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Seed Advisory

NEM Financial Resilience

Report for the Private Generators Group, the National Generators Forum and the Energy Supply Association of Australia

14 August 2013

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1. Executive Summary

Around two thirds of current electricity derivative trades are already reported and, with the introduction of reporting of commodity derivatives by financial institutions, this proportion will increase. There is no significant net benefit to the economy from increasing the reporting coverage of electricity derivatives to include those derivative transactions not captured elsewhere.

Our high level modelling, using high and conservative assumptions about the spot and derivative market prices following a default, suggests that the total cost of an OTC market default is dominated by the spot and derivative market behaviour after the default, not experienced as an immediate loss, but only crystallised over the remaining contract period following the initial default.

The initial loss, or Settlement Risk, from the failure of a large derivative counterparty is estimated to be $140 million for the vertically integrated participant used in our analysis ($10 million for a stand-alone generator). As a result of the linked timing of NEM and OTC settlements, this loss likely will require immediate and short term access to additional cash. Extrapolating from a single counterparty's exposure to the wider market, we estimate that the short term funding requirement could range from $200 million to $560 million, spread over a number of counterparties (see Section 4.3). While margining OTC contracts could provide security to secure short term funding, access to the margin account is unlikely to be sufficiently rapid to eliminate the need for additional funding.

The larger part of the estimated potential loss relates to the loss of enterprise value from replacing the ineffective positions with newer, more expensive positions. This loss, which could amount to up to $490 million for the largest individual exposure in the scenarios considered and between around $750 million and just under $2 billion for the market as a whole (see the calculation in Section 4.4), is crystallised over the duration of the replacement contracts, which, for our sample, covers a period extending for more than 3 years. This represents a 'gross' potential loss, not allowing for any pass-through of higher costs, for example through re-pricing.

Based on the results of our modelling, introducing mandated credit support for all OTC derivatives or requiring margining have the potential to increase the capital required of industry participants without necessarily reducing the risks to those participants. Policy proposals should prioritise changes to the market design and the NER to remedy those elements of the market design that would be likely to affect the market's performance in the event of a default.

1.1. Background

Consistent with the derivatives reform agenda agreed by the G-20 nations, the Australian Government has introduced a legislative framework to ensure:

- the reporting of all over-the-counter (OTC) derivatives to Trade Repositories;
- the clearing of all standardised OTC derivatives through central counterparties; and
- the execution of all standardised OTC derivatives on exchanges or electronic trading platforms, where appropriate.[1]

[1] *Corporations Legislation Amendment (Derivative Transactions) Act 2012* (Cth).

Electricity derivatives are to receive specific consideration in the implementation of the G-20 derivative reform agenda in Australia. As with all classes of derivatives, a direction from the Treasurer to the Australian Securities and Investment Commission (ASIC) is required before ASIC undertakes the mandated consultations on the application of the legislative framework to electricity derivatives. For commodity derivatives, the legislation requires the Treasurer to have regard to the likely impact on any Australian market or markets in issuing a determination to make rules in regard to commodity derivatives; the Government has indicated that "the Minister would be expected to seek the written agreement of relevant ministers with portfolio responsibility for the underlying market, for example in the case of electricity derivatives, this would include the Commonwealth Minister with responsibility for Energy"[2]; and, that "regulatory agencies and regulatory bodies with responsibilities for the underlying physical market" would be consulted in addition to the Minister.[3] Currently, the Treasury's view, also referred to in the Australian Energy Market Commission 's (AEMC) *First Interim Report on NEM Financial Resilience,* is that no direction from the Treasurer will be made until the AEMC's final report on national electricity market (NEM) financial resilience, expected around the end of 2013.

Seed Advisory (Seed) has been asked by the Private Generators Group (PGG), the National Generators' Forum and the Energy Supply Association of Australian (ESAA) to prepare a report exploring the impact that the application of trade reporting and higher margin requirements for non-centrally cleared OTC derivatives could have on energy markets, focusing on Australia but drawing also on the experience of international jurisdictions that have implemented rules for reporting and margining requirements through the Commodity Futures Trading Commission under the Dodd-Frank Act and the European Market Infrastructure Regulation under the European Energy Market Association.

In considering the risks present in electricity markets for participants and the wider economy in relation to these objectives, we have made a high level estimate of the costs that could be incurred by one of two specified types of industry participant – a large vertically integrated retailer and a large merchant (stand-alone) generator – as the result of gaps between the institutional/regulatory requirements and organisational risk mitigation and management measures in the National Electricity Market (NEM). We consider whether, in the event of a failure giving rise to a cost similar in size to our estimate, systemic risk would arise either in spot and derivative electricity markets or in Australian financial markets.[4]

Finally, we consider, again at a high level, the case for the application of the legislative framework to OTC electricity derivatives and alternative options that might exist for addressing the gaps identified, considering the potential costs and benefits and the implications for the efficient functioning of the broader electricity market.

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[2] Supplementary Explanatory Memorandum, paras 1.8, 1.10, February 2013

[3] The Treasury, 2012; from the AEMC's discussion (AEMC, 2012, pps 4-5) it appears that, as at the date of preparation of that report, the proposed regulation to give effect to this commitment had not been made.

[4] The separation of the spot and derivatives markets in this analysis reflects the institutional arrangements for the NEM, which operate, except under conditions of severe stress, to reduce or eliminate the principal risks associated with credit risk from the spot market. See the discussion in Section 3.

1.2. Our findings

Based on our high level estimates, systemic risk to the wider economy is unlikely to follow from the failure of a large OTC electricity derivative position held with a large electricity market participant. Although our estimates are based on high and conservative movements in spot and derivative market prices, relative to the financial sector or the real economy, the estimated costs of a default are low.

Table 1.1 OTC Counterparty Default: indicative costs, $ million, rounded

Risk	Definition	Defaulting counterparty position: Largest	Average
		$ million, rounded	
	Vertically integrated retailer		
Settlement, *plus 1 of:*	Settlement amount not received	140	15
Market, *or*	Unhedged exposure, declining over 6 month period	230	10
Credit	Replacement of in-the-money position, first 2 years only	200	65
	Replacement of in-the-money position, total	490	70
	Possible call on funds, out-of-the money position[1]	330	50
	Stand-alone generator		
Settlement, *plus 1 of:*	Settlement amount not received	10	2
Market, *or*	Unhedged exposure, declining over 6 month period	15	3
Credit	Replacement of in-the-money position, first 2 years only	95	20
	Replacement of in-the-money position, total	105	25
	Possible call on funds, out-of-the money position[1]	70	20

Note (1): This loss may not be crystallised in this amount or immediately, depending on the effect of the one-way Termination events apparently used by a number of electricity market participants in their schedules to their ISDA Master Agreements.

Table 1.1 presents our estimates of the costs of each of the individual risks discussed in this report, calculated on the basis of the default of the largest OTC counterparty and an average OTC counterparty and using the assumptions for the behaviour of the spot and contract markets outlined in Section 4.2.2. Our key findings include:

- The risks are not additive across the Settlement, Market and Credit Risks or between the vertically integrated retailer and stand-alone generator categories. Vertically integrated retailers generally hold purchased OTC positions and are therefore exposed to increases in contract prices, while generators typically hold sold OTC positions and are therefore exposed to decreases in contract prices.

- The largest total loss in the scenarios modelled for a vertically integrated retailer occurs where the retailer locks in replacement contract(s) at unfavourable market prices for the total term of the contracts now in default, adding the cost of Credit Risk to its Settlement Risk. The total loss is $630 million, of which $140 million (Settlement Risk) represents a requirement for cash over the immediate and very short term (a 5 week period). The comparable figure for a large stand-alone generator is $115 million, of which $10 million represents a requirement for cash over a 5 week period.
  - A more realistic estimate of the total cost of the default, with only the first two years of long dated positions replaced, reduces the retailer's total recognised loss to $340 million ($140 million near term cash). For a generator, the comparable figure is only reduced to $105 million ($10 million of which is required to meet settlement).
- Based on the data provided, the exposures for average counterparties are materially smaller than for a large counterparty. The average settlement loss, based on our data, is $15 million for a vertically integrated market participant and $2 million for a stand-alone generator.
- Generator exposures are materially smaller than vertically integrated retailer exposures. This is driven by two factors:
  - The data provided highlights that generators' portfolios are typically smaller and of shorter duration than retailers' portfolios.
  - A generator is affected by decreases in spot and contract prices. This risk is asymmetrical and smaller than the risk of increased spot and contract prices, as a result of the floor and cap on spot prices.
- Three quarters of our estimated total potential loss of $630 million represents the loss of enterprise value resulting from replacing the contracts now in default (the ineffective positions) with newer, more expensive positions. Who bears this loss is influenced by the level of competition, regulatory arrangements and customer contracting patterns. This loss is crystallised over the duration of the replacement contracts.

Our estimates of the potential losses for a vertically integrated retailer assume that in the aftermath of the failure of a major market participant, spot prices are persistently high. However, this is not the only realistic possibility: the potential for high spot prices will encourage uncontracted generators to increase their bids, while retailers with uncommitted capacity have an incentive to reduce spot prices and/or dampen volatility to manage their own potential exposures. The spot price outcome will depend on the regional demand/supply balance, participants' incentives and the size of the failure.

1.3. Interpreting the results

How are we to interpret these results and their implications for the NEM and financial markets and the wider economy?

First, the immediate loss as the result of the failure of a large derivative counterparty is $140 million for the vertically integrated participant ($10 million for a stand-alone generator).

- Is this a sufficiently large amount to result in further contagion and systemic risk to the NEM? Considering the two largest vertically integrated retailers whose results are published, a loss of $140 million represents between a quarter and a third of company-wide annual profits, based on mid-year results for 2012/13 and, we anticipate, would present no funding issues. The costs are also relatively small when compared to their annual cash flows and year end cash positions. We believe the risk of further failures in these circumstances appears low.

- Margining could compensate for (the larger part of) this loss. However, depending on the time between the default and access to the margin deposited, it may not remove the requirement to access additional short term funding.
  - Margining may not, however, cover all of these losses where the spot price volatility underpinning the settlement risk exposure does not result in a commensurate contract price change and an increase in the margin held.

Secondly, the defaulting counterparty is unlikely to have had only one counterparty. How should these findings be extrapolated to the wider market? We estimate that the short term funding requirement could range from $200 million to $560 million, spread over a number of counterparties (see Section 4.3). Looking at the 2011/12 turnover in the NEM of around $6 billion, at its maximum this represents just under 10 per cent of total annual turnover, which, although significant, is unlikely in our judgement to represent an immediate systemic risk[5].

The larger part of our estimate of the potential loss relates to the loss of enterprise value resulting from replacing the ineffective positions with newer, more expensive positions. This loss, which could amount to up to $490 million for the largest individual exposure in the scenarios we have considered and between around $750 million and just under $2 billion for the market as a whole (see the calculation in Section 4.4), is crystallised over the duration of the replacement contracts.

- The full loss is a result of the assumption that the non-defaulting party replaces its ineffective contract(s). If the non-defaulting party replaces only the first two years of its contracts, the credit risk is reduced to $200 million.
- A loss of between $200 and $490 million in enterprise value over a period of two plus years is unlikely to result in immediate failures.
  - However, depending on participants' financial strength, customer contracts and the regulatory environment, a loss of this size is likely to affect shareholders' valuations. The effect on shareholders could be sufficient to affect valuations across the sector generally, resulting in a reduction in loans to the sector and, potentially, pressure on loan covenants, the orderly disposal of assets and the potential withdrawal of participants from the sector.

1.4. Options for addressing the residual risks

1.4.1. Reporting

Given the share of the exchange traded market in electricity derivative trading, around two thirds of current electricity derivative trades are already reported and, with the introduction of reporting requirements on financial sector participants, a significant share of electricity OTC transactions could also be reported. Following from this, it could be argued that:

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[5] In the case of a vertically integrated retailer, the comparison with NEM-wide aggregates is appropriate, as the larger vertically integrated retailers have national footprints. In the case of a generator, the relevant comparison is the regional spot market. However, the potential losses by a large stand-alone generator are so much smaller in our modelling than those for a vertically integrated retailer that our discussion focusses on the larger risk.

- There is no significant net benefit to the economy from increasing the coverage of reported electricity derivative transactions to include those OTC derivatives not captured elsewhere.
- Alternatively, with other end-users, electricity market participants should argue that hedging activities by end-users should be exempt from reporting entirely. The Australian Accounting Standard AASB 139 already requires listed companies and their auditors to take a view about those derivative positions that are hedge activities and those that are speculative, providing a high degree of transparency into the positions of listed companies in the sector.

The alternative, a partial end-use exemption, is less attractive because it is unlikely to provide the transparency sought by the reforms (See Section 5).

Whatever the reporting requirement, it is important that the overall costs to industry participants are minimised by requiring only one set of reporting requirements. That information that the G-20 derivative reform agenda requires is designed to highlight significant leverage to the derivative markets, not necessarily the oversight of market conduct.

1.4.2. Central counterparty and exchange based trading

We believe there is no current concrete commitment to proceeding to this stage of the proposed reform agenda. The appropriate discussion of the real, as opposed to the theoretical benefits of greater reporting and the case for introducing a central counterparty are linked: if there is no net benefit to additional reporting, there is similarly no net benefit to the requirement to use a central counterparty.

However, there are several important issues that should be part of any discussion of the G-20 derivative reform agenda with a view to framing any future discussion of the second stage in the G-20 derivative reform agenda:

- the absence of systemic risk to the financial sector or the wider economy from the electricity OTC derivative market;
- the illiquid and under-developed exchange traded markets for electricity derivatives in Queensland and South Australia and the absence of a Tasmanian contract; and
- the significance of non-standardised products – contingent payoffs, non-standard caps and other options – in the risk management task, given the contingent nature of electricity market risks.

