Independent Expert Report for Directions in Queensland and Victoria

Final Report under clause 3.15.17A of the National Electricity Rules

August 2009

Synergies Economic Consulting Pty Ltd
www.synergies.com.au

Disclaimer

Synergies Economic Consulting (Synergies) has prepared this advice exclusively for the use of the party or parties specified in the report (the client) and for the purposes specified in the report. The report is supplied in good faith and reflects the knowledge, expertise and experience of the consultants involved. Synergies accepts no responsibility whatsoever for any loss suffered by any person taking action or refraining from taking action as a result of reliance on the report, other than the client.

In conducting the analysis in the report Synergies has used information available at the date of publication, noting that the intention of this work is to provide material relevant to the development of policy rather than definitive guidance as to the appropriate level of pricing to be specified for particular circumstance.

Contents

1 Introduction

Synergies Economic Consulting (Synergies) and ROAM Consulting (ROAM) have been appointed as independent experts under clause 3.15.7A of the National Electricity Rules (the Rules) to determine compensation for directed NEM participants. The directions have been classified as being for "Other Service – Network Support". Because the directions were not for energy or market ancillary services (which are treated in accordance with clause 3.15.7 of the Rules) compensation is to be determined as set out in clause 3.15.7A in accordance with the "Fair Payment Price" methodology.

Clause 3.15.7A(c)(3) requires this final report to set out

> the description of the services provided in response to the direction;
>
> the independent expert's determination of each fair payment price for the services provided;
>
> the methodology and assumptions used by the independent expert in making the determination of each fair payment price; and
>
> summaries of the submissions made by interested parties.

In accordance with clause 3.15.7A(c)(5) confidential information and the identity of the directed participants are not disclosed.

This final report is structured as follows:

- Section 2 details the market circumstances around the directions;
- Section 3 describes the service provided by directed participants;
- Section 4 considers the principles for the fair payment price under the Rules;
- Section 5 summarises relevant previous independent expert reports;
- Section 6 details our preferred compensation methodology; and
- Attachment A reproduces clause 3.15.7A of the Rules.

Since our appointment to determine the fair payment price in these circumstances, NEMMCO has been subsumed within the Australian Energy Market Operator (AEMO). In this report we have continued to use NEMMCO because at the time the directions were issued in the NEM, AEMO had not commenced operation.

2 Circumstance of directions

Market events that led to directions in the Queensland and Victorian region are detailed below.

2.1 Queensland

Directions classified as being for "Other Service – Network Support" were made to generation units with fast start generation capacity in North Queensland on 22 and 23 January 2009.

The timing of the directions is provided in the tables below.

Table 1 North Queensland Directions issued 22 January 2009

Direction issued	Direction cancelled
19:03, 22 January	01:00, 23 January
19:20, 22 January	22:35, 22 January

Source: NEMMCO.

Table 2 North Queensland Directions issued 23 January 2009

Direction issued	Direction cancelled
20:50, 23 January	21:15, 23 January
20:50, 23 January	21:15, 23 January

Source: NEMMCO.

On both occasions, transmission line failure led to a constraint equation being invoked to limit the flow of power from Central Queensland to North Queensland to 230MW.

On 22 January, double circuit 275kV transmission lines between Strathmore and Ross failed at 17:32, and a black system was declared by NEMMCO for NQ at 17:36. By 17:42 one of the two lines was returned to service, and some generation in NQ was returned to service. The flow of power on the restored line from CQ to NQ was limited to 230MW.

The constraint equation invoked was violated at 19:00 and 19:10. Consequently, NEMMCO directed a generator to synchronise and follow dispatch targets.

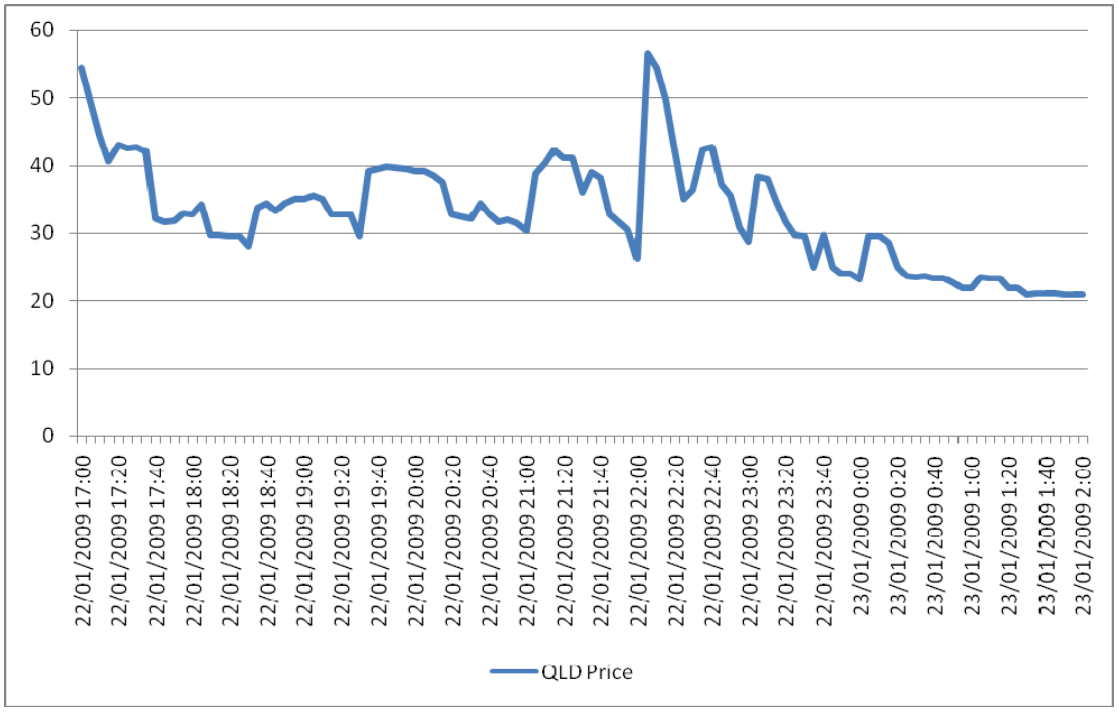
The black system was cancelled at 19:58, the remaining transmission line was restored at 00:38 and the constraint on power flows was cancelled at 00:55.

One of the same double circuit transmission lines tripped at 20:37 on 23 January. A constraint on power flows from CQ to NQ of 230MW was again invoked. The

constraint violated during the dispatch interval ending at 20:50. The directed participant was instructed to synchronise and provide an initial load of 45MW and follow dispatch instructions from then on.

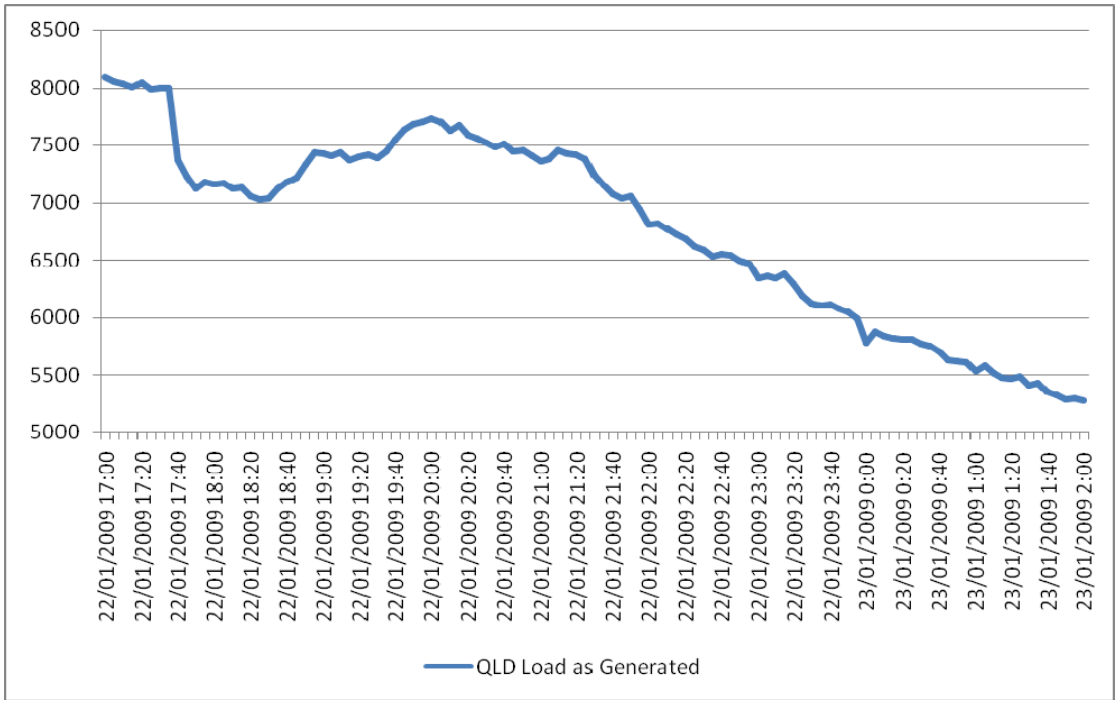
Figure 1 and 3 below show that during the period of each direction, the regional reference price in Queensland was relatively low when compared to the costs of peaking generation located within the constrained on region. Figure 2 and 4 below demonstrate the loss of load in north Queensland.

