DETERMINATION

Application for authorisation

Amendments to the National Electricity Code

Date: 19 October 1998

Authorisation nos:	Commissioners:
A90652	Fels
A90653	Asher
A90654	Lieberman
	Shogren
File no:	Smith
CA98/1	

Contents

Glossary

ACA	Australian Cogeneration Association
BCA/EWG	Business Council of Australia / Energy Working Group
Colin Taylor	C. Taylor & Associates Pty Ltd
EGA	Exempt Generation Agreement
EME	Edison Mission Energy Holdings Pty Ltd
EPD	Energy Projects Division, Victorian Department of Treasury and Finance
IPPA	Independent Power Purchase Agreement
IRH	Inter-Regional Hedge
MW	Megawatt
MWh	Megawatt hour
NECA	National Electricity Code Administrator
NEM	National Electricity Market
NEM1	National Electricity Market Stage 1
NEMMCO	National Electricity Market Management Company Ltd
NRF	National Retailers' Forum
NSP	Network Service Provider
PASA	Projected Assessment of Systems Adequacy
QCA	Queensland Competition Authority
QERU	Queensland Electricity Reform Unit
QNI	Queensland — New South Wales Interconnector
QTSC	Queensland Transmission Supply Company
SAERSU	South Australian Electricity Reform and Sales Unit
SECV	State Electricity Commission of Victoria
SHT	Snowy Hydro Trading Pty Ltd
SMHEA	Snowy Mountains Hydro-Electric Authority
TPA	*Trade Practices Act 1974*
VPX	Victorian Power Exchange

1. Introduction

On 19 February 1998 the Australian Competition and Consumer Commission (the Commission) received applications for authorisation (Nos A90652, A90653 and A90654) of proposed changes to the National Electricity Code (the Code). The applications were submitted under Part VII of the *Trade Practices Act 1974* (the TPA) and, together with a supporting submission, were lodged jointly by the National Electricity Code Administrator (NECA) and the National Electricity Market Management Company Ltd (NEMMCO). Amendments to the applications were received on 28 April and 11 May 1998.

Authorisation under Part VII of the TPA provides immunity from court action for certain types of market arrangements or conduct which would otherwise be in breach of Part IV of the TPA where the Commission concludes that the public benefits of the arrangements or conduct would outweigh the anti-competitive detriments of such arrangements or conduct.

The Commission released a draft determination on 5 August 1998, outlining its analysis and views on the key competition issues. In response to the draft determination a pre-determination conference was requested. The conference was held in Canberra on 27 August 1998. The matters raised by the applicants and interested parties at the conference have informed the Commission's analysis in this final determination.

The Commission has previously considered the existing Code and granted authorisation to it on 10 December 1997[1] to take effect when the Commission was satisfied the conditions of authorisation set out in that determination had been met.

NECA provided the Commission with changes to the Code required to meet those conditions on 30 January 1998 and 28 April 1998. On 30 July 1998 the Commission advised NECA that the changes satisfied the conditions and that authorisation of the existing Code would take effect from that date.

NECA also provided amendments concerning matters arising from the Commission's NEM Access Code draft determination of 22 August 1997. Those amendments were considered by the Commission as part of its final Access Code determination of 16 September 1998.

This introduction briefly describes the National Electricity Market (NEM) arrangements and outlines the Commission's processes and consultation arrangements. The Commission's statutory assessment criteria are documented in section 2. Sections 3 and 4 describe the Commission's assessment of the application for authorisation and section 5 sets out the Commission's determination.

Background information regarding competition policy, the importance of electricity industry reform and the extent of reform in the electricity industry can be found in the Commission's 10 December 1997 determination.

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[1] This and other related documents are available on the Commission's website at http://www.accc.gov.au.

1.1 The National Electricity Market

In a process coordinated through the Council of Australian Governments, the jurisdictions of New South Wales, Victoria, Queensland, South Australia and the Australian Capital Territory have moved to create the NEM in southern and eastern Australia. The NEM will establish a single wholesale market for electricity and an access regime for the transmission and distribution networks in the participating jurisdictions.

The arrangements for the operation of the NEM are set out in the Code. The Code comprises two distinct but inter-related elements:

- the wholesale electricity market arrangements; and
- the arrangements for access to the transmission and distribution systems.

The market arrangements govern the operation of the wholesale spot market and include the establishment of market institutions, system security and reliability requirements, the market rules for bids, offers and dispatch and metering standards.

The access arrangements govern connection to and use of the physical wires infrastructure for transporting electricity. The access and market arrangements also stipulate the technical standards and requirements necessary to preserve system security.

The Code also includes derogations to allow certain jurisdictional based arrangements, which depart from the requirements of the Code, to continue either over a transitional period or indefinitely. Furthermore, State and Territory governments retain responsibility for environmental issues, retail arrangements and more general electricity regulation.

The Code has been endorsed by the participating jurisdictions who have agreed to enact co-operative legislation, the National Electricity Law, to implement the regulatory arrangements that support the effective operation of the Code. This legislation enables the Code to have identical force and effect in the participating jurisdictions at all times.

It is envisaged that the NEM will commence in November 1998. In the interim the operation of the harmonised arrangements in New South Wales, Victoria and the Australian Capital Territory, known as NEM1, are expected to continue. Detail on the NEM1 arrangements can be found in *National Electricity Market 1 Stage 1 — Commission Working Paper, March 1997*.

Queensland and South Australia are in the process of structural and regulatory reform in the lead up to NEM commencement. An interim State market commenced operation in Queensland on 1 October 1997. Those market arrangements are subject to an interim authorisation which was granted by the Commission in September 1997 and will expire when the NEM commences or 31 December 1998, whichever first occurs.

1.2 Public consultations

Under the TPA the Commission has a statutory obligation to follow a public process when assessing an application for authorisation.

The Commission received the initial application for authorisation of the changes to the Code on 19 February 1998. Notification of the application was advertised in *The Australian* and the *Australian Financial Review* on 28 February 1998 and a list of interested parties was contacted by letter on 26 February 1998. Interested parties were asked to make submissions to the Commission regarding their views on the possible issues of public benefit and anti-competitive detriment arising from implementation of the proposed changes.

On 28 April 1998, the applicants submitted amendments to the initial application which contained further Code changes. The Commission notified interested parties and called for further submissions. Overall, 28 interested parties provided submissions (see Appendix A). All submissions have been placed on the Commission's public register. The Commission also undertook discussions with representatives from user groups, generators and retail businesses. A minor variation to the ancillary services derogation was provided to the Commission on 11 May 1998. Further submissions were provided to the Commission after the release of the draft determination (see Appendix B).

To assist the Commission's assessment of the proposed changes to the Code, C. Taylor & Associates Pty Ltd (Colin Taylor) was engaged by the Commission to assess the chapter 8 technical derogations and the technical derogations put forward under chapter 9 of the Code on behalf of Queensland. A copy of the report from Colin Taylor is available at the Commission's website.

The Commission has released this final determination outlining its analysis and views on the proposed changes to the Code according to the statutory assessment criteria set out in section 2. A person dissatisfied with this determination may apply to the Australian Competition Tribunal for its review.

2. Statutory test

In the context of this application, authorisation is granted in order to provide immunity from court action by the Commission or any other party for specified conduct or arrangements that might otherwise contravene s. 45 and/or s. 47 of the TPA.

Section 45 of the TPA prohibits the making of, or giving effect to, contracts, arrangements or understandings containing provisions which:

- have the purpose, effect or likely effect of substantially lessening competition in a market;
- are exclusionary; or
- have the purpose, effect or likely effect of fixing, controlling or maintaining prices.

Section 47 prohibits certain exclusive dealing practices between suppliers and acquirers. Generally this involves either the supply or acquisition of goods or services on terms or conditions that substantially lessen competition or involve third line forcing. Third line forcing involves the supply of goods or services on condition that the purchaser acquire particular goods or services from a third party.

However, if an authorisation is granted under:

- sub-s. 88(1), an action for breach of s. 45 cannot be brought against the parties referred to in the application for authorisation or, if the authorisation so provides, persons who become parties to the contract, arrangement or understanding; or
- sub-s. 88(8), an action for breach of s. 47 cannot be brought against the party who applied for the authorisation or, if the conduct referred to is expressly required or permitted under a contract, arrangement understanding or industry code of practice, any person named or referred to in the application as a party or proposed party to the contract, arrangement, understanding or code of practice.

However, the Commission must not authorise:

- matters which may contravene s. 45 (excluding exclusionary provisions) or s. 47 (excluding third line forcing) unless it is satisfied in all the circumstances that:
  - the provisions or conduct would result (or be likely to result) in a benefit to the public; and
  - that benefit would outweigh the detriment to the public constituted by any lessening of competition that would result (or be likely to result) from the proposed contract, arrangement, understanding or conduct (sub-s. 90(6)); and
- exclusionary provisions which may contravene s. 45 or third line forcing under s. 47 unless it is satisfied in all the circumstances that the proposed provision or conduct would result (or be likely to result) in such a benefit to the public that the proposed contract, arrangement, understanding or conduct should be allowed (sub-s. 90(8)).

In deciding whether it should grant authorisation, the Commission must be satisfied that, in all the circumstances, the proposed conduct or arrangements:

- are likely to result in a benefit to the public which outweighs the potential detriment from any lessening of competition that would result if the proposed conduct or arrangements were made, or engage in; or
- are likely to result in such a benefit to the public that the proposed conduct or arrangements should be allowed to take place or be arrived at,

as the case may be.

The Commission may grant authorisation subject to conditions as a means of ensuring that these tests are met.

3. Amendments relating to market arrangements

The applicants propose a number of changes to the market arrangements contained in the Code. The Commission considers that many of the proposed changes do not raise competition issues and has limited its analysis below to those changes that either raise competition issues or that have been drawn to the Commission's attention by interested parties.

3.1 Bidding and rebidding

The proposed changes adopt bidding and rebidding provisions similar to those that currently apply in the NEM1. The changes:

- allow the bidding and rebidding of certain generator and customer inputs into the spot market dispatch process such as ramp rates of change, fixed loading levels and the daily energy available for energy constrained plant;
- revise off-loading price bidding rules to be consistent with rules for other price bids; and
- require prices for bid and offer price bands to increase for higher load levels.

Issue for the Commission

The Commission must consider whether the efficiency benefits of allowing more extensive bidding and rebidding outweigh the potential for this feature of the market to be used to manipulate spot prices. While such behaviour may not contravene the TPA it has the potential to detract from the public benefit of the market arrangements.

In its 10 December 1997 determination, the Commission authorised the existing rebidding provisions on the condition that NECA monitor the market for any significant variations between forecast and actual spot prices and issue a report regarding the reasons for each such variation.

What the applicants say

The applicants state that the changes will allow participants to more effectively respond to price signals while still being subject to the market surveillance required by the Commission.

What the interested parties say

London Economics has two concerns regarding the bidding and rebidding of ramp rates.

The first is that the ramp rate constraints may lead to inefficient spot market prices. London Economics cited the experience of the Queensland interim market where only a few generators have been able to meet the constraint. In such cases those generators have set the spot prices. London Economics claim that the remaining generators have no incentive to invest in plant which could meet the ramp rates at more efficient prices when they can simply benefit from the higher prices set by the existing unconstrained plant.

The second concern is that the risk of tacit collusion between generators to allow such plant to set inefficient prices will be exacerbated if ramp rates can be bid and rebid.

Issues arising from the draft determination

Rebidding provisions generally

At the pre-determination conference and in subsequent submissions, members of the National Retailers Forum (NRF)[2] reiterated the concern expressed to the Commission prior to its 10 December 1997 determination that permitting rebidding would create the opportunity for generators to manipulate spot market prices in a time frame within which the customer side of the market could not effectively respond.

EnergyAustralia says that, in order to overcome the problem, generators should only be allowed to rebid volumes up in price bands at or below the market spot price up until one and a half hours prior to dispatch.

The NRF members are also concerned that NECA had not yet informed participants how it planned to monitor rebidding behaviour in accordance with the condition of authorisation imposed by the Commission in its 10 December 1997 determination. They submit that the rebidding provisions of the Code should be reviewed one year after market start with specific reference to the effectiveness of the monitoring mechanism and the market value implications of allowing rebidding.

Pacific Power states that the market rules relating to bidding and rebidding need to be kept in place for a substantial period of time in order to provide the certainty required to facilitate investment in plant capacity.

Bidding and rebidding of ramp rates

The Queensland Electricity Reform Unit (QERU) states that Queensland has recently amended its interim State market code to provide that, in situations where generators are ramp rate constrained, the marginal constrained generator sets the pool price and unconstrained generators whose outputs are dispatched at that time are paid their offer price by way of an uplift payment.

Ergon Energy submits that this solution is effective in that it reduces the total amount payable by market customers than would otherwise have been the case.

Hazelwood Power rejects the imposition of restrictions on the rebidding of ramp rates claiming that they provide a key signal to the market regarding the need for further plant capacity.

Commission considerations

Rebidding provisions generally

As pointed out above, the Commission decided in its 10 December 1997 determination that, rather than restricting the operation of the rebidding provisions, its preferred approach was to require NECA to monitor the market to identify the scope of any price manipulation caused by rebidding. The matter could then be addressed using the mechanisms available to participants under the Code.

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2 The relevant retailers were ACTEW Energy, AGL, CitiPower, Eastern Energy, Energex, Energy 21, EnergyAustralia, Great Southern Energy, North Power, PowerCor and United Energy.

The Commission does not propose to revisit this issue at this time. However, the Commission agrees that it is important that market participants are able to be confident that the way in which NECA has planned to undertake the market monitoring will be effective in revealing the scope of any manipulation. In this regard, the Commission has been kept informed of NECA's market monitoring proposal and understands that an outline of those arrangements will be made publicly available by NECA before market commencement.

Bidding and rebidding of ramp rates

The Commission agrees with London Economics that the treatment of ramp rate constraints may undermine the public benefits of the NEM.

However, the Commission notes that London Economics has been able to provide it with evidence of only one instance during the operation of the Queensland interim market where such a constraint affected the market spot price. In addition, any reduction in the public benefits of the NEM is likely to be to a lesser extent than is claimed to have been experienced in Queensland as there will be more generators with differing ramp rates in the NEM. Also, enabling bidding and rebidding in the NEM of ramp rate constraints will allow increased flexibility. The competition aspects of the overall impact will also be moderated to the extent that generators and customers enter into contracts to limit the financial risks of dealing in the spot market.

For these reasons, the Commission is not prepared to endorse the solution implemented by Queensland for its interim state market at this stage. For the NEM, the Commission considers it appropriate to rely on the market monitoring to be performed by NECA to identify the impact of bidding and rebidding ramp rates on spot market outcomes. The mechanisms available to participants under the Code may then be used to address the problem and the Commission notes in this regard that other ways of resolving the ramp rate constraint issue have already been suggested.[3]

3.2 Dispatch software

The applicants propose changes which:

- adopt as a general principle that the software will determine the dispatch outcome consistent with the market rules and that the spot price will be consistent with the dispatch process;
- clarify the definitions of inter- and intra-regional losses and loss factors;
- include ancillary services and ancillary services constraints in the dispatch process to maximise the value of spot market trading;
- allow NEMMCO to relax constraints under an agreed process to resolve situations which would not otherwise be feasible under the dispatch process;
- require scheduled loads to be variable (non-quantised) within price bands; and
- allow the software to treat off-loading prices in a manner consistent with other bids.

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3 See, for example, *Initial Experience in the Queensland Electricity Market: Dispatch/Pricing Processes and Outcomes*, Putnam Hayes & Bartlett — Asia Pacific Ltd.

Issues for the Commission

The first issue is whether ancillary services and related constraints should be included in the dispatch software to maximise the value of spot market trading. Although not a breach of the TPA, the provision of such services on a less than competitive basis may detract from the efficiency benefits of the NEM arrangements.

