedging instruments included.

4.2.2.2. *Forward and cap prices*

Given the extremely volatile behaviour of electricity spot prices in Australia that are considered as being significantly more volatile and spike-prone than other comparable electricity spot markets (Higgs and Worthington, 2008), market participants might be expected to hedge spot price risks at least partially by entering electricity derivative contracts such as forward, futures or cap electricity futures contracts. The non-storability of electricity limits the standard no-arbitrage approach in modeling the prices of such derivative contracts, since inventories cannot be used to smooth out electricity supply and demand shocks. Therefore, the dynamic relationship between electricity spot and futures prices reflects expectations about future supply and demand characteristics for electricity as well as risk aversion amongst agents with heterogeneous requirements for hedging the uncertainty of future spot prices (Bessembinder and Lemon, 2002; Shawky et al., 2003; Longstaff and Wang, 2004).

$$F_{t,T} = E(S_T) + PREM_{t,T}$$

The observed futures price in the market can then be determined as the expected spot price during the delivery period plus an ex ante risk premium. The expected spot price for the delivery period may be based on historical observations for the same delivery period in previous years, current spot price and volatility levels in the market as well as additional information available to market participants that will help them to determine future price levels and volatilities in the spot market (e.g. information about capacity constraints, weather patterns, demand etc.). The risk premium, i.e. the difference between forward prices – forwards, futures or caps – and expected spot prices can be interpreted as compensation for bearing the spot price risk.

For the Australian electricity markets one would generally expect to find a positive risk premium for futures contracts,

$$PREM_{t,T} = F_{t,T} - E(S_T) > 0$$

However, like in many other financial markets, risk premiums in Australian electricity markets have been found to vary significantly through time, see e.g. Handika and Trück (2011). Reasons for this are the strong variation in price levels and volatility for different periods of time, as well as changing expectations of market participants about realised spot prices in upcoming periods.

While there is only a very limited number of academic literature on Australian electricity derivative contracts, in empirical studies the majority of authors seem to find positive risk premiums in electricity futures markets. (See Appendix C for further details). Therefore, on average, futures prices at the time when the contract is entered are expected to be higher than expected spot prices during the period of delivery. Similarly, market quotes for caps are expected on average to be above the realised payoff for these products at the time the contract is entered into.

As pointed out in the literature, there is often a significant difference between expected spot prices for the delivery period and observed futures quotes for this period. Therefore, risk premiums need to be considered when evaluating possible risk management strategies for large customers who might either buy these contracts themselves or deal with retailers who will hedge their risk using derivative contracts and pass the costs of hedging on to their customers.

4.2.2.3. Risk premium calculation

The risk premium – the difference between the forward price and the expected spot price – can be interpreted as compensation for bearing spot price risk (Bessembinder and Lemmon, 2002; Longstaff and Wang, 2004). The question what determines this premium has been thoroughly discussed in the literature on electricity markets (see e.g. Bessembinder and Lemmon, 2002; Longstaff and Wang (2004); Hadsell and Shawky (2006); Diko et al. (2006); Bierbrauer et al. (2007); Benth et al. (2008), Daskalakis and Markellos (2009); Redl et al. (2009)).

Existing studies (see Appendix C for further details) suggest that the forward premium can be modelled as being dependent on the mean price, the volatility of realised electricity prices and/or electricity demand. Further, extreme outcomes such as price spikes also have an impact on the magnitude of the risk premium (Redl and Bunn, 2011).

The maturity or time to delivery of the derivative contracts also seems to be an important factor: as pointed out by Benth et al. (2008), economic intuition might suggest long-term negative or zero risk premiums while short-term risk premiums (up to three months) are expected to be positive. The reasons for this are that long-term contracts with maturities greater than several months may be used by producers to hedge their future electricity production. Producers might be willing to accept prices lower than the actual expected spot price in order to guarantee that the produced electricity can be sold in the market. Such behaviour could result in negative long-term risk premiums. On the other hand, in the short-term, retailers or consumers aiming to hedge the risk of price spikes might be willing to pay an additional premium for locking in prices and avoiding extreme price outcomes and costs.

Also, as suggested by e.g. Handika and Trück (2011), there is strong seasonality in observed risk premiums for Australian electricity forward markets, while realised risk premiums in the market show extreme variation through time. They also suggest that average realised risk premiums in Australian regional markets are positive indicating a tendency for futures prices to overstate average spot prices during the delivery period. Their results also suggest that observed risk premiums are significantly influenced by historical spot price behaviour and can at least partially be explained by spot price levels and variables such as the standard deviation, variance, skewness and kurtosis of historical spot prices. However, their results also show that the sign of the average risk premium is also dependent on the considered quarter: for Q1 base load futures contracts, average premiums were highly positive in all markets, while the average premiums were found to be slightly negative for Q2 contracts.

Therefore, following the literature, in our model we consider realised electricity spot price levels and their volatility and also seasonality, considering the quarter referring to the delivery period of the considered cap and forward contracts. We also take into account the maturity of the contracts, i.e. the remaining time until the beginning of the delivery period of the contract. As mentioned above, the literature suggests that risk premiums in electricity markets may also be dependent on the remaining time until the start of the delivery period.

Futures prices are defined as the sum of the expected average spot price during the delivery period – for caps, the expected cap payoff during the delivery period – plus the risk premium. We model futures and, in a separate model, cap prices, as a function of the following variables:

- the current spot price level
- volatility in the spot market
- realised payoffs for futures and cap contracts referring to the same quarter in the previous year.

By using these variables, we assume that when pricing futures contracts, market participants take into account information about the current price level and volatility in the spot market as well as information about historical payoffs for futures and cap contracts dating further back in time.

To take into account the remaining time to the beginning of the delivery period, we estimate separate models for Q1, Q2, Q3, Q4 futures and cap futures contracts in T+1 as well as for the Cal Year Strip futures contract in T+2.

In this way we are able to estimate appropriate futures quotes for the representative LPLV, LPHV, HPLV, and HPHV states in the South Australian and Victorian markets. For further details on the estimated models, see Appendix C.

The estimated futures and caps prices are shown in Table 4.2 following. The results clearly illustrate the impact of (current) spot price and volatility levels in the market on the futures quotes. Generally, during the high price regimes (HPLV and HPHV), futures

Table 4.2 Estimated forward and cap prices, Victoria and South Australia, $/MWh

		LPLV	LPHV	HPLV	HPHV	LPLV	LPHV	HPLV	HPHV
		Victoria				South Australia			
Futures	**Q1 T+1**	73.50	76.56	92.72	105.43	56.55	75.32	120.91	108.72
Futures	**Q2 T+1**	60.54	56.85	72.48	93.57	47.09	47.09	79.15	49.48
Futures	**Q3 T+1**	62.57	58.24	88.48	88.48	53.73	46.50	76.08	45.43
Futures	**Q4 T+1**	60.97	62.70	74.29	74.29	57.57	51.29	66.34	63.92
Futures	**Cal T+2**	63.02	68.15	77.30	80.01	54.72	57.01	64.47	70.46
$300 Caps	**Q1 T+1**	17.83	24.06	24.59	26.52	24.75	27.95	37.79	44.58
$300 Caps	**Q2 T+1**	2.94	3.18	5.94	6.56	3.51	1.55	3.38	2.00
$300 Caps	**Q3 T+1**	3.56	3.71	6.81	6.64	4.00	4.31	4.50	4.18
$300 Caps	**Q4 T+1**	2.76	5.32	5.73	4.30	5.13	7.71	7.75	7.75

quotes for quarterly contracts in T+1 as well as yearly contracts in T+2 are higher. However, the results also illustrate how market participants take into account historical information about realised payoffs from futures and cap contracts dating further back in time. For example, for South Australia, Q2 and Q3 futures quotes for T+1 are significantly lower for the considered HPHV state (between $30 and $35) than for the HPLV regime (between $60 and $65). While one would normally expect to observe even higher futures quotes under a HPHV regime than under a HPLV regime, as it is observed for the market states considered in Victoria, this illustrates that not only most recent observations In the spot market are relevant for expected future spot prices, but also historical price levels for the same quarters in previous years.

4.2.3. Adjustment for the Carbon Tax

To better represent current prices including the carbon tax component, all South Australian prices have been increased by $14.95/MWh and all Victorian prices have been increased by $27.60/MWh, reflecting the states' respective emission coefficients. Both estimated futures and electricity spot prices have been adjusted. The adjustment has only a very small effect on the characteristics of the respective price distributions.

4.2.4. Calculating the price the customer pays

4.2.4.1. Customer size and load profiles

The customer profiles used are:

- <u>Flat</u>: load factor of 95 per cent, with random variation of plus/minus 10 per cent between the maximum and minimum load.
- <u>Summer peaking</u>: very high volatility in the first quarter (Q1) of the year. We have used the South Australian regional profile, scaled to a customer of 30 GWh as the basis for the profile.
  - The choice of the South Australian regional profile exaggerates the additional costs and risks we would anticipate a large commercial and industrial customer would experience, as maximum daily summer demand is over 65 per cent higher than average summer (working day) demand.
- <u>Winter peaking</u>: peaks in the second and third quarters of the year with high volatility associated with the peak. We have used the Tasmanian regional profile, which is winter peaking, scaled to a customer of 30 GWh as the basis for the profile.
  - We acknowledge that, in using the Tasmanian profile, any load/price relationship that might follow from having one or more large customers with this consumption profile operating in either the South Australian or Victorian markets will not be taken account of in our analysis. However, over the period of our analysis, maximum consumption in both markets occurred in the summer, so we believe this issue is unlikely to have had a material effect on our results.

4.2.4.2. Contract premium calculation

The contract premiums applied to the combined forward prices of the hedge products used to produce a load following hedge are based on the ratio of demand weighted prices in the relevant region to time weighted regional prices in an HPHV state, calculated by month from January 2007 to December 2011. The HPHV state was chosen consistent with the role of the contract premium, which is designed to compensate the retailer in the event that the customer's load increases during high price periods, resulting in the hedge used being partly ineffective. The minimum demand weighted to time weighted ratio was applied to the flat profile, the median to the winter peaking customer and the average to the summer peaking customer. These values are not inconsistent with our understanding of load risk premiums applied to large commercial and industrial customers.

Table 4.3 Calculated Contract Premiums, by customer profile and NEM region, $/MWh

Customer profile	Victoria	South Australia
Flat	1.02	1.02
Summer	1.08	1.15
Winter	1.04	1.07

However, these values are not the premiums that would result from a calculation using the specific customer profile chosen to calculate the ratio the load weighted to time weighted price for that profile. If we had used the load weighted price associated with the summer peaking profile chosen, then the premium applied would have biased the results against load following contracts.[22]

We have undertaken a limited amount of testing to identify if our results were sensitive to the contract premium calculated. Our results suggest that load following contacts are, without exception, the most expensive hedge of the strategies we considered, taking into account only the expected cost. The difference to the second most expensive hedging strategy may be sensitive to the calculation methodology, but ranking of the strategies is unlikely to be.

4.2.4.3. Contract price calculation

We have matched the customer profiles with the quantity of exchange traded base load and peak forwards and caps, in the amounts required to provide a good hedge for the customer load, including the optionality in the summer and winter loads. We have used two decision rules across all customer types:

- Hedge to average demand, and
- Cap to the maximum demand.

In following these rules, we undertook a very small number of alternative calculations to consider the preferred combination of cap contracts, without seeking to optimise the outcome for the lowest cost.

Where required, we have used partial contracts, reflecting a retailer's ability to maximise the value of the hedges it purchases across a portfolio in contrast to a typical customer's inability to do so. The cost of that portfolio, expressed in $/MWh, was multiplied by the appropriate calculated contract premium in Table 4.3 to arrive at the retail contract price for the load following hedge for each customer type in Victoria and South Australia.

[22] Our results conclude that for summer peaking customers load following contracts are materially more expensive than the next best alternative, progressive hedges. The extent of the differential may be a result of the extreme nature of the profile chosen. See Section 5.3.3.

4.2.5. Comparing the outcome of the strategies

4.2.5.1. Hedge strategies tested

We have compared the unhedged spot price outcome for each customer profile with the effective costs – that is, the costs considering any spot price exposure, the cost of the hedging instruments, the payoff from any hedges, the costs (benefits) of over- or under-hedging, where relevant, and the contract premium – of the following strategies:

- Spot price exposure combined with $300 caps: the flat and winter peaking customer profiles assume 1 by 1 MW cap contract, while the summer peaking profile is assumed to buy 2 by 1 MW cap contracts.
  - At these levels, the customer may not be optimally hedged, but the inability to hedge to an optimal level where that level would involve a fraction of a standard contract in the exchange traded market is an important restriction on customer's ability to implement its desired risk management strategy.
- Part hedge, part spot exposure: the customer purchases 2 by 1 MW base load futures contracts (swaps) and is pool exposed for the remainder of its load.
- Progressive hedge strategy: the customer hedges 50 per cent of its load every year for the next two years, purchasing 2 by 1 MW base load futures contracts (swaps).
  - In considering the results of this strategy, it cannot be scaled to any size commercial and industrial customer. Considering the customer's annual load, the customer is over-hedged by around 17 per cent, reflecting the inability to transact in fractional contracts in the exchange traded market. A customer half the assumed size (consuming 15 GWh/year), would be over-hedged to a similar amount implementing the strategy by purchasing 1 by 1 MW base load futures contract for each of the next two years, but a customer with, say, 25 GWh/year, would be significantly under-hedged with 2 contracts. In this latter case, we would expect the customer's costs to be higher, given the higher spot price exposure.
  - We acknowledge that the difficulties in the implementation of this strategy in practice, in particular where the exchange traded market is insufficiently liquid outside the immediate four quarters following the current quarter, mean that it is more a theoretical rather than a practical risk management approach.
  - Further, for customers towards the smaller end of the large commercial and industrial customer classification, this strategy could not be undertaken in the exchange traded markets (standard contract sizes are too large) or without some penalty in the OTC market, where typical contract sizes are even larger.[23]
- Full load following hedge: the customer has a two year full load following contract with a retailer, the price for which is calculated using exchange traded futures and cap prices for fractional contracts where required, with the addition of a contract premium relating to the customer's load profile.
  - The choice of a two year contract is a reflection of the liquidity of the exchange traded markets. In the South Australian market, a two year contract based on exchange traded instruments may be difficult, given the very low level of liquidity

[23] For this and other hedge strategies that rely on exchange traded products, we have taken no account of the cash flow implications or the potential accounting treatment of the derivative contracts where there is a mismatch between the customer's load profile and the profile of payments received from the derivative contract.

in that market. We have chosen to rely on the exchange traded market because prices can be reliably observed. We acknowledge, however, that in doing so, customers' hedging strategies modeled may be less flexible and/or shorter in duration than the strategies available in the OTC market or through sophisticated retailers.
  - In practice, we expect retail margins to exceed the contract premium applied. The contract premium does not provide for retail costs unrelated to the customer's load shape or retailers' profits.
- Load curtailment: the customer is assumed to be able to reduce its load by 50 per cent immediately in response to spot prices reaching $150/MWh and to revert to full consumption immediately on spot prices falling below $150/MWh. Any cost the customer incurs in deferring production is not included in the effective cost of this strategy.
  - We acknowledge that the customer's instantaneous adjustment represents an extreme case of this strategy. The longer the lag time required between forecast prices and actual prices for the customer to adjust production, the less valuable this strategy will be; either the customer will be required to defer production more often and for longer periods than required by actual high price periods or the customer will, from time to time, be unable to respond sufficiently rapidly to avoid high prices.

4.2.5.2. Choice of the metrics to compare the outcomes

In comparing the performance of the strategies tested, we have compared:

- The expected cost of the customer's electricity consumption, measured as the expected (average) cost of the strategy for each customer profile for the total number of cases tested with the expected cost of that customer's spot price exposure, taking into account the four market states, LPLV, LPHV, HPLV and HPHV.
  - For each customer profile, this means that the value of progressive strategy was calculated for 64 combinations, all of the possible combinations of a two period strategy, where the first year and second years could be one of the four market states, LPLV, LPHV, HPLV and HPHV.
- The risk of the cost for a particular strategy being materially higher than the expected cost, measured by the cost of the strategy at the 95th percentile
- The performance of the strategy in the event of a "worst case scenario" case.

In comparing strategies, we have referred to a strategy as either *superior* or *preferred.*

- A strategy is regarded as *superior* where for a similar cost it offers a materially higher lower level of risk for the customer.
- A strategy is regarded as *preferred* where, for a small additional cost, the customer can achieve a materially lower level of risk.

4.2.5.3. Adding a "worst case scenario"

The decision to compare the strategies at the 95th percentile underestimates the value of certain risk management strategies, where the strategy provides protection against all high price events. We have tested the strategies by including a "worst case scenario" based on pricing behaviour that goes close to triggering an administered price period (APP). An APP is triggered when the sum of the spot prices in a single region for the previous 336 trading intervals (seven days) reaches the cumulative price threshold (CPT), currently $193,900. This is equivalent to an average spot price of$577.08/MWh over the previous 7 days.

Based on our review of recent high price events discussed in previous State of the Energy Market reports, the "worst case scenario" defined skirts an APP without actually triggering it over a three day period.

4.2.5.4. *Our evaluation of the strategies: the naïve weighting strategy*

No market participant knows which market state will prevail in the following year. From a customer's perspective, we have evaluated the strategies included in this analysis on the basis that each state defined has an equal chance of occurring – the naïve weighting strategy. The customer compares the expected outcome of the strategy, based on the current year's conditions and the prices available, against the alternatives and the expected cost of pool exposure, taking into account the states defined. In comparing a multi-year retail contract with the alternatives, which are typically of a shorter duration, the customer considers the fixed costs of the multi-year contract with the possible paths available to it in managing its electricity price risk.

Looking at our results in total, we have an advantage over the customer in that we can and have included the results of a very large number of permutations and combinations of the four defined market states and our initial discussion of our results in Section **5** is based on the average outcomes of all the tested strategies in all the tested combinations. In Section **5**, we discuss some of the implications of individual results.

4.2.5.5. *Stress testing*

In a number of areas, our assumptions significantly depart from conditions that market participants could expect to replicate. We have tested our results to identify where:

- Our assumptions – risk premiums, for example, or contract premiums – would, if amended, change the preferred strategy
- If there were competing possibilities, our results were sensitive to our choice of representative year
- Our truncating the distribution of possible spot price outcomes undervalues a particular hedge strategy, by testing a "worst case scenario" in a limited number of cases.

4.3. The Limitations of our Analysis

- Our modeling is based on a customer that annually consumes 30 GWh/year electricity. As a result, some strategies are available to this customer that would not be available to the typical large commercial and industrial customer implementing its own risk management approach.
- We assume that forward prices for the following period(s) are set on the basis of spot prices in the current period. The basis for the forward prices used is discussed in Appendix **C**.
- Forward prices including risk premiums have been modeled by as a function of: the current spot price level; volatility in the spot market; and, the last realised payoff for the futures and cap contracts referring to the same quarter in the current year. This approach is discussed in Appendix **C**.
- We have relied on the exchange traded market as a basis for the hedging strategies implemented. The issues associated with this assumption are discussed in Section 4.2.2. As a result, our calculation of the relative merits of the alternative strategies is

likely to be conservative, in that it will underestimate the cost of hedging instruments. In addition, to the extent that the exchange traded market is less flexible than the over-the-counter market, contracting only for standard contracts, our approach takes account of the issues even very large users would experience in managing their electricity price risk directly.