Changes to the market that could lower participation and liquidity in the OTC market are likely to adversely affect the price and/or the liquidity of the OTC market, with an ultimate cost and detriment to end-users.

1.4.3. Margining OTCs and mandated credit support arrangements

Our high level modelling suggests that the total cost of an OTC market default is dominated by the spot and derivative market behaviour after the default. Assuming this is correct, then introducing mandated credit support for all OTC derivatives or requiring margining has the potential to increase the capital required of industry participants without necessarily reducing all the risks to those participants. In addressing this issue, policy proposals should:

- Prioritise changes to the market design and the NER to remedy those elements of the market design that would be likely to affect the market's performance in the event of a default, such as the issues raised by the Australian Energy Market Operator (AEMO) in relation to the continued generation of an insolvent generator, and, to the maximum extent consistent with the current market design, reduce the likelihood of spot market outcomes following a default giving rise to further stress on participants' positions.

- Consider the (re)allocation of existing risk capital required of industry participants, to provide for a higher and more robust outcome in the event of insolvency without increasing the level of capital committed across the sector.
- Although ASIC could require participants with AFSL to meet higher individual capital adequacy requirements, from the perspective of a regulatory response, this is a relatively inefficient instrument because it is poorly targeted at the risks associated with derivative markets, operating only to provide a higher amount to all creditors in the event of a default. All other solutions should, therefore, be preferred to this solution.

2. Risks in National Electricity Market Derivatives

2.1. The OTC Derivative Reform Agenda: electricity derivatives

How will electricity derivatives be considered in implementing Australia's commitments?

Electricity derivatives are to receive specific consideration in the implementation of the G-20 derivative reform agenda in Australia. As with all classes of derivatives, a direction from the Treasurer to the Australian Securities and Investment Commission (ASIC) is required before ASIC undertakes the mandated consultations on the application of the legislative framework to electricity derivatives. The original bill was amended during its consideration by Parliament to require the Treasurer to have regard to the likely impact on any Australian market or markets in issuing a determination to make rules in regard to commodity derivatives. The Explanatory Memorandum accompanying the legislation indicates that "the Minister would be expected to seek the written agreement of relevant ministers with portfolio responsibility for the underlying market, for example in the case of electricity derivatives, this would include the Commonwealth Minister with responsibility for Energy; currently the Minister for Resources, Energy and Tourism".[6] The Government's speech following the introduction of the amendments indicated that "regulatory agencies and regulatory bodies with responsibilities for the underlying physical market" would be consulted in addition to the Minister and proposed that ASIC be required to consult with the AEMC and other electricity regulators.[7]

Inconsistency between the principal G-20 nations' implementations and Australia's – by treating electricity differently from all other derivatives in a way that hasn't been adopted internationally – is seen by some ASIC representatives as undermining Australia's perceived commitment to the G-20 derivative reforms. It is also inconsistent with ASIC's view of its goal, which is to implement the G-20 commitments.[8]

If, on the other hand, electricity derivatives were treated in a similar way to other commodities, to which ASIC expects "a common set of factors" to be applied or there was to be some, limited divergence from the treatment of other commodities, based on the characteristics of the electricity market, then ASIC would find the position easier to justify in the context of its response to the international reform agenda. ASIC is encouraging electricity market participants to engage with and respond to the forthcoming consultation paper on end-user exemptions.[9]

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[6] Supplementary Explanatory Memorandum, paras 1.8, 1.10, February 2013

[7] The Treasury, 2012; from the AEMC's discussion (AEMC, 2012, pps 4-5) it appears that, as at the date of preparation of that report, the proposed regulation to give effect to this commitment had not been made.

[8] Seed interview, 11 June 2013.

[9] ASIC, *CP 205*, 2013. The end-user exemption consultation paper is scheduled to be released in the second half of 2013.

What is the process proposed from here?

No direction from the Treasurer is expected to be made until the AEMC's final report on the financial resilience of the NEM, expected towards the end of 2013[10]. The AEMC expects to publish a second interim report during the second half of 2013 – possibly by October – to be followed by a final report, which will consolidate the material covered in both Interim Reports and stakeholder feedback, at the end of 2013.

Neither the Treasury nor DRET anticipate the timetable for considering the treatment of electricity derivatives moving more rapidly than this, given the high priority and high work load associated with the introduction of the G-20 derivative reform agenda for high volume, internationally significant derivative markets and the lack of certainty about the precise scope of the obligations the Australian regulatory regime will need to assume to achieve compliant status for these markets. Any significant delay by the AEMC, however, in providing its advice could prejudice the proposed sequence of events.

In a parallel process, ASIC is scheduled to publish in the second half of 2013 a consultation paper on proposed end user exemptions from the reporting obligations contained in the G-20 derivative reform agenda. ASIC proposes to discuss where requiring both reporting entities to report a reportable transaction would be appropriate for end users (two-sided vs. one sided reporting), as well as whether a minimum threshold (e.g. calculated on aggregated gross notional outstanding in OTC derivatives totalled across all asset classes or some other measure) should apply, below which end users will be exempt from reporting.

What has the AEMC been asked to provide advice on?

In its second Interim Report, the AEMC has been asked to address:

- the risks to financial stability in the NEM arising from financial interdependencies between market participants, and the impacts of those risks if they materialise and result in financial instability;
  - The AEMC has distinguished this category of risks from the Retailer of Last Resort contagion risks reviewed in its First Interim Report. However, some of the issues bought to light in the course of its first review – for example, the issues raised by AEMO in its submission to the AEMC relating to the inability of a generator to trade during insolvency – are likely to influence the AEMC's view of the risk of failure in the context of interdependency.
- the existing mechanisms to mitigate risks to financial stability and manage the consequences in the NEM and whether they are adequate; and
- if they are inadequate, recommendations to strengthen, enhance or supplement the mechanisms for minimising the risks and consequences.

Although the AEMC proposes to address the issues in the context of the National Electricity Objective, it has been asked to consider a wider than usual range of developments in its response, including in particular:

- ….
- relevant developments in electricity markets in other jurisdictions;
- approaches to financial stability regulation in other markets;

[10] Treasury, private communication, July 2013

- relevant developments in the regulation of financial markets in Australia and other jurisdictions;
- relevant work being undertaken by the Council of Financial Regulators;
- the role of the Australian Securities and Investments Commission (ASIC) and obligations on participants under the *Corporations Act 2001* (Cth); …[11]

Once the AEMC has reported, Treasury anticipates there will be further consultations about any proposed course of action.

[11] AEMC, *NEM Financial Market Resilience: First Interim Report*, June 2013, p.2.

3. Systemically Important Risks to NEM Financial Markets

In comparison to other spot commodity markets and some other energy markets, the NEM has a number of design features that limit the residual risks to market participants in the electricity spot market. These design features are likely to give rise to some, unquantifiable reduction in the risks to participants in electricity derivative markets and, arguably, a reduction in contagion risk. Transparent spot prices, for example, provide an independent, observable and continuous input into derivative valuations and settlements. Chain failures – where non-delivery of the commodity by one counterparty causes the failure of further market participants – are not typical of cash settled markets. Cash settlement is substantially secured by the prudential regime operated by AEMO.

Electricity derivative markets are characterised by a higher degree of private activity designed to limit individual participant's residual risks and facilitate efficient contracting compared with electricity spot markets, which demonstrate a high level of regulatory control of the residual risks.

These private efforts include:

- the development of the AFMA Electricity Addendum to the ISDA Master Agreement, extensively used as the basis for electricity OTC derivative trades;
- the ASX's electricity derivative offerings;
- a range of insurance products offered by international insurers designed to address specific electricity industry and market risks; and
- the risk management policies and processes of electricity market participants.

In some cases, the private efforts are reinforced by regulatory requirements.

Residual risks remain, however, with market risk the largest of these. Market participants' risk management policies typically have a very strong focus on managing exposure to market risk. Incomplete and illiquid electricity derivative markets can limit participants' abilities to manage their risks in normal market conditions. In extreme circumstances and conditions of stress, illiquidity could increase, increasing the risk to participants.

Participants limit their risks. The larger part of reported electricity derivative trade is subject to daily margining. In 2011/12 exchange traded derivatives made up about two thirds of total reported electricity trades (see Figure 3.1). Further, market participants limit their leverage, that is, the ratio of derivative positions to the underlying requirement for a physical hedge (see Section 3.3).

Finally, at a conceptual level, not all the risks electricity market participants face in the event of a counterparty default are crystallised at the time of default (Section 3.4). Depending on the duration of the OTC derivatives in default, credit and market risk, both of which can represent a significant cost to a market participant, may be incurred over a long period following the default. Remedies designed to address the risks faced by market participants need to consider the timeframes over which the risks are likely to be experienced.

3.1. Our approach

As with other complex markets, the list of potential risks to Market Participants in the NEM could be very long, if it was to be exhaustive. In this report we have focused on those risks that we regard as having the potential to be systemically important to the NEM and wider financial markets. In the NEM, we view a risk as having the potential to be systemically important based on its size or the reasonably foreseeable contagion in related electricity markets, while, considering wider financial markets, our view is that the principal reason why a risk is likely to be systemically important is the size of the prospective impact on the financial sector and, potentially, the wider economy.

In Table 3.1, we define those risks we have focused on in this report and discuss briefly the specific context in which the risk occurs in the NEM. The definitions have their origin in definitions originally proposed by the Committee of Chief Risk Officers in the USA, but have been augmented and amended to better reflect Australian market conditions.[12] In the discussion, we distinguish where appropriate between the risk to participants in the electricity spot market and those risks to participants in electricity derivative markets, both OTC and exchange traded. The institutional arrangements of the NEM spot market differ from those in other electricity markets internationally and other commodity spot markets in a number of important ways and the effects that these arrangements have for participants' risks are discussed in more detail in Table 3.2 and Table 3.3.

In Table 3.2 and Table 3.3, we look at each of these risks, considering first the institutional and regulatory controls and risk mitigations that exist to manage the risks participants are exposed to, then the internal and organisational measures in our experience market participants typically use to monitor, manage and measure the risks they are exposed to and finally, we look at the residual risks that participants are exposed to and the high level circumstances in which a risk might occur.

In Figure 3.2, we look at the key risks, when the associated exposure is incurred, and the period over which costs are incurred in the event of an OTC counterparty default. Considering these issues is significant in understanding the extent to which mandatory margining or additional credit support addresses participants' risks in default.

[12] For example, in the US private spot markets exist alongside the various ISO operated pools. Electricity spot markets trade similar contracts to those traded in Australian OTC and exchange based markets. The US definitions separate *market* and *volumetric risks*: in the US, unlike in the NEM spot market, a purchaser of electricity (a retailer or end user) could fail to purchase sufficient electricity for delivery, while in the NEM a retailer purchases all the electricity its customers require, as a matter of market design.

Table 3.1 Key Risks: Definitions

Risk Type	Description
Market	The risk of loss due to changes in market prices on spot and financial portfolio positions. In the NEM, we have used Market Risk to capture a range of risks, including the *volumetric risk* associated with the strong weather linkage to spot prices. (High demand periods and high prices are strongly associated.)
Operational	The risk of loss resulting from energy assets failing to perform as expected. This risk includes unplanned outages, worse than projected availability, fuel supply failures and the performance of critical infrastructure, such as the transmission network. In the NEM, not all spot market participants are exposed directly to operational risks, although participants with generators in their portfolio are. All NEM participants are exposed indirectly, where the operational risk gives rise to higher prices than would otherwise have been the case.
Credit	The risk of loss due to a counterparty defaulting on its commitment to pay for its spot purchases and/or amounts owed on a contract. In some circumstances and particularly under conditions of market stress, the non-defaulting counterparty may also incur additional costs replacing contracts terminated on less favourable terms. In the NEM, all customers (all retailers and other customers) able to provide the minimum required security are entitled to participate in the spot market, restricting a generator's ability to manage its spot market credit exposure. As a result, the NEM Prudential Standard is intended to provide a level of security against most, but not all, possible events of default (see *Settlement Risk,* below).
Liquidity	The risk that there will be insufficient parties actively participating in a given market to support willing buyers or sellers transacting their desired products at acceptable prices or, under certain circumstances, at all. In the NEM, the spot market is designed so as to not incur liquidity risk except in very rare circumstances. However, both the OTC and exchange traded markets have illiquid regions, may not be liquid for all time periods and large trades may not be able to be completed, completed without moving the price or completed within a short period of time.
Settlement	The risk that, at settlement, expected payments are not made as the result of a counterparty defaulting on its commitment to pay for its spot purchases or amounts owed on a contract. In the NEM, the institutional arrangements for the spot market are intended to reduce, but not eliminate this risk. In the exchange traded market, initial and variation margins reduce the risk of a material loss at settlement.
Other	For the purpose of this analysis, we have used this category to capture the key elements of the risks associated with financial institution's participation in the electricity derivative market and the potential failure of a financial institution on the electricity markets. Although financial institution participation in Australian electricity markets has been limited, the failure of financial institutions in other jurisdictions has been the source of contagion for other electricity markets.