The second issue relates to how far NEMMCO should be allowed to relax power system constraints in order to resolve otherwise infeasible dispatch situations. Permitting too wide a scope may bestow an artificial market advantage on some participants which, while not necessarily a contravention of the TPA, may detract from the public benefits of the NEM.

A third issue is whether the requirement that scheduled customer loads be non-quantised reduces the efficiency of the spot market and disadvantages customers and advantages generators to the detriment of the public benefit.

What the applicants say

The applicants claim the changes are designed to correct anomalies in the Code which affect certification of the spot market dispatch software as being Code compliant.

The applicants claim the non-quantised scheduled load change is necessary because the linear programming model used by NEMMCO cannot resolve both a customer's quantised demand and price preferences (schedule) in the timeframes required for dispatch. A 'quantised' load is a load which cannot operate when the power being supplied to it is continuously variable.

What the interested parties say

Edison Mission Energy Holdings Pty Ltd (EME) notes that the change introducing ancillary services as a constraint in the dispatch software refers only to those services acquired under contract. Those services may also be provided in response to a direction by NEMMCO or, under the proposed ancillary services derogation submitted by the applicants (discussed at Section 4.1 below), by regulated acquisition. The compensation methods differ for each and EME is concerned that those differences may operate to the detriment of particular generators.

Ecogen Energy says the proposal that scheduled customer loads become non-quantised means that those customers will have to rebid their loads to ensure that their power needs are met. Ecogen Energy claims that the inability of the spot market software to guarantee supply at the required levels, in combination with the constrained nature of demand side rebidding, means that there is no incentive for customers to become scheduled load. Further, a decline in the number of scheduled customers will lead to less accurate forecasting by NEMMCO and therefore greater use of its reserve trading powers.

Issues arising from the draft determination

Members of the NRF and Eastern Energy have concerns regarding the co-optimisation of ancillary services. Eastern Energy states that the proposed co-optimisation runs against the original intention that the wholesale market being an 'energy only' market. Eastern Energy further states that co-optimisation could lead to increases in energy prices, since the market power wielded by ancillary services providers will impact on the costs of those services.

Hazelwood Power, Ergon Energy and QERU support Ecogen Energy's submission that the non-quantisation of scheduled customer loads will lead a large amount of load being classified as unscheduled, rendering that load 'invisible' to the wholesale market and therefore significantly hampering NEMMCO's ability to forecast demand.

Hazelwood Power states that the proposed change disadvantages generators who are required to inform the market of all decisions they take which affect the balance of supply and demand.

The NRF members, QERU and Eastern Energy also state that any changes to the dispatch software should be tested against the principle in the Code that the dispatch process should aim to maximise the value of spot market trading. They submit that a review of the assumptions underlying the software should take place after market commencement as a condition of authorisation of the proposed changes.

Commission considerations

The Commission is aware that NEMMCO is presently reviewing the ancillary services provisions of the Code. The review is due to be completed by 1 March 1999 and the applicants have submitted a derogation designed to cover the procurement of ancillary services during the intervening period. That derogation is discussed at section 4.1 below.

The Commission has concerns regarding the potential market power of some providers of ancillary services but considers that the NEMMCO review should address this issue in considering options for procurement of those services necessary for operation of the NEM.

The Commission therefore considers it appropriate that the amendment proposed by NEMMCO be implemented at market commencement. That is, the value of the spot market trading be maximised taking into account both the costs of energy and ancillary services. However, the proposed amendment must be altered to include all ancillary services irrespective of how they are acquired, be it through contracts, regulated acquisition or direction.

The Commission is satisfied that the changes which provide for the relaxation of power system constraints to resolve otherwise infeasible situations should be authorised. The changes require NEMMCO to develop relaxation procedures in consultation with Code participants and to report to those participants where events requiring the use of such procedures occur. This should ensure that the interests of participants are properly taken into account.

The Commission agrees with participant's concerns regarding the non-quantisation of scheduled customer loads. The Commission considers that load scheduling has the potential to become an important demand side management tool contributing to the efficiency of the NEM and would view seriously any attempt to discourage that potential.

However, the Commission recognises that changing the dispatch model at this stage of development would be likely to incur additional costs and further delay market start. While accepting that this means that NEMMCO's ability to forecast demand may initially be less effective than was originally envisaged, the Commission notes that NEMMCO has an obligation under clause 1.6 of the Code to promote changes to the NEM which improve its efficiency and considers that this includes an obligation to continue to develop the dispatch software to remove constraints on the effectiveness of load scheduling and demand side rebidding.

In particular, under clause 3.8.1(f) of the Code, NEMMCO is required to investigate and report on the scope for further development of the dispatch software within two years of market start. The Commission considers it appropriate that NEMMCO should, as part of that obligation, also assess the sufficiency of the dispatch software in meeting the minimum requirements set out in clause 3.8.1(b).

The Commission also considers that the above, along with the restriction under clause 3.17.1 of the Code that NEMMCO may not alter the dispatch software without first obtaining sanction from NECA or via the Code change approval process, also address participant's concerns that software changes must aim to maximise the value of spot market trading.

Condition of authorisation

C3.1 Clause 3.8.1(b) must be amended to take into account all ancillary services dispatched, irrespective of the manner in which they are acquired.

C3.2 Clause 3.8.1(f) must be amended to require NEMMCO to also assess, consult and report on the sufficiency of the dispatch algorithm in meeting the minimum requirements specified in clause 3.8.1(b) in the same way and time frame required with respect to the investigation referred to in the existing clause.

3.3 Dispute resolution procedures

3.3.1 Definition of Code participant

The applicants propose that clause 8.2.1 be amended such that NECA is **not** included in the definition of Code Participant with respect to the Code's dispute resolution procedures.

Although NECA is bound by the Code, it is not actually defined as a Code Participant. However, in the context of chapter 8, NECA is defined as a Code Participant so that it is subject to the dispute resolution provisions set out in that chapter. This means other participants have an avenue to dispute decisions made by NECA, subject to the same procedures used for other disputes. The proposed change removes NECA from the disputes process on the basis of identified conflicts of interest.

Issue for the Commission

The removal of NECA from the disputes process may result in a detriment to the rights of other participants, a diminution of NECA's accountability and thus a loss in public benefit overall.

What the applicants say

The applicants argue that including NECA in the dispute procedures may undermine its enforcement role by giving participants an avenue to challenge enforcement action taken by NECA. They further state that:

> it is therefore not appropriate that NECA be subject to the dispute resolution procedures as any Code Participant on whom NECA serves notice of Code breach could invoke the dispute resolution procedures in relation to NECA's 'application or interpretation of the Code' (clause 8.2.1(a)(1)) in taking those enforcement steps, thereby subjecting NECA's enforcement role to the dispute resolution procedures.

The applicants also state the Disputes Adviser will not be independent (as the Code requires) if NECA, which appoints the Adviser, is a Code Participant for chapter 8 purposes.

What the interested parties say

Snowy Hydro Trading Pty Ltd (SHT) does not support the removal of NECA from the dispute resolution regime:

> There are many instances when participants could have disputes with NECA, particularly in the areas where NECA approves NEMMCO recommendations or manages reviews itself. These areas can substantially affect participants and the market as a whole. Thus NECA should be subject to the same dispute resolution process as anyone else.

The NRF also expresses concern that NECA would be less accountable for its formal and informal decisions and processes. The NRF points out that NEMMCO will be subject to the Code's breach and dispute provisions and that making NECA subject to the dispute process 'would increase the depth of transparency in NECA Code violation investigations and ensure that is subject to Code procedures and processes'. The NRF is concerned that:

> there is little incentive on NECA to operate efficiently and little recourse if NECA's actions, intentionally or otherwise, cause commercial damage to a participant. By subjecting NECA to the dispute resolution procedure, as a means for Code participants to raise concerns, it may have the desirable effect of influencing the market behaviour of NECA.

Issues arising from the draft determination

No issues were raised in response to this aspect of the Commission's draft determination.

Commission considerations

In its 10 December 1997 determination, the Commission paid particular attention to the operation of the Code dispute resolution procedures at all stages because it considered that such procedures would have a major incentive and corrective effect on the interpretation of the Code and the behaviour of both market participants and Code administrators. Inclusion of NECA in the coverage of the dispute resolution regime was seen as an essential element of the overall framework. As Code administrator, NECA makes many decisions which impact on the rights and obligations of other participants. The Commission is concerned that those decisions which are not reviewable by the National Electricity Tribunal are subject to the scrutiny offered under the dispute arrangements.

However, the applicants point to a number of instances where inclusion of those decisions in the dispute resolution process has the potential to undermine NECA's other functions. The Commission recognises the importance of such concerns and considers that the legitimate exercise by NECA of its functions and obligations should not be thwarted by unintended conflicts with other provisions of the Code.

The Commission is also concerned that removal of NECA from the dispute resolution process is a substantial change relative to the identified problems and will sharply reduce

NECA's accountability to other Code participants. For example, the applicants do not explain how disagreements over non-reviewable decisions made by NECA will be handled if NECA is no longer covered by the dispute process. Similar concerns are emphasised in participants' submissions.

Further, the Commission believes that the potential conflicts of interest identified by the applicants could be remedied by less drastic measures than exempting non-reviewable NECA decisions from the dispute resolution procedures. Other options which could be examined include:

- exempting NECA's exercise of its enforcement function from the dispute process; and
- including NECA's appointment of the Adviser as an exception to the Adviser's independence from NECA.

While exempting NECA's enforcement function from the dispute provisions may not meet the NRF's concerns regarding the accountability and transparency of NECA investigations, it should be noted that the Commission's access determination of 16 September 1998 requires that the Code include suitable procedures based on natural justice to govern NECA enforcement actions. Compliance with these access requirements would be a condition of the Commission authorising any exemption of NECA's enforcement functions from the dispute provisions as an alternative to the present proposal.

Condition of authorisation

C3.3 Clause 8.2.1 must be amended to provide that:

(a) NECA's exercise of its enforcement function and any decision by NECA which is reviewable by the National Electricity Tribunal are exempted from the dispute process; and

(b) NECA's appointment of the Adviser is an exception to the Adviser's independence from NECA.

3.3.2 Dispute resolution adviser

Clause 8.2 imposes specific obligations on the Adviser. The proposed change clarifies that the Adviser can do all things necessary to facilitate the effective resolution of first and second stage disputes.

Issue for the Commission

The issue is whether the benefits flowing from the wider facilitation role of the Adviser are offset by a greater degree of intervention by NECA or the Adviser in the capacity for disputants to manage the resolution process themselves.

What the applicants say

The applicants state the proposed change allows the Adviser to perform a more general facilitation role. This includes the provision of facilities and assistance on appropriate dispute resolution procedures in relation to individual disputes.

What the interested parties say

Members of the NRF express concern that the wording of the proposed change allows NECA 'in its absolute discretion' to determine how the Adviser may be involved in either or both of the first and second stages of the dispute resolution process. The NRF suggests that the wording of the proposed change be amended to limit the automatic involvement of NECA to the second stage of the dispute process:

> Eliminating this wording protects NECA's involvement in Stage Two disputes while preserving for Code Participants the right to solve disputes among themselves, without undue NECA influence and any resultant additional cost burdens.

Issues arising from the draft determination

No issues were raised in response to this aspect of the Commission's draft determination.

Commission considerations

The design of the dispute resolution procedures provides for a first stage of internal dispute resolution (supported by detailed guidelines) which is managed by the disputants themselves. The benefit is that disputants have a mechanism and incentive to resolve disputes by negotiation or mediation prior to moving to more formal processes (the second and third stages).

While the objective of facilitating this initial phase through assistance from the Adviser is a positive one, there is a valid concern that the proposed provision is worded too broadly in terms of NECA's discretion to intervene.

Accordingly, the Commission will only authorise this proposed change if it is amended to limit the facilitation role of the Adviser to Stage 2 disputes and to Stage 1 disputes at the invitation of the disputing parties.

Condition of authorisation

C3.4 Clause 8.2.2(c) must be amended to limit the facilitation role of the Adviser to Stage 2 disputes generally, and to Stage 1 disputes only at the invitation of the disputing parties.

3.3.3 Other dispute resolution changes

The applicants propose further amendments to the disputes procedures such that:

- parties to a dispute can jointly agree to extend the timeframes prescribed under the Code;
- the Dispute Resolution Panel may extend the timeframes under which parties to a dispute must report back to it;
- the costs of a dispute are clearly born by the parties to the dispute; and

- the Chief Executive Officer of NECA may act as Chairman of the Code Change Panel, even where the Code Change Panel is considering a matter referred to it by NECA.

Analysis of these four changes reveals no issues of concern and the Commission has received no comments from interested parties on them. The Commission considers that these changes clarify existing procedures and make them more efficient and flexible in meeting Code objectives.

3.4 Excess generation

The applicants propose changes to clarify the identification of excess generation periods and the calculation of excess generation spot prices.

Issues for the Commission

The Commission must consider whether the proposed changes are consistent with the removal of the floor price one year after market commencement, a condition of authorisation imposed by the Commission in its 10 December 1997 determination. A related issue is whether the changes add to the overall public benefit of the market arrangements by simplifying the treatment of excess generation matters.

What the applicants say

The applicants claim that the existing excess generation Code provisions are inconsistent with the other spot pricing rules, cannot be implemented in the dispatch software algorithm and complicate the settlement process. They state that the changes will produce a pricing outcome consistent with the removal of the floor price one year after market commencement and that the proposed changes are based upon rules for existing State markets which have worked effectively.

What the interested parties say

London Economics claims the wording of the changes makes it difficult for participants to understand exactly how constraints, not only excess generation constraints, will impact upon spot market prices.

Issues arising from the draft determination

QERU points out that a further minor drafting change will be necessary to ensure that the changes operate in the way that is intended.

Commission considerations

The proposed changes simplify and remove anomalies in the existing Code and are consistent with the removal of the floor price within one year of market commencement.

The Commission acknowledges the concern that the changes are likely to make it more difficult for participants to understand how constraints will impact upon spot prices. However, the Code was never intended to explain the spot market process at that level of detail and adding further changes to provide the explanation may be a self-defeating exercise.

NEMMCO is obliged under clause 3.8.13 of the Code to publish the parameters used in the dispatch algorithm to model constraints. In addition, the Commission understands that NEMMCO will arrange for the release of the entire dispatch algorithm to market participants.

The Commission also notes that it has recently received further Code changes from the applicants which they claim will remedy the minor defects pointed out by QERU.

Accordingly, the Commission is satisfied that the proposed changes should be authorised.

3.5 Generator self commitment

The applicants propose a change which removes the requirement that generators advise NEMMCO of their self commitment decisions at least two days in advance.

Issue for the Commission

The issue for the Commission is whether reducing the information burden on generators by removing the self commitment requirement will diminish the overall public benefit of the NEM. The key factor is whether the lack of this information will increase the risk of a threat to power system security.

What the applicants say

NEMMCO states the existing requirement was designed to allow it to assess and manage any excess generation problems that may occur as a result of the commitment decision but that the amended excess generation Code provisions provide the market with a mechanism for managing the problem without having a significant effect on power system security.

Issues arising from the draft determination

No issues were raised in response to this aspect of the Commission's draft determination.

Commission considerations

The proposed change reduces the information burden on generators but may lead to a small increase in the risk of excess generation occurring and, consequently, of a threat to power system security during such periods. However, the Commission is satisfied that the Code contains mechanisms to resolve periods of excess generation adequately and that, despite the possible increase in risk, the market intervention powers provided to NEMMCO are sufficient to protect system security.

3.6 Management of power system security and supply reliability

The applicants propose a number of changes in respect of power system security and supply reliability. The changes are intended to:

- clarify NEMMCO's powers and obligations in respect of power system security and supply reliability;
- specify that the term 'direction' is used when referring to power system security concerns, provide clear guidelines on the use of such directions and specify that the power is to be used as a last resort;

- specify that the term 'intervention' is used when referring to reserve trading and establish that reserve trading and 'what-if' pricing[4] are means for maintaining supply reliability;

- limit reserve trading to short and medium term reserve, as contingency and reactive reserve are provided under ancillary services; and

- remove what-if pricing and generator compensation in relation to power system security directions given by NEMMCO.