  - This is a particular issue in the case of the progressive hedge. In Section 3 we have argued this strategy would be difficult for a typical commercial and industrial customer to achieve even in the NSW or Victorian markets, which are the most liquid in Australia, and unachievable in South Australian. In implementing this hedge, we have assumed a price can be obtained for a two year forward in any state of the market. Further, our assumption about the customer size means that the customer can implement this strategy with a rolling series of forward contracts. A smaller commercial and industrial customer would not have the same opportunity unless it contracted through a retailer or in the OTC market directly.

- We have modeled only that element of contract premiums that relate to the customer's load shape. To this extent, the costs of a retailer intermediated strategy are lower than we would expect contract premiums to be. The significance of this issue is discussed in Section 4.2.4.
- In our analysis, we assume that large customers evaluate alternative hedging strategies and enter into contracts relevant to their hedging strategy during the last quarter of each calendar year; prices for futures or cap electricity futures contracts are estimated only for that period.
- In evaluating the customer's decision under conditions of uncertainty, we have used a naïve weighting scheme of equal weights for each of the four distinct spot market outcomes to represent the uncertainty of a particular market outcome in any period. The implications of this weighting scheme are discussed in Section 4.2.5.4.
- In calculating the "at risk" component of the hedging strategies reviewed and the alternative, unhedged spot price exposure at the 95th percentile, we have ignored the potential for those rare events to result in very significant costs to electricity spot market participants with spot price exposures, underestimating the value of those risk management strategies that provide protection against rare, very high price events. The "worst case scenario", discussed in Section 4.2.5.3 and **5.4.2**, is designed to address this limitation.

5. Why hedge? Our Findings

In this section we discuss our findings on the relative merits of the hedge strategies considered under a range of market conditions for different customer profiles. We begin by discussing the pool price outcomes for the customer profiles tested under the 4 market states chosen – HPHV, HPLV, LPHV and LPLV– and the implications of the pool price outcomes for customers' preferences. In our view, unless the customer is able to pass through the full range of its electricity costs or is able to costlessly and effectively manage its load so as to avoid high pool prices, customers will prefer hedging to the alternative.

Before considering our results, we discuss our approach to comparing single and multi-year hedging strategies. We then look at the preferred hedging strategies, taking into account all the potential cases we have modeled. Our results suggest that, unless the customer falls into one of the two rate categories above – full pass through or costless demand reduction – a higher level of hedging will be preferred to a lower level. Finally, we review the results of our sensitivity tests. In looking at our "worst case scenario", our conclusions reinforce our earlier finding: if a "worst case scenario" occurs, then the higher the pool exposure, the higher the customer's costs are likely to be.

5.1. Why hedge?

5.1.1. Differences in the outcomes from market state to market state

Figure 5.1 and Figure 5.2 show the distribution of a summer peaking customer's spot market costs in the South Australian pool for an LPLV year and an HPHV year resulting from our modeling. The customer's mean (expected) cost in an LPLV year is $1,426,766, while in an HPHV year the customer's mean costs is $2,581,830. Unsurprisingly, given the characteristics of the years chosen as representative of the market states, the customer's costs vary significantly between the two market states. The distribution of the results is significantly wider in the HPHV case, with just over $1 million between the lowest and highest outputs of the model, compared with just over $30,000 between the lowest and highest results in LPLV.

The results also support the hypothesis that different market states can be identified. The two distributions – representing the extreme cases for the market states used in this study – do not overlap at all.

Figure 5.1 Distribution of spot price outcomes, summer peaking customer, LPLV, SA, $

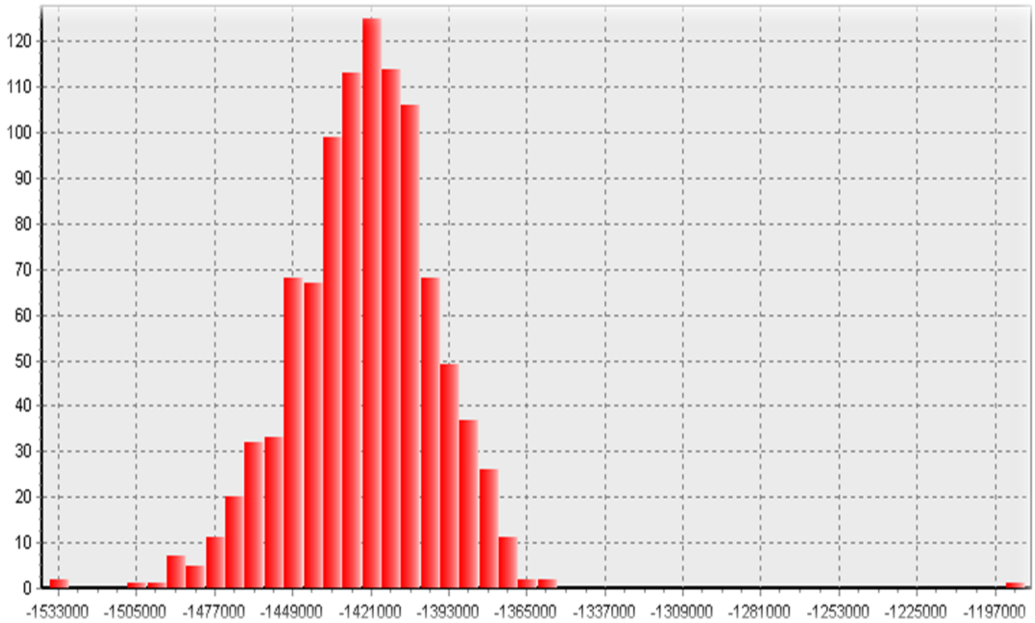
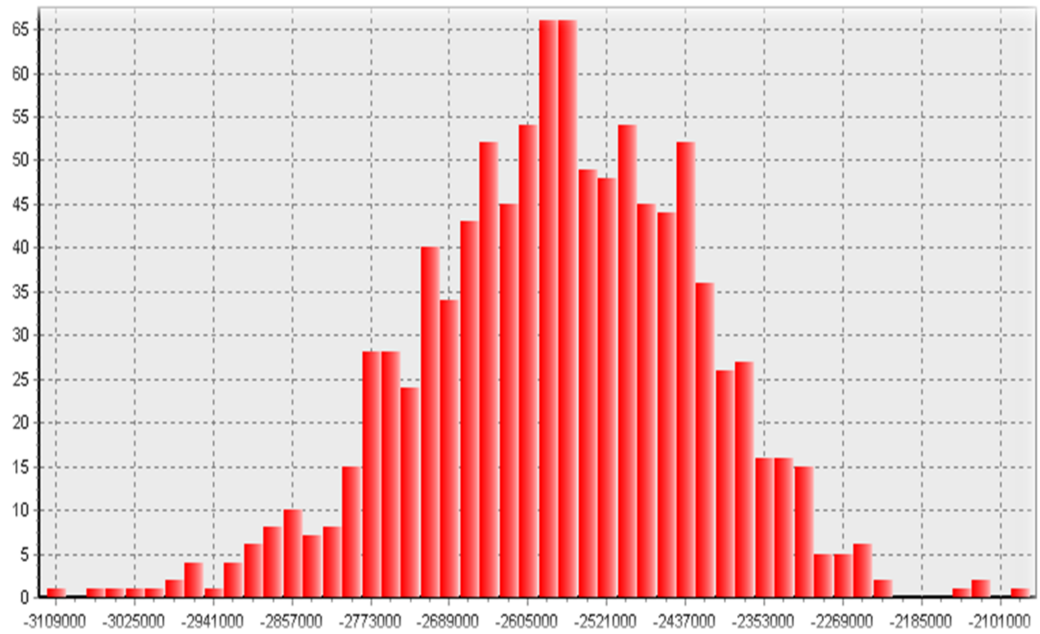


Figure 5.2 Distribution of spot price outcomes, summer peaking customer, HPHV, SA, $



5.1.2. Customers' expected spot prices by market state

Among the reasons customers hedge is to achieve price certainty. Figure 5.3 and Figure 5.4 on the following page illustrate the potential difference in the spot wholesale electricity costs a customer faces, depending on the customer's load profile and the market state in a given year for the Victorian and South Australian NEM regions respectively. The costs are expressed in $/MWh. The error bars represent the customers' costs at the 5th and 95th percentiles of the distribution for customer profile and market state.

Looking at our results:

- While prices are lower in South Australia than in Victoria, prices vary by more on average in South Australia.
  - Prices in South Australia are lower on average than in Victoria by slightly less than the difference in the emissions intensity coefficient between the two regions.
  - However, the South Australian price distributions are on average significantly wider than those in Victoria: Victorian prices averaged across the customer profiles and market states vary by -2.8 to +3.0 per cent, while in South Australia the comparable figures are -5.4 to +5.7 per cent.
  - The price variation from one market state to another can be very large, particularly at the extremes. In our results, customers face a higher level of uncertainty about their expected costs as a result of their inability to predict what the prevailing market state will be. Relative to the differences from state to state, the distribution of the results within a given state (see below) is relatively lower.
- A South Australian customer with a summer peaking load profile expects to pay $46.81/MWh for its electricity consumption in an LPLV market state. The expected price increases to $84.66/MWh in an HPHV state, an increase of 81 per cent.
  - In Victoria, the comparable figures are $54.90/MWh and $97.54/MWh, an increase of 78 per cent.
- Within a high volatility market state – either LPHV or HPHV – a customer's costs can differ significantly.
  - For example, in an HPHV state in South Australia, a summer peaking customer's costs could range from $77.07/MWh at the 5th percentile of the calculated price distribution to $92.53/MWh at the 95th percentile of the distribution, a difference of -9.3 per cent and +9.0 per cent.
  - The comparable figures in Victoria are $94.34/MWh and $100.96/MWh, a difference of -3.3 per cent to +3.5 per cent.
- While customers' profiles reinforce the effects of a changing market state, all customer types are affected.
  - In South Australia, the difference between the effective cost to a customer in an LPLV market state and an HPHV market state is an increase of 60 per cent, 81 per cent and 57 per cent with a flat, summer peaking or winter peaking load profile respectively. In Victoria, the comparable figures are 69 per cent, 78 per cent and 64 per cent respectively.

Figure 5.3 Expected pool costs by customer profile, market state with 5th and 95th percentiles, Victoria, $/MWh

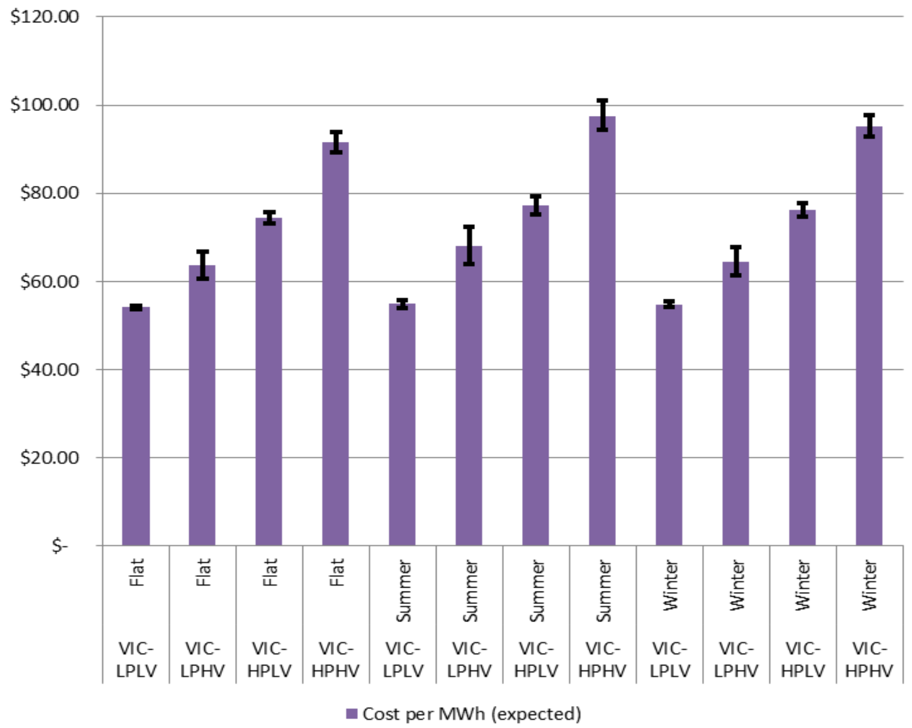
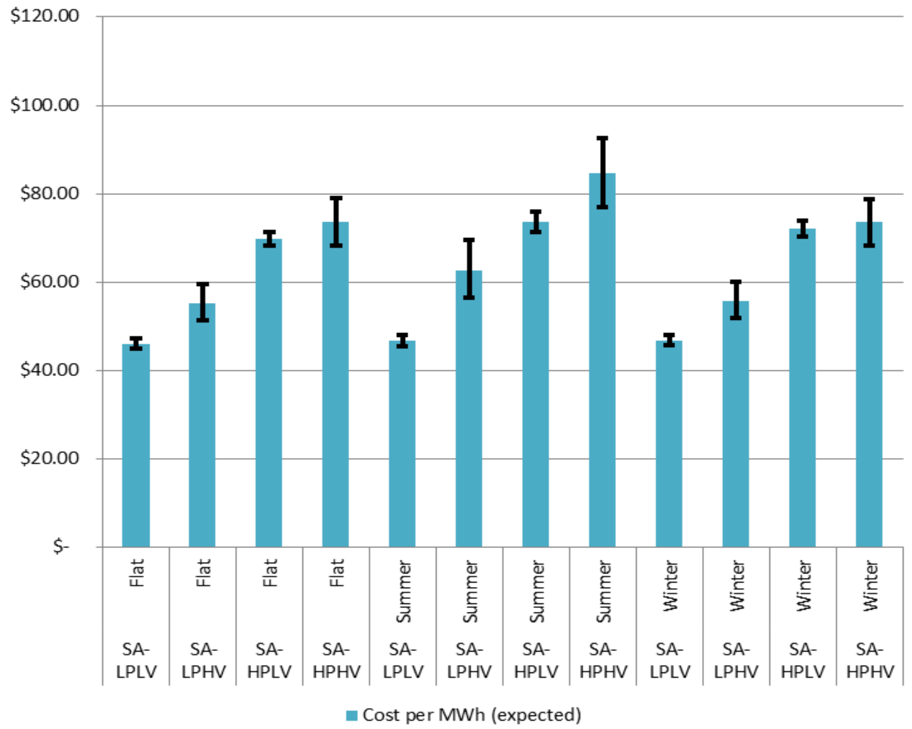


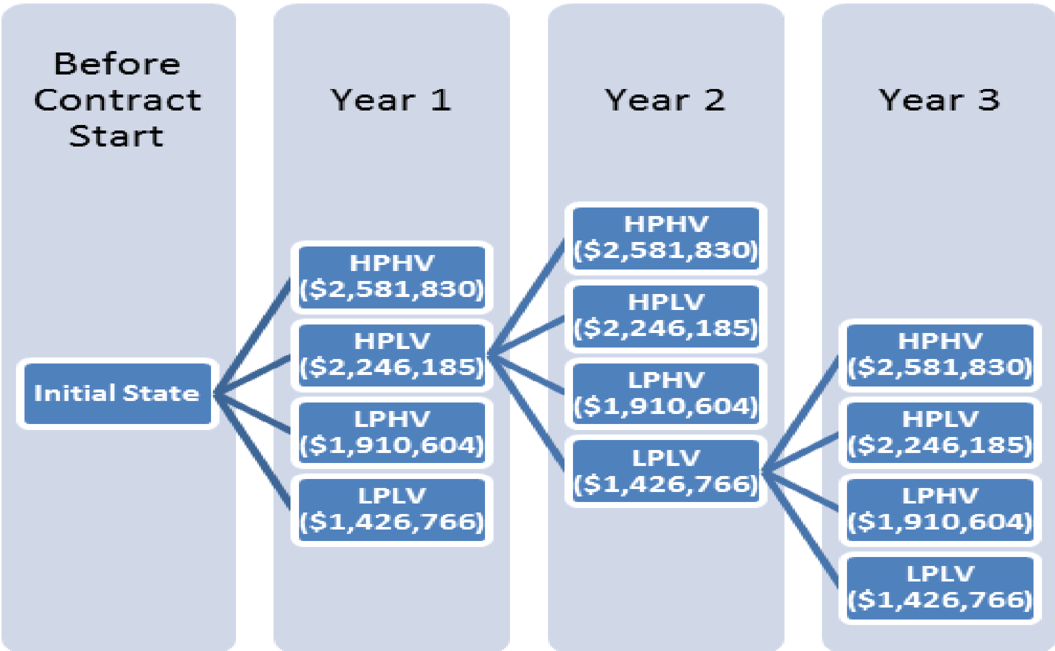
Figure 5.4 Expected pool costs by customer profile, market state with 5th and 95th percentiles, South Australia, $/MWh



What are the implications of our results?

- Unless a customer has the ability to pass through in full changes in its wholesale electricity costs, a customer that wants some price certainty will prefer to hedge.
  - Our working assumption is that neither the customers nor other market participants can forecast with certainty future market states. Given this, a South Australian customer could expect to pay on average between \$61.22/MWh and \$66.95/MWh depending on its profile, but in 5 per cent of cases will pay as much as \$64.32/MWh to \$71.61/MWh. The difference in the customer's wholesale electricity costs between the expected wholesale electricity price and that at the 95th percentile cost ranges from \$372,000/year up to \$578,000/year.
- Even if the customer has the ability to pass through in full changes in its wholesale electricity costs, the customer may meet resistance in doing so.
  - In the most affected case, the summer peaking customer, the potential variation in costs from the most benign market state (LPLV) to the least (HPHV) ranges from 78 per cent in Victoria to 81 per cent in South Australia, a significant change in downstream customers' costs, should the price increase be passed through.
- If the transition from one market state to another is unpredictable, then a customer's ability to project its expected price over time will be very limited. Figure 5.5, below, shows just one of the possible paths for a summer peaking South Australian customer's spot costs. In Figure 5.5, the first year of the customer's pool exposure is HPLV, followed by an LPLV year, which in turn could be followed by any one of the four defined states. The difference between the first and second years is a fall of 35 percent in expected cost. In the third year, however, using the naïve weighting approach, the customer should expect an increase of 43 percent, but the increase could be as high as 81 per cent (from LPLV to HPHV).

Figure 5.5 Summer peaking customer, possible expected pool costs by market state and year, South Australia, \$

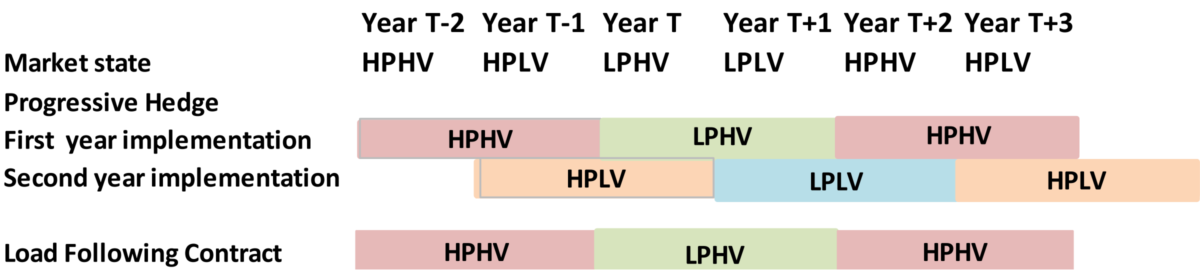


5.2. Comparing single and multi-year hedge strategies

5.2.1. Visualising the relationship between multi-year hedges and market states

Figure 5.6 presents a very simple schematic showing the implementation of a progressive hedge and a load following hedge, beginning at Year T-2 and assuming the market cycles through the defined market states and then repeats the cycle from the beginning. The purpose of the schematic is to provide a guide to the following discussion about the relationship between the current market state, Year T and those of previous years, T-1 and T-2.