3.2. Electricity market risks: spot market risks

Table 3.2 highlights the interaction of key design characteristics of the NEM and the residual risks retained by market participants. In comparison to other spot commodity markets and some other energy markets:

- Although spot prices can be highly volatile, under defined conditions of market stress the market operator can introduce an administered price cap, limiting the risks to spot exposed participants.
- There are a range of regulatory controls and requirements designed to limit the potential abuse of market power by generators. To the extent these controls are effective, spot prices provide an unbiased input into derivative prices settled with reference to regional spot prices.
- Participants have little direct exposure to the operational risks of their hedge counterparties. Their residual exposure is limited to the extent of the participant's exposure to spot prices and by the relationship between the operational failure and spot prices. A small operational failure may leave spot prices unaffected, in which case the residual spot market exposure would be zero.
- Even under conditions of extreme stress, the spot market will be liquid, that is, it will clear and, further, it will clear at a transparent price. Depending on market conditions, however, in well-defined circumstances that price could depart from participants' offers (generators' bids) as a result of the regulatory requirements (Cumulative Price Threshold or CPT) event).
- Assuming that the AEMO administered prudential regime performs as expected, settlement risk is low: sellers (generators) are likely to receive payment for spot sales. The prudential regime is designed to achieve a 2 percent probability of a loss given default, restricting residual settlement risk to very low probability events.
- Market participation is limited to those participants with a role in the physical delivery chain (retailers, generators, customers and demand side aggregators). The residual risk of contagion to or from other sectors of the economy from the behaviour of the spot market is, therefore, very low[13].

Those design features that limit the residual risks in the electricity spot market are likely to give rise to some, unquantifiable reduction in the risks to participants in electricity derivative markets and, arguably, a reduction in contagion risk. Transparent spot prices, for example, provide an independent, observable and continuous input into derivative valuations and settlements. Chain failures – where non-delivery of the commodity by one counterparty causes the failure of further market participants – are not typical of cash settled markets. Cash settlement is substantially secured by the prudential regime operated by AEMO.

Residual risks remain, however, with market risk the largest of these. Market participants' risk management policies typically have a very strong focus on managing exposure to market risk.

[13] Participants with a role in the physical delivery chain are also significant participants in the derivative market. Participants' presence in both markets may act as a stabiliser in the event of a disruption from one to the other, for example, as the result of a default.

Table 3.2 Electricity Spot Market: Institutional and Organisational Risk Management Measures and Residual Risks, by estimated materiality

		Electricity Spot Market			
Market	**Operational**	**Credit**	**Liquidity**	**Settlement**	**Other**
		Institutional/regulatory arrangements			
Generator bidding requirements • Information provided by generators, generator bidding, rebidding to ensure spot market functions effectively are all regulated. **Administered price caps** • Following a period of sustained high prices, administered prices are introduced for a limited period, capping generators' prices received/ retailers' prices paid. • In event of a sustained disruption to the market, the administered price period can be extended. **Risk Management Policies** • Australian financial services (AFS) licence holders, have an	**Market Design** • Market Operator monitors and forecasts available Reserve Capacity • Market design eliminates retailer exposure to physical failure, individual generator(s). • There may be financial implications of other operational decisions by the Market Operator/ transmission networks, e.g. the operation of the constraint regime, the dispatch of interconnection, etc. – Under limited defined circumstances, compensation may be paid to affected Market Participants for the effects of the Market Operator's decisions.	**Market prudential requirements** • Below a high minimum credit quality, all Market Participants required to lodge prudential securities. **Risk Management Policies** • Australian financial services (AFS) licence holders, have an ongoing legal obligation under s912A(1)(h) of the *Corporations Act 2001* to have adequate risk management systems.	**Generator bidding requirements** • Information provided by generators, generator bidding, rebidding to ensure spot market functions effectively are all regulated to ensure spot market functions effectively. **Generator dispatch requirements** • All generators above a minimum size obliged to schedule generation in market and dispatch as instructed. • Under certain, extreme circumstances, generation can be dispatched where not bid. • All physical electricity sales in the NEM go through the spot market. **Risk Management Policies**	**Cash settlement only** • Cash settled, eliminating risk of "chain failures" as a result of failure to deliver. **Market prudential requirements** • Prudential Standard designed to manage the risk of generators' exposure during the defined spot market Settlement Cycle. • Incoming Prudential regime designed to provide a defined level of security to generators in the event of retailer failure. The required performance for the prudential standard is that sufficient capital should be held to ensure that the Probability of a Loss Given Default (PLGD) is no more than 2 percent. Extreme	**Market participation restrictions** • Unlike a number of other electricity markets, spot market participation is restricted to participants buying/selling electricity. Risk of contagion from failures in the wider economy restricted.

Electricity Spot Market

Market	Operational	Credit	Liquidity	Settlement	Other
ongoing legal obligation under s912A(1)(h) of the *Corporations Act 2001* to have adequate risk management systems	**Market disclosure requirements** • Generators are obliged to provide information on current status of generation for dispatch and information on any planned outages. **Risk Management Policies** • Australian financial services (AFS) licence holders, have an ongoing legal obligation under s912A(1)(h) of the *Corporations Act 2001* (Corporations Act) to have adequate risk management systems.		• Australian financial services (AFS) licence holders, have an ongoing legal obligation under s912A(1)(h) of the *Corporations Act 2001* to have adequate risk management systems.	events (PLGD less than 2 per cent) are outside the designed cover. • AEMO Procedures outline the processes required to call on the securities lodged; to increase the security as required from time to time in response to changing market conditions; and to regularly review all Participants' obligations. • Market Participants are required to respond to AEMO's requests for additional security within a defined timeframe or risk default. **Risk Management Policies** • Australian financial services (AFS) licence holders, have an ongoing legal obligation under s912A(1)(h) of the *Corporations Act 2001* to have adequate risk management systems.	

Electricity Spot Market					
Market	**Operational**	**Credit**	**Liquidity**	**Settlement**	**Other**
		Internal/organisational measures			
Risk management policies and processes • Generators' Risk Management Policies typically limit exposure to spot market • Generators are required to have trained staff (AFSL requirement). • Generators' bids submitted (offers) are structured with regard to expected bids from other generators, expected demand, hedges in place and operating costs. **Vertical integration** • Vertical integration can reduce generators' (and retailers') net exposure to the spot market. **Customer pricing** • Retailers' price and volume risks are managed in the financial market and through customers' prices.	**Risk management policies and processes** • Generators' Risk Management Policies typically address operational risks and related exposures. **Insurance** • Participants typically hold Business Continuity, Generator Outage and other forms of insurance. **Customer pass through** • Retailers' end user contracts do not guarantee delivery and exclude liability for losses relating to failure to supply resulting from infrastructure, other failures. • Some large customer contracts may allow for direct pass-through of costs related to operational failures, other events. **Portfolio diversification** • Many large market	**Vertical integration** • Vertically integrated electricity companies can reduce the prudential security required by offsetting expected retail and generation positions.	—	**Prudential market requirements** • Some Market Participants lodge additional security to manage the risk of a call for further prudential deposits.	—

Electricity Spot Market					
Market	**Operational**	**Credit**	**Liquidity**	**Settlement**	**Other**
	participants have multiple generating units sometimes spread across a number of regions. This provides diversification should one or more units have operational issues.				
Residual Risks					
• Sustained low spot prices can give rise to a risk of financial distress for generators. • Sustained high spot prices may exceed buyers'/sellers' expectations (volume and length of period), increasing forward prices for hedge products (financial market risk). • In addition, where retailers' hedge positions inadequate, high spot prices may result in losses unrecoverable from customers.	• Insurance payout not timely/ inadequate, giving rise to a risk of failure. • Compensation falls short of Participant costs.	• Credit support offsets may reduce the available capital below the target level to meet the Prudential Standard.	—	• Default occurs outside the Prudential Standard (PLGD less than 2 per cent). Generators share losses in proportion to share of generation in relevant period(s). • Disproportionate share may be borne by peaking/ intermittent generation, giving rise to a risk of failure.	—
Materiality of Residual Risks (Qualitative assessment only)					
• **High:** under normal circumstances.	• **Medium/low:** under normal circumstances;	• **Low:** under normal circumstances,	—	• **Low:** under normal circumstances,	—

Electricity Spot Market					
Market	**Operational**	**Credit**	**Liquidity**	**Settlement**	**Other**
• **Extreme:** in worst case scenario	• **High:** in worst case scenario,	assuming incoming Prudential Standard operates as intended. • **High/extreme:** in worst case scenario where loss associated with PLGD < 2 per cent expected to be very high.		assuming incoming Prudential Standard operates as intended. • **High/extreme:** in worst case scenario where loss associated with PLGD < 2 per cent expected to be very high.	

3.3. Electricity market risks: derivative market risks

As Table 3.3 illustrates, electricity derivative markets are characterised by a higher degree of private activity designed to limit individual participant's residual risks and facilitate efficient contracting compared with electricity spot markets, which demonstrate a high level of regulatory control of the residual risks. These private efforts include: the development of the AFMA Electricity Addendum to the ISDA Master Agreement, extensively used as the basis for electricity OTC derivative trades; the ASX's electricity derivative offerings; a range of insurance products offered by international insurers designed to address specific electricity industry and market risks; and the risk management policies and processes of electricity market participants. In some cases, the private efforts are reinforced by a regulatory requirement. The ASIC requirement for AFSL licensees, for example, to have adequate risk management systems reinforces companies' policies and behaviours. Other regulatory controls are likely to result in risk management activity additional to that the companies would undertake – the requirement for trained personnel for AFSL licensees, for example, may drive a different form of training than would otherwise be chosen by participants.

As with electricity spot markets, market participants in electricity derivative markets retain a number of residual risks, of which the largest is likely to be participants' market risk. Incomplete and illiquid electricity derivative markets can limit participants' abilities to manage their risks in normal market conditions. In extreme circumstances and conditions of stress, illiquidity could increase, increasing the risk to participants.

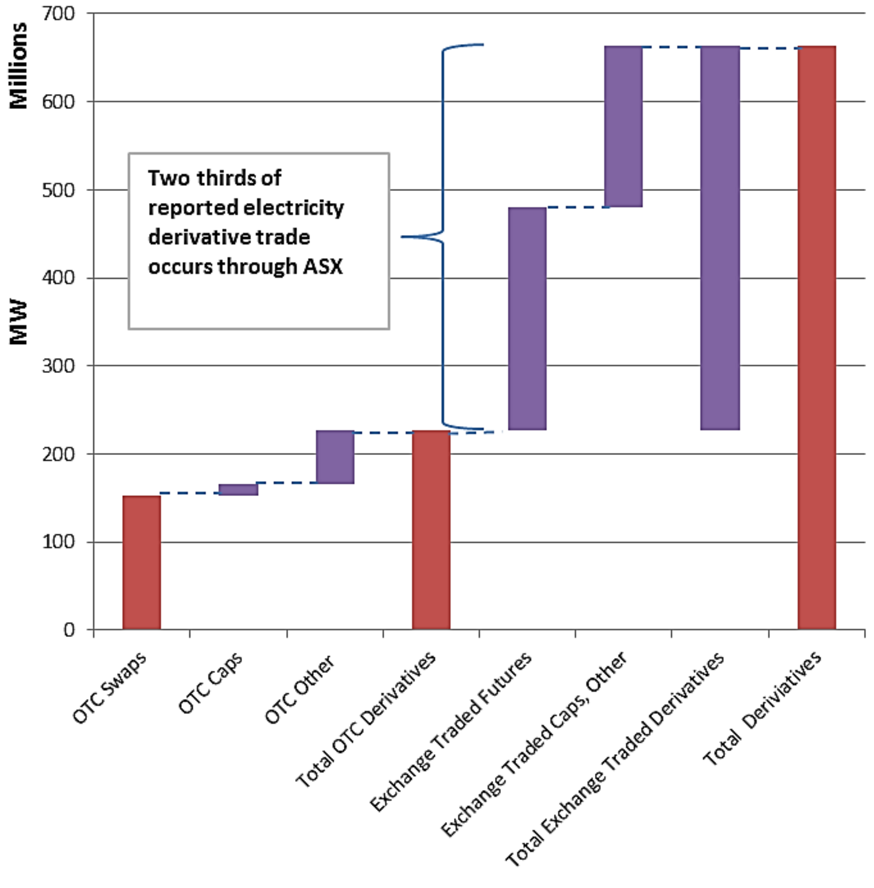
Participants have acted to limit their risks:

- The larger part of reported electricity derivative trade is subject to daily margining. Based on the published figures, in 2011/12 exchange traded derivatives made up about two thirds of total reported electricity trades (Figure 3.1, below).
- Trade with intermediaries in the electricity derivatives market tends to improve credit quality. On average over the past 5 years, intermediaries participating in the electricity derivative market have accounted for around 25 percent of total OTC derivative trade, with intermediaries' market share increasing to just over 50 percent of reported transactions in 2011/12.[14]
- A number of market participants inform us that their AFMA Electricity Addenda have been amended to remove the risk of automatic two-way termination in the event of default.
  - This amendment, if effective in a default, removes the risk that the non-defaulting counterparty would be required to make an unexpected one off payment to the defaulting counterparty representing the value of an out-of-the-money derivative position.[15]

[14] AFMA, *2012 Australian Financial Markets Report*, p. 51; Seed calculations

[15] To this extent, it protects the non-defaulting party from the consequences of having to provide for the unanticipated pay-out of positions to its defaulting counterparties. However, in the event of its own default event, a one-way termination may be a worse outcome for the creditors and shareholders of the party initiating the amendment.

Figure 3.1 Total traded electricity derivatives by category and market, 2011/12, MW, millions



Source: AFMA; Seed calculations

- Market participants have minimum credit criteria for their counterparties, typically accompanied by a tiered structure for determining lines of credit, based on the counterparty's published rating.
  - Some counterparties entering the market with a lower than acceptable credit rating or unacceptable parent company guarantee have been willing to accept one-way margining to establish a sufficiently broad range of counterparties to deal with.
- Market participants limit their leverage, that is, the ratio of derivative positions to the underlying requirement for a physical hedge.
  - Generators and retailers typically retain clear relationships between their derivative positions and the underlying physical position being hedged. Retailers restrict the extent to which their derivative positions outstrip their required purchases to limit their total spot market exposure: an over-hedged position represents an exposure to the spot market in a similar way to an under- or unhedged position. Generators also typically restrict their derivative positions, both in relation to their underlying physical position and also in relation to the region in which they produce.
  - Looking at the reported data again, then some high level calculations suggest leverage across the sector is low.