Figure 1 Queensland regional reference price – first directions period



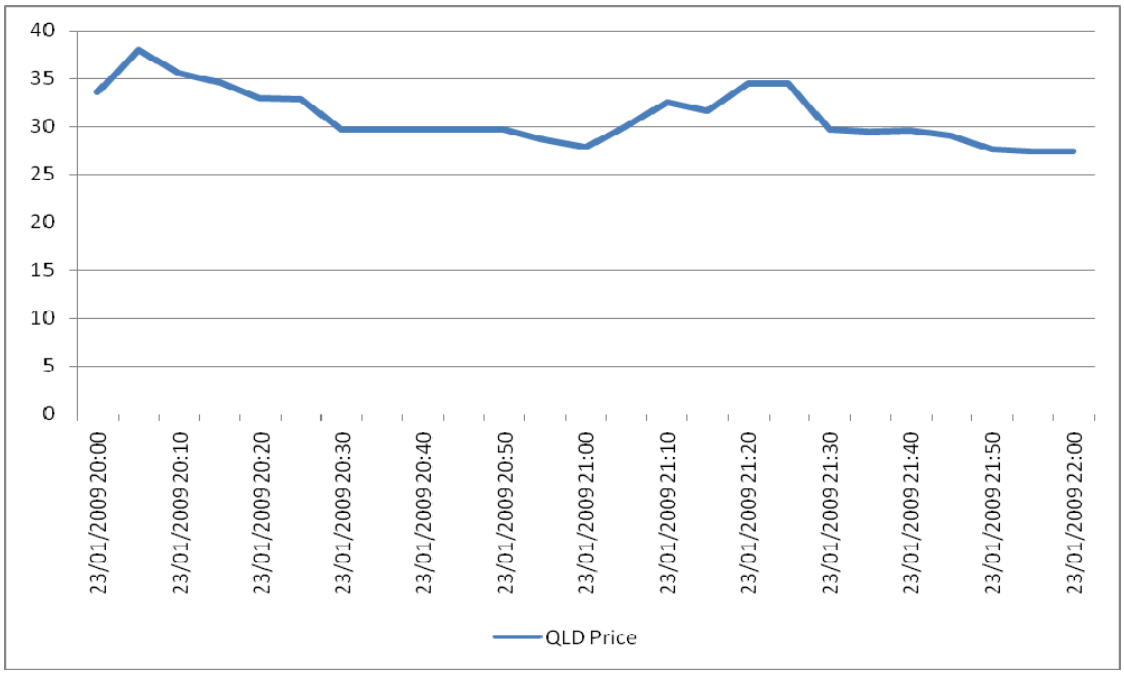
Data source: NEMMCO.

Figure 2 Queensland load – first directions period



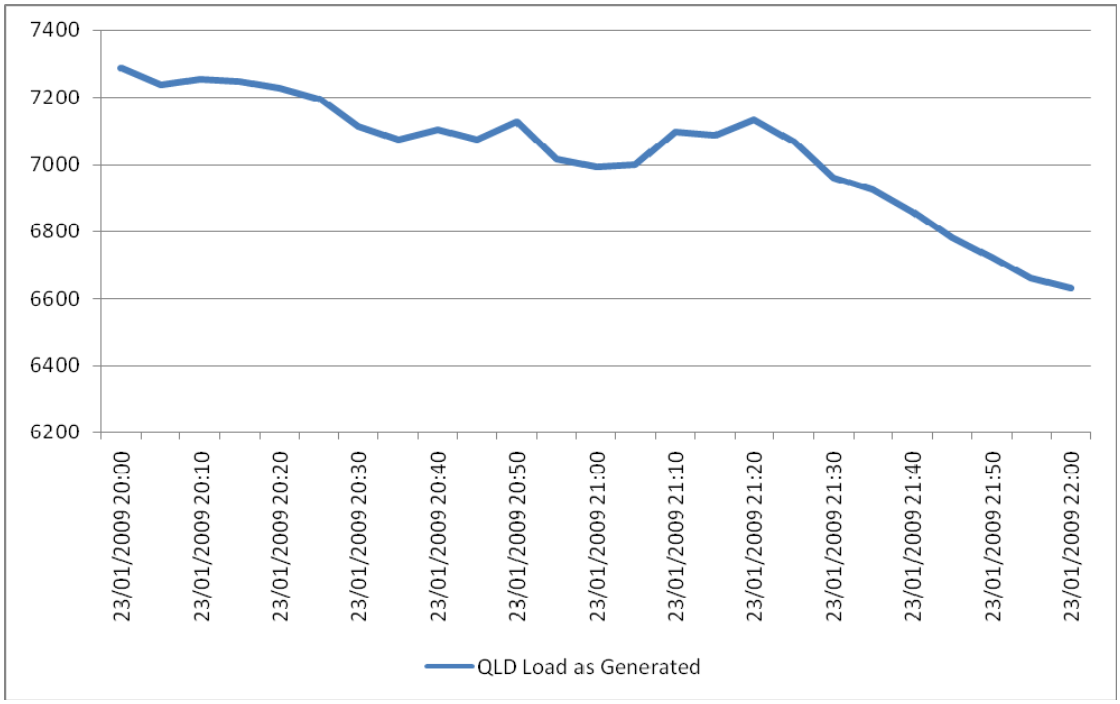
Data source: NEMMCO.

Figure 3 Queensland regional reference price – second directions period



Data source: NEMMCO.

Figure 4 Queensland load – second directions period



Data source: NEMMCO.

2.2 Victoria

Market circumstances in Victoria were more complex than those that occurred in the Queensland region. Directions were made to generators during a period of market instability. It was identified that by directing the generators, the volume of load shedding required could be minimised. Timing of the directions is provided in the table below. NEMMCO has classified the directions as being for "Other Service – Network Support".

Table 3 Victorian Directions issued 30 January 2009

Direction issued	Direction cancelled
17:50, 30 January	23:10, 30 January
17:53, 30 January	23:10, 30 January

Source: NEMMCO.

2.2.1 Events prior to the direction

Victoria and South Australia were experiencing sustained high temperatures in late January 2009, which affected both demand and prices in the NEM from 27 January 2009 onwards.

The directions period of interest did not occur until 30 January 2009, but market conditions in the preceding days are a factor in events that transpired. Specifically, the cumulative price threshold of $150,000 was exceeded on Thursday 29 January as a result of the high demand and prices prevailing at that time. In South Australia, an Administered Price Period was declared from trading interval 15:30 on 29 January: in Victoria an Administered Price Period was declared from trading interval 17:30 on 29 January. In any Administered Price Period, spot prices are capped at $300/MWh and the minimum energy price is set to minus $300/MWh (see Box 1 below). These spot price limits remained in place until 3pm Saturday 7 February in South Australia, and until 5pm Friday 6 February in Victoria.

Box 1 Administered Price Period

An administered price period for a region is declared for a trading interval for a range of reasons. These are:

the sum of the spot price in the previous 336 trading intervals, calculated as if this clause did not apply, exceeds the cumulative price threshold;

the sum of the ancillary service price for a market ancillary service in the previous 2016 dispatch intervals, calculated as if this clause did not apply, exceeds 6 times the cumulative price threshold;

the trading interval occurs in a trading day in which a prior trading interval is an administered price period under this clause 3.14.2; or

the previous trading interval was an administered price period and in NEMMCO's opinion one or more trading intervals in the next business day will be an administered price period and NEMMCO deems, with the consent of the AER, the trading interval to be an administered price period.

Until 1 July 2010, the cumulative price threshold will be $150,000, and the VoLL will remain at $10,000/MWh. From 1 July 2010, the cumulative price threshold will increase to $187,500 while VoLL will increase to $12,500. The increase in cumulative price threshold would not have had an impact on whether an Administered Price Period was in place in the relevant regions during the direction.

During the Administered Price Period, an Administered Price Cap of $300/MWh and an Administered Price Floor of minus $300/MWh are in place. If the dispatch price in the region in which the Administered Price Period applies would be greater than the Administered Price Cap or less than the Administered Price Floor then price will be set to the Administered Price Cap or Administered Price Floor as required.