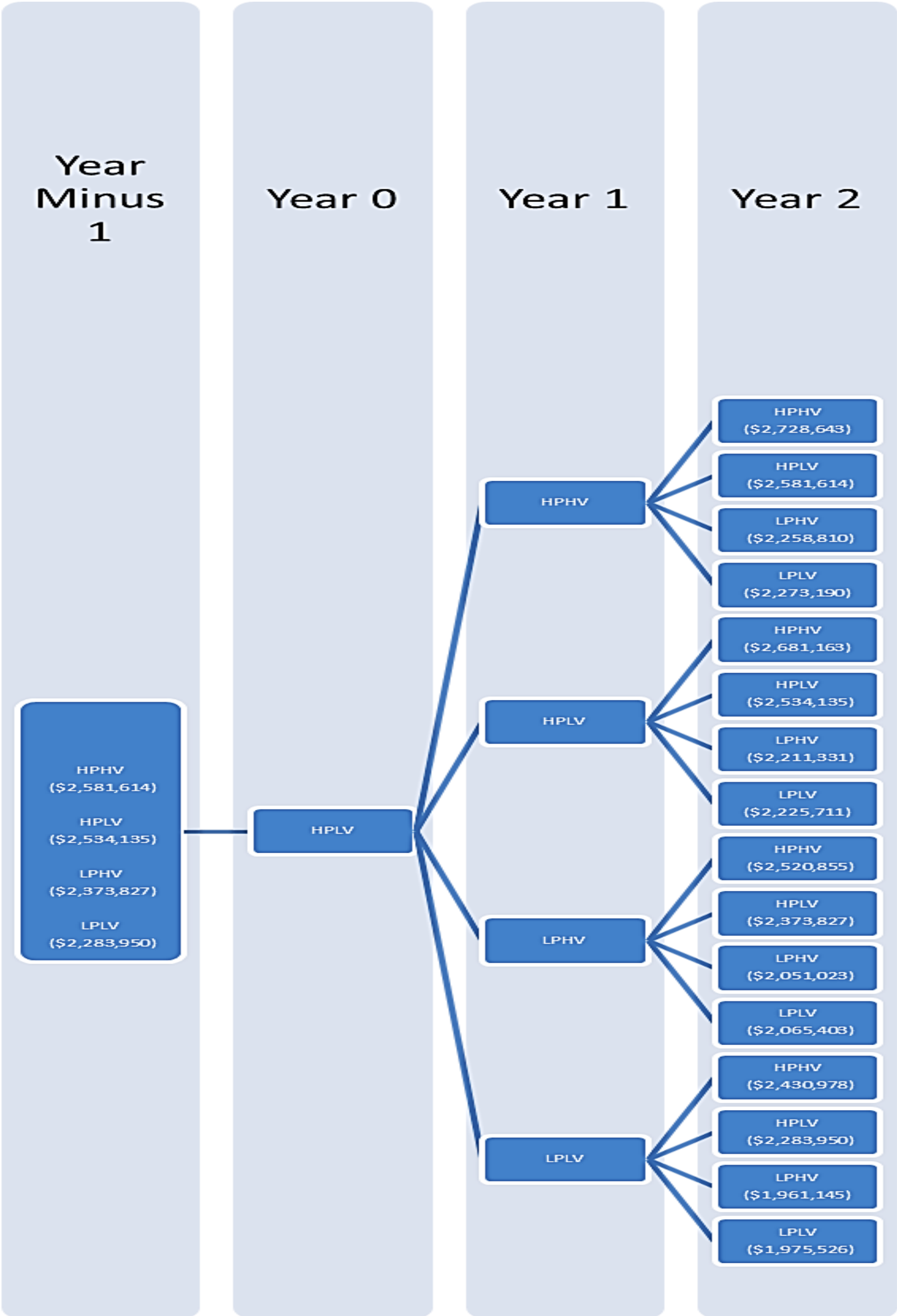
Figure 5.6 Pricing and the market state, progressive and load following hedges, schematic



The lattice illustrated in Figure 5.7 provides a more comprehensive, but more complicated view of the same process, looking at the progressive hedging strategy and allowing for all of the possible outcomes over time. That part of the customer's costs agreed in the year prior to the year of the evaluation depend on the then market state and could vary by up to \$300,000/year. The customer contracts for a further two years in an HPLV market state and fixes the cost for 50 percent of its load at the current market price. In the following year, depending on the market outcome, it will again face a range of prices, with its costs potentially varying by up to \$500,000/year.

In Section 5.2.2, we discuss how our approach allows us to compare the complex path through time for a multi-year hedge with the costs of a single year hedge strategy.

Figure 5.7 Progressive Hedge Pricing, schematic with illustrative costs, Victorian summer peaking customer, $



5.2.2. Evaluating the effects of a multi-year hedge on customers' costs

5.2.2.1. The current market state is HPHV

To illustrate the impact that hedging may have on the costs for a large customer, let us first consider the costs for one year only based on different outcomes for the price and volatility regime.

Figure 5.8 and Figure 5.9 illustrate the costs for a customer with a flat load profile in South Australia under different scenarios. In both figures, the costs of pool exposure (no hedge) in a HPHV regime for year T are compared with a progressive hedge strategy implemented under four different regimes.

In both cases, the current market state – the state the performance of the hedge is being evaluated under – is HPHV.

- Figure 5.8 compares the results under a HPHV scenario in year T for pool exposure and the expected cost of the progressive hedge strategy that was either implemented under HPLV in T-2/ HPLV in T-1 or HPHV in T-2/HPLV in T-1. In this scenario, the progressive hedge was implemented under a high price scenario in both years. As illustrated in Sections 4.2.2.2 and 4.2.2.3 and in Table 4.2, due to the high price (and high volatility) level in T-2 and T-1 regimes, futures quotes for the delivery periods in T will be quite high. This is due to higher expectations about realised spot prices in T as well as higher risk premiums required to be paid to holders of short positions in the futures market as compensation for bearing the spot price risk under a high price (and volatile) regime.
  - Looking first at the average or expected cost of a progressive hedge ($2,255,040 and $2,359,984), the expected cost is higher than the average cost of the pool exposure ($2,210,804).
  - However, the cost distribution for the pool exposure illustrates that there is still some probability that the cost of the pool exposure strategy will be higher than the cost of the progressive hedge. This can be considered as a typical situation in a market with positive risk premiums for futures contracts. The average cost of hedging is higher, but hedging avoids a worst-case outcome.
- Figure 5.9 illustrates the costs of pool exposure versus the progressive hedge strategy when one of the T-1/T-2 regimes was a low price regime. It compares the results under a HPHV scenario in year T for pool exposure with the expected cost of the progressive hedge strategy that was either implemented under LPLV in T-2/HPHV in T-1 ($1,755,923) and under HPHV in T-2/LPHV in T-1 ($1,825,911).). As illustrated in Sections 4.2.2.2 and 4.2.2.3, due to the low price (and low volatility) level in either T-2 or T-1 regime, futures quotes for the delivery periods in T will be significantly lower than when futures prices is conducted under a HP regime in both T-2 and T-1. This is due to lower expectations about realised spot prices in T under a LP regime as well as lower risk premiums in the futures market.

  - In both cases the expected cost of the progressive hedge strategy is significantly lower for the customer than the pool exposure. The cost savings are between 17 per cent and 21 per cent, respectively, under these two scenarios, since the futures contracts were partially bought under a low price regime and the evaluation is occurring in an HPHV regime.

The progressive hedge strategy can be implemented under 16 different scenarios – 4 possible regimes for T-2, and 4 possible regimes for T-1. Interestingly, if the market in time T when the hedge is evaluated is a HPHV regime for two of these 16 possibilities only, then the expected cost of the pool exposure in these circumstances will be lower than the expected cost of the progressive hedge. For 14 out of the possible 16 scenarios, hedging will be cheaper for the customer in an HPHV scenario for T.

5.2.2.2. The current market state is LPHV

To illustrate that the situation could also be reversed, let us now consider the cost of electricity for one year for the same customer profile in SA under a realised LPHV regime in Year T.

Figure 5.10 and Figure 5.11 illustrate the costs of pool exposure (no hedge) in a LPHV regime for Year T versus a progressive hedge strategy implemented under four different regimes. In this case, the average cost of the pool exposure is only ($1,658,306), significantly lower than the average cost of pool exposure under a HPHV regime ($2,210,804).

- Figure 5.10 compares the results under a LPHV scenario in Year T for pool exposure and the expected cost of the progressive hedge strategy that was either implemented under LPLV in T-2/ LPLV in T-1 or LPHV in T-2 / LPLV in T-1. In this scenario, the progressive hedge was implemented under a low price scenario in both years. Therefore, as pointed out in Sections 4.2.2.2 and 4.2.2.3, futures quotes for the year T delivery period will be fairly low based on lower expectations about realised spot prices in T and low risk premiums in the futures market, given the LPLV regime in T-2 and/or T-1.
  - The expected cost of a progressive hedge is either lower ($1,621,668) or about the same ($1,661,789) as the average cost of the pool exposure ($1,658,306).
  - However, the cost distribution for the pool exposure illustrates that there is still some probability that the cost of the pool exposure strategy will be even lower than the cost of the progressive hedge.
- Figure 5.11 illustrates the costs of pool exposure versus the progressive hedge strategy implemented under a high price regime in T-1/T-2. It compares the results under a LPHV scenario in year T for pool exposure and the expected cost of the progressive hedge strategy that was either implemented under HPLV in T-2/HPHV in T-1 ($2,019,691) and under HPHV in T-2/HPHV in T-1 ($2,124,636). Under such a high price (and high volatility) regime in T-2 and T-1, futures quotes for the year T delivery periods will be rather high: higher expectations about realised spot prices in T as well as higher risk premiums as compensations for holding a short positions in the futures market under a high price (and volatility) regime will be observed in the market.
  - In both cases, the expected cost of the progressive hedge strategy is significantly higher (22 and 28 per cent respectively) than the pool exposure. The reason for this is that the futures contracts were entered under a high price/high volatility

regime and the market in which the strategies are being evaluated was a LPHV regime.

Again the progressive hedge strategy could be implemented under 16 different scenarios. Under a LPHV regime for two of these 16 possibilities only the expected cost of the pool exposure is higher than the expected cost of the progressive hedge. In other words, for 14 out of 16 scenarios a no hedge strategy can be expected to be cheaper when evaluated in an LPHV market state at Year T.

5.2.2.3. Implications

Overall, when we only consider a one year period, the key determinant of whether hedging pays off or not for a customer is the actual price and volatility regime in T in comparison, and also the price and volatility regime in T-1 and T-2 when the futures or cap contracts were entered by the customer for the assumed progressive hedge strategy entered into. Sections 4.2.2.2 and 4.2.2.3 illustrate the substantial differences between futures prices under different regimes. While under HPHV regime in T-2 and T-1, futures quotes for delivery periods in T will be quite high, while they will normally be significantly lower under a LPLV regime. Under the latter both expectations about realised spot prices in T as well as risk premiums will be lower such that we observe low futures prices.

As we can see from Figure 5.1 to Figure 5.4, the differences between costs of a pool exposure strategy under a high price and low price the price regimes are quite substantial. However, almost equally important for the outcome whether hedging pays off or not, are the differences between the costs of hedging, and therefore the price regime (LPLV, LPHV, HPLV, and HPHV) under which the futures contracts are entered by the large customer.

Very similar results can also be found when considering summer and winter customer profiles for South Australia and also for all customer profiles in the Victorian market. Overall we find that the realised regime in Year T significantly determines the cost of the pool exposure and therefore, also whether a hedging strategy will be cheaper or more expensive than not hedging. The cost of electricity for a large customer under all of the considered hedging strategies and the load following contract is mainly determined by the price regimes in T-2, T-1. Also, the differences between the considered price regimes seem to be more substantial than the volatility of electricity spot prices within each of the regimes.

One important result for the exercise of considering a one-year period only is the following: while for the pool exposure there is a lot of uncertainty about the actual expected outcome for the costs of electricity in T, the costs of a progressive hedge are mainly determined by the price and volatility regimes in T-1 and T-2. Therefore, under a progressive hedge and, in a similar way for all the other hedging strategies considered in this report, by the beginning of Year T a customer will know the approximate cost of electricity for period T. The customer does not know whether the hedge strategy in the end will be cheaper or more expensive than the pool exposure, but clearly has more certainty about the costs of electricity for period T.

The left panel illustrates a cost comparison between pool exposure (blue curve) and the expected cost of a progressive hedge, when the hedge was implemented under HPLV in T-2 and HPLV in T-1 (black) and under HPHV in T-2 and HPLV in T-1 (red). The right panel illustrates a cost comparison between pool exposure (blue curve) and the expected cost of a progressive hedge, when the hedge was implemented under LPLV in T-2 and HPHV in T-1 (black) and under HPHV in T-2 and LPHV in T-1 (red).

Figure 5.8 Electricity cost, flat customer profile, pool and progressive hedge, current market state HPHV, South Australia, $'000s

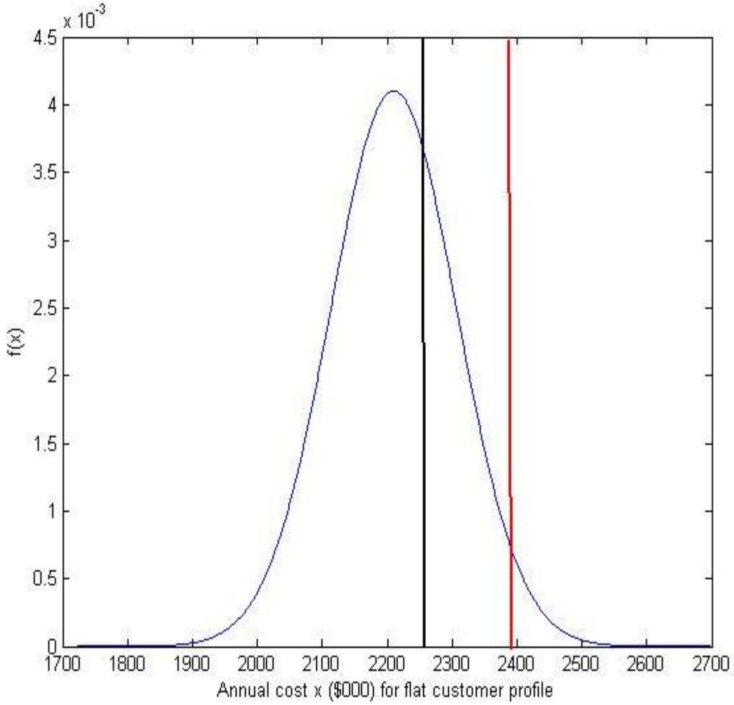
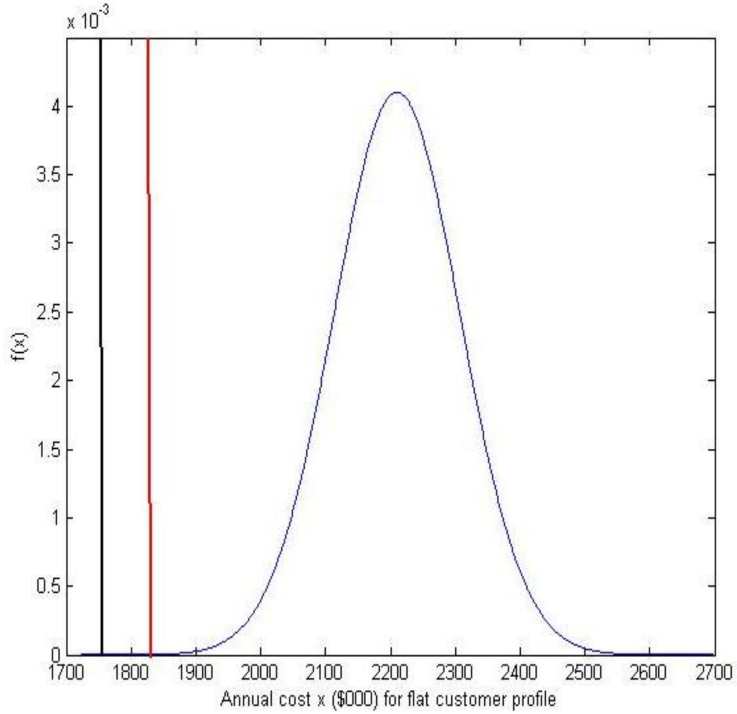


Figure 5.9 Electricity cost, flat customer profile, pool and progressive hedge, current market state HPHV, South Australia, $'000s



The left panel illustrates a cost comparison between pool exposure (blue curve) and the expected cost of a progressive hedge, when the hedge was implemented under LPLV in T-2 and LPLV in T-1 (black) and under LPHV in T-2 and LPLV in T-1 (red). The right panel illustrates the cost comparison between pool exposure (blue curve) and the expected cost of a progressive hedge, when the hedge was implemented under HPLV in T-2 and HPHV in T-1 (black) and under HPHV in T-2 and HPHV in T-1 (red).