Issue for the Commission

The issue is whether the increase in the certainty and clarity of the NEM arrangements may be offset by any restriction in competitive conduct, place unnecessary burdens on market participants or deter entry into the NEM.

The Commission expressed concern in its 10 December 1997 determination that NEMMCO's powers to conduct reserve trading and to direct market participants may substantially lessen competition. Authorisation was granted on condition that NEMMCO's reserve trader powers cease on 30 June 2000, that a review be conducted into whether such powers would be appropriate beyond that date and that the use of the powers of direction be subject to regular review.

What the applicants say

The applicants claim the changes enhance the public benefits of the NEM by providing greater operational certainty, particularly during the initial phase of the market.

The applicants state the removal of what-if pricing in relation to power system security directions is desirable as what-if pricing will mute market signals indicating a supply shortfall. NEMMCO notes that this leaves a hole in terms of protecting the revenue of generators directed into the market in order to resolve the problem since the spot price is unlikely to be as high as the generator's offer price. However, NEMMCO does not consider that the matter needs to be resolved before market start. The applicants also wish to ensure that generators do not have an incentive to induce security problems in order to obtain compensation.

What the interested parties say

Ecogen Energy claims that the removal of what-if pricing will disadvantage generators directed by NEMMCO to the advantage of other participants. It also argues that some form of intervention pricing should be included in the Code.

Issues arising from the draft determination

The Commission imposed the following condition in its draft determination:

C3.4 No later than 1 July 1999 the Code must be amended such that:

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4 'what-if' pricing refers to an estimate of the spot price that would have occurred in the absence of the intervention taken by NEMMCO in response to the market incident.

(a) **any generator, apart from a generator reasonably held by NEMMCO to have intentionally or recklessly induced the security situation leading to the direction, which is directed in accordance with clause 4.8.10(a) of the Code at any time after market commencement is adequately compensated; and**

(b) **if NEMMCO fails to reasonably resolve the meaning of the term 'adequately' by the time of the amendment, that term shall mean the fair market value of the service provided by the generator in response to that direction.**

Ergon Energy states that the failure by the Commission to specify a compensation methodology leaves open the possibility that the method eventually settled upon will reward the monopolistic nature of the services provided by generators to the disadvantage of other market participants. It proposes that the condition be altered to mandate a cost or cost plus fixed margin methodology. QERU suggests that a competition test be included to limit the ability of generators to extract price premiums from the market.

Ecogen Energy claims that the reference in the draft condition to a default 'fair market value' basis is appropriate provided that an arbitration process for resolving disputes relating to the interpretation of those words in specific instances is also included.

Hazelwood Power supports the restoration of 'what-if' pricing in relation to power system security directions.

Ecogen Energy states that there are a number of instances under the Code where compensation is to be paid to directed participants (for example, ancillary services and reliability directions) but that the methods for assessing compensation varied. It claims that this lack of consistency reduces market transparency and also allows NEMMCO to characterise a direction given as one in respect of which the least amount of compensation will be payable.

Ecogen Energy also notes that the applicants have proposed a change to the Code that NEMMCO be required to restore the power system to a secure operating state within a maximum of thirty minutes following either a contingency event or a substantial change in power system conditions. Ecogen Energy argues that the change is inappropriate because it will discourage the development of responses to such events which have a smaller impact on participants than the enforcement of a thirty minute restriction. It argues that the limit should be included in procedural documentation instead.

EnergyAustralia says that a list of prohibited generator activities would help minimise the risk that generators will induce power system security problem in order to obtain compensation.

Commission considerations

The Commission agrees with participant's concerns that the issue of generator compensation when directed in relation to power system security should be resolved.

The Commission also agrees *in principle* that the transparency of the market arrangements would be improved, and the risk of disadvantage to particular generators reduced, if there was broad consistency between the methods of compensation provided in relation to the different types of directions which NEMMCO is entitled to give under the Code. However, this is not to say that different methods are not justified under different circumstances and the Commission is not prepared to conclude that the compensation methods must be uniform.

The Commission considers that the appropriate compensation methodology in respect of power system security directions is best developed by NEMMCO in consultation with market participants. In doing so, NEMMCO:

- should recognise that a balance needs to be struck between increasing market efficiency by ensuring that customers do not pay generators monopoly rents and ensuring that proper incentives are provided to maintain sufficient generation capacity where system security is threatened; and

- must explicitly consider whether the methods of compensation provided under other provisions of the Code would be suitable.

While noting energyAustralia's suggestion that specifying a list of prohibited generator actions would reduce the risk that a generator may intentionally or recklessly induce a power system security problem, the Commission is concerned that this may also unduly restrict *bona fide* generator activities. The Commission considers instead that the matter is better addressed on a case by case basis.

The Commission also notes Ecogen Energy's submission that it would encourage the development of more efficient responses if the time period during which NEMMCO must take steps to restore the power system to a secure operating state was included in procedural documentation rather than making it a Code requirement. However, the Commission is satisfied that including the limit in the Code:

- has the advantage of providing a clear signal to participants regarding the point in time when NEMMCO may be prepared to taking action to shed load; and

- will not present enough of a hurdle to participants that it will prevent them from advocating more efficient solutions by way of a Code change proposal.

The remaining changes clarify the powers, and use of those powers, available to NEMMCO to manage power system security and ensure supply reliability. The Commission is satisfied that the changes provide greater certainty to market participants without adding significantly to the burden imposed on them and that the changes should be authorised.

Condition of authorisation

C3.5 The Code must be amended such that:

(a) any generator, apart from a generator reasonably held by NEMMCO to have intentionally or recklessly induced the security situation leading to the direction, which is directed in accordance with clause 4.8.10(a) of the Code at any time after market commencement is adequately compensated; and

(b) no later than 1 July 1999, NEMMCO must:

(i) **determine the methodology for assessing adequate compensation in accordance with Code consultation procedures;**

(ii) **compare and contrast the methodologies for compensating generators in respect of directions given under clauses 3.11.2(c), 4.5.2(b), 4.8.6(c) and Schedule 9G5.8(a) of the Code and publish the results in order to facilitate the consultation process; and**

(iii) **publish the rationale underlying its determination of the compensation methodology.**

3.7 Market audit

Under the Code NEMMCO is required to conduct an annual audit of, as a minimum, the following five features of the market:

- the metering and settlements systems;
- the billing and information systems;
- the scheduling and dispatch processes;
- the processes for software management; and
- NEMMCO's procedures and its compliance with the Code.

The applicants propose changes to clarify the audit requirements of the Code.

Issues for the Commission

The issue is whether the adoption of the proposed review audit standard will reduce market transparency and the confidence participants have in the integrity of NEMMCO's procedures. A further issue is whether any such reduction is outweighed by the benefit of lower audit costs.

What the applicants say

The applicants state that the existing provisions use the terms 'audit', 'auditing' and 'review' in a way that is inconsistent with Australian Auditing Standard AU106. The applicants propose that NEMMCO adopt, as a minimum, a moderate level of assurance as defined in that standard (a 'review audit').

The applicants claim that the proposed changes will benefit market participants by providing an appropriate level of audit at a reasonable cost and that adopting the higher level of assurance described in AU106 (a 'positive audit') would result in an eight-fold increase in audit costs.

Further, the applicants state positive audits are unnecessary as any system faults would be inherently visible and because participants will monitor much of the information themselves.

Problems that are identified may be adequately dealt with under the procedures available to participants under the Code.

What the interested parties say

Ergon Energy claims that three of the prescribed features (the metering and settlements systems, the billing and information systems and NEMMCO's procedures and compliance with the Code) are critical features of the market and that positive audits are necessary to ensure the confidence of market participants. This claim is supported by other NRF members.

Issues arising from the draft determination

The Commission imposed the following condition in its draft authorisation:

C3.5 The Code must be amended such that the work required to be performed by the market auditors referred to in clause 3.13.10 of the Code is:

(a) with respect to the matters set out in sub-paragraphs (3), (4) and (5) of that clause, to carry out reviews in the sense in which that term is defined in the Code; and

(b) with respect to the matters set out in sub-paragraphs (1) and (2) of that clause:

(i) to carry out audits, in the sense of providing a high level of assurance as set out in Australian Auditing Standard AUS106, during the first three years after market commencement; and

(ii) thereafter to carry out reviews.

NEMMCO submits that conducting audits of the identified features of the market at different levels will be impractical as the positive audit of one system will necessitate auditing other identified systems at the same level. It claims that positive audits will result in significantly higher costs, not only to NEMMCO, but also to metering data agents and possibly transmission network service providers and concludes that the benefits of positive audits will be outweighed by the large increase in costs to market participants.

NEMMCO submits that the applicants' original proposal should be authorised on the condition that, prior to market start, NEMMCO provide market participants with a proper understanding of the scope of and security provided by review audits and that there be a review of the effectiveness of conducting audits of the identified features at the review level one year after market start.

QERU says that, in order to be independent, the auditor should be appointed by and report to NECA, not NEMMCO. It also submits that the metering and settlements systems and billing and information systems be audited at the positive level for the first few years of market operations.

EnergyAustralia says that, for transparency reasons, audits of the schedule and dispatch process should be conducted at the positive level for at least three years but that the remaining identified features of the market could be audited at the review level without causing an unreasonable risk to market participants.

Commission considerations

The Commission is not convinced that a positive assurance level is necessary in the auditing of NEMMCO's performance or the scheduling and dispatch process as any problems in relation to these market features are likely to be identified by individual participants and adequately resolved through the Code's consultation and (if necessary) dispute resolution procedures.

However, the Commission considers that a higher level of confidence than that originally proposed by the applicants in the operation of the metering and settlements systems and the billing and information systems will be important in ensuring the accuracy of market signals and minimising the risks borne by market participants.

Accordingly, while the Commission accepts that the review level of audit is generally appropriate, it considers that additional tests of the metering and settlements systems and billing and information systems should be performed as part of the audits to be conducted and the results of those tests included in the opinions which the market auditor provides to NEMMCO.

The Commission notes that NEMMCO has already held a forum involving members of the NRF to discuss the need for those additional tests. It also agrees with NEMMCO's proposal that the effectiveness of the proposed changes should be reviewed after an appropriate period of time has elapsed after market commencement.

The Commission is satisfied that this approach will ensure an appropriate level of confidence in the features required to be audited while reducing the cost burden on market participants and alleviating concerns that the audit costs may act as a barrier to potential entrants.

Finally, the Commission is satisfied that the requirement under the Code that the market auditor must be an independent person, in combination with the fact that market participants will themselves conduct some monitoring of the identified features renders QERU's suggestion that the market auditor must be appointed by and report to NECA, and not NEMMCO, unnecessary.

Condition of authorisation

C3.6 The Code must be amended such that NEMMCO must:

(a) no later than two months after market start:

(i) provide market participants with a copy of the audit plan to be followed by the market auditor;

(ii) in accordance with the Code consultation procedures, determine the number and scope of additional tests of the metering and settlements systems and billing and information systems necessary to provide market participants with, in the context of a review audit level, a reasonable level of confidence in the operation of those systems; and

(iii) require the market auditor to perform those additional tests and include consideration of the test results in the opinion which it provides as part of its reports to NEMMCO; and

(b) no later than fifteen months after market start, conduct in accordance with the Code consultation procedures a review of the effectiveness of market audits conducted under clause 3.13.10 of the Code and publish that report.

3.8 Market information

Proposed changes to the spot market information provisions of the Code include daily forecasts of inter-regional loss factors and excess generation prices for the following trading day and providing generating unit and customer ramp rate information relating to the previous day's trading. The existing requirement of providing forecasts of power system loads within set confidence levels as part of the daily pre-dispatch schedules will be removed.

Issue for the Commission

The public benefit of the existing information requirements will be strengthened if the changes enhance system security or provide more accurate market data. The benefit will be weakened if the collection and provision of the information imposes unreasonable burdens upon market participants or allows them greater scope for anti-competitive conduct.

What the applicants say

The applicants state that the usefulness of the power system load confidence levels declines rapidly as dispatch time approaches due to the impact of exogenous variables such as the weather. Accordingly, the confidence levels will remain in the short-term projected assessment of systems adequacy (PASA) but will be removed from the pre-dispatch schedule. Any concerns arising from this will be addressed by NEMMCO publishing the appropriate number of price sensitivity forecasts as part of the pre-dispatch schedules.

What the interested parties say

The Snowy Mountains Hydro-Electric Authority (SMHEA), NRG Australia and EME object to the removal of the confidence levels from the pre-dispatch schedule. They claim the levels are important because they determine the value of the price sensitivity forecasts provided by NEMMCO.

Issues arising from the draft determination

No issues were raised in response to this aspect of the Commission's draft determination.

Commission considerations

The Commission understands generators' concerns regarding the provision of adequate information to enable participation in the market. However, it accepts NEMMCO's argument that the value of the information lost by removing the confidence levels from the pre-dispatch schedule will be met by publishing the appropriate number of price sensitivities in that schedule. The Commission notes that NEMMCO has consulted market participants regarding the number of sensitivities to be provided.

Further, the Commission expects that any problems arising from the removal of the forecasts or from the provision of inadequate price sensitivity information will be addressed by NECA as part of the review of information provisions which it is required under clause 3.13.9 of the Code to carry out within one year of market commencement.

The remaining changes are required as a consequence of the other changes submitted by the applicants. The Commission is satisfied that they add to the functionality of the spot market while involving only a relatively small increase in the volume of information required to be collected from market participants.

3.9 Settlements timetable

The Code prescribes the times for payment of settlement amounts. The applicants propose changes so that the relevant times are set out in the market timetable instead of the Code.

Issue for the Commission

The issue in assessing the effect on the overall benefits and detriments of the arrangements is whether the changes adequately provide for the setting up and amendment of the timetable so that it continues to properly reflect conditions which impact upon the market in relation to the settlements process.

What the applicants say

The applicants claim that the changes will increase the flexibility of the market to accommodate externally imposed time factors such as daylight saving or bank trading hours, and that the inclusion of settlement times in the timetable will remove the need to apply to the Commission for authorisation of such changes in the future.

What the interested parties say

Ergon Energy submits that there should be some guarantee that the timetable will be developed by NEMMCO in co-operation with market participants.

Issues arising from the draft determination

QERU argues that the timetable should make adequate provision to enable retailers to undertake the final banking functions that have to be done on the final settlement date and that it account for time zone differences in the participating jurisdictions.

Commission considerations

The changes will benefit market participants by increasing the flexibility of the settlements process and removing the need to submit further revisions to the Commission to account for external changes. Further, clause 3.4.3 of the Code provides that the drawing up and amendment of the timetable are subject to the Code's consultation procedures. The Commission is satisfied that this will provide adequate protection that the timetable will properly reflect any changes or differences which impact on the market.

3.10 Validity of certain actions prior to market start

The applicants propose to amend the Code so that actions taken by NECA, NEMMCO and other bodies constituted under the Code prior to market start are deemed to be valid at market start to the extent that the actions are consistent with the obligations imposed on those bodies by the Code.

Issue for the Commission

The issue is the accountability of those bodies for taking action to ensure that participants are not disadvantaged to the detriment of the public benefit of the NEM arrangements.

What the applicants say

The applicants state that the change is necessary to ensure the validity of actions taken for Code purposes before the Code itself comes into force.

Issues arising from the draft determination

No issues were raised in response to this aspect of the Commission's draft determination.

Commission considerations

The Commission's concern is to ensure that Code participants are, where appropriate, able to seek review of such actions (or improper failures to take action) under the same processes that would be available had the action been taken after market start.