Data source: National Electricity Rules Clause 3.14.2.

During the period of the directions, energy prices were limited to a range between minus $300/MWh and $300/MWh. The Administered Price Cap and Administered Price Floor clearly have the potential to distort market outcomes in the sense that they limit market prices and are therefore likely to result in pricing offers and availability offers that are different from those that would be forthcoming in their absence. Sustained high prices in the NEM, where they reflect a shortage of supply relative to demand, provide an important and efficiency enhancing signal of the need for

increased capacity or reduced demand.[1] The Administered Price Period rules clearly dull these important signals. It is also possible that the Administered Price Period induces generators to offer generation at prices that do not reflect their true reservation price associated with offering the service. The implications of these distortions will be considered in further detail below.

Peak demands on 30 January were 3,295MW for South Australia and 10,380MW for Victoria. The Administered Price Period rules in place in both South Australia and Victoria constrained prices to between minus $300/MWh and $300/MWh. However, in Tasmania, which was also affected by high temperatures and record demand along with the other southern States, the Administered Price Period rules were not in operation and prices fluctuated between a maximum of $6,880.22/MWh and a minimum of minus $999.73/MWh. It is not a stretch to believe that, but for the Administered Price Periods rules in place in Victoria and South Australia, their prices would have shown a similar range.

A direction was issued to a generator in South Australia to increase capacity from 240MW to 270MW for dispatch intervals ending 12:35 to 16:35. During this time NEMMCO, under intervention pricing, set energy and Frequency Control Ancillary Services (FCAS) prices in all regions based on dispatch that would have occurred absent the direction.[2] If scheduled generators are dispatched to different targets because of the intervention process NEMMCO must also determine the compensation for them.[3]

Flows from Tasmania on Basslink were limited during part of the day. Basslink contributed up to 540MW to Victoria during the morning. At 12:50 however, Basslink shut down from a 200MW target due to the abnormally high temperatures exceeding design limits. At 15:05 Basslink returned to service, but capability remained limited during part of the period of the direction as temperatures remained in excess of the operating conditions for which Basslink was designed.

Due to lack of reserve (LOR 3 condition) 90MW of load was shed in South Australia from 12:52 to 15:35. In Victoria, up to 360MW of load was shed from 12:25 to 16:15. The market price cap ($10,000/MWh) was invoked for the purposes of the cumulative price

---

1 In the short term, the signal is important in encouraging power saving measures by flexible load and encouraging generators to increase the available capacity that they can offer to the market. In the longer term, these price signals are essential to encourage appropriate investment.

2 Intervention pricing is applied by NEMMCO to achieve compensation that "would have applied as the dispatch price and ancillary services prices for that dispatch interval in the relevant region had the plant provided under the reserve contract not been dispatched or had the direction not been issued." National Electricity Rules Clause 3.9.3.

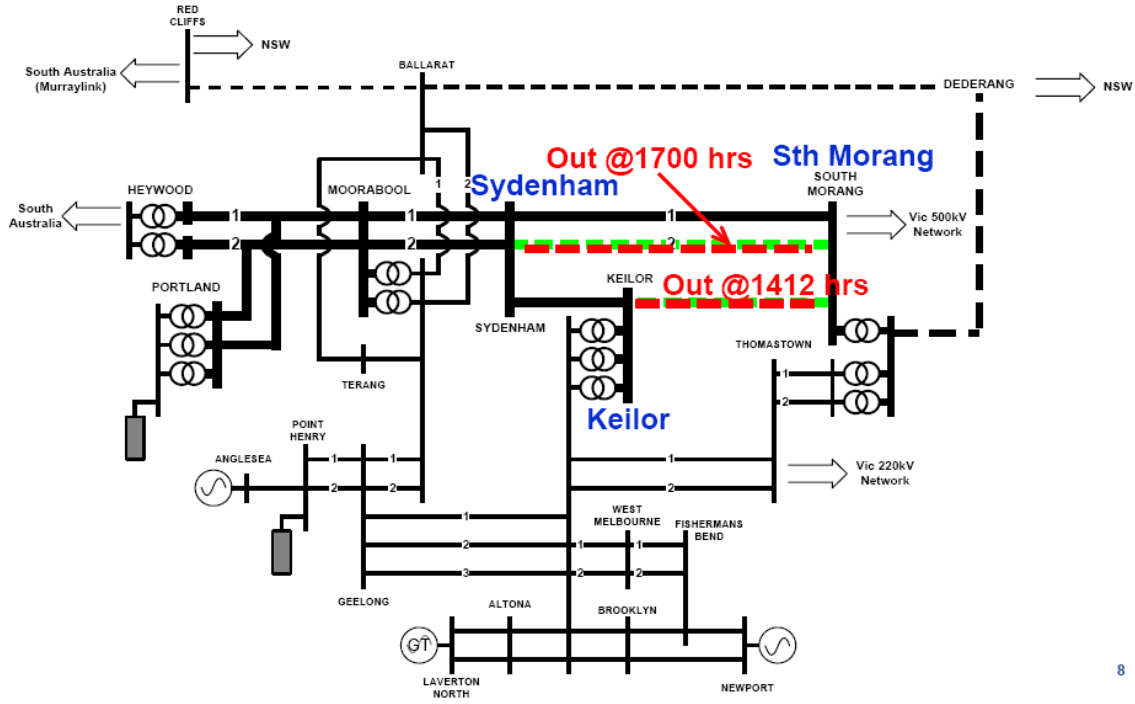
3 NEMMCO, Operation of the Intervention Price Provisions in the National Electricity Market, 9 March 2009.

calculation (used to determine Administered Price Periods), but the published prices at which transactions are settled were maintained at $300/MWh or less due to the Administered Price Period rules. It should be noted that load shedding in this instance was due to reliability and a lack of reserve in the market.

2.2.2 Directions period

At 14:12, 500kV transmission lines from Keilor to South Morang were lost. Subsequently at 17:00, 500kV lines from Sydenham to South Morang No 2 (at 17:00) were lost. At that time the power system was in a satisfactory but not secure state. Specifically, NEMMCO determined that the loss of South Morang No 1 would result in system collapse. The market situation is shown in the diagram below.

Figure 5 Unplanned 500kV line outages

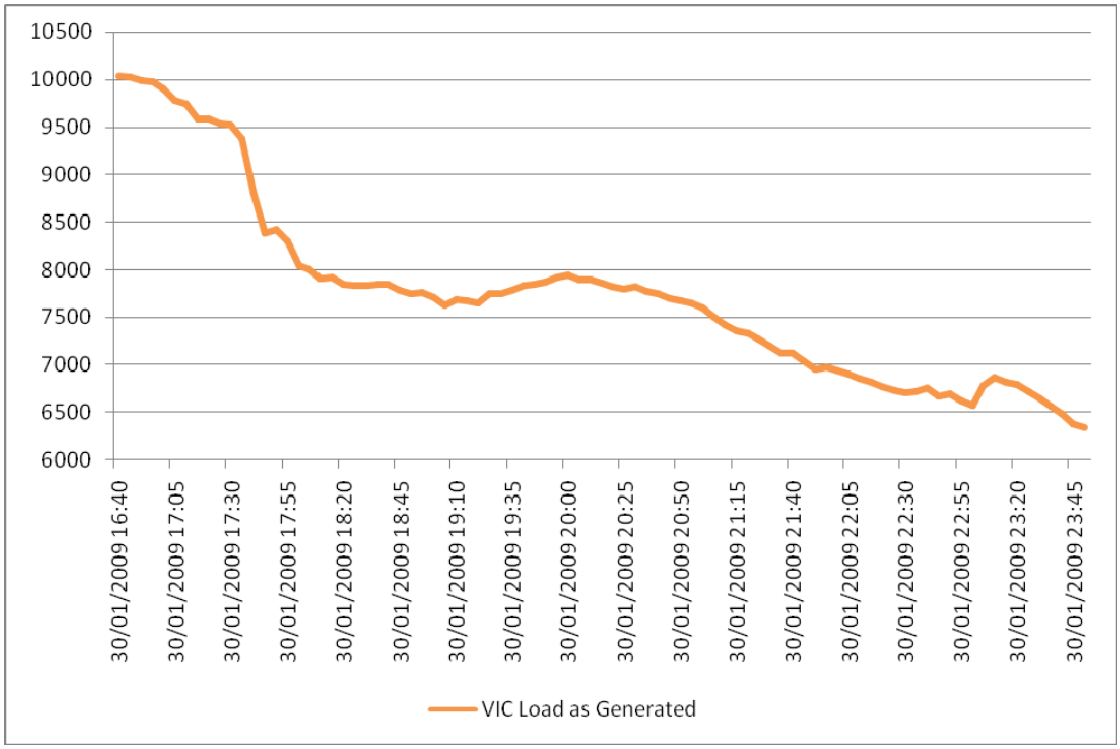


Data source: NEMMCO.