Figure 5.10 Electricity cost, flat customer profile, pool and progressive hedge, current market state LPHV, South Australia, $'000s

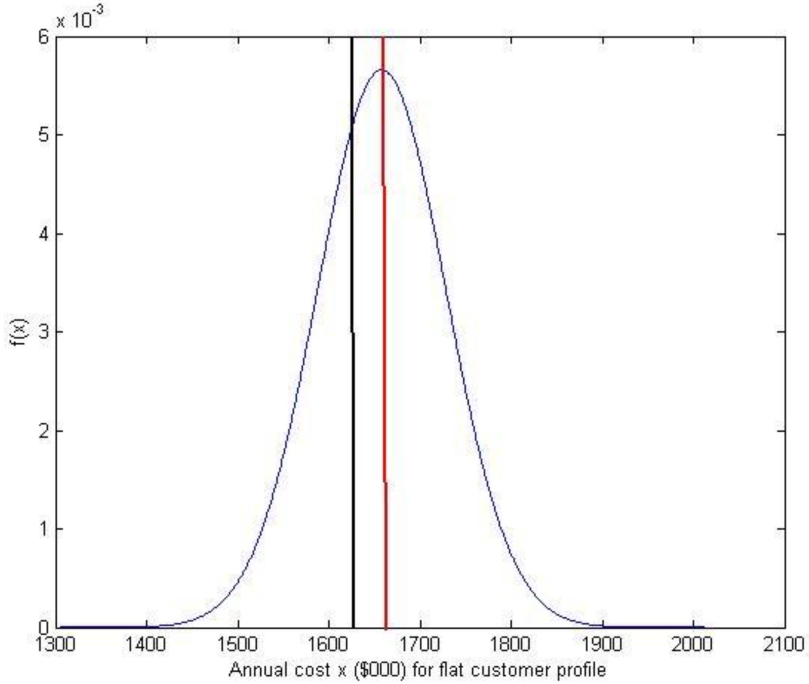
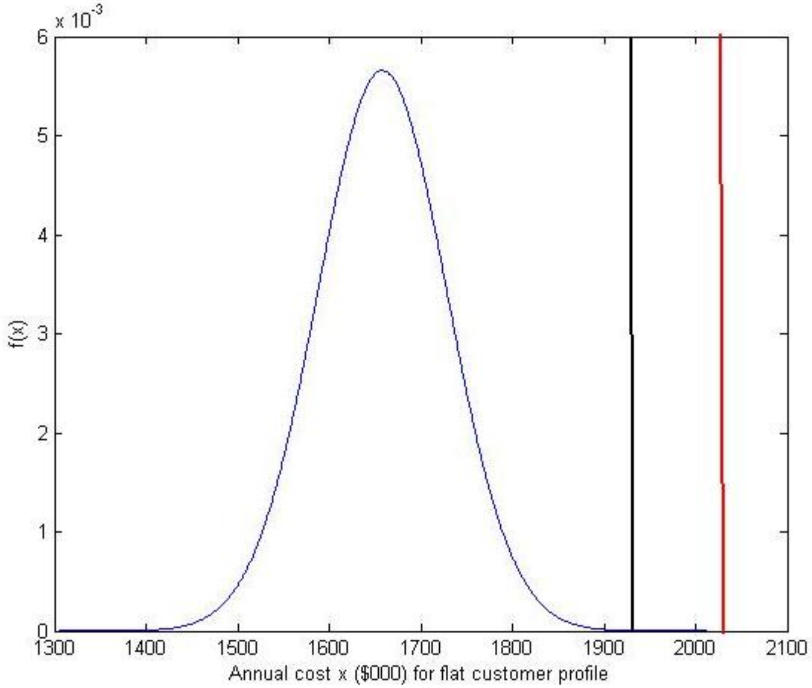


Figure 5.11 Electricity cost, flat customer profile, pool and progressive hedge, current market state LPHV, South Australia, $'000s



5.3. When does it pay to hedge?

The following discussion of our results considers the results for average annual costs of electricity for the large customer looking at a multi-year cost, rather than a single year snap shot.

Earlier, we discussed customers' preferences taking into account both the absolute cost and the level of price variation. In the discussion that follows, we have used the following decision rules in evaluating the results:

- A strategy is regarded as *superior* where for a similar cost it offers a materially higher lower level of risk for the customer.
- A strategy is regarded as *preferred* where, for a small additional cost, the customer can achieve a materially lower level of risk.

Table 5.1 presents the results for the strategies tested by customer profile and region, ranked from the strategy with the highest average cost to the strategy with the lowest. The average cost for each strategy is the naïve average of the mean cost of each of the 4 market states – LPLV, LPHV, HPLV and HPHV. The difference between the highest and the lowest result is the difference between the lowest expected value for any one of these states – typically, LPLV – and the highest expected value for any of the states – HPHV. The strategies in bold are discussed in the following section, as either superior or preferred.

Table 5.1 Hedging strategies, by customer profile, region, average cost and maximum range, $

Customer Profile	Hedging Strategy	Average cost, $	Potential incremental cost, $
		Victoria	
Flat	**Progressive**	$2,220,587	$956,354
	Load Following Contract	$2,212,932	$766,615
	Part hedge	$2,200,042	$937,250
	Pool + Caps	$2,165,658	$1,085,134
	Pool	$2,128,153	$1,123,691
	Load Curtailment	$1,992,296	$825,517
Summer	**Load Following Contract**	$2,638,389	$932,280
	Progressive	$2,356,450	$860,043
	Pool + Caps	$2,339,027	$1,221,686
	Part hedge	$2,335,905	$1,112,359
	Pool	$2,264,016	$1,298,800
	Load Curtailment	$2,089,672	$920,792

Customer Profile	Hedging Strategy	Average cost, $	Potential incremental cost, $
		Victoria	
Winter	**Load Following Contract**	$2,332,913	$816,159
	Progressive	$2,298,887	$868,388
	Part hedge	$2,249,876	$1,025,215
	Pool + Caps	$2,215,493	$1,173,100
	Pool	$2,177,988	$1,211,656
	Load Curtailment	$2,028,316	$871,394
		South Australia	
Flat	**Load Following Contract**	$1,922,814	$382,438
	Progressive	$1,914,271	$970,257
	Part hedge	$1,906,630	$899,929
	Pool + Caps	$1,844,090	$746,480
	Pool	$1,836,841	$827,852
	Load Curtailment	$1,632,094	$606,040
Summer	**Load Following Contract**	$2,598,323	$657,808
	Progressive	$2,118,776	$1,031,979
	Part hedge	$2,111,135	$1,227,142
	Pool + Caps	$2,055,844	$887,679
	Pool	$2,041,346	$1,155,064
	Load Curtailment	$1,765,055	$676,113
Winter	**Load Following Contract**	$2,116,889	$445,214
	Progressive	$1,936,612	$995,412
	Part hedge	$1,928,970	$901,033
	Pool + Caps	$1,866,431	$795,622
	Pool	$1,859,181	$802,696
	Load Curtailment	$1,654,626	$639,444

5.3.1. In very specific circumstances, load curtailment is superior

Load curtailment, under the conditions assumed and regardless of customer profile, always results in cheaper wholesale electricity costs than the pool. This result is expected: customers average their costs down by instantaneously reducing consumption by 50 per cent on every occasion when the spot price reaches $150/MWh. The pay-off to load curtailment – the reduction in costs compared with the alternative, pool costs – is higher in South Australia than in Victoria; depending on the customer profile, a South Australian customer reduces its electricity costs by between 11.0 and 13.5 per cent relative to its spot market costs, while in Victoria the improvement ranges from 6.4 to 7.7 per cent.

However, some caveats need to be considered in evaluating this result:

- The benefit of load curtailment takes no account of the costs to the customer in lost production. To the extent that the customer incurs some positive cost from curtailing its load, then the net benefits will be lower. However, in our modeling, the losses, measured only in terms of reduced output from reduced electricity usage are small.
  - Customers in South Australia and Victoria using load curtailment consume 0.6 per cent less electricity a year on average across all market states and customer profiles.
  - The reduction in consumption is disproportionately borne by summer peaking customers, whose consumption is reduced by 0.7 per cent a year in South Australia on average across all market states and by 1.2 per cent a year in Victoria.
- The net benefits to the customer from this strategy would also be lower if the assumption that the customer can react instantaneously to high prices – alternatively, that the customer can predict with certainty all the occasions when the price will exceed $150/MWh – was relaxed. If the customer is unable to respond without more than a very short period of notice, the customer's gains from this strategy would be lower (their wholesale electricity prices higher).

5.3.2. The load following contract is preferred

A Victorian customer with a flat load profile should *prefer* a load following contract to the alternatives. A Victorian customer with a winter peaking load profile or a South Australian customer with a flat profile could *prefer* a load following contract to the alternatives. In the case of the winter peaking customer, the load following contract is around $35,000 a year more expensive than the nearest alternative, the progressive hedge, but relative to the progressive hedge, the customer's costs are invariant to changes in its load.[24] In the case of the South Australian flat customer, the difference is significantly lower, at around $8,000 a year.

[24] See also the discussion in Section 4.2.5.1. relating to the issues associated with the implementation of progressive hedge for smaller customers.

5.3.3. The progressive hedge is preferred

A customer with a *summer peaking load profile* should prefer a progressive hedge to the alternatives.

- Relative to the pool plus caps strategy, the cost is only marginally higher, but the customer's costs are then invariant to changes in both its load within the boundary of the hedge and the price duration curve under $300/MWh
- Relative to the part hedge strategy, the cost is marginally higher, but the customer avoids all the risks associated with its load and the shape of the price duration curve. In addition (see Section 5.4.2), the customer's costs would be unaffected by a "worst case scenario" event.
- The cost is materially lower than a full load following contract and, within the boundary of the hedge, the customer's risk transfer is identical.

5.4. Testing our results

5.4.1. The "at risk" component

In a small number of the strategies tested, the customer retains some pool price exposure and, as a result, the customer's achieved price can differ from its expected price.

Table 5.2 looks at the results under an LPLV state, while Table 5.3 looks at the outcomes in HPHV. So as to capture only the effects of characteristics of the underlying price distribution, the strategies included are only those priced in the same market state; that is, for the LPLV market state, a part hedge or pool plus caps strategy priced in an LPLV market, measured by the outcome in an LPLV market. In both tables, the results have been ordered from highest to lowest value for the maximum (95th percentile) price.

Table 5.2 and Table 5.3 show the customer's potential price, measured as the mean or expected price and as the maximum (95th percentile) price in $/MWh. The results suggest that the effects of spot price uncertainty on the choice of strategy are a function of the market state. In a consistent LPLV world (Table 5.2), a customer could be justified in concluding that hedging doesn't pay. The pool is the preferred strategy relative to the alternative strategies; the cost of the part hedge and pool plus cap strategies are higher, while these strategies also result in higher maximum (95th percentile) prices. The difference between the expected and maximum (95th percentile prices), however, is higher in the pool than the alternative strategies.

Table 5.2 Customer's expected and maximum price, LPLV state: by region, load profile and strategy, $/MWH and % change

Region	Customer Profile	Strategy	Expected Price, $/MWh	Max Price, $/MWh	% increase
Victoria	Flat	Part hedge	**60.11**	60.36	0.4%
		Pool + Caps	**56.08**	56.44	0.6%
		Pool	**54.14**	54.55	0.8%
	Summer	Part hedge	**60.78**	61.62	1.4%
		Pool + Caps	**58.72**	59.58	1.5%
		Pool	**54.90**	55.80	1.6%
	Winter	Part hedge	**60.81**	61.30	0.8%
		Pool + Caps	**56.78**	57.34	1.0%
		Pool	**54.84**	55.45	1.1%
South Australia	Flat	Part hedge	**50.56**	51.07	1.0%
		Pool + Caps	**48.33**	49.21	1.8%
		Pool	**46.10**	47.29	2.6%
	Summer	Pool + Caps	**51.21**	52.13	1.8%
		Part hedge	**51.20**	52.10	1.8%
		Pool	**46.81**	48.18	2.9%
	Winter	Part hedge	**51.23**	51.86	1.2%
		Pool + Caps	**49.00**	49.96	2.0%
		Pool	**46.76**	48.01	2.7%

In an HPHV market state, however, the pool is never the preferred strategy, with the expected and maximum prices higher than the alternatives regardless of customer profile in South Australia. In addition, the difference between expected and maximum prices with pool exposure is greater than the alternatives in South Australia and Victoria. The rankings suggest that the higher the hedge protection, the better in an HPHV market state: the part hedge strategy is *preferred to* the pool plus caps strategy for all customer profiles across both regions, with the exception of the South Australian summer peaking customer, where pool plus caps is the *preferred* strategy.

Table 5.3 Customer's expected and maximum price, HPHV state: by region, load profile and strategy, $/MWH and % change

Region	Retail	Strategy	Expected Price	Max Price	Difference
Victoria	Flat	Pool + Caps	**92.25**	94.00	1.9%
		Pool	**91.60**	93.82	2.4%
		Part hedge	**90.87**	91.83	1.1%
	Summer	Pool + Caps	**98.82**	101.43	2.6%
		Pool	**97.54**	100.96	3.5%
		Part hedge	**96.82**	99.22	2.5%
	Winter	Pool + Caps	**95.93**	97.89	2.0%
		Pool	**95.28**	97.68	2.5%
		Part hedge	**94.55**	95.91	1.4%
South Australia	Flat	Pool	**73.69**	79.01	7.2%
		Pool + Caps	**70.30**	74.07	5.4%
		Part hedge	**69.61**	71.86	3.2%
	Summer	Pool	**84.66**	92.53	9.3%
		Part hedge	**80.65**	86.06	6.7%
		Pool + Caps	**77.99**	83.43	7.0%
	Winter	Pool	**73.54**	78.81	7.2%
		Pool + Caps	**70.15**	73.88	5.3%
		Part hedge	**69.45**	71.74	3.3%

5.4.2. Hedging and “worst case scenario”

If the prices that occurred between 8 and 10 February, 2010 were replicated, the pool costs of the customers in this analysis would have increased by around $300,000, the equivalent of adding $10/MWh to the customer’s costs across the entire year. The effect of an event of this type on the relative merits of the strategies tested is shown in the table below. The change in the relative expense of pool exposure is shown. The effects on the part hedged strategy, which would also increase in cost, have not been calculated.

A single event of this kind has the effect of moving the cost of pool exposure from the second cheapest strategy to the most expensive for Victorian and South Australian customers with flat or winter peaking profiles. For summer peaking customers in either region a full load following contract continues to be dearer, although, in Victoria the difference between the two is relatively small.

Table 5.4 Average cost, by customer profile, hedging strategy and region; with and without a "worst case scenario", $

Customer Profile	Hedging Strategy	Average cost, excl worst case scenario $	Hedging Strategy	Average cost, incl worst case scenario $
		Victoria		
Flat	Progressive	$2,220,587	**Pool**	**$2,428,153**
	Load Following Contract	$2,212,932	Progressive	$2,220,587
	Part hedge	$2,200,042	Load Following Contract	$2,212,932
	Pool + Caps	$2,165,658	Part hedge	N/A
	Pool	**$2,128,153**	Pool + Caps	$2,165,658
	Load Curtailment	$1,992,296	Load Curtailment	$1,992,296
Summer	Load Following Contract	$2,638,389	Load Following Contract	$2,638,389
	Progressive	$2,356,450	**Pool**	**$2,564,016**
	Pool + Caps	$2,339,027	Progressive	$2,356,450
	Part hedge	$2,335,905	Pool + Caps	$2,339,027
	Pool	**$2,264,016**	Part hedge	N/A
	Load Curtailment	$2,089,672	Load Curtailment	$2,089,672
Winter	Load Following Contract	$2,332,913	**Pool**	**$2,477,988**
	Progressive	$2,298,887	Load Following Contract	$2,332,913
	Part hedge	$2,249,876	Progressive	$2,298,887
	Pool + Caps	$2,215,493	Part hedge	N/A
	Pool	**$2,177,988**	Pool + Caps	$2,215,493
	Load Curtailment	$2,028,316	Load Curtailment	$2,028,316
		South Australia		
Flat	Load Following Contract	$1,922,814	**Pool**	**$2,136,841**
	Progressive	$1,914,271	Load Following Contract	$1,922,814
	Part hedge	$1,906,630	Progressive	$1,914,271
	Pool + Caps	$1,844,090	Part hedge	N/A
	Pool	**$1,836,841**	Pool + Caps	$1,844,090
	Load Curtailment	$1,632,094	Load Curtailment	$1,632,094

Customer Profile	Hedging Strategy	Average cost, excl worst case scenario $	Hedging Strategy	Average cost, incl worst case scenario $
Summer	Load Following Contract	$2,598,323	Load Following Contract	$2,598,323
	Progressive	$2,118,776	**Pool**	**$2,341,346**
	Part hedge	$2,111,135	Progressive	N/A
	Pool + Caps	$2,055,844	Part hedge	$2,111,135
	Pool	**$2,041,346**	Pool + Caps	$2,055,844
	Load Curtailment	$1,765,055	Load Curtailment	$1,765,055
Winter	Load Following Contract	$2,116,889	**Pool**	**$2,159,181**
	Progressive	$1,936,612	Load Following Contract	$2,116,889
	Part hedge	$1,928,970	Progressive	$1,936,612
	Pool + Caps	$1,866,431	Part hedge	N/A
	Pool	**$1,859,181**	Pool + Caps	$1,866,431
	Load Curtailment	$1,654,626	Load Curtailment	$1,654,626

5.4.3. Sensitivity of the results

5.4.3.1. The choice of representative year

The results are sensitive to our choice of representative year. However, the representative years chosen are a more conservative choice than the identified alternatives. Substituting our Test years for the designated South Australian LPLV and HPHV representative years increases the difference in costs in comparing one market state to another; the Test HPHV state results in a significantly higher expected price than the year chosen for our analysis.

Table 5.5 Pool costs, by representative year and Test year: expected, 5th and 95th percentiles, South Australia, $

Customer Profile	State	Expected	5th Percentile	95th Percentile
Flat	HPHV (test)	2,516,460	2,346,749	2,696,657
	HPHV	2,210,804	2,050,176	2,370,421
	LPLV (test)	1,436,863	1,401,183	1,479,178
	LPLV	1,382,952	1,351,240	1,418,700
Summer	HPHV (test)	2,864,416	2,628,272	3,121,856
	HPHV	2,581,830	2,350,359	2,821,773
	LPLV (test)	1,511,141	1,463,133	1,566,787
	LPLV	1,426,766	1,387,086	1,468,626
Winter	HPHV (test)	2,548,883	2,379,508	2,724,935
	HPHV	2,203,238	2,049,347	2,360,923
	LPLV (test)	1,456,601	1,419,172	1,499,971
	LPLV	1,400,542	1,367,269	1,437,869

A. Glossary

Terms in this glossary are italicised when first used in the body of the report.

