NGF

Physical Market Cap Trigger Rule Change Proposal

October 2008

NGF

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1. Introduction

1.1. Rule Change Request

The National Generators Forum[1] requests the AEMC to make a Rule under Part 7 of the National Electricity Law (NEL). The address of the NGF is: Level 6, 60 Marcus Clarke St, GPO Box 1301, Canberra ACT 2601. The proposed Rule would establish a physical trigger for invoking price capping arrangements, complementing the existing financial trigger established in clause 3.14.1 and 3.14.2 ("Cumulative Price Threshold and Administered Price Cap") of the existing Rules.

1.2. Purpose of proposed Rule

The proposed Rule has been designed to address an existing issue where generators – individually or collectively - may suffer substantial financial losses following an incident that causes major power system disruption. Whilst such incidents are uncommon, the direct and indirect costs associated with them are significant. Under the proposed Rule, the financial impacts would be substantially mitigated and the costs associated with them reduced.

1.3. Structure of this Proposal

This Rule change proposal contains the elements required by AEMC in its guidelines[2]. Table 1 shows where these elements can be found in this document

Element	**Section**
Proponent is expressly identified with full name and address.	1.1
Evidence as to authority to lodge Rule change proposal	covering letter
Ensure that the subject matter of the Rule change proposal falls within the matters on which the AEMC is permitted to make changes to the Rules	2.4
Description of the proposed Rule	3
Statement of Issue identifying the nature and scope of each problem or issue with the existing Rules	2
Statement of Issue describing the proposed solution for each issue identified	4
Analysis of how the proposed Rule (if made) will contribute or is likely contribute to the achievement of the National Electricity Objective.	5
Explanation of the expected benefits and costs of the change and the potential impacts on the change on those likely to be affected	6
In relation to a request by an electricity market regulatory body that could be fast tracked under section 96A of the NEL, a summary of the consultation conducted.	n/a
Attach a draft of the proposed Rule.	attachment 1

Table 1: Structure of this Proposal

[1] This Rule change is not supported by Snowy Hydro or Tasmania Hydro.
[2] Guidelines for proponents: Preparing a Rule change proposal, January 2008, Attachment 1.

2. Statement of Issue

2.1. Overview

Generators rely on a stable and secure power system to make sales, directly or indirectly, to retailers through the forward and spot wholesale markets. The power system is designed and operated to be robust against normal, or "credible" single contingency events and operates effectively for the vast majority of the time. Infrequently, a "non-credible contingency event"[3] or an unexpected, non-robust response to a credible contingency event, may lead to widespread power system disruption. Such non-credible contingency events (NCCEs) can have severe financial consequences for market participants in general and for generators in particular where generating plant is tripped off-line or constrained off due to disruption on the power system.

For market participants, these risks are largely unmanageable. It is common in other wholesale markets for such risks to be mitigated through Force Majeure (FM) arrangements, which provide that the financial consequences of certain specified "FM events" are shared between market participants (eg between buyer and seller) and not allowed to adversely affect individual players. However, implementing such arrangements in the NEM has proven problematic..

Indeed, the NEM design originally envisaged that the financial consequences of serious disruptive events would be ameliorated by FM provisions included in the Rules. However these foundered on the practical difficulties of defining FM events.

An alternative approach to risk mitigation was then introduced[4]: the "Cumulative Price Threshold" (CPT) arrangements, which are triggered by sustained high price outcomes in a rolling 7 day window, thus avoiding the need to specify or identify any specific cause for the disruption. The CPT arrangements, whilst effective for market disruptions, are unlikely to be triggered by power system disruptions. Indeed the CPT arrangements have been deliberately designed not to be triggered by transient market stress - and so will not mitigate the financial risks associated with severe, but transient, power system disruption.

In summary, the issue which the proposed Rule is intended to address relates to the unmanageable financial risks associated with occasional severe power system disruption and the need to establish risk-sharing arrangements to manage these risks. The remainder of this chapter elaborates on this issue.

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[3] Rule 4.2.3(e) A "*non-credible contingency event*" is a *contingency event* other than a *credible contingency event*. Without limitation, examples of *non-credible contingency events* are likely to include:

(1) three phase electrical faults on the *power system*; or

(2) simultaneous disruptive events such as:

(i) multiple *generating unit* failures; or

(ii) double circuit *transmission line* failure (such as may be caused by tower collapse).

[4] in December 1999

2.2. *Financial Impact on Generators*

The proposition that serious contingency events will adversely impact generators may at first sight appear counterintuitive. Shouldn't market stress lead to higher prices which generators should then benefit from? Why are generators concerned with this issue?

The answer is that these events disrupt generator participation in the electricity forward market, the market which covers the vast majority of generator sales (and retailer purchases) and is fundamental to the provision of an efficient and reliable electricity supply.

The forward market involves the buying and selling of forward electricity contracts: commitments by generators to sell specified amounts of electricity to retailers at specified prices in future trading periods. Because all wholesale electricity is required to be delivered and settled through the spot market, forward commitments are made and enforced through financial derivatives against the spot price.

Using, for illustration, the case of a standard "swap" forward contract[5], the net financial settlement for a generator is thus the total revenue from the NEM plus (or minus) the "difference payments" due under the swap contract: payments are made from swap buyer (ie retailer) to swap seller (ie generator) when the spot price is lower than the contract price and from seller to buyer when the spot price exceeds the contract price.

However, for ease of exposition, this proposal uses a *financial analogy* of generators selling into the spot market only the surplus dispatch that they have after meeting their forward sales and "buying" from the spot market where dispatch falls short of forward sales. For standard swaps, the financial analogy yields identical income to the actual settlement, as illustrated by the examples in the box below.

In example 1, a 300MW generator is "long" and so sells into the spot market in the financial analogy; in example 2, a partial outage leave this same generator "short" and so it buys from the spot market in the financial analogy.

[5] A variety of other forms of derivatives exists, but standard swaps are probably the most commonly used and are the simplest to describe.

Example 1: Financial Analogy for a "long" 300MW Generator
Assume that a generator has:

200MW of sales in the forward market, with a forward price of $30/MWh.
300MW of dispatch in the spot market, and the spot price is $100/MWh.

Generator hourly revenue in the NEM and forward market:

NEM revenue	300MW* $100/MWh	= $30,000
Difference payments	200MW * ($100 - $30)/MWh	= ($14,000)
Net revenue		= *$16,000*

Generator hourly revenue in the *financial analogy*

Forward sales	200MW * $30/MWh	= $ 6,000
Spot market sales	100MW * $100/MWh	= $10,000
Net revenue		= *$16,000*

Example 2: Financial Analogy for a "short" 300MW Generator
Assume that, following a partial outage a generator has:

200MW of sales in the forward market, with a forward price of $30/MWh.
150MW of dispatch in the spot market, and the spot price is $100/MWh.

Generator hourly revenue in the NEM and forward market:

NEM revenue	150MW* $100/MWh	= $15,000
Difference payments	200MW * ($100 - $30)/MWh	= ($14,000)
Net revenue		= *$ 1,000*

Generator hourly revenue in the *financial analogy*

Revenue from forward sales	200MW * $30/MWh	= $ 6000
Spot market purchases	50MW * $100/MWh	= ($ 5000)
Net revenue		= *$ 1000*

Power system disruption may lead to a generator's dispatch being curtailed, either because some of its generating units trip off the power system, or because transmission constraints force them to be backed off. The financial effects of this are two-fold. Firstly, it may now have insufficient dispatch to back its forward sales and so must buy from the spot market. Secondly, the shortage of generation may cause spot prices to rise. Examples 3, 4 and 5 in the box below show the financial impact of this on a "hedged" generator using the financial analogy method.

Example 3: Generator Position before Disruption
Assume that a 300MW generator is fully "hedged": it has:

300MW of sales in the forward market, with a forward price of $30/MWh.
300MW of dispatch in the spot market, and the spot price is $100/MWh.

Generator hourly revenue (using financial analogy)

Revenue from forward sales	300MW * $30/MWh	= $ 9000
Spot market purchases	0MW * $100/MWh	= ($ 0)
Net revenue		= *$9000*

Example 4: Generator Position following moderate disruption
Assume forward sales unchanged from example 3
Assume that moderate disruption then causes:

Dispatch to be reduced to 200MW
Spot price to increase to $1000/MWh.

Generator hourly revenue during the disruption is then:

Revenue from forward sales	300MW * $30/MWh	= $ 9,000
Spot market purchases	100MW * $1000/MWh	= ($100,000)
Net revenue (loss)		= *($ 91,000)*

Example 5: Generator Position following major disruption
Assume forward sales unchanged from example 3
Assume that major disruption then causes:

Dispatch to be reduced further to 100MW
Spot price to increase further to $5000/MWh.

Generator hourly revenue during the disruption is then:

Revenue from forward sales	300MW * $30	= $ 9,000
Spot market purchases	200MW * $5000/MWh	= ($1,000,000)
Net revenue (loss)		= *($ 991,000)*

It is seen that the financial impact is proportional to both the dispatch impact and the spot price impact. Since the increase in the spot price will itself be related to the aggregate dispatch impact across a region as higher cost plant is scheduled, there is a multiplicative effect on revenue losses. This is seen by comparing example 4 with example 5. The more severe disruption in example 5 causes five times the price impact and twice the dispatch impact compared with example 4. As a result, the revenue impact in example 5 is *10* times the revenue impact in example 4: a $100,000 impact has increased to a $1,000,000 impact on an hourly basis.

This multiplicative effect explains how the financial impacts of large scale power system disruption can be so severe. At worst, in relation to the above example, dispatch could reduce to zero and spot price increase to $10,000, creating an hourly revenue loss of almost $3m.