At 17:27 NEMMCO instructed 1,200MW of load shedding from western Melbourne, to prevent system collapse in the event of this contingency.

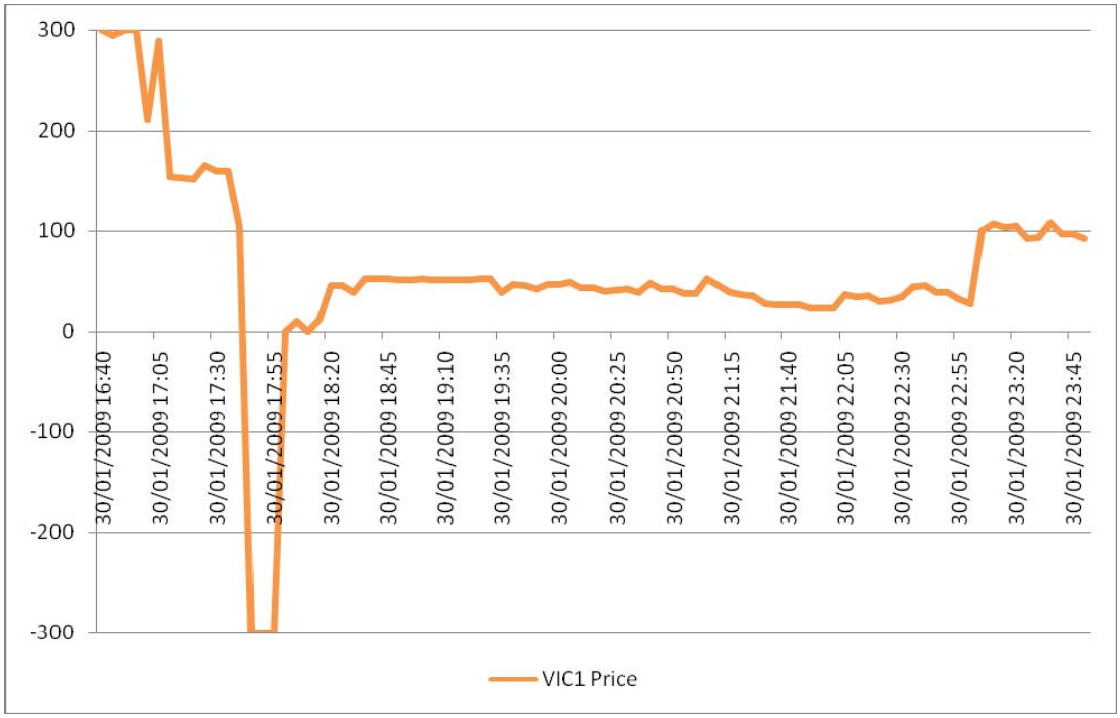
Unlike the previous load shedding event, which was for reliability, this load shedding event was to maintain system security. In response to the load shedding, price collapsed to the minimum price of minus $300/MWh for dispatch intervals from 17:45 to 17:55 (Figure 7 below).

Figure 6 Victorian load



Data source: NEMMCO.

Figure 7 Victorian regional reference price



Data source: NEMMCO.

Directions were issued to power stations that could mitigate the volume of load shedding needed in western Melbourne. The directed power stations are located close to the major customer load centre in Victoria, and the regional reference node. They are located in an electrically 'strong'[4] part of the Victorian electricity grid that rarely experiences circumstances such as those that occurred to prompt a direction. The majority of generation in the Victorian region is located in the Latrobe Valley. In these circumstances, this generation was located upstream of the area in which network security was at risk. More generation from Latrobe Valley generators could not have ameliorated the volume of load shedding required in western Melbourne because the transmission failures prevented the secure transmission of power from the Latrobe Valley to western Melbourne.

There are two important observations that can be made in relation to the market outcomes during the directions period:

- after the load was shed, there was substantially more generation available in the Victorian zone than connected demand, necessitating that some generators were required to back down. This was done in order of the generator offers. Given the available offers, this led to the regional reference price in Victoria becoming negative during some dispatch intervals. Clearly, this is a somewhat perverse outcome, with involuntary load shedding indicating that market clearing prices should be at the market price cap, while actual reference prices are negative. However, it is a quite likely outcome under a zonal pricing model when very rare sets of contingencies occur that affect strong parts of the zonal network; and
- sustained high prices in preceding periods in the Victorian region in combination with the Administered Price rules had probably led to some generators in Victoria altering their bidding behaviour and submitting negative spot market bids. For example, one directed participant had bid its entire available generating capacity only just short of the minimum price level in the NEM of minus $1,000/MWh.[5]

[4] The grid at that point has several transmission lines in parallel to ensure close coupling between generation and load, and therefore normally does not experience congestion.

[5] However, one participant had bid its capacity at the minimum price level and had been doing so since Jan 28th – preceding the operation of the Administered Price Cap. This was likely in response to the high demand periods in anticipation of high prices.

Box 2 Security and Reliability in the NEM

End users of electricity may lose supply of electricity for either security or reliability reasons. While to the end user the reason for the loss of supply cannot be distinguished, it is important to draw a distinction between security and reliability for the purposes of NEM design and operation.

The AEMC defines a loss or interruption of supply due to security as

action has been taken to ensure that power system equipment is protected from damage or exceeding operating limits that, if left unchecked, may lead to wider interruptions to supply.

Loss or interruption of supply due to reliability is described as

not enough capacity to generate or transport electricity across the networks to meet all consumer demand

Reliability in the NEM must be sufficient to meet credible contingencies (essentially those considered to be reasonably possible), while more serious contingency events are considered to be for security. As a result, a security issue for the NEM is likely to be related to a technical problem, while a reliability issue is often economic in nature. An example of a reliability issue is insufficient supply available to meet peak demand as occurred in Victoria prior to the directions that were issued that are the subject of current consideration.

The NEM has been designed so that the market price cap is reached during periods of supply deficiency resulting from a reliability issue. This helps to ensure, through price signalling, that investment is sufficient to maintain reliability in the NEM. By contrast, under NEM design the market is not required to have sufficient supply to meet non-credible or multiple contingencies. Sufficient investment to address security issues is not required.

As the requirement for an electricity market to have sufficient supply to meet unforeseeable contingencies increases, the cost of power system infrastructure in the market (generation, transmission and distribution assets) will increase.

Data source: AEMC, Comprehensive Reliability Review Final Report, December 2007.

3 Description of service provided

The Rules require a description of the directed services by the independent expert. In this context it should be noted that NEMMCO has already identified that the services are not for energy or market ancillary services.

There are two potential services that may have been provided by the generators in Queensland and Victoria. These services are constrained on energy and reserve.

3.1 Constrained on energy service

The services provided cannot be considered to be an energy service for the purposes of the Rules as they were not procured through market operation. However from the perspective of an energy consumer, the network support service provided is indistinguishable from an energy service procured through market operation, had such an energy service been available.

It can be seen from the description of market events that intra-regional congestion within the NEM led to a breakdown in the normal operation of the market. As a result, an energy service procured through market operation was not available in sufficient quantity to meet demand.

In the NEM, congestion of transmission elements between regions is managed by price mediated rationing of the inter-regional transmission capacity. This occurs because prices are allowed to separate in the regions either side of the congested interconnector. By contrast, within a single NEM zone or region, prices in different points within that zone cannot separate in the event that a transmission element becomes congested. Intra-regional congestion can therefore result in two possible effects on generators that are relevant from the perspective of compensation:

- constrained off, in which case the generator is not able to generate although their offers would have been accepted and they would have been dispatched but for the intra-zonal congestion; and
- constrained on, which occurs when units are compelled to operate in order to minimise disruptions to the market downstream of the intra-regional congestion, even though their offers would not have been accepted and they would not have been dispatched but for the intra-zonal congestion.

The services provided by the generators under consideration in this case were a constrained on energy service.

3.2 Reserve service

For some of the directed generators, units were directed to generate, but at less than their available peak capacity. This additional capacity can be considered to be reserve. As an energy only market however, unused reserve receives no explicit payment in the NEM.

Units that are directed to synchronise but generate less than their peak capacity are also providing a reserve service, in addition to the energy service that is provided by their dispatch into the NEM.