Condition of authorisation

C3.7 The Code must be amended to provide that any action (including a failure to take action) taken by NECA, NEMMCO or any Code body in the context of paragraph (a) of clause 1.13 which, had that action been after the Code commencement date would have been a reviewable decision, is also a reviewable decision in the manner in which that term is defined in the Code.

3.11 Intending participants

The applicants propose to amend the wording of the revised clause 2.7 regarding the registration of intending participants.

Issue for the Commission

The Commission is concerned that the wording of the proposed amendments may undermine the intention behind them that intending participants have the benefits associated with being subject to the provisions of the Code.

What the applicants say

The applicants state the amendment is meant to ensure that intending participants are covered by the Code prior to registration in a particular category, especially with regard to the access and disputes provisions of the Code.

Issues arising from the draft determination

No issues were raised in response to this aspect of the Commission's draft determination.

Commission considerations

The Commission agrees with the intention of this clause, that is, to ensure that intending participants are covered by the Code prior to registration in a particular category, especially with regard to the Code's access and dispute mechanisms.

However, the wording in clause 2.7 (a) requires that any intending participant must satisfy NEMMCO that 'it has entered into binding commitments to commence an activity such that it would be entitled to be registered as a Code Participant'. The term 'binding commitments' is not defined and the Commission is concerned that this may preclude intending participants from initial registration under the Code and therefore from the rights and obligations outlined in clause 2.7 (d). This has the potential of undermining the benefit of registration as an intending participant if it entails that, until binding commitments of some kind are executed, such participants are not able to rely on the access or dispute procedures to protect their interests.

For example, the access procedures in chapter 5 involve a range of negotiated interactions and requirements prior to the completion of a connection agreement. Given the potential for disagreement in following these procedures, the Commission considers that access applicants need to be covered by the Code's dispute provisions from the outset to resolve such problems, should they arise. However, if these preliminary procedures do not qualify as 'binding commitments', then this coverage might not be possible under the present wording of clause 2.7.

Accordingly, the Commission requires that the reference to 'binding commitments' be removed from clause 2.7 (a).

Condition of authorisation

C3.8 Clause 2.7 must be amended as follows:

> **Any person intending to act in any Code Participant category may register with NEMMCO as an Intending Participant if that person can satisfy NEMMCO that it would be entitled to be registered as a Code Participant.**

4. Transitional matters

4.1 Ancillary services

Ancillary services are services that are essential to the management of power system security, facilitate orderly trading in electricity and ensure electricity supplies are of an acceptable quality. Schedule 9G sets out the ancillary service provisions that are to apply in the NEM until 1 July 1999. Schedule 9G will over-ride the provisions of clause 3.11 of the Code, with the exception of clause 3.11.1(c), which states that NEMMCO must:

> investigate, consult with Code participants in accordance with the Code consultation procedures and report to NECA by 1 March 1999 on the possible development of market based arrangements for the provision of ancillary services, including a short term market in which Market Participants which are not parties to ancillary services agreements may submit offers for the provision of regulating capability or contingency capacity reserve.

The arrangements in Schedule 9G are based on the arrangements currently in place in the NEM1[5] markets and provide for a three stage acquisition of ancillary services:

- competitive tender;
- regulated acquisition; and
- direction.

These arrangements do not impact upon the provision of ancillary services as specified in connection agreements under chapter 5 of the Code.

The derogation specifies that the tenders offered in response to an invitation to tender jointly issued by NEMMCO, Victorian Power Exchange (VPX), the New South Wales Electricity Transmission Authority (TransGrid) and the Electricity Trust of South Australia Transmission Corporation, is to be taken as a call for offers as contemplated under this derogation. The derogation also sets out the compensation, disputes and settlements arrangements.

The derogation will only apply from Code commencement until 1 July 1999.

Issue for the Commission

The Commission noted in its 10 December 1997 determination that the central purchasing of ancillary services may breach some elements of Part IV of the TPA. However, the Commission also recognised that possible market failures may occur in the provision of ancillary services unless NEMMCO has an active role and agreed that there was substantial

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5 The Commission has been advised that the only substantial differences between the NEM1 arrangements and the proposed NEM arrangements are in respect of:
(a) the dispute procedures for regulated acquisition (NEM1 uses an independent expert, NEM uses the chapter 8 provisions of the Code);
(b) the arrangements for payment of compensation for constraints for ancillary services acquired through regulated acquisition; and
(c) the compensation arrangements for generators providing ancillary services under direction.

public benefit arising from the provision of adequate ancillary services to the market at all times.

The proposal set out in Schedule 9G introduces a greater degree of market provision of ancillary services. However, the arrangements may still represent exclusive dealing in contravention of the TPA as participants trade in the NEM on condition that NEMMCO will only acquire ancillary services from market participants.

What the applicants say

In the NEM1 submissions the applicants (which include NEMMCO) state that the provision of ancillary services is vital to the security of the electricity system and the success of the spot market in matching demand and supply. The applicants also state that the proposed arrangements are consistent with the principles outlined in the existing Code. Further, the applicants consider that the competitive tendering process will bring the benefits of competition to the purchasing of ancillary services, while centralised purchasing will offset the likely free rider effects and ensure that a sufficient quantity is supplied.

The applicants state that the proposed arrangements offer public benefits through the introduction of competitive tendering, coupled with the ability of NEMMCO to request that ancillary services be provided where the competitive tendering process has failed, ensuring the security of the electricity system.

The applicants also state that, where practical and efficient, it is desirable to develop a sub market for the provision of ancillary services. However, due to the public good characteristics of ancillary services and uncompetitive supply in some cases, an unregulated market will not be efficient and intervention through regulated acquisition or direction will offer efficiency gains. The applicants also note that it is desirable that those who benefit most from the provision of ancillary services should pay for such services.

The NEM1 submission states that these issues will be addressed in the review of ancillary services to be undertaken by NEMMCO. This review must be completed and recommendations made to NECA prior to 1 March 1999. Notwithstanding the outcome of the review, the proposed arrangements specified in Schedule 9G to the Code will lapse on 1 July 1999.

What the interested parties say

The Commission received a number of submissions regarding the proposed arrangements in the context of the NEM1 markets.[6] There are two broad concerns that arise. Firstly, market customers are concerned about the imposition of fees for ancillary services solely upon market customers. This concern arises from the expected increase in fees over current levels in the NEM1 markets, the limited ability of electricity retailers to pass on the fees to end use consumers and the equity implications of only levying one side of the market for services that benefit all participants.

Secondly, some likely suppliers of ancillary services (generators) have concerns regarding the regulated acquisition process. EME states that the regulated acquisition process is unnecessarily coercive and the time allowed to respond to a request from NEMMCO is

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6 Submissions were received from Eastern Energy, EME, Ergon Energy, Citipower, AGL and Integral Energy.

insufficient. EME suggests that the disputes process will therefore generally be invoked. Further EME argues that regulated acquisition is unnecessary, as NEMMCO has the ability to direct participants to provide ancillary services, and that power is sufficient to ensure good faith negotiations on the part of the providers.

EME also raises the issue of compensation for ancillary services, stating that the original intentions of the NEM1 Working Group were that providers would be indifferent between receiving income from ancillary services or the energy market. EME claims the current arrangements set out three different compensation provisions, depending on the method of acquiring ancillary services and notes the consequence that providers will prefer to be directed or contracted under regulatory acquisition rather than through the competitive tender arrangements.

Issues arising from the draft determination

In the draft determination the Commission outlined its concerns regarding ancillary services but stated that it considered it appropriate for the NEMMCO review to resolve outstanding issues.

Submissions from EnergyAustralia, the NRF and Eastern Energy state that, although they support the NEMMCO review, the current arrangements are flawed. In particular, the NRF and Eastern Energy express concern regarding the incremental approach to changes and the impact this has had on mandatory services. Eastern Energy provided details of the impact Code changes have had in respect of governor system, dead band and governor response time requirements. Eastern Energy claims the combined effect of these proposed changes will not only be to force the market to pay for services that were previously mandated but will also limit the number of providers, on technical grounds, thus creating a niche market and market power to providers.

Eastern Energy also raises concerns about the cost impact of the co-optimisation of ancillary services as it expects increases in ancillary services costs will flow through to the energy market.

The NRF considers that any changes to the Code that may impact upon ancillary services, including changes to network connection requirements, should be subject to the ancillary services review. NEMMCO addressed this concern at the pre-determination conference stating that it understood that the ancillary services review would consider all relevant aspects of the Code.

The South Australian Electricity Reform and Sales Unit (SAERSU) raises concerns about the competitive sourcing of ancillary services, stating that the natural monopoly element will remain inherent in the provision of certain services, limiting the scope for competitive provision of these services. It states that it is important that the regulatory regime include appropriate incentives regarding existing and new investment in relation to such services. Further, SAERSU notes that an ongoing regulatory arrangement may be required to limit the scope for abuse of market power and ensure the competitive energy market can function efficiently.

Commission considerations

As discussed in its 10 December 1997 determination, the Commission recognises the importance of ancillary services to the market and supports the implementation of market based arrangements for the procurement of ancillary services where feasible. The Commission views the proposed three stage acquisition process as a step towards market based arrangements.

Invitation to tender

The Commission considers the tender process to have the potential to provide market based outcomes for the provision of those ancillary services which can be competitively sourced. However, such a process relies on both NEMMCO and the service providers negotiating in 'good faith'. Without this key step the arrangements are likely to be ineffective. Concerns raised with the Commission regarding NEMMCO's relative bargaining strength reflect some dissatisfaction with the negotiation process. In this market NEMMCO acts as the sole buyer of ancillary services, resulting in significant bargaining strength.

However, the main focus of activities of ancillary service providers is not ancillary services — it is, rather, the production of electricity and for many ancillary service providers that will enable them to refuse to enter into ancillary service contracts with little detriment. In fact, the detriment they face is the risk of being directed to provide ancillary services but the provisions in Schedule 9G allow for compensation to be paid where directions are issued. This factor goes some way to mitigating NEMMCO's ability to exercise its power of acquisition without regard to the financial impact on ancillary service providers.

In noting these issues, the Commission does have some concerns if the invitation to tender process were to be effectively undermined by the absence of good faith negotiations by any parties to the process. The outcome of the current tendering process may provide a good indicator of the likely effectiveness of any arrangements put forward as the result of the NEMMCO review of ancillary services.

Regulated acquisition

While competitive market based provision of ancillary services is desirable, the Commission recognises that it may not be achievable due to the nature of some of the services required. That is, a competitive market may not be viable, especially where the ancillary services are location specific or where only one potential provider exists. In such instances the competitive tendering process may not yield acceptable price or quantity outcomes to NEMMCO and the regulated acquisition arrangement provides an option which may replicate market outcomes prior to NEMMCO having to take the step of issuing directions. Thus, while noting EME's comments, the Commission considers the regulatory acquisition process preferable to direction, in that it provides scope for a negotiated outcome between NEMMCO and ancillary service providers.

However, it must be considered that in the regulated acquisition process both parties, NEMMCO and the service provider, are likely to be in a position of some market power - NEMMCO is the only buyer and the service provider may be the only market participant capable of offering the required service. Negotiations in good faith may not achieve the desired result and this is recognised by specifying that the dispute resolution provisions of clause 8.2.5 of the Code shall apply.

The Commission considers that the dispute resolution provisions provide an adequate basis for resolving any negotiating difficulties which may be experienced in establishing ancillary services contracts.

The Commission is concerned if EME's comments in regard to compensation provide a true indication of the likely outcome of the whole ancillary service procurement process. That is, ancillary service providers may opt to be dispatched under direction or through regulated acquisition contracts in preference to contracts stemming from the competitive tender process. Such an outcome will undermine the expected benefits from competitive sourcing of ancillary services.

The Commission also notes the view expressed by SAERSU regarding the natural monopoly characteristics of some ancillary services and the possible incentive effects of any regulated acquisition process on future investments. It is important that the compensation mechanisms chosen provide adequate incentives for both existing participants and potential new entrants into the market. At the same time, these must be balanced against limit the ability of service providers extort monopoly rents from the market.

The comments from those currently participating in the ancillary services tender process cast doubt on the appropriateness of the current compensation mechanisms, from both the perspective of appropriate incentives and appropriate cost outcomes. However, at this point the Commission is prepared to authorise the arrangements set out in Schedule 9G, so that the market experience gained in the months prior to the finalisation of the NEMMCO review will inform the NEMMCO review and any such anomalies in incentives can be addressed in that forum.

The Commission understands the NEMMCO review will also consider and develop procurement and compensation mechanisms for those ancillary services that cannot be competitively sourced. It considers that the design of any regulated acquisition arrangements will have to be assessed against the impact those arrangements have upon the incentives to service providers and on the overall cost of ancillary services.

The timeframes for considering contracts put forward by NEMMCO must take into account their complexity and the urgency involved in procuring ancillary services. The provisions of Schedule 9G state that, within three days of receiving a regulated acquisition request from NEMMCO, a Code participant must inform NEMMCO if it cannot comply with the request or if it believes it already has a contract with NEMMCO for the provision of such services as set out in the request. NEMMCO and the participant then have two days to resolve those issues.

Where the participant can comply and no previous contract exists, NEMMCO and the participant have 10 days to negotiate (in good faith) the terms of the regulated acquisition contract before the matter is referred to the disputes process. Again, the Commission notes EME's view that the time allowed to negotiate contracts is insufficient but is prepared to authorise the transitional arrangements, noting that the NEMMCO review should address this issue and may bring forward alternative arrangements prior to 1 July 1999. If that does not occur, the Commission understands that the negotiated acquisition process will not continue under the provisions of clause 3.11 of the Code.

Fees

Estimates of the expected level of ancillary service fees range from $100m to $400m[7]. This represents at least a two and a half fold increase over the level of fees currently being paid by customers in the NEM1 markets.

The Commission has concerns regarding the imposition of fees for the provision of ancillary services. As stated above, ancillary services are essential to the management of power system security, facilitate orderly trading and ensure electricity is of an acceptable quality. These features benefit all market participants, including buyers and sellers. It therefore appears to be inherently inequitable that only buyers are expected to pay for the provision of such services.

Further, the Commission considers that the best signals will be sent to the market if the fee recovery model allocates costs to those who caused the need for ancillary services or, if that is not feasible, then charges for those services should be based on the benefit received, perhaps determined by reference to energy transactions in the market.

The applicants argue that such decisions over the allocation of fees are contentious and will take time for market participants to reach an agreed position, if such a position is achievable. Further, the applicants state that such conflicts are best resolved through the NEMMCO review process. The Commission is prepared to authorise the proposed transitional arrangements until July 1999, pending the outcomes of the NEMMCO review of ancillary services.

A remaining issue is the levying of fees through the settlements process, which market customers claim will increase their difficulties in managing payments because of the expected variability of ancillary service fees. They suggest an annual fee (ex post) would be more manageable. Again, the Commission is prepared to authorise the change at this time, and let the matter be resolved by market participants through the NEMMCO review process.

Review

The Commission notes the issues raised by Eastern Energy and the NRF in respect of incremental changes to the Code and the impact of such changes on ancillary services. In particular, the Commission notes the changes to the technical provisions of the Code and the impact these will have on the mandatory provision of ancillary services. Those changes must be assessed in conjunction with both the technical derogations from the Code and the reviews of ancillary services and technical provisions.

The Commission has previously stated that the technical derogations applying to incumbent generators could represent a barrier to entry to new generation, or load, being able to compete in both the energy and ancillary services markets in the medium to long term. For that reason the Commission supports the review of technical standards, while recognising that it will impact upon other issues such as ancillary services.

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7 Provided in the submissions made by NEMMCO and Integral Energy.

The Commission understands that the NEMMCO review of ancillary services will consider the issue of mandatory services, and considers the review an appropriate forum from which changes to existing and previous arrangements can be analysed.