It is worth noting here that there is no corresponding negative revenue impact on a fully hedged retailer. Suppose that the generator in the above example has sold to a retailer with a 300MW retail demand. The retailer's net hourly purchase cost is then $9000 (300MW * $30) and, since it is entirely hedged against the spot price, this purchase cost is unaffected by the power system disruption[6].

2.3. *Identifying FM Events*

In the light of these extreme financial risks, we believe that there is a need to establish market intervention arrangements to mitigate these risks. Such market intervention must be carefully targeted, so that the "collateral damage" associated with unnecessary market intervention is minimised. In particular, there should be no market intervention to address financial risks associated with *credible* contingency events. These risks should remain with participants.

The arrangements, therefore, need to incorporate a test of whether market circumstances warrant intervention with a view to minimising:

- *false positives*: where market intervention takes place although it is *not* warranted; and
- *false negatives:* where market intervention does *not* take place although it *is* warranted;

The litmus test for intervention should be that the risk created is both *substantial* and genuinely *unmanageable*. If the risk is insubstantial, the detriment of frequent market intervention is likely to outweigh the benefit of risk mitigation. On the other hand, if the risk is manageable, market intervention creates moral hazard, where a generator no longer has an incentive to take steps to manage its risk, because the risk is managed for it.

2.4. *Why Rule Changes are required*

The examples in section 2.2 illustrate how the financial risks associated with market disruption arise from the financial interaction between a generator's forward market and spot market sales. In this respect, a question arises as to whether risk mitigation is best achieved through changes to forward market or to spot market arrangements. Changes to forward market arrangements are, of course, outside the scope of the Rules. We believe that risk mitigation through the forward markets is not feasible, for the reasons discussed below. Therefore, Rule changes are needed to address the issue.

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[6] Except where there is load shedding, in which case the retailer is likely to *benefit* from the disruption, as explained in section 6.3

The conventional approach in other contract markets to mitigating the impact of unmanageable risks is to establish Force Majeure (FM) provisions within the supply contracts which have the effect of lessening the contractual and financial obligations of the supplier or customer when specified FM events occur. In principle, such an approach could be adopted in electricity forward contracts, with FM provisions triggered by serious power system disruption. However, a number of practical concerns arise with this approach.

Firstly, an FM provision does not remove the risks associated with power system disruption but simply allows generators to pass these risks onto retailers. With its forward contracts becoming ineffective, a retailer would now become fully exposed to the spot market at a time of high and volatile spot prices. It is therefore unlikely that a retailer would agree to such an FM provision unless it could pass these risks onto its retail customers. Such a pass-through may itself be problematic, since a retailer typically manages its spot price risk on a portfolio basis, leaving it unclear how the FM costs would be allocated between customers.

Secondly, there would be a matter of how FM events would be identified. Since only NEMMCO has the information to identify these events in real time[7], generators and retailers would require that NEMMCO identify and inform them of these events. However, it would seem to be improper for NEMMCO to agree to act in this role outside of its responsibilities under the Rules, and it would similarly seem to be outside the jurisdiction of the AEMC to make a Rule change requiring NEMMCO to undertake activities for the contract market.

Finally, there is the practical matter of how such FM contracts would be implemented. Historically, it has been impossible for generators to gain market acceptance to introducing FM provisions in forward contracts, much as they would have liked to. Furthermore, the trend in the forward market is towards the increasing use of exchanges and simple “vanilla” contracts so as to promote forward market efficiency, transparency and liquidity and to encourage entry of non-physical participants. Introducing new FM provisions would run counter to this trend.

In summary, introducing FM provisions in forward contracts does not appear to be an efficient, practical or desirable solution to resolving the issue of NCCE-related risks in the forward market and it is for this reason that a solution is being sought through a Rule change.

[7] And it would need to be real-time to be effective.

3. Description of Proposed Rule

3.1. Overview

The existing Rules establish arrangements for the triggering and operation of an Administered Price Period (APP), during which spot prices are capped and floored at pre-defined levels[8]. The trigger for the commencement of an APP is a sustained period of high spot prices, such that the rolling weekly sum of spot prices exceeds a specified cumulative price threshold (CPT)[9].

The proposed Rule would establish a parallel set of arrangements, in which a "Contingency Administered Price Period" (CAPP) could be triggered by certain types of disruptive events and incidents on the power system, referred to as "trigger events". A trigger event will cause a CAPP to be initiated only if the event also has a material impact on dispatch.

The proposed Rule establishes how:

- a trigger event is defined;
- material impact on dispatch is defined and determined;
- the NEM region or regions in which the CAPP should apply are determined
- spot prices are capped during a CAPP;
- the ending of the CAPP is defined and determined.

The interaction and juxtaposition of these elements is illustrated in the process diagram show in Figure 1, overleaf. The elements are described in turn below.

3.2. Defining a Trigger Event

A trigger event is any sequence of related events[10] affecting the power system that has the following two characteristics:

- if the events in the sequence of events had occurred simultaneously, it would be regarded as a non-credible contingency event (NCCE) as this is currently defined in the Rules; and
- the sequence of events was not initiated by a failure of generating plant or, if it were, its effects were not contained within a power station site.

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[8] During an APP, if the dispatch price or an FCAS price exceeds the pre-defined Administered Price Cap (APC) then the price is reset to be equal to the APC. Similarly, if the dispatch price or an FCAS price is less than the negative of the APC, then it is reset to be equal to the negative of the APC.
[9] The sum of the last 336 trading prices (one week's worth), and the sums of the last 2016 FCAS prices (again, one week's worth) for each FCAS component are calculated and if any of these sums exceeds a pre-defined Cumulative Price Threshold (CPT) then an APP commences in the next trading period.
[10] noting that a "sequence" could comprise just a single event

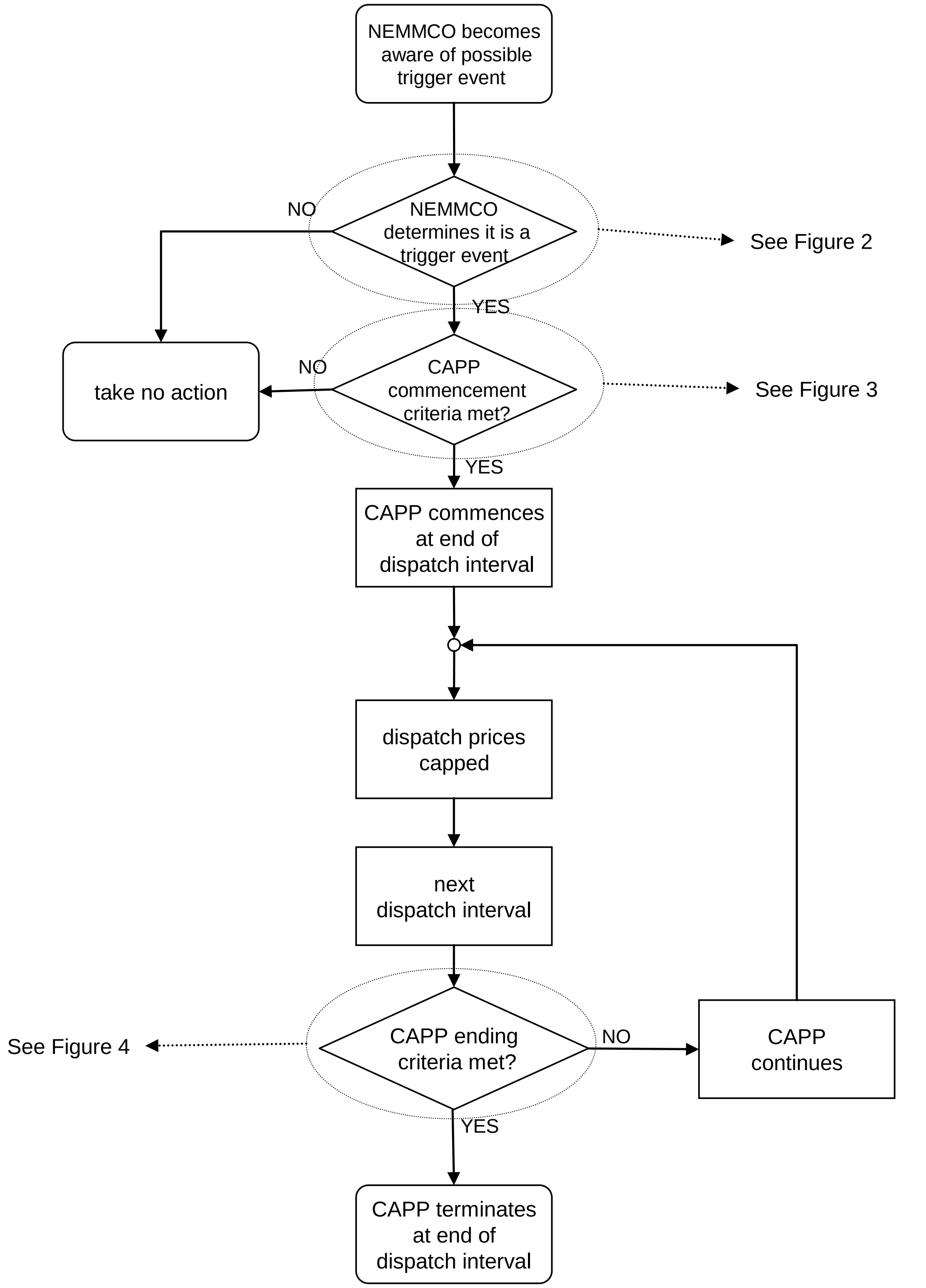

Figure 1: CAPP Related Processes

The purpose of allowing for the possibility of a sequence of events is that it is not clear whether these would constitute a NCCE as defined in the Rules, even though they may have a similarly unmanageable impact as a NCCE.

The reason for disallowing events whose direct impact is restricted to the generator that caused them is that such events should be manageable for that generator. However, if the impact spreads to other "innocent" generators then the impact is not "manageable" for those generators.

The definition is illustrated in Figure 2, overleaf. Some examples, which may clarify this definition, are discussed below.

Double Circuit Transmission Line NCCE

First, consider a NCCE that occurs on the transmission system: eg a double circuit outage not reclassified as credible. Even if there are no subsequent, related events (eg cascade transmission failures), this is a trigger event because it is a sequence (of one event), it is an NCCE and it is clearly not initiated by a generation failure (since no generation has actually failed).

Multiple Unit Failure and Consequential Cascade Tripping

Second, consider a failure of multiple units at one power station, which causes a power system disruption and the consequential tripping of other generators at other sites. The events in this sequence would clearly be considered non-credible if they occurred simultaneously. This is a trigger event, whether or not the sequence of events was *initiated* by generation failures, as the effects of those failures have spread outside the initiating site.

Multiple Unit Failure caused by TNSP

Thirdly, consider a failure of multiple units at a power station, caused by a TNSP or due to incorrect or delayed protection clearance of a transmission system fault. Since this sequence of events was not *initiated* by the generating unit failures, it matters not whether its effects spread beyond the power station fence, it would still be a trigger event.

Transmission Failure unexpectedly causes Generating Unit Failure

Fourthly, consider a failure of a single transmission element, which unexpectedly[11] causes a generating unit to trip. This is a trigger event, as it was not generation-initiated, and it involves two contingency events which, had they occurred simultaneously, would be non-credible.

[11] If, on the other hand, the transmission failure caused a local generating unit to trip as *expected* (eg because it interrupted that unit's electrical path to the transmission network), this would be a *credible* contingency event and so would not be a trigger event, unless accompanied by other related and unexpected events.

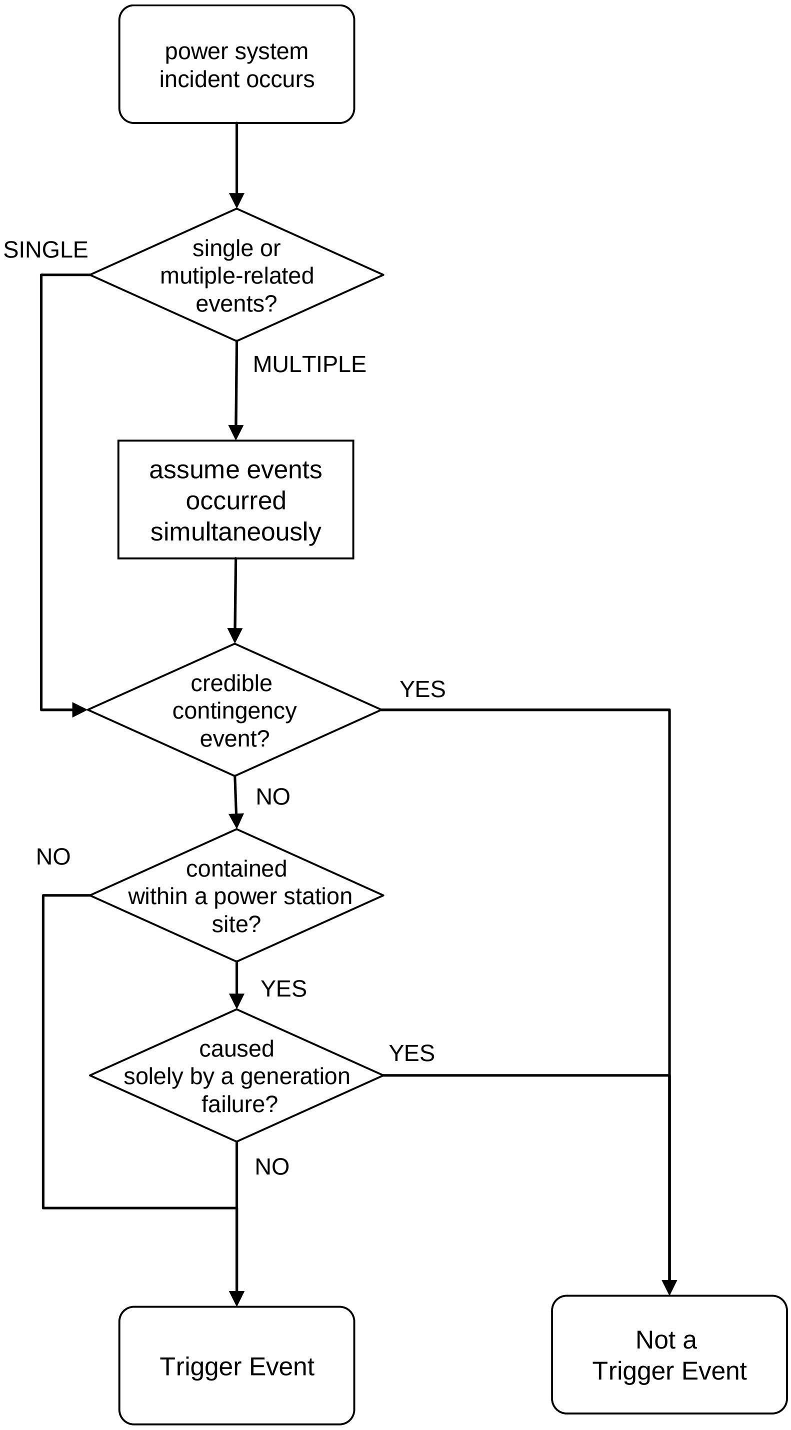

Figure 2: Process for determining a Trigger Event

Multiple Unit Failure caused by Generator

Finally, consider the tripping of multiple units at a power station, caused by a fuel supply failure, which does not lead to cascade tripping outside of the power station. Since this was generation-initiated and contained within the power station, it is *not* a trigger event.

3.3. *Material Impact on Dispatch*

A trigger event will only prompt the commencement of a CAPP if it has a material impact on dispatch (MIOD). A trigger event is defined to have a MIOD if it has caused at least one of the following to occur:

- one or more scheduled generating units, with aggregate capacity exceeding the "CAPP threshold" (see section 3.5 below), are "tripped"(ie automatically disconnected from the transmission network); or
- network constraints invoked by NEMMCO following the event cause an aggregate reduction in flows across the constrained part of the network by an amount greater than the CAPP threshold: such constraints are referred to in the proposed Rule as "material network constraints".

The MIOD criteria are illustrated in Figure 3, overleaf. Some examples to clarify the application of these criteria are discussed below.

Unit Tripping

Firstly, consider a trigger event which causes the tripping of one or more large generating units. There will be an MIOD in a region if the total of the capacity of the tripped units exceeds the CAPP threshold for that region.

Unit "capacity" is defined by reference to the available capacity offered for dispatch immediately *prior* to the trigger event[12.] The MIOD test refers to capacity rather than the dispatch level as the units – if they had not tripped - would normally have increased generation to full availability post-contingency, in response to high spot prices.

Intra-regional Transmission Constraint Invoked

Secondly, consider a trigger event which leads to an extended outage of a Latrobe Valley-Melbourne transmission line and which causes NEMMCO to invoke a new network constraint. This may or may not cause the dispatch of Latrobe Valley generating units or of Basslink to be reduced, depending upon how much spare network capacity there was pre-contingency.

Suppose that power flow between the Latrobe Valley and Melbourne[13] is 5000MW pre-contingency and suppose also that the post-contingency constraint limits flows to 4000MW. The 1000MW flow reduction exceeds the CAPP threshold for Victoria (400MW) and so there is an MIOD.

[12] Obviously, once a unit is tripped, its available capacity will be rebid to zero

[13] strictly speaking, power flow across a "cut set" that separates Latrobe Valley generators from Melbourne

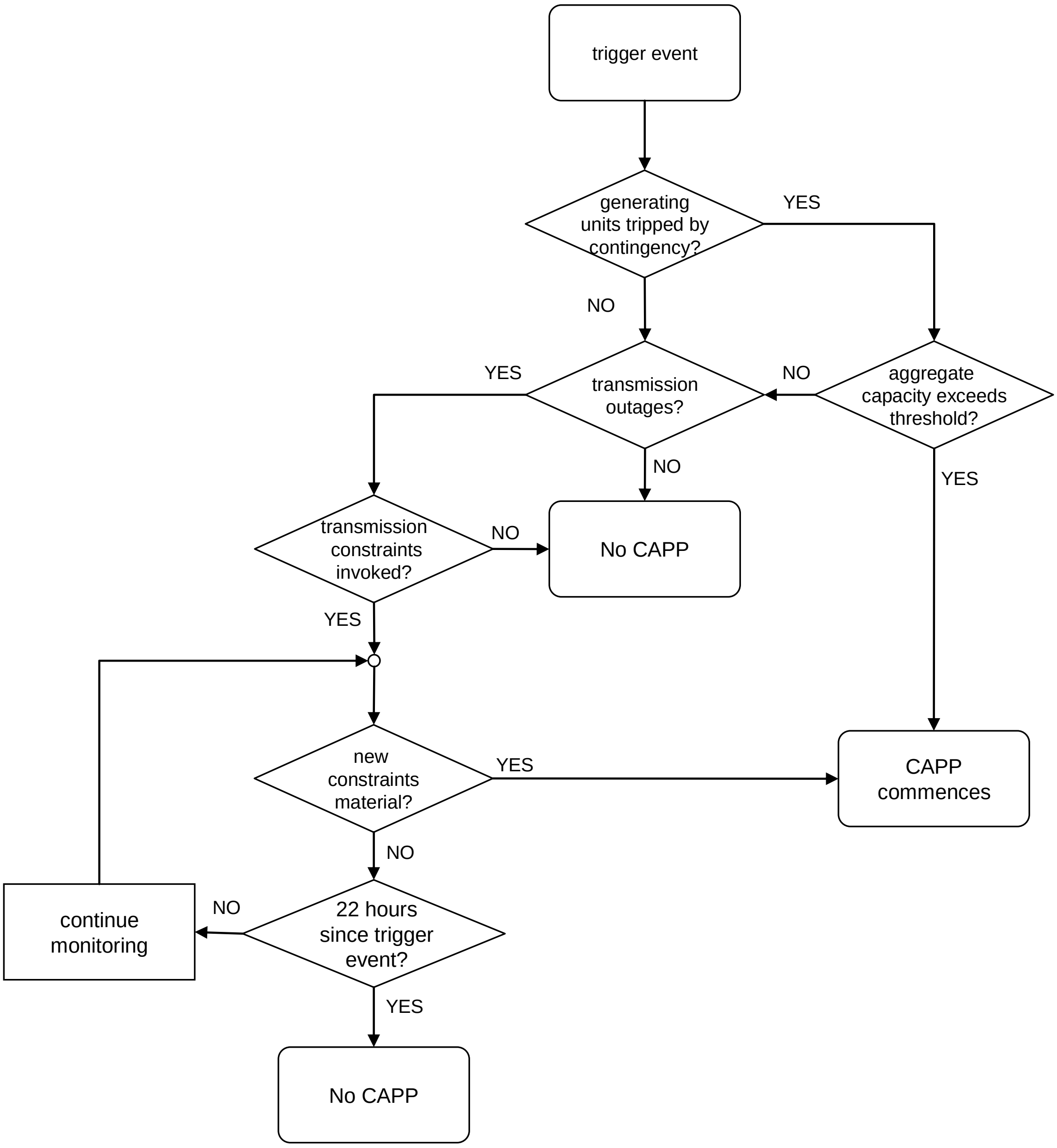

Figure 3: Process for commencing a CAPP following a Trigger Event

If, on the other hand, the pre-contingency Latrobe-Melbourne power flow was only 4300MW, the constraint would reduce flow by only 300MW and so there would not be a MIOD[14].

Inter-regional Transmission Constraint invoked

Consider that the QLD-NSW double circuit interconnector is carrying 1000MW southwards and suddenly trips out of service as a result of a non-credible contingency event. Aside from possible over-frequency conditions in QLD and excessive under-frequency conditions on the NSW side that could cause the tripping of generating units in either or both regions – and so create MIOD - NEMMCO would also invoke a transmission constraint that limited the QNI flow to zero.

The reduction in interconnector flow from 1000MW to 0MW represents a MIOD. However, if the pre-contingency interconnector flow was only 200MW, say, the reduction to 0MW would not be material, since this is less than the CAPP thresholds in Queensland and NSW.

Delayed Impact on Dispatch

Consider again the QNI example above, and suppose that pre-contingency interconnector flow is only 200MW. However, suppose that, in the *absence* of the contingency and associated loss of QNI, the interconnector flow would have increased to 800MW six hours after the time of the contingency: for example, because of a demand increase in NSW.

In this scenario, the contingency has no immediate MIOD, but instead has a delayed MIOD, since the flow has been reduced by 800MW compared to the "what if" counterfactual of no contingency.[15]

Where there is a delayed impact on dispatch, a CAPP will be triggered once the dispatch impact (in this example the "what if" interconnector flow) exceeds the CAPP threshold, except that a CAPP may not commence more than 22 hours[16] after the trigger event occurs. Once 22 hours has elapsed, there is no longer any possibility of a CAPP being invoked.

Load Shedding

Next, consider a trigger event in NSW which causes 700MW of load to be shed (for example because of a double-circuit outage on transmission serving a remote load centre), but which does not lead to any generation tripping. Of course, generation dispatch (in aggregate) must be 700MW less than pre-contingency. It is possible also that flows on an importing interconnector have reduced.

[14] The CAPP threshold for Victoria is 400MW – see section 3.5
[15] assuming that the NSW demand increase was unrelated to the contingency
[16] this time interval arises from 24 hours (being the latest time after the trigger event that a CAPP must end) minus 2 hours (being the minimum length of a CAPP).

However, neither of these constitutes an MIOD, because they are not caused by a post-contingency transmission constraint invoked by NEMMCO. NEMMCO does not need to invoke a transmission constraint, because the 700MW reduction in demand will be registered automatically by SCADA and the central dispatch process will take account of the demand reduction.

Rebidding following Trigger Event

Finally, consider a trigger event that does not affect the capacity of an interconnector. However, rebidding by generation in the importing region causes the interconnector flow to reduce. This does not constitute a MIOD, because there is no constraint on the interconnector flow that was invoked during or following the trigger event.

3.4. Determining the Affected Regions

As for an APP, a CAPP may be declared in one region, several regions or the entire NEM. The proposed Rule defines how the relevant regions are identified.

The important consideration is not where the trigger event occurs but where the MIOD occurs. Thus, it is the aggregate impact on generation dispatch and interconnector flows in a region (through tripping or network constraints) that will determined whether a CAPP is declared in that region.

In the event that an invoked constraint limits flows on an interconnector, a CAPP may be declared in either or both interconnected regions, depending on the extent of the limitation compared to the CAPP threshold in each region.

For example, if a contingency causes the failure of the SA-Vic interconnector: then

- a CAPP will be invoked in Victoria, if the interconnector flow in the absence of the contingency would have been greater than the CAPP threshold in Victoria;
- a CAPP will be invoked in SA, if the interconnector flow in the absence of the contingency would have been greater than the CAPP threshold in SA

3.5. Setting the CAPP Threshold

To trigger a CAPP, the impact on dispatch in a region must exceed the CAPP threshold for that region. The proposed Rule defines the CAPP threshold to be:

- 4% of average-weather summer peak demand for that region for that year, as estimated by NEMMCO in the previous year's Statement of Opportunities, rounded to the nearest 100MW ; or
- 300MW

whichever is *higher*.

The current CAPP thresholds are presented in Table 2 below.

Region	Peak Demand[17]	CAPP threshold
NSW	13820	600
Queensland	9461	400
South Australia	2990	300
Tasmania	1381	300
Victoria	9198	400

Table 2: Current CAPP Thresholds

NEMMCO will be required to review these values each year, and update as required, when it publishes the SOO.

The CAPP threshold is set to ensure that a CAPP is triggered infrequently. It is set to be proportional to regional demand so that it is appropriate in size to each region: for example, a 500MW dispatch impact would be a moderate event in NSW but a serious contingency in Tasmania. There is no specific rationale for choosing 4%: it is a "line in the sand" rather than a scientifically-determined factor. However, it gives thresholds in each State which broadly correspond to the impact of more serious *credible* contingencies. Thus, to trigger a CAPP, a trigger event should have a greater impact on dispatch than most credible contingencies would. Generators would be expected to be able to manage or bear the risk associated with credible contingencies.

The minimum threshold level of 300MW is set to limit the number of CAPPs in the smaller regions. This is because, for small regions, the impact of contingencies is largely invariant of demand, being driven more by typical unit sizes and individual line capacities.

The rounding to the nearest 100MW is to ensure that the CAPP thresholds are easily remembered and to prevent them changing frequently.

3.6. How Spot Prices are Capped

The algorithmic logic for capping spot prices during a CAPP is exactly the same as the capping logic for an APP under the existing Rules. That is:

- if the calculated dispatch price or FCAS price exceeds the price cap then it will be reset to equal the price cap;
- if the calculated dispatch price is below the price floor then it will be reset to equal the price floor; and
- if price capping or "flooring" in one region causes negative settlement residues on a regulated interconnector to a neighbouring region then prices must be adjusted in the neighbouring region, and so on until all negative residues are eliminated

[17] Statement of Opportunities, Executive Briefing, NEMMCO 2007, p4

In examining the existing Rules for preventing negative settlement residues during an APP[18], an apparent error has been discovered in relation to the administration of a price floor. The draft Rules attached to this proposal correct this mistake in relation to CAPP but not for an APP[19].

We also note that the existing Rules[20] refer to *spot* prices being capped and floored, when it would perhaps be more accurate to refer to *dispatch* prices. Again, we have not proposed to change this Rule.

The proposed Rule provides for the same price cap and floor to be applied during CAPPs as apply during APPs. Thus only one price cap (and associated price floor) needs to be determined by the AEMC as part of its normal periodic review process.

The existing Rules allow a generator, MNSP or demand-side bidder to claim compensation where it is adversely affected by the price capping during an APP[21]. The proposed Rule would give these parties identical rights in relation to price capping during a CAPP[22].

3.7. Ending the CAPP

The ending time for the CAPP is determined by the following criteria:

- the CAPP will have a minimum length of 24 dispatch intervals (2 hours);
- the CAPP will end no later than 24 hours after the time of the trigger event;
- the CAPP will end when NEMMCO determines that the trigger event no longer has a material impact on dispatch; and
- the CAPP may also end when sufficient disconnected generation is restored and when all but one of the transmission outages have been restored.

The CAPP ending criteria are illustrated in Figure 4, overleaf. Some examples, below, will help to illustrate how these would be applied in practice.

Tripped Units able to Resynchronise

Firstly, consider where a trigger event involves tripping of major generating units but no transmission outages. The CAPP will end once sufficient of the tripped units have come back on-line, or when they should have been reasonably able to come back on-line, so that the capacity of the remaining disconnected units is less than the CAPP threshold.

[18] clause 3.14.2(e)(4)
[19] Of course, the AEMC may decide to correct this error in the APP Rules either in this Rule change process or as a separate Rule change.
[20] clauses 3.14.1(a) and (b)
[21] note these provisions are currently the subject of a Rule change proposal
[22] and any changes to these rights pursuant to another current Rule change could apply also to the CAPP

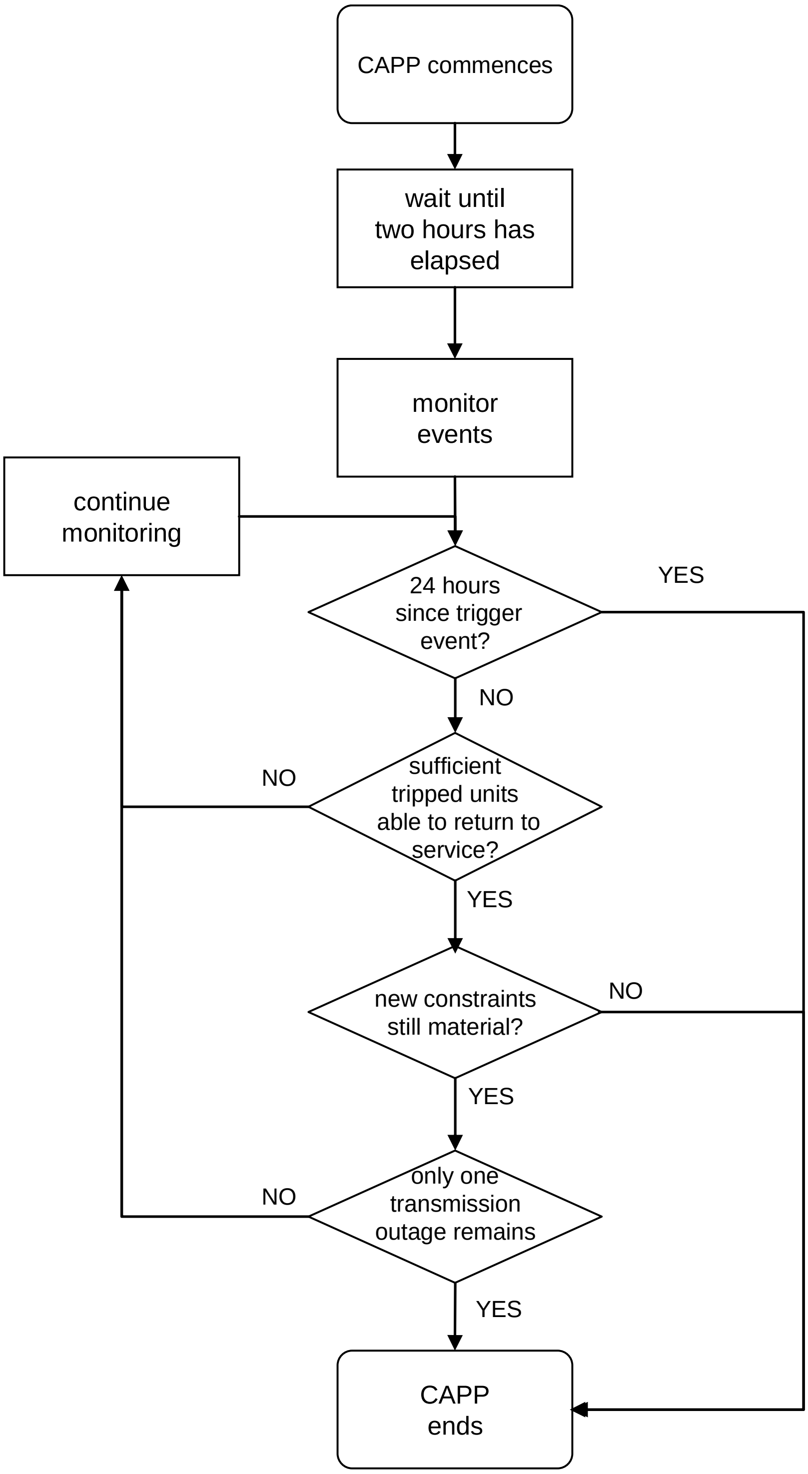

Figure 4: process for ending a CAPP

For example, if the trigger event occurred at the evening peak, by the time that power system has been restored sufficiently, the demand may have fallen and a generator may make a commercial decision not to re-commit units that were tripped during the trigger event. However, so long as those units were reasonably able to come back on-line, this decision would not postpone the end of the CAPP.

NEMMCO will be required to specify in its operating procedure how it decides whether a unit that has not yet resynchronised is nevertheless reasonably able to re-synchronise. For example, NEMMCO might decide to consider factors such as the state of the transmission system (has a generator's connection point be reconnected to the main transmission network; has the power system voltage and frequency stabilised; does the power station have an auxiliary supply?) and also the state of the relevant generating plant (was a unit damaged by the trigger event; has the power station operator been able to restabilise the unit in order to commence a start-up process, has sufficient time elapsed to allow that start-up process to be completed?).

Transmission Constraint no longer Material

Consider the earlier example of a total outage of QNI. This constraint is material so long as the flow on QNI in the absence of the contingency (the "counterfactual flow") would have exceeded the CAPP threshold in the relevant region (either Queensland or NSW).

When the counterfactual flow exceeds the CAPP threshold, the CAPP commences. When the counterfactual flow first falls below the CAPP threshold (assuming that this is more than 2 hours after the CAPP commenced), the CAPP will end.

A trigger event can cause at most one CAPP to be invoked. If the counterfactual flow again rises above the CAPP threshold, there will not be a second CAPP triggered.

Multiple Failed Lines return to Service

Next, consider a trigger event which includes multiple transmission line outages. Now suppose that all but one of these lines has returned to service, but the N-1 constraint associated with the last remaining outage is nevertheless material.

In this situation, the CAPP will end when the penultimate line returns to service. The rationale for this approach is that, although the N-1 constraint is material, it has the same effect as a credible contingency (ie the outage of just the remaining line) and so is a risk that should be managed by generators anyway.

Shed Load restored

Next, consider a trigger event which causes a large amount of load shedding, which causes some generating units to be tripped as a result of the resulting over-frequency. Depending upon the pattern of remaining generation and any interconnector constraints, it may or may not be possible to resynchronise the tripped units before restoring all of the load. The ending of the MIOD will be determined by the resynchronisation time, *not* by the load restoration time.

Sustained Damage

Next, consider that the event causes sustained damage to transmission or generation assets, the MIOD may continue for a sustained period. In this case, the CAPP will end 24 hours after the time of the trigger event.

APP Invoked

The market disruption caused by the trigger event may lead to sustained high (uncapped) prices, which may in turn trigger an APP[23]. If an APP and CAPP operate concurrently, prices will be capped at the administered price cap as normal.

A CAPP will commence shortly after the event and continue for no more than 24 hours. An APP will only commence, if at all, some hours or even days after the event[24] and will then continue for at least the remainder of the trading day and possibly for longer. Therefore, if there is sustained, major disruption where both the CAPP and APP are triggered on the same day, then the CAPP will operate first, then the CAPP and APP together and then just the APP, until the disruption ends.

3.8. NEMMCO Obligations

Obligations are placed on NEMMCO to:

- determine whether and when a trigger event has occurred;
- to determine whether and when a CAPP should be invoked;
- to determine when an invoked CAPP should end

The draft rules establish only high-level principles for determining these matters. NEMMCO, therefore, is also obliged to develop an operating procedure describing how it will interpret and apply these principles.

The existing Rules do not allow spot prices to be retrospectively changed[25] and the proposed Rule will not change this principle. Therefore, the commencement of a CAPP must be determined in real-time; a CAPP can commence only once NEMMCO has determined that it should commence and, similarly, can end only once NEMMCO has determined it should end. For this reason, it is important that NEMMCO makes determinations quickly. It is anticipated that this should mean that the CAPP commences no more than 30 minutes after the initiation of a qualifying trigger event[26].

It may be difficult for NEMMCO to determine quickly the initiating factor for a potential trigger event. NEMMCO would only need to do this for the rare situation of a multiple unit trip at a power station that is not preceded or followed by transmission or generation failures outside the power station. It is acknowledged that in this rare situation, it may take slightly longer for NEMMCO to determine whether it was a trigger event.

[23] Note that the CPT trigger will be based on the uncapped prices, so a CAPP will not affect the triggering of an APP
[24] For example, it may take up to 7 1/2 hours of VoLL prices before the CPT is reached
[25] except under certain specified circumstances: eg when there were manifestly incorrect inputs to the dispatch calculation
[26] Except where the trigger event has only a delayed impact on dispatch. .

When it has determined that a trigger event has occurred and caused a MIOD, NEMMCO will announce this to the market[27] and the CAPP shall commence in the next dispatch interval[28]. Similarly, the CAPP will end in the dispatch interval following NEMMCO's determination that the ending criteria have been met.

When a trigger event has occurred, there are three types of events that NEMMCO must identify and monitor in order to determine start and end times for any associated CAPP:

- generating units tripped by the contingency and their return – or potential return – to service;
- transmission outages caused by the contingency and their endings;
- post-contingency transmission constraints and their materiality

Table 3 below shows how these three event categories relate to CAPP commencement and ending.

Event category	**criterion for CAPP commencement**	**criterion for CAPP ending**
tripped units	aggregate capacity exceeds the CAPP threshold	aggregate capacity less than the CAPP threshold
transmission outages	not relevant	only a single outage remaining
transmission constraints	one or more material constraints	no remaining material constraints

Table 3: Events monitored by NEMMCO

The proposed Rule envisages that NEMMCO will maintain a list of these three categories of events and "cross events off the list" as assets return to service or transmission constraints are revoked.

[27] NEMMCO will also be required to announce when it has determined that a possible trigger event was, in fact, *not* a trigger event
[28] note that, while an APP commences and ends at the start of a *trading* interval, the CAPP commences and ends at the start of a *dispatch* interval

3.9. Consequential Changes

The proposed Rule for triggering and ending a CAPP and for capping prices during this period – as described above – is contained in a new clause: 3.14.2A. There are also a number of consequential changes to existing clauses. These are listed below:

- a new subclause 3.9.2(e)(5) is inserted, which requires NEMMCO to cap the dispatch price during a CAPP, analogous to the existing subclause 3.9.2(e)(4) for APP price capping.
- clause 3.14.2(c) is amended, to ensure that price capping or flooring during a CAPP does not affect the triggering of the CPT trigger for APPs.
- clause 3.14.6 is amended to allow scheduled generators, MNSPs and demand-side bidders to claim compensation following a CAPP in the same way as they can currently in relation to an APP.
- new defined terms are added into the Glossary for contingency administered price period, trigger event, material network constraint and CAPP threshold.

3.10. Drafting the proposed Rule

A draft set of changes to the Rules to implement the proposed Rule is provided in Attachment 1.

4. How the proposed Rule would address the Issue

4.1. *Overview*

Section 2.1 described how there are two aspects to the issue:

- the adverse financial impact on generators that may follow incidents that cause serious power system disruption; and
- the need to define and identify such incidents, so that market intervention can be targeted at these and detriment associated with unnecessary market intervention can be minimised.

The next two sections explain how the proposed Rule will address these two aspects.

4.2. *Mitigating the Financial Impact*

The proposed Rule mitigates the post-contingency financial impact on generators by capping spot prices for a period following a serious incident. The example in section 2.2 showed how the worst case impact on a 300MW generator was $3m/hour[29]

Under the proposed Rule, spot prices would be capped: at $300/MWh, say[30]. So, the worst case financial impact is now just 300MW*$300/MWh = $90,000/hour[31]. The worst-case impact is reduced by a factor of over 30.

4.3. *Triggering Market Intervention*

As discussed in section 2.3, market intervention is only justified following a power system disruption where risks would otherwise be both *substantial* and *unmanageable*. The proposed Rule identifies such incidents by applying three criteria, which must all be satisfied before market intervention occurs:

1. the incident must be genuinely unexpected and unusual;
2. the consequential power system disruption must physically affect generators (or other market participants) that did not cause it; and
3. there must be a likelihood of substantial financial impacts on generators (or other market participants) from the incident.

The sections below discuss:

- why these criteria are applied; and
- how these criteria are applied by the proposed Rule.

[29] Because the generator may have to "purchase" up to 300MW from the spot market at a price up to $10,000/MWh.
[30] this is the current level of the APC.
[31] once the CAPP commenced. There would be some intervening period, whilst NEMMCO identified and determined the Trigger Event and risks during this short period will not be managed

Criterion 1: Unexpected and Unusual

Applying the first criterion ensures that market intervention is infrequent. The proposed Rule applies this criterion by requiring that either a NCCE or a sequence of related credible contingency events equivalent to a NCCE has occurred.

It can be seen from the historical record that such circumstances are unusual. The Reliability Panel's annual NEM Performance Review[32] enumerates the NCCEs and multiple contingencies occurring each year. According to these reports, there were a total of 47 such incidents in the four years to 2007: about one per month. Whilst such incidents would normally constitute trigger events, we would expect that the majority would not have had a material impact on dispatch (although we have not analysed this). Even where a CAPP is invoked, the price capping may not affect dispatch prices if these remain under the price cap.

The first criterion also ensures that the risks are genuinely *financially* unmanageable. NCCEs or multiple contingency events are likely to take the power system outside its technical envelope[33], meaning that their consequences are extremely uncertain. Impacts may be widespread and affect parties remote from the initiating incident. This unpredictability makes it impossible to hedge the financial impacts of such incidents in the way that one can hedge the financial uncertainties of normal market operation[34].

Criterion 2: Physically affects Third Parties

Applying the second criterion ensures that the event physically impacts on parties (such as tripping of generating units and/or shedding of load) whose actions did not cause the problem[35].

The proposed Rule applies this criterion by excluding any incident:

- whose effects are contained within a single power station site; and
- which was caused by failure of generating plant at that site.

Such incidents can be seen to only affect the generator whose plant failure caused the incident. All incidents not so excluded would affect one or more parties who did *not* cause the incident.

[32] Annual Electricity Market Performance Review: Reliability & Security, Reliability Panel
[33] ie its normal zone of operation
[34] in contrast, a single credible contingency event, such as a single unit failure, can be financially managed – eg by selling only up to "N-1" – because the consequences of the event are limited and known in advance.
[35] of course, this still means that one party – the causer – may be unreasonably protected from the consequences of its own actions. This "moral hazard" is discussed further in section 5.3

Criterion 3: Substantial Financial Impact

Applying the third criterion ensures that market intervention only occurs where this is necessary to manage the financial impact of an incident; thus unnecessary market intervention is avoided.

The proposed Rule applies this criterion by requiring that the incident has a "material impact on dispatch" (MIOD): ie that generation output and/or interconnector flows following the incident are markedly different to what they would have been had the incident not occurred. Recall from the example in section 2.2 that the financial impact of an incident will be in proportion to both the dispatch impact and the post-contingency spot price, so the financial impact will only be substantial if both of these elements are significant.

Table 4 below considers the four possible combinations of high or low dispatch impact and high or low spot prices following a trigger event.

Scenario	Dispatch Impact	Price Level	Financial Impact	CAPP invoked?	Prices capped?
1	Low	Low	low	no	no
2	Low	High	low	no	no
3	High	Low	low	yes	no
4	High	High	high	yes	yes

Table 4: Impacts of the CAPP under Price and Dispatch Scenarios

Scenarios 1 and 2 do not have material impact on dispatch and so the CAPP is not invoked and market intervention does not occur. Whilst the CAPP is invoked in scenario 3, spot prices are low and so price capping has no effect. Only in scenario 4 is there market intervention in the form of adjustment to the spot prices.

Scenario 4 is also the only scenario where the financial impact is high. Therefore, by causing market intervention where, and only where, there is substantial financial impact, the proposed Rule applies the third criterion correctly.

4.4. Summary

In summary, the proposed Rule addresses the issue by:

- intervening in the market to reduce risks following a power system disruption giving rise to financial impacts which are substantial and unmanageable; and
- defining and applying criteria to each power system disruption, so that intervention occurs where it is warranted and does not occur where it is unwarranted.

5. How the Proposed Rule would contribute to the National Electricity Objective

5.1. Overview

To contribute to the National Electricity Objective (NEO), the proposed Rule must provide some net improvement to the economic efficiency of the NEM, to the long-term benefit of electricity consumers.

The net improvement will consist of three elements:

- the *improvement to efficiency* as a result of addressing or mitigating the issues discussed in section 2; minus
- *any efficiency detriment* arising from the capping of spot prices during a CAPP and so the removal or dilution of the efficient signals that they may provide; minus
- the *additional transaction costs* associated with identifying and operating CAPPs.

These three elements are discussed in turn below.

5.2. Efficiency Improvements from addressing the Issue

Efficiency improvements will occur in four areas:

- *the spot market*: as a result of a more "orderly" dispatch process in the aftermath of non-credible contingencies that cause power system disruptions;
- *the forward markets*: as a result of mitigating unmanageable financial risks on existing generators;
- *inter-regional trading*: as a result of a reducing risks arising from non-firmness of IRSR instruments; and
- *generation investment*: as a result of mitigating unmanageable financial risks for future generators.

These improvements are discussed below.

The Spot Market

Generators continuously manage their dispatch level against their forward sales through self-commitment and bidding decisions. This allows them to manage their spot price risks and also has the effect of linking and reinforcing competition in the forward and spot markets.

A generator's dispatch level will, amongst other things, be affected by the bidding behaviour of its competitors and so iterative bidding and rebidding between competitors is an intrinsic component of the spot market and a key to creating effective generator competition.

The effects of such rebidding competition are benign under normal market circumstances. However, in the aftermath of a major dispatch shock created by a NCCE, such activity may potentially create or exacerbate market instability as generators seek to rapidly manage their dispatch position in the context of competitors seeking to do the same thing.

This instability may have the effect of creating a "disorderly market", where rebidding simply cannot take place fast enough to respond to rapidly changing commercial and physical circumstances. This is a potential weakness in all spot markets having to respond in real-time to changing external factors. It is common for spot market arrangements to incorporate "circuit breakers", where pricing or trading is suspended or controlled during periods of rapid change.

In the NEM, this disorder will be manifested in volatile dispatch outcomes, and also possible volatile responses of non-dispatched generation and load. The volatility will make harder NEMMCO's urgent task of restoring the power system. For example, units which are already ramping up or down as a result of the market volatility may not have the additional flexibility needed to accommodate restoration of load blocks. Although NEMMCO has the intervention tools – such as directions – to control or overcome this dispatch volatility – invoking such tools further complicates its activity.

Thus, a disorderly spot market in the aftermath of a serious incident could delay power system restoration. This may mean higher levels of unserved energy as load restoration is delayed, or higher generation costs where lower cost generation remains constrained off for longer. It could even cause the disruption to become more widespread.

Because the market disorder stems from generators attempting to manage their financial risks, the proposed market intervention to mitigate these risks directly should avoid or at least moderate this disorder. This will have the beneficial effect of hastening system restoration and so improving the reliability and efficiency of electricity supply.

Forward Markets

As we have seen, power system disruptions have the potential for causing a major adverse financial impact on generators that cannot be managed. Although relatively rare, the size of such impacts will significantly increase the risk profile of generators, and require them to hold higher levels of "risk capital": ie capital that is liquid or can be liquidated at short-notice in order to ensure continued solvency following such incidents. Higher risks and higher levels of risk capital materially increase funding costs for generators. These costs, therefore, could be materially reduced if the proposed Rule was adopted.

However, the potential benefits are not confined to generators. Because the current risks on generators depend upon their level of forward sales[36], generators have the opportunity to at least partially manage such risks either by increasing their contract offer prices in order to incorporate a risk premium or by reducing the volume offered to

[36] in the absence of such forward sales, the risks would instead pass to retailers, through the higher spot price

provide a degree of safety margin. Thus, the risks and costs are likely to flow, at least in part, to retailers, who will in turn manage them by increasing retail prices.

The proposed Rule therefore, by providing an alternative mechanism for managing these risks, is likely to have the effect of materially reducing generation costs, wholesale prices and retail prices.

Inter-regional Trading

As discussed so far, the financial impact of serious incidents falls on the *seller* in the forward market. However, in relation to one important forward market contract – the inter-regional settlement residue (IRSR) contract sold in the Settlement Residue Auction – the financial impact falls on the *buyer*. Specifically, if the capacity of an interconnector is substantially reduced following a serious incident, the IRSR will be commensurately reduced.

The buyer of an IRSR contract may be a generator or a retailer and will typically have purchased the contract in order to hedge price exposure resulting from inter-regional trading[37]. Analogous to the generator impact discussed earlier, the IRSR holder will see a financial impact in proportion both to the amount by which interconnector capacity is reduced and to the inter-regional price spread following the incident.

Because they are generally highly utilised and poorly diversified, interconnectors are at high risk of failure following a serious incident. For example, multiple generating unit tripping in one region will lead to increased interconnector imports which can quickly exceed safe limits and lead to tripping and islanding. Or, to take another example, non-credible transmission outages on or close to an interconnector can create cascade tripping of other interconnector circuits as they become overloaded, again leading to islanding. Even where islanding does not occur, transmission outages are likely to create more severe constraints at interconnector “bottlenecks” than in highly-meshed parts of the network.

Just as generators can manage the risks by reducing their participation in the forward market, IRSR holders can manage risks by reducing their amount of inter-regional trading. As such, the risks to interconnector capacity from serious incidents create a major impediment to inter-regional trading. The proposed Rule, by substantially removing this impediment, will promote inter-regional trading which, in turn, will support a more competitive and efficient wholesale market.

Generation Investment

Any potential investor in new generating capacity will assess the future profits and risks arising from the electricity spot and forward markets. In considering risks, they will focus on those risks that cannot easily be managed and which may create the largest commercial impact, even if the likelihood of occurrence is relatively low. The incident-related risks described above are therefore likely to feature strongly in their considerations.

[37] for a generator, this may involve selling forward contracts in a region other than where its generation is located; for a retailer, this may involve buying forward contracts in a region other than where its customers are located

These risks, therefore, create a significant impediment to investment in new generation capacity. The proposed Rule, by removing this impediment, will improve investment efficiency, increase the level of investment and, other things being equal, lead to lower wholesale and retail electricity prices.

Summary
In summary, other things being equal, the effects of the proposed Rule will be:

- wholesale and retail prices will be lower;
- power system restoration will be faster and more secure and so power system reliability will be increased and unserved energy reduced; and
- a significant barrier to investment in new generation capacity will be removed, leading to greater generation competition and capacity and so lower wholesale and retail prices.

5.3. Potential Detriments

There are three areas of potential detriment arising from the proposal:

- the financial mitigation provided to generators whose units are tripped in the aftermath of a serious incident may weaken the incentives on generators to ensure that units are appropriately robust to power system disturbances: ie it may create *moral hazard*;
- capping of prices during CAPPs may weaken the incentive to *efficiently invest* in new generation capacity; and
- capping of prices during CAPPs may weaken the incentive to provide *availability* and participate in dispatch in the NCCE aftermath.

The proposed Rule has incorporated a number of design elements with the intent of minimizing the likely impact of these potential detriments. Specifically:

- serious incidents will only trigger market intervention if they satisfy the three criteria discussed in section 4.3;
- the CAPP shall not be prolonged beyond the period necessary for the power system to be restored; and
- the incentives for dispatched generation and load to participate in dispatch that are established under the existing APP Rules will also apply during a CAPP.

The three areas of potential detriment are discussed in turn below.

Moral Hazard
The first potential detriment is that the protection provided to generators by the CAPP might weaken the incentives on generators to maintain high reliability of their generating assets. If this were to affect generator investment or operating decisions, it could lead to more frequent incidents and so a lower reliability of electricity supply.

However, several factors will limit the extent of this potential detriment:

- serious incidents are often caused by transmission failures, and TNSPs do not currently face the market consequences of such failures and so are unaffected by the proposed Rule.
- generators have, and will continue to have, obligations and incentives to comply with the technical standards set out in the Rules;
- generators have, and will continue to have, strong commercial incentives to take precautions to prevent incidents which could damage their generating plant; and
- many incidents are not reasonably foreseeable and so no precautionary action could have been taken.

Furthermore, the proposed Rule has sought to limit moral hazard further by ensuring that market intervention is not triggered where the causer of the incident is the only party affected (see section 4.3).

Dilutes Investment Incentives

A second potential detriment is that capping prices may reduce incentives on generators or demand-side managers to invest in new capacity in regions where there is a *genuine*[38] supply shortfall. This may happen where spot prices are high *before* a serious incident and are then capped – in accordance with the proposed Rule – following the incident.

The materiality of this impact will depend upon how frequently a potential investor expects this scenario to occur. Market intervention will only occur when an incident satisfies the three criteria discussed in section 4.3 and this in itself will be quite rare. For intervention to occur when pre-incident spot prices happen to be high will be rarer still. On this basis, the detriment is unlikely to be material.

Now, this conclusion might appear to contradict the conclusion in section 5.2 that the proposed Rule will materially *benefit* generation investment efficiency. In fact there is no contradiction. The benefit discussed in that section arose from the reduction in *unmanageable risk*. The potential efficiency detriment discussed in this section would only arise from a reduction in *expected return* for a region with a genuine supply shortfall and it is concluded that this would not be material. In short, the impact on risk can materially affect efficiency, even when the impact on expected return does not.

Dilutes Availability Incentives

A related concern is that price capping reduces the incentives on generation and demand-side response to be available for dispatch following a serious incident, potentially extending the period of power system disruption or creating additional supply shortfalls and load shedding.

This concern is largely addressed by the provision of compensation to generation and demand that is dispatched below its offer price, in the same way as it is addressed

[38] ie not one triggered by the random aftermath of a serious incident

currently for price capping during an APP. Furthermore, if necessary, NEMMCO can direct dispatchable generation and demand.

Non-dispatched generation and load cannot be directed and is not eligible for compensation. However, these parties would not be expected to respond quickly to sudden, unexpected price changes in any case, and so the price capping would probably not materially affect their behaviour.

There may be a related concern that a generator could aim to deliberately extend the CAPP because of its contractual position[39] or because it is costly to rapidly resynchronize its tripped units. The proposed Rule addresses this concern by ensuring that a generator cannot cause a CAPP to be prolonged:

- a generator choosing not to re-synchronise tripped units will not prolong a CAPP: the CAPP will end once the units are reasonably able to re-synchronise.
- a generator choosing to rebid to reduce its dispatch compared with pre-incident levels will not prolong a CAPP: changes to dispatch are only considered material if they are caused by the incident: for example by creating new transmission constraints.

Indeed, a generator that does not rapidly resynchronize its tripped units runs the risk of having a dispatch shortfall when the CAPP ends. Therefore, the incentive to restore availability as quickly as possible remains.

For these reasons, there is not expected to be a material impact on availability incentives.

Summary

In summary, the carefully targeted design of the CAPP Rules mean that any efficiency detriment arising from market intervention is unlikely to be material.

5.4. Transaction Costs

Overview

The proposed Rule places additional obligations on NEMMCO and the AEMC[40] but not on any other parties. Therefore, any extra transaction costs are likely to fall on NEMMCO/AEMC.

The processes for capping prices and settling compensation claims under the proposed Rule are be identical to the existing APP processes in order to minimize additional transaction costs.

[39] eg because it its contract sales exceed its dispatch and so it would benefit from lower prices
[40] in relation to compensation determination

Transaction costs can be categorized as follows:

- *establishment costs*: costs incurred once the proposed Rule is adopted;
- *post-incident operating costs*: costs incurred following an incident and during any CAPP; and
- *post-CAPP operating costs*: costs incurred following a CAPP.

These are considered in turn, below.

Establishment Costs

Given the existing APP arrangements, we would expect that NEMMCO already has systems for applying administered caps and floors to dispatch prices during a specified period. Therefore, we would not expect any major additional establishment costs from the introduction of the CAPP.

NEMMCO will be required to develop and consult on a new operating procedure to define and determine trigger events and the commencement and ending of CAPPs.

Arrangements for assessing, paying and then recovering compensation costs are assumed to be already established, since these are present in the existing APP arrangements.

In summary, establishment costs are likely to be modest.

Post-NCCE operating costs

Following a serious incident, NEMMCO must determine whether a CAPP should commence. Where it determines that it is, NEMMCO must declare the commencement of a CAPP and then, for each dispatch interval during the CAPP, must determine whether the CAPP should continue or should be ended. If a trigger event is declared but a CAPP is not invoked immediately, NEMMCO potentially has to monitor the materiality of any post-contingency transmission constraints until they are revoked, or for at most 22 hours after the trigger event.

These obligations could potentially impose additional resource costs on NEMMCO, and at a time that NEMMCO staff will already be very busy managing and then restoring the power system[41]. There is, then, the potential for some disruption to NEMMCO's operations.

It is for this reason that the proposed Rule has been drafted to give NEMMCO flexibility to design an effective and practical procedure for determining whether and when to commence and end a CAPP. We would expect that this would allow the MIOD assessment, at least, to be automated, which should reduce post-incident operating costs, although it would add somewhat to establishment costs.

[41] Although, for the most serious incidents, determining whether a CAPP should be invoked is likely to be straightforward. It is for the less serious, marginal incidents that the proper determination may be unclear.

As noted in the previous section, we would expect price capping during a CAPP to be automated, based on existing systems.

Therefore, whilst there may be additional costs on NEMMCO associated with the post-incident period, the design of the proposed Rule allows these to be minimized.

Post-CAPP Operating Costs

Following the conclusion of the CAPP, affected NEM participants may submit claims for compensation and these claims must be assessed and decided upon by the AEMC, on the advice of an expert panel. This is an identical arrangement to the one provided for under the current APP Rules.

The costs associated with this are unclear. The arrangements are currently the subject of a Rule change request, which may simplify (or might complicate) the process. Unlike the post-incident operating costs, there is no urgency in undertaking these tasks and so they are unlikely to tie up scarce resources. Furthermore, it is anticipated that CAPPs will be quite uncommon. For these reasons, these transaction costs are unlikely to be material.

Summary

We acknowledge that there will be some additional transaction costs associated with this proposed Rule, but expect these to be modest. Since NCCEs and trigger events only occur infrequently, the additional ongoing transaction costs will be small.

5.5. Overall Summary

In summary, the proposed Rule is expected to:

- provide significant market benefits - from enhanced generation competition, more efficient generation investment, improved reliability, and lower wholesale and retail electricity prices;
- not materially impact the efficiency of spot prices in signaling generation investment and availability;
- create only a modest increase in transaction costs

Therefore, the proposed Rule is considered to contribute to the achievement of the National Electricity Objective.

6. Expected Costs and Benefits of the Change

6.1. Overview

The AEMC guidelines for a Rule change proposal[42] require that:

> "A Rule change proposal should identify who is likely to be affected by the proposed change and explain how and why that person or groups of persons is likely to be affected by the change"

For the purposes of describing the costs and benefits of the change, we divide stakeholders into the following classes:

- generators
- retailers
- customers
- NEMMCO

The stakeholder impacts are complex as they occur on a number of different timescales:

- dispatch (ie real-time)
- spot and contract market settlement (ie weekly billing cycle)
- contracting (eg one to 3 year ahead)
- investment (eg over 3 years out)

These timescales are discussed in turn below.

6.2. Dispatch Timescale

Section 5.2, discussed how the proposed Rule could ensure a more orderly spot market following a system incident. To the extent that this allows a faster restoration of load, this will have major benefits for consumers.

A more orderly market will reduce transactions costs for NEMMCO and generators. However, as CAPPs are expected to be rare, the overall benefits here will be small.

As noted in section 5.4, the need to determine the timing of CAPP commencement and end will add somewhat to NEMMCO costs.

6.3. Settlement Timescale

In this timescale, we will distinguish between incidents where load is shed and those where no load is shed. Clearly, there is only an impact where a CAPP is invoked and price capping occurs.

[42] Guidelines for proponents: Preparing a Rule change proposal, AEMC, January 2008

Where there is no load shed, and assuming that retailers are hedged against spot prices, retailers will be unaffected by price capping. Since retailers are the ultimate source of all generation revenue and they are unaffected, total revenue to generators must also be unaffected. Therefore, the impact is a wealth transfer, from one group of generators to another group.

As discussed in section 2.2, the financial impact of serious incidents currently is in proportion both to the dispatch impact and to the level of post-incident prices. In regions where post-incident prices are high, generators whose dispatch is reduced ("dispatched-off generators") as a result of the incident – because units have been tripped or transmission constraints limit their dispatch – will be adversely affected. Conversely, generators whose dispatch is increased ("dispatched-on generators") as a result of the incident – to replace the dispatch lost from other generators – may benefit from selling additional energy at the high price. In some cases, the higher post-incident prices may cause forward contracts to become active[43]. In this case, the benefit may not go to the dispatched-on generator, but to the retailer who holds such contracts and who receives additional difference payments as a result.

The proposed Rule, by capping prices, will substantially reduce the magnitude of the wealth transfers. Therefore, the impact of the proposed Rule will be beneficial for the dispatched-off generators and detrimental to the dispatched-on generators or to the retailers which hold cap contracts.

Since most generating companies own several power stations, it is possible that they may be dispatched-off at one site and dispatched-on at another, offsetting the overall impact. Furthermore, a power station which is dispatched-on in one incident may be dispatched-off in a later incident, so again the impacts may be offsetting. In the light of this, it is impossible to predict in advance who will gain and who will lose from the proposed Rule. However, the reduction in the *risk* associated with these uncertain wealth transfers benefits all generators.

Where there is load shedding, the corresponding retailer spot market payments will be reduced whilst difference payments from forward contracts remain unchanged or even increase. Therefore, retailers may currently benefit financially from a serious incident: Correspondingly, there will be more dispatched-off generation and/or less dispatched-on generation, so generators as a whole will see a net detriment. So there is now an overall wealth transfer from generators to retailers, as well as between dispatched-off and dispatched-on generators.

By capping prices, the proposed Rule will reduce the size of the wealth transfer. Therefore, the proposed Rule may be detrimental to retailers and beneficial to generators as a whole, when there is load shedding.

As discussed in section 5.2, the loss of interconnector capacity in a serious incident will adversely affect holders of IRSR contracts who are using such contracts to hedge price risks arising from inter-regional trading. IRSR holders may be generators or retailers. The financial impact will be in proportion to the reduction in interconnector capacity and the inter-regional price difference.

[43] ie by bringing cap contracts "into-the-money"

The proposed Rule may cause prices in the importing region to be capped, so reducing the inter-regional price difference and reducing the financial impact on the IRSR holder. Therefore, the proposed Rule will generally benefit an IRSR holder, whether retailer or generator.

The above discussion has assumed high post-incident prices which are capped under the proposed Rule. The proposed Rule also provides that very low (negative) post-incident prices may be "floored". Low prices might occur, for example, where islanding following the loss of an interconnector creates a generation surplus in the previously-exporting island. Since the price flooring has the effect of raising spot prices, the effects described above are generally reversed: ie dispatched-off generators may now lose out, dispatched-on generators may benefit and so on. The exception is IRSR holders, since the price flooring will again have the effect of reducing the inter-regional price difference and so will again benefit the IRSR holder.

6.4. Contracting Timescale

As discussed in section 5.2, generators are likely to respond to the reduction in risk resulting from the proposed Rule by increasing the amount, or reducing the price, of forward contracts offered to retailers. Thus, other things being equal, forward prices are likely to fall. In a competitive retail market, retailers are likely to respond by reducing retail prices. Therefore, some of the benefits to generation seen in settlement timescales are likely to flow through to end customers. The extent of this flow through will depend upon the competitiveness of the wholesale and retail markets.

6.5. Investment Timescale

Other things being equal, the reduction in investment risk (as discussed in section 5.2) resulting from the proposed Rule should benefit investors, since revenue will not materially change and risk-weighted cost of capital will be reduced.

However, in this case, other things are not equal. Reduced investment risk will also lead to an increase in investment. Thus, some of the benefit of the lower costs will be passed through to retailers as wholesale prices fall. This in turn will flow through to customers.

Therefore, in this timescale, there will be a sharing of benefit between generators, retailers and customers. The more competitive the generation and retail markets, the greater the proportion of the benefit passed through to customers.

6.6. Summary

The costs and benefits associated with the proposed Rule will be most noticeable and quantifiable in the settlement timescale. It would be theoretically possible to review serious incidents in the historical record and quantify the costs and benefits to each generator and retailer from intervening to cap prices.

However, such analysis would miss the point that these costs and benefits are largely random – at least for generators – and a winner from one incident may be a loser from the next. It would be extremely difficult to predict who may win and lose from future incidents.

More importantly, there is a systematic effect of the proposed Rule in reducing the financial risks arising from serious incidents. Whilst in the short-term, the main beneficiaries of this will be generators, in the medium and longer term the benefits will be passed through to retailers and customers as forward market and investment responses cause wholesale and retail prices to fall. The extent to which benefits reach the customer will depend upon the competitiveness of the wholesale and retail markets.

7. Conclusion

The National Generators Forum has concerns in relation to an issue whereby generators may face substantial and unmanageable financial losses following an incident which leads to serious power system disruption and tripping of, or constraints on, generators. The existing “cumulative price threshold” arrangements, which are only triggered following an extended period of high spot prices, are inadequate to address this issue.

The proposed Rule addresses this issue by identifying these incidents and then invoking a Contingency Administered Price Period, during which spot prices are capped by an administered price cap. This period would continue until the disruption had ceased, but for no more than twenty four hours.

We believe that the proposed Rule will improve the efficiency and competitiveness of the wholesale market by reducing generator and retail risks and by removing impediments to generation investment. Other things being equal, this should lead to lower wholesale and retail prices, to the long-term benefit of the electricity consumer