4 Guiding principles under Rules

Clause 3.15.7A provides that the independent expert must take into account:

> other relevant pricing methodologies in Australia and overseas, including but not limited to:
>
> > other electricity markets;
> >
> > other markets in which the relevant service may be utilised; and
> >
> > relevant contractual arrangements which specify a price for the relevant service;
>
> the following principles:
>
> > the disinclination of *Scheduled Generators, Market Generators, Scheduled Network Service Providers* or *Market Customers* to provide the service the subject of the *direction* must be disregarded;
> >
> > the urgency of the need for the service the subject of the *direction* must be disregarded;
> >
> > the *Directed Participant* is to be treated as willing to supply at the market price that would otherwise prevail for the directed services the subject of the *direction* in similar demand and supply conditions; and
> >
> > the fair payment price is the market price for the directed services the subject of the *direction* that would otherwise prevail in similar demand and supply conditions;

Analysis of other markets and contractual arrangements is provided below.

The Rules also require clause 3.15.7A to be read subject to cl 3.15.7(d), which provides

> If at the time *NEMMCO* issues a direction, the *Directed Participant* had submitted a valid *dispatch bid*, *dispatch offer* or *rebid* for *dispatch* of the service that is to be *dispatched* in accordance with the *direction*, the *Directed Participant* is entitled to receive compensation for the provision of that service at a price equal to the *price* in that *dispatch bid*, *dispatch offer* or *rebid* as appropriate.

The above clause is not directly relevant to determining the fair payment price because the services provided by the directed participants have been classified as non market services, specifically "Other Service – Network Support". The clause does however reflect the more general efficiency requirement for electricity markets, that offers for

dispatch should reflect reservation prices for generation. This may be a relevant consideration for compensation.

4.1 NEM design

There are three broad options approaches to location based pricing for competitive electricity markets:

- Uniform pricing
- Nodal pricing
- Zonal pricing

Uniform pricing is a type of electricity market structure in which the same price is used across the whole control region. This type of structure generally leaves the market open to more frequent issues regarding intra-regional congestion and problems associated with such congestion than would be the case if the same market operated under zonal or nodal paradigms.[6]

Prices in a nodal electricity market are set at generator nodes (or busses) according to a security constrained dispatch. In the event of congestion and/or differential marginal losses, prices can separate across each and every node in the market. In effect, market clearing prices are established at every point in the network, such that no network elements are congested.

Australia's NEM is an example of zonal pricing, in which prices are consistent across identified zones of the market as a whole. In Australia, these zones have developed primarily based upon state boundaries. Under the zonal model, prices are allowed to separate between regions.

Intra-regional congestion (as happened in the directions in Queensland and Victoria) can occur in electricity markets that do not have nodal market design. Intra-regional congestion can lead to generators being constrained on, in the event that they are located on the import side of a constraint, or constrained off, in the event that they are located on the export side of a constraint. In each case under consideration in this advice, the directed generators were on the import side of a constraint (located near the major load zone), and were directed to generate in order to ensure that load shedding was minimised.

[6] Although it should be noted that transmission development in such markets -- the initial design of the England and Wales market was an example -- tends to minimise the occurrence and importance of intra-regional congestion.

The NEM does not, in ordinary circumstances and where resources are dispatched up to their offered availability, provide compensation for directed energy generation at levels that are above the prevailing regional reference price at the time that the energy is supplied.

Nor does the NEM pay for the provision of reserve, other than in specified circumstances under the Reliability and Emergency Reserve Trader mechanism.[7] The NEM operates as an energy only market, and no additional payments are provided for reserve or capacity provided by generators. The NEM differs from some of the markets in other jurisdictions considered below.

4.2 Other jurisdictions

The Rules require a consideration of pricing methodologies in electricity markets in other jurisdictions. Prominent examples of approaches to dealing with local congestion are considered in relation to each of these forms of market below. Each form of pricing for an electricity market can be associated with energy only market design (as with Australia's NEM) or with separate markets to procure generation capacity (as in some US markets).

4.2.1 Uniform pricing

Uniform pricing is characterised by the same energy price applying across a whole control region. As a result, congestion pricing through separation of prices across nodes or zones is not a feature of market operation.

Britain

British Electricity Trading and Transmission Arrangements (BETTA) is the electricity market model for England, Wales and Scotland. Electricity is traded through bilateral contracts (OTC and power exchanges are used) ahead of time, with a balancing mechanism operated by Elexon providing changes in the real time market as required.

Under the balancing mechanism, offers to sell energy (increase generation or decrease consumption) and bids to buy energy (decrease generation or increase consumption) are placed by market participants, with the market then managed in accordance with

[7] The RERT operates outside the NEM, allowing NEMMCO to contract capacity reserves when it projects a reserve shortfall. Under RERT reserves may be contracted up to 9 months in advance of the projected reserve inadequacy.

minimising cost based on offers and bids subject to transmission constraints. Prices are based on a volume weighted average of offers and bids.[8]

4.2.2 Nodal pricing

PJM is a nodal pricing market in the United States. Unlike a zonal or uniform system, prices in a nodal electricity market are set separately at generator and load busses (nodes). Prices will vary across nodes in such a way as to ensure that there is no congestion. In effect, prices signal when incremental demand will result in congestion and result in additional generation or reduced load at the appropriate points in the network to ensure that the congestion does not arise.

Nodal pricing can lead more frequently to generators possessing local market power in the event that they are constrained on. In order to mitigate this, PJM has implemented both a low offer cap (relative to the NEM) of $1,000/MWh and capacity markets.[9]

In PJM a capacity market (the Reliability Pricing Model or RPM) is separately run unlike the NEM's energy only design. Capacity markets provide revenue to market participants reflecting capacity scarcity, without introducing the same issues as an energy only market in relation to substantial spot market price increases. RPM incorporates offers from generation, transmission and demand side resources, in order to clear the market based on an administratively determined demand curve for capacity.[10]

PJM is a very different design from the NEM, particularly the operation of both energy and capacity markets, and the use of nodal prices. As a result, the situations that have occurred in the NEM that are considered in this report are unlikely to occur in PJM. At the least, in the event of local congestion, generators set the nodal price, so the generator will receive at least its own offer price. This form of design would also be expected to have led to different bid prices from the negative bids offered to the market by one Victorian generator during the direction (considered in more detail in section 6 below).

[8] http://www.elexon.co.uk/documents/Publications/Publications_-_Information_Sheets/Trading_Arrangements.pdf .

[9] The RPM Market is intended to replace the need for Reliability Must Run contracts that had been used as another mechanism to ensure provision of capacity to the market.

[10] Monitoring Analytics, 2008 State of the Market Report for PJM Volume 1: Introduction, p29.

4.2.3 Zonal pricing

Two alternative approaches using zonal market design to similar situations to that in the NEM have been considered in previous market designs. These are the zonal market structures in Texas and California in the United States prior to their adoption of nodal market design.

ERCOT

The former design of the Texas market operated by the Electric Reliability Council of Texas (ERCOT) in the United States provides an example of alternative approaches to zonal pricing. Under this market design, intra-zonal congestion was managed by ERCOT by using out of merit dispatch, out of merit capacity and reliability must run (RMR) agreements. These alternatives are considered below.

Out of merit energy

Out of merit dispatch either increased or decreased a generator's energy output in order to relieve intra-zonal congestion. OOME Up (out of merit energy up) payments were made to a generator based on the higher of pre-determined OOME Up generator payment (based on unit size, unit type and fuel price) or the balancing energy price. The quantity of energy compensated was based on the difference between scheduled and actual output for the unit. OOME Down (out of merit energy down) payments were made based on the avoided costs of generation. Compensation paid were equal to the balancing energy price minus the avoided costs of generation.[11]

Out of merit capacity

Out of merit capacity (OOMC) payments were made in accordance with a pre-determined method based on unit size, unit type, fuel price, duration of commitment and start-up costs (if incurred). Any available energy offered into the market received the balancing energy price in addition to the OOMC payment.[12]

[11] 2006 State Of The Market Report For The Ercot Wholesale Electricity Markets, ERCOT Independent Market Monitor, August 2007 pp115-116.

[12] 2006 State Of The Market Report For The Ercot Wholesale Electricity Markets, ERCOT Independent Market Monitor, August 2007 p116.

Reliability Must Run

RMR agreements were entered into with generators that would otherwise be mothballed or retired. If called on, a generator with an RMR agreement was paid as provided for under the agreement.[13] Agreements were based on start-up costs, energy costs and a standby fee.[14]

CAISO

Intra-zonal congestion was a feature of the California zonal energy market design in similar physical conditions to those that result in intra-zonal congestion in the NEM. Energy and ancillary services markets were operated in California. Local Resource Adequacy requirements, Reliability Must Run contracts and out of sequence dispatch could all be used to address intra-zonal congestion. Additional capacity payments pursuant to the Reliability Capacity Services Tariff could also be paid.