The Commission accepts that the NEMMCO review process will offer an opportunity for market participants to resolve outstanding issues, possibly with the benefit of experience offered by the commencement of the NEM and implementation of the proposed arrangements. The timing of the review means that any changes to the current arrangements should be implemented by 1 July 1999 and the current arrangements will only be in place for the transitional period of around eight months. The Commission therefore considers it appropriate that the proposed arrangements be allowed to stand at this time to enable NEMMCO to conduct the review as specified in the derogation.

4.2 Queensland derogations

The Commission granted interim authorisation to the initial Queensland market arrangements on 17 September 1997. The term of the interim authorisation runs from 1 October 1997 until the commencement of the NEM or 31 December 1998, whichever occurs first.

The applicants, on behalf of Queensland, submitted a range of derogations under chapter 9 of the Code to operate when the present interim arrangements (and the interim authorisation) cease and the Queensland market becomes subject to the Code.

A number of issues have arisen from the Commission's analysis of the proposed derogations. The first concerns the length of some of the derogations — those which run beyond a reasonable transition period will need to be amended. Other issues arising from the Commission's analysis concern:

- the independence of the Ministerial bodies which decide such issues as regions, ancillary services, loss factors and sensitive loads;
- the methodology to be used by the Queensland Competition Authority (QCA) in determining network pricing;
- the use of customer charges to subsidise transmission pricing arrangements in specific generator agreements; and
- technical and metering derogations.

4.2.1 The independence of Ministerial bodies

The applicants propose that the relevant Queensland Minister appoint bodies which will be responsible for determining regional boundaries, ancillary service contracts, management of sensitive loads, transmission intra-regional loss factors and distribution loss factors during the transitional period.

Issues for the Commission

To the extent that the national arrangements in the Code provide efficient signals, the appointment of separate bodies to determine these matters may lessen competition in that it may result in price distortions between final consumers, impacting on market efficiency and pricing signals.

The proposed derogations could also have the effect of advantaging Code participants in Queensland over participants in other jurisdictions, affecting inter-state trade and competition.

What the interested parties say

EME notes that, under the proposed derogation in relation to regions, the appointed body will be required to give a higher priority to minimising the number and changes to the boundaries of regions. At present there is only one region in Queensland and EME claims that having too few regions will unfairly discriminate against potential new generation and network augmentation by muting efficient locational signals.

EME believes that new investment in generation in Queensland is likely to be substantial, particularly once it is connected to the rest of the national market, and that economic efficiency requires new entrants to be subject to appropriate locational signals.

QERU states that these Ministerial bodies are necessary to produce an efficient market and an orderly and smooth transition from government control to industry-wide NEM arrangements. It adds that these Ministerial bodies are not influenced by any government or departmental views.

Issues arising from the draft determination

In its draft determination, the Commission imposed the following conditions of authorisation:

C4.1 Clause 9.35.4 must be amended:

- **(a) to specify that the derogation ends on 31 December 2002 or the date of interconnection between New South Wales and Queensland, whichever is the earlier; and**
- **(b) so that the reference in paragraph (c) to the criteria set out in clause 3.5.1(b)(2) refers to those criteria as amended following the review by NECA required under clause 3.5.1(e).**

C4.2 Clauses 9.36.5, 9.35.11 and 9.35.12 must be amended to specify that the derogation ends on 31 December 2002 or the date of interconnection between New South Wales and Queensland, whichever is the earlier.

C4.3 Clause 9.35.7 must be amended to specify that those derogations which are not specified to end on 1 July 1999 end on 31 December 2002 or the date of interconnection between New South Wales and Queensland, whichever is the earlier.

At the pre-determination conference, QERU rejected the view that the current situation of there being only one region in Queensland was distorting investment decisions. NEMMCO stated that the region frequently has internal constraints and that it would be appropriate to review the definition of that region.

In its submission, CS Energy argues that the situation of having only one region in Queensland has created significant market distortions and inefficiencies. It calls for an immediate review of the number of regions.

At the pre-determination conference, discussion also focused on the end date attached to clause 9.36.5 which concerns the management of sensitive loads. QERU states that it is essential that this derogation be allowed to remain without imposing an end date. QERU notes that it is a long standing policy of the jurisdictions to set load shedding priorities, and argued there was a benefit in continuing the policy in terms of knowledge of the impact of load shedding. EME states that the derogation, being long term, would be more appropriately dealt with under Chapter 8 of the Code.

In subsequent submissions, QERU and Comalco similarly argue that it is not appropriate for the Commission to place a time limit on this derogation. QERU notes that further Code changes have been proposed which establish Jurisdictional Co-ordinators, nominated by the relevant Ministers, who will be responsible for the specification of sensitive loads and load shedding priorities in each jurisdiction participating in the NEM. These Code changes have recently been submitted to the Commission for authorisation.

Commission considerations

The Commission considers that bodies appointed by the Minister may face a conflict between their responsibilities under the Code and the interests of the Queensland government. The risk is that decisions will be made which do not take proper advantage of the efficiency benefits of the NEM arrangements or address the concerns of participants.

The Commission considers that the derogation will only be acceptable if the appointed bodies are independent from the policy development processes of government, operate under clearly defined guidelines and make their decisions in a transparent, impartial and accountable way. In order to be able to do so they will need to be adequately resourced, have access to relevant information and be able to administer effective sanctions for non-compliance with Code requirements or regulatory directions.

The following sections detail specific areas of concern in relation to the use of appointed bodies.

Regions

The derogation provides that Queensland will comprise a single region at the time of market commencement and that, prior to connection with the national market, an appointed body will determine the number and boundaries of regions into which the Queensland market is to be divided. The appointed body will be subject to the principles for determining such matters contained in clause 3.5.1(b)(2) of the Code. Beyond interconnection, NEMMCO has an obligation to consider alterations to regional boundaries in accordance with those principles.

The Commission is concerned that the appointed body will have too wide a discretion in determining the number and boundaries of regions. This may foster uncertainty which will discourage entry into the market. The Commission also accepts EME's concerns regarding the detriment to the public benefit of the loss of efficient locational signals if the appointed body decides to maintain Queensland as a single region.

It was a condition of the Commission's 10 December 1997 determination that NECA review the adequacy and appropriateness of the principles for determining regions within two years of market commencement. The Commission is prepared to authorise the derogation on the conditions that the appointed body take into account any alterations to the principles of determination as a consequence of the NECA review and that, if interconnection has not taken place by 31 December 2002, the derogation must cease.

The Commission notes the arguments of CS Energy that an immediate review of the number of regions is warranted. Clause 9.35.4(b) provides that a review of the number and configuration of regions must take place before interconnection. However, in the light of CS Energy's comments, the Commission encourages Queensland to consider whether it would be appropriate for this review of regions to take place in the near future. Application of the principles for determining regions during the review should be consistent and kept beyond political influence.

Losses

The derogations provide for the appointment of a government body to calculate intra-regional transmission and distribution loss factors (clauses 9.35.11 and 9.35.12). Accurate loss calculations provide efficient locational price signals to ensure the most economic outcome in terms of the location of generation and load on the grid. It is also important to ensuring that the right balance is achieved between investment in generation, demand side measures and the transmission network.

If the body calculating losses is subject to government influence there may be pressure for it to calculate loss factors which comply with government policy in a non-transparent way and the benefits of reform of the electricity supply industry may be limited as a result.

The Commission is prepared to authorise the proposed derogation on condition that, if interconnection has not taken place by 31 December 2002, the derogation must cease. It also recommends that an independent regulator be appointed to calculate loss factors.

Sensitive loads

The Commission has concerns over the derogation which allows the Minister to nominate a person other than a System Operator as the person whose approval is required to interrupt supply to or prevent reconnection of a sensitive load in Queensland (clause 9.36.5). It is possible that this clause could be used by a government body to prevent the interruption of supply in Queensland in an arbitrary manner.

The concerns of the Commission are heightened by the fact that this derogation does not have an end date and will therefore affect the operation of the Code outside Queensland in the period after interconnection. In the draft determination, the Commission imposed a condition that the derogation be amended to limit its effect to the Queensland market in the period before interconnection.

The Commission notes the submissions of QERU, Comalco and CS Energy that there are strong benefits in having a permanent solution to the question of load shedding priorities. However, the Commission is not willing to grant a permanent derogation under Chapter 9 of the Code. The Commission is therefore satisfied that the draft condition should stand.

A separate set of Code changes have recently been submitted to the Commission for authorisation which establish Minister-nominated Jurisdictional Co-ordinators who will be responsible for the specification of sensitive loads and load shedding priorities. It is possible that, depending on the view reached by the Commission, those proposed Code changes may offer a long term solution to Queensland's the sensitive load management issue. However, if this is not the case or if the Commission refuses to authorise them, it may be appropriate for the Commission to consider authorising a derogation extending beyond 31 December 2002.

Ancillary services contracts

Clause 9.35.7 derogates from the ancillary services arrangements in clause 3.11 and Schedule 9G of the Code. It allows for ancillary services in Queensland to be provided by Code participants pursuant to contracts to be entered into between those participants and a body nominated by the Minister. Certain parts of the derogations cease on 1 July 1999 and the remainder on the date of interconnection.

It is important for the integrity of the market that the nominated body make decisions in a transparent and accountable manner at arm's length from other government decision making processes.

The Commission, however, accepts that the derogations and the related transitional periods are reasonable. It therefore proposes to authorise the derogation on the condition that those parts of the derogations specified to end on the date of interconnection shall cease if interconnection has not taken place by 31 December 2002.

Conditions of authorisation

C4.1 Clause 9.35.4 must be amended:

- **(a) to specify that the derogation ends on 31 December 2002 or the date of interconnection between New South Wales and Queensland, whichever is the earlier; and**
- **(b) so that the reference in paragraph (c) to the criteria set out in clause 3.5.1(b)(2) refers to those criteria as amended following the review by NECA required under clause 3.5.1(e).**

C4.2 Clauses 9.36.5, 9.35.11 and 9.35.12 must be amended to specify that the derogation ends on 31 December 2002 or the date of interconnection between New South Wales and Queensland, whichever is the earlier.

C4.3 Clause 9.35.7 must be amended to specify that those derogations which are not specified to end on 1 July 1999 end on 31 December 2002 or the date of interconnection between New South Wales and Queensland, whichever is the earlier.

4.2.2 Exempted generation agreements

A derogation has been included in the Code to accommodate the existing contractual arrangements between the Queensland government and the generators listed in Schedule 9E1 of the Code. Clause 9.34.6 outlines how these exempted generation agreements (EGAs) will be handled through the Code.

Issue for the Commission

Meeting the provisions of existing agreements through the Code's rules could have the effect of distorting the market and reducing the public benefits of competition and may be exclusionary or exclusive dealing provisions in contravention of the TPA.

What the interested parties say

The Business Council of Australia Energy Working Group (BCA/EWG) notes that all existing generators not owned by the previous Austa organisation and still contracted to the Queensland Transmission Supply Company (QTSC) are proposed to be fully exempted from the Code provisions.

The BCA/EWG argues that the plants contracted to the QTSC, if freed from their contractual obligations to the State and available to contract direct with contestable customers, would introduce 'much needed competition in generation in Queensland'.

Issues arising from the draft determination

In its draft determination, the Commission imposed the following conditions of authorisation:

C4.4 The derogation must be amended by:

(a) removing the ability of EGAs to be amended; and

(b) including in Schedule 9E1 the end dates of the contracts listed in that Schedule.

Discussion at the pre-determination conference reflected concerns that an inability to amend the EGAs could prevent the NEM from commencing in Queensland. QERU noted that the derogation does not exempt the EGAs from their obligations under the Code. QERU proposed that the Commission should consider a condition that clearly sets out the original intention of the derogation, that is that any amendment should not confer any additional competitive advantage to the parties to the contracts. Comalco supported QERU's position.

Subsequent submissions from QERU, Comalco, NRG Asia-Pacific, NRG Gladstone, NRGenerating Holdings, Energy Developments have similarly focused on the need for the EGAs to be amended. These parties argue that EGAs need to be amended to retain their relevance and workability. QERU also argues that it is sufficient that the identity of the parties to and the start dates of the EGAs are included in the Code and that the end dates should remain confidential.

Comalco argues that its Independent Power Purchase Agreement (IPPA) must be capable of amendment to allow for changes in circumstance, such as Code changes, for the agreement to continue for the duration of its term. It claims that the requirement which prevented the amendment of the IPPA could render the agreement unworkable if the parties' obligations became inconsistent with the Code.

NRG Gladstone states that since the environment of the electricity industry continues to change, freezing the structure of the customer relationships currently authorised in the IPPA would present a potential impediment to the development of a competitive industry.

Comalco, however, recognises the Commission's concern that, without appropriate limitations, the parties could amend the IPPA to create a competitive advantage. Comalco argues that the derogation could allow IPPA amendments, but not so as to have the effect of substantially increasing the parties' competitive advantage over other market participants.

Commission considerations

While of the view that some of the pre-existing contracts extend beyond a reasonable transition period, the Commission accepts that they will need to be adhered to.

The Commission notes the concern raised at the pre-determination conference and in subsequent submissions over the condition of authorisation outlined in the draft determination removing the ability of EGAs to be amended. The Commission acknowledges that it is likely that the EGAs will need to be amended in the future if they are to remain workable but will impose a condition along the lines suggested by QERU that any amendment must not confer any additional competitive advantage to the parties to the EGAs over other participants in the market.

Condition of authorisation

C4.4 Clause 9.34.6 must be amended to provide that:

(a) no amendment, other than an amendment to correct a typographical error, may be made to an EGA unless the parties to the EGA submit to the ACCC:

(i) the proposed amendment, a copy of the EGA and such supporting information as those parties consider necessary;

(ii) a request that the ACCC notify those parties whether the ACCC considers that the proposed amendment would or may:

(A) substantially and materially change the circumstances of:

- **any authorisation granted by the ACCC;**
- **any condition of authorisation granted by the ACCC; and/or**
- **any undertaking given to the ACCC relating to the Code;**

(B) constitute a minor variation of any authorisation granted by the ACCC; and/or

(C) contravene a provision of the *Trade Practices Act 1974*; and

(iii) if requested to do so, such further information as may be required by the ACCC in order to consider the matters referred to in sub-paragraph (a)(ii) above;

(b) upon receipt of the material referred to in paragraph (a) above, the ACCC has ten business days to respond to the request made in accordance with

sub-paragraph (a)(ii), unless the ACCC and the parties who made the request otherwise agree to vary that period;

(c) if, within the ten business days or such other period as varied in accordance with paragraph (b), the ACCC responds that it considers that the proposed amendment would or may have any or all of the effects referred to in sub-paragraph (a)(ii), then the proposed amendment may not be made; and

(d) if, after the ten business days or such other period as varied in accordance with paragraph (b), the ACCC has not provided a response to the request, the ACCC shall be deemed to have no objection to the proposed amendment.

4.2.3 Transmission network pricing

Regulation of transmission network pricing in Queensland will be undertaken by the QCA according to the methodologies applicable in that State immediately prior to market commencement (clause 9.38.1). The derogation expires on 31 December 2001.

Issues for the Commission

It is an issue whether the extension of the period Queensland is allowed to regulate its transmission pricing from 1 July 1999 to the end of 2001 enhances the public benefit of the market arrangements.

A further issue is whether the applicants' failure to include Queensland's proposed regulation methodology in the Code reduces the transparency of the regulator's operations and, therefore, the public benefit of the market arrangements.

What the interested parties say

The BCA/EWG opposes the extension of the period of State regulation from that specified in the existing Code because of the effect that this will have on the arrangements relating to the treatment of the Queensland-New South Wales Interconnector (QNI) as a regulated interconnector. BCA/EWG argues that authorisation of QNI as a regulated interconnector is effectively conditional upon the Commission taking over regulation on 1 July 1999.

Issues arising from the draft determination

The Commission imposed the following condition of authorisation in the draft determination:

C4.5 Clause 9.38 must be amended to require that:

(a) the proposed methodology for regulating the Queensland transmission network during the period of the derogation must:

(i) be included in the Code; and

(ii) adopt chapter 6 of the Code as the basis for that methodology; and

(b) QCA make details of that methodology available to the public prior to market commencement.