Term	Meaning
Cap (caps, $300 caps, capped price)	In exchange for an agreed *premium*, the purchaser of a *cap* receives a payment whenever a defined event occurs. In the Australian electricity market, the most frequently available *cap* is a *$300 cap*: whenever the relevant regional *spot price* exceeds $300/MWh, the purchaser of the *cap* receives a payment from the seller equal to the *spot price* less $300/MWh for each MWh of the *cap* volume. Over the term of the *cap*, the purchaser's wholesale electricity cost is the lower of the relevant regional *spot price* or $300/MWh. The purchaser's *effective cost* per MWh is the lower of the *spot price* plus the *premium* or $300/MWh plus the *premium*.
Contract (contract price, contract quantity, contract term, contracting, contracted)	In the Australian electricity market, the most common pricing structure for *large commercial and industrial customers* is a fixed energy price for an agreed quantity of electricity over a term of one to three years into the future. This *contract price* is the sum of the wholesale *forward price*, a *contract premium* and a retail margin. In addition, the contract price is generally combined with the pass through of network payments, renewable energy charges and market charges. In derivative pricing terms, the fixed energy price or *contract price* for wholesale electricity purchases is a *forward price* – a fixed price for an agreed term, known in advance and not subject to change. A customer that is fully *contracted* can also be described as having a *load following hedge.* With a full *load following hedge*, in *contracting* with a *retailer*, the *retailer* and the customer typically discuss the size and shape of the customer's load over each year of the *contract term*. There is usually some flexibility – both upwards and downwards – in the agreed *contract quantity*. The *retailer* typically assumes the customer may change the shape of its load during the life of the contract.
Contract for difference (CfD, swap)	A *contract for difference* is an agreed price between two parties at which a transaction for a given quantity will take place, settled with reference to a moving underlying price over the contract term. In the Australian electricity market, the *strike price* in a *contract for difference* is that price which one party is willing to pay and the other party is willing to receive for wholesale electricity. No trade in electricity is required to take place between the contracting parties. The payments made (received) are sufficient to ensure that combined with the relevant regional *spot price* outcome, the effective cost (price) of wholesale electricity is the *strike price*. Each party's obligations per MWh of contract volume are calculated with reference to the difference between the relevant regional *spot price* and the *strike price* at half hourly intervals over the *contract term*.
Contract premium	Where the customer chooses an intermediary to hedge its risks, the *contract premium* is the cost required over and above the forward market price to provide for the risks associated with offering a forward contract with significant volume and/or load shape uncertainty to a customer. *Retailers' contract premiums* differ according to the shape of the customer's load – peakier customers' loads incur higher *contract premiums* because of the observed relationship between high electricity load and high prices – and may vary with the term of the contract, the liquidity of the market for which the contract is required, the creditworthiness of the customer and other factors, such as the *retailer's* portfolio, considered as a

Term	Meaning
	whole.
Effective cost	Includes the wholesale cost of electricity plus the cost of any other derivatives, insurance or administrative costs associated with a given purchasing or contracting approach. For example, the *effective cost* of an unhedged *spot price* strategy, where the customer becomes a Market Participant, includes both the relevant regional *spot price* and all the costs of market participation (AEMO fees, the cash flow effects of changed payment terms, the opportunity costs of the AEMO prudential requirements; any incremental management costs).
Ex ante	Calculated in advance/before the event. For example, *ex ante risk premium* cannot be observed, as market participants' spot market expectations cannot be observed. As a result, *ex post risk premiums* are used as an unbiased estimate of *ex ante risk premiums.*
Exchange traded derivatives (exchange traded market)	Electricity CfDs (called futures) and option contracts traded on the Australian Stock Exchange (ASX – the *exchange traded market*) and settled with reference to the relevant regional *spot price. Exchange traded contracts* have standardised quantities, terms and dates of expiry. The ASX operates a margining process requiring contracting parties to pay a daily amount representing the cost of any change in the value of their position on the previous day. The margining process imposes cash flow opportunity costs on participants, but is designed to reduce the risk of a loss in the event of counterparty failure (credit risk).
Ex post	Calculated in arrears/after the event. *Ex post risk premiums* can be either positive or negative, depending on the relationship between expected *spot prices* and actual *spot prices* over the contract term.
Exposure	The extent to which a change in *spot, forward or contract prices* in either direction can result in a change in the customer's economic position. A large customer that purchases its electricity at the *spot price* and is able to change rapidly and directly its end users' prices to reflect changes in electricity *spot price* has no *exposure* to electricity *spot prices*. An analogous position is that of a refiner of crude oil where the price of refined products adjusts in response to changes in the market price for crude oil.
Fat tailed distribution	The distribution of *spot price* outcomes in a *fat tailed* distribution, compared with a normal distribution, typically has more (and larger) outliers in the tail of the distribution – that is, over a given period of time there are on average more short term high price intervals than are demonstrated by the price behaviour of other traded commodities.
Forward price (forward contract)	A fixed price for an agreed term, known in advance and not subject to change. Where a *forward price* is agreed, if the underlying price – for example, the relevant regional *spot price* for electricity – is subject to change and prices rise, the seller makes an opportunity loss. For this reason and given the cost of hedging, the seller charges a *risk premium* over and above the expected *spot price* when selling a *forward contract*. A *forward contract* buyer may suffer (make) an opportunity cost (gain) over the contract term, depending on the relevant regional *spot price* outcome. Where *forward contracts* are tradable, these gains (losses) can be realised (crystallised). However, the typical large C&I customer *contract* in the Australian market is not

Term	Meaning
	tradable.[25]
Futures price (futures contract)	As for a *contract for difference*, a *futures price* is an agreed price between two parties, settled with reference to a moving underlying price. In the event that the price has increased (decreased) over the term of the agreement above the agreed price, one party will make and the other receive a payment equivalent to the difference between the prevailing price and the *strike price* (the *strike price* and the prevailing price). If the *strike price* for a *futures contract* is the same as the *forward price* for an equivalent term, then a futures contract and a *forward price* result in the same price at the end of the contract term for the buyer, ignoring cash flow effects. However, unlike a *forward contract*, a *futures contract* distributes the gains and losses differently: if prices fall over the life of the contract, then unlike a *forward contract*, there are no gains to the buyer. The buyer pays the seller, ensuring the agreed *strike price* is achieved for both parties.
Hedged (fully hedged, partially hedged, unhedged)	A *large commercial and industrial customer* that is *hedged* is protected to the extent consistent with the customer's risk preferences and budget against changes to its wholesale electricity price. A *large commercial and industrial customer* that is *fully hedged* is not subject to any future price movements over its *contract* term. A customer with a *load following hedge* is a special case of being *fully hedged. With a load following hedge, the hedge* provider provides a fixed price covering the customer's unknown and variable volume and load shape, that is, the *hedge* provider assumes all the risks of the customer's load. A *partially hedged* large customer might *contract*, for example, to eliminate movements in its peak electricity price, but be *unhedged* against movements in off peak prices, that is, subject to all movements in either direction to off-peak electricity prices. Similarly, a large customer with the capacity to self-generate – for example a refinery – or to interrupt its processes for a period of time in response to high prices – for example, a concrete manufacturer – is *partially hedged*: to the extent that it can reduce its electricity consumption in response to forecast high prices, then it has a *hedge* against high prices.[26] A large customer exposed to the spot market without any protection against price movements in either direction is *unhedged.*
Large commercial and industrial customer	Although *retailers'* specific definitions differ, *retailers* typically define *a large commercial and industrial customer* ("C&I") as a customer that consumes more than 10 GWh electricity a year. At $60/MWh, the wholesale electricity component of an I&C customer's bill would be a minimum of $600,000/year.

[25] There have been instances where large customers with favourable forward prices in US electricity markets, for example, have closed production facilities to maximise the benefits of trading their forward contracts. See, for example, BCS for Industrial Technologies Program Energy Efficiency and Renewable Energy U.S. Department of Energy, *U.S. Energy Requirements for Aluminium Production: Historical Perspective, Theoretical Limits and Current Practices*, *February 2007,* introduction. Refer: https://www1.eere.energy.gov/manufacturing/industries_technologies/aluminum/pdfs/al_theoretical.pdf

[26] Technically, the customer has a *cap*, where the *strike price* is set by the rule adopted in response to price movements. For example, if the customer suspends processing to reduce its electricity consumption whenever the spot price is projected to increase above $100/MWh, then the effective cap strike price is $100/MWh. The cost of the cap – equivalent to the loss of production and the associated loss of revenue – is the equivalent to the cap *premium*. Unlike a purchased cap, however, the cost of this cap is unknown in advance: the number of interruptions to production may be more or less than estimated when the strategy was determined. Alternatively, the *ex post* cost differs from the *ex ante* estimated cost.

Term	Meaning
	Given the minimum *contract* size of 1 MW for exchange traded *forward contracts,* a customer consuming 10 GWh a year is would be around 80 per cent *hedged* by one flat *contract* (or the identical peak/off-peak *contract* combination). Two contracts would result in the customer being very significantly (around 60%) over-*hedged*.
Load following hedge	A customer with a typical *contract* has a *load following hedge* – regardless of the shape of the customer's consumption or, within contracted limits, the size of the customer's consumption, the customer is not subject to future wholesale energy price movements over the contract term. A *load following hedge* is a specialist product. Except in the circumstances where a large customer has a very large load, subject only to very small variation and with a load shape consistent with the product definitions for *exchange traded* electricity derivatives, a *load following hedge* is only available from a *retailer* or in the *OTC market*.
Over-the-counter contracts (OTC, OTC derivatives)	Privately exchanged, bilateral contracts including CfDs (swaps), forwards and options. The typical size for an OTC contract is 5 MW, significantly larger than the standard contract size for *exchange traded contracts*. Relative to the *exchange traded market*, participants have greater flexibility about contracted amounts, contract terms and the types of product traded. However, prices are less transparent; published price indices have been subject to criticism as unrepresentative; participants are subject to bilateral credit risk and/or may be required to lodge security with the counterparty to provide surety against credit risk.
Premium	The fixed payment made by a purchaser for a derivative contract.[27] For example, *cap prices* are quoted as a *premium* in $/MWh. A *premium* of $7.50 for a minimum annual base load 1 MW *cap* contract represents a payment of $65,700 by the buyer to the seller ($7.50 x 1MW x 8,760 hours in a year).
Retailer	An entity with an electricity retail license in the relevant NEM region. Could include, for example, a generator with a retail license, a gentailer (a *retailer* that also has some generation to service its retail portfolio's requirements), or a *retailer* without material generation assets.
Risk premium	The *risk premium* required by a market participant or intermediary to offer a fixed price for some future period (a *forward*, *swap* or *contract for difference*) in exchange for *spot market exposure*. In the absence of a *risk premium*, at the time the transaction is entered into, the market price for the *forward contract* would be equal to the expected *spot price* over the term of the agreed *contract* leaving the parties to the transaction indifferent to the choice of the spot or fixed price. The generally used explanation for the difference between the expected *spot price* and the *forward price* is that the party offering a fixed price requires compensation for the risk it is assuming in accepting the *spot price*.
Spot price (regional reference price, RRP)	Half hourly regional reference price for the relevant region as published by AEMO.
Strike price	Agreed price at which transaction occurs – for example, in the case of a *contract for difference* the price the parties agree to pay/receive. In the case of a *cap,* the price at which the purchaser's *exposure* is *capped*.

[27] Or its equivalent. Refer Footnote 26.

Term	Meaning
Weather derivative	Either an insurance contract or a derivative contract, where a defined payoff is related to a weather – typically temperature – variable at a defined location, for example, the temperature at Sydney Airport exceeding 40 degrees Celsius. The purchaser pays a *premium* in advance for the cover.

B. The SimEnergy Model

SimEnergy® is the most popular energy trading and risk management system in Australia. It is a front, middle and back office system designed specifically for traders, retailers and generators operating in the Australian and New Zealand electricity markets. Over the last 10 years, SimEnergy has been implemented at 15 companies, ranging from small start-ups to large corporations.

With a robust and intuitive interface, SimEnergy facilitates segregation of duties with a deal-approval workflow, including delegated authorities. The Calibration module supports portfolio valuation with half-hourly forward price curves, load forecasts and calculation of parameters for a mean-reverting jump-diffusion (MRJD) simulation model.

The Spot Analytics module forecasts retail loads, models generator dispatch and values these physical positions together with exchange-traded and over-the-counter derivatives. The valuation may be based on historical spot prices, forward price curves or prices simulated from an MRJD or discrete model. SimEnergy supports accrual and cash-flow accounting and discounting.

SimEnergy is a suite of Windows applications connecting to an Oracle or SQL Server database. It can be implemented as a stand-alone system or interface with your existing system(s). The Automation module provides the ability to run a selection of reports and functions on a daily, weekly or monthly basis.

C. The Relationship of Spot and Futures Prices in Electricity Markets

Generally, there are two theories explaining the relationship between spot and futures prices in commodity markets, see e.g. Botterud et al. (2002), Redl et al. (2009). The first theory argues that the cost and convenience of holding inventories explains the difference between the spot and futures price of a commodity. This theory is well known as the 'cost of carry' approach and goes back to Kaldor (1939). According to the 'cost of carry' approach, the forward price can be determined as a function of the current spot price, the interest rate and cost of storage. However, electricity as a flow commodity is produced and consumed instantaneously and continuously. Therefore, a standard cost of carry approach towards spot and forward markets cannot be applied.

Instead, the literature usually follows the second theory that considers equilibrium in expectations and risk aversion amongst agents with heterogeneous requirements for hedging the uncertainty of future spot prices (Keynes, 1930). From this angle the electricity forward price is then determined as the expected spot price plus an ex-ante risk premium of the market. The difference between the forward price and the expected spot price can then be interpreted as a compensation for bearing spot price risk (Bessembinder and Lemmon, 2002; Longstaff and Wang, 2004).

Bessembinder and Lemmon (2002) suggest a model for the Pennsylvania, New Jersey, Maryland (PJM) and California Power Exchange (CALPX) where the ex-ante one-month forward premium is modelled as being dependent on the mean, standard deviation and variance of electricity demand. A similar approach has been suggested by Redl et al. (2009) who examine the ex-post premium in the European Energy Exchange (EEX) and Scandinavian Nordpool electricity markets. Considering monthly forward contracts, they suggest an extended model that incorporates the volatility and skewness of daily spot prices in the month prior to the delivery period as well as a consumption and generation index of hydro and nuclear power generation. As proposed by Redl and Bunn (2011), extreme outcomes in the spot market such as price spikes have an impact on the magnitude of the risk premium. Further, they propose that additional variables such as gas futures prices, reserve margins, oil market volatility, and market power may have an impact on the premium. Handika and Trück (2012) suggest that there is strong seasonality in observed risk premiums for Australian electricity futures markets and find usually higher premiums for Q1 and Q3 in the regional Australian markets considered. Similar results with respect to strong seasonality in risk premiums are also reported by Cartea and Villaplana (2007) and Redl and Bunn (2011). Benth et al. (2008) point out that the maturity or time to delivery of the derivative contract is an important factor and suggest long-term negative or zero risk premiums while short-term risk premiums (up to three months) are expected to be positive.

Empirical studies have generally found significant positive premiums in electricity forward markets. Longstaff and Wang (2004) find positive risk premiums up to 14 per cent for the PJM day-ahead market, while Redl et al. (2009) find positive premiums for month-ahead forward contracts in the Nordpool and EEX market. They report premiums ranging from 8 per cent for considered base load forward contracts in the Nordpool market and 9 per cent for base load and 13 per cent for peak load contracts in the EEX market. Botterud et al. (2010) report premiums ranging from 1.3 to 4.4 per cent for the Nord Pool market when considering forward contracts with one week up to six weeks ahead. A number of other studies confirm the significance of forward premiums in various electricity markets. Significant premiums are reported, for example, by Hadsell and Shawky (2006) for the NYISO, Diko et al. (2006) for the APX, Bierbrauer et al. (2007) for the EEX, Weron (2008) for the Nordpool, Kolos and Ronn (2008) and Daskalakis and Markellos (2009) for the EEX, Nordpool and Powernext market. It is important to point out that unlike in this report, the majority of studies concentrate on nearest term futures contracts where current spot price and volatility levels might be more important than past observations of average historical spot prices or payoffs from similar futures contracts.

Interestingly, some studies provide quite different results on the actual sign of the risk premium even for the same markets: while Redl et al. (2009) find significant positive short-term premiums for nearest term monthly base load and peak load futures contracts in the EEX market, Kolos and Ronn (2008) find a negative forward premium for monthly, quarterly and yearly contracts at the EEX during the 2002-2003 trading period. Bierbrauer et al. (2007), also analysing the EEX market, find positive ex-ante risk premiums for short-term futures contracts while for contracts with maturities more than six months ahead the observed premiums are negative. Also Diko et al. (2006) and Benth et al (2007), investigating EEX futurespeak load contracts, find that forward premiums generally decrease as time to maturity increases.

Overall, the majority of authors seem to find rather positive risk premiums in electricity futures markets, while the time to the beginning of the delivery period also seems to play an important role for the magnitude and sign of the risk premium. Also, authors report that there is often seasonality in realised risk premiums for electricity futures markets.

Therefore, following the literature, in our model we consider realised electricity spot price levels and their volatility as well as seasonality by considering the quarter referring to the delivery period of the considered futures, cap futures or forward contract. We also take into account the maturity of the contracts, i.e. the remaining time until the beginning of the delivery period of the contract. . Recall that we have to estimate risk premiums, futures and cap prices not only for nearest term contracts but also for contracts where the delivery period starts in approximately 90-180 days (Q2 in T+1), 180-270 days (Q3 in T+1), 270-360 days (Q4 in T+1), and also for as for the Cal Year Strip futures contract in T+2. Therefore, in our model it is reasonable to assume that information dating back longer in time such as average historical spot prices and payoffs from futures and cap contracts in T, T-1, etc. may impact on expected spot prices and quotes for derivative contracts in T+1 and T+2.

Futures prices $F_{t,[Q_i,T+1]}$ at time t for quarter Q_i (i=1,2,3,4) in T+1 are defined as the sum of the expected average spot price during the delivery period $E\left(\bar{S}_{t,[Q_i,T+1]}\right)$ – for caps, the expected cap payoff during the delivery period – plus a risk premium $PREM_{t,[Q_i,T+1]}$ for the specific quarter. Overall, we model futures and, in a separate model, cap prices, as a function of the following variables:

- the current spot price level $\tilde{S}_t$ (based on a moving average model that is less sensitive to short-term movements and extreme observations in electricity spot prices)
- an estimate of the current volatility $\tilde{V}_t$ in the spot market (based on an exponentially weighted moving average (EWMA) model for the volatility of electricity spot prices)

- historical realised payoffs for futures F_T,F_(T-1),… and cap futures contracts C_T,C_(T-1),… referring to the same quarter in the current and previous years. Note that the payoff for the cap futures contract C_T can also be considered as a proxy for the number of extreme observations or price spikes in the market that have been suggested as an explanatory variable for risk premiums e.g. by Redl and Bunn (2011). Interestingly, usually only the most recent observations F_T and C_T for futures and cap payoffs were significant in the model while information on previous years T-1, T-2 did not seem to add any significant additional explanatory power such that these variables were omitted.
- To take into account the seasonality as well as the remaining time to the beginning of the delivery period, we estimate separate models for Q1, Q2, Q3, Q4 futures and cap futures contracts in T+1 as well as for the Cal Year Strip futures contract in T+2.

For futures contracts, our model takes the following form:

$$\begin{aligned} F_{t,[Q_i,T+1]} &= E\left(\bar{S}_{t,[Q_i,T+1]}\right) + PREM_{F_t,[Q_i,T+1]} \\ &= \beta_0 + \beta_1 \tilde{S}_t \; + \beta_2 \tilde{V}_t \; + \beta_3 F_T + \beta_4 C_T + \varepsilon_t \end{aligned}$$

while for cap futures contracts we estimate the following model:

$$\begin{aligned} C_{t,[Q_i,T+1]} &= E\left(C_{t,[Q_i,T+1]}\right) + PREM_{C_t,[Q_i,T+1]} \\ &= \beta_0 + \beta_1 \tilde{S}_t \; + \beta_2 \tilde{V}_t \; + \beta_3 F_T + \beta_4 C_T + \varepsilon_t \end{aligned}$$

As pointed out above, by using these variables, we assume that when pricing futures contracts, market participants do take into account information about the current price level and volatility in the spot market as well as information about historical payoffs for futures and cap contracts dating further back in time.

These models are estimated using all observations for futures and cap prices during October – December in Year T, assuming that this is the period where large customers will negotiate these contracts for period T+1 (and T+2 for the calendar futures contract). We used available futures and cap futures prices from 2005 to 2011. The model is estimated for each of the considered contracts (futures and cap futures in Q1, Q2, Q3, and Q4) separately. In our estimation we also distinguish between the South Australian and Victorian markets. We then use the average of the estimated futures and cap futures prices during the considered period as input for the simulation analysis. As illustrated in Table 2.2 we get quite different estimates for the futures and cap futures prices depending on the market state (LPLV, LPHV, HPLV, HPHV) when these contracts are struck. Generally, futures and cap futures prices are significantly higher for HPLV and HPHV regimes, illustrating the impact of the current price level and volatility of electricity spot prices, as well as most recent realisations of futures and cap prices on risk premiums and futures quotes.