Out of sequence (OOS) dispatch was coupled with local market power mitigation (LMPM) when it used to address intra-zonal congestion. The LMPM operated automatically in the event that "an energy bid that is priced greater than $50 or 100 percent above the 5-minute interval imbalance Market Clearing Price". When that occurred the "bid price is mitigated to the higher of the 5-minute interval imbalance Market Clearing Price or the Reference Price for that resource." In the event of low prices, the LMPM operated to provide a higher price to OOS dispatched generation. When decremental OOS dispatch occurred, the bid price was replaced with a decremental reference price. The Reference Price is explained below.[15]

> The Reference Price is a resource-specific series of prices corresponding to the various levels of output for that resource and is based on one or more factors that are not tied to current market outcomes. Options for the Reference Price basis include resource specific variable cost, average of historical market bids for the resource in competitive periods over the past 90-days, historical Market Clearing Prices in periods where that resource was dispatched over the past 90 days, or through consultation between the resource scheduler and the independent entity that calculates the Reference Prices.

[13] 2006 State Of The Market Report For The Ercot Wholesale Electricity Markets, ERCOT Independent Market Monitor, August 2007 pxxix.

[14] 2006 State Of The Market Report For The Ercot Wholesale Electricity Markets, ERCOT Independent Market Monitor, August 2007 p116.

[15] Department of Market Monitoring – California ISO, Market Issues and Performance 2007 Annual Report, p2.61.

4.2.4 Summary

International electricity markets have used a combination of approaches to address similar issues to those that have arisen in the NEM. The options identified for compensation based on international approaches include compensation at the generator's bid price, the prevailing market price or as agreed ex ante between the parties in a contractual arrangement. The need to mitigate market power is a common feature of compensation for intra-zonal congestion. Our consideration of alternatives jurisdictions has identified that:

- in the absence of nodal pricing, all markets have mechanisms for compensating constrained on generation;
- the compensation rules recognise generator opportunity cost and this is often linked to generator offers;
- they include market power mitigation measures such as price caps;[16] and
- where constrained on generation is fairly common or predictable, they often establish longer term contractual arrangements for its management.

4.3 Other markets

The generation services provided pursuant to the network support directions could otherwise have been used in the NEM spot market for energy. This energy service was supplanted by the directions that were issued by NEMMCO. Generation capacity that was synchronised in order to comply with the direction could also have been offered into the NEM ancillary services market.

4.4 Contractual provisions

There is a transmission limit for power flows from central Queensland to north Queensland. In order to meet NEM reliability standards, the Regulatory Test has been applied to identify the most efficient method to meet energy demand during peak periods in north Queensland. The application of the Regulatory Test has identified that generators in north Queensland are able to provide network support services to assist in meeting reliability standards at lower cost than transmission augmentation. To

[16] Where there is local market power generators will have incentives to extract rent for that market power through whatever mechanisms the market design allows, whether the market is energy only or has a capacity market, and whether it has zonal, nodal or uniform pricing. Exploitation of market power by generators may have distributional consequences but it is not necessarily inefficient to the extent that it results in investment behaviour that mitigates the local market power, and to the extent that regulation to mitigate that market power is costly.

procure these network support services bilateral contracts between Powerlink and north Queensland generators have been reached.

Compensation based on the terms of these bilateral agreements might form a possible benchmark for a fair payment price compensation pursuant to clause 3.15.7A. However, the terms of generator compensation for network support services provided pursuant to network support contracts are confidential. And furthermore, the arrangements in Queensland deal with relatively frequent intra-zonal congestion likely to occur over a prolonged period of time. They may not, therefore, be appropriate for fair payment price compensation for intra-zonal congestion events that are unlikely and occur during periods in which the transmission system is not intact, such as non-credible contingencies.

Although reserve services are separately contracted when required to meet projected reserve shortfalls, it would be inconsistent with the proposed NEM design to provide compensation for a reserve service provided by scheduled NEM generators. This is because the NEM is designed as an energy only market, and the use of the RERT mechanism is restricted to procuring services that have not (or cannot) be offered to the market in other ways. The contractual basis for paying compensation under RERT is not appropriate for the determination of the fair payment price.

4.5 Principles of payment for constrained on generation

Based on our interpretation of clause 3.15.7A of the Rules and the broader NEM objectives we believe that the following principles are useful to guide the determination of fair payment price compensation payments in the current case:

(i) Compensation for directions issued in the NEM should minimise distortion to market offers or outcomes.

A compensation methodology that leads to incentives for distorted offers from generators would compromise achieving efficient market outcomes from the NEM design.

(ii) Compensation should be consistent with efficient NEM investment.

There is potential for the fair payment price to introduce distortions to investment decisions in the NEM. It would not be consistent with efficient market outcomes to heavily compensate generators who are directed in circumstances that are unlikely to occur. Substantial remuneration received in very rare circumstances is unlikely to affect (or in fact have been considered) in locational investment decisions made in the past or to be made in the future. For example, there is no rationale for fair payment price compensation to provide substantial compensation to generators who are

directed for a constrained on energy service who are located in a strong part of the grid.

(iii) Compensation should deliver certainty for market participants.

There is a clear rationale for following precedent that has developed in previous similar circumstances when determining fair payment price compensation to provide certainty to NEM participants. Precedent should not be followed however if it would lead to excessive distortions in the market.

(iv) Compensation should not facilitate the misuse of market power by market participants.

When NEMMCO is forced to direct generators and has little or no choice over which to direct, then there is clearly a possibility that the generators will possess market power. It is important that the compensation rules for these directions minimise the risk that these generators will be able to profit excessively from the misuse of that market power.

(v) Compensation should be consistent with the opportunity cost of market participants.

Compensation consistent with opportunity cost has the practical implication that the directed participant should be left no worse off following their compliance with the direction. At a minimum, directed participants must be made whole in order for consistency with the fairness required by the fair payment price.

(vi) Compensation should be consistent with the overarching principles of NEM design and operation.

For the purposes of considering constrained on energy, the most important element of NEM design is the energy only, zonal approach that has been developed. Periods of high prices are essential to signal the need for new investment to meet supply as there is no capacity or reserve contracting, other than the limited application of the RERT.

5 Previous approaches

Previous independent experts regarding constrained on generation have considered the appropriate approach to the determination of the fair payment price in the NEM. We consider the approaches of NECG, ROAM Consulting and Harding Katz below.

5.1 NECG

NECG provided the first determination of the fair payment price for constrained on generation in the NEM, finding that[17]

> the fair payment for the constrained on energy service should be set at a level which can be reasonably expected to recover the generator's costs and as such, be set as a default at the average cost of the generator based on the sum of:
>
> - the full recovery of the variable costs in complying with the direction; and
> - the recovery of average fixed costs based on the generator's output in the year preceding the direction.

The formula as applied by NECG is reproduced below.

Figure 8 NECG Compensation Methodology

$$VariableCost + EnergyGenerated(MWh) \times \frac{1000 \times UnitFixedCost(\$/kW/yr) \times MDC(MW)}{AnnualGeneration(MWh/yr)}$$

Data source: NECG.

The following further information was provided.[18]

> MDC (MW) = Registered capacity of the unit (as advised by the Code Participant to NEMMCO). This broadly equates to the name plate rating of the unit in MW.
>
> Variable Cost ($) = The actual and verifiable variable costs incurred in meeting the direction from NEMMCO. This would include those costs currently outlined in 3.15.6B(a3).
>
> EnergyGenerated (MWh) = Defined the same as the current 3.15.7(c) DQ (A).

[17] NECG, NEMMCO – Independent Expert Report for Directions of 11 and 12 December 2002, p41.

[18] NECG, NEMMCO – Independent Expert Report for Directions of 11 and 12 December 2002, pp42-43.

> Unit Fixed Cost ($/kW/yr) = is determined by examining the annualised fixed costs for a new entrant of similar capacity and of the same technology as the unit directed allowing for the depreciation of the directed generator's plant. Fixed costs would be taken to include (but not limited to), capital expenditure, fixed operations and maintenance, market fees, return to shareholders and debt holders, costs associated with securing debt and equity funding, etc).
>
> Annual Generation (MWh/yr) = The expected annual generation of the unit determined by historical activity levels (in the year preceding the direction). For a new generator, the expected annual generation would be determined by NEMMCO (using the annual energy it determines when calculating the forward looking loss factors for new generators).

An annuity approach was preferred for the depreciation of the asset.

5.2 ROAM Consulting

ROAM upheld the approach to compensation developed by NECG. It was concluded after a detailed consideration of compensation options that:[19]

> We have therefore not found any valid reason to depart from the compensation methodology determined by the previous independent expert for directions of 11 and 12 December 2002.

ROAM noted that the NECG methodology may have a tendency to provide for over-recovery of generator fixed costs in the event that a generator has limited running historically. It was noted that this over-compensation would however wash out over time.