QERU argues that it is unnecessary to include such detail in the Code and that it is more appropriate that regulatory documents are simply incorporated into the Code by reference. QERU provided the Commission with a confidential draft of the proposed network pricing methodology. It claims that the document reflects the network pricing arrangements in the Code and that the methodology, once final, will become public when gazetted under Queensland law.

Commission considerations

The requirements governing network pricing are a central part of any access arrangement. While noting that it may have been preferable for transparency reasons to have included the proposed methodology in the derogation itself, the Commission is satisfied that the document be incorporated into the Code by reference and has amended its draft condition of authorisation accordingly.

The Commission notes BCA/EWG's concerns but accepts that the proposed transitional period lasting until 31 December 2001 is not excessive. On this basis a re-examination of the QNI derogation is not warranted.

Condition of authorisation

C4.5 Clause 9.38 must be amended to require that:

(a) the proposed methodology for regulating the Queensland transmission network during the period of the derogation must:

(i) be specified in the Code, through inclusion or by reference to a document defining that methodology; and

(ii) adopt chapter 6 of the Code as the basis for that methodology; and

(b) the methodology be made available to the public prior to market commencement.

4.2.4 Transmission pricing subsidies

Clause 9.38.5 provides that the amount of any difference between the transmission charges applicable under an EGA and those under the transmission pricing methodologies contained in the Code is to be recovered from Queensland transmission customers.

Issue for the Commission

The issue is whether there is any change in the public benefit of the market arrangements by moving the incidence of costs from the relevant parties to an EGA onto all transmission customers.

Issues arising from the draft determination

In the draft determination, the Commission expressed significant concerns over the derogation. At that stage, the applicants had not submitted any information regarding the need for the subsidy proposal and how the difference was proposed to be recovered from transmission customers, matters which may have significant effects on the public benefit. Accordingly, the Commission imposed the following condition of authorisation:

C4.6 Paragraphs (b) and (c) of clause 9.38.5 must be deleted from the proposed derogation.

In response to the Commission's concerns, QERU explains that the derogation merely reflects existing arrangements in Queensland's interim market necessary owing to the operation of the EGAs and that the levy is imposed on all transmission customers.

In justifying the derogation, QERU claims that the derogation will increase the transparency of the arrangements and that the Queensland electricity industry and Queensland customers will be in the same position they were in prior to the advent of the NEM.

Comalco argues that it is inappropriate to label the arrangements as transmission pricing subsidies.

Commission considerations

After receiving QERU's information, the Commission is willing to allow the derogation to stand. While the arrangement is not ideal, the Commission notes that the derogation merely reflects the arrangements already in place. The parties to the EGA, the Queensland electricity industry and Queensland customers are therefore in the same position they were in prior to the advent of the market — no customer will be worse off relative to where they were before the NEM commences.

4.2.5 Technical derogations

The applicants propose a number of derogations from the technical standards set out in the Code.

Issue for the Commission

The exemption of older generators (typically coal fired plant) from the Code's technical standards may create a competitive advantage for incumbent generators over new entrants.

What the interested parties say

The BCA/EWG argues that non-standard fault clearance times could be used to discriminate against new generation entrants and impose unacceptable technical constraints and operating limitations. The BCA/EWG requests that the proviso of 'as long as these times do not have material effect on power system stability and security' and similar provisions be extended to explicitly protect against the use of technical shortcomings inhibiting new participants from entering the industry.

South West Power argues that, to comply with clause 9.37.12, it and other rural network providers will have to incur large development costs that will impact severely on the corporations involved and their customers.

The consultant's view

The Commission's technical consultant, Colin Taylor, highlighted a number of proposed clauses where standards would need to be reviewed when Queensland connects with the other States. These clauses are outlined in the table below.

Clause	Description
9.36.3	Satisfactory operating state
9.36.4	Contingency capacity reserves
9.37.9	Credible contingency events
9.37.13	Voltage harmonic or voltage notching distortion
9.37.14	Voltage unbalance
9.37.16	Fault clearance times
9.37.17	Automatic reclosure of overhead transmission lines
9.37.18	Quality of electricity generated
9.37.22	Harmonics and voltage notching

Colin Taylor argues that these clauses are acceptable while Queensland is an isolated system but that they will need to be reviewed as part of the interconnection agreement.

Issues arising from the draft determination

In its draft determination, the Commission imposed the following conditions of authorisation:

C4.7 Clauses 9.37.13, 9.37.14, 9.37.16- 9.37.18 and 9.37.22 must be amended to specify that they end on or before 31 December 2002 or the date of interconnection between New South Wales and Queensland, whichever is the earlier.

C4.8 Clause 9.37.21(e) must be amended to provide for performance based excitation control system assessment.

QERU argues that some plant in Queensland may never, for technical reasons, be able to meet the Code requirements. It argues that where there is no commercial justification, and where there is no technical capability to retrofit to meet the standards, issues will be brought forward under Chapter 8.4.

Commission considerations

The Commission's approach to the consideration of the Queensland technical derogations mirrors its approach to the consideration of other jurisdictional technical derogations. The Commission accepts that the need for the derogations arises because none of the incumbent generators can meet the existing Code requirements. The effect of the derogations is *generally* to reduce the technical standards to those currently in operation, which have *generally* provided high standards of safety and reliability.

The purpose of chapter 9 is to allow for derogations which enable participants to effect an orderly transition to the requirements of the Code. For derogations of a more permanent or non-transitory nature Code participants are able to apply for a derogation under clause 8.4 of the Code.

The Commission is concerned that entry barriers could be created by grandfathering existing facilities while requiring new facilities to meet Code requirements. Consequently, the Commission considers that these derogations should cease after a short transitional period, thereby allowing the facility owners (Code participants) to seek a derogation under chapter 8 of the Code.

To minimise the entry barriers such technical derogations may create, the Commission believes that the participants should be obliged to upgrade their facilities to bring them more into line with Code requirements, but only where such upgrades are commercially justifiable. Moreover, new entrants should not be required to compensate for existing equipment which does not meet Code requirements.

The Commission notes that some of the technical derogations do not appear to have a sunset clause, meaning in some instances that incumbents will be able to derogate from the Code indefinitely. The Commission is of the view that over the long term the anti-competitive effects of these derogations will outweigh any public benefits they may have. It is essential that they include a reasonable end date.

The Commission's purpose in imposing end dates on the technical derogations is not to unilaterally decree that all facilities must upgrade to the Code standards. In imposing the condition, the Commission notes that an alternative process for derogations exists and recommends that if the technical derogations currently set out in chapter 9 of the Code need to be extended (and QERU claims some will), then the processes outlined in clause 8.4 of the Code should be followed.

The Commission also notes that connection with the interconnected New South Wales, Victorian and South Australian system is likely to change system operating requirements in Queensland and some of the derogations relating to equipment and supply standards and system security may no longer be appropriate.

The Commission considers that these derogations must be amended so that they do not affect the operation of the Code outside Queensland in the period after interconnection.

Excitation control

The proposed clause 9.37.21(e) specifies that static excitation technology is to be used for new generation installations, unless otherwise agreed with the relevant network service provider (NSP). Although most installations will use this technology the Commission is of the view that this clause should be technology neutral. The Commission considers that it is more appropriate for a performance requirement to be used allowing generators to select a technology meeting the performance specification (in a similar manner to clause S5.2.6.5 in the Code).

Voltage fluctuations

As noted above, South West Power argues that clause 9.37.12 will impose enormous costs on rural NSPs. The Commission does not consider that it is in a position to amend technical derogations. However, it recommends that the applicants review the impact of the derogation on South West Power and the other distributors to which it has referred.

Conditions of authorisation

C4.6 Clauses 9.37.13, 9.37.14, 9.37.16- 9.37.18 and 9.37.22 must be amended to specify that they end on or before 31 December 2002 or the date of interconnection between New South Wales and Queensland, whichever is the earlier.

C4.7 Clause 9.37.21(e) must be amended to allow generators to select any technology to meet the performance specification.

4.2.6 Metering

Clause 9.39 outlines the transitional metering arrangements for Queensland.

Issue for the Commission

The issue is whether the benefits of an orderly transition of metering standards are outweighed by any detriment arising from the risks flowing from less accurate metering.

Issues arising from the draft determination

In its draft determination, the Commission imposed the following conditions of authorisation:

C4.9 Clause 9.39.4 must be amended to specify that the derogation ends on or before 31 December 2002.

C4.10 Clause 9.39.5 must be amended to specify that the derogation ends on or before 31 December 2002.

In its submission, QERU argues that the time limits of the metering derogations should be permitted to remain. It states that the true economic worth of upgrading the metering in Queensland can only be measured after a reasonable period of operation in the interconnected market. It also claims that these conditions impose a requirement on Queensland more severe than allowed under Schedule 9F1.

Commission considerations

The Commission acknowledges that the metering derogations may be required to allow for an orderly transition to the metering arrangements in the NEM. If the metering provisions outlined in chapter 7 of the Code were enforced from market commencement, some existing Queensland metering installations would be in breach of the Code's requirements and the immediate costs to the market could be considerable. It would also be costly to make all metering installations comply with the Code at market commencement. Accordingly, the Commission accepts that there is a need for some metering derogations during a transitional period.

Clause 9.39.4 derogates from the Code metering standards for a number of market customers and generating units. The Commission is of the view that there is financial risk involved in allowing tolerances on meter accuracy to exceed those in the Code. While the Commission recognises the need for some transitional metering arrangements, this derogation extends to 31 December 2005. The Commission is of the view that this exceeds the time necessary to upgrade the meters to the required standard and therefore requires the derogation to be amended as a condition of authorisation.

Clause 9.39.5 grants the Gladstone Power Station and Boyne Island Smelter exemptions from the Code's metering standards should they meet the metering standards set out in the IPPA held with the Queensland Electricity Commission. This derogation covers two of the largest market participants in Queensland and errors in their meters could result in significant financial risk being passed to other market participants. Accordingly, the Commission is of the view that after an appropriate transitional period the meters should be required to comply with the Code.

QERU argues that there is evidence to suggest that the whole metering installation might comply with the Code's requirements, despite certain elements being of a lesser standard and that this should be sufficient in the circumstances. Irrespective of this, the derogation as proposed would have effect for the duration of the IPPA and the Commission is of the view is that it is more appropriate that the derogation should be sought under Chapter 8 of the Code.

Conditions of authorisation

C4.8 Clause 9.39.4 must be amended to specify that the derogation ends on or before 31 December 2002.

C4.9 Clause 9.39.5 must be amended to specify that the derogation ends on or before 31 December 2002.

4.3 Inter-regional settlements surplus distribution derogations

4.3.1 New South Wales settlements surplus derogation

This derogation permits the settlement surplus accruing to New South Wales from trade on inter-connection assets between Victoria and New South Wales to be distributed first to SHT[8] and then to TransGrid to enable reductions in network charges as proposed in the Code. The amount to be distributed to SHT will be sufficient to make up differential losses arising from inter-regional price differences on eligible SHT contracts not exceeding 1850MW total capacity. The total capacity of eligible contracts will be reduced to 1700MW from 30 November 1999.

The applicants propose that the derogation cease either upon a declaration by the relevant Minister that effective inter-regional hedging arrangements based on the settlements surplus are available or 31 December 2002, whichever is the earlier.

Issue for the Commission

The expected benefit accruing to end use customers from reductions in network service fees due to the settlements surplus will be reduced by allocation of some of the settlements surplus away from the transmission NSP. Further, this derogation may impact upon the viability of

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8 Snowy Hydro Trading Pty Limited (SHT) is an independent agency of the entitlement holders of the electricity output from the Snowy Mountains Hydro Electric Scheme. The entitlement holders are the States of Victoria and New South Wales, represented by the SECV and Pacific Power respectively. It is proposed that the Commonwealth Government will also become a shareholder in SHT in the near future.

inter-regional trade, thus reducing the overall public benefits arising from implementation of the NEM.

What the applicants say

The applicants state that the derogation is required because of the definition of regional boundaries adopted by NECA and the lack of an inter-regional hedge (IRH) facility based on the settlements surplus.

The applicants state that under the current definition of regional boundaries the SMHEA generation assets are isolated in a geographic area that does not include any load. This means that SHT will not be able to enter into financial contracts for supply of electricity with other parties in the Snowy region. Any financial contracts entered into by SHT will have to be with counter parties in other regions, and hence SHT will be exposed to the financial risks that arise from trading across regional boundaries.

The applicants state that revenue from financial contracts is essential for all generating businesses in the NEM, including SHT. Financial contracts offer participants a tool for managing exposure to the spot price by establishing price certainty in respect of the contracted capacity. However, SHT will not be able to enter into such contracts unless a viable tool for managing the inter-regional price risk is available. The applicants claim the proposed timetable for implementation of an IRH market means that the NEM will commence without such a scheme in place.

The applicants note that SHT could use its position to manage the inter-regional price risk by pricing at the expected maximum price of the adjoining New South Wales and Victorian regions. They note such behaviour is contrary to the intention of the NEM and could lead to substantially higher prices across the whole NEM. The applicants also contend that the proposed derogation renders such behaviour unnecessary. Further, the applicants claim such a strategy would often be ineffectual as an inter-regional price differential due to constraints may mean SHT is constrained on and, under clause 3.9.2 of the Code, is unable to set the price in the Snowy region. Such a strategy does not offset the risks completely as SHT does not have perfect knowledge of price outcomes in the adjoining regions.

The applicants also note that the existence of vesting contracts means that the SHT is exposed to inter-regional price differentials from the commencement of the NEM. The derogation sought is similar to the arrangements currently in place in the NEM1 markets and will provide SHT with a means of financially underwriting its trading risks associated with inter-regional financial contracts, including the vesting contracts.

The applicants note that the proposed capacity for which the surplus can be used to hedge contracts is set at a level which will not restrict the flows of electricity from the Victorian region through the Snowy region into the New South Wales region.

What the interested parties say

Concern was expressed regarding the impact that this arrangement will have on the viability of the proposed IRH market to be developed by NEMMCO. In particular EME notes that this derogation effectively limits the amount of inter-regional settlements surplus available to NEMMCO to auction and that this in itself may reduce the viability of the auction process.

EME also raises concerns about the proposed end date and the element of Ministerial discretion allowed by the derogation. Specifically, the conditions under which an effective IRH market would be deemed to exist are not spelled out, rendering the end date subjective.

The Australian Cogeneration Association (ACA) states that if SHT wants IRH instruments developed it should be prepared to pay the very high prices required in the first instance and in that manner attract more providers into the market.

SHT states that it has sought hedging contracts with which to manage its inter-regional price risks but in general the product was not available in the quantities or form required by SHT. SHT says that it could effectively only purchase price caps in the Victorian market rather than actual inter-regional hedges and notes that NEMMCO's IRH working group also believes that effective IRH's are currently not available in the market. Similarly SHT states it has not been able to purchase inter-regional swaps in the volumes required.

SHT also contends that the derogation should not impact upon the NEMMCO IRH market and should cease once that market is operational, depending on the definition of effective IRH market determined by New South Wales and Victoria.

SHT strongly supports the arguments put forward by both New South Wales and Victoria in respect of how this derogation will allow SHT to participate in the market, on an equal footing with other generators, to the benefit of consumers (through lower than otherwise spot prices).

Issues arising from the draft determination

The Commission included the following condition as part of its draft determination:

C4.11 The derogation must be amended to specify that it will end no later than one year after market commencement.

Submissions concerning this draft condition were raised in the context of the Victorian settlements surplus derogation discussed at Section 4.2.3 below.

Commission considerations

The Commission considers that interstate trade is one of the key elements that will contribute to the realisation of expected public benefits from the NEM proposals.