  - Total reported transactions in MW in 2011/12 represented 663 million MW, or about 3.5 times total electricity spot sales over the same period, down from 4.5 times for the same period in the previous year[16].
  - Further, if we assume that intermediaries account for 30 percent of total trades[17], the ratio for end users falls to around 2.5 times.
  - As some trading relates to future periods – in 2011/12, for example, for 2012/13 and 2013/14– a higher degree of leverage could have been anticipated and would still have been consistent with a low and controlled relationship between underlying physical positions and hedging activity. The level of leverage is consistent with the further published information that shows the share of reported transactions with a duration of more than 12 months duration at its lowest level in the past decade, having fallen persistently throughout the decade.
  - The 2011/12 figures, although the most recent full year available on the OTC market, may have been unrepresentatively low given the impact on trade of the implementation of a carbon price. However, in 2012/13, exchange traded volumes fell for the third successive year to below the volumes traded in 2009/10. Leverage may have fallen again as a result.
- Vertical integration allows a market participant to limit its leverage and, depending on the way in which the vertically integrated portfolio is constructed, to restrict the chosen level of leverage to specific markets, whether product (base or peak load) or regional.
  - From the perspective of the individual firm the reduction in leverage and the internalisation of the risks may be rational, but from a market perspective the reduction in leverage and liquidity risks a cycle of further integration, lower liquidity and further integration.
  - For "stranded" generators, that is, generators in a regional market without a related retail load where vertical integration reduces the market for the sale of derivatives, the longer term effects of vertical integration may be an increase in the degree of leverage at the individual firm level. However, risk aversion and highly geared balance sheets mean that it is unlikely that an increase in leverage of this kind will offset that reduction that resulted from vertical integration.

[16] Explanations cited for the decline in leverage include the increase in vertical integration, in particular as a result of the sale of government owned retailers in NSW and Queensland and the uncertainties associated at the time with the proposed implementation of the Carbon Pollution Reduction Scheme. The latter effect is most likely to have affected trade in the out-years, for 2012/13 and beyond.

[17] This is an arbitrary assumption. In 2011/12, intermediaries represented just over 50 per cent of total OTC trades in MW, up from an average of just over 17 per cent in the preceding 4 years. The share of intermediaries in the exchange traded market is unknown, although from time to time, intermediaries have been reported as representing a significant component, even a majority, of trades in that market.

Table 3.3 Electricity Derivatives Markets: Institutional and Organisational Risk Management Measures and Residual Risks, by estimated materiality

Electricity Derivatives Markets					
Market	**Operational**	**Credit**	**Liquidity**	**Settlement**	**Other**
Institutional/regulatory arrangements					
AFSL requirements • Australian financial services (AFS) licence holders, have an ongoing legal obligation under s912A(1)(h) of the *Corporations Act 2001* to have adequate risk management systems and include other obligations (e.g., minimum training, personnel). **Industry supported standards** • AFMA Electricity Addendum developed to provide a template contractual framework to support bilateral negotiations and contracting.	**Industry supported standards** • Current AFMA Electricity Addendum excludes operational events from Termination Events, reducing the potential for contagion from operational failure. **Customer pass through** • Some costs associated with events such as infrastructure failure may be able to be passed through to customers, depending on the nature of the event and the jurisdiction.	**AFSL requirements** • Australian financial services (AFS) licence holders, have an ongoing legal obligation under s912A(1)(h) of the *Corporations Act 2001* to have adequate risk management systems. • AFSL License requirements relating to minimum surplus liquid funds. **Exchange traded market** • ASX standard derivatives and Exchange for Physical facility use a Central Counterparty. Both require initial and variation margins. **Credit support** • Credit guarantees and credit support, either one way or bilateral may be used in OTC market. **Government ownership**	**AFSL requirements** • Australian financial services (AFS) licence holders, have an ongoing legal obligation under s912A(1)(h) of the *Corporations Act 2001* to have adequate risk management systems. **Exchange traded market** • ASX offers both standard derivatives and Exchange for Physical facility for standardised OTC contracts, providing an alternative source of liquidity for some participants over some contract lengths.	**Cash settlement** • Cash settled, eliminating risk of “chain failures” as a result of failure to deliver. **AFSL requirements** • Australian financial services (AFS) licence holders, have an ongoing legal obligation under s912A(1)(h) of the *Corporations Act 2001* to have adequate risk management systems. • AFSL License requirements relating to minimum surplus liquid funds. **Exchange traded markets** • ASX standard derivatives and Exchange for Physical facility require initial and variation margins. At settlement, only overnight changes in value at risk.	**AFSL/APRA requirements** • Other participants in electricity derivatives markets may have to meet APRA requirements/ be required to meet AFSL requirements. **Exchange traded markets** • ASX offers both standard derivatives and Exchange for Physical facility for standardised OTC contracts. • Individuals trading through ASX required to meet initial and variation margin requirements. **Industry supported standards** • AFMA Electricity Addendum developed to support bilateral contracting.

Electricity Derivatives Markets					
Market	**Operational**	**Credit**	**Liquidity**	**Settlement**	**Other**
		• A small number of participants continue to benefit from the lower risk associated with government ownership, with/out formal guarantees.		**Industry supported standards** • ISDA Master Agreement/ AFMA Electricity Addendum have procedures designed to shorten period between termination event and pay-out.	
Internal/organisational measures					
Balance of hedging and speculative activity (leverage) • The relationship between physical and financial positions (leverage) is typically subject to tight limits, with many generators undertaking only limited speculative trading. • Retailers also typically tightly control the relationship between physical and financial positions (leverage), with most retailers restricting their derivative transactions (OTC and exchange	**Insurance** • Participants typically hold Business Continuity, Generator Outage and other forms of insurance. **Risk management policies and processes** • Stand-alone generators typically restrict contracts/sold futures obligations to less than physical capacity (N-1 rule) to cover potential outage risk. • Portfolio generators may apply N-1 rule to (regional) portfolio. Portfolios may also offer wider risk diversification benefits.	**Industry supported standards** • OTC contracts entered into using AFMA Electricity Addendum; may be tailored to individual participant's requirements. **Risk management policies and processes** • Risk management policies required by AFSL • Participants typically limit net exposure to counterparties by: establishing position limits, limiting the line of credit extended; using the EFP facility; and trading in the	**Risk management policies and processes** • Risk management policies required by AFSL • Risk management policies typically require progressive hedging forward commitments. • Most participants use some combination of futures, OTC and other, insurance-type products to manage exposures. • Standardised products offer higher liquidity, but are less well designed to cover contingent risks, e.g. load shape risk.	**Risk management policies and processes** Risk management policies required by AFSL **Exchange traded markets** • At settlement, only overnight value changes in exchange traded contracts at risk. **Industry supported standards** • ISDA Master Agreement/ AFMA Electricity Addendum have procedures designed to shorten period between termination event and pay-out.	**Industry supported standards** • OTC contracts entered into using AFMA Electricity Addendum. **Risk management policies and processes** • Participants typically limit net exposure to counterparties by: establishing position limits, limiting the line of credit extended; using the EFP facility; and trading in the exchange traded market.

Electricity Derivatives Markets					
Market	**Operational**	**Credit**	**Liquidity**	**Settlement**	**Other**
traded) to their estimated physical position and undertaking little or no speculative trading. **Risk management policies and processes** • Generators, retailers undertake detailed forecasting, expected load and prices, using a variety of in-house and well established external models. • Retailers, generators typically have detailed risk management policies to manage load, load shape risk, including use of contingent contracts (insurance, weather derivatives) to address low frequency/high cost events. • Risk management policies typically address future price and volume risks by requiring a level of forward contracting **Vertical integration** • Vertical integration and	• Retailers diversify hedge counterparties to extent feasible to minimize risk of lengthy outages resulting in financial distress and counterparty default.	exchange traded market. • Some participants require/supply credit support, particularly where parent guarantee/bank guarantees provided assessed as insufficient. • Counterparty credit ratings (where available) and net exposure monitored. • Retailers diversify hedge counterparties to extent feasible to minimize risk of financial distress and counterparty default.	**Vertical integration** • Vertical integration can provide cover against high price (peak demand) events, depending on the generation assets in the portfolio.		

Electricity Derivatives Markets					
Market	**Operational**	**Credit**	**Liquidity**	**Settlement**	**Other**
regional diversification allow market participants to reduce or diversify risks across portfolio. **AFSL requirements.** • AFSL requirements including risk management policies, training personnel.					
Residual Risks					
• Forecasting and model risk, projected volumes and prices. • Financial markets incomplete, and illiquid in some regions/duration/product types, including standardised contracts. In event of distress, illiquid markets may become more illiquid, severely limiting participants' ability to manage short term (spot market) risks or replace forward contracts. • In illiquid markets, limited ability to manage basis risk from	• Insurance payout not timely/ inadequate, giving rise to a risk of failure. • Failure of a counterparty as a result of operational risk is likely to result in a failure to receive net payments owed; could require existing hedges to be replaced on less favourable terms; and, may require payout of net amounts owing on OTC contracts depending on nature of agreements entered into.	• Cash flow mismatch between margining requirements exchange traded market and spot market may stress participant without access to adequate working capital. • Failure of a counterparty is likely to result in a failure to receive net payments owed; could require existing hedges to be replaced on less favourable terms; and, may require payout of net amounts owing on OTC contracts depending on nature of agreements entered	• Illiquidity can hinder implementation desired hedging strategy; limit ability to replace existing position at an acceptable price or at all; and expose participants in some markets (region/peak/ contingent) to higher than desired risks.	• Cash flow mismatch between margining requirements exchange traded market and spot market may stress participant without access to adequate working capital. • Failure of a counterparty at settlement could result in material loss, depending on total exposure and credit risk policy. • May also affect future hedge position and, depending on the impacts for liquidity, could affect implementation desired	• Speed of deterioration in financial institution's credit worthiness may be faster than counterparties' ability to respond. • To extent that financial participants have been a source of liquidity, failure could reduce liquidity in OTC and exchange traded markets.

Market	Operational	Credit	Liquidity	Settlement	Other
liquid to illiquid region, even where two regions typically correlated. • Settlement Residue Auctions units (SRAs) hedging basis risk from liquid to illiquid markets not robust in all circumstances. • Non-performance/ unexpected basis risk, contingent products in event of risk crystallising.		into.		hedging strategy; limit ability to replace existing position at an acceptable price or at all; and expose participants in some markets (region/peak/ contingent) to higher than desired risks.	
Materiality of Residual Risks (Qualitative assessment only)					
• **High:** under normal circumstances • **Extreme:** in a worst case scenario, where continuing high spot prices could be combined with little/no liquidity. **See Section 4.3 for our estimate of the potential costs in the event of the failure of a counterparty under conditions of stress.**	• **Low**: under normal circumstances, but depending on nature of exposure to counterparty default. • **Medium/high**: in a worst case scenario, where, for example, effects are regional and protracted.	• **Medium:** under normal circumstances, but depending on nature of exposure to counterparty default. • **High:** in a worst case scenario, depending on nature of exposure to counterparty default. **See Section 4.3 for our estimate of the potential costs in the event of the failure of a counterparty under conditions of stress.**	• **High:** under normal circumstances. • **High/extreme:** in a worst case scenario, market illiquidity may prevent participants reducing market risk at an acceptable price/at all, compounding market risks. **See Section 4.3 for our estimate of the potential costs in the event of the failure of a counterparty under conditions of stress.**	• **Medium**: under normal circumstances, but depending on nature of exposure to counterparty default. • **High**: in a worst case scenario, depending on nature of exposure to counterparty default. **See Section 4.3 for our estimate of the potential costs in the event of the failure of a counterparty under conditions of stress.**	• **Medium/low:** under normal circumstances, given relatively low level of participation in electricity derivatives market. • **Medium/low:** in a worst case scenario, given relatively low level of participation in electricity derivatives market.

3.4. When a risk crystallises: exposure and timing

Figure 3.2 is a high level schematic that looks at the timing and exposure of the risks an electricity OTC market participant experiences on the default of its counterparty.

- In Figure 3.2, the event of default occurs in mid-February.
- **Settlement Risk :** The defaulting counterparty fails to make the expected settlement payments relating to the previous 4 weeks' spot market prices, as well as failing to make those settlement payments that would have become due relating to the current week, prior to the event of default.[18]
  - This failure may require the non-defaulting counterparty to find an alternative source of cash to meet its spot market settlement obligations and/or other settlement obligations in the OTC market. Depending on market conditions in the period immediately following the default, the need for additional capital may be compounded by requirements for additional margin in the exchange traded market.
  - Margining alleviates this exposure to the extent that the non-defaulting counterparty can use the existence of the margin as an asset in raising additional cash. We assume, however, that access to margin deposits would be too slow to prevent the need for additional cash to be raised.
- **Credit Risk (termination payout):** After a relatively short period following the default, expected to be around 4 to 6 weeks, the non-defaulting party calculates the (net) termination value of its OTC contracts with the defaulting counterparty. Typically, counterparties are likely to have multiple contracts with different terms and related market values with each other; the net value of all the outstanding contracts is the basis for the termination amount that the defaulting counterparty owes the non-defaulting counterparty (in Figure 3.2, the Termination Settlement Amount).[19]
  - Depending on the position in the creditors' queue, the Termination Settlement Amount may not be paid in full or at all and, in any event, may not be received for a significant time.
  - Margining reduces this exposure by requiring the counterparty to the unprofitable side of the contract to provide additional capital, calculated based on the relationship between the contract's original terms and the current market. In the event of a default, subject to the availability of the margin payment, the loss by the in-the-money counterparty should be restricted[20] to

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[18] Under the ISDA Master Agreement, the Event of Default can be triggered by a number of events, including a failure to pay funds due, but is then determined by a process between the Counterparties that results in the Event of Default being fixed at some nominated date following the failure. The time taken in this process is not fixed. In our discussion, rather than deal with the uncertain lapse of time between the failure and the Event of Default, we have treated the two as co-incident, although this is not strictly accurate.