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D. Detailed Results

D. 1 Costs of risk management strategies, by customer profile and strategy, VIC, LPLV, $ and $/MWh

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
		Total cost		$/MWH	
Flat Load Profile					
Load Curtailment	n/a	-$1,622,545	-$1,632,398	$54.09	$54.42
Pool	n/a	-$1,624,121	-$1,636,360	$54.14	$54.55
Pool + Caps	1 MW Cap priced in LPLV	-$1,682,235	-$1,692,921	$56.08	$56.44
Pool + Caps	1 MW Cap priced in LPHV	-$1,702,200	-$1,712,885	$56.75	$57.10
Pool + Caps	1 MW Cap priced in HPLV	-$1,717,122	-$1,727,808	$57.25	$57.60
Pool + Caps	1 MW Cap priced in HPHV	-$1,719,113	-$1,729,798	$57.31	$57.67
Part hedge	2 MW Swap priced in LPHV	-$1,788,618	-$1,796,039	$59.63	$59.88
Part hedge	2 MW Swap priced in LPLV	-$1,802,998	-$1,810,419	$60.11	$60.36
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,944,094	-$1,950,128	$64.81	$65.01
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,958,475	-$1,964,508	$65.29	$65.49
Progressive	2 MW Swap priced in LPHV then LPHV	-$2,033,972	-$2,040,005	$67.81	$68.01
Progressive	2 MW Swap priced in LPHV then LPLV	-$2,048,352	-$2,054,386	$68.29	$68.49
Part hedge	2 MW Swap priced in HPLV	-$2,111,422	-$2,118,843	$70.39	$70.64
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,194,280	-$2,200,313	$73.15	$73.35
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,208,660	-$2,214,694	$73.63	$73.83
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,241,759	-$2,247,793	$74.74	$74.94
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,256,139	-$2,262,173	$75.21	$75.42
Part hedge	2 MW Swap priced in HPHV	-$2,258,450	-$2,265,871	$75.29	$75.54
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,266,899	-$2,272,932	$75.57	$75.77
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,356,776	-$2,362,810	$78.57	$78.77
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,413,927	-$2,419,960	$80.47	$80.68
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,503,805	-$2,509,838	$83.47	$83.67
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,517,084	-$2,523,118	$83.91	$84.12
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,564,563	-$2,570,597	$85.50	$85.70
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,664,113	-$2,670,146	$88.82	$89.02
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,711,592	-$2,717,625	$90.40	$90.60
		Summer Peaking Profile			
Load Curtailment	n/a	-$1,668,288	-$1,694,376	$54.84	$55.70
Pool	n/a	-$1,670,010	-$1,697,517	$54.90	$55.80
Pool + Caps	2 MW Cap priced in LPLV	-$1,786,239	-$1,812,341	$58.72	$59.58
Pool + Caps	2 MW Cap priced in LPHV	-$1,826,168	-$1,852,270	$60.03	$60.89
Part hedge	2 MW Swap priced in LPHV	-$1,834,507	-$1,859,988	$60.31	$61.14
Part hedge	2 MW Swap priced in LPLV	-$1,848,888	-$1,874,368	$60.78	$61.62
Pool + Caps	2 MW Cap priced in HPLV	-$1,856,014	-$1,882,116	$61.01	$61.87
Pool + Caps	2 MW Cap priced in HPHV	-$1,859,994	-$1,886,096	$61.14	$62.00
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,989,984	-$2,014,973	$65.42	$66.24

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
Progressive	2 MW Swap priced in LPLV then LPLV	-$2,004,364	-$2,029,353	$65.89	$66.71
Progressive	2 MW Swap priced in LPHV then LPHV	-$2,079,861	-$2,104,850	$68.37	$69.19
Progressive	2 MW Swap priced in LPHV then LPLV	-$2,094,242	-$2,119,231	$68.84	$69.67
Part hedge	2 MW Swap priced in HPLV	-$2,157,312	-$2,182,792	$70.92	$71.76
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,240,169	-$2,265,158	$73.64	$74.46
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,254,550	-$2,279,539	$74.11	$74.94
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,287,649	-$2,312,638	$75.20	$76.02
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,302,029	-$2,327,018	$75.67	$76.50
Part hedge	2 MW Swap priced in HPHV	-$2,304,340	-$2,329,820	$75.75	$76.59
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,312,788	-$2,337,777	$76.03	$76.85
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,402,666	-$2,427,655	$78.98	$79.80
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,459,816	-$2,484,805	$80.86	$81.68
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,549,694	-$2,574,683	$83.82	$84.64
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,562,974	-$2,587,963	$84.25	$85.07
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,610,453	-$2,635,442	$85.81	$86.64
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,710,002	-$2,734,991	$89.09	$89.91
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,757,481	-$2,782,470	$90.65	$91.47
	Winter Peaking Profile				
Load Curtailment	n/a	-$1,640,966	-$1,656,526	$54.79	$55.31
Pool	n/a	-$1,642,708	-$1,660,859	$54.84	$55.45
Pool + Caps	1 MW Cap priced in LPLV	-$1,700,822	-$1,717,506	$56.78	$57.34
Pool + Caps	1 MW Cap priced in LPHV	-$1,720,787	-$1,737,470	$57.45	$58.01
Pool + Caps	1 MW Cap priced in HPLV	-$1,735,710	-$1,752,393	$57.95	$58.50
Pool + Caps	1 MW Cap priced in HPHV	-$1,737,700	-$1,754,383	$58.01	$58.57
Part hedge	2 MW Swap priced in LPHV	-$1,807,205	-$1,821,592	$60.33	$60.82
Part hedge	2 MW Swap priced in LPLV	-$1,821,585	-$1,835,973	$60.81	$61.30
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,962,682	-$1,976,081	$65.53	$65.97
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,977,062	-$1,990,461	$66.01	$66.45
Progressive	2 MW Swap priced in LPHV then LPHV	-$2,052,559	-$2,065,959	$68.53	$68.97
Progressive	2 MW Swap priced in LPHV then LPLV	-$2,066,939	-$2,080,339	$69.01	$69.45
Part hedge	2 MW Swap priced in HPLV	-$2,130,009	-$2,144,397	$71.11	$71.59
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,212,867	-$2,226,267	$73.88	$74.33
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,227,247	-$2,240,647	$74.36	$74.81
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,260,346	-$2,273,746	$75.46	$75.91
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,274,727	-$2,288,126	$75.94	$76.39
Part hedge	2 MW Swap priced in HPHV	-$2,277,038	-$2,291,425	$76.02	$76.50
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,285,486	-$2,298,885	$76.30	$76.75
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,375,363	-$2,388,763	$79.30	$79.75
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,432,514	-$2,445,914	$81.21	$81.66
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,522,392	-$2,535,791	$84.21	$84.66
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,535,671	-$2,549,071	$84.65	$85.10

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,583,151	-$2,596,550	$86.24	$86.69
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,682,700	-$2,696,099	$89.56	$90.01
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,730,179	-$2,743,579	$91.15	$91.60

D. 2. Costs of risk management strategies, by customer profile and strategy, VIC, LPHV, $ and $/MWh

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
		Total cost		$/MWH	
		Flat Load Profile			
Load Curtailment	n/a	-$1,757,583	-$1,805,014	$58.69	$60.27
Pool + Caps	1 MW Cap priced in LPLV	-$1,888,280	-$1,956,091	$62.94	$65.21
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,896,089	-$1,913,065	$63.21	$63.77
Part hedge	2 MW Swap priced in LPHV	-$1,907,586	-$1,947,090	$63.59	$64.91
Pool + Caps	1 MW Cap priced in LPHV	-$1,908,244	-$1,976,056	$63.61	$65.87
Pool	n/a	-$1,910,063	-$2,005,695	$63.67	$66.86
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,910,469	-$1,927,445	$63.68	$64.25
Part hedge	2 MW Swap priced in LPLV	-$1,921,966	-$1,961,470	$64.07	$65.38
Pool + Caps	1 MW Cap priced in HPLV	-$1,923,167	-$1,990,979	$64.11	$66.37
Pool + Caps	1 MW Cap priced in HPHV	-$1,925,157	-$1,992,969	$64.17	$66.43
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,985,967	-$2,002,943	$66.20	$66.77
Progressive	2 MW Swap priced in LPHV then LPLV	-$2,000,347	-$2,017,323	$66.68	$67.25
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,146,275	-$2,163,251	$71.54	$72.11
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,160,655	-$2,177,631	$72.02	$72.59
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,193,754	-$2,210,730	$73.13	$73.69
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,208,134	-$2,225,110	$73.61	$74.17
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,218,893	-$2,235,869	$73.97	$74.53
Part hedge	2 MW Swap priced in HPLV	-$2,230,390	-$2,269,894	$74.35	$75.67
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,308,771	-$2,325,747	$76.96	$77.53
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,365,922	-$2,382,898	$78.87	$79.43
Part hedge	2 MW Swap priced in HPHV	-$2,377,419	-$2,416,922	$79.25	$80.57
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,455,799	-$2,472,775	$81.86	$82.43
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,469,079	-$2,486,055	$82.31	$82.87
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,516,558	-$2,533,534	$83.89	$84.45
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,616,107	-$2,633,083	$87.21	$87.77
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,663,587	-$2,680,563	$88.79	$89.36
		Summer Peaking Load Profile			
Load Curtailment	n/a	-$1,863,733	-$1,935,664	$61.39	$63.75
Pool + Caps	2 MW Cap priced in LPLV	-$2,024,098	-$2,116,241	$66.51	$69.54
Progressive	2 MW Swap priced in LPLV then LPHV	-$2,053,690	-$2,115,587	$67.49	$69.52
Pool + Caps	2 MW Cap priced in LPHV	-$2,064,027	-$2,156,170	$67.83	$70.85
Part hedge	2 MW Swap priced in LPHV	-$2,065,187	-$2,153,924	$67.86	$70.78
Pool	n/a	-$2,067,664	-$2,202,871	$67.95	$72.39
Progressive	2 MW Swap priced in LPLV then LPLV	-$2,068,071	-$2,129,967	$67.96	$69.99
Part hedge	2 MW Swap priced in LPLV	-$2,079,568	-$2,168,305	$68.34	$71.25

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
Pool + Caps	2 MW Cap priced in HPLV	-$2,093,873	-$2,186,016	$68.81	$71.84
Pool + Caps	2 MW Cap priced in HPHV	-$2,097,853	-$2,189,996	$68.94	$71.97
Progressive	2 MW Swap priced in LPHV then LPHV	-$2,143,568	-$2,205,464	$70.44	$72.47
Progressive	2 MW Swap priced in LPHV then LPLV	-$2,157,948	-$2,219,844	$70.91	$72.95
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,303,876	-$2,365,772	$75.71	$77.74
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,318,256	-$2,380,152	$76.18	$78.21
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,351,355	-$2,413,251	$77.27	$79.30
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,365,735	-$2,427,632	$77.74	$79.77
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,376,495	-$2,438,391	$78.09	$80.13
Part hedge	2 MW Swap priced in HPLV	-$2,387,992	-$2,476,729	$78.47	$81.39
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,466,372	-$2,528,268	$81.05	$83.08
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,523,523	-$2,585,419	$82.93	$84.96
Part hedge	2 MW Swap priced in HPHV	-$2,535,020	-$2,623,757	$83.30	$86.22
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,613,401	-$2,675,297	$85.88	$87.91
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,626,680	-$2,688,576	$86.32	$88.35
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,674,159	-$2,736,056	$87.88	$89.91
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,773,709	-$2,835,605	$91.15	$93.18
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,821,188	-$2,883,084	$92.71	$94.74
		Winter Peaking Load Profile			
Load Curtailment	n/a	-$1,777,411	-$1,828,096	$59.43	$61.13
Pool + Caps	1 MW Cap priced in LPLV	-$1,911,769	-$1,985,773	$63.81	$66.28
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,919,579	-$1,942,456	$64.07	$64.84
Part hedge	2 MW Swap priced in LPHV	-$1,931,076	-$1,977,622	$64.46	$66.01
Pool + Caps	1 MW Cap priced in LPHV	-$1,931,734	-$2,005,738	$64.48	$66.95
Pool	n/a	-$1,933,552	-$2,033,097	$64.54	$67.86
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,933,959	-$1,956,837	$64.55	$65.32
Part hedge	2 MW Swap priced in LPLV	-$1,945,456	-$1,992,002	$64.94	$66.49
Pool + Caps	1 MW Cap priced in HPLV	-$1,946,657	-$2,020,660	$64.98	$67.45
Pool + Caps	1 MW Cap priced in HPHV	-$1,948,647	-$2,022,650	$65.04	$67.51
Progressive	2 MW Swap priced in LPHV then LPHV	-$2,009,456	-$2,032,334	$67.07	$67.84
Progressive	2 MW Swap priced in LPHV then LPLV	-$2,023,837	-$2,046,714	$67.55	$68.32
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,169,764	-$2,192,642	$72.42	$73.19
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,184,145	-$2,207,022	$72.90	$73.67
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,217,244	-$2,240,121	$74.01	$74.77
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,231,624	-$2,254,501	$74.49	$75.25
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,242,383	-$2,265,261	$74.85	$75.61
Part hedge	2 MW Swap priced in HPLV	-$2,253,880	-$2,300,426	$75.23	$76.79
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,332,261	-$2,355,138	$77.85	$78.61

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,389,412	-$2,412,289	$79.76	$80.52
Part hedge	2 MW Swap priced in HPHV	-$2,400,909	-$2,447,455	$80.14	$81.69
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,479,289	-$2,502,167	$82.76	$83.52
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,492,569	-$2,515,446	$83.20	$83.96
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,540,048	-$2,562,925	$84.78	$85.55
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,639,597	-$2,662,475	$88.11	$88.87
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,687,076	-$2,709,954	$89.69	$90.46

D. 3. Costs of risk management strategies, by customer profile and strategy, VIC, HPLV, $ and $/MWh

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
		Total cost		$/MWH	
		Flat Load Profile			
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,842,182	-$1,852,805	$61.41	$61.76
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,856,562	-$1,867,186	$61.89	$62.24
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,932,059	-$1,942,683	$64.40	$64.76
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,946,439	-$1,957,063	$64.88	$65.24
Part hedge	2 MW Swap priced in LPHV	-$2,040,910	-$2,060,331	$68.03	$68.68
Part hedge	2 MW Swap priced in LPLV	-$2,055,290	-$2,074,712	$68.51	$69.16
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,092,367	-$2,102,991	$69.75	$70.10
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,106,747	-$2,117,371	$70.22	$70.58
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,139,846	-$2,150,470	$71.33	$71.68
Load Curtailment	n/a	-$2,140,995	-$2,165,935	$72.01	$72.85
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,154,227	-$2,164,851	$71.81	$72.16
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,164,986	-$2,175,610	$72.17	$72.52
Pool	n/a	-$2,230,617	-$2,272,881	$74.35	$75.76
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,254,863	-$2,265,487	$75.16	$75.52
Pool + Caps	1 MW Cap priced in LPLV	-$2,269,897	-$2,305,982	$75.66	$76.87
Pool + Caps	1 MW Cap priced in LPHV	-$2,289,861	-$2,325,947	$76.33	$77.53
Pool + Caps	1 MW Cap priced in HPLV	-$2,304,784	-$2,340,870	$76.83	$78.03
Pool + Caps	1 MW Cap priced in HPHV	-$2,306,774	-$2,342,860	$76.89	$78.10
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,312,014	-$2,322,638	$77.07	$77.42
Part hedge	2 MW Swap priced in HPLV	-$2,363,714	-$2,383,136	$78.79	$79.44
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,401,892	-$2,412,516	$80.06	$80.42
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,415,171	-$2,425,795	$80.51	$80.86
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,462,651	-$2,473,275	$82.09	$82.44
Part hedge	2 MW Swap priced in HPHV	-$2,510,742	-$2,530,164	$83.69	$84.34
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,562,200	-$2,572,824	$85.41	$85.76
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,609,679	-$2,620,303	$86.99	$87.34
		Summer Peaking Load Profile			
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,961,145	-$1,998,781	$64.43	$65.67
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,975,526	-$2,013,161	$64.90	$66.14
Progressive	2 MW Swap priced in LPHV then LPHV	-$2,051,023	-$2,088,658	$67.38	$68.62
Progressive	2 MW Swap priced in LPHV then LPLV	-$2,065,403	-$2,103,039	$67.86	$69.09
Part hedge	2 MW Swap priced in LPHV	-$2,159,873	-$2,206,053	$70.96	$72.48
Part hedge	2 MW Swap priced in LPLV	-$2,174,254	-$2,220,433	$71.43	$72.95
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,211,331	-$2,248,966	$72.65	$73.89
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,225,711	-$2,263,347	$73.12	$74.36
Load Curtailment	n/a	-$2,237,586	-$2,280,566	$74.30	$75.73
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,258,810	-$2,296,446	$74.21	$75.45

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,273,190	-$2,310,826	$74.68	$75.92
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,283,950	-$2,321,585	$75.04	$76.27
Pool	n/a	-$2,349,581	-$2,412,681	$77.19	$79.27
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,373,827	-$2,411,463	$77.99	$79.23
Pool + Caps	2 MW Cap priced in LPLV	-$2,428,140	-$2,480,539	$79.77	$81.49
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,430,978	-$2,468,614	$79.87	$81.10
Pool + Caps	2 MW Cap priced in LPHV	-$2,468,070	-$2,520,468	$81.09	$82.81
Part hedge	2 MW Swap priced in HPLV	-$2,482,678	-$2,528,857	$81.57	$83.08
Pool + Caps	2 MW Cap priced in HPLV	-$2,497,915	-$2,550,314	$82.07	$83.79
Pool + Caps	2 MW Cap priced in HPHV	-$2,501,895	-$2,554,294	$82.20	$83.92
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,520,855	-$2,558,491	$82.82	$84.06
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,534,135	-$2,571,771	$83.26	$84.49
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,581,614	-$2,619,250	$84.82	$86.05
Part hedge	2 MW Swap priced in HPHV	-$2,629,706	-$2,675,886	$86.40	$87.91
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,681,163	-$2,718,799	$88.09	$89.32
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,728,643	-$2,766,278	$89.65	$90.88
	Winter Peaking Profile				
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,892,890	-$1,913,611	$63.18	$63.87
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,907,271	-$1,927,991	$63.66	$64.35
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,982,768	-$2,003,488	$66.18	$66.87
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,997,148	-$2,017,869	$66.66	$67.35
Part hedge	2 MW Swap priced in LPHV	-$2,091,618	-$2,120,282	$69.81	$70.77
Part hedge	2 MW Swap priced in LPLV	-$2,105,999	-$2,134,662	$70.29	$71.25
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,143,076	-$2,163,796	$71.53	$72.22
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,157,456	-$2,178,177	$72.01	$72.70
Load Curtailment	n/a	-$2,182,526	-$2,212,550	$73.64	$74.65
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,190,555	-$2,211,275	$73.12	$73.81
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,204,935	-$2,225,656	$73.60	$74.29
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,215,695	-$2,236,415	$73.96	$74.65
Pool	n/a	-$2,281,326	-$2,329,627	$76.15	$77.76
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,305,572	-$2,326,293	$76.96	$77.65
Pool + Caps	1 MW Cap priced in LPLV	-$2,320,605	-$2,362,606	$77.46	$78.86
Pool + Caps	1 MW Cap priced in LPHV	-$2,340,570	-$2,382,571	$78.12	$79.53
Pool + Caps	1 MW Cap priced in HPLV	-$2,355,493	-$2,397,493	$78.62	$80.02
Pool + Caps	1 MW Cap priced in HPHV	-$2,357,483	-$2,399,483	$78.69	$80.09
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,362,723	-$2,383,443	$78.86	$79.55
Part hedge	2 MW Swap priced in HPLV	-$2,414,423	-$2,443,086	$80.59	$81.54
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,452,600	-$2,473,321	$81.86	$82.55
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,465,880	-$2,486,601	$82.31	$83.00
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,513,359	-$2,534,080	$83.89	$84.58
Part hedge	2 MW Swap priced in HPHV	-$2,561,451	-$2,590,114	$85.50	$86.45