In the 10 December 1997 determination, the Commission indicated that it considered it appropriate for the settlements surplus to be used to underwrite an inter-regional hedging market, despite the misgivings held about the IRH proposal included in version 2.0 of the Code. In addition, the Commission is aware of the work undertaken by NEMMCO to develop an IRH market that has broad support from likely NEM participants. The current proposal being considered involves staggered auctions of rights to a proportion of the settlements residue by the holders of the hedging instruments. The Commission notes that the NEM is planned to commence prior to an IRH market being established and in such a circumstance considers that inter-regional trade in the NEM is likely to be extremely limited.

The proposed derogation impacts on the distribution of the settlements surplus such that, instead of flowing to customers, a portion of the surplus is set aside to underwrite the inter-regional trading of the SHT in New South Wales.

The applicant's claims indicate that the derogation is essential if SHT is to operate in the NEM. This is because the SHT will not accept the risk of exposure to inter-regional price differences without some form of hedging or insurance instrument available to them. SHT claims that currently it is unable to purchase insurance to cover them for the risk of high inter-regional price differences at **any** price and that IRH instruments are unavailable at a 'realistic' price. Therefore, without access to the settlements surplus to underwrite their trading position SHT claims it will not be able to trade in the New South Wales market. Further because of the vesting contracts it holds with some New South Wales based market participants, it will be exposed to inter-regional price differences from NEM commencement.

Concerns have been expressed about the likely impact on the proposed IRH market of the derogations being put forward by both New South Wales and Victoria. In particular, the structure of the derogations means that all of the inter-regional settlements surplus could be claimed by SHT in some circumstances, leaving NEMMCO to operate its IRH market without anything to auction.

Despite the assurances from SHT, the Commission also has concerns about the effectiveness of an IRH market if one of the key players has no need to participate in that market. The Commission considers that, while SHT has hedging arrangements for the bulk of its output, it is unlikely to be a dominant bidder in the IRH market. With the derogation in place, the potential revenue stream from the settlements surplus is diminished by an uncertain amount, and possibly eliminated in total, thereby reducing the funds that holders of IRH instruments are able to access. This element may also significantly undermine the viability of the proposed IRH market. However, the Commission acknowledges that this derogation will be important in facilitating inter-regional trade in the period prior to the commencement of the IRH market.

The crucial issue then becomes that of cessation of this derogation. The applicants have proposed that the derogation should end when the Minister declares an effective IRH market to exist. In the draft determination, the Commission considered that the uncertainty associated with this proposal was unsatisfactory and imposed a condition of authorisation that the derogation must be amended to specify that it will end no later than one year after market commencement.

However, after further discussions with concerned participants in light of the submissions made at the pre-determination conference in relation to aspects of the proposed Victorian settlements surplus derogation (see 4.3.2 below), the Commission considers that it is appropriate instead that the New South Wales derogation should end prior to the first trading period in which any proposed NEMMCO auction of the settlements surplus is referenced — that is, the settlements surplus that is the subject of an auction process will not be available to SHT except through participation in that auction process.

Condition of authorisation

C4.10 Clause 9.13.3 of the Code must be amended to specify that the derogation will at the earlier of:

(a) the first trading period out of which NEMMCO proposes to auction any settlements surplus that may accrue in that trading period; or

(b) one year after NEM commencement.

4.3.2 Victorian settlements surplus derogation

The applicants have, on behalf of the Victorian government, proposed a derogation to permit the settlement surplus accruing to Victoria from trade on inter-connection assets between the Snowy region and Victoria to be distributed in the following order of priority to:

1. the State Electricity Commission of Victoria (SECV) — to make up differential losses incurred by the SEC Trader under franchise vesting contracts, of up to 720MW of capacity;

2. SHT — to make up differential losses under contract arrangements between the nominated State body and SHT, of up to 180MW of capacity; and

3. the nominated State body to enable, directly or indirectly, a reduction in network service charges.

In the first instance NEMMCO must pay the settlements residue accruing to Victoria to a State body nominated by the Victorian government, which will distribute the funds according to the priorities listed above. The SECV is responsible for ensuring the State body complies with this derogation, although NEMMCO must validate both the SECV's and the State body's compliance with the derogation.

In respect of the SECV contracts, it is proposed that the derogation cease by a declaration by the relevant Minister that effective IRH arrangements are available to the SECV or at 31 December 2000, whichever is earlier. In the case of the SHT the derogation is to cease by a declaration by the relevant Minister that effective IRH arrangements are available to SHT or at the expiry of the hedging contract between SHT and the State body (31 December 2002), whichever is earlier.

Issue for the Commission

The expected benefit accruing to end use customers, from reductions in network service fees due to the settlements surplus, will be reduced by allocation of the settlements surplus away from the transmission NSP. Further, this derogation may impact upon the viability of inter-regional trade, thus reducing the overall public benefits arising from implementation of the NEM.

What the applicants say

SECV allocation

The applicants state that the SECV has responsibility for managing several vesting contracts that support franchise customer demand.[9] The contracts were established prior to the privatisation of the Victorian distribution/retail businesses. The contracts are between the

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9 The vesting contracts are in the form of two way financial contracts for differences. Under such contracts both the buyer (the Victorian distribution retail businesses) and the seller (SECV) of electricity agree to make good the difference between the spot price and the contract strike price. Thus if the contract price is \$40/MWh and the spot price is \$10/MWh the buyer will pay to NEMMCO \$10/MWh and to SECV \$40-\$10 = \$30/MWh. Alternatively if the spot price is \$100/MWh the seller (SECV) will pay to the buyer \$100-\$40 = \$60/MWh. Therefore the price the parties receive/pay is effectively fixed at \$40/MWh.

SECV as notional supplier of electricity and each of the distribution businesses and the smelter trader as purchasers of electricity.

The contracts were negotiated for the start of the Victorian market in 1994, at which time it was unclear as to the timing and form of the expected NEM arrangements. The applicants state that, at that time, the State of Victoria was a party to the Interconnection Operating Agreement, and had access to its share of the SHT entitlement. Both of these elements of imports to the Victorian Pool were used to manage SECV's obligations under the vesting contracts.

Since that time both the Interconnection Operating Agreement and the SHT entitlement arrangements have been disbanded to allow for the introduction of interstate trade under the transitional NEM1 market arrangements, paving the way for the implementation of the NEM. However, the SECV still has contractual obligations in respect of the vesting contracts, which it now manages through a contract for differences with SHT. As such it is exposed to risk from price differences between the Victorian region and the Snowy region.[10] The applicants state that some mechanism to manage the SECV's inter-regional trading risk is required.

Under the proposed derogation the State body will use a portion of the settlements surplus to provide a hedge to the SECV, exactly offsetting the financial exposure due to the vesting contracts. The maximum revenues that the SECV can receive from the State body is limited to the capacity of the vesting contracts (720MW) times the price differential between the Victorian and Snowy regions. This derogation will only take effect at times when the SHT is unable to export a full 720MW of electricity to Victoria and a price differential exists between Victoria and Snowy regions.

The applicants state that the SECV will only get access to a maximum of 720MW share of the settlements surplus, which represents the vesting contract arrangements in place until January 2001. This element of the derogation will expire at 31 December 2000 or when the Minister declares an effective IRH market to exist, whichever is the earlier.

SHT contracts

The applicants state that the derogation also allows SHT access to a proportion of the settlements surplus to facilitate inter-regional trading by SHT into the Victorian market, above the contractual arrangements which the SHT has with the SECV. These issues are addressed in detail in respect of the New South Wales settlements surplus derogation at section 4.3.1.

In the Victorian proposal SHT has access to the settlements surplus to offset its contracts up to 180MW, again under conditions of constraint when SHT can not export electricity to the Victorian region.

State body

The applicants state that the relevant Victorian NSP currently is VPX. However, VPX is in the process of being wound up and it is not clear to the Victorian government that VENCorp,

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[10] The applicants state that while theoretically the same problem could exist with respect to the South Australian region, the SECV does not hold contracts with South Australian generators and is not exposed to risks related to price differentials.

which will take over residual responsibilities of VPX, will be in a position to take on the transitional role envisioned under this derogation. Hence the derogation proposes that the relevant Minister will nominate a State body which will have the role of receiving and distributing the settlements surplus in accordance with the above priorities, but in a manner to be determined by the State body and the Regulator General.

What the interested parties say

Concerns of the interested parties are described in respect of the NSW settlements surplus derogation in section 4.3.1.

Issues arising from the draft determination

The Commission included the following conditions of authorisation in its draft determination:

C4.12 The derogation must be amended to specify that it will end no later than one year after NEM commencement.

C4.13 The derogation must be amended to include detail on the timing and process of the distribution of settlements surplus through the State body to end use consumers.

The Energy Projects Division (EPD) of the Victorian Department of Treasury and Finance states that the impact of the Commission's condition of authorisation would be an unknown risk to the Victorian government (SECV) that would have to be funded by a taxation levy, which the government is not prepared to accept. Further, EPD argues that:

- while an IRH market is important, the Victorian government considers full retail deregulation more important;
- the benefit is not the pass through of the surplus but price path certainty for franchise customers;
- the current IRH market proposal being put forward by NEMMCO does not allow for the hedging of the existing 24 month vesting contracts;
- an independent assessment of the NEMMCO proposal by Mercers must be made available as soon as possible;
- at least 40% of the surplus will be available to NEMMCO; and
- the derogation could be reviewed in the light of future market developments.

NEMMCO reported that the Mercer's report should be available in a week and that NEMMCO is well aware of transitional issues in the market. However, in the event of a constraint on the interconnector, (the very time that high regional price differences are most likely) under the proposed derogation less than 40% of the settlements surplus would remain.

EME argues against the derogation, whilst accepting that a transitional element is required until a form of IRH market exists. In particular, EME states that the benefits to the market as a whole from inter-regional trade are strongly accepted, and in the contract market to date there has been very limited inter-regional trade. EME cites the instance of 25 November 1997, where hot weather and maintenance on the interconnector combined to force prices very high in Victoria, and market participants with inter-regional contracts were exposed to severe price differentials.

EME also argues that the contracts to which SECV is a party should be able to be redrafted in the event of changes to the market rules, and that the figure of 720 MW should not be fixed but variable. EME strongly contends that an IRH auction process will not be effective if the Victorian derogation was allowed for 2 years.

Pacific Power supports the position of EME.

SAERSU supports the position of the EPD and notes that South Australia would be bringing forward a similar derogation extending out to 2002.

Commission considerations

The Commission considers that interstate trade is one of the key elements that will contribute to the realisation of expected public benefits from the NEM proposals.

The 10 December 1997 determination indicated that the Commission considered it appropriate for the settlements surplus to be used to underwrite an IRH market.

The proposed derogation impacts on the distribution of the settlements surplus such that, instead of flowing to customers, a portion of the surplus will be set aside to underwrite the inter-regional trading of the SECV and SHT in Victoria.

SECV allocation

The applicant’s claims indicate that the derogation is essential if the SECV is to operate in the NEM and acts to enable the SECV to honour its existing contracts without exposure to high risk from inter-regional price differences.

The Commission accepts that some arrangement to manage the risk is necessary but has concerns regarding the impact of the proposed arrangement upon the development of the proposed IRH market. This is discussed in section 4.2.1, in respect of the NSW settlements surplus derogation.

In the light of the discussion at the pre-determination conference the Commission held discussions with the EPD and NEMMCO. The Commission believes that the impact of the derogation on the proposed settlements surplus auction can be minimised if the derogation is recast to specify an maximum percentage of the settlements surplus that can be accessed by the SECV, while retaining the feature that the actual flow of settlements surplus to the SECV will exactly match the SECV’s exposure. The remaining funds, a minimum percentage of at least 40% of the settlements surplus would be available to NEMMCO for its proposed auction process.

This allows the SECV to manage its exposure at the same time as giving NEMMCO a certain proportion of the settlements surplus with which to conduct its auction process.

SHT allocation

The applicant’s claim that the derogation is essential if SHT is to operate in the NEM and be able to manage its exposure to risks from inter-regional trading; risks it faces from market commencement. This issue is discussed in the section 4.3.1, above.

State body

The Commission also has some concerns about the settlements surplus actually being returned to end use consumers in Victoria. The applicants claim that because of the structure of the Tariff Order the effect of passing settlements surplus funds to the transmission NSP will be that the distribution businesses are able to retain the received money, but will not have to pass it through to their customers. Thus the distribution businesses benefit, and not the end users as intended. For this reason the settlements surplus is to be held and distributed by a State body at a later date, when the Regulator General and State body can determine a methodology for pass through that will benefit end use customers. The Commission's concerns revolve around the delay that this process entails in getting the settlements revenues to the intended beneficiaries. However, the Commission accepts that the intent of this element of the derogation is valid and recommends that the Victorian proponents publicly provide more detail about the proposed methodology and timing of the distribution of the settlements surplus.

The Commission also notes that the proposed State body is not specified in the derogation and would prefer that it were named. However, the Commission considers the derogation is clear on the role of the State body, and accepts that the Victorian government is unable to specify its name at this time.

Conditions of authorisation

C4.11 Clause 9.5.3A must be amended to specify that in respect of any settlement surplus being made available to the Snowy Hydro Trader, the derogation will end at the earlier of:

(a) the first trading period out of which NEMMCO proposes to auction any settlements surplus that may accrue in that trading period; or

(b) one year after NEM comencement.

C4.12 Clause 9.5.3A must be amended to specify that a maximum of 60% of the settlements surplus accruing to Victoria may be allocated to the SECV to underwrite their exposure due to franchise vesting contracts.

4.4 Chapter 8 derogations

The applicants propose derogations under the provisions of chapter 8 of Code regarding:

- technical standards to apply to generators in New South Wales and South Australia;
- an agreement between NEMMCO and SHT regarding classification of the SHT output to notional generators; and
- the calculation of intra-regional loss factors by NEMMCO.

Under the provisions of chapter 8 of the Code, NECA may not grant these derogations unless authorisation is granted by the Commission.

4.4.1 Generator technical standards

Issue for the Commission

In its 10 December 1997 determination, the Commission noted that technical derogations sought by Victoria may confer some competitive advantage on the incumbent generators. The Commission considers that the technical derogations now sought by South Australia and New South Wales may similarly offer competitive advantage to incumbent generators, and thus detract from the overall level of public benefit likely to be derived from the implementation of the NEM arrangements.

The consultant's view

Colin Taylor supports the derogations specified by South Australia, noting that to the best of his knowledge they reflect the current operating capabilities of the plant.

In respect of the New South Wales derogations Colin Taylor notes that the minimum loading requirements specified are towards the lower end of the capabilities that might be expected from black coal burning plant and suggests some justification be sought.

Colin Taylor further comments on the whole of chapter 5 of the Code, supporting a review of the arrangements and noting the need for the incumbent generators to be able to derogate away from the Code requirements. He states in his view that the connection requirements for generators in chapter 5 of the Code are overly stringent and will force existing generators to meet those requirements at high cost and should only be undertaken where it can be shown to be economic.

What the applicants say

The applicants state that the proposed derogations have been subject to extensive consultations with market participants and are similar to the technical derogations included in the original Code in respect of Victorian generators. Further, the applicants state that the derogations are time limited to end at 31 December 2002 and, in the intervening time, NECA will undertake a review of chapter 5 of the Code with a view to assessing the need for technical standards at the level currently set and with a view to achieving a consistent market outcome.

In response to the consultant's comment the applicants note that the New South Wales interpretation and derogation regarding the loading rates is consistent with earlier derogations from Victoria.

What the interested parties say

SAERSU has informed the Commission that the derogations referring to the governor system maximum response within six seconds are no longer required as the relevant section of the Code (Schedule 5.2.6.4) has been amended.

Issues arising from the draft determination

No issues were raised in response to this aspect of the Commission's draft determination.