[19] The ISDA Master Agreement is based on an Automatic Two-Way Termination on default, which effectively requires the party whose net OTC derivatives are out-of-the-money or unprofitable to pay the other party, whether or not that party is the defaulting party. We understand that electricity OTC market participants routinely amend their OTC documentation to remove this clause. If the clause is not removed, then, although the non-defaulting party retains the right to calculate the value of the Termination Payment, the non-defaulting party may be required to pay the defaulting counterparty the net amount owed in settlement and on a timely basis.

[20] Margins are calculated with reference to a price distribution that excludes extreme market prices, so there is some small (theoretical) possibility of a price movement that is larger than anticipated resulting in an inadequate margin calculation. Less theoretically, recent failures of commodity brokers in the US and other

unexpected movements in the value of the position from the first day of default to the effective close-out of the position.

- **Credit Risk – hedge replacement cost:** The non-defaulting counterparty begins to replace the now ineffective contract(s) in the market. The cost incurred is a function of the difference between the price in the derivative market at the time of the original contracts and the prevailing price when the contracts are replaced.
  - This cost (Credit Risk – hedge replacement cost) is experienced over the life of replacement contracts: the non-defaulting counterparty is in a worse position than it would otherwise have been, had the original contracts remained in place. Margining does not address all of this loss; it only addresses the portion of the movement in contract prices between the original hedge price and the time of default and not the price movement post default.
  - Depending on the level of competition in the end-user market that the non-defaulting counterparty sells into and the regulatory arrangements in that market, the incidence of the loss could fall on customers or shareholders.
  - The cost of this exposure is a function of the size of the position(s) that are the subject of the default and the behaviour of the derivative markets in the aftermath of the default. The higher and more volatile the spot market, the more expensive OTC contracts are likely to be and the higher the replacement cost.
- **Market Risk:** Alternatively, the non-defaulting counterparty may choose not to replace the ineffective contracts in the short term as a result of market conditions in the period following the default. In practice even if a participant wanted to replace the ineffective contracts it may not be possible to replace the contracts with the original characteristics – other market participants may be unwilling to offer long term contracts until there is greater clarity about future market conditions. For the period up to the replacement of the ineffective contracts, the non-defaulting counterparty will be exposed to the spot market, incurring market risk.
  - The cost of this exposure is a function of the size of the newly ineffective position and the behaviour of the spot market in the aftermath of the default. Margining does not address this loss.
  - In other commodity markets, depending on the standard terms for trade this risk may be shared with customers. However, in the NEM, most customer contracts provide the customer with a fixed price and limit the frequency of repricing, so any market risk will typically be borne by shareholders.

In Section 4, based on information provided to us about participants' OTC exposures, we calculate the potential costs of the settlement, counterparty and market risks under extreme conditions of stress that a market participant could experience as a result of the default of an OTC counterparty and consider the potential for these losses to present a systemic risk.

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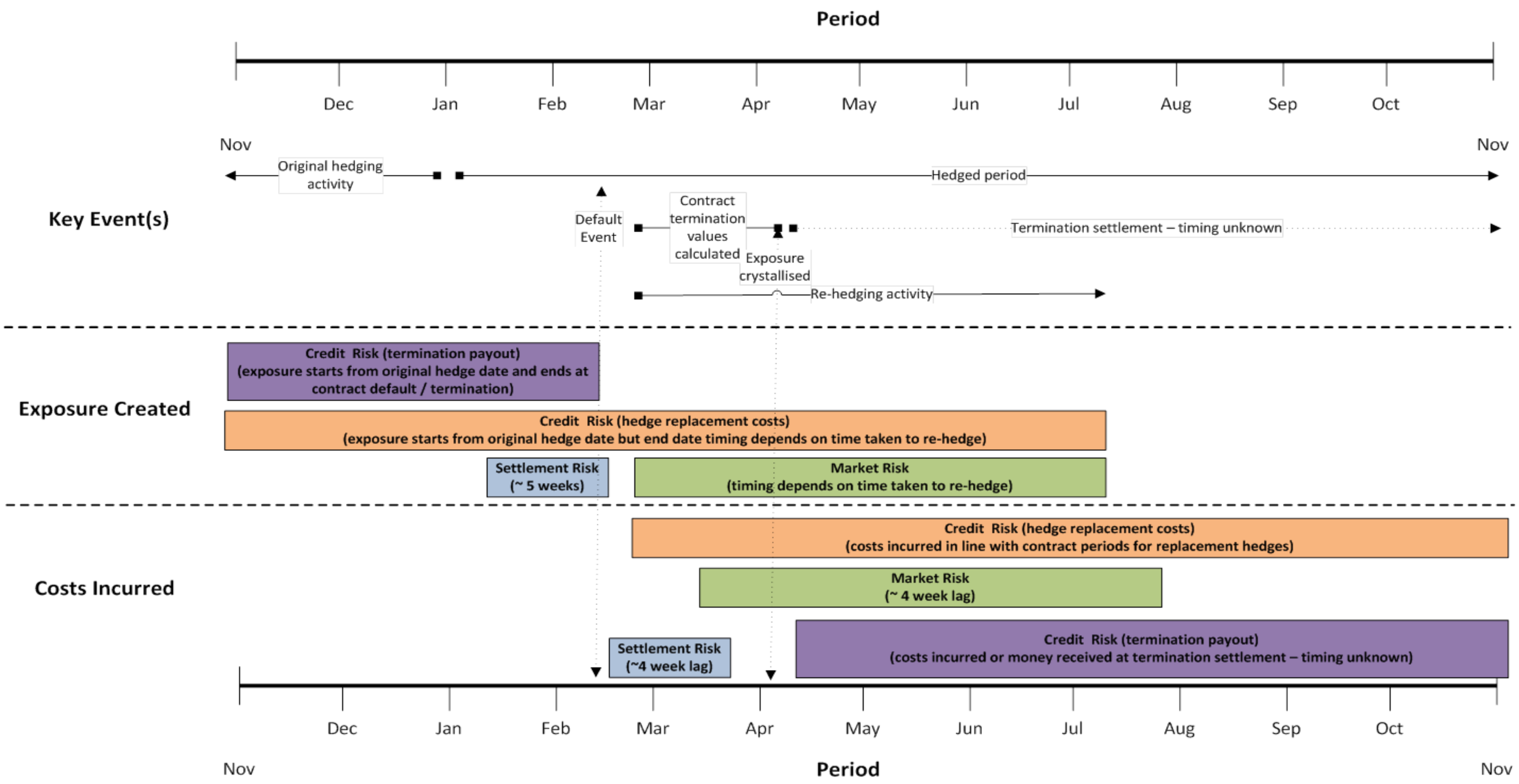
markets have illustrated the risks to participants' margins where, for example, margin payments are not segregated.

Figure 3.2 Key Risks: when exposure created and costs incurred, schematic



4. The potential cost of a counterparty default

Based on our modelling, the immediate loss as the result of the failure of a large derivative counterparty is $140 million for the vertically integrated participant ($10 million for a stand-alone generator). This loss represents the cash shortfall relative to the contracted position and, given the linked nature of spot and derivative market settlements, that cash is likely to be required by the non-defaulting counterparty over a 4 to 5 week period immediately following the default to meet its coincident obligations in the spot and derivative markets.

Is this a sufficiently large amount to result in further contagion and systemic risk to the NEM? Considering the published results of the largest vertically integrated retailers, then based on their cash and cash equivalent holdings as at December 2012 $140 million would appear to present no funding issues, with the resulting risk of further follow-on failures low.

Secondly, the defaulting counterparty is unlikely to have had only one counterparty. We estimate that the short term funding requirement could range from $200 million to $560 million, spread over a number of counterparties. If these losses result from the failure of a large stand-alone generator, the effects would be concentrated among regional spot market participants, although the knock-on effects could spread to other regional spot markets. The market-wide short term funding requirement is unlikely to represent a stress to the financial sector as a whole. Since 2007, RBA figures indicate that lending to business by all financial institutions has averaged $2.3 billion a month; even our highest estimate amounts to only 25 per cent of this amount.

The larger part of our estimate of the potential loss relates to the loss of enterprise value resulting from replacing the ineffective positions with newer, more expensive positions. This loss, which could amount to up to $490 million for the largest individual exposure in the scenarios we have considered and between around $750 million and just under $2 billion for the market as a whole, is crystallised over the duration of the replacement contracts, a period of more than three years. The full extent of this loss is a result of the assumption that the non-defaulting party replaces its ineffective contract(s) for their entire remaining term. If the non-defaulting party replaces only the first two years of its contracts, the credit risk is reduced to $200 million. In the absence of a short term funding requirement, a loss of between $200 and $490 million over a period of two plus years is unlikely to result in immediate failures. From the perspective of the economy as a whole, the loss is unlikely to present an immediate systemic risk.

4.1. Our approach

Our approach tests an individual participant's settlement, credit and market risks in the event of the default of the participant's largest and average OTC counterparties. We have focused on large market participants and their largest positions, as the risk of systemic risk within the NEM is, in our view, a result of the size of the initial event or and the potential for contagion in related electricity markets. Considering both the wider financial markets and the economy as a whole, our view is that the principal reason why a risk could be regarded as systemically important is the size of the prospective impact on the financial sector and the real economy. We discuss the potential for the risk to present a systemic risk for the wider economy in Section 4.3, where we discuss our results.

We have not analysed participants' overall or specific portfolios: this would only be required if we were modelling the underlying market risk inherent in each business. Nor have we modelled the potential risks and associated costs of contagion, which are outside the scope of this analysis. We have based our analysis on the data provided by seven large market participants covering the vertically integrated retailer and stand-alone generator categories. We have not audited or validated the data provided by these participants.

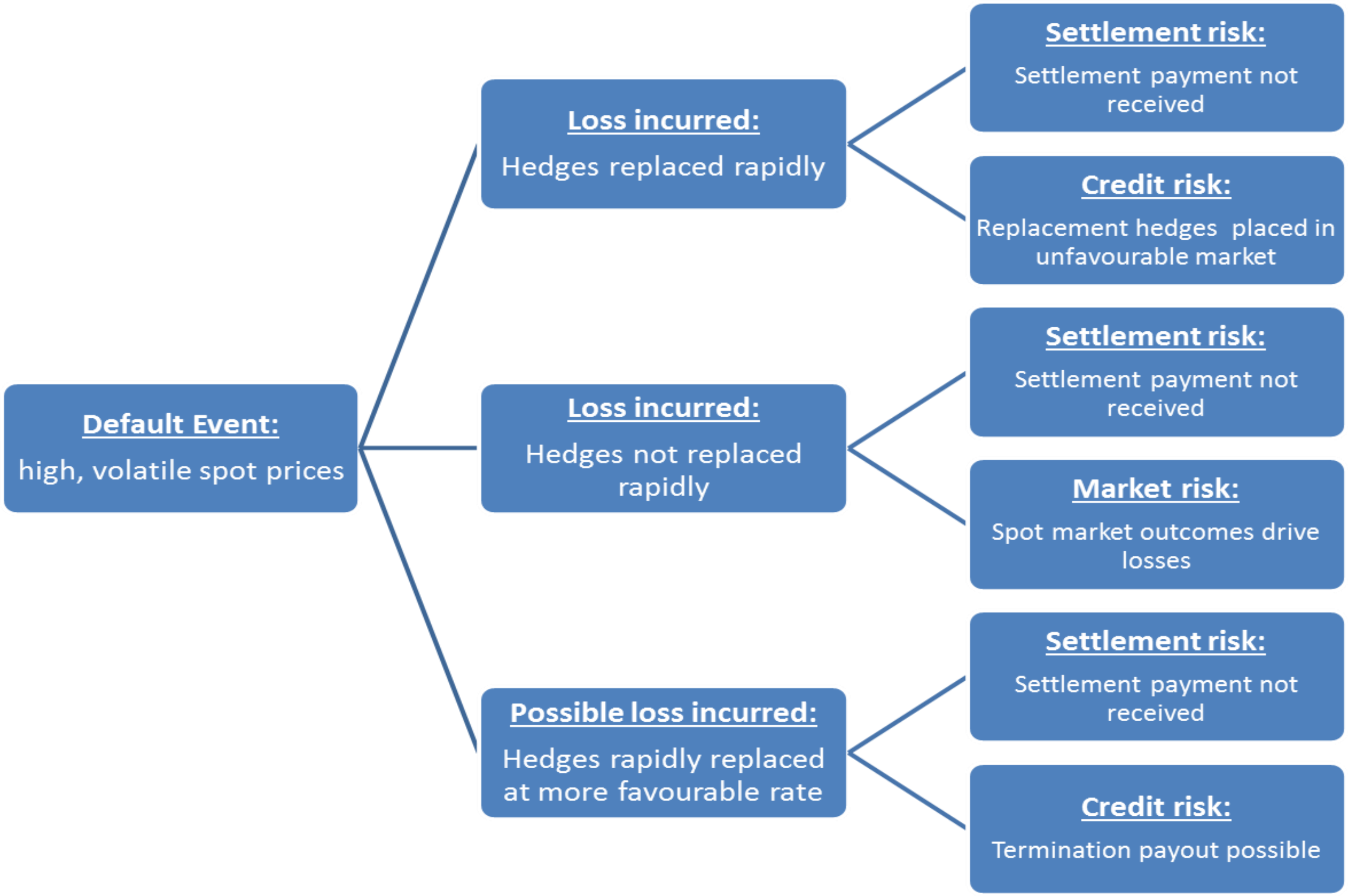
Even using our simplified approach, it needs to be recognised that the total costs of a counterparty default to an individual participant are affected by:

- The relationship between derivative prices at the time at which the contract was entered into and the time of default, or whether the derivative was *in* or *out* of the money at the time of default;
- The behaviour of the spot and contract markets in the immediate aftermath of the default and during the period when the affected participant replaces the now ineffective derivative position;
  - Our modelling assumes very large and persistent shifts in spot and derivative prices relative to historic experience. This behaviour in the spot and derivative markets, although the obvious result, may not be the way in which the markets react. Market participants with both generation and sales to end users may have an incentive to ensure that spot prices remain low and less volatile and, to the extent that these participants respond by changing the bidding behaviour of the generation they control, may influence spot price outcomes away from the direction we have assumed.
- The choices made by the affected participant in replacing the newly ineffective position;
- The level of competition in the relevant retail and generation markets. The more competitive the market, the less likely it is that the affected participant will be able to pass its losses through to its customers; the level of competition influences the ultimate incidence of the costs of the default.