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,612,908	-$2,633,629	$87.21	$87.90
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,660,388	-$2,681,108	$88.80	$89.49

D. 4. Costs of risk management strategies, by customer profile and strategy, VIC, HPHV, $ and $/MWh

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
		Total cost		$/MWH	
		Flat Load Profile			
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,755,238	-$1,770,531	$58.51	$59.02
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,769,618	-$1,784,911	$58.99	$59.50
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,845,116	-$1,860,409	$61.51	$62.02
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,859,496	-$1,874,789	$61.99	$62.50
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,005,424	-$2,020,717	$66.85	$67.36
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,019,804	-$2,035,097	$67.33	$67.84
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,052,903	-$2,068,196	$68.43	$68.94
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,067,283	-$2,082,576	$68.91	$69.42
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,078,042	-$2,093,335	$69.27	$69.78
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,167,920	-$2,183,213	$72.27	$72.78
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,225,071	-$2,240,364	$74.17	$74.68
Part hedge	2 MW Swap priced in LPHV	-$2,256,035	-$2,284,938	$75.21	$76.17
Part hedge	2 MW Swap priced in LPLV	-$2,270,416	-$2,299,318	$75.69	$76.65
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,314,948	-$2,330,241	$77.17	$77.68
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,328,228	-$2,343,521	$77.61	$78.12
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,375,707	-$2,391,000	$79.20	$79.71
Load Curtailment	n/a	-$2,448,062	-$2,483,624	$83.88	$85.09
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,475,256	-$2,490,549	$82.51	$83.02
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,522,735	-$2,538,028	$84.10	$84.61
Part hedge	2 MW Swap priced in HPLV	-$2,578,840	-$2,607,742	$85.97	$86.93
Part hedge	2 MW Swap priced in HPHV	-$2,725,868	-$2,754,771	$90.87	$91.83
Pool + Caps	1 MW Cap priced in LPLV	-$2,730,492	-$2,782,827	$91.02	$92.77
Pool	n/a	-$2,747,812	-$2,814,460	$91.60	$93.82
Pool + Caps	1 MW Cap priced in LPHV	-$2,750,457	-$2,802,792	$91.69	$93.43
Pool + Caps	1 MW Cap priced in HPLV	-$2,765,379	-$2,817,715	$92.19	$93.93
Pool + Caps	1 MW Cap priced in HPHV	-$2,767,369	-$2,819,705	$92.25	$94.00
		Summer Peaking Load Profile			
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,976,236	-$2,033,555	$64.93	$66.81
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,990,616	-$2,047,935	$65.40	$67.28

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
Progressive	2 MW Swap priced in LPHV then LPHV	-$2,066,114	-$2,123,432	$67.88	$69.76
Progressive	2 MW Swap priced in LPHV then LPLV	-$2,080,494	-$2,137,813	$68.35	$70.24
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,226,422	-$2,283,740	$73.15	$75.03
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,240,802	-$2,298,121	$73.62	$75.50
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,273,901	-$2,331,220	$74.71	$76.59
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,288,281	-$2,345,600	$75.18	$77.06
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,299,040	-$2,356,359	$75.53	$77.42
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,388,918	-$2,446,237	$78.48	$80.37
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,446,069	-$2,503,387	$80.36	$82.25
Part hedge	2 MW Swap priced in LPHV	-$2,477,033	-$2,550,209	$81.38	$83.78
Part hedge	2 MW Swap priced in LPLV	-$2,491,414	-$2,564,589	$81.85	$84.26
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,535,946	-$2,593,265	$83.32	$85.20
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,549,226	-$2,606,545	$83.75	$85.63
Load Curtailment	n/a	-$2,589,080	-$2,653,036	$87.91	$90.08
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,596,705	-$2,654,024	$85.31	$87.19
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,696,254	-$2,753,573	$88.58	$90.46
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,743,734	-$2,801,052	$90.14	$92.02
Part hedge	2 MW Swap priced in HPLV	-$2,799,838	-$2,873,013	$91.98	$94.39
Pool + Caps	2 MW Cap priced in LPLV	-$2,934,170	-$3,013,564	$96.40	$99.01
Part hedge	2 MW Swap priced in HPHV	-$2,946,866	-$3,020,041	$96.82	$99.22
Pool	n/a	-$2,968,810	-$3,072,869	$97.54	$100.96
Pool + Caps	2 MW Cap priced in LPHV	-$2,974,099	-$3,053,493	$97.71	$100.32
Pool + Caps	2 MW Cap priced in HPLV	-$3,003,945	-$3,083,338	$98.69	$101.30
Pool + Caps	2 MW Cap priced in HPHV	-$3,007,925	-$3,087,319	$98.82	$101.43
	Winter Peaking Load Profile				
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,861,791	-$1,889,023	$62.15	$63.06
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,951,668	-$1,978,900	$65.15	$66.06
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,111,976	-$2,139,208	$70.50	$71.41
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,159,455	-$2,186,687	$72.08	$72.99
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,184,595	-$2,211,827	$72.92	$73.83
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,274,473	-$2,301,705	$75.92	$76.83

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,331,623	-$2,358,855	$77.83	$78.74
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,331,623	-$2,358,855	$77.83	$78.74
Part hedge	2 MW Swap priced in LPHV	-$2,362,588	-$2,403,478	$78.86	$80.23
Part hedge	2 MW Swap priced in LPLV	-$2,376,968	-$2,417,858	$79.34	$80.71
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,421,501	-$2,448,733	$80.83	$81.74
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,421,501	-$2,448,733	$80.83	$81.74
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,434,781	-$2,462,013	$81.27	$82.18
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,482,260	-$2,509,492	$82.86	$83.77
Load Curtailment	n/a	-$2,512,360	-$2,551,703	$86.63	$87.99
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,581,809	-$2,609,041	$86.18	$87.09
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,581,809	-$2,609,041	$86.18	$87.09
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,629,288	-$2,656,520	$87.77	$88.67
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,629,288	-$2,656,520	$87.77	$88.67
Part hedge	2 MW Swap priced in HPLV	-$2,685,392	-$2,726,282	$89.64	$91.00
Part hedge	2 MW Swap priced in HPHV	-$2,832,420	-$2,873,310	$94.55	$95.91
Pool + Caps	1 MW Cap priced in LPLV	-$2,837,044	-$2,895,655	$94.70	$96.66
Pool	n/a	-$2,854,364	-$2,926,428	$95.28	$97.68
Pool + Caps	1 MW Cap priced in LPHV	-$2,857,009	-$2,915,620	$95.37	$97.32
Pool + Caps	1 MW Cap priced in HPLV	-$2,871,932	-$2,930,542	$95.87	$97.82
Pool + Caps	1 MW Cap priced in HPHV	-$2,873,922	-$2,932,532	$95.93	$97.89

D. 5. Costs of risk management strategies, by customer profile and strategy, South Australia, LPLV, $ and $/MWh

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
		Total cost		$/MWH	
		Flat Load Profile			
Load Curtailment	n/a	-$1,355,032	-$1,374,133	$45.19	$45.82
Pool	n/a	-$1,382,952	-$1,418,700	$46.10	$47.29
Pool + Caps	1 MW Cap priced in LPLV	-$1,449,938	-$1,476,126	$48.33	$49.21
Pool + Caps	1 MW Cap priced in LPHV	-$1,458,950	-$1,485,138	$48.63	$49.51
Pool + Caps	1 MW Cap priced in HPLV	-$1,484,709	-$1,510,897	$49.49	$50.36
Pool + Caps	1 MW Cap priced in HPHV	-$1,495,655	-$1,521,843	$49.86	$50.73
Part hedge	2 MW Swap priced in LPLV	-$1,516,728	-$1,531,994	$50.56	$51.07
Part hedge	2 MW Swap priced in LPHV	-$1,538,154	-$1,553,420	$51.27	$51.78
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,667,713	-$1,675,430	$55.59	$55.85
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,689,139	-$1,696,856	$56.31	$56.56
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,707,834	-$1,715,551	$56.93	$57.19
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,729,260	-$1,736,977	$57.64	$57.90
Part hedge	2 MW Swap priced in HPHV	-$1,743,931	-$1,759,197	$58.13	$58.64
Progressive	2 MW Swap priced in HPLV then LPLV	-$1,838,533	-$1,846,250	$61.29	$61.54
Progressive	2 MW Swap priced in HPLV then LPHV	-$1,859,959	-$1,867,676	$62.00	$62.26
Progressive	2 MW Swap priced in LPLV then HPHV	-$1,894,916	-$1,902,633	$63.17	$63.42
Progressive	2 MW Swap priced in LPHV then HPHV	-$1,935,036	-$1,942,754	$64.50	$64.76
Progressive	2 MW Swap priced in HPHV then LPLV	-$1,943,478	-$1,951,195	$64.78	$65.04
Progressive	2 MW Swap priced in HPHV then LPHV	-$1,964,904	-$1,972,621	$65.50	$65.76
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,065,736	-$2,073,453	$68.86	$69.12
Part hedge	2 MW Swap priced in HPLV	-$2,072,227	-$2,087,493	$69.08	$69.59
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,170,680	-$2,178,398	$72.36	$72.62
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,223,212	-$2,230,929	$74.11	$74.37
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,263,333	-$2,271,050	$75.45	$75.70
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,394,032	-$2,401,749	$79.80	$80.06
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,498,977	-$2,506,694	$83.30	$83.56
		Summer Peaking Load Profile			
Load Curtailment	n/a	-$1,399,030	-$1,427,991	$45.92	$46.87
Pool	n/a	-$1,426,766	-$1,468,626	$46.81	$48.18

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
Part hedge	2 MW Swap priced in LPLV	-$1,560,542	-$1,588,082	$51.20	$52.10
Pool + Caps	2 MW Cap priced in LPLV	-$1,560,738	-$1,588,921	$51.21	$52.13
Pool + Caps	2 MW Cap priced in LPHV	-$1,578,763	-$1,606,946	$51.80	$52.72
Part hedge	2 MW Swap priced in LPHV	-$1,581,968	-$1,609,508	$51.90	$52.81
Pool + Caps	2 MW Cap priced in HPLV	-$1,630,281	-$1,658,464	$53.49	$54.41
Pool + Caps	2 MW Cap priced in HPHV	-$1,652,173	-$1,680,356	$54.21	$55.13
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,711,527	-$1,734,709	$56.15	$56.91
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,732,953	-$1,756,135	$56.86	$57.62
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,751,648	-$1,774,830	$57.47	$58.23
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,773,074	-$1,796,256	$58.17	$58.93
Part hedge	2 MW Swap priced in HPHV	-$1,787,745	-$1,815,285	$58.65	$59.56
Progressive	2 MW Swap priced in HPLV then LPLV	-$1,882,347	-$1,905,529	$61.76	$62.52
Progressive	2 MW Swap priced in HPLV then LPHV	-$1,903,773	-$1,926,955	$62.46	$63.22
Progressive	2 MW Swap priced in LPLV then HPHV	-$1,938,730	-$1,961,912	$63.61	$64.37
Progressive	2 MW Swap priced in LPHV then HPHV	-$1,978,851	-$2,002,033	$64.92	$65.68
Progressive	2 MW Swap priced in HPHV then LPLV	-$1,987,292	-$2,010,474	$65.20	$65.96
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,008,718	-$2,031,900	$65.90	$66.66
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,109,550	-$2,132,732	$69.21	$69.97
Part hedge	2 MW Swap priced in HPLV	-$2,116,041	-$2,143,581	$69.42	$70.33
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,214,495	-$2,237,677	$72.65	$73.41
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,267,026	-$2,290,208	$74.38	$75.14
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,307,147	-$2,330,329	$75.69	$76.45
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,437,846	-$2,461,028	$79.98	$80.74
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,542,791	-$2,565,973	$83.42	$84.19
		Winter Peaking Load Profile			
Load Curtailment	n/a	-$1,373,148	-$1,395,208	$45.86	$46.60
Pool	n/a	-$1,400,542	-$1,437,869	$46.76	$48.01
Pool + Caps	1 MW Cap priced in LPLV	-$1,467,528	-$1,496,516	$49.00	$49.96
Pool + Caps	1 MW Cap priced in LPHV	-$1,476,541	-$1,505,528	$49.30	$50.26
Pool + Caps	1 MW Cap priced in HPLV	-$1,502,300	-$1,531,287	$50.16	$51.12
Pool + Caps	1 MW Cap priced in HPHV	-$1,513,246	-$1,542,233	$50.52	$51.49
Part hedge	2 MW Swap priced in LPLV	-$1,534,319	-$1,553,256	$51.23	$51.86
Part hedge	2 MW Swap priced in LPHV	-$1,555,745	-$1,574,682	$51.94	$52.57

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,685,303	-$1,699,632	$56.27	$56.75
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,706,730	-$1,721,058	$56.98	$57.46
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,725,424	-$1,739,752	$57.61	$58.08
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,746,850	-$1,761,179	$58.32	$58.80
Part hedge	2 MW Swap priced in HPHV	-$1,761,521	-$1,780,458	$58.81	$59.44
Progressive	2 MW Swap priced in HPLV then LPLV	-$1,856,123	-$1,870,452	$61.97	$62.45
Progressive	2 MW Swap priced in HPLV then LPHV	-$1,877,550	-$1,891,878	$62.69	$63.16
Progressive	2 MW Swap priced in LPLV then HPHV	-$1,912,506	-$1,926,834	$63.85	$64.33
Progressive	2 MW Swap priced in LPHV then HPHV	-$1,952,627	-$1,966,955	$65.19	$65.67
Progressive	2 MW Swap priced in HPHV then LPLV	-$1,961,068	-$1,975,396	$65.47	$65.95
Progressive	2 MW Swap priced in HPHV then LPHV	-$1,982,494	-$1,996,823	$66.19	$66.67
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,083,326	-$2,097,654	$69.56	$70.03
Part hedge	2 MW Swap priced in HPLV	-$2,089,818	-$2,108,755	$69.77	$70.40
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,188,271	-$2,202,599	$73.06	$73.54
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,240,803	-$2,255,131	$74.81	$75.29
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,280,923	-$2,295,252	$76.15	$76.63
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,411,623	-$2,425,951	$80.52	$80.99
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,516,567	-$2,530,896	$84.02	$84.50

D. 6. Costs of risk management strategies, by customer profile and strategy, South Australia, LPHV, $ and $/MWh

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
		Total cost		$/MWH	
		Flat Load Profile			
Load Curtailment	n/a	-$1,440,863	-$1,505,459	$48.13	$50.28
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,621,668	-$1,642,475	$54.05	$54.75
Pool + Caps	1 MW Cap priced in LPLV	-$1,622,835	-$1,716,042	$54.09	$57.20
Part hedge	2 MW Swap priced in LPLV	-$1,631,383	-$1,685,149	$54.38	$56.17
Pool + Caps	1 MW Cap priced in LPHV	-$1,631,847	-$1,725,055	$54.39	$57.50
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,643,094	-$1,663,901	$54.77	$55.46
Part hedge	2 MW Swap priced in LPHV	-$1,652,809	-$1,706,575	$55.09	$56.88
Pool + Caps	1 MW Cap priced in HPLV	-$1,657,606	-$1,750,814	$55.25	$58.36
Pool	n/a	-$1,658,306	-$1,785,768	$55.28	$59.52
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,661,789	-$1,682,596	$55.39	$56.08
Pool + Caps	1 MW Cap priced in HPHV	-$1,668,552	-$1,761,760	$55.62	$58.72
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,683,215	-$1,704,022	$56.11	$56.80
Progressive	2 MW Swap priced in HPLV then LPLV	-$1,792,488	-$1,813,295	$59.75	$60.44
Progressive	2 MW Swap priced in HPLV then LPHV	-$1,813,914	-$1,834,721	$60.46	$61.16
Progressive	2 MW Swap priced in LPLV then HPHV	-$1,848,871	-$1,869,678	$61.63	$62.32
Part hedge	2 MW Swap priced in HPHV	-$1,858,585	-$1,912,352	$61.95	$63.74
Progressive	2 MW Swap priced in LPHV then HPHV	-$1,888,992	-$1,909,799	$62.96	$63.66
Progressive	2 MW Swap priced in HPHV then LPLV	-$1,897,433	-$1,918,240	$63.25	$63.94
Progressive	2 MW Swap priced in HPHV then LPHV	-$1,918,859	-$1,939,666	$63.96	$64.65
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,019,691	-$2,040,498	$67.32	$68.01
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,124,636	-$2,145,443	$70.82	$71.51
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,177,167	-$2,197,974	$72.57	$73.26
Part hedge	2 MW Swap priced in HPLV	-$2,186,882	-$2,240,648	$72.89	$74.69
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,217,288	-$2,238,095	$73.91	$74.60
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,347,987	-$2,368,794	$78.26	$78.96
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,452,932	-$2,473,739	$81.76	$82.46
		Summer Peaking Load Profile			
Load Curtailment	n/a	-$1,594,231	-$1,701,542	$52.45	$55.98
Pool + Caps	2 MW Cap priced in LPLV	-$1,839,662	-$1,987,364	$60.35	$65.20

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
Pool + Caps	2 MW Cap priced in LPHV	-$1,857,687	-$2,005,389	$60.94	$65.79
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,873,966	-$1,966,740	$61.48	$64.52
Part hedge	2 MW Swap priced in LPLV	-$1,883,681	-$2,028,040	$61.79	$66.53
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,895,392	-$1,988,167	$62.18	$65.22
Part hedge	2 MW Swap priced in LPHV	-$1,905,107	-$2,049,466	$62.50	$67.23
Pool + Caps	2 MW Cap priced in HPLV	-$1,909,205	-$2,056,906	$62.63	$67.48
Pool	n/a	-$1,910,604	-$2,123,507	$62.68	$69.66
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,914,087	-$2,006,861	$62.79	$65.84
Pool + Caps	2 MW Cap priced in HPHV	-$1,931,097	-$2,078,798	$63.35	$68.20
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,935,513	-$2,028,287	$63.49	$66.54
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,044,786	-$2,137,560	$67.08	$70.12
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,066,212	-$2,158,987	$67.78	$70.83
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,101,169	-$2,193,943	$68.93	$71.97
Part hedge	2 MW Swap priced in HPHV	-$2,110,883	-$2,255,243	$69.25	$73.98
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,141,290	-$2,234,064	$70.25	$73.29
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,149,731	-$2,242,505	$70.52	$73.57
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,171,157	-$2,263,931	$71.23	$74.27
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,271,989	-$2,364,763	$74.53	$77.58
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,376,934	-$2,469,708	$77.98	$81.02
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,429,465	-$2,522,239	$79.70	$82.74
Part hedge	2 MW Swap priced in HPLV	-$2,439,180	-$2,583,539	$80.02	$84.75
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,469,586	-$2,562,360	$81.02	$84.06
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,600,285	-$2,693,059	$85.30	$88.35
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,705,230	-$2,798,004	$88.75	$91.79
	Winter Peaking Load Profile				
Load Curtailment	n/a	-$1,456,477	-$1,522,058	$48.72	$50.91
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,634,274	-$1,662,077	$54.55	$55.48
Pool + Caps	1 MW Cap priced in LPLV	-$1,635,440	-$1,729,162	$54.59	$57.72
Part hedge	2 MW Swap priced in LPLV	-$1,643,988	-$1,701,224	$54.88	$56.79
Pool + Caps	1 MW Cap priced in LPHV	-$1,644,453	-$1,738,175	$54.89	$58.02
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,655,700	-$1,683,503	$55.27	$56.20
Part hedge	2 MW Swap priced in LPHV	-$1,665,415	-$1,722,650	$55.59	$57.50