Commission considerations

The Commission accepts the need for some technical derogations to apply at market commencement to avoid unnecessary and costly equipment upgrades, but has concerns regarding the cost implications of the technical derogations, in particular upon new entrants. This issue is discussed in some detail in the Commission's 10 December 1997 determination. The Commission notes the intention of NECA to conduct a review of the technical standards set out in chapter 5 of the Code and considers that the issues of appropriate technical standards for both incumbent participants and new entrants to the NEM should be addressed in that forum. The Commission notes that the derogation will cease to apply in respect of both the South Australian and New South Wales generators at 31 December 2002.

Condition of authorisation

C4.13 The following derogations must be deleted:

(a) Torrens Island Power Station A units 1-4: not required to achieve more than 85 per cent of the maximum response within six seconds above 85 per cent MCR;

(b) Torrens Island Power Station B units 1-2: not required to achieve more than 85 per cent of the maximum response within six seconds above 85 per cent MCR; and

(c) Torrens Island Power Station B units 3-4: not required to achieve more than 85 per cent of the maximum response within six seconds above 85 per cent MCR.

4.4.2 Snowy Hydro Trading notional units derogation

This derogation allows SHT to bid its generation capacity as if from a single (notional) generating unit, rather than having to place separate bids for each generating unit.

Issue for the Commission

This derogation may offer SHT a competitive advantage in the NEM trading environment through greater flexibility to manage their output than other generator participants are allowed.

The consultant's view

Colin Taylor supports this derogation and notes that the ability to manage generating capability through notional units should be available to all generators.

What the applicants say

The applicants state that this derogation is necessary to allow the physical infrastructure to be put in place that will enable SHT to bid the individual units into the market. The present SMHEA control system is holistic and until the system is replaced SHT does not have the ability to bid individual units into the NEM. The applicants state that work on altering the control system will be completed by 31 March 2001 at the latest. The derogation is to cease upon agreement between NECA, NEMMCO and SHT or 31 March 2001, whichever occurs first.

What the interested parties say

SHT states it requires the notional units derogation as the physical control system infrastructure is arranged on a notional unit basis (i.e. with no direct mapping to physical generating units). Effective control of the SMHEA electricity production under the Code's regime of physically aggregated units at common connection points will require the existing control systems to be replaced and modified, and fully automated real time rebidding systems to be implemented. SHT has commenced work on altering the control system infrastructure but estimates that it will not be operational until January 2000.

Issues arising from the draft determination

No issues were raised in response to this aspect of the Commission's draft determination.

Commission considerations

The Commission accepts that SHT is unable to comply with the Code at market commencement unless this derogation is accepted. The Commission notes that the end date specified is possibly some 15 months beyond the implementation of the new systems, although the intention appears to be that the derogation will cease when the systems are implemented. The Commission requires the end date to be clarified.

Condition of authorisation

C4.14 The derogation in respect of SHT notional units must specify an end date which is the earlier of:

(a) 31 March 2001; or

(b) the time the required control system infrastructure becomes operational, as agreed in writing between NECA, NEMMCO and SHT.

4.4.3 Loss factor derogation

This derogation amends the Code to allow single yearly loss factors to apply for each connection rather than a range of loss factors which can vary according to time and operating conditions.

Issue for the Commission

The proposed derogation affecting intra-regional loss factors may be considered to contravene the TPA to the extent that the loss factors will impact on the price determined for electricity in each region and may be considered to have the effect of fixing, controlling or maintaining the price of electricity in a region; and

A second issue is the extent to which the averaging of loss factors may lead to cross-subsidies. This may represent a lessening of competition and reduction in the efficiency of market signals in the NEM.

The consultant's view

Colin Taylor queries the need for this derogation, stating that NEMMCO has based its rationale for the derogation upon a misunderstanding regarding the intent of the Code.

In respect of the proposal to delete from the Code the words 'for a defined period of time and associated operating conditions', Colin Taylor suggests redrafting the Code to allow yearly loss factors to be calculated.

In respect of the proposal to delete from the Code the 'excessive standard deviation' trigger for calculating subsets of loss factors (with acceptable standard deviations) which would then be used to determine a volume weighted loss factor, Colin Taylor recommends that further supporting argument be provided by NEMMCO. He further recommends that the requirement on NEMMCO to publish statistical information be retained.

Colin Taylor then notes that if his recommendations are adopted the proposed review of time varying loss factors is not required.

What the applicants say

The applicants note that the requirement for the intra-regional loss factors derogation stems from the inability of the market IT systems to accommodate time/operating conditions varying loss factors by market start. The proposed derogation has been discussed through the Code change forum and is supported by market participants and the Code change panel on the basis that NEMMCO conduct a review into the merits of time/operating conditions varying transmission and distribution loss factors within one year of market commencement.

The proposed derogation allows fixed intra-regional loss factors to apply for a year after market commencement while the review by NEMMCO is undertaken to determine the need for varying loss factors and modifying the software if the need is substantiated.

The applicants claim that the proposed derogation will alleviate difficulties that metering data agents will have in meeting Code requirements prior to market commencement. Further, they state the experience of the NEM1 markets is such that the current Code provisions will require expensive modifications to software that may not result in sufficient improvements to justify the cost.

The applicants note that there is some interest in using time varying loss factors in Queensland and on the part of some other customers, but do not support implementation prior to market commencement. Additionally, the use of time varying loss factors creates some risks for market participants in that they can not easily calculate their local price from the regional reference price if loss factors are not constant.

In response to Colin Taylor's comment regarding the interpretation of the wording of the Code the applicants note that interpretation is subjective and that, based on their own interpretation of the Code, the derogation is needed. They also state that the proposed derogation will not delete the current requirement upon NEMMCO to publish intraregional loss factors and standard deviations.

Issues arising from the draft determination

No issues were raised in response to this aspect of the Commission's draft determination.

Commission considerations

The Commission considers that where any ambiguity regarding the intent or interpretation of the Code exists, it is in the best interests of the Code participants to clarify that interpretation including through seeking a derogation from the Code. The Commission does not consider that this derogation will have a detrimental impact on competition in the NEM and proposes to authorise this derogation without amendment.

5. Determination

After consideration of the issues raised in sections 3 and 4 the Commission concludes that, subject to the conditions set out below, in all the circumstances, the proposed amendments to the Code:

- are likely to result in a benefit to the public which outweighs the potential detriment from any lessening of competition that would result if the proposed conduct or arrangements were made, or engage in; and

- are likely to result in such a benefit to the public that the proposed conduct or arrangements should be allowed to take place or be arrived at,

as the case may be.

The Commission therefore grants authorisation to applications A90652, A90653 and A90654 until 31 December 2010, the time set down by the Commission in the 10 December 1997 determination for authorisation of the existing Code.

The Commission's authorisation is granted subject to the following conditions:

C3.1 Clause 3.8.1(b) must be amended to take into account all ancillary services dispatched, irrespective of the manner in which they are acquired.

C3.2 Clause 3.8.1(f) must be amended to require NEMMCO to also assess, consult and report on the sufficiency of the dispatch algorithm in meeting the minimum requirements specified in clause 3.8.1(b) in the same way and time frame required with respect to the investigation referred to in the existing clause.

C3.3 Clause 8.2.1 must be amended to provide that:

(a) NECA's exercise of its enforcement function and any decision by NECA which is reviewable by the National Electricity Tribunal are exempted from the dispute process; and

(b) NECA's appointment of the Adviser is an exception to the Adviser's independence from NECA.

C3.4 Clause 8.2.2(c) must be amended to limit the facilitation role of the Adviser to Stage 2 disputes generally, and to Stage 1 disputes only at the invitation of the disputing parties.

C3.5 The Code must be amended such that:

(a) any generator, apart from a generator reasonably held by NEMMCO to have intentionally or recklessly induced the security situation leading to the direction, which is directed in accordance with clause 4.8.10(a) of the Code at any time after market commencement is adequately compensated; and

(b) no later than 1 July 1999, NEMMCO must:

(i) determine the methodology for assessing adequate generator compensation in accordance with Code consultation procedures;

(ii) compare and contrast the methodologies for compensating generators in respect of directions given under clauses 3.11.2(c), 4.5.2(b), 4.8.6(c) and Schedule 9G5.8(a) of the Code and publish the results in order to facilitate the consultation process; and

(iii) publish the rationale underlying its determination of the compensation methodology.

C3.6 The Code must be amended such that NEMMCO must:

(a) no later than two months after market start:

(i) provide market participants with a copy of the audit plan to be followed by the market auditor;

(ii) in accordance with the Code consultation procedures, determine the number and scope of additional tests of the metering and settlements systems and billing and information systems necessary to provide market participants with, in the context of a review audit level, a reasonable level of confidence in the operation of those systems; and

(iii) require the market auditor to perform those additional tests and include consideration of the test results in the opinion which it provides as part of its reports to NEMMCO; and

(b) no later than fifteen months after market start, conduct in accordance with the Code consultation procedures a review of the effectiveness of market audits conducted under clause 3.13.10 of the Code and publish that report.

C3.7 The Code must be amended to provide that any action (including a failure to take action) taken by NECA, NEMMCO or any Code body in the context of paragraph (a) of clause 1.13 which, had that action been taken after the Code commencement date, would have been a reviewable decision, is also a reviewable decision in the manner in which that term is defined in the Code.

C3.8 Clause 2.7 must be amended as follows:

Any person intending to act in any Code Participant category may register with NEMMCO as an Intending Participant if that person can satisfy NEMMCO that it would be entitled to be registered as a Code Participant.

C4.1 Clause 9.35.4 must be amended:

(a) to specify that the derogation ends on 31 December 2002 or the date of interconnection between New South Wales and Queensland, whichever is the earlier; and

(b) so that the reference in paragraph (c) to the criteria set out in clause 3.5.1(b)(2) refers to those criteria as amended following the review by NECA required under clause 3.5.1(e).

C4.2 Clauses 9.36.5, 9.35.11 and 9.35.12 must be amended to specify that the derogation ends on 31 December 2002 or the date of interconnection between New South Wales and Queensland, whichever is the earlier.

C4.3 Clause 9.35.7 must be amended to specify that those derogations which are not specified to end on 1 July 1999 end on 31 December 2002 or the date of interconnection between New South Wales and Queensland, whichever is the earlier.

C4.4 Clause 9.34.6 must be amended to provide that:

(a) no amendment, other than an amendment to correct a typographical error, may be made to an EGA unless the parties to the EGA submit to the ACCC:

(i) the proposed amendment, a copy of the EGA and such supporting information as those parties consider necessary;

(ii) a request that the ACCC notify those parties whether the ACCC considers that the proposed amendment would or may:

(A) substantially and materially change the circumstances of:

- **any authorisation granted by the ACCC;**
- **any condition of authorisation granted by the ACCC; and/or**
- **any undertaking given to the ACCC relating to the Code;**

(B) constitute a minor variation of any authorisation granted by the ACCC; and/or

(C) contravene a provision of the *Trade Practices Act 1974*; and

(iii) if requested to do so, such further information as may be required by the ACCC in order to consider the matters referred to in sub-paragraph (a)(ii) above;

(b) upon receipt of the material referred to in paragraph (a) above, the ACCC has ten business days to respond to the request made in accordance with sub-paragraph (a)(ii), unless the ACCC and the parties who made the request otherwise agree to vary that period;

(c) if, within the ten business days or such other period as varied in accordance with paragraph (b), the ACCC responds that it considers that the proposed amendment would or may have any or all of the effects referred to in sub-paragraph (a)(ii), then the proposed amendment may not be made; and

(d) if, after the ten business days or such other period as varied in accordance with paragraph (b), the ACCC has not provided a response to the request, the ACCC shall be deemed to have no objection to the proposed amendment.

C4.5 Clause 9.38 must be amended to require that:

(a) the proposed methodology for regulating the Queensland transmission network during the period of the derogation must:

(i) be specified in the Code, through inclusion or by reference to a document defining that methodology; and

(ii) adopt chapter 6 of the Code as the basis for that methodology; and

(b) the methodology be made available to the public prior to market commencement.

C4.6 Clauses 9.37.13, 9.37.14, 9.37.16- 9.37.18 and 9.37.22 must be amended to specify that they end on or before 31 December 2002 or the date of interconnection between New South Wales and Queensland, whichever is the earlier.

C4.7 Clause 9.37.21(e) must be amended to allow generators to select any technology to meet the performance specification.

C4.8 Clause 9.39.4 must be amended to specify that the derogation ends on or before 31 December 2002.

C4.9 Clause 9.39.5 must be amended to specify that the derogation ends on or before 31 December 2002.

C4.10 Clause 9.13.3 of the Code must be amended to specify that the derogation will end at the earlier of:

(a) the first trading period out of which NEMMCO proposes to auction any settlements surplus that may accrue in that trading period; or

(b) one year after NEM commencement.

C4.11 Clause 9.5.3A must be amended to specify that in respect of any settlement surplus being made available to the Snowy Hydro Trader, the derogation will end at the earlier of:

(a) the first trading period out of which NEMMCO proposes to auction any settlements surplus that may accrue in that trading period; or

(b) one year after NEM comencement.

C4.12 Clause 9.5.3A must be amended to specify that a maximum of 60% of the settlements surplus accruing to Victoria may be allocated to the SECV to underwrite their exposure due to franchise vesting contracts.

C4.13 The following derogations must be deleted:

(a) Torrens Island Power Station A units 1-4: not required to achieve more than 85 per cent of the maximum response within six seconds above 85 per cent MCR;

(b) Torrens Island Power Station B units 1-2: not required to achieve more than 85 per cent of the maximum response within six seconds above 85 per cent MCR; and

(c) Torrens Island Power Station B units 3-4: not required to achieve more than 85 per cent of the maximum response within six seconds above 85 per cent MCR.

C4.14 The derogation in respect of SHT notional units must specify an end date which is the earlier of:

(a) 31 March 2001; or

(b) the time the required control system infrastructure becomes operational, as agreed in writing between NECA, NEMMCO and SHT.

This determination is made on 19 October 1998. If no application for a review of the determination is made to the Australian Competition Tribunal, it will come into force on the day the Commission advises the applicants in writing that it is satisfied that conditions of authorisation C3.1 to C4.14, listed above, have been complied with.

If an application for a review is made to the Tribunal, the determination will come into force:

- if the application is not withdrawn — on the day on which the Tribunal makes a determination on the review; or
- if the application is withdrawn — on the latter of the day on which the application is withdrawn or the day on which the Commission advises the applicants in writing that it is satisfied that conditions of authorisation C3.1 to C4.14 have been complied with.

Appendix A. Submissions

Australian Cogeneration Association

Bardak Energy Services

Business Council of Australia (BCA) Energy Task Force

BCA Energy Working Group (identical submission also received from Normandy Mining)

Delta Electricity

Department of Premier and Cabinet, Tasmanian Government

Ecogen Energy

Edison Mission Energy Australia

energyAustralia

Ergon Energy

Hazelwood Power

Hydro Electric Corporation

London Economics

Loy Yang Power Management Ltd

National Retailers' Forum

NRG

Pacific Power

Queensland Electricity Reform Unit

Snowy Hydro Trading

South Australia Electricity Reform and Sales Unit

South West Power

Victorian distribution businesses

Yamasa Seafood

NEM1 Ancillary Services

AGL

Citipower

Eastern Energy

Edison Mission Energy Holdings Pty Ltd

Ergon Energy

Integral Energy

Appendix B. Submissions regarding the draft determination

Comalco Aluminium Ltd

CS Energy Ltd

C. Taylor & Associates Pty Ltd

Eastern Energy

Ecogen Energy

energyAustralia

Energy Developments Ltd

Energy Projects Division, Victorian Department of Treasury and Finance

Ergon Energy

Hazelwood Power

National Retailers' Forum

NEMMCO

NRG Asia-Pacific Ltd

NRGenerating Holdings (No. 1) B.V.

NRG Gladstone Operating Services Pty Ltd

Pacific Power

QERU

Queensland Minister for Mines and Energy

South Australian Electricity Reform and Sales Unit