Figure 4.1 shows, in a highly stylised way, the possible outcomes when a vertically integrated retailer's counterparty defaults

- The default is immediately followed by high and volatile spot prices (far left hand side).
- The costs to the retailer are a function of the value of the position at default;
  - Either a loss is incurred, that is, the position was entered into on more favourable terms that would be available at the time of default (in-the-money); *or*
  - If the position is out-of-the-money at the time of the default, depending on the movement of the market following the default, given the lags in the settlement process, it may revert to an in-the-money position.
- Finally, the non-defaulting party's actions are important to the total loss (far right hand side).
  - The position may be replaced rapidly, but at a relatively high cost, reflecting current market conditions; *or*
  - Slowly. If the non-defaulting party replaces the existing position slowly, it will be exposed to high spot prices until the original position is replaced..

Figure 4.1 Simplified schematic of actions/reactions and crystallised risks



A similar stylised description can be given of the risks facing a generator with a defaulting counterparty. From a generator's perspective, however, the principle risk is that the spot market conditions following a counterparty default result in low, not high, prices, increasing the cost of the generator's crystallised credit or market risks.

Looking at the components of the costs incurred, then:

- Settlement risk is present in all the scenarios.
  - However, a vertically integrated participant's risk and a large generator's risk are not additive to arrive at a view of total risk: they are based on opposite movements in prices and cannot occur simultaneously.
- Credit risk (the cost of replacing an in-the-money position) and market risk are mutually exclusive, considering each as the ends of the spectrum of possibilities. A participant either experiences market risk, as a result of not hedging the spot price exposure, or credit risk, as a result of replacing the exposure at a potentially higher cost.
  - More realistically, a participant is likely to incur some part of both: even if the participant's intention is to replace the ineffective position as soon as possible, this would normally take some time and in times of stress, could take longer.
  - A vertically integrated participant's risk and a large generator's risk are not additive to arrive at a view of total risk: they are based on opposite movements in prices and cannot occur simultaneously.
- A position cannot be simultaneously both in- and out-of-the-money. The credit risk that arises where the position that suffers the default is out-of-the-money (termination payout possible) and that when the position is in-the-money (replacement hedges required at an unfavourable price) are mutually exclusive.[21]
  - A vertically integrated participant's risk and a large generator's risk are not additive to arrive at a view of total risk: they are based on opposite movements in prices and cannot occur simultaneously.

4.2. Our assumptions

In looking at the potential cost of a counterparty default, we have looked at:

- Two Representative Participant types:
  - Large vertically integrated retailer (national footprint), who is a net buyer of electricity in the spot market and hedges the net position in the derivative markets; and
  - Large stand-alone generator, a seller of electricity, hedging its position in the derivative markets.
- Typical net position in MWs for two counterparties for each of the Representative Participant types based on the net position details provided by industry participants, which included the size (MW), duration and product type (swap, cap etc.) for each respondent's:
  - Largest counterparty; and
  - Average counterparty.

[21] Further, because of the rejection of the Automatic Two-Way Termination requirement of the ISDA Master Agreement, industry participants are of the view that the capital payment that would otherwise be incurred when the position at default is out-of-the-money will not be made, although the scheduled contractual payments will be required to continue to be made.

- The consequences of default in the event of the failure of:
  - A large counterparty of the Representative Participant; and
  - An average counterparty of the Representative Participant.

In analysing these situations we have:

- Not modelled or analysed the reason for default as this is not relevant[22].
- Analysed the consequences against the key risk categories of:
  - Market;
  - Credit/Settlement;
  - Liquidity.

Liquidity risk is not directly modelled, but rather influences the level of the resultant market risk. We are also assuming that, given the market design, the default of a counterparty gives rise to no operational risk for a representative participant.

Our assumptions are summarised below.

4.2.1. Counterparty exposures

Our analysis is based on high level OTC portfolio information provided by 7 large market participants covering vertically integrated retail businesses and stand-alone generators. We have not validated or audited this information.

Due to commercial sensitivities we are not able to disclose any participant specific information or any information from which a participant's position could be readily inferred. Our analysis below describes our view of the key features of the largest and average OTC counterparty net positions.

4.2.1.1. Largest net counterparty position

- Reported swap positions are relatively similar in size across participants and follow a typical declining profile over time. Positions are approximately 2 – 3 years' duration. However, some positions are longer.
- Reported cap positions differ materially in size by participant. The differences between participants and in the absolute size of reported cap positions are likely to be reflective of:
  - The differing risk exposures and risk management strategies employed by participants and the use of caps to manage these risks; and
  - The smaller number of parties selling and buying caps relative to those transacting swaps, resulting in a larger concentration of cap transactions

4.2.1.2. Average net counterparty position

- The duration of the average swap positions reported is relatively similar with an average of 2 – 3 years. However, some positions have a longer duration. The positions follow a similarly declining profile, tailing off over a two to three year period.
- The average counterparty swap position is typically between 15 – 35 per cent of the largest OTC counterparty position.

[22] We have assumed the reason for default is not a prolonged physical asset related issue as this may have different consequences and not be relevant to this analysis. The reforms required to address this type of event are more likely to require changes to the reserve margin and the ways in which reserve capacity are procured, rather than changes to derivative markets.

- Consistent with the wide range of cap sizes reported for the largest typical position, the size of the average cap position can be less than 15 per cent of the largest reported position.

4.2.2. Spot and derivative prices in the event of a default

4.2.2.1. Vertically integrated retailer

We have assumed the following characterises spot and contract prices at and following an event of default:

- At the time of default:
  - Spot prices reach VoLL for 7.5 hours until the CPT is reached.[23]
  - Subsequent to CPT, swap prices increase on average by $50/MWh above previously prevailing contract prices, to around $100/MWh.
- Following the default, in a post stress environment and affecting the non-defaulting party's credit risk costs, there is:
  - A parallel shift upwards in all prices in forward curve, by $20/MWh (swaps) and $3/MWh (caps).
  - Additional stress factor of 50 per cent to underlying movements to represent a post stress environment.
  - A similar shift in prices is experienced where the position is out-of-the money, but without the additional stress factor.
- Relative to the ineffective position and affecting the market risk costs of the non-defaulting party, the non-defaulting party experiences:
  - An increase in the average spot price of $30/MWh to previous swap contract prices.
  - Further price spikes averaging $5,000/MWh for 3 hours per week relative to previous cap costs.

4.2.2.2. Large generator

- At the time of default:
  - Spot prices average -$1,000 for 7.5 hours
  - Swap prices fall by an average of $20/MWh *below* previously prevailing contract prices, to around $30/MWh, closer to an SRMC level.
- Following the default:
  - A similar shift in prices is experienced, with an underlying fall of $20/MWh (swaps) and $3/MWh (caps) and a parallel shift of all prices in forward curve.
  - No stress factor used.
- Relative to the ineffective position and affecting the market risk costs of the non-defaulting party, the non-defaulting generator experiences no market risk.
  - For a sold cap position, we assume no market risk as the premium was received and the settlement payments are only one way.

[23] In recognising the effect of the CPT, our scenario, while extreme, is less extreme than that used in the First Interim Report, where the AEMC assumes, that regardless of the CPT, the average daily price following a default can increase to $1,000/MWh, page 72.

4.2.3. Duration of exposure

- Settlement risk:
  - Missed settlement periods cover 5 weeks, representing the settlement cycle for OTC settlements of 4 weeks in arrears, plus an extra week to allow for current week.
- Market risk:
  - 75 per cent of net position with counterparty unhedged for 12 weeks.
  - Remaining 25 per cent of position remains unhedged for a further 8 weeks.

4.3. Our results

Table 4.1 presents our estimates of the costs of each of the individual risks identified, calculated on the basis of the default of either the largest OTC counterparty or an average OTC counterparty and using the assumptions for the behaviour of the spot and contract markets outlined above.

There are a number of issues that should be noted in considering these results.

- There are two contributory factors to the very much smaller costs potentially incurred by a stand-alone generator: the smaller OTC positions reported to us and used in our calculations and the asymmetry of the risks presented by spot prices.
  - Spot prices can increase to $12,900/MWh, but can only fall to -$1,000/MWh. Generators' positions deteriorate when, post default, prices fall, but the extent of the deterioration is limited by the price floor. Retailers' potential costs following a default increase when prices rise; the price increase is limited by the price ceiling, but at typical price levels the extent of the deterioration a retailer is exposed to is significantly higher than that faced by a generator.
  - The risks are not additive. The largest total loss in the scenarios modelled for a vertically integrated retailer occurs where the retailer locks in replacement contract(s) for the total term of the ineffective positions at unfavourable market prices, adding the cost of Credit Risk to Settlement Risk. In this case, the total loss experienced is $630 million, of which $140 million (the Settlement Risk) represents a requirement for cash over the immediate and very short term.
  - A more realistic position, with only the first two years of long dated positions replaced, reduces the retailer's total recognised loss to $340 million ($140 million cash). The comparable figure for a large stand-alone generator is $115 million, of which $10 million represents an immediate requirement for cash.
- Figure 4.2 and Figure 4.3 are more detailed versions of the stylized representation of the possible losses (Figure 4.1), showing the inter-relationships between the risk categories and the costs associated with the largest and average OTC positions reported to us.
  - The non-defaulting party will incur those costs associated with market risk or credit risk, but not both in total. More realistically, the non-defaulting counterparty will incur some combination of market risk and credit risk, reflecting the practical difficulties of replacing the ineffective contract(s) with a new contract(s) in the post default market.
  - The costs associated with market and credit risk are better thought of as opportunity costs or losses. They represent the total estimated deterioration in the non-defaulting counterparty's position relative to its position pre-default over some future period.

- As we discuss in Section 3.4, the incidence of the opportunity costs or losses depends on the level of competition in the relevant market and the regulatory framework.

Table 4.1 OTC Counterparty Default: indicative costs, $ million, rounded

Risk	Definition	Defaulting counterparty position: Largest	Defaulting counterparty position: Average
		$ million, rounded	
	Vertically integrated retailer		
Settlement, *plus 1 of:*	Settlement amount not received	140	15
Market, *or*	Unhedged exposure, declining over 6 month period	230	10
Credit	Replacement of in-the-money position, first 2 years only	200	65
	Replacement of in-the-money position, total	490	70
	Possible call on funds, out-of-the money position[1]	330	50
	Stand-alone generator		
Settlement, *plus 1 of:*	Settlement amount not received	10	2
Market, *or*	Unhedged exposure, declining over 6 month period	15	3
Credit	Replacement of in-the-money position, first 2 years only	95	20
	Replacement of in-the-money position, total	105	25
	Possible call on funds, out-of-the money position[1]	70	20

Note (1): as previously discussed, this loss may not be crystallised in this amount or immediately, depending on the effect of the one-way Termination events apparently used by a number of electricity market participants in their schedules to their ISDA Master Agreements.