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
Pool + Caps	1 MW Cap priced in HPLV	-$1,670,212	-$1,763,934	$55.75	$58.88
Pool	n/a	-$1,670,911	-$1,798,069	$55.78	$60.02
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,674,395	-$1,702,198	$55.89	$56.82
Pool + Caps	1 MW Cap priced in HPHV	-$1,681,158	-$1,774,879	$56.12	$59.25
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,695,821	-$1,723,624	$56.61	$57.54
Progressive	2 MW Swap priced in HPLV then LPLV	-$1,805,094	-$1,832,897	$60.26	$61.18
Progressive	2 MW Swap priced in HPLV then LPHV	-$1,826,520	-$1,854,323	$60.97	$61.90
Progressive	2 MW Swap priced in LPLV then HPHV	-$1,861,477	-$1,889,279	$62.14	$63.07
Part hedge	2 MW Swap priced in HPHV	-$1,871,191	-$1,928,427	$62.46	$64.37
Progressive	2 MW Swap priced in LPHV then HPHV	-$1,901,597	-$1,929,400	$63.48	$64.41
Progressive	2 MW Swap priced in HPHV then LPLV	-$1,910,039	-$1,937,842	$63.76	$64.69
Progressive	2 MW Swap priced in HPHV then LPHV	-$1,931,465	-$1,959,268	$64.47	$65.40
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,032,297	-$2,060,099	$67.84	$68.77
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,137,241	-$2,165,044	$71.34	$72.27
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,189,773	-$2,217,576	$73.10	$74.03
Part hedge	2 MW Swap priced in HPLV	-$2,199,488	-$2,256,723	$73.42	$75.33
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,229,894	-$2,257,697	$74.44	$75.36
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,360,593	-$2,388,396	$78.80	$79.73
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,465,538	-$2,493,341	$82.30	$83.23

D. 7. Costs of risk management strategies, by customer profile and strategy, South Australia, HPLV, $ and $/MWh

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
		Total cost		$/MWH	
		Flat Load Profile			
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,548,150	-$1,558,533	$51.60	$51.95
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,569,576	-$1,579,959	$52.32	$52.66
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,588,271	-$1,598,653	$52.94	$53.28
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,609,697	-$1,620,080	$53.65	$54.00
Progressive	2 MW Swap priced in HPLV then LPLV	-$1,718,970	-$1,729,353	$57.30	$57.64
Progressive	2 MW Swap priced in HPLV then LPHV	-$1,740,396	-$1,750,779	$58.01	$58.36
Progressive	2 MW Swap priced in LPLV then HPHV	-$1,775,353	-$1,785,735	$59.17	$59.52
Part hedge	2 MW Swap priced in LPLV	-$1,813,122	-$1,835,272	$60.43	$61.17
Progressive	2 MW Swap priced in LPHV then HPHV	-$1,815,473	-$1,825,856	$60.51	$60.86
Progressive	2 MW Swap priced in HPHV then LPLV	-$1,823,915	-$1,834,297	$60.79	$61.14
Part hedge	2 MW Swap priced in LPHV	-$1,834,548	-$1,856,698	$61.15	$61.89
Progressive	2 MW Swap priced in HPHV then LPHV	-$1,845,341	-$1,855,724	$61.51	$61.85
Progressive	2 MW Swap priced in HPLV then HPHV	-$1,946,173	-$1,956,555	$64.87	$65.21
Load Curtailment	n/a	-$1,961,072	-$1,991,311	$66.32	$67.34
Part hedge	2 MW Swap priced in HPHV	-$2,040,325	-$2,062,474	$68.01	$68.74
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,051,117	-$2,061,500	$68.37	$68.71
Pool	n/a	-$2,095,302	-$2,144,225	$69.84	$71.47
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,103,649	-$2,114,032	$70.12	$70.46
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,143,770	-$2,154,153	$71.45	$71.80
Pool + Caps	1 MW Cap priced in LPLV	-$2,150,701	-$2,192,787	$71.69	$73.09
Pool + Caps	1 MW Cap priced in LPHV	-$2,159,714	-$2,201,800	$71.99	$73.39
Pool + Caps	1 MW Cap priced in HPLV	-$2,185,473	-$2,227,559	$72.84	$74.25
Pool + Caps	1 MW Cap priced in HPHV	-$2,196,418	-$2,238,504	$73.21	$74.61
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,274,469	-$2,284,852	$75.81	$76.16
Part hedge	2 MW Swap priced in HPLV	-$2,368,621	-$2,390,771	$78.95	$79.69
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,379,414	-$2,389,797	$79.31	$79.65
		Summer Peaking Load Profile			
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,699,032	-$1,741,982	$55.72	$57.13
Progressive	2 MW Swap priced in LPLV then	-$1,720,458	-$1,763,408	$56.43	$57.83

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
	LPHV				
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,739,153	-$1,782,103	$57.04	$58.45
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,760,579	-$1,803,529	$57.74	$59.15
Progressive	2 MW Swap priced in HPLV then LPLV	-$1,869,852	-$1,912,802	$61.32	$62.73
Progressive	2 MW Swap priced in HPLV then LPHV	-$1,891,278	-$1,934,228	$62.03	$63.44
Progressive	2 MW Swap priced in LPLV then HPHV	-$1,926,235	-$1,969,185	$63.17	$64.58
Part hedge	2 MW Swap priced in LPLV	-$1,964,004	-$2,017,269	$64.41	$66.16
Progressive	2 MW Swap priced in LPHV then HPHV	-$1,966,356	-$2,009,306	$64.49	$65.90
Progressive	2 MW Swap priced in HPHV then LPLV	-$1,974,797	-$2,017,747	$64.77	$66.18
Part hedge	2 MW Swap priced in LPHV	-$1,985,430	-$2,038,695	$65.12	$66.86
Progressive	2 MW Swap priced in HPHV then LPHV	-$1,996,223	-$2,039,173	$65.47	$66.88
Load Curtailment	n/a	-$2,075,143	-$2,124,154	$69.25	$70.89
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,097,055	-$2,140,005	$68.78	$70.18
Part hedge	2 MW Swap priced in HPHV	-$2,191,207	-$2,244,471	$71.86	$73.61
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,202,000	-$2,244,950	$72.22	$73.63
Pool	n/a	-$2,246,185	-$2,319,285	$73.67	$76.06
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,254,531	-$2,297,481	$73.94	$75.35
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,294,652	-$2,337,602	$75.26	$76.67
Pool + Caps	2 MW Cap priced in LPLV	-$2,356,982	-$2,421,308	$77.30	$79.41
Pool + Caps	2 MW Cap priced in LPHV	-$2,375,007	-$2,439,333	$77.89	$80.00
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,425,351	-$2,468,301	$79.54	$80.95
Pool + Caps	2 MW Cap priced in HPLV	-$2,426,525	-$2,490,851	$79.58	$81.69
Pool + Caps	2 MW Cap priced in HPHV	-$2,448,417	-$2,512,743	$80.30	$82.41
Part hedge	2 MW Swap priced in HPLV	-$2,519,503	-$2,572,768	$82.63	$84.38
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,530,296	-$2,573,246	$82.99	$84.39
	Winter Peaking Load Profile				
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,614,881	-$1,634,353	$53.90	$54.55
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,636,307	-$1,655,779	$54.62	$55.27
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,655,002	-$1,674,474	$55.24	$55.89
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,676,428	-$1,695,900	$55.96	$56.61
Progressive	2 MW Swap priced in HPLV then LPLV	-$1,785,701	-$1,805,173	$59.60	$60.25
Progressive	2 MW Swap priced in HPLV then	-$1,807,127	-$1,826,599	$60.32	$60.97

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
	LPHV				
Progressive	2 MW Swap priced in LPLV then HPHV	-$1,842,084	-$1,861,556	$61.48	$62.13
Part hedge	2 MW Swap priced in LPLV	-$1,879,853	-$1,911,297	$62.75	$63.79
Progressive	2 MW Swap priced in LPHV then HPHV	-$1,882,205	-$1,901,677	$62.82	$63.47
Progressive	2 MW Swap priced in HPHV then LPLV	-$1,890,646	-$1,910,118	$63.11	$63.76
Part hedge	2 MW Swap priced in LPHV	-$1,901,279	-$1,932,723	$63.46	$64.51
Progressive	2 MW Swap priced in HPHV then LPHV	-$1,912,072	-$1,931,544	$63.82	$64.47
Load Curtailment	n/a	-$2,012,592	-$2,048,710	$68.33	$69.55
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,012,904	-$2,032,376	$67.19	$67.84
Part hedge	2 MW Swap priced in HPHV	-$2,107,056	-$2,138,500	$70.33	$71.38
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,117,849	-$2,137,321	$70.69	$71.34
Pool	n/a	-$2,162,034	-$2,215,990	$72.16	$73.96
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,170,380	-$2,189,852	$72.44	$73.09
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,210,501	-$2,229,973	$73.78	$74.43
Pool + Caps	1 MW Cap priced in LPLV	-$2,217,432	-$2,266,552	$74.01	$75.65
Pool + Caps	1 MW Cap priced in LPHV	-$2,226,445	-$2,275,565	$74.31	$75.95
Pool + Caps	1 MW Cap priced in HPLV	-$2,252,204	-$2,301,324	$75.17	$76.81
Pool + Caps	1 MW Cap priced in HPHV	-$2,263,150	-$2,312,270	$75.54	$77.18
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,341,200	-$2,360,672	$78.14	$78.79
Part hedge	2 MW Swap priced in HPLV	-$2,435,352	-$2,466,796	$81.29	$82.34
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,446,145	-$2,465,617	$81.65	$82.30

D. 8. Costs of risk management strategies, by customer profile and strategy, South Australia, HPHV, $ and $/MWh

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
		Total cost		$/MWH	
		Flat Load Profile			
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,528,720	-$1,558,105	$51.03	$52.01
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,550,147	-$1,579,531	$51.67	$52.65
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,568,841	-$1,598,226	$52.37	$53.35
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,590,267	-$1,619,652	$53.00	$53.98
Progressive	2 MW Swap priced in HPLV then LPLV	-$1,699,540	-$1,728,925	$56.73	$57.71
Progressive	2 MW Swap priced in HPLV then LPHV	-$1,720,967	-$1,750,351	$57.36	$58.34
Progressive	2 MW Swap priced in LPLV then HPHV	-$1,755,923	-$1,785,308	$58.61	$59.59
Load Curtailment	n/a	-$1,771,407	-$1,852,031	$59.04	$61.73
Progressive	2 MW Swap priced in LPHV then HPHV	-$1,796,044	-$1,825,428	$59.95	$60.93
Progressive	2 MW Swap priced in HPHV then LPLV	-$1,804,485	-$1,833,870	$60.14	$61.12
Progressive	2 MW Swap priced in HPHV then LPHV	-$1,825,911	-$1,855,296	$60.95	$61.93
Part hedge	2 MW Swap priced in LPLV	-$1,861,158	-$1,928,801	$62.03	$64.29
Part hedge	2 MW Swap priced in LPHV	-$1,882,584	-$1,950,227	$62.84	$65.10
Progressive	2 MW Swap priced in HPLV then HPHV	-$1,926,743	-$1,956,128	$64.22	$65.20
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,031,688	-$2,061,072	$68.13	$69.12
Pool + Caps	1 MW Cap priced in LPLV	-$2,063,385	-$2,176,505	$69.28	$73.08
Pool + Caps	1 MW Cap priced in LPHV	-$2,072,397	-$2,185,517	$69.17	$72.95
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,084,220	-$2,113,604	$69.47	$70.45
Part hedge	2 MW Swap priced in HPHV	-$2,088,361	-$2,156,003	$69.71	$71.97
Pool + Caps	1 MW Cap priced in HPLV	-$2,098,156	-$2,211,276	$69.93	$73.70
Pool + Caps	1 MW Cap priced in HPHV	-$2,109,102	-$2,222,222	$70.40	$74.18
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,124,340	-$2,153,725	$70.80	$71.78
Pool	n/a	-$2,210,804	-$2,370,421	$73.79	$79.12
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,255,040	-$2,284,424	$75.16	$76.14
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,359,984	-$2,389,369	$78.77	$79.75
Part hedge	2 MW Swap priced in HPLV	-$2,416,657	-$2,484,300	$80.55	$82.80
		Summer Peaking Load Profile			
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,899,747	-$2,014,539	$62.30	$66.06
Progressive	2 MW Swap priced in LPLV then	-$1,921,173	-$2,035,965	$64.13	$67.96

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
	LPHV				
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,939,868	-$2,054,659	$63.61	$67.38
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,961,294	-$2,076,086	$65.37	$69.20
Load Curtailment	n/a	-$1,991,814	-$2,117,199	$65.32	$69.43
Progressive	2 MW Swap priced in HPLV then LPLV	-$2,070,567	-$2,185,359	$67.90	$71.66
Progressive	2 MW Swap priced in HPLV then LPHV	-$2,091,993	-$2,206,785	$69.16	$72.96
Progressive	2 MW Swap priced in LPLV then HPHV	-$2,126,950	-$2,241,741	$71.00	$74.83
Progressive	2 MW Swap priced in LPHV then HPHV	-$2,167,070	-$2,281,862	$72.23	$76.05
Progressive	2 MW Swap priced in HPHV then LPLV	-$2,175,512	-$2,290,303	$72.62	$76.45
Progressive	2 MW Swap priced in HPHV then LPHV	-$2,196,938	-$2,311,730	$73.22	$77.05
Part hedge	2 MW Swap priced in LPLV	-$2,232,184	-$2,397,224	$74.51	$80.02
Part hedge	2 MW Swap priced in LPHV	-$2,253,611	-$2,418,650	$73.90	$79.31
Pool + Caps	2 MW Cap priced in LPLV	-$2,286,992	-$2,452,670	$76.23	$81.75
Progressive	2 MW Swap priced in HPLV then HPHV	-$2,297,770	-$2,412,561	$76.70	$80.53
Pool + Caps	2 MW Cap priced in LPHV	-$2,305,017	-$2,470,695	$76.94	$82.47
Pool + Caps	2 MW Cap priced in HPLV	-$2,356,535	-$2,522,213	$78.54	$84.07
Pool + Caps	2 MW Cap priced in HPHV	-$2,378,427	-$2,544,105	$79.27	$84.80
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,402,714	-$2,517,506	$80.20	$84.03
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,455,246	-$2,570,038	$80.51	$84.28
Part hedge	2 MW Swap priced in HPHV	-$2,459,387	-$2,624,426	$81.97	$87.47
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,495,367	-$2,610,159	$83.29	$87.12
Pool	n/a	-$2,581,830	-$2,821,773	$86.05	$94.05
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,626,066	-$2,740,858	$87.66	$91.49
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,731,011	-$2,845,803	$91.02	$94.85
Part hedge	2 MW Swap priced in HPLV	-$2,787,684	-$2,952,723	$91.41	$96.83
	Winter Peaking Load Profile				
Progressive	2 MW Swap priced in LPLV then LPLV	-$1,521,155	-$1,560,262	$49.88	$51.16
Progressive	2 MW Swap priced in LPLV then LPHV	-$1,542,581	-$1,581,688	$50.58	$51.87
Progressive	2 MW Swap priced in LPHV then LPLV	-$1,561,276	-$1,600,383	$51.20	$52.48
Progressive	2 MW Swap priced in LPHV then LPHV	-$1,582,702	-$1,621,809	$52.83	$54.13
Progressive	2 MW Swap priced in HPLV then LPLV	-$1,691,975	-$1,731,082	$56.39	$57.70
Progressive	2 MW Swap priced in HPLV then	-$1,713,401	-$1,752,508	$56.19	$57.47

Strategy	Hedge	Expected	95th Percentile	Expected	95th %ile
	LPHV				
Progressive	2 MW Swap priced in LPLV then HPHV	-$1,748,358	-$1,787,464	$58.36	$59.66
Load Curtailment	n/a	-$1,776,288	-$1,856,492	$58.25	$60.88
Progressive	2 MW Swap priced in LPHV then HPHV	-$1,788,478	-$1,827,585	$59.61	$60.91
Progressive	2 MW Swap priced in HPHV then LPLV	-$1,796,920	-$1,836,027	$58.93	$60.21
Progressive	2 MW Swap priced in HPHV then LPHV	-$1,818,346	-$1,857,453	$59.63	$60.91
Part hedge	2 MW Swap priced in LPLV	-$1,853,592	-$1,922,062	$60.78	$63.03
Part hedge	2 MW Swap priced in LPHV	-$1,875,019	-$1,943,488	$62.59	$64.87
Progressive	2 MW Swap priced in HPLV then HPHV	-$1,919,178	-$1,958,284	$62.93	$64.22
Progressive	2 MW Swap priced in HPHV then HPHV	-$2,024,122	-$2,063,229	$67.46	$68.77
Pool + Caps	1 MW Cap priced in LPLV	-$2,055,819	-$2,167,744	$67.41	$71.09
Pool + Caps	1 MW Cap priced in LPHV	-$2,064,832	-$2,176,756	$67.71	$71.38
Progressive	2 MW Swap priced in LPLV then HPLV	-$2,076,654	-$2,115,761	$69.32	$70.62
Part hedge	2 MW Swap priced in HPHV	-$2,080,795	-$2,149,264	$69.35	$71.63
Pool + Caps	1 MW Cap priced in HPLV	-$2,090,591	-$2,202,515	$68.56	$72.23
Pool + Caps	1 MW Cap priced in HPHV	-$2,101,537	-$2,213,461	$68.91	$72.58
Progressive	2 MW Swap priced in LPHV then HPLV	-$2,116,775	-$2,155,882	$69.41	$70.70
Pool	n/a	-$2,203,238	-$2,360,923	$72.25	$77.42
Progressive	2 MW Swap priced in HPLV then HPLV	-$2,247,474	-$2,286,581	$73.70	$74.98
Progressive	2 MW Swap priced in HPHV then HPLV	-$2,352,419	-$2,391,526	$77.14	$78.42
Part hedge	2 MW Swap priced in HPLV	-$2,409,092	-$2,477,561	$79.00	$81.24