5.3 Harding Katz

Harding Katz considered a wide range of compensation methodologies before concluding that the long run average cost methodology developed by NECG was the most appropriate. It was also noted that applying a methodology the same as that previously applied by independent experts provided the following benefits:[20]

[19] ROAM Consulting, Compensation for Directions – South Australia, 21 July 2005, p26.

[20] Harding Katz, *Final Report: Compensation for Directions on 10 January 2007*, p10.

stability: generators – including potential new entrants – have more certainty about how much they may be paid in the future should they be directed for similar services;

robustness: the methodology has been applied by NEMMCO in relation to numerous directions and has produced fair payment prices which – as far as we are aware – are reasonable in the circumstances and consistent with the requirements of the Rules; and

acceptability: interested parties have been able to make submissions to previous independent expert reports and the current methodology reflects these submissions.

Harding Katz identified four aspects of the developed methodology that could be altered:[21]

the determination of variable costs to reflect the costs of a notional new entrant, rather than the actual costs of the directed participant;

the determination of fixed costs to reflect the actual fixed costs of the directed participant, rather than the costs of a notional new entrant;

the period over which the expected output of the directed participant is calculated; and

the depreciation method.

The only change that was made was with regard to the depreciation method, where it was suggested that the fair payment price be independent of the age of the directed generating plant.

[21] Harding Katz, *Final Report: Compensation for Directions on 10 January 2007*, p11.

6 Compensation methodologies

The market events that led to the directions in the Queensland region have occurred previously in the NEM and have been the subject of compensation determined by independent experts. Previous compensation determinations have adopted a long run average cost methodology, and this remains the appropriate approach in Queensland.

The situation in Victoria has some additional complicating factors. The NEM market mechanism appears to have failed in the Victorian region during the directions, in so far as more load was shed than was needed to clear the market, which then resulted in generator offers being rejected that, in the absence of the excessive shedding would have been accepted. The impact of distortions on prices in the NEM during the Victorian directions has been discussed earlier in this report. As a result of the multiple market distortions, the market clearing price that resulted is unlikely to be a sensible, fair or efficient price for the purposes of compensation. As a result, some other method of compensation is preferable.

Unlike in Queensland, more complex market events in Victoria have not resulted in a 'normal' case of constrained on generation for a zonal electricity market, as the constrained on generators have been located in strong grid locations. However in both Queensland and Victoria directions have been issued to constrained on generation to minimise load shedding in the event of network failure.

Participant bids, market price outcomes, and distortions in the Victorian region have necessitated the consideration of alternative compensation approaches in order to identify if long run average cost compensation is appropriate. Three options for compensation have been considered based on the analysis of international approaches and the previous independent expert approaches:

- Generator bids
- The market price cap
- Long run average cost

These compensation options have been assessed against the compensation principles discussed above, namely:

- Compensation for directions issued in the NEM should minimise distortion to efficient market offers or outcomes.
- Compensation should be consistent with efficient NEM investment.

- Compensation should deliver certainty for market participants.
- Compensation should not facilitate the misuse of market power by market participants.
- Compensation should be consistent with the opportunity cost of market participants.
- Compensation should be consistent with the overarching principles of NEM design and operation.

6.1 Generator bids

When the NEM operates efficiently, the bidding profile submitted by generators (the prices at which they offer their generation into the NEM) will reflect their reservation price for providing their generation. It can be assumed that if the generator's bid is consistent with its reservation price, it will prefer not to generate when market prices are below its bid, and will be willing to supply the market with the nominated level of energy at all prices above its bid price. As this situation is consistent with efficient long term operation of the market, the NEM design should encourage to the greatest extent possible generators to bid in the NEM consistent with their reservation prices.

Based on this rationale (and in the absence of a generator misusing market power) the bid submitted by a *directed* generator for NEM dispatch is an efficient price at which to provide them with compensation when they are constrained on. The reservation price for the generator should reflect the underlying opportunity costs of generation at that time if the market is functioning efficiently.

With respect to the generator's bids, it is noted that for one directed participant this would result in negative compensation payments. The practical effect of this approach would be to require one directed generator to pay NEMMCO for its generation during the direction. We have serious doubts that the negative offer price reflected the true opportunity cost of the generator in question, and is more likely to reflect an offer strategy aimed at ensuring ongoing generation in the face of spot prices in the NEM that are sometimes volatile around the level of its true opportunity cost.[22]

While it is superficially tempting to adopt a '*caveat venditor*' approach to discourage bidding that differs dramatically from true opportunity cost in the future — which might (depending upon other factors motivating a bidding strategy over time) be

[22] It may also reflect a high degree of interdependence between the calling regime and the opportunity cost of the generator.

efficient in the long term — we do not consider it an appropriate compensation approach in this instance. It would be at odds with our interpretation of the fair payment price compensation, could only be a sound approach if the NEM were known to be efficient (in the economic sense of always producing an efficient market clearing price), which it manifestly is not in this instance, and would require the independent expert to make specific inferences about generator bidding behaviour that could well be erroneous.

Generator bids as the methodology for compensation would not be consistent with the "fairness" required in the fair payment price compensation in this case.[23] Furthermore, compensation based on generator bids (while not an issue in the case of negative offers) could result in distortion of market outcomes when NEM participants are able to predict when they will be directed and use that information to enable them to misuse market power.

6.2 Market price cap

When load shedding occurs in the NEM it is consistent with the intentions of NEM design that prices in the energy spot market will increase. Over the long-term, price increases provide an incentive for increased investment in generation, and intra-regional congestion can indicate locations in which investment in generation is necessary.

Due to the Administered Price Period, the maximum market price was capped at $300/MWh. During a period of supply shortfall, such as resulted in the case of these directions, it can be argued that a well functioning market under the same exogenous event (supply shortfall) would have moved to higher prices. Indeed, if the market price cap used in periods that are not administered genuinely reflects the economic cost on unexpected lost load, there is a compelling argument that the value of extra power that would alleviate the load shedding is equal to the market price cap.

However, the Administered Price rules are simply part of the NEM design and it is accepted that they and the price caps they implement have been determined to enhance the NEL objective. For this reason, compensation at the $300/MWh level may be justified. If one were to accept this compensation rule, it would lead to the

[23] Clause 3.15.7A(c)(1)(ii) provides a number of principles to inform the fair payment price that are consistent with efficient market operation and pricing. As compensation should be consistent with effective market operation, and market prices that do not cover resource costs of participants are inconsistent with effective market operation, compensation that made the directed participant worse off for complying with the direction is suggested to be inconsistent with the Rules.

conclusion that if the same events took place outside of an Administered Price Period, the appropriate compensation could be considerably higher than this level.

The market price cap may enable compensation of the directed participant to be consistent with what a generator would have received but for the direction as it would reflect the shortage of generation available to meet required customer demand. However the shortage of generation was not for the Victorian region as a whole, but instead only due to the isolation of the majority of Victoria's generation from customer load due to the network failure.

Compensation at the market price cap would also ensure that the directed participant was not left worse off following their compliance *provided that the cap is above the opportunity cost or reservation price of the directed resource*.

Compensation at the market price cap is not an appropriate signal to investment in all situations. The Victorian directions were issued in a part of the grid that would under usual market circumstances or a credible contingency be considered a strong network location. Paying high prices to generators located in such a region based on a very uncommon circumstance could be considered to be overcompensating generators for their good fortune[24] in locating in a strong grid location that has nevertheless experienced a shortfall of supply to customers due to network security. This should be contrasted with areas where the network is weaker. A high electricity price for generators in weaker grid locations during supply shortage is a valuable signal of the need for investment to meet customer demand. This issue of overcompensation can be ameliorated when using the long run average cost method considered below.

6.3 Long run average cost

A long run average cost methodology has been applied previously by independent experts in relation to directions for intra-regional congestion. In particular, in the Queensland region very similar issues with the part of the transmission network that failed during these directions have been previously considered by independent experts and a fair payment price based on LRAC has been adopted.

The importance of applying consistent precedent in relation to independent expert decisions has been noted in independent expert decisions: consistency of precedent in fair payment price compensation may be important to maintaining the fairness of the direction process.[25]

---

[24] In the sense that market participants take no account of the possibility of such events in making their operating or investment decisions.

[25] Harding Katz, *Final Report: Compensation for Directions on 10 January 2007*, p9.

An analysis of alternative approaches to compensation has not revealed inherent difficulties with the application of the LRAC in relation to these events. The use of generator bids would be expected in this case to compromise the fairness required of the fair payment price. Compensation at the market price would ensure that pricing reflected both scarcity of generation within the NEM, and would be expected to cover the costs of complying with the direction for generators. However, the previously developed LRAC methodology also ensures the cost of generators in complying with the direction are recovered.