Figure 4.2 Potential costs of a default: total position replaced by market participant and category of risk, $ millions

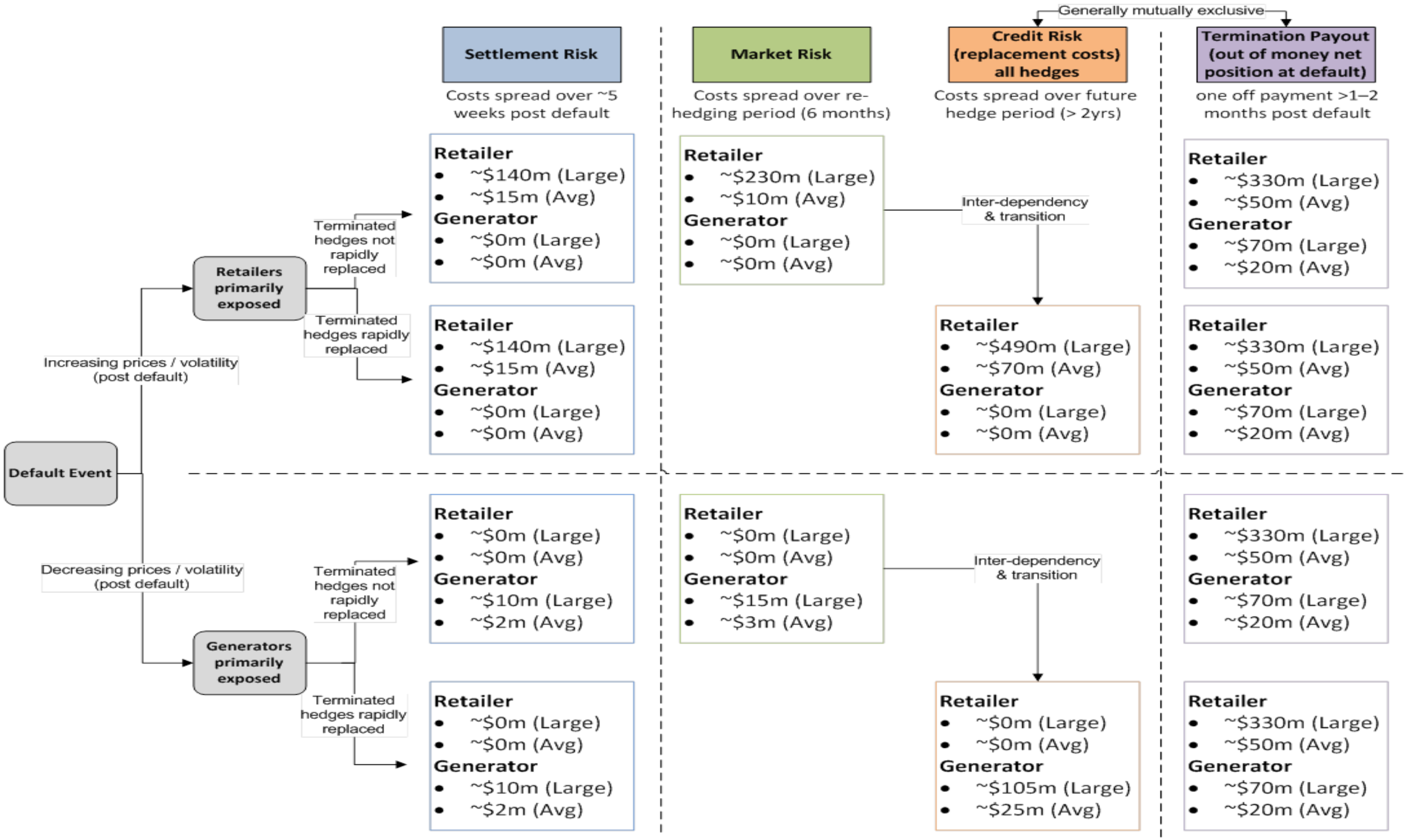
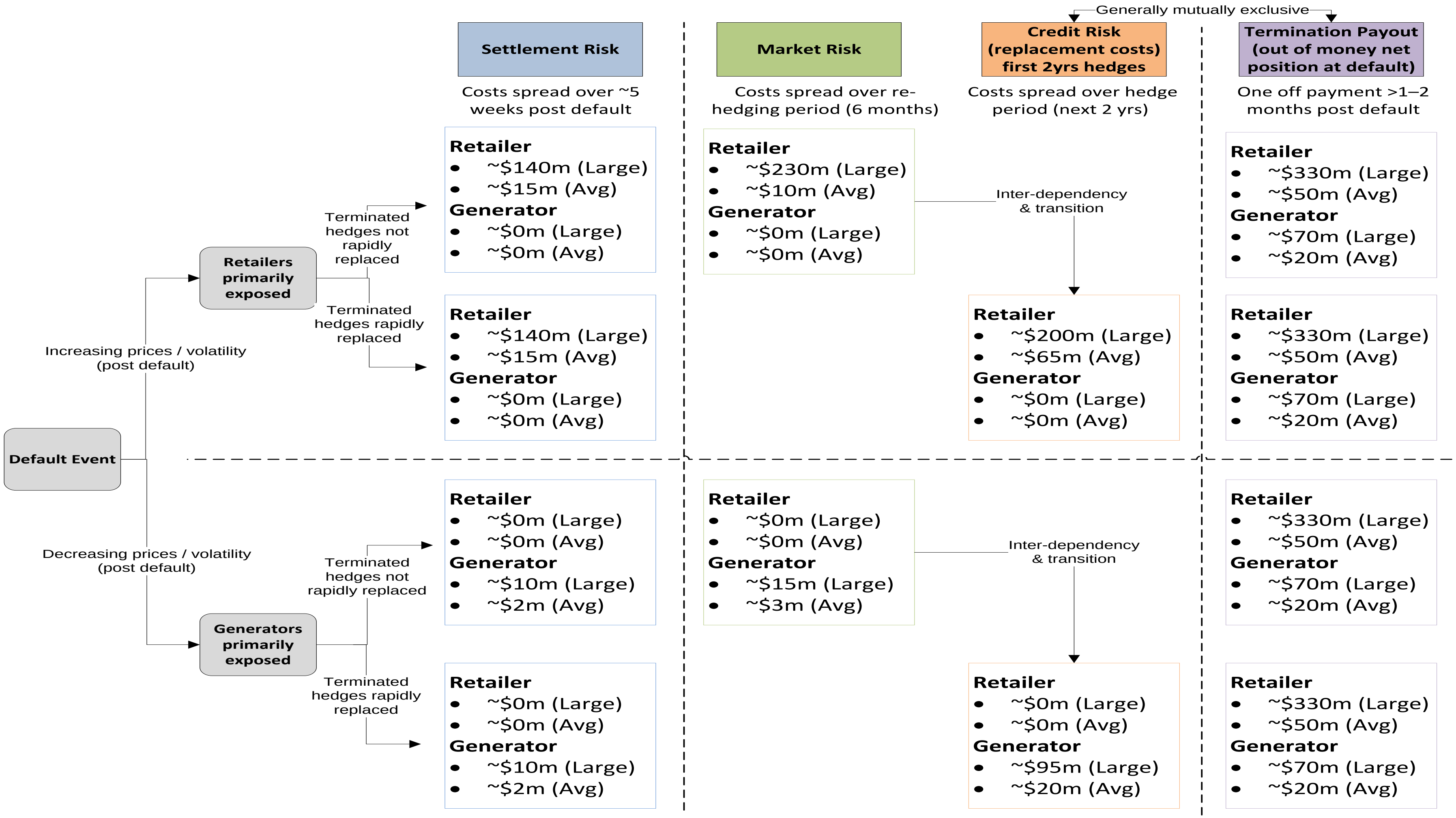


Figure 4.3 Potential costs of a default: first two years' position replaced by market participant and category of risk, $ millions



4.4. Interpreting the results

How are we to interpret these results and their implications for the NEM and financial markets and the wider economy?

First, the immediate loss as the result of the failure of a large derivative counterparty is $140 million for the vertically integrated participant ($10 million for a stand-alone generator).

- This loss represents the cash shortfall relative to the contracted position and, given the linked nature of spot and derivative market settlements, that cash is likely to be required by the non-defaulting counterparty over a 4 to 5 week period immediately following the default to meet its coincident obligations in the spot and derivative markets.
- Is this a sufficiently large amount to result in further contagion and systemic risk to the NEM? The size of this loss is strongly influenced by our data; the average settlement loss, based on our data, would have been $15 million ($2 million for a stand-alone generator). Considering the published results of the largest vertically integrated retailers, then in the context of their cash and cash equivalent holdings as at December 2012 $140 million would appear to present no funding issues, with the resulting risk of further follow-on failures low.
- Margining would compensate for (the larger part of) this loss. However, depending on the time between the default and access to the margin deposited, it may not remove the requirement for additional short term funding.

Secondly, the defaulting counterparty is unlikely to have had only one counterparty. How should these findings be extrapolated to the wider electricity market? We estimate that the short term funding requirement could range from $200 million to $560 million, spread over a number of counterparties. If these losses result from the failure of a large stand-alone generator, the effects would be concentrated among regional spot market participants, although the knock-on effects could spread to other regional spot markets.

- If we assume that the large positions captured in our data represent 25 per cent of the counterparty’s underlying physical position, then there could be up to 4 times this loss incurred by the default. On this basis, the upper bound for the cash required by the market is $560 million spread over a larger number of counterparties.
- The lower bound could be just over $200 million, again spread over a large number of counterparties, if we assume the defaulting counterparty’s derivatives are held between the OTC and exchange traded markets in similar proportions to the reported trades.
- We have not taken into account in these estimates the gains to other market participants as a result to changes in market conditions. While it may be the case that, considering the sector as a whole, the negative impact of market conditions on derivative values is offset by the improvement in some other participants’ positions, an individual participant’s exposure will be a function of its portfolio, its strategy and its net exposure.

The market-wide short term funding requirement is also unlikely to represent a stress to the financial sector as a whole. Since 2007, RBA figures indicate that lending to business by all financial institutions has averaged $2.3 billion a month; even our highest estimate amounts to only 25 per cent of this amount.

The larger part of our estimate of the potential loss relates to the loss of enterprise value resulting from replacing the ineffective positions with newer, more expensive positions. This loss, which could amount to up to $490 million for the largest individual exposure in the scenarios we have considered and between around $750 million and just under $2 billion for the market as a whole, is crystallised over the duration of the replacement contracts.

- The full extent of this loss is a result of the assumption that the non-defaulting party replaces its ineffective contract(s) for their entire remaining term. If the non-defaulting party replaces only the first two years of its contracts, the credit risk is reduced to $200 million.
  - In our judgement, replacing only the first two years of the ineffective contracts is both the more rational and the more likely course of action. The opportunity cost relative to the original position ($200 million) of replacing the first two years' cover is less than the cost of the market risk based on our assumptions ($230 million). There would also be a high level of uncertainty about future market conditions, working against entering into long term positions in the short term.
- In the absence of a short term funding requirement, a loss of between $200 and $490 million over a period of two plus years is unlikely to result in immediate failures.
  - However, depending on participants' financial strength, customer contracts and the regulatory environment, a loss of this size could affect shareholders' valuations. The effect on shareholders could be sufficient to affect valuations across the sector generally, resulting in a reduction in loans to the sector and, potentially, pressure on loan covenants, the orderly disposal of assets and the potential withdrawal of participants from the sector.
- From the perspective of the economy as a whole, the loss is unlikely to present an immediate systemic risk.
  - Assuming that AEMO's prudential arrangements work as designed and that the Retailer of Last Resort arrangements function, then customers would continue to receive electricity without disruption and the spot market would function. The disruptions to markets and customers of the default would be lower than those following the insolvency of HIH, for example.
  - The reduction in shareholder value would affect shareholders, while any restructuring in the sector would affect employees and closely related sectors. Whether these disruptions present a systemic risk is difficult to judge, although we would argue that it is unlikely.[24]

[24] The Enron failure, which occurred during a period where the financial sector in the US was reducing its net exposure to energy trading businesses, had significant effects on the regional economy, shareholders and employees. In the case of employees, US regulations governing retirement funds arguably reinforced the effects, as employees can hold a significant proportion of their retirement account in their employer's shares.

5. Suggested approaches to the G-20 Program

There is no strong argument for changes to OTC electricity derivative markets, based on the risks to the economy, the financial sector or the NEM. The case for requiring reporting of electricity derivatives or for further elements of the G-20 derivative reform agenda is weak; the level of participant leverage to electricity derivative markets is low and falling and, even based on highly conservative modelling assumptions, an OTC counterparty failure in the electricity market is highly unlikely to present systemic risks to the financial sector or the economy as a whole.

Margining OTC derivatives increases the sector's required capital, without eliminating the immediate and short term cash flow requirements in the event of a failure or reducing the larger part of the losses likely in the event of an OTC failure. The release of the margin account is likely to be slower than the requirement for cash to meet other, linked settlement obligations; while margining may make raising the cash easier, it is unlikely to relieve the requirement for cash in the immediate to short term.

Three quarters of the losses in our analysis are a result of our assumptions about the behaviour of the spot and derivative markets following a default. Policy proposals should prioritise changes to the NER to remedy those elements of the market design that would be likely to affect the market's performance in the event of a default.

5.1. Implications of our results

Considering the results of our high level modelling and the discussions we've had with stakeholders about the AEMC's work and the G-20 agenda implementation, we think that a persuasive case can be made that:

- There is no strong argument for changes to OTC electricity derivative markets, based on the risks to the economy, the financial sector or the NEM. Given this, the case for requiring reporting of electricity derivatives or for further elements of the G-20 derivative reform agenda is weak.
  - The publicly available data suggests participants' leverage to the electricity derivative markets is low and falling. Even assuming that the published data falls short of the total OTC market, the level of leverage is more consistent with a conservative approach to hedging than a sizable speculative market with risks to the real economy.
  - High and conservative assumptions about the size of an OTC failure and the associated spot and derivative prices suggest that an OTC counterparty failure in the electricity market is highly unlikely to present systemic risks to the financial sector or the economy as a whole: the immediate and short term cash requirements as a result of the default of a large counterparty are small in the context of the economy and the financial sector, considered against a range of possible measures. They are also relatively low compared to the publicly available information on the 2012 cash positions for large electricity participants.
  - Depending on the scenario, the NEM could experience no immediate systemic risk as the result of a large OTC counterparty failure, although, in the more extreme scenarios, there could be significant longer term effects on the health of the electricity sector as a whole.

- Margining OTC derivatives increases the sector's required capital, without eliminating the immediate and short term cash flow requirements in the event of a failure or reducing the larger part of the losses likely in the event of an OTC failure.
  - Using a similar approach to that outlined in Section 4, we have calculated at a high level the potential margining requirements for participant types. These are discussed in more detail in Section 5.2.3.
  - Given that the release of the margins is likely to be slower than the requirement for cash to meet other, linked settlement obligations, margining is unlikely to relieve the requirement for cash in the immediate to short term, although it may make raising the cash easier, if the margin account can be used as security.
  - Three quarters of the losses in our analysis are a result of our assumptions about the behaviour of the spot and derivative markets following a default. Margining does not address these losses.
- The risks of a default of an OTC counterparty to the electricity market are critically influenced by the behaviour of the spot and derivative markets following a default.
  - Our assumptions – that both spot and derivative prices increase sharply and persistently – represent a possible worst case. However, policy needs to be developed in the light of the results from a better articulated model of spot and derivative prices, considering in particular the operation of incentives on participants to maximise the scheduling of their available generation in the event of a significant market disruption.
  - In the absence of a more detailed market modelling exercise, identifying and seeking to resolve other regulatory barriers to the functioning of the spot market in the aftermath of a default is very important in managing the potential risks of a default.
    - The issues identified by AEMO in its submission to the AEMC on the First NEM Financial Resilience Review relating to the ability of a generator to participate in the market during insolvency need to be reviewed.
    - In addition, the robustness of the prudential regime during insolvency needs more detailed consideration, in particular, the way in which offsets are expected to function.
    - Finally, retailers in particular should consider how spot and derivative market conditions following a default would affect market and regulated customer contracts, with a view to identifying the incidence of any costs.

5.2. Possible approaches to the policy agenda

5.2.1. Reporting

Given the share of the exchange traded market in electricity derivative trading, around two thirds of current electricity derivative trades are already reported and, with reporting on commodity derivatives by financial institutions, this proportion will increase without any additional action. There is further limited annual reporting of derivative positions by those participants required to report under AASB 7 Financial Instruments Disclosures.

Following from this, we would suggest:

- As the default position, arguing that there is no significant net benefit to the economy from increasing the reporting coverage of electricity derivatives to include those derivative transactions not captured elsewhere. [25]
- Alternatively, with other end-users, arguing that hedging activities by end-users should be exempt from reporting entirely. The Australian Accounting Standard AASB 139 already requires listed companies and their auditors to take a view about those derivative positions that are hedge activities and those that are speculative[26], providing a high degree of transparency into the positions of listed companies in the sector.
- In the event that the end-user exemption is partial, not complete – for example, requiring reporting by participants of more than a threshold size or with more than some threshold volume of trades – then seeking to restrict the reporting required to only the largest companies and standardised product based speculative trades, with speculative trades defined in a way that is consistent with the approach of AASB 139.
  - While this last approach provides additional information relative to the default position, there is some risk that it could diminish trading volumes, by reducing participants' willingness to take "speculative positions" with a reduction in market liquidity as a whole. This may be the case particularly with derivative positions where hedge effectiveness has traditionally been difficult to receive.
  - However, the partial end-user exemption could result in only 3 or 4 market participants being required to report. The limited number of participants would restrict the publication of the data, even at the aggregated level proposed for the Trade Repositories' reporting, because of the potential to identify commercially sensitive information about participants' positions and strategies. If the additional limited information is incapable of being published, then the objectives of the reform agenda related to transparency are unlikely to be achieved.

Whatever the reporting requirement, it is important that the overall costs are minimized by requiring only one set of reporting requirements. That information that the G-20 derivative reform agenda requires, designed to highlight significant leverage to the derivative markets and derivative market concentration risk, would not provide for the oversight of market conduct, which requires (retrospective) information on hedging positions capable of being matched with spot market bidding.

5.2.2. Central counterparty and exchange based trading

We believe there is no firm commitment to proceeding to this stage of the proposed reform agenda at this stage. The appropriate discussion of the real, as opposed to the theoretical benefits of greater reporting should also weaken the case for introducing a central counterparty. However, there are two important issues that should be part of

[25] If, as we understand to be the case, there is some difficulty in attracting organisations to undertake the Trade Repository role for high volume standardised transactions, then capturing lower volume electricity derivative transactions is likely to be both more expensive and considerably less attractive to third party providers.

[26] We appreciate that the accounting definition of speculative versus hedging activities for derivatives under AASB 139 may not necessarily be consistent with risk management views of hedging versus speculative activities. For example, we understand that caps are treated as speculative under AASB 139 where as they are generally considered hedge instruments for retailers and generators.

any discussion of the G-20 derivative reform agenda with a view to framing any future discussion of the second stage in the G-20 derivative reforms:

- The absence of systemic risk to the financial sector or the wider economy from the electricity OTC derivative sector, which needs to be weighed against the costs of requiring higher centralisation.
  - Arguably, current electricity spot market prudential requirements make a contribution to the more robust performance of the electricity derivative market relative to other commodity spot markets and this contribution should be considered in assessing the risks to the economy as a whole.
- The significance of non-standardised products – contingent payoffs, non-standard caps and other options – in the risk management task, given the contingent nature of the risks. Changes to the market that result in lower participation and liquidity in the OTC market are likely to adversely affect the price and/or the liquidity of the OTC market, with an ultimate detriment to end-users, transforming but not necessarily eliminating the risk.
  - Not all markets are characterised by liquid exchange traded markets. In South Australia and Queensland, exchange traded markets are highly illiquid and the absence of and the price of preferred OTC hedge products are already affecting the availability of cost effective contracts for large users. Further changes that affected market participants' willingness to participate in these markets risks increasing the current illiquidity and, potentially, the cost.

5.2.3. ASIC's agenda: margining OTCs and mandated credit support arrangements

Our high level modelling suggests that the total cost of an OTC market default is dominated by the costs arising from spot and derivative market behaviour after the default. Assuming this is correct, then introducing mandated credit support for all OTC derivatives or requiring margining has the potential to increase the capital required of industry participants without necessarily reducing the risks to those participants.

We have calculated the approximate additional capital requirements over a one and seven day period for a vertically integrated retailer and a stand-alone generator. These capital requirements are based on the same counterparty positions used in the analysis is Section 4. In addition, based on our analysis of historic OTC price movements over one and seven day periods, we have assumed the following contract price changes over a one and seven day periods:

- One day period - $3/MWh swap curve change and $0.50/MWh cap curve change; and
- Seven day period - $8/MWh swap curve change and $1.50/MWh cap curve change.

The costs in Table 5.1 are not implausible: even larger movements have occurred historically in the exchange traded market, requiring exchange traded market participants to post large additional margins overnight. For example:

- In the week beginning 14 May 2007, the NSW Calendar Swap price moved from between $50 and $55 to around $70/MWh, an increase of between $15 to $20/MWh. Considering a 1 MW sold contract, the additional margin required in that week amounted to between $131,000 and $175,200.
- On 27 June 2007, the Victorian regional Q4 Flat contract price moved by $18/MWh in a day, giving rise to an additional margin requirement of $39,744 for each MW sold contract.

Table 5.1 OTC indicative margin requirements by time period, $ million, rounded.

	Defaulting counterparty position: Largest	Average
	$ million, rounded	
Vertically integrated retailer		
One day potential margin requirement	15	7
Seven day potential margin requirement	40	18
Stand-alone generator		
One day potential margin requirement	10	2
Seven day potential margin requirement	30	7

5.2.4. Recommended approach

In addressing the issues raised by the proposed G-20 reform implementation in the Australian electricity market, we propose that policy proposals should:

- Prioritise changes to the NER to remedy market those elements of the market design that would be likely to affect the market's performance in the event of a default, such as the issues raised by the Australian Energy Market Operator (AEMO) in relation to the continued generation of an insolvent generator.
- To the maximum extent consistent with the current market design, reduce the likelihood of spot market outcomes following a default giving rise to further stress on participants' positions.
  - This could require, for example, the introduction of a special (lower) CPT and APC regime only following a major default. This will reduce the settlement and market risks that are a function of spot price behaviour and, to the extent contract price increases are reduced by less volatile spot prices, it will also decrease participant's credit risk.
- Assess the costs and benefits of the (re)allocation of existing risk capital required of industry participants, to provide for a higher and more robust outcome in the event of insolvency without increasing the level of capital committed across the sector.
  - The spot market prudential requirements administered by AEMO, while contributing to a lower level of risk in the spot and derivative markets than would be the case in their absence, are higher than they would be as a result of the length of the current settlement cycle.
    - By international standards, the NEM settlement cycle is long and the capital required to ensure the prudential standard relatively high as a result.
    - The length of the settlement cycle also contributes to the settlement risk identified in our modelling. A shorter settlement cycle would reduce the amount at risk on a pro-rated basis.
  - Existing and proposed AEMO administered offset arrangements may not be robust in the event of an insolvency and, in the worst case, could undermine the achievement of the Prudential Standard. These should be reviewed and if necessary, amended prior to market-wide introduction.

  - Netting settlements across the spot and derivative markets – whether voluntary or mandatory; whether including the exchange traded as well as the OTC markets – offers the potential for a more efficient use of prudential capital and a reduction in the risk of non-payment at default, but needs to be robust in the event of an insolvency.
    - AEMO itself has concluded that the skills needed for a comprehensive settlement regime across the spot and derivative markets requires a different skill set to its core skill set. The introduction of netting would, therefore, require a significant change to existing market institutions.
  - The changes required could be introduced as a package, or, alternatively, in sequence, commencing with the reduction in the settlement cycle and the linked change to settlements in the derivative markets.
- ASIC could require participants with AFSL to meet higher individual capital adequacy requirements. Although within ASIC's powers, from the perspective of a regulatory response, this is a relatively inefficient instrument because it is poorly targeted at the risks associated with derivative markets, operating only to provide a higher amount to all creditors in the event of a default. All other solutions should, therefore, be preferred to this solution.

A. National Electricity Market Financial Market Resilience: Terms of Reference

Background

In 2012, the Australian Energy Market Commission (AEMC) initiated its review into the financial stability of the NEM. The terms of reference for the review asked the AEMC to provide advice to the Standing Council for Energy and Resources (SCER) on the nature of the risks to financial stability in the NEM arising from financial interdependencies between market participants and whether the existing mechanisms to mitigate these risks were adequate. The AEMC's initial conclusion was the National Electricity Market (NEM) was generally robust, with the Retailer of Last Resort (ROLR) posing the largest individual risk to the electricity market's financial stability.

Concurrently, international and domestic consultations have been investigating how best to implement the 2009 G-20 Pittsburgh Declaration:

> *All standardised OTC derivative contracts should be traded on exchanges or electronic trading platforms, where appropriate, and cleared through central counterparties by end-2012 at the latest. OTC derivative contracts should be reported to trade repositories. Non-centrally cleared contracts should be subject to higher capital requirements.*

The domestic reviews have been influenced by the international consultations due to Australia's international obligations and the Reserve Bank (RBA) and the Australian Securities and Investment Commission (ASIC) participating in the international consultations through the Committee for Payments and Settlements Systems (CPSS) for the RBA and the International Organisation for Securities Commissions (IOSCO), for ASIC. The RBA and ASIC, have also each undertaken domestic consultations within the remit of their own statutory obligations and in conjunction with other regulators under the auspice of the Council of Financial Regulators.

The reviews undertaken in Australia over the past year have included:

Organisation	Consultation	Date final report
ASIC	CP177 Electricity Derivative Market Participants: Financial Requirements	May 2012
ASIC	CP201 Derivative Trade Repositories	March 2013
ASIC	CP205 Derivative Transaction Reporting	March 2013
AEMC	NEM Financial Markets Resilience Review	November 2012
RBA	Consultation on New Financial Stability Standards	December 2012
Council of Financial Regulators	OTC Derivative Market Reform Considerations	March 2012
Council of Financial Regulators	Report on the Australian OTC Derivatives Market	October 2012
Senate	Inquiry into the Corporations	October 2012

Organisation	Consultation	Date final report
	Legislation Amendment (Derivative Transactions) Bill 2012	
The Commonwealth Treasury	Implementation of Australia's OTC Derivative Commitments – Corporations Legislation Amendment (Derivatives Transactions) Act 2012	December 2012

Scope of work

The Private Generators Group intends to commission a report exploring the impact that trade reporting and higher margin requirements for non-centrally cleared OTC derivatives could have on energy markets. The report should focus on Australia but draw on the experience of international jurisdictions, particularly the United States and Europe, which have implemented rules for reporting and margining requirements through the Commodity Futures Trading Commission under the Dodd-Frank Act and the European Market Infrastructure Regulation under the European Energy Market Association.

Specifically, the report should focus on but not be explicitly limited to:

1. Define the key policy objectives for Treasury, ASIC and the RBA in the implementation of Australia's G-20 commitments and related regulatory reforms to mitigate systemically important risks to Australia's financial markets as they apply to electricity derivatives. Compare and align with the objectives for the AEMC's NEM financial market resilience review and the National Electricity Objective.
2. Describe the systemically important risks to NEM financial markets and their implications for the Australian financial system, including:
   a. Market;
   b. Operational;
   c. Credit;
   d. Liquidity;
   e. Settlement; and
   f. Any other risk deemed relevant.
3. Outline current regulatory obligations and requirements that energy businesses must comply with that relate to these risks. Identify how these businesses currently comply with the requirements, including internal and external risk management practices and arrangements (policies and limits, physical assets, insurance, weather derivatives etc.). Where possible, determine what "worst case" risk scenario the current regulatory frameworks are designed to meet and what, if any, residual risks remains.
4. Identify any perceived gaps between the defined objectives and the risk management frameworks currently in place, and the associated risks. Assess the materiality of the risks arising from these gaps for systemically important components.

5. Identify a spectrum of options to address any gaps identified under the current regulatory framework and for each option assess:
    a. The potential costs and benefits; and
    b. Any potential implications for the broader energy market including, efficient NEM operations focusing on:
        i. Efficient hedging and overall hedging costs;
        ii. Risk management more generally; and
        iii. Market liquidity and wholesale and retail competition.

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