It has previously been noted that excessive compensation of generators in strong grid locations should be avoided. The LRAC formula may assist in avoiding such an outcome. This is because the LRAC formula incorporates the historic generation of directed participants. Generators that provide supply into the NEM regularly (for example because they are baseload or mid merit generators in a strong grid location) will receive less compensation than generators who only rarely supply into the market (for example peaking plant located near weak grid locations that rely upon supply during a few high priced events to recover their high costs).

During usual market operation it is expected that generator bids in the NEM will reflect their costs of generation. For this reason, compensation based on generator costs is likely to be consistent with the compensation that the generator would have received but for the direction being made. The LRAC methodology would also ensure that generators are not worse off following their compliance with the direction.

Analysis of the market events has not identified any relevant basis on which the market events in Victoria and Queensland can be distinguished. In each case, intra-regional congestion of the transmission network occurred, creating a security issue for the NEM, leading to directions to maximise generation within the affected region to minimise load shedding. The only substantive difference between the two events was that the Victorian directions were issued to generators in strong grid locations.

As a result, it is suggested that using the previously developed approach to calculating the fair payment price, LRAC, is appropriate for the Queensland and Victorian region.

7 Compensation

As noted above, the market circumstances in Victoria had led to a situation of bids by generating units that were not cost reflective, market prices that were negative and did not represent the state of unmet demand in Victoria, and constraints on the movement of market prices that could have contributed to inefficient market outcomes.

Compensation based on generator bids was identified as a mechanism that, absent the misuse of market power, would ensure that in future generator bids were cost reflective. Compensation based on generator bids would be expected to lead to a situation in which market prices during similar circumstances reflected more accurately the costs of generating units supplying the market. We would note however that there was no strong basis on which to distinguish events in Victoria from those in Queensland, as both occurred in circumstances of constrained on generation and that perverse market outcomes would have resulted from compensation using alternatives other than LRAC in the Victorian region. We have preferred the LRAC methodology as it will be the least disadvantageous to long term market outcomes.[26]

Harding Katz, in their independent expert report, suggested that the fair payment price should be independent of the age of the directed generating plant. We have used the NECG approach of annuity depreciation to reflect the age of the generating units. Annuity depreciation will most accurately reflect the economic value of the generator compared to other depreciation alternatives available. In general, annuity depreciation will provide an asset value that would make the owner of the directed generating units indifferent to owning those units or new generating units.

The NECG approach to determining compensation payments was based on actual variable costs of directed participants. Our proposed compensation has been based on variable cost assumptions that are publicly available. If a directed participant believes that the proposed compensation would be insufficient to meet its variable costs of complying with the direction, they may provide verifiable evidence as to the variable

[26] Congestion that has to be alleviated with constrained on generation is not necessarily a market failure, but having to both shed load and shed generation intra-zonally when bid and offer prices may not reflect reservation prices, and have those effects feed through into a zonal price is likely to be. It would, in the longer term, be helpful to the NEM if it did not encourage the significantly negative offers by generators that have resulted in perverse price outcomes in this case. To this end, and noting that it is not our role as independent experts to dictate future directions of NEM reform, an issue that may be worthy of consideration is whether the AEMO could be asked to advise market participants of the benefits of remunerating constrained on generation at its offer price, even if that offer price is below the zonal market clearing price. We note that it is dangerous to consider a single issue relating to bidding in isolation of the other aspects of the bidding behaviour provided in the National Electricity Law and the Rules.

costs that have been incurred in complying with the direction that are at variance to the assumed costs.

Compensation based on the LRAC methodology is provided below.

Table 4 Compensation

Generator	Generation During Direction	Revenue during Direction	Compensation due	Net Compensation
Queensland	1,150 MWh	$36,525.74	$1,146,905.65	$1,110,379.91
Victoria	1,796 MWh	$56,165.32	$423,323.21	$367,157.89
Victoria	3,020 MWh	$96,595.77	$313,601.96	$217,006.19
Total			$1,883,830.82	$1,694,543.98

Source: ROAM Consulting.

A NER Provisions

3.15.7A Payment to Directed Participants for services other than energy and market ancillary services

(a) Subject to clause 3.15.7(d) and clause 3.15.7B, *NEMMCO* must compensate each *Directed Participant* for the provision of services pursuant to a *direction* other than *energy* and *market ancillary services*, at the fair payment price of the services determined in accordance with this clause 3.15.7A.

(b) Subject to clause 3.15.7A(e) and clause 3.15.7A(e1), *NEMMCO* must, in accordance with the *intervention settlement timetable* and any guidelines developed by *NEMMCO* in accordance with the *Rules consultation procedures*, determine if in *NEMMCO's* reasonable opinion, an independent expert could reasonably be expected to determine a fair payment price for the services provided pursuant to the *direction* within a reasonable time period.

(b1) If *NEMMCO* determines pursuant to clause 3.15.7A(b) that an independent expert could reasonably be expected to determine a fair payment price for the services provided pursuant to the *direction* within a reasonable time period it must as soon as reasonably practicable after making such determination *publish* its determination and, subject to clause 3.15.7A(e1), appoint an independent expert, in accordance with the *intervention settlement timetable*, to determine the fair payment price for the services provided pursuant to the *direction*.

(c) *NEMMCO* must include as part of the terms of appointment of an independent expert the following requirements:

(1) that the independent expert must, in determining the fair payment price of the relevant service for the purposes of clause 3.15.7A, take into account:

(i) other relevant pricing methodologies in Australia and overseas, including but not limited to:

(A) other electricity markets;

(B) other markets in which the relevant service may be utilised; and

(C) relevant contractual arrangements which specify a price for the relevant service;

(ii) the following principles:

(A) the disinclination of *Scheduled Generators*, *Semi-Scheduled Generators*, *Market Generators*, *Scheduled Network Service Providers* or *Market Customers* to provide the service the subject of the *direction* must be disregarded;

(B) the urgency of the need for the service the subject of the *direction* must be disregarded;

(C) the *Directed Participant* is to be treated as willing to supply at the market price that would otherwise prevail for the directed services the subject of the *direction* in similar demand and supply conditions; and

(D) the fair payment price is the market price for the directed services the subject of the *direction* that would otherwise prevail in similar demand and supply conditions;

(2) that the independent expert must determine and publish a draft report, in accordance with the intervention settlement timetable, setting out:

(i) a description of the services provided in response to the direction;

(ii) the independent expert's draft determination of each fair payment price for the services provided;

(iii) the methodology and assumptions used by the independent expert in making the draft determination of the fair payment price; and

(iv) a request for submissions from interested parties on the matters set out in the draft report;

(3) that the independent expert must, in accordance with the *intervention settlement timetable*, determine the fair payment price for the services provided, taking into account the submissions received, and must prepare and *publish* a final report setting out:

(i) the description of the services provided in response to the *direction*;

(ii) the independent expert's determination of the fair payment price for the services provided;

(iii) the methodology and assumptions used by the independent expert in making the determination of each fair payment price; and

(iv) summaries of the submissions made by interested parties;

(4) that the independent expert must deliver to *NEMMCO* a final tax invoice for the services rendered at the time he or she *publishes* the final report; and

(5) that a report *published* by the independent expert pursuant to clause 3.15.7A(c) must not disclose *confidential information* or the identity of a *Directed Participant*.

(d) In accordance with the *intervention settlement timetable*, *NEMMCO* must calculate the compensation payable to the Directed Participant using the fair payment price *published* by the independent expert under clause 3.15.7A(c)(3).

(e) The fair payment price determined in accordance with clause 3.15.7A(c)(3) is to be the fair payment price for that service to be applied in all future occurrences where there is a *direction* for that service at any time within a period of 12 calendar months from the date on which the determination of that price was published.

(e1) *NEMMCO* must not appoint an independent expert under clause 3.15.7A(b1) in respect of a *direction* for a service in respect of which:

(1) there is a determination of an independent expert in place in accordance with clause 3.15.7A(e) in relation to that service; or

(2) *NEMMCO* has appointed an independent expert to determine the fair payment price for that service under clause 3.15.7A and the independent expert has not yet made a determination of the fair payment price.

In these circumstances, *NEMMCO* must apply to the subsequent *direction* the fair payment price for that service determined, or to be determined, by the independent expert.

(f) Within 1 *business day* of calculating the compensation payable pursuant to clause 3.15.7A(a) by application of clause 3.15.7A(e) or pursuant to clause 3.15.7A(d), *NEMMCO* must advise the relevant *Directed Participant* in writing of the amount of compensation.

(g) The determination of a fair payment price pursuant to clause 3.15.7A(c)(1) and the calculation of compensation payable to *Directed Participants* pursuant to clause 3.15.7A(d) is final